BP PLC
Form 20-F
April 06, 2017
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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

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

For the fiscal year ended 31 December 2016

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)

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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 February 2018	New York Stock Exchange
Floating Rate Guaranteed Notes due May 2018	New York Stock Exchange
Floating Rate Guaranteed Notes due August 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
Floating Rate Guaranteed Notes due 2021	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**
1.676% 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**
2.112% 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**
3.216% 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**
3.224% Guaranteed Notes due 2024	**New York Stock Exchange**
3.506% Guaranteed Notes due 2025	**New York Stock Exchange**
3.119% Guaranteed Notes due 2026	**New York Stock Exchange**
3.017% Guaranteed Notes due 2027	**New York Stock Exchange**
3.588% Guaranteed Notes due 2027	**New York Stock Exchange**
3.723% Guaranteed Notes due 2028	**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	21,049,696,078
Cumulative First Preference Shares of £1 each	7,232,838
Cumulative Second Preference Shares of £1 each	5,473,414

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

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

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 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 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 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

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The energy we produce serves to power economic growth and lift people out of poverty. In the future, the way heat, light and mobility are delivered will change. We aim to anchor our business in these changing patterns of demand, rather than in the quest for supply. We have a real contribution to make to the world s ambition of a low carbon future.

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Strategic report

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« **Glossary**

Words with this symbol« are defined in the glossary on page 280.

Cautionary statement

This document should be read in conjunction with the cautionary statement on page 269.

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Chairman s letter

Dear fellow shareholder,

2016 was a year of change on many fronts. The global community witnessed further challenges raised by economic, political and social forces, and many nations experienced internal stresses and tensions, which remain present. In the energy world, our world, it has been a period of transition. From a 12-year low in oil prices, to digital technologies that are transforming how we work, and the drive to a lower carbon economy, our team has had to manage through a period of uncertainty, complexity and volatility.

Against this backdrop, we have shown great resilience and character: we returned to profit and maintained our dividend. We had a good year in a tough environment. We have set a new strategic direction for BP and we have a great team carrying it out.

The record since 2010

BP s performance in 2016 was based on the foundations rebuilt following the 2010 Deepwater Horizon accident an event that could have put the very existence of our company at risk.

Over the past six years, Bob Dudley and his team have steered the business through the recovery from the crisis of 2010 and then through the response to lower oil and gas prices.

During that period, safety has improved significantly. The portfolio has been strengthened. Operating cash flow has remained strong. The dividend has been restored and increased. Investment for growth has continued, while capital and costs have been controlled. The relationships on which we depend have been deepened. And all of this has been done while managing a charge of $63 billion for the 2010 accident, for which the major liabilities have now been clarified and for which we have a plan to manage the remaining payments and residual litigation. All of this sets a firm base for the future, which is bound to have its own challenges.

2016 performance and shareholder distributions

In 2016 the team has again focused on the careful stewardship of shareholders investments.

We continued making progress in safety performance, with serious incidents and injury rates falling. We delivered strong cash flow, disciplined capital spending and lower costs. We met our cost reduction target a year early. New major projects took shape. And we have continued to invest in opportunities for future growth, securing a set of innovative portfolio additions as well as divesting non-strategic assets.

This performance enabled us to maintain the dividend at 10 cents per ordinary share through 2016 and the board s policy remains to grow sustainable free cash flow and distributions to shareholders.

Looking ahead

We can now look forward and outward, and the board and executive team have set out BP s strategic priorities for the future.

Caption: Members of the board examine BP operations at Baku in Azerbaijan.

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Our refreshed strategy is designed to ensure BP is good for all seasons in an uncertain environment. It enables us to compete in a world of volatile oil and gas prices, changing customer preferences and of course, the transition to a lower carbon future.

As our *BP Energy Outlook 2035* predicts, the growth in consumption of oil will gradually slow and likely peak. This is a result of slowing demand growth, not limited supply, as was once thought. In a world of longer-term abundance, oil prices are likely to remain under pressure. Focus will shift to greater efficiency and low-cost production. Gas will grow as a cleaner alternative to coal. Advanced fuels and lubricants will help motorists reduce emissions. Renewable energy will grow rapidly to become commercial at scale.

As a global business, we plan to play our part in this energy transition. Our strategy provides BP with greater agility combining lower cost oil production, increasing gas supply, greater market-led downstream activities, and growing renewables and venturing businesses.

We are also proud to be playing a leading role among our peers through the Oil and Gas Climate Initiative, where Bob s chairmanship has seen an unprecedented convergence of national and international energy companies

In 2016 Nils Andersen joined us as a non-executive director, bringing considerable insight gained in the energy, shipping and consumer goods industries. He has led major companies, including as chief executive of A.P. Møller-Mærsk A/S and Carlsberg A/S.

Cynthia Carroll and Andrew Shilston are standing down as directors at the forthcoming AGM. On behalf of the board I thank them for the substantial contributions they have made to our work both in the board and its committees over the years in some difficult times.

The board is proposing that Melody Meyer is elected as a director at the AGM. Melody has had an extensive career in the global oil and gas industry with Chevron and will bring experience of safe and efficient operations and world class projects. We continue to work to increase the diversity of the board as this enhances independent thinking and healthy challenge.

Conclusion

$7.5bn

total dividends distributed to BP shareholders

6.0%

ordinary shareholders annual dividend yield«

6.4%

ADS shareholders annual dividend yield

to act on this issue.

Remuneration

At the 2016 AGM, we heard a clear message from shareholders on executive pay. During the past year we have sought to address these concerns, recognizing they reflect the concerns of society more broadly.

The decisions we have taken, and for which we seek shareholder approval, mark a significant break from past policy. The total pay for executive directors in 2016 is much reduced compared to 2015.

The policy we propose for 2017 and beyond is a simpler approach to executive remuneration and reduces the total amount executive directors can earn compared with the previous policy. Executive reward will be driven even more closely than before by the company s performance and shareholder returns. I particularly want to emphasize that the future remuneration of senior management will be directly linked to the delivery of our new strategic priorities, including BP s contribution to the longer-term transition in supplying lower carbon energy to drive the global economy.

This new approach aims to take account of shareholder concerns on the level of executive pay while recognizing the clear need for a global business like BP to attract and retain the best talent. With those two primary considerations in mind, my fellow board members and I believe the new policy to be appropriate, balanced and responsive to all those we serve as a business.

BP is a global business operating in over 70 countries. To do this effectively over the long term, we need the trust of our shareholders that we will deliver value, but also the trust of the societies where we work both at home and across the world.

I believe this report, along with our Sustainability Report, demonstrates BP s progress in working for all stakeholders, shareholders, customers, partners, governments, employees and communities.

Bob and his team have guided BP from a time of crisis in 2010 to a position where we have sound prospects for greater value creation and growth in the years ahead. Please join me in thanking Bob and his team for their exceptional stewardship of BP. Thank you to the board and to all our employees and thank you all for your continued support.

We are now beginning a new journey.

Carl-Henric Svanberg

Chairman

6 April 2017

Governance and the board

Today s world presents a range of risks operational, commercial, geopolitical, environmental and financial. On the board, we aim to maintain the breadth and depth of experience needed to fulfil our critical role of monitoring and managing those risks, working with the executive team.

Caption: Meeting employees in Brazil.

More information

Corporate governance

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« **See Glossary.**

Group chief executive s letter

Dear fellow shareholder,

In 2016 BP started to look forward again. It may have been one of the toughest years we have yet seen in the business environment, with oil prices the lowest since 2004. But it was a year when we turned the challenges into opportunities, finding new ways to compete and grow in a fast-changing industry. Over the last six years, we have been making BP safer, stronger and more resilient. And in 2016 we once again began building for growth and setting a course for a low cost, lower carbon future.

Our results

Our top priority is always safety and in 2016 we continued the progress made in recent years, with 80% fewer serious incidents and a 40% lower injury rate than in 2011. A good safety record is one sign of disciplined operations. Another sign is reliability and here too we have seen improvement, with upstream plant reliability of 95% up from 86% in 2011 and refining availability of 95.3%, maintaining our strong record in recent years.

The good progress that the team made was reflected in the financial results with a return to headline profit in 2016 compared with a significant headline loss in 2015, which reflected our provisioning for Gulf of Mexico settlements. Our underlying replacement cost profit represents resilient performance given the environment of low oil and gas prices and weak refining margins. Net cash provided by our operating activities was $10.7 billion after payments for the oil spill of $6.9 billion.

The work we have done to reduce capital spending and costs played a large part in these results. More than two years ago we recognized that energy prices could be lower for longer . Since then, we have been dedicated to changing the way we work, putting in place cost savings and efficiencies that can be sustained. As a result, our 2016 capital spend was significantly lower than peak levels in 2013. Not only did we meet our 2017 target for cash cost reduction we did so a year ahead of schedule.

Capital discipline is not only about reducing spending, but ensuring that the money we continue to invest is spent well. One example in 2016 was the sanction of the second phase of our Mad Dog operation in the US Gulf of Mexico at a budget of $9 billion less than half the original estimate. This helps make this project highly competitive even in a lower oil price environment.

I am pleased to report that the major liabilities from the Deepwater Horizon accident have been resolved with most of the outstanding governmental and commercial claims clarified. Cash payments were around $7 billion in 2016 which we expect to fall to $4.5-5.5 billion in 2017, $2 billion in 2018 and a little over $1 billion per year thereafter. Our disciplined financial

Caption: The *BP Energy Outlook* Launch

at our headquarters in London, UK.

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framework can accommodate these outflows and, with this resolution, our management team can focus with greater confidence on the future.

Our portfolio

We started the year with a goal to increase production from new projects by 800,000 barrels a day by 2020. During 2016 we remained on track for that goal, and we have increased our ambition to over a million barrels a day by 2021. Given the competitive environment, this goal goes hand in hand with a disciplined focus on costs.

In the Upstream, we launched six major project start-ups, from Algeria to the Gulf of Mexico, and made final investment decisions on a further five. We are maintaining that momentum in 2017 with more significant start-ups scheduled including the Quad 204 development in the UK, the giant Khazzan field in Oman and the West Nile Delta project in Egypt. These projects bring us significant reserves, flowing supplies and lower our per unit cost structure. They reposition our portfolio for the future.

Our future

This was also a year when we set out our strategic priorities for the longer term. They are rooted in society s need to use more energy bringing heat, light and mobility to millions of people while positioning BP for a lower carbon world. These priorities will help us drive progress and respond with agility to external changes whether in supply and demand, oil and gas prices, in environmental policy or in technology.

Competitive upstream portfolio: we will expand the gas portfolio alongside lower cost oil production, managing these cost-effectively.

Market-led Downstream: we will provide a range of fuels and lubricants that help make vehicles more efficient and grow our fuels marketing and lubricants businesses.

Low carbon and venturing: we will broaden our renewable energy and low carbon businesses through reinvestment in the current portfolio, build a dynamic venturing arm, and further our work in tackling climate change.

95.3%

2016 refining availability«

95%

Upstream BP-operated plant reliability«

The Downstream has continued to improve performance and grow with earnings up more than 25% compared with 2014, despite lower industry refining margins. We have enhanced our retail offer to customers rolling out our new fuels with *ACTIVE* technology in 13 countries and building great retail partnerships such as with M&S in the UK, REWE in Germany and, subject to regulatory approvals, Woolworths in Australia. Plus, our partnership with Fulcrum BioEnergy should help bring low carbon jet fuel to the market at scale.

We have announced a number of strategic additions to our portfolio. We broadened our positions in world-class gas fields: in the West African basin through an agreement with Kosmos Energy; in Egypt s Zohr field, thought to be the largest discovered in the Mediterranean; and in Oman s Khazzan development, a giant project that has now become even bigger. These underline our focus on gas, the fastest growing hydrocarbon fuel with the lowest carbon content.

We have also been innovative in terms of business models. In Abu Dhabi, we concluded an agreement to renew an onshore oil concession, stretching to 2050, in exchange for a 2% stake in BP. We have operated there for 75 years and this transaction underscores the value of long-term relationships. In Norway, we combined Det norske s nimble business practices, Aker s industrial experience and our global scale expertise to form Aker BP the country s largest independent oil company. This gives us access to substantive offshore oil and gas resources as well as dividends for shareholders.

Modernizing the whole group: we will be deploying advanced technologies such as robotics and big data analytics to improve and simplify our processes as well as using our trading expertise to maximize the value from our assets.

I am extremely proud of the global BP team. Without the women and men of BP, we would not have been able to preserve and transform the business over the past six years. I am grateful to our partners, host governments, and other stakeholders who have stood by us as we have stabilized BP and built up our resilience. And I say thank you, to you, our shareholders who have afforded us the time and support to take the actions needed to restore BP to a position of strength from which we can grow and prosper in the years ahead.

Since 2010, BP s story has been one of recovery, rebuilding and resilience. Now we are increasingly looking ahead with a spirit of purpose and invention. From 2017, you can expect a story of growth.

Bob Dudley

Group chief executive

6 April 2017

Putting all these initiatives together, we are creating a substantial core of long-term, cost-efficient major projects that can deliver material operating cash flow and earnings for decades to come.

Caption: Speaking with investors at the field trip in Baku, Azerbaijan.

More information

Business model

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« **See Glossary.**

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Main image: Sherbino wind farm in Pecos County, Texas.

Inset image: Service station in Chippenham, UK, selling our latest fuels with *ACTIVE* technology.

Lower oil price environment

Oil prices have been substantially lower since 2014, primarily due to oversupply. The market is gradually readjusting, as both demand and supply respond to lower prices. However, the high level of oil inventories suggests this adjustment is likely to take some time.

In line with our refreshed strategy, we test our investments against a range of oil and gas prices to check their profitability over the long term. We take into account current price levels and our long-term outlook.

Importantly, the break-even price of many of our investments is going down as BP and industry suppliers reduce costs to meet market conditions.

Energy consumption by region

(billion tonnes of oil equivalent)

Growing demand for energy

Affordable energy is essential for economic prosperity. Energy provides heat and light for homes, fuel for transportation and power for industry. And everyday objects from plastics to fabrics are derived from oil.

We expect world demand for energy to increase by around 30% between 2015 and 2035 largely driven by rising incomes in emerging economies. The extent of this increase is being curbed by gains in energy efficiency, as there is greater attention around the world on using energy more sustainably.

Energy mix is shifting

New technologies and consumer preferences for low carbon energy are leading to changes in the fuel mix, resulting in a gradual decarbonization. Renewables are the fastest-growing energy source. They are expected to increase at around 7% a year and account for 40% of the growth in power generation over the next two decades. Renewables currently contribute around 3% of total global energy demand, and we estimate that, as a result of rapid improvements in their competitiveness, they will contribute around 10% by 2035.

Over the same period, 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.

By 2035 we think oil will have around a 29% share, with annual growth slowing down over this period. Meanwhile we believe the share of gas will go up slightly to 25% of global energy, placing it ahead of coal and not far behind oil.

BP is gearing up to meet this shifting demand by increasing its gas and renewables activities.

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Advances in technology

Emerging technologies such as improved batteries, solar conversion, electricity storage and autonomous vehicles are accelerating the energy transition. For example, the base case scenario in our *Energy Outlook* suggests that the use of electric vehicles will grow almost one hundred-fold by 2035. That means that about 6% of the cars on the road would be electric, with a reduction in total oil demand of around one million barrels a day. However, a faster mobility revolution including car sharing, ride pooling, autonomous vehicles and electric cars could reduce oil demand by several times that amount.

Our *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.

We prioritize certain new technologies for in-depth analysis based on their fit with our strategy and how soon and likely we think they are to break through technological and commercial barriers. We also invest in start-up companies to understand and participate in these

Emerging greenhouse gas policy and regulation

Governments are putting in place taxes, carbon trading schemes and other measures to limit greenhouse gas (GHG) emissions. We expect around two-thirds of BP s direct emissions will be in countries subject to emissions and carbon policies by 2020.

To help anticipate greater regulatory requirements for GHG emissions, we factor a carbon cost into our own investment decisions and engineering designs for large new projects and those for which emissions costs would be a material part of the project. In industrialized countries, this is currently $40 per tonne of carbon dioxide equivalent, and we also stress test at a carbon price of $80 per tonne.

Our carbon cost, along with energy efficiency considerations, encourages projects to be set up in a way that will have lower GHG emissions.

More information

Challenging global energy markets

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

See *bp.com/energyoutlook*

See *bp.com/technologyoutlook*

See *bp.com/sustainability* for performance data, case studies and information on our approach to managing our sustainability impacts.

potentially transformational technologies.
See page 12.

Our strategy

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A changing energy mix

Energy consumption billion tonnes of oil equivalent[a]

Change in CO_2 emissions from 2015

[a] The sum of the fuel shares may not equal 100% due to rounding.

Energy outlook	Base case	Faster transition	Even faster transition
The three scenarios reflect different assumptions about the pace of the energy transition due to factors such as policy and consumer behaviour.	This scenario outlines our view of the most likely path for energy to 2035. The growing world economy will require more energy but consumption will increase less quickly than in the past.	This scenario sees carbon prices in leading economies rise to $100/tonne by 2035 and policy interventions encourage more rapid efficiency gains and fuel switching.	This scenario matches the path of the International Energy Agency s 450 scenario , which aims to limit the global temperature rise to 2ºC.

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How we run our business

From the deep sea to the desert, from rigs to retail, we deliver energy products and services to people around the world. We provide customers with fuel for transport, 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.

Enabling our business model

Safe and reliable operations

We strive to create and maintain a safe operating culture where safety is front and centre. This is not only safer for people and the environment it also improves the reliability of our assets.

See Safety on page 40.

Talented people

We work to attract, motivate, develop and retain the best talent the world offers our performance and ability to thrive globally depends on it.

See People on page 46.

Our diverse portfolio is balanced across businesses, resource types and geographies. Having upstream and downstream businesses, along with well-established trading capabilities, helps to mitigate the impact of lower oil and gas prices. Our geographic reach gives us access to growing markets and new resources, as well as diversifying exposure to geopolitical events.

Creating shareholder value

Our role in society

The energy we produce helps to support economic growth and improve quality of life for millions of people. We strive to be a world-class operator, a responsible corporate citizen and a good employer.

We believe that the societies and communities we work in should benefit from our presence. In supplying energy we contribute to economies around the world by employing local staff, helping to develop national and local suppliers, and through the taxes we pay to governments. Additionally, we aim to create meaningful and sustainable impacts in those communities through our social investments.

$11.2bn

employee wages and benefits

$2.2bn

taxes paid to governments

comprising income and

production taxes

$7.5bn

total dividends distributed to BP

shareholders

Finding oil and gas

New access allows us to renew our portfolio, discover additional resources and replenish our development options. We focus our exploration activities in the areas that are competitive in the portfolio. We develop and use technology to reduce costs and risks.

Developing and extracting

oil and gas

We create value by seeking to progress hydrocarbon resources and turn them into proved reserves, or sell them on if they do not fit with our strategic priorities. We

projects gives us choice about which we pursue see page 28.

We also seek to grow or extend the life of existing fields and are using new business models to increase value. Our US Lower 48 onshore business and Aker BP in Norway (see page 26) are two examples of how we ve used innovative new business models in response to the competitive environment.

Transporting and trading

We move oil and gas through pipelines and by ship, truck and rail. We also trade a variety of products including oil, natural gas, *bp.com/sustainability*

develop and produce the resources that meet our return threshold, which we then sell to the market or distribute to our downstream facilities. Our upstream pipeline of future

liquefied natural gas, power and currencies. Our traders complete around 550,000 transactions and serve more than 12,000 customers across some 140 countries in a year.

Technology, innovation and venturing

New technologies are enabling us to produce energy safely and more efficiently. We selectively research and invest in areas with the potential to add greatest value to our business now and in the future.

See Using technology on page 12.

Partnerships and collaboration

We aim to build enduring relationships with governments, customers, partners, suppliers and communities in the countries where we operate.

See Rosneft on page 35.

Governance and oversight

Our risk management systems and policy provide a consistent and clear framework for managing and reporting risks. The board regularly reviews how we identify, evaluate and manage risks.

See How we manage risk on page 47.

We use our market intelligence to analyse supply and demand for commodities across our global network. This helps us deliver what the market needs, when it needs it, identify the best markets for BP s crude oil, source optimal raw materials for our refineries and provide competitive supply for our marketing businesses.

Manufacturing and marketing fuels and products

We produce refined petroleum products at our refineries and supply distinctive fuel and convenience retail services to consumers. Our advantaged infrastructure, logistics network and key partnerships help us to have differentiated fuels businesses and deliver compelling customer offers.

Our lubricants business has premium brands and access to growth markets. It also leverages technology and customer relationships, all of which we believe gives us competitive advantage. We serve automotive, industrial, marine and energy markets across the world.

And in petrochemicals our proprietary technology solutions deliver leading cost positions compared to our competitors. In addition to our own petrochemicals plants, we work with partners and license our technology to third parties.

Generating renewable energy

We have the largest operated renewables business among our oil and gas peers. We operate a biofuels business in Brazil, using

one of the world s most sustainable and advantaged feedstocks to produce both low carbon ethanol and low carbon power.

We provide renewable power through our significant interests in onshore wind energy in the US. We develop and deploy technology in our wind business to drive efficiency and capacity.

More information

Upstream

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Downstream

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Alternative energy

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Using technology

Developments in technology will shape and influence the way we identify, extract, convert, store and ultimately consume energy in the future.

Our approach is not about trying to do everything, but to focus on the areas that have the greatest potential value to our business now and in the future.

We focus our activities on:

- managing safety and operational risk
- capturing business value
- competitively differentiating BP from others.

The right technology is central to the safety and reliability of our operations. This covers everything from assessment and management of technical risk to maximizing our businesses efficiency and performance. It helps us to grow value through innovation, acquisition of competitive new capabilities and application of best practice.

In Upstream, this technology investment also supports business strategy by focusing on increased recovery and gaining new access. And in Downstream we develop and apply technology that enhances operational integrity, boosts conversion efficiency or reduces CO_2 emissions in some of our operations and

When a facility is unexpectedly out of action, production revenues are lost and costs rise from unscheduled maintenance. But plant operations advisor, a new digital solution we are developing in collaboration with GE Oil & Gas, will help our engineers respond to issues in real time, reducing unplanned downtime and improving the reliability of operational facilities. The system identifies early warning signs of potential performance problems. It gathers machinery and plant data, analyses it and brings it all to a single screen so that engineers can troubleshoot quickly and resolve potential issues. We are now piloting the system at an offshore operating hub in the Gulf of Mexico.

provides high-performance products for our customers.

We have scientists and technologists at seven major technology centres in the US, UK and Germany. BP and its subsidiaries hold more than 3,800 granted patents and pending patent applications throughout the world. In 2016 we invested $400 million in research and development (2015 $418 million, 2014 $663 million). The reduction was largely due to halting major conversion technology programmes in Downstream and biofuels.

Around the world, BP engineers are now using the big data Argus platform to make critical decisions about wells, reservoirs and fields with state-of-the-art analytical tools that draw on historical and real-time data points. With these new capabilities, well-sensor data is being made available to engineers and operators within seconds for monitoring, analysis and value optimization.

BP is partnering with others to understand and develop solutions for the future including sustainable mobility, carbon management, power and storage, bio-products and digital energy.

Our long-term research is vital to BP s capacity to adapt and grow. For example, the BP Institute for Multiphase Flow at the University of Cambridge has examined a range of complex and challenging problems associated with the flow of matter for the past 15 years. Our research into rock and fluid interactions has led to significant developments in the use of low salinity water to improve oil recovery from our fields.

bp.com/technology

Seismic data helps us see into reservoir rock and detect where hydrocarbon potential may lie. Achieving high-quality images in difficult terrains is costly and needs many people in the field with existing technology. In partnership with Rosneft and Schlumberger s WesternGeco, we are developing innovative technologies to improve our surveys with faster, better-quality data, captured at a lower cost with less risk. Our project has the potential to expand the industry s ability to image the subsurface, especially in challenging land environments across the world and it also offers environmental and safety benefits when working in extreme climates and areas that are difficult to access.

People are increasingly choosing to live in cities, so roads have become much busier meaning repetitive stopping, waiting and starting again. In fact, independent global research shows that drivers spend up to a third of urban journeys idling and slowly, but permanently, this wears away critical engine parts. That s why we ve launched new engine oils containing our latest patented molecules, designed for the needs of

DUALOCK contains molecules that lock together to form a powerful layer of engine protection. We ve been helping to protect engines worldwide against warm-up wear for 20 years. Now our unique *DUALOCK* technology builds on that by reducing both warm-up and stop-start wear by up to 50%.

today s engines. *Castrol MAGNATEC* with

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Working smarter

We have been reshaping our portfolio for some years, with a focus on achieving operational excellence to grow margins.

We seek to get more from our existing assets and capture value from each dollar we spend. We encourage everyone at BP to find and implement smarter ways of working, without compromising safety. From small and simple ideas to large-scale deployment of tools like Argus, which has optimized monitoring and analysis for 99.5% of our wells (see page 12), our people are helping to make a positive difference to our operations.

In the Upstream we also launched a modernization and transformation programme to find ways to improve flexibility, embrace digitization and drive capital and operational performance. This includes a series of online events to allow employees to offer ideas on how we can simplify and improve many of our processes and ways of working.

A lot for less

Each year we buy an annual supply of caustic soda for use at Cherry Point refinery. To help achieve competitive pricing for this product we introduced a fair and transparent reverse auction where sellers compete to obtain our business. Compared with the standard purchase prices offered to us, the auction generated savings of more than $250,000 for this one commodity in a challenging supply market. We now aim to use reverse auctions more widely in markets where the level of competition lends itself to this approach.

Less data, more know-how

Before beginning seismic acquisition in the shallow water area around the Absheron Peninsula in the Azerbaijani Caspian Sea, a subsea hazard identification survey was needed. This process required a lot of data collection for analysis and processing causing a backlog that was costing time and money. We assessed this and discovered time was being wasted gathering and analysing data, regardless of height from the seabed, when we only needed to identify targets with heights greater than half a metre. By reassessing the survey s scope with the contractor and establishing a new process to only capture what was needed, we saved around $750,000.

Improving competitiveness

In the UK we have historically supplied fuels to our retail sites using our own in-house transportation fleet. After a strategic review to continue to improve competitiveness, we transferred all our UK secondary transport activities including scheduling, dispatching and delivery operations to Hoyer a leading large-scale logistics service provider. This change further strengthens our business by giving us access to a cost-effective and flexible service from a professional international haulier with a reliable safety track record.

Getting onboard savings

To access a rig in Trinidad, operators used complex scaffolding that took around 11 days to set up. By replacing this with a fixed-structure platform we decreased set up time by nine days and reduced risk of joint failure by removing scaffolding connections. This has made significant savings in rig costs and is already being reused to achieve further savings at other facilities in Trinidad.

Lightening the load

As part of our review of rental equipment at the PSVM development in Angola, we removed a number of items like tool boxes, gas racks and welding machines that were being held on the vessel but not used. This has already delivered equipment savings of $750,000 in 2016 and eliminated man hours required for maintaining and inspecting the equipment. We are now looking for similar opportunities to review excess equipment and inventories elsewhere.

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Our strategy

Fit for the future

Our industry is changing at a pace not seen in decades. All forms of energy fossil fuels and renewables are becoming more abundant and less costly. Through new technologies, energy will be produced more efficiently and in new ways, helping to meet the expected rise in demand. And the world is working towards a lower carbon future.

We are evolving our strategy allowing us to be competitive in a time when prices, policy, technology and customer preferences are changing.

Our strategic priorities help us to deliver heat, light and mobility solutions for a changing world.

How we do this

Shift to gas and advantaged oil in the upstream

Invest in new large-scale gas projects, pursue quality oil projects in core basins and seek out new opportunities in selected regions.

Around 75% of our planned start-ups by 2021 are in gas projects.

All of our planned oil start-ups out to 2021 are lower cost or around our existing basins.

Maximize recovery, manage decline and extend the life of our existing oil and gas fields.

Optimize our portfolio by making investments and divestments to deliver long-term value, with the potential to start increasing earnings or cash flow within a short time frame.

2016 activities

We renewed our interest in the Abu Dhabi ADCO onshore concession and signed a letter of intent for the future development of the Azeri-Chirag-Gunashli field boosting our lower-cost oil production for decades to come. We also made deals to expand our gas exposure in China, Egypt, Indonesia, Mauritania and Senegal, and Oman.

Read more in Upstream on page 24.

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Market-led growth in the downstream	Venturing and low carbon across multiple fronts	Modernizing the whole group
Build competitively advantaged businesses in manufacturing and expand our marketing businesses.	Pursue new ventures and partnerships to meet rapidly evolving technology, consumer and policy trends, and develop cross-business solutions to create new opportunities or strengthen our existing relationships.	Simplify and modernize so we can continue to compete and seize new opportunities with our partners and stakeholders in a changing world.
Strengthen the competitiveness of our refineries and petrochemicals plants.	Optimize and grow our renewables activities.	Simplify our organizational structures and processes.
Grow our fuels marketing and lubricants businesses in existing and new markets.	Partner with start-ups to broaden our options and use our ability to bring successful technologies to fruition on a large scale.	Introduce digital solutions to enhance our productivity and services for our customers.
Create new fuels, lubricants and petrochemicals offers to meet the evolving needs of our customers and partners.	Help customers offset their personal and business emissions through renewables generation or carbon trading.	Maximize value from our assets through our oil, gas, power and renewables trading activities.
Develop and prove new business models through partnerships with vehicle manufacturers and others.	Deepen our understanding of future energy, technology and climate change trends through collaboration with academic and research institutions.	Transform how it feels to work for BP motivating our people to perform at their best.
		Strive for ways to continue improving the safety and reliability of our operations.

We released BP fuels with *ACTIVE* technology, designed to fight engine dirt and protect against it building up. Now sold in 13 countries, this was our largest fuel launch in a decade. BP announced a strategic partnership with one of Australia s largest supermarket retailers Woolworths to acquire, rebrand and operate their fuel and convenience sites[a].

We established a presence in China s fast developing emissions trading market, striking the largest deal yet. And we are partnering with Fulcrum BioEnergy a company that produces lower carbon jet fuel from household waste to help them bring biojet to the market at scale.

We are using cloud-based platforms for rapid analysis and decision making with state-of-the-art visualization and predictive tools. We are introducing digital apps in our retail and aviation businesses that can improve customer service and convenience. Our new fleet of underwater robots are improving how we monitor the ocean environment and assess risks. And we have expanded our global business services organization, with plans to open our 10th BP centre in late 2017.

Read more in Downstream on page 30.

Read about our activities in Using technology on page 12 and Alternative energy on page 38.

Read more in Group performance on page 21.

[a] Subject to regulatory approval.

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The foundations for strong performance

Safe and reliable operations, a balanced portfolio and a focus on returns provide the platform for growth which is critical to the successful delivery of our strategy.

These build on our group business model: having the right people, partnerships, processes and technology in place to deliver value across all our activities.

Safe, reliable and efficient execution

Operational excellence is essential to our success. Good safety leads to reliable operation of our assets, greater efficiency and ultimately better financial results. Our operating management system« promotes continuous improvement and systematic ways of working. And, we are using technology to produce energy more safely and efficiently.

Operating reliability and availability

Distinctive portfolio with optionality

We benefit from having upstream, downstream and alternative energy businesses   challenges in one part of the group can create opportunities in another. Around the world, we are investing in upstream projects expected to deliver operating cash margins[a]« 35% better than 2015 levels. We are driving sustainable competitiveness in our downstream business, with a focus on customers, cost efficiency and margin capture.

Our well-established oil and gas trading function can generate value by providing the link between our businesses and third parties. And our equity interest in Rosneft gives us access to one of the largest and lowest-cost hydrocarbon resource bases in the world.

[a] Based on 2015 oil prices.

Disciplined growth

Personal and process safety performance

Marketing and customer focus

More than **50% of downstream** profits are from marketing activities.

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Focused on delivering competitive returns

In 2014 we set out our financial framework in response to the sharp decline in the oil price. The framework underpins our commitment to sustain the dividend for our shareholders. We have been meeting those expectations each year and even reaching our cash cost reduction target a year early. We also reduced our upstream and downstream headcount by a total of 6,000 in 2016 a reduction of 17% since 2014.

We have now updated and extended the framework out to 2021. We expect our strong balance sheet to be able to deal with any near-term volatility. Beyond that, we aim to increase operating cash flow from our planned upstream start-ups and growth in the downstream. With a constant capital frame we intend to grow sustainable free cash flow and distributions to shareholders in the long term.

Principle >	2016 achievement >	2017 guidance >	Looking ahead 2018 to 2021
Optimize capital expenditure	2016 organic capital expenditure was $16 billion* after excluding the consideration for the renewal of 10% of the Abu Dhabi ADCO onshore oil concession. This was well below our original guidance of $17-19 billion.	We expect organic capital expenditure of $15-17 billion.	We expect organic capital expenditure of $15-17 billion per year.
Make selective divestments	$3.2 billion[a] achieved in 2016.	We expect divestments of $4.5-5.5 billion.	$2-3 billion of divestments as a result of active portfolio management.

	This was within the expected guidance of $3-5 billion for the year.		
Payments related to the Gulf of Mexico oil spill	2016 payments totalled $6.9 billion, reflecting faster resolution of outstanding claims.	We expect $4.5-5.5 billion of cash payments.	Around $2 billion in 2018 and moving to annual payments of just over $1 billion from 2019 onwards.
Maintain flexibility around gearing	Gearing« at the end of 2016 was 26.8%**. This was within our target range of 20-30%.	Within the 20-30% band.	Within the 20-30% band.
Group ROACE«	ROACE was 2.8%*** in 2016.		We are aiming to exceed 10% by 2021 at real oil prices around $55/barrel.

[a] Includes $0.6 billion for the sale of 20% from our shareholding in Castrol India Limited.

Balancing our sources and uses of cash

We aim for our operating cash flow (excluding payments related to the Gulf of Mexico oil spill) to cover our dividend payments and organic capital expenditure«.

Nearest GAAP equivalent measures

* Additions to non-current assets: $21 billion.

** Ratio of gross debt to gross debt plus equity: 37.6%.

*** Numerator: Profit attributable to BP shareholders $115 million; Denominator: Average capital employed $153 billion.

For the year ended 31 December ($ billion)

« See Glossary.

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Measuring our 2016 progress

We assess our performance across a wide range of measures and indicators.

Our key performance indicators (KPIs) help the board and executive management assess performance against our strategic priorities and business plans. 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 used for executive remuneration. Overall annual bonuses and performance shares for 2016 are all based on performance against measures and targets linked directly to the strategy and KPIs.

Changes to KPIs

We have updated some of our KPIs this year to better align to our evolved strategy and future remuneration policy.

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«.

2016 performance Profit for the year reflected lower charges for the Gulf of Mexico oil spill than 2015. The reduction in underlying RC profit compared with 2015 was mainly due to lower oil and gas prices and the weaker refining environment, see pages 24 and 30.

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.

2016 performance Operating cash flow of $10.7 billion was lower, mainly due to higher Gulf of Mexico oil spill payments which amounted to $6.9 billion in 2016. Operating cash flow was also impacted by lower realizations, partly offset by lower costs and working capital effects.

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 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

We ve added return on average capital employed and upstream unit production costs as these will be important measures for assessing future performance and pay outcomes.

We re showing replacement cost profit at group level rather than on a per-share basis as this aligns with the measure used for executive remuneration.

We ve removed gearing, or net debt ratio, as a group KPI but will continue to report it in Group performance.

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.

2016 performance We started up two major projects in Algeria, two in the Gulf of Mexico, and one each in Alaska and Angola.

standard cubic feet of natural gas = 1 boe.

A minor adjustment has been made to 2015 and 2014, see page 25 for further information.

2016 performance BP s total reported production including Upstream and Rosneft segments was slightly higher than in 2015.

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

2016 performance The number of tier 1 process safety events has decreased since 2012. 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.

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.

2016 performance We saw an increase of LOPCs in 2016, partly due to harsher winter operating conditions in our unconventional gas operations in the US. Figures for 2014 to 2016 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 previous years reporting, our LOPC figure is 233 (2015 208, 2014 246).

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.

2016 performance Increased TSR reflects share price growth in 2016, as well as maintaining the dividend per share.

Return on average capital employed (ROACE) gives an indication of a company s capital efficiency, dividing the underlying RC profit after adding back net interest by average capital employed, excluding cash and goodwill. See page 285 for more information including the nearest GAAP equivalent data.

For the past few years, ROACE has been lower in the oil and gas sector, due to the impact of lower oil prices on earnings and the capital overhang of investments made during the preceding period of $100 per barrel oil prices.

2016 performance The 2016 reduction in ROACE is mainly due to weaker oil and gas prices and refining margins, partly offset by lower costs.

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.

2016 performance This year s reserves replacement ratio was higher than our five-year average primarily as a result of the Abu Dhabi onshore concession renewal. See page 244 for more information.

The upstream unit production cost indicator shows how supply chain, headcount and scope optimization impact cost efficiency.

Refining availability represents Solomon Associates operational availability. The measure shows the percentage of the year that a unit is available for processing after

Reported recordable injury frequency (RIF) measures the number of reported work-related employee and contractor incidents that result in a fatality or injury

2016 performance The lower unit production costs in 2016 reflect increased efficiency, reduced headcount, as well as deflation. This continues the cost reduction trend, down by over 35% since 2013.

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.

2016 performance Refining availability increased by 0.6% from 2015 to 95.3%, reflecting strong operational performance across our portfolio. This performance is underpinned by our global reliability improvement programme which provides our refineries with a more structured and systematic approach to improving availability.

per 200,000 hours worked.

2016 performance Our workforce RIF has improved steadily over five years and is also reflected in our other occupational safety metrics. While this is encouraging, continued vigilance is needed. For detail on employee and contractor safety against industry benchmarks, see page 40.

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

We provide data on greenhouse gas (GHG) emissions material to our business on a carbon dioxide-equivalent basis. This includes 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 for the relevant periods.

Minor adjustments have been made to the 2014 and 2015 figures. See page 43.

2016 performance The increase in our reported emissions is primarily due to operational variations such as returning to normal operations after planned shutdowns and start-up activities in

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 and how it is managed in terms of leadership and standards.

2016 performance Our group priorities engagement measure increased in 2016. Confidence in the future of BP also rose to 64% (2015 58%, 2014 63%).

[b] Relates to BP employees.

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

2016 performance The percentage of our group leaders who are women or non-UK/US rose. We remain committed to our aim that women will represent at least 25% of our group leaders by 2020.

Canada and Angola.

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The world economy remained weak in 2016, with global GDP growth at 2.3%. This was significantly lower than the average of nearly 3% over the past 20 years. Economic growth in the OECD slowed to 1.7%, (2.3% 2015) partly due to weak global trade and lower business investment in the US.

In contrast, the non-OECD economy grew by 3.4% (3.3% 2015). This follows six years of declining growth and is partly driven by relative stability in China and improvements in Russia and Brazil.

Oil

Crude oil prices ($/bbl quarterly average)

Prices

Dated Brent« crude oil prices averaged $43.73 per barrel in 2016 a further drop from the 2015 average of $52.39. But prices recovered over the year, rising from around $30 per barrel in January to nearly $54 in December.

Consumption

Natural gas

Natural gas prices ($/mmBtu quarterly average)

Prices

Gas prices were low in all key markets in 2016 as markets continued to adjust to the oversupply that built up during 2015, with increasing trade ensuring that the effect of ample supplies was felt globally.

Gas prices in the US averaged $2.46 per million British thermal units (mmBtu), slightly lower than 2015 ($2.67). The Japanese spot price fell to an average of $5.7/mmBtu in 2016 (2015 $7.4) with rising supplies in the region outpacing growth in demand, including new and emerging markets. The UK National Balancing Point« hub price was 34.63 pence per therm, 19% lower than in 2015 (42.61), as higher demand was easily met by rising pipeline imports, especially from Russia.

Broad differentials between regional gas prices also remained low, as US gas prices moved closer to Asian and European spot prices.

Global consumption increased by 1.6 million barrels per day (mmb/d) to 96.6mmb/d for the year (1.7%) mostly due to continued low oil prices.[a] Demand grew most rapidly in Asia s emerging economies, but OECD demand also increased for the second consecutive year.

Production

Strong consumption growth outpaced growth in global production. Non-OPEC production fell by 0.8mmb/d the largest drop since 1992 driven by the collapse of drilling in the US and a sharp decline in Chinese investment. However, OPEC production grew by 1.2mmb/d, reaching a record level of 39.3mmb/d, due to the recovery of Iranian production and large increases in Saudi Arabia and Iraq.

Inventories

Oil inventories remained high. And although data on global inventories is not available, OECD commercial inventories, as at 31 December, remained 290 million barrels above the five-year average, even though they had begun to reduce.

Consumption[b]

Global consumption grew significantly faster than in 2015. The pattern of growth across markets shifted, with strong demand growth in the OECD and China offsetting weakness in other markets. Gas consumption in the power sector continued to grow globally, gaining share from coal helped by the local production curbs in China. And with coal production curbs in China taking hold, the market tightened in 2016. In addition, higher weather-related demand towards the end of the year boosted the total annual demand.

Production[b]

Total production in 2016 was similar to 2015, with strong growth in Australia and Russia making up for declining production in Europe where existing fields are maturing and not being replaced.

Global LNG supply capacity expanded strongly in 2016, following a small increase in 2015.

[a] From IEA Oil Market Report, February 2017 ©, OECD/IEA 2017.

[b] Based on BP estimates from the BP Energy Outlook.

More information

Prices and margins

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$2.6bn
underlying replacement cost profit«

(2015 $5.9bn)

$7bn
cash cost« reduction versus 2014 the costs which we consider to be controllable

$115m
profit attributable to BP shareholders

(2015 $6.5bn loss)

$69m
reduction in total costs[a] versus 2014 reflects an increase in Gulf of Mexico oil spill charges of $5.9bn, and a reduction of $6.0bn in other costs, some of which are not considered controllable

Segment RC profit (loss) before interest and tax

($ billion)

Financial and operating performance

			$ million except per share amounts
	2016	2015	2014
Profit (loss) before interest and taxation	**(430)**	(7,918)	6,412
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,865)**	(1,653)	(1,462)
Taxation	**2,467**	3,171	(947)
Non-controlling interests	**(57)**	(82)	(223)
Profit (loss) for the year[b]	**115**	(6,482)	3,780

Inventory holding (gains) losses«, before tax	**(1,597)**	1,889	6,210
Taxation charge (credit) on inventory holding gains and losses	**483**	(569)	(1,917)
Replacement cost profit (loss)«	**(999)**	(5,162)	8,073
Net charge (credit) for non-operating items«, before tax	**5,661**	15,328	9,132
Taxation charge (credit) on non-operating items	**(2,833)**	(4,056)	(4,512)
Net (favourable) unfavourable impact of fair value accounting effects«, before tax	**1,085**	(261)	(898)
Taxation charge (credit) on fair value accounting effects	**(329)**	56	341
Underlying replacement cost profit	**2,585**	5,905	12,136
Dividends paid per share cents	**40.0**	40.0	39.0
pence	**29.418**	26.383	23.850
Additions to non-current assets[c]	**21,204**	20,080	26,492
Capital expenditure on an accruals basis«[d e]			
Organic capital expenditure«[f]	**18,440**	18,748	22,892
Inorganic capital expenditure«	**939**	710	601
	19,379	19,458	23,493

Main Image: A pipe rack on board the *Discoverer Luanda* drill ship, off the coast of Angola.

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Other businesses and corporate

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Oil and gas disclosures for the group

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[a] Production and manufacturing expenses and distribution and administration expenses from the income statement.

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

[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

[d] A reconciliation to GAAP information is provided on page 285.

[e] The definitions of capital expenditure on an accruals basis and inorganic capital expenditure have been revised to exclude asset exchanges as they are non-cash transactions. Previously reported amounts have been amended. Previously reported amounts for organic capital expenditure are unchanged.

[f] 2016 includes amounts relating to the renewal of a 10% interest in the Abu Dhabi onshore oil concession for which new ordinary shares in BP were issued.

« **See Glossary.**

The profit for the year ended 31 December 2016 was $115 million, compared with a loss of $6.5 billion in 2015. Excluding inventory holding gains, replacement cost (RC) loss was $1.0 billion, compared with a loss of $5.2 billion in 2015.

The net charge for non-operating items mainly relates to additional charges for the Gulf of Mexico oil spill which are partially offset by net impairment reversals. There were net unfavourable fair value accounting effects. After adjusting for non-operating items and fair value accounting effects, underlying RC profit for the year ended 31 December 2016 was $2.6 billion, a decrease of $3.3 billion compared with 2015. The reduction was predominantly due to lower results in both the Upstream and Downstream segments reflecting lower oil and gas prices and the weaker refining environment (see pages 24 and 30).

Non-operating items in 2016 also include a restructuring charge of $0.8 billion (2015 $1.1 billion), cumulative restructuring charges from the beginning of the fourth quarter 2014 totalled $2.3 billion by the end of 2016. Non-operating restructuring charges are expected to continue into 2017.

The loss for the year ended 31 December 2015 was $6.5 billion, compared with a profit of $3.8 billion in 2014. Excluding inventory holding losses, 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.

More information on non-operating items and fair value accounting effects can be found on page 285. See Other businesses and corporate on page 37 and Financial statements Note 2 for further information on the impact of the Gulf of Mexico oil spill on BP s financial results.

Taxation

The credit for corporate income taxes in 2016 and 2015 reflects the deferred tax impact of the increased provisions in respect of the Gulf of Mexico oil spill. The effective tax rate (ETR) on the loss for the year was 107% in 2016 and 33% in 2015; the ETR on the profit for the year in 2014 was 19%. The ETR in 2016 and 2015 was impacted by various one-off items.

Adjusting for inventory holding impacts, non-operating items, fair value accounting effects and the deferred tax adjustments as a result of the reductions in the UK North Sea supplementary charge in 2016 and 2015, the adjusted ETR« on RC profit was 23% in 2016 (2015 31%, 2014 36%). The adjusted ETR for 2016 is lower than 2015 predominantly due to changes in the geographical mix of profits as a result of the lower oil price and the absence of foreign exchange impacts from the strengthening of the US dollar in 2015. The adjusted ETR for 2015 was lower than

2014 mainly due to changes in the geographical mix of profits.

In the current environment, and reflecting the recent transaction to renew a 10% interest in the Abu Dhabi onshore oil concession, the adjusted ETR in 2017 is expected to be in the region of 40%.

Cash flow and net debt information

			$ million
	2016	2015	2014
Operating cash flow«	**10,691**	19,133	32,754
Net cash used in investing activities	**(14,753)**	(17,300)	(19,574)
Net cash provided by (used in) financing activities	**1,977**	(4,535)	(5,266)
Cash and cash equivalents at end of year	**23,484**	26,389	29,763
Gross debt	**58,300**	53,168	52,854
Net debt«	**35,513**	27,158	22,646
Gross debt to gross debt plus equity	**37.6%**	35.1%	31.9%
Net debt to net debt plus equity«	**26.8%**	21.6%	16.7%

Operating cash flow

Net cash provided by operating activities for the year ended 31 December 2016 was $8.4 billion lower than 2015. Of this amount, $6.0 billion was a result of higher pre-tax cash outflows associated with the Gulf of Mexico oil spill ($7.1 billion in 2016 compared with $1.1 billion in 2015). Cash flows were impacted by the continuing low oil price environment, with a lower average oil price in 2016 compared with 2015, working capital effects, and a reduction of $0.7 billion in income taxes paid.

Movements in inventories and other current and non-current assets and liabilities adversely impacted cash flow in the year by $3.2 billion. There was an adverse impact from the Gulf of Mexico oil spill of $4.8 billion. Other working capital effects, arising from a variety of different factors, had a favourable impact of $1.6 billion. The group actively manages its working capital balances to optimize cash flow, particularly in the current lower oil price environment. Inventories increased during the year because volumes were increased in our trading business to benefit from market opportunities, and due to higher prices towards the end of the year. The increase in inventory was largely offset by a corresponding increase in payables, limiting the increase in working capital.

There was a decrease in net cash provided by operating activities of $13.6 billion in 2015 compared with 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.

Net cash used in investing activities

Net cash used in investing activities for the year ended 31 December 2016 decreased by $2.5 billion compared with 2015.

The decrease mainly reflected a reduction in cash outflow in respect of capital expenditure, including investment in joint ventures« and associates«, of $2.8 billion. The decrease of $2.3 billion in 2015 compared with 2014 reflected a reduction in cash outflow in respect of capital expenditure of $3.9 billion, partly offset by a reduction of $0.7 billion in disposal proceeds. The reductions in cash capital expenditure in both years reflect the group s response to the lower oil price environment.

There were no significant cash flows in respect of acquisitions in 2016, 2015 and 2014.

The group has had significant levels of capital investment for many years. Cash flow in respect of capital investment, excluding acquisitions, was $17.5 billion in 2016 (2015 $20.2 billion and 2014 $23.1 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 organic capital expenditure on an accruals basis to be in the range of $15-17 billion in 2017.

Disposal proceeds for 2016, as per the cash flow statement, were $2.6 billion (2015 $2.8 billion, 2014 $3.5 billion), including amounts received for the sale of certain midstream assets in the Downstream fuels business and our Decatur petrochemicals complex. In addition, in 2016 we also received $0.6 billion in relation to the sale of 20% from our shareholding in Castrol India Limited, shown within financing activities in the cash flow statement, giving total proceeds of $3.2 billion for the year. In 2015 disposal proceeds 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. We expect disposal proceeds to be in the range of $4.5-5.5 billion in 2017.

Net cash used in financing activities

Net cash provided by financing activities for the year ended 31 December 2016 was $2.0 billion, compared with $4.5 billion used in 2015. This was mainly the result of higher net proceeds from financing of $3.6 billion ($4.0 billion higher net proceeds from long-term debt offset by a decrease of $0.4 billion in short-term debt). In addition, there was a cash inflow of $0.9 billion relating to increases in non-controlling interests, including the sale of 20% from our shareholding in Castrol India Limited noted above. The total dividend paid in cash in 2016 was $2.1 billion lower than in 2015 see below for further information.

The decrease in net cash used in financing activities of $0.7 billion in 2015 compared with 2014 reflected 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), and an increase in the total dividend paid in cash of $0.8 billion see below for further information.

Total dividends distributed to shareholders in 2016 were 40 cents per share, the same as 2015 on a US dollar basis and up 11.5% in sterling terms. This amounted to a total distribution to shareholders of $7.5 billion (2015 $7.3 billion, 2014 $7.2 billion), of which shareholders elected to receive $2.9 billion (2015 $0.6 billion, 2014 $1.3 billion) in shares under the scrip dividend programme. The total amount distributed in cash amounted to $4.6 billion during the year (2015 $6.7 billion, 2014 $5.9 billion).

Net debt

Gross debt at the end of 2016 increased by $5.1 billion from the end of 2015. The gross debt ratio at the end of 2016 increased by 2.5%. Net debt at the end of 2016 increased by $8.4 billion from the 2015 year-end position. The net debt ratio« at the end of 2016 increased by 5.2%.

We continue to target a net debt ratio in the range of 20-30%. 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.

The total cash and cash equivalents at the end of 2016 were $2.9 billion lower than 2015.

For information on financing the group s activities, see Financial statements Note 28 and Liquidity and capital resources on page 242.

Group reserves and production (including Rosneft segment)

	2016	2015	2014
Estimated net proved reserves[a] (net of royalties)			
Liquids« (mmb)	**10,333**	9,560	9,817
Natural gas (bcf)	**43,368**	44,197	44,695
Total hydrocarbons« (mmboe)	**17,810**	17,180	17,523
Of which: Equity-accounted entities[b]	**8,679**	7,928	7,828
Production[a] (net of royalties)			
Liquids (mb/d)[c]	**2,048**	2,007	1,917
Natural gas (mmcf/d)	**7,075**	7,146	7,100
Total hydrocarbons[c] (mboe/d)	**3,268**	3,239	3,141
Of which: Subsidiaries«[c]	**1,939**	1,969	1,889
Equity-accounted entities[d]	**1,329**	1,270	1,253

[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 35 and Supplementary information on oil and natural gas on page 187 for further information.

[c] A minor adjustment has been made to comparative periods, see page 25 for further information.

[d] Includes BP s share of Rosneft. See Rosneft on page 35 and Oil and gas disclosures for the group on page 251 for further information.

Total hydrocarbon proved reserves at 31 December 2016, on an oil-equivalent basis including equity-accounted entities, increased by 4% compared with 31 December 2015. The change includes a net increase from acquisitions and disposals of 520mmboe (decrease of 128mmboe within our subsidiaries, increase of 648mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in Abu Dhabi (increase of interest in ADCO concession from 9.5% to 10%) Indonesia, the US and the UK, and divestment activity in our subsidiaries occurred in Norway, Indonesia, Australia, Trinidad and the US. In our equity-accounted entities the most significant items were purchases in Russia, Norway and Venezuela.

Our total hydrocarbon production for the group was 0.9% higher compared with 2015. The increase comprised a 1.5% decrease (0.3% increase for liquids and 3.5% decrease for gas) for subsidiaries and a 4.7% increase (3.9% increase for liquids and 7.4% increase for gas) for equity-accounted entities.

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71,000km^2	6	11
new exploration access (2015 8,000km^2)	major project« start-ups (2015 3)	successful completion of turnarounds (2015 15)
5	95%	2.2
final investment decisions (2015 4)	upstream BP-operated plant reliability« (2015 95%)	million barrels of oil equivalent per day hydrocarbon production (2015 2.2mmboe/d)

Upstream profitability ($ billion)

Main image: *Deep Blue* and *Grand Canyon II* vessels support the Thunder Horse South expansion project in the US Gulf of Mexico.

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 2016 our activities took place in 28 countries.

Our strategy is to have a balanced portfolio across the world s key oil and gas basins, while maintaining a focus on capital discipline and quality execution to deliver value. Our incumbent positions and the relationships we hold with resource owners create both stability and opportunity.

Our strategy is enabled by:

More information

Upstream regional analysis

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

The US Lower 48 continues to operate as a separate, asset-focused, onshore business.

A relentless focus on safety, reliability and the systematic management of risk.

The quality execution of our projects, our operations, our drilling, and managing our reservoirs the greatest source of value and returns that we have.

Growing value through improving returns and cash flow. We actively manage our portfolio, divesting where it makes sense, and pursue acquisitions where value can be created.

The capability of our people, who are motivated and equipped to take on the world s great oil and gas challenges. We have a global workforce that is embracing digital technology to drive improved productivity in everything we do.

Our future growth includes an expected 800,000 barrels of oil equivalent per day of production from new projects by 2020, with 500,000 barrels of oil equivalent per day of this new capacity planned to be online by end of 2017. This, combined with our recent portfolio additions, is expected to increase our production by around 1 million barrels per day by 2021.

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We see our scale and long history in many of the great basins in the world as a differentiator for BP and believe in the strength of our incumbent positions. We are resilient and balanced in terms of geography, hydrocarbon type and geology and rather than being restricted by a traditional way of working, we have and will continue to use creative business models to generate value. We are also investing to modernize and transform the Upstream embracing innovation, digitization and the adoption of big data, which we believe can drive a real step change in performance and efficiency.

Financial performance

			$ million
	2016	2015	2014
Sales and other operating revenues[a]	**33,188**	43,235	65,424
RC profit (loss) before interest and tax	**574**	(937)	8,934
Net (favourable) unfavourable impact of non-operating items« and fair value accounting effects«	**(1,116)**	2,130	6,267
Underlying RC profit (loss) before interest and tax	**(542)**	1,193	15,201
Organic capital expenditure«	**16,048**[b]	16,307	18,994
Additions to non-current assets	**17,879**	17,635	22,587
BP average realizations[c]			$ per barrel
Crude oil[d e]	**39.99**	49.72	94.74
Natural gas liquids	**17.31**	20.75	36.15
Liquids«[d]	**38.27**	47.32	88.88
			$ per thousand cubic feet
Natural gas	**2.84**	3.80	5.70
US natural gas	**1.90**	2.10	3.80
			$ per barrel of oil equivalent
Total hydrocarbons«[d]	**28.24**	35.46	61.17
Average oil marker prices[f]			$ per barrel
Brent«	**43.73**	52.39	98.95
West Texas Intermediate	**43.34**	48.71	93.28
Average natural gas marker prices			$ per million British thermal units
Average Henry Hub« gas price[g]	**2.46**	2.67	4.43
			pence per therm
Average UK National Balancing Point gas price«[f]	**34.63**	42.61	50.01

[a] Includes sales to other segments.
[b] 2016 includes the consideration for the Abu Dhabi ADCO onshore oil concession renewal.
[c] Realizations are based on sales by consolidated subsidiaries only, which excludes equity-accounted entities.
[d] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq has been simplified to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There is no impact on the financial results.
[e] Includes condensate and bitumen.
[f] All traded days average.
[g] 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)

The dated Brent price in 2016 averaged $43.73 per barrel. Prices were lowest early in the year, averaging just $34 in the first quarter; rebounding to an average of about $46 in both the second and third quarters, and rising again in the fourth quarter to $49 as OPEC and non-OPEC members discussed and ultimately agreed co-ordinated production cuts.

The 2016 Henry Hub First of Month Index price was slightly lower than 2015 ($2.67).

The average UK National Balancing Point gas price in 2016 fell by 19% compared with 2015 (2015 a decrease of 15% on 2014). This reflected ample supplies in Europe with record Russian flows offsetting declining indigenous production. For more information on the global energy market in 2016, see page 20.

Financial results

Sales and other operating revenues for 2016 decreased compared with 2015, primarily reflecting lower liquids and gas realizations, and lower gas marketing and trading revenues. The decrease in 2015 compared with 2014 primarily reflected significantly lower liquids and gas realizations and lower gas marketing and trading revenues partly offset by higher production.

Replacement cost loss before interest and tax for the segment included a net non-operating gain of $1,753 million. This primarily relates to the reversal of impairment charges associated with a number of assets, following a reduction in the discount rate applied and changes to future price assumptions. See Financial statements Note 4 for further information. Fair value accounting effects had an unfavourable impact of $637 million relative to management s view of performance.

« **See Glossary.**

The 2015 result included a net non-operating charge of $2,235 million, 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. 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.

After adjusting for non-operating items and fair value accounting effects, the underlying RC result before interest and tax was a loss, compared with a profit in 2015. This lower result primarily reflected lower liquids and gas realizations, as well as adverse foreign exchange impacts and lower gas marketing and trading results. This was partly offset by lower costs including the benefits of simplification and efficiency activities, lower exploration write-offs, lower depreciation, depletion and amortization expense and lower rig cancellation charges.

Compared with 2014 the 2015 result reflected significantly lower liquids and gas realizations, as well as 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.

Additions to non-current assets were $17.9 billion and organic capital expenditure on an accruals basis was $16.0 billion. Excluding the Abu Dhabi onshore oil concession renewal for which shares were used as consideration, organic capital expenditure was $13.6 billion, significantly lower than the $16.3 billion in 2015.

In total, disposal transactions generated $0.8 billion in proceeds in 2016, with a corresponding reduction in net proved reserves of 241mmboe within our subsidiaries.

The major disposal transaction during 2016 was the transfer of our Norway assets to Aker BP. More information on disposals is provided in Upstream analysis by region on page 244 and Financial statements Note 4.

Outlook for 2017

We expect to start up seven new major projects in 2017.

We expect underlying production« to be higher than 2016. 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 expect oil prices will continue to be challenging in the near term (see page 20).

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.

Our exploration and new access teams work to enable us to optimize our resource base and provide us with a greater number of options. In the current environment, we are spending less on exploration and we will spend a material part of our exploration budget on lower-risk, shorter-cycle-time opportunities around our incumbent positions.

New access in 2016

We gained access to new acreage covering almost 71,000km^2 in 10 countries Australia, Canada, China, Egypt, Ireland, Mauritania, Norway, Russia, the UK and the US.

Exploration success

We participated in eight potentially commercial discoveries in 2016 Baltim SW-1, Baltim SW-2, Nooros East and Nooros West in Egypt, Gibson and Nozomi in the Gulf of Mexico, and Golfinho and Zalophus in Angola.

Exploration and appraisal costs

Excluding lease acquisitions, the costs for exploration and appraisal were $1,402 million (2015 $1,794 million, 2014 $2,911 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 20% of exploration and appraisal costs were directed towards appraisal activity. We participated in 40 gross (21.68 net) exploration and appraisal wells in seven countries.

Exploration expense

Total exploration expense of $1,721 million (2015 $2,353 million, 2014 $3,632 million) included the write-off of expenses related to unsuccessful drilling activities, lease expiration or uncertainties around development in the Gulf of Mexico ($611 million), Brazil ($601 million), and others ($167 million), partially offset by a net write-back of $103 million across several blocks in India (see Financial statements Note 7).

Reserves booking

Reserves bookings 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 2016, decreased by less than 1% (a decrease of 1% for subsidiaries and an increase of 9% for equity-accounted entities) compared with reserves at 31 December 2015.

Proved reserves replacement ratio«

The proved reserves replacement ratio for the segment in 2016, including the impact of the Abu Dhabi onshore oil concession renewal, was 96% for subsidiaries and equity-accounted entities (2015 33%), 101% for subsidiaries alone (2015 28%) and 61% for equity-accounted entities alone (2015 76%). For more information on proved reserves replacement for the group see page 251.

Upstream proved reserves[a] (mmboe)

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

	2016	2015	2014
Liquids			million barrels
Crude oil[b]			
Subsidiaries«	**3,778**	3,560	3,582
Equity-accounted entities[c]	**771**	694	702
	4,549	4,254	4,283
Natural gas liquids			
Subsidiaries	**373**	422	510
Equity-accounted entities[c]	**16**	13	16
	389	435	526
Total liquids			
Subsidiaries[d]	**4,151**	3,982	4,092
Equity-accounted entities[c]	**787**	707	717
	4,938	4,689	4,809
Natural gas			billion cubic feet
Subsidiaries[e]	**28,888**	30,563	32,496
Equity-accounted entities[c]	**2,580**	2,465	2,373
	31,468	33,027	34,869
Total hydrocarbons			million barrels of oil equivalent
Subsidiaries	**9,131**	9,252	9,694
Equity-accounted entities[c]	**1,232**	1,132	1,126
	10,363	10,384	10,821

[a] Because of rounding, some totals may not agree exactly with the sum of their component parts.
[b] Includes condensate and bitumen.
[c] BP s share of reserves of equity-accounted entities in the Upstream segment. During 2016 upstream operations in Argentina, Bolivia, Russia and Norway as well as some of our operations in Angola, Abu Dhabi and Indonesia, were conducted through equity-accounted entities.
[d] Includes 16 million barrels (19 million barrels at 31 December 2015 and 21 million barrels at 31 December 2014) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.
[e] Includes 2,026 billion cubic feet of natural gas (2,359 billion cubic feet at 31 December 2015 and 2,519 billion cubic feet at 31 December 2014) in respect of the 30% non-controlling interest in BP Trinidad & Tobago LLC.

Developments

We achieved six major project« start-ups in 2016: two in Algeria, one in Alaska, one in Angola and two in the Gulf of Mexico. In addition to these, we made good progress in projects in AGT (Azerbaijan, Georgia, Turkey), the Gulf of Mexico, Oman and Egypt.

Azerbaijan, Georgia, Turkey the Shah Deniz 2 project continues to move ahead with the award of contract for the transport and installation of the deep water subsea production systems. We also signed a letter of intent for the future development of the Azeri-Chirag-Gunashli field, covering the development of the field to the end of 2049.

Gulf of Mexico we sanctioned the re-evaluated Mad Dog Phase 2 project, having reduced overall project cost by approximately 60% compared to initial design.

Oman development of the Khazzan project continued, with the project being more than 92% complete as at the year-end. We also signed an agreement to extend the licence area, allowing for a second phase of development in the future.

Egypt we sanctioned the development of the Atoll Phase 1 project and signed concession amendments in three other projects that allow for the economic development of the Nooros field.

Subsidiaries development expenditure incurred, excluding midstream activities, was $11.1 billion (2015 $13.5 billion, 2014 $15.1 billion).

« See Glossary.

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Our project pipeline

Gas

*BP operated

Oil

Project	Location	Type
2016 start-ups		
Angola LNG (restart)	Angola	
In Amenas compression	Algeria	
In Salah Southern Fields	Algeria	
Point Thomson	US Alaska	
Thunder Horse water injection*	US Gulf of Mexico	
Thunder Horse South expansion*	US Gulf of Mexico	
Expected start-ups 2017-2021		
Projects currently under construction[a]		
Atoll Phase 1*	Egypt	
Culzean	UK North Sea	
Juniper*	Trinidad	
Oman Khazzan Phase 1*	Oman	
Persephone	Australia	
Shah Deniz Stage 2*	Azerbaijan	
Tangguh expansion*	Indonesia	
Trinidad onshore compression*	Trinidad	
West Nile Delta Giza/Fayoum/Raven*	Egypt	
West Nile Delta Taurus/Libra*	Egypt	
Western Flank Phase B	Australia	
Zohr	Egypt	
Clair Ridge*	UK North Sea	
Constellation	US Gulf of Mexico	
Quad 204*	UK North Sea	
Mad Dog Phase 2*	US Gulf of Mexico	
Expected start-ups 2017-2021		
Design and appraisal phase		
Angelin*	Trinidad	
Trinidad offshore compression*	Trinidad	
KG-D6 D55	India	
KG-D6 R-Series	India	
Oman Khazzan Phase 2*	Oman	
Vorlich*	UK North Sea	

West Nile Delta 2 Follow On*	Egypt
Alligin*	UK North Sea
Atlantis Phase 3*	US Gulf of Mexico

Beyond 2021

We have a deep hopper of projects that are currently under appraisal. Our focus here is to ensure we maximize the business opportunity and select the optimum project concept before we move it forward into design. We do not expect to progress all of the projects only the best. This includes:

- **a mix of resource types:** split across conventional oil, deepwater oil, conventional gas and unconventionals«
- **geographic spread:** from Alaska to Australia and Argentina to Russia
- **a range of development types:** from exploration to brownfield and near-field.

[a] For further information on the development of the Taas-Yuryakh oil field (also expected to start up in the period 2017-2021) see page 248.

Production

Our offshore and onshore oil and natural gas production assets 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. Our 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 2016, efficient delivery of turnarounds and strong infill drilling performance, we have flattened base decline to less than 3% on average over the last four years. Our long-term expectation for managed base decline remains at the 3-5% per annum guidance we have previously given.

Production (net of royalties)[a]

	2016	2015	2014
Liquids		thousand barrels per day	
Crude oil[b]			
Subsidiaries[c]	**943**	933	834
Equity-accounted entities[d]	**179**	165	163
	1,122	1,099	997
Natural gas liquids			
Subsidiaries	**82**	88	91

Equity-accounted entities[d]	**4**	7	7
	86	95	99
Total liquids			
Subsidiaries[c]	**1,025**	1,022	926
Equity-accounted entities[d]	**184**	172	170
	1,208	1,194	1,096
Natural gas	million cubic feet per day		
Subsidiaries	**5,302**	5,495	5,585
Equity-accounted entities[d]	**494**	456	431
	5,796	5,951	6,016
Total hydrocarbons	thousand barrels of oil equivalent per day		
Subsidiaries[c]	**1,939**	1,969	1,889
Equity-accounted entities[d]	**269**	251	245
	2,208	2,220	2,133

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

[b] Includes condensate and bitumen.

[c] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq has been simplified to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There is no impact on the financial results.

[d] Includes BP s share of production of equity-accounted entities in the Upstream segment.

Our total hydrocarbon production for the segment in 2016 was 0.5% lower compared with 2015. The decrease comprised a 1.5% decrease (0.3% increase for liquids and 3.5% decrease for gas) for subsidiaries and a 7.2% increase (6.7% increase for liquids and 8.3% increase for gas) for equity-accounted entities compared with 2015. For more information on production see Oil and gas disclosures for the group on page 251.

In aggregate, underlying production was flat versus 2015.

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.

The activity primarily takes place in North America, Europe and Asia, 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 280.

« **See Glossary.**

95.3%

refining availability«

(2015 94.7%)

1.7

million barrels of oil refined per day

(2015 1.7mmb/d)

Downstream profitability ($ billion)

43%

of lubricants sales were

premium grade

(2015 42%)

14.2

million tonnes of

petrochemicals produced

(2015 14.8mmte)

Main Image: Vaporizer towers

convert liquid nitrogen to gas

at our US Whiting refinery.

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, logistic networks, fuels marketing and convenience retail businesses, together

Our 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 as measured through net cash margin per

More information

Downstream plant capacity

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with global oil supply and trading activities that make up our integrated 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«.

barrel«, 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.

Simplification and efficiency this remains central to what we do to support performance improvement and make our businesses even more competitive.

Transition to a lower carbon and digitally enabled future we are pursuing and developing new offers and products that support the transition to a lower carbon and digitally enabled future over the long term.

Disciplined execution of our strategy is helping improve our underlying performance, capture opportunities for further growth, generate attractive returns and create a more resilient business that is better able to withstand a range of market conditions; and create opportunities for future growth. We aim to ensure Downstream remains a reliable source of cash flow growth for BP.

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Financial performance

$ million

	2016	2015	2014
Sale of crude oil through spot and term contracts«	**31,569**	38,386	80,003
Marketing, spot and term sales of refined products	**126,419**	148,925	227,082
Other sales and operating revenues	**9,695**	13,258	16,401
Sales and other operating revenues[a]	**167,683**	200,569	323,486
RC profit (loss) before interest and tax[b]			
Fuels	**3,337**	5,858	2,830
Lubricants	**1,439**	1,241	1,407
Petrochemicals	**386**	12	(499)
	5,162	7,111	3,738
Net (favourable) unfavourable impact of non-operating items« and fair value accounting effects«			
Fuels	**390**	137	389
Lubricants	**84**	143	(136)
Petrochemicals	**(2)**	154	450
	472	434	703
Underlying RC profit (loss) before interest and tax[b]			
Fuels	**3,727**	5,995	3,219
Lubricants	**1,523**	1,384	1,271
Petrochemicals	**384**	166	(49)
	5,634	7,545	4,441
Organic capital expenditure«	**2,141**	2,101	2,995
Additions to non-current assets	**3,109**	2,130	3,121

[a] Includes sales to other segments.

[b] Income from petrochemicals produced at our Gelsenkirchen and Mülheim sites in Germany is reported in the fuels business. Segment-level overhead expenses are included in the fuels business result.

Financial results

Sales and other operating revenues in 2016 and 2015 were lower due to lower crude and product prices.

Replacement cost profit before interest and tax for the year ended 31 December 2016 included a net non-operating charge of $24 million, mainly relating to a gain on disposal in our fuels business which was more than offset by restructuring and other charges. The 2015 result included a net non-operating charge of $590 million, mainly relating to restructuring charges, while the 2014 result included a net non-operating charge of $1,570 million, primarily relating to impairment charges in our petrochemicals and fuels businesses. In addition, fair value accounting effects had an unfavourable impact of $448 million, compared with a favourable impact of $156 million in 2015 and $867 million in 2014.

After adjusting for non-operating items and fair value accounting effects, underlying RC profit before interest and tax in 2016 was $5,634 million.

Additions to non-current assets in 2016 included the asset exchange relating to the dissolution of our German refining joint operation with Rosneft as well as organic capital expenditure.

Outlook for 2017

- We anticipate a gradual improvement in the refining environment, although refining margins for the year are expected to remain at the lower end of the recent historical range.

- We expect the financial impact of routine refinery turnarounds to be slightly higher than 2016 as a result of increased turnaround activity, particularly in Europe.

Our fuels business

The fuels strategy focuses primarily on fuels value chains (FVCs). This includes building a top-quartile net cash margin 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.

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

Underlying RC profit before interest and tax was lower compared with 2015 reflecting a significantly weaker refining environment and the impact from a particularly large turnaround at Whiting refinery, partially offset by lower costs reflecting the benefits from our simplification and efficiency programmes, an increased fuels marketing performance driven by retail growth and higher refining margin capture in our operations. Compared with 2014, the 2015 result was higher reflecting a strong refining environment, improved refining margin optimization and operations, and lower costs from simplification and efficiency programmes.

« See Glossary.

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	**2016**	2015	2014
US North West	Alaska North Slope	**16.9**	24.0	16.6
US Midwest	West Texas Intermediate	**13.2**	19.0	17.4
Northwest Europe	Brent«	**10.0**	14.5	12.5
Mediterranean	Azeri Light	**9.0**	12.7	10.6
Australia	Brent	**10.9**	15.4	13.5
BP RMM		**11.8**	17.0	14.4

BP refining marker margin ($/bbl)

The average global RMM in 2016 was $11.8/bbl, $5.2/bbl lower than in 2015, and the lowest since 2010. The decrease was driven by product oversupply resulting from higher refinery utilization which outstripped growth in demand.

Refining

At 31 December 2016 we owned or had a share in 11 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 249.

In 2016 refinery operations were strong, with refining availability« sustained at around 95.3% and utilization rates of 91% for the year. Overall refinery throughputs in 2016 were flat compared with 2015 with increased throughputs in our refining portfolio offset by the impact from ceasing operations at Bulwer in 2015 and the large turnaround at Whiting.

In December 2016 the previously announced dissolution of our German refining joint operation with Rosneft was completed. This will simplify and refocus our refining business in the heart of Europe.

	2016	2015	2014
Refinery throughputs[a]	thousand barrels per day		
US	**646**	657	642
Europe	**803**	794	782
Rest of world[b]	**236**	254	297
Total	**1,685**	1,705	1,721
			%
Refining availability	**95.3**	94.7	94.9
Sales volumes	thousand barrels per day		
Marketing sales[c]	**2,825**	2,835	2,872
Trading/supply sales[d]	**2,775**	2,770	2,448
Total refined product sales	**5,600**	5,605	5,320
Crude oil[e]	**2,169**	2,098	2,360
Total	7,769	7,703	7,680

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

[b] Bulwer refinery in Australia ceased refining operations in 2015.

[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. 71,000 barrels per day relate to revenues reported by the Upstream segment.

Marketing and logistics

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 2016 we completed the sale of our Amsterdam oil terminal and announced our intention to divest some of our fuels terminals in the UK. This reflects our continued focus on increasing our competitiveness through having an advantaged portfolio. 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]	**2016**	2015	2014
US	**7,100**	7,000	7,100
Europe	**8,100**	8,100	8,000
Rest of world	**2,800**	2,900	2,900
Total	**18,000**	18,000	18,000

[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* and includes our interest in equity-accounted entities.

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 and plan to expand our networks further. Retail is a significant source of growth today and is expected to be so in the future. This year we continued the rollout of our new BP fuels with *ACTIVE* technology which are now sold in 13 countries globally (see page 34). We also entered into two new convenience partnerships in Europe with leading food retailing companies, REWE to go® in Germany and Albert Heijn to go® in the Netherlands.

In December 2016 we announced that we will be establishing a strategic partnership with Woolworths in Australia. The agreement includes us acquiring Woolworths fuel and convenience sites for a total consideration of $1.3 billion and entering into a strategic convenience partnership with them. The transaction is subject to regulatory approvals.

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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:

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 280.

Aviation

Air BP is one of the world   s largest global aviation fuels suppliers. Our strategic aim is to maintain a strong presence in our core locations of Europe and the US, while expanding our portfolio in airports that offer long-term competitive advantage in material growth markets such as Asia and South America. Air BP serves many major commercial airlines as well as the general aviation sector. We have marketing sales of more than 430,000 barrels per day, and in 2016 entered into two joint venture« partnerships to market aviation fuels in Peru and Indonesia. We also announced a strategic partnership with Fulcrum BioEnergy® and partnered with RocketRoute® to launch a digital app that provides online fuel purchasing and payment functionality across our global network of aviation fuel locations.

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 60% 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. This year we launched *Castrol MAGNATEC* with *DUALOCK* technology, our latest premium brand lubricant, which reduces warm-up and stop-start wear by up to 50% (see page 12).

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 that was higher compared with 2015 which in turn was higher than 2014. In fact this 2016 result was a record performance for lubricants. Both the 2016 and 2015 results reflected continued strong performance in growth markets and premium brands as well as lower costs achieved through simplification and efficiency programmes.

In 2016 we sold approximately 20% from our shareholding in Castrol India Limited, reducing our shareholding to 51%. We continue to be the majority shareholder and have strategic control of the company.

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.

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 two years into our strategic programme to significantly improve the resilience of the business to a bottom-of-cycle environment through:

- Repositioning a significant portion of our portfolio including shutting down older capacity in the US and Asia.
- Retrofitting our best technology at 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 additional value through simplification and efficiency programmes.

In 2016 the petrochemicals business delivered a higher underlying RC profit before interest and tax compared with 2015 which in turn was higher than 2014. The result reflected strong operations and margin capture supported by the continued rollout of our latest advanced technology, as well as benefits from a slightly improved environment particularly in olefins and derivatives. Compared with 2014, the 2015 result reflected improved operational performance and benefited from our simplification and efficiency programmes leading to lower costs. Our petrochemicals production of 14.2 million tonnes in 2016 was lower than 2015 but higher than 2014 (2015 14.8mmte, 2014 14.0mmte), due to the divestment of the Decatur petrochemicals complex in 2016 and the low margin environment in 2014 compared with 2015 driving reduced output.

As part of our strategy to refocus our global petrochemicals business for long-term growth, we completed the sale of the Decatur petrochemicals complex in Alabama, US in March 2016.

We completed the upgrade of our PTA plant in Geel, Belgium, using our latest proprietary technology and are continuing the upgrade at Cooper River in South Carolina, US, which is scheduled to complete in early 2017. We expect these investments to significantly increase manufacturing efficiency at both facilities.

We are also leveraging our proprietary technology to offer a low carbon PTA solution to manufacturers, brand owners and their customers. In 2016 we launched *PTAir,* which supports a carbon footprint of around 30% lower than the average European PTA production.

Our licensing business continues to be a core part of our growth strategy and in December 2016 Reliance Industries Limited successfully commissioned the first phase of its paraxylene plant in Gujarat, India using BP s proprietary technology. The plant, with a capacity of 1.8 million tonnes, is the world s largest paraxylene unit and is built with BP s leading crystallization technology which delivers greater energy efficiency.

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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 one of the largest and lowest cost hydrocarbon resource bases in the world and its resources play an important role in long-term energy supply to the global economy.

BP s strategy in Russia is to support Rosneft s overall performance and growth through collaboration on technology and best practice, and to build a material business based on standalone projects with Rosneft in Russia and internationally. BP remains committed to our strategic investment in Rosneft, while complying with all relevant sanctions.

2016 summary

Rosneft continued optimizing its portfolio and increased total hydrocarbon production by 4%.

Rosneft s largest shareholder is Rosneftegaz JSC (Rosneftegaz), which is wholly owned by the Russian government. In December an agreement was signed to sell 19.5% from Rosneftegaz s 69.5% shareholding in Rosneft to a consortium of international investors, comprising Qatar Investment Authority and Glencore. Following completion of the transaction, at the year-end Rosneftegaz s shareholding in Rosneft was 50% plus one share.

Rosneft acquired a 50.0755% stake in Russian oil company Bashneft in October and subsequently increased its shareholding to 60.33% as a result of an offer to buy out minority shareholders. This acquisition is expected to provide Rosneft with significant synergies and additional refining throughput and liquid hydrocarbon production. BP accounts for its share of production and reserves resulting from the acquisition through its 19.75% stake in Rosneft.

Rosneft also agreed to purchase a 49% stake in Essar Oil Limited, which owns the Vadinar refinery in India, one of the largest and most advanced refineries in the world.

In July BP received $332 million, net of withholding taxes (2015 $271 million, 2014 $693 million), representing its share of Rosneft s dividend of 11.75 Russian roubles per share. This dividend stood at 35% of Rosneft s 2015 IFRS net profit, an increase from the 25% paid in the previous year.

Two BP nominees, Bob Dudley and Guillermo Quintero, serve on Rosneft s nine member Board of Directors. Bob Dudley is a member of its Strategic Planning Committee and Guillermo Quintero is a member of its HR and Remuneration Committee.

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

About Rosneft

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 Russia s key hydrocarbon regions. Rosneft s hydrocarbon production reached a record of 5.4mmboe/d in 2016. Gas production for the year increased by 7.3% to 67.1bcma or 6.47bcf/d compared with 2015.

Rosneft is also the leading Russian refining company based on throughput. It owns and operates 13 refineries in Russia, including three recently acquired in the Bashneft transaction. Rosneft also owns and operates more than 2,950 retail service stations in Russia and abroad. These include BP-branded sites operating under a licensing agreement acquired as part of the TNK-BP acquisition in 2013, and Bashneft-branded stations. Downstream operations include jet fuel, bunkering, bitumen and lubricants. Rosneft refinery throughput in 2016 reached a record level of 2.028mmb/d versus 1.966mmb/d in 2015.

BP s strategy in Russia

Our strategy is to work in co-operation with Rosneft to increase total shareholder return and partner with it in building a material business outside of the shareholding. This strategy is implemented through our activities in four areas:

- Rosneft Board of Directors: BP has two nominees on the Rosneft Board of Directors and its committees.
- Technology: develop and apply technology to improve oil and gas field and refining performance in collaboration with Rosneft.
- Joint ventures: partner with Rosneft to generate incremental value from joint ventures that are separate from BP s core shareholding.
- Technical services: the partners collaborate on the provision of technical services on a contractual basis to improve asset performance.

The following developments and activities in 2016 have served to support and progress this strategy:

- BP holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas), a joint venture« with Rosneft that is developing the Srednebotuobinskoye oil and gas condensate field in East Siberia. In October Rosneft sold a 29.9% interest in the joint venture to a consortium consisting of Oil India Limited, Indian Oil Corporation Limited and Bharat PetroResources Limited. BP s interest in Taas is reported through the Upstream segment.

Rosneft and BP completed a transaction in October to create a new joint venture, Yermak Neftegaz LLC (Yermak). It will conduct onshore exploration in the West Siberian and Yenisei-Khatanga basins. Yermak is 51% owned by Rosneft and 49% by BP, and currently holds seven exploration and production licences. The venture will also carry out further appraisal work on the Baikalovskoye field, an existing Rosneft discovery in the Yenisei-Khatanga area of mutual interest. BP s interest in Yermak is reported through the Upstream segment.

Rosneft, BP and Schlumberger signed agreements in September for collaboration on seismic research and the development of an innovative cableless onshore seismic acquisition technology. The technology aims to revolutionize the design and acquisition of seismic surveys and increase the efficiency of exploration, appraisal and field development (see page 12).

BP and Rosneft completed the dissolution of their German refining joint operation Ruhr Oel GmbH (ROG) in December.

During the year Rosneft continued actively managing its portfolio. Highlights included:

Selling a 49.9% share in its subsidiary Vankorneft (excluding infrastructure) to ONGC Videsh Limited and a consortium of Indian companies comprising Oil India Limited, Indian Oil Corporation Limited and Bharat PetroResources Limited. The base price was $4.2 billion.

Signing an agreement to sell a 20% interest in its Verkhnechonskneftegaz subsidiary to the Beijing Gas Group in November. The parties are in the process of obtaining the necessary regulatory approvals.

Signing an agreement for the purchase of a 49% stake in Essar Oil Limited (EOL), an Indian downstream business, from the Essar group in October. As a result of this transaction, Rosneft will acquire an interest in the Vadinar refinery and related infrastructure in India, which is among the top 10 refineries in terms of scale and complexity worldwide. EOL s business also includes a network of Essar-branded retail outlets across India. The parties are in the process of obtaining the necessary regulatory approvals.

Signing an agreement for the acquisition of 30% of the concession agreement for the development of the Zohr gas field in Egypt in December for $1.125 billion plus $450 million as reimbursement of 2016 historical expenses. The agreement also includes an option for Rosneft to acquire an additional 5% interest on the same terms. The parties are in the process of obtaining the necessary regulatory approvals.

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
	2016	2015	2014
Profit before interest and tax[a b]	**643**	1,314	2,076
Inventory holding (gains) losses«	**(53)**	(4)	24
RC profit before interest and tax	**590**	1,310	2,100
Net charge (credit) for non-operating items«	**(23)**		(225)
Underlying RC profit before interest and tax«	**567**	1,310	1,875
Average oil marker prices			$ per barrel
Urals (Northwest Europe CIF)	**41.68**	50.97	97.23

[a] 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.

[b] Includes $3 million (2015 $16 million, 2014 $25 million) of foreign exchange losses arising on the dividend received.

Market price

The price of Urals delivered in North West Europe (Rotterdam) averaged $41.68/bbl in 2016, $2.05/bbl below dated Brent«. The differential to Brent widened from $1.42/bbl in 2015, amid 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 2016 and 2014 included non-operating gains of $23 million and $225 million respectively whereas the 2015 result did not include any non-operating items.

After adjusting for non-operating items, the decrease in the underlying RC profit before interest and tax compared with 2015 primarily reflected lower oil prices and increased government take, partially offset by favourable duty lag effects. Compared with 2014, the 2015 result primarily was affected by lower oil prices and foreign exchange, partially offset by favourable duty lag effects. See also Financial statements Notes 16 and 31 for other foreign exchange effects.

Balance sheet

			$ million
	2016	2015	2014
Investments in associates«[c] (as at 31 December)	**8,243**	5,797	7,312

Production and reserves

	2016	2015	2014
Production (net of royalties) (BP share)			
Liquids« (mb/d)			

Crude oil[d]	**836**	809	816
Natural gas liquids	**4**	4	5
Total liquids	**840**	813	821
Natural gas (mmcf/d)	**1,279**	1,195	1,084
Total hydrocarbons (mboe/d)	**1,060**	1,019	1,008
Estimated net proved reserves[e] (net of royalties) (BP share)			
Liquids (million barrels)			
Crude oil[d]	**5,330**	4,823	4,961
Natural gas liquids	**65**	47	47
Total liquids	**5,395**[f]	4,871	5,007
Natural gas (billion cubic feet)	**11,900**[g]	11,169	9,827
Total hydrocarbons (mmboe)	**7,447**	6,796	6,702

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

[d] Includes condensate.

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

[f] Includes 347 million barrels of crude oil in respect of the 6.58% 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 300 billion cubic feet of natural gas in respect of the 2.53% non-controlling interest in Rosneft held assets in Russia including 3 billion cubic feet held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

« See Glossary.

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Financial performance

			$ million
	2016	2015	2014
Sales and other operating revenues[a]	**1,667**	2,048	1,989
RC profit (loss)« before interest and tax			
Gulf of Mexico oil spill	**(6,640)**	(11,709)	(781)
Other	**(1,517)**	(1,768)	(2,010)
RC profit (loss) before interest and tax	**(8,157)**	(13,477)	(2,791)
Net unfavourable impact of non-operating items«			
Gulf of Mexico oil spill	**6,640**	11,709	781
Other	**279**	547	670
Net charge (credit) for non-operating items	**6,919**	12,256	1,451
Underlying RC profit (loss) before interest and tax«	**(1,238)**	(1,221)	(1,340)
Organic capital expenditure«	**251**	340	903
Additions to non-current assets	**216**	315	784

[a] Includes sales to other segments.

The replacement cost (RC) loss before interest and tax for the year ended 31 December 2016 was $8.2 billion (2015 $13.5 billion, 2014 $2.8 billion). The 2016 result included a net charge for non-operating items of $6,919 million primarily relating to costs for the Gulf of Mexico oil spill (2015 $12,256 million, 2014 $1,451 million). For further information, see Gulf of Mexico oil spill and Financial statements Note 2.

After adjusting for these non-operating items, the underlying RC loss before interest and tax for the year ended 31 December 2016 was $1.2 billion, similar to prior years (2015 $1.2 billion, 2014 $1.3 billion).

Outlook

Other businesses and corporate annual charges, excluding non-operating items, are expected to be around $1.4 billion in 2017.

Gulf of Mexico oil spill

Following the 2015 settlements with the United States and the Gulf states, that were approved by the federal district court in 2016, further significant progress was made in 2016 towards resolving outstanding claims arising from the 2010 Deepwater Horizon accident and oil spill.

This included:

Progress in resolving the outstanding business economic loss claims under the Plaintiffs Steering Committee (PSC) settlement.

Progress in resolving economic loss and property damage claims from individuals and businesses that either opted out of the PSC settlement and/or were excluded from that settlement.

The finalization by the claims administrator of six of the claims categories under the PSC settlement, the largest of which was the seafood compensation programme.

The settlement of the class action brought by ADS holders who purchased their shares after the accident.

As a result of this progress, we have clarified the remaining material uncertainties arising from the incident.

The cumulative pre-tax income statement charge since the incident, in April 2010, amounted to $62.6 billion.

More information

Financial statements Note 2.
Process safety and ethics monitors page 42.
Legal proceedings page 261.

Main image: The fermentation tanks at our biofuels Ituiutaba sugar cane to ethanol plant in Brazil.

Inset image: An engineer at the top of a wind turbine tower at Sherbino wind farm in Texas.

« **See**

Glossary.

Alternative energy

BP has the largest operated renewables business among our oil and gas peers.

Renewables will play an increasingly important role in a lower carbon future. They are projected to grow seven times faster than all other energy types combined. Today, they account for around 3% of global energy demand, excluding large-scale hydroelectricity.

BP has been producing renewable energy for more than a decade. Our strategy is to invest where we can build commercially viable businesses at scale. With a focus on biofuels and wind, we have the largest operated renewables business among our oil and gas peers. This means that we are directly managing these businesses from manufacturing biofuels from sugar cane feedstock to generating and distributing wind energy.

We are also evaluating other areas where we can grow our involvement in lower carbon opportunities, particularly where they may play a role in complementing existing businesses such as natural gas.

Find out about the actions we are taking to address climate change including low carbon venturing on pages 12 and 43.

Our Tropical site achieved the Bonsucro certification for sustainability, legal compliance and production processes for the fourth consecutive year.

We produced 733 million litres of ethanol equivalent and generated 562GWh of power for Brazil s national grid.

We continue to invest 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.

Wind

BP is among the top wind energy producers in the US. At 31 December 2016, we directly operated 14 wind farms across eight US states, while holding an interest in a separate facility in Hawaii. Our net generating capacity« from this portfolio, based on our financial stake was 1,452MW of electricity.

Our net share of US wind generation for 2016 was 4,389GWh.

Biofuels business model and strategy

Biofuels can help reduce emissions from transportation, the fourth largest source of greenhouse gas (GHG) emissions today. They can be used in existing cars and infrastructure without major changes. 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 bioethanol sites with a combined nameplate capacity of 10 million tonnes per year. We also export 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.

BP also runs one wind farm at our refinery sites in the Netherlands, operating on a much smaller scale and managed by our Downstream segment, with 22.5MW of generating capacity.

Safety remains our number one priority and a number of sites achieved safety milestones in 2016. For example, Silver Star and Titan both achieved seven years without a recordable injury, and Fowler 1 and 3 have received awards from Vestas a leading wind turbine manufacturer for best overall balanced scorecard which includes metrics for safety and availability.

Caption: Producing biofuels from sugar cane at our Tropical site in Brazil.

More information

See *bp.com/renewables* or our Sustainability Report.

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Caption: Our *British Merchant* LNG

tanker was built in 2003 and measures

279 metres in length.

Shipping

BP s shipping and chartering activities help to ensure the safe transportation of our hydrocarbon products using a combination of BP-operated, time-chartered and spot-chartered vessels. At 31 December 2016, BP had four vessels supporting operations in Alaska, and 46 BP-operated and 28 time-chartered vessels for our international oil and gas shipping operations. In 2016 13 new oil tankers were delivered into the BP-operated fleet, a further 13 are expected in 2017, and six technically advanced LNG tankers are on order and planned for delivery into the BP-operated fleet between 2018 and 2019.

As part of our fleet rejuvenation programme, the new ships will all be equipped with new technologies that help improve their safety, efficiency and emissions. For example tankers and product carriers are built with extra-long stroke engines that reduce fuel consumption with fewer revolutions per minute. And within the fleet certain ships have low enough sulphur dioxide emissions to enable us to trade in parts of the world with the most stringent regulations. All vessels conducting BP shipping activities are required to meet BP approved health, safety, security and environmental standards.

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 funding and investment, 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 or if specific circumstances require such a review.

See *bp.com/sustainability* for case studies, country reports and an interactive tool for health, safety and environmental data.

Safety

Safety is one of our values and our number one priority. Our stated aim is to have no accidents, no harm to people and no damage to the environment.

The fundamentals of how we deliver safe and reliable operations remain unchanged in a lower oil price environment. We are working to continuously improve personal and process safety and operational risk management across BP, with our group-wide operating management system at its core. Our approach builds on our experience, including learning from incidents, operations audits, annual risk reviews and sharing lessons learned with our industry peers.

In 2016 BP reported three workforce fatalities. One contractor died following a leg injury sustained at our biofuels business in Brazil and two contractors died in a pipeline construction incident in Oman. We deeply regret the loss of these lives and continue to focus our efforts on eliminating the risk of injuries and fatalities in our work.

Process safety

Major accidents or spills can result in serious harm to people and the environment, which is why process safety is so important. Process safety means designing our facilities to appropriate standards and using robust engineering principles. It also underlines the

Process safety events

(number of incidents)

Recordable injury frequency

(workforce incidents per 200,000 hours worked) importance of having capable people and rigorous operating and maintenance practices.

Main image: Mad Dog platform in the Deepwater Gulf of Mexico.

Inset image: Two of our wind farms achieved seven years without a recordable injury in 2016.

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	2016	2015	2014
Tier 1 process safety events«	**16**	20	28
Tier 2 process safety events	**84**	83	95
Loss of primary containment number of incidents[a]	**275**	235	286
Oil spills number[b]	**149**	146	156
Oil spills contained	**91**	91	93
Oil spills reaching land and water	**58**	55	63
Oil spilled volume (thousand litres)	**677**	432	400
Oil unrecovered (thousand litres)	**311**	142	155

[a] Does not include non-hazardous releases.

[b] Number of spills greater than or equal to one barrel (159 litres, 42 US gallons).

To track our safety performance we use industry metrics, such as the American Petroleum Institute recommended practice 754 and the International Association of Oil and Gas Producers recommended practice 456. These include tier 1 process safety events, which are losses of primary containment of greater consequence such as causing harm to a member of the workforce, costly damage to equipment or exceeding defined quantities. Tier 2 events are those of lesser consequence. The overall number of process safety events decreased in 2016, continuing the downward trend of the past five years.

Another metric that tracks unplanned or uncontrolled releases of our products from pipes, containers or vehicles is loss of primary containment (LOPC). This is a BP metric that includes events within our operational boundary, excluding releases of non-hazardous substances such as water. We saw an increase of LOPCs in 2016, partly due to harsher winter operating conditions in our unconventional gas operations in the US.

We have seen improvements in our process safety performance over the past five years. For example, at our Rotterdam refinery the number of tier 2 events has reduced from 12 in 2012 to just one in 2016. Alongside this, the refinery s availability has increased, with 2016 its best year in over a decade. We see examples of this right across our operations we believe this shows that the rigour needed to produce safe operations tends also to produce reliable operations.

Personal safety

All members of our workforce have the responsibility and the authority to stop unsafe work. Our golden rules of safety guide our workers on staying safe while performing tasks with the potential to cause most harm. The rules are aligned with our operating management system« and focus on areas such as working at heights, lifting operations and driving safety.

	2016	2015	2014
Recordable injury frequency[c]	**0.21**	0.24	0.31
Day away from work case frequency[c d]	**0.051**	0.061	0.081
Severe vehicle accident rate[e]	**0.05**	0.11	0.13

[c] Incidents per 200,000 hours worked.

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

[e] This figure is based on our new definition which aligns with industry practice. We estimate that based on our previous definition, the rate would have been around 0.09%.

We monitor and report on key workforce personal safety metrics and include both employees and contractors in our data.

We measure our workforce recordable injury frequency, which is the number of reported work-related incidents that result in a fatality or injury per 200,000 hours worked. We also measure our day away from work case frequency, which is the number of incidents per 200,000 hours worked that resulted in an injury where a person is unable to work for a day (or shift) or more.

Our recordable injury frequency and our day away from work rates have reduced across BP in 2016. This continues a pattern of improvement in personal safety over a number of years, which is encouraging. However

Caption: Using technology to monitor

conditions on board our Thunder Horse

platform in the Gulf of Mexico.

we know we must maintain our efforts to continue improving safety in our operations.

Managing safety

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 How we manage risk on page 47 and SEEAC s report on page 74.

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. 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 42 for information about contractors and joint arrangements«.

« **See Glossary.**

Technology

New technologies are helping us increase the amount and quality of data we gather from our operations and speed up our analysis, allowing us to act more quickly. For example, we are piloting software that identifies early warning signs of potential performance problems by gathering machinery and plant data, analysing it and bringing it all to a single screen so engineers can more quickly troubleshoot and resolve potential issues. See page 12 for more information.

We are also testing magnetic crawler robots to inspect the pipelines that connect our deepwater wells with our platforms in the Gulf of Mexico. The robots use lasers to identify corrosion or damage. This can provide us with earlier warnings of potential safety issues.

Emergency preparedness and response

The scale and spread of BP s operations means we must be prepared to respond to a range of possible disruptions and emergency events. We maintain disaster recovery, crisis and business continuity management plans and work to build day-to-day response capabilities to support local management of incidents.

Security

BP monitors for hostile actions that could cause harm to our people or disrupt our operations. We assess risk on an ongoing basis in those areas that are affected by political and social unrest, terrorism, armed conflict or criminal activity. Our central security team provides guidance and support to our businesses through a network of regional security advisers.

Oil spill response

Our requirements for oil spill preparedness and response planning incorporate what we have learned over many years of operations. We take steps to improve our ability to respond to spills. For example, we used satellite technology to enhance our response in the UK North Sea in 2016.

Cyber security

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. See page 48.

Process safety and ethics monitors

Two independent monitors an ethics monitor and a process safety monitor were appointed under the terms of the plea agreement that BP reached with the US government in 2012, following the Deepwater Horizon accident in 2010. The ethics monitor was also appointed under the terms of an administrative agreement reached with the US Environmental Protection Agency in 2014. Under the terms of both agreements, we are taking additional actions to further enhance ethics and compliance across BP and the safety of our drilling operations in the Gulf of Mexico.

The agreements have terms of five years and we are working closely with the monitors who will review ongoing progress until the agreements end.

Working with contractors and partners

With more than half the hours worked in BP carried out by contractors, our ability to be a safe operator depends in part on the capability and performance of those who help us carry out our work. We seek to set clear and consistent expectations of our contractors. Our standard model contracts include health, safety, security, human rights and environmental requirements. Bridging documents are necessary in some cases to define how our safety management system and those of our contractors co-exist to manage risk on a site.

We expect and encourage our contractors and their employees to act in a way that is consistent with our code of conduct and we take appropriate actions where we believe they have not met our expectations or their contractual obligations. Our OMS includes requirements and practices for working with contractors.

Our partners in joint arrangements

In joint arrangements where we are the operator, our OMS, code of conduct and other policies apply. We aim to report on all aspects of our business where we are the operator as we directly manage the performance of these operations.

Where we are not the operator, our OMS is available as a reference point for BP businesses when engaging with operators and co-venturers. We monitor performance and how risk is managed in our joint arrangements, whether we are the operator or not. For example, in Canada we have 50% ownership of the Sunrise oil sands project but it is operated by another company. We benchmark the operator s safety, financial and environmental performance against our expectations. And BP representatives on the venture s governance committee are responsible for confirming that activities are consistent with our investment requirements and code of conduct.

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

Caption: Monitoring activities

at our office in Cairo, Egypt.

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Climate change

Working with others, BP can help drive the transition to a lower carbon future.

Calling for a price on carbon

BP believes that carbon pricing by governments is the most comprehensive and economically efficient policy to limit GHG emissions. We assess how potential carbon policy could affect our businesses now and in the future.

To help anticipate greater regulatory requirements for GHG emissions, we factor a carbon price into our own investment decisions and engineering designs for large new projects and those for which emissions costs would be a material part of the project. In industrialized countries, this is currently $40 per tonne of CO_2 equivalent and we also stress test at a carbon price of $80 per tonne.

Supplying natural gas

Around half of BP s upstream portfolio is currently natural gas, which produces about half as much GHG emissions as coal when burned to generate power. We have several new big gas projects coming onstream in the next few years including Khazzan in Oman, West Nile Delta and Zohr in Egypt, Juniper in Trinidad and the Southern Gas Corridor from the Caspian Sea to Europe.

Providing renewable energy

BP invests in renewable energy where we can build commercially viable businesses at scale. With a focus on biofuels and wind, we have the largest operated renewables business among our oil and gas peers.

Pursuing efficient operations

We are focusing on ways to reduce our GHG emissions. This includes looking to improve the energy efficiency of our operations and reducing flaring and methane emissions.

Investing in start-ups and innovation

Over the past decade, we have invested in start-up companies to help accelerate development and commercial viability of certain technologies. As at 31 December 2016, we had invested around $300 million in emerging technology companies around half of these investments focus on low carbon solutions.

Helping customers reduce their emissions

BP provides an increasing number of lower carbon, energy-efficient and high-performance products to help our customers reduce their carbon footprint from *Castrol* lubricants with lower viscosity, which helps manufacturers improve the efficiency of their vehicles to *PTAir* PTA with around a 30% lower carbon footprint than average European production.

We are collaborating with others to help address this global challenge. As one example, the Oil and Gas Climate Initiative currently chaired by our chief executive Bob Dudley brings together 10 oil and gas companies working to reduce the GHG emissions from our industry s operations and the use of our products.

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

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[ab]

($MteCO_2$ equivalent)

[a] This is based on BP s equity share basis (excluding BP s share of Rosneft).

[b] A minor adjustment has been made from the reported 2015 figure of 48.9.

Our direct GHG emissions are impacted year-on-year by changes in our portfolio and operations. For example, emissions can increase when we start up new projects or when we bring operations back online after planned maintenance. Both of these activities are essential for the safe performance and growth of BP s portfolio. In 2016, the increase in our direct GHG emissions was primarily due to operational changes that include the start-up activities of the Sunrise oil sands project in Canada and the LNG plant in Angola. And one of our US refineries restarted operations following a planned shutdown for maintenance. Around a quarter of the increase is due to changes in how we calculate emissions.

This increase has been partially offset by our real sustainable reductions these are actions taken by our businesses to permanently reduce their GHG emissions in areas such as flaring, methane and energy efficiency. We began tracking this in 2002, and the running total by the end of 2016 exceeded 9.1Mte.

Greenhouse gas emissions ($MteCO_2e$)

	2016	2015	2014
Operational control[a]			
Direct emissions	**51.4**	51.2[b]	54.1
Indirect emissions	**6.2**	7.0	7.5
BP equity share[c]			
Direct emissions	**50.1**	49.0[d]	48.7[e]
Indirect emissions	**6.2**	6.9	6.8

[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.
[b] A minor adjustment has been made from the reported 2015 figure of 51.4.
[c] BP equity share comprises our share of BP s consolidated entities and equity-accounted entities, other than BP s share of Rosneft.
[d] A minor adjustment has been made from the reported 2015 figure of 48.9.
[e] A minor adjustment has been made from the reported 2014 figure of 48.6.

The ratio of our total GHG emissions reported on an operational control basis to gross production was $0.24teCO_2e/te$ production in 2016 (2015 $0.24teCO_2e/te$, 2014 $0.25teCO_2e/te$). Gross production comprises upstream production, refining throughput and petrochemicals produced.

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Value to society

We aim to have a positive and enduring impact on the communities in which we operate.

We contribute to economies through our core business activities, such as helping to develop the national and local supply base, and through the taxes we pay to governments. Additionally, our social investments support communities efforts to increase their incomes and improve standards of living. For example, in Egypt we support healthcare in the communities that are closest to our West Nile Delta project by funding emergency equipment for local hospitals.

We run programmes to help build the skills of businesses and develop the local supply chain in a number of locations. In Angola, for example, we have supported the foundation of local businesses, providing community members with technical and hands-on training. Our enterprise and development programme in Azerbaijan helps local companies build their skills so that they can improve their competitiveness when bidding for work with international firms.

We aim to recruit our workforce from the community or country in which we operate. At our Tangguh LNG plant in West Papua, Indonesia, more than half of our workforce is Papuan. This is a direct result of internship and apprentice programmes that focus on training graduates from Papua and Papua Barat. We are committed to reaching an 85% Papuan workforce by 2029.

We contributed $61.1 million in social investment in 2016.

See *bp.com/society* for more information on how we are maximizing value to society.

Tax and financial transparency

We contribute to economies around the world through the taxes that we pay. We paid $2.2 billion in income and production taxes to governments in 2016 (2015 $3.5bn, 2014 $8.0bn).

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

The Extractive Industries Transparency Initiative (EITI) supports disclosure of payments made to, and received by, government in relation to oil, gas and mining activity. As a member of EITI, BP works with governments, non-governmental organizations and international agencies to improve the transparency of payments to governments.

BP discloses information on payments to governments for our upstream activities. We report on a country-by-country and project basis as required by UK regulation which incorporates the EU Accounting Directive. These payments could be made in the form of production entitlements, taxes, royalties, bonuses, fees and infrastructure improvements. We also make payments to governments in connection with other parts of our business such as the transporting, trading, manufacturing and marketing of oil and gas.

See *bp.com/tax* for our approach to tax and our payments to governments report.

Human rights

We strive to conduct 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 and our code of conduct. Through our code of conduct, employees are required to report any human rights abuse in either our operations or those of our business partners.

Caption: Operations at the Rumaila oil

field in southern Iraq.

We are working towards alignment with the UN Guiding Principles on Business and Human Rights by implementing our human rights policy. Our focus is on identifying and addressing human rights risks, including those associated with the recruitment and living conditions of contracted workforces on our sites, and on enhancing community grievance mechanisms and channels for workforces to raise their concerns.

In 2016 our actions included:

- Initiation of a review examining the risk of modern slavery, focusing on the parts of our business and supply chain where we believe there could be greater risk.

- Development and piloting of a human rights due diligence process that can be used to screen suppliers in a consistent way anywhere in the world.

- Evaluation of key sites community complaints mechanisms against the Guiding Principles to identify good practice and 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.

Local environmental impacts

We work to avoid, minimize and mitigate environmental impacts from our activities.

We consider local conditions when determining which issues would benefit from the greatest focus. At a site close to communities, for example, the immediate concern may be air quality, whereas a remote desert site may require greater consideration of water management issues.

Water

BP recognizes the importance of managing freshwater use and water discharges in our operations and we review our water risks annually. We consider the local environment and quantity, quality and regulatory impacts. We assess different approaches for optimizing water consumption and wastewater treatment performance. For example, at our Khazzan operation in Oman, we treat wastewater from our sewage treatment plant and re-use it for irrigation, road construction and dust suppression, reducing freshwater demand in an area of water scarcity.

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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 Germany and the US.

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

Air quality

We put measures in place to manage our air emissions, in line with regulations and guidelines designed to protect the environment and the health of local communities.

For example, our Whiting refinery is one of the largest refineries in the US, with the potential to have a significant impact on local air quality. We have reduced our air emissions there by more than 50% over the past five years by minimizing the amount of gas flared and emissions from process equipment. We monitor sulphur dioxide, hydrogen sulphide, benzene and other pollutants at the periphery of the refinery and make this data available on the refinery s website.

Unconventional gas and hydraulic fracturing

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 practices to mitigate these risks. For example, our wells are designed, constructed, operated and decommissioned to prevent gas and hydraulic fracturing fluids entering underground aquifers, such as drinking water sources.

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. At our Khazzan site in Oman we have built a central processing facility that reduces the need for processing equipment at each individual well site, which can be additional sources of methane emissions in gas production. 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.

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

Caption: Safety checks at Cherry

Point refinery, US.

Ethical conduct

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 how we work at BP. It applies to all BP employees 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 is potentially unsafe, unethical or harmful can discuss these with their managers, supporting teams, works councils (where relevant) or through OpenTalk, a confidential helpline operated by an independent company.

A total of 956 people contacted OpenTalk with concerns or enquiries in 2016 (2015 1,158, 2014 1,114). The most common concerns related to the people section of the code. This includes treating people fairly, with dignity and giving everyone equal opportunity; creating a respectful, harassment-free workplace; and protecting privacy and confidentiality.

We take steps to identify and correct areas of non-conformance and take disciplinary action where appropriate. In 2016 our businesses dismissed 109 employees for non-conformance with our code of conduct or unethical behaviour (2015 132, 2014 157). This excludes dismissals of staff employed at our retail service stations.

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

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 to the countries and communities in which we do business to be ethical and lawful in all our work. Our code of conduct explicitly prohibits engaging in bribery or 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 prohibit the use of BP funds or resources to support any political candidate or party.

We recognize the rights of our employees to participate in the political process. Their rights to do so are governed by the applicable laws in the countries in which we operate. For example, in the US we support the operation of the BP employee political action committee (PAC), which is a non-partisan committee that encourages voluntary employee participation in the political process. All BP employee PAC contributions are reviewed for compliance, comply with the law and are publicly reported in accordance with US election laws.

The way in which we interact with governments depends on the legal and regulatory framework in each country. We engage across a range of issues that are relevant to our business, from regulatory compliance, to understanding our tax liabilities, to collaborating on community initiatives.

Our people

BP s success depends on having a highly skilled and motivated workforce that reflects the societies where we operate.

BP employees

Number of employees at 31 December[a]	**2016**	2015	2014
Upstream	**18,700**	21,700	24,400
Downstream	**41,800**	44,800	48,000
Other businesses and corporate	**14,000**	13,300	12,100
Total	**74,500**	79,800	84,500
Service station staff	16,200	15,600	14,400
Agricultural, operational and seasonal workers in Brazil	4,600	4,800	5,300
Total excluding service station staff and workers in Brazil	53,700	59,400	64,800

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

A lower oil price has meant that we have continued to adapt and reshape our organization. This has contributed to a reduction in overall headcount of 10,000 over the past two years. Our focus is on retaining the skills we require to maintain safe and reliable operations.

The group people committee helps facilitate the group chief executive s oversight of policies relating to employees. In 2016 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.

Attracting and retaining the right people

We prefer building capability and promoting people from within our organization and we complement this with selective external recruitment for specialist roles.

We provide on-the-job learning and mentoring programmes, as well as online and classroom-based courses. Structured leadership courses help employees move into more senior positions. Our average expenditure on learning and development was around $4,000 per person in 2016 (2015 $4,000).

We continued to invest in graduate recruitment and early career recruitment in 2016, albeit at a reduced level. A total of 231 global graduates joined BP in 2016 (2015 298, 2014 670). We are working to increase our visibility in the graduate job market and in 2016, students voted us the UK s Most Popular Graduate Recruiter in the energy and utilities sector at the Target Jobs Sector Awards.

Diversity

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

Our gender balance is steadily improving, with women representing 33% of BP s population and 22% of group leaders our most senior managers at the end of 2016. Our aim is for women to represent at least 25% of group leaders by 2020. Following the retirement of our executive vice president of corporate business activities in 2016, we are considering how best to increase female representation at executive level.

At the end of 2016 there were three female directors (2015 3, 2014 2) on our board. Our nomination committee remains mindful of diversity when considering potential candidates.

For more information on the composition of our board, see page 65.

Workforce by gender

Numbers as at 31 December	Male	Female	Female %
Board directors	11	3	21%
Group leaders	308	86	22%
Subsidiary« directors	1,056	174	14%
All employees	50,200	24,300	33%

We are also committed to increasing the national diversity of our workforce to reflect the countries in which we operate. A total of 26% of our group leaders came from countries other than the UK and the US in 2016 (2015 23%, 2014 22%).

Inclusion

Our goal is to create an environment of inclusion and acceptance, where everyone is treated equally 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, 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, training and occupational assistance where needed.

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 regularly communicate with employees on factors that affect company performance, and seek to maintain constructive relationships with labour unions formally representing our employees.

Our annual employee survey found that confidence in the future of BP has risen to 64% in 2016 (2015 58%, 2014 63%), with solid improvements in pride in working for BP and trust in management.

However, scores related to career opportunities, reward and recognition are not as high as we would like them to be and we will review actions to address these areas in 2017.

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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How we manage 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 49.

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 seek to 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 management 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 designed 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 team meeting for strategic and commercial risks.

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

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

Group disclosure committee for financial reporting risks.

Group people committee for employee risks.

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

Resource commitment meeting for investment decision risks.

BP board.

Audit committee.

Safety, ethics and environment assurance committee.

Geopolitical committee.

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 2017 are listed in this section. 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 49.

More information

Board and committee reports page 64.

Risks for particular oversight by the board and its committees in 2017

The risks for particular oversight by the board and its committees in 2017 have been reviewed and updated. These risks remain the same as for 2016.

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.

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.

Cybersecurity

The threats to the security of our digital infrastructure continue to evolve rapidly and, like many other global organizations, we rely on digital systems and network technology. 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.

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, North Africa and Europe.

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 plea agreement with the US government 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.

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.

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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 242 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, policies and obligations relating to climate change, including carbon pricing, could impact our assets, costs, revenue generation and strategic growth opportunities and demand for our products.

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.

« **See Glossary.**

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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. Some risks are insured with third parties and reinsured by group insurance companies. Uninsured losses could have a material adverse effect on our financial position, particularly if they arise at a time when we are facing material costs as a result of a significant operational event which could put pressure on our liquidity and cash flows.

Safety and operational risks

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

Technical integrity failure, natural disasters, extreme weather, 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 40.

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 sometimes conducted in extremely challenging environments which heighten the risks of technical integrity failure and the impact of natural disasters and extreme weather. 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 failure to comply with the terms of 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 or liabilities 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 and expose us to severe penalties,

financial or otherwise, 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 imposed on similar 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.

The Strategic report was approved by the board and signed on its behalf by David J Jackson, company secretary on 6 April 2017.

Board of directors
As at 6 April 2017

See BP s board governance principles relating to director independence on page 266.

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Carl-Henric Svanberg

Chairman

Tenure

Appointed 1 September 2009

Board and committee activities

Chair of the nomination and chairman s committees; attends the safety, ethics and environment assurance, remuneration and geopolitical committees

Outside interests

Chairman of AB Volvo

Age 64 **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 December 2009, he was president and chief executive officer of Ericsson, also serving as the chairman of Sony Ericsson Mobile Communications AB. He was a non-executive director of Ericsson between 2009 and 2012. He was appointed chairman and a member of the board of AB Volvo 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 chief executive officer and chairman to several high profile businesses, leading them through both periods of growth and restructuring. These experiences bring not only a deep understanding of international strategic and commercial issues, but the skills to co-ordinate the diverse range of knowledge and perspectives provided by the board. He therefore enables the board to present clear and united leadership on behalf of shareholders.

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

Bob Dudley

Group chief executive

Tenure

Appointed to the board 6 April 2009

Outside interests

- Non-executive director of Rosneft
- Member of the Tsinghua Management University Advisory Board, Beijing, China
- Member of the BritishAmerican Business International Advisory Board
- Member of the US Business Council
- Member of the US Business Roundtable
- Member of the 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 61 **Nationality** American and British

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

Relevant skills and experience

Bob Dudley has spent his whole career in the oil and gas industry. During his tenure as group chief executive, Bob has transformed BP into a safer, stronger and simpler business. This approach, governed by a consistent set of values, has guided BP to a position of greater resilience, enabling it to continue delivering results in an uncertain economic environment. Bob has demonstrated excellent leadership and vision throughout this process and continues to develop the group s strategy to adapt to new challenges ahead.

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

Dr Brian Gilvary

Chief financial officer

Tenure

Appointed 1 January 2012

Outside interests

- Non-executive director of L Air Liquide
- Non-executive director of the Navy Board
- Member of the 100 Group Committee
- Visiting professor at Manchester University

GB Age Group triathlete

Age 55 **Nationality** British

Career

Dr Brian Gilvary was appointed chief financial officer in January 2012. The role includes responsibility for tax, planning, treasury, mergers and acquisitions, investor relations and audit.

He joined BP in 1986 after obtaining a PhD in mathematics from the University of Manchester. Following a variety of roles in 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 until 2009 he was chief executive of the integrated supply and trading function, BP s commodity trading arm. In 2010 he was appointed deputy group chief financial officer with responsibility for the finance function.

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 is also accountable for integrated supply and trading, global business services, information technology activities, procurement and shipping.

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Relevant skills and experience

Dr Brian Gilvary has spent his entire career with BP. His broad experience across the group has given him a deep insight into BP s assets and businesses. This knowledge has been invaluable as BP has implemented its strategy to transform into a value not volume based business and adapt to a low oil price environment.

His strong understanding of finance and trading has been vital in adjusting capital structures and operational costs while ensuring the group continues to be capable of meeting new opportunities going forward.

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

Nils Andersen

Independent non-executive director

Tenure

Appointed 31 October 2016

Board and committee activities

Member of the audit and chairman s committees

Outside interests

Non-executive director of Unilever Plc and Unilever NV

Chairman of Dansk Supermarked Group A/S

Age 58 **Nationality** Danish

Career

Nils Andersen was group chief executive of A.P. Møller-Mærsk from 2007 to June 2016. Prior to this he was executive vice president of Carlsberg A/S and Carlsberg Breweries A/S from 1999 to 2001, becoming president and chief executive officer from 2001 to 2007.

Previous roles include non-executive director of Inditex S.A. and William Demant A/S. He has also served as managing director of Union Cervecera, Hannen Brauerei and chief executive officer of the drinks division of the Hero Group.

Nils received his graduate degree from the University of Aarhus.

Relevant skills and experience

Nils Andersen has extensive experience in consumer goods, retail and logistics, and leading global corporations with integrated operations worldwide. The skills and knowledge gained in these roles make him an ideal addition for the board given his experience in marketing, brand and reputation issues. His specialist logistics awareness also aligns with BP s shipping business. His leadership in earlier roles was notable for the transformation of businesses through focused portfolios, leaner organizations and increasing competitiveness, as well as increasing transparency and communication with stakeholders.

Nils economics and broad financial background make him well suited to his role on the audit committee.

Paul Anderson

Independent non-executive director

Tenure

Appointed 1 February 2010

Board and committee activities

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

Outside interests

No external appointments

Age 72 **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. His specific experience of driving safety-related cultural change throughout a business has been invaluable during his tenure as chair of the safety, ethics and environment assurance committee from 2012 to 2016, and he remains a valuable member of the committee.

Paul s experience of business in the US and its regulatory environment is a great asset to the geopolitical committee.

Alan Boeckmann

Independent non-executive director

Tenure

Appointed 24 July 2014

Board and committee activities

Chair of the safety, ethics and environment assurance committee; member of the remuneration, nomination and chairman s committees

Outside interests

Non-executive director of Sempra Energy

Non-executive director of Archer Daniels Midland

Age 68 **Nationality** American

Career

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

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

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

Alan was previously a non-executive director of BHP Billiton and the Burlington Santa Fe Corporation, and has served on the boards of the American Petroleum Institute, the National Petroleum Council, the Eisenhower Medical Center 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 worked in a wide range of industries including engineering, construction, chemicals and in the energy sector. In his senior roles he directed the focus of global corporations towards the advanced technology needed to remain competitive in response to the growth of the internet, e-commerce and the globalization of the workforce. At the same time he actively promoted fairness, transparency, accountability and responsibility in business dealings at a time when many corporations were struggling with these issues.

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This experience as a chairman and chief executive makes Alan ideal to lead the SEEAC and brings added value to both the remuneration and nomination committees.

Admiral Frank Bowman

Independent non-executive director

Tenure

Appointed 8 November 2010

Board and committee activities

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

Outside interests

President of Strategic Decisions, LLC

Director of Morgan Stanley Mutual Funds

Director of Naval and Nuclear Technologies, LLP

Age 72 **Nationality** American

Career

Frank L Bowman served for more than 38 years in the US Navy, rising to the rank of Admiral. He commanded the nuclear submarine *USS City of Corpus Christi* and the submarine tender *USS Holland.* After promotion to flag officer, he served on the joint staff as director of political-military affairs and as the chief of naval personnel. He served over eight years as director of the Naval Nuclear Propulsion Program where he was responsible for the operations of more than 100 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 US CNA military advisory board and has participated in studies of climate change and its impact on national security, and on future global energy solutions and water scarcity. 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 s exemplary safety record in running the US Navy s nuclear submarine program indicates his deep understanding of process safety and its implementation in a widely dispersed workforce. Combined with his specific knowledge of BP s safety goals from his work on the BP Independent Safety Review Panel, and his special interest in climate change, he brings a unique perspective to the board and the SEEAC.

In addition, Frank s experience of the US and global political and regulatory systems is a valuable asset to the geopolitical committee.

Cynthia Carroll

Independent non-executive director

Tenure

Appointed 6 June 2007

Board and committee activities

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

Outside interests

- Chair of Vedanta Resources Holding Ltd
- Non-executive director of Hitachi Ltd
- Advisory board member of America Securities LLC

Age 60 **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, 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 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 is an experienced former chief executive who has spent all of her career in the extractive industries. 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 experience of leading large complex global businesses which require a high level of interaction with governments, the media and other stakeholders is an asset to both the board and the geopolitical committee.

Ian Davis

Independent non-executive director

Tenure

Appointed 2 April 2010

Board and committee activities

Member of the remuneration, geopolitical, nomination and chairman s committees

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 66 **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 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 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. This enables him to draw on knowledge of diverse issues and outcomes to assist the board and, in particular, the remuneration and nomination committees.

He led the board s oversight of the response in the Gulf and chaired the Gulf of Mexico committee from its formation until it was stood down in 2016. His previous role in the Cabinet Office gives him a unique perspective on government affairs which is an asset to both the board and the geopolitical committee.

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Professor Dame Ann Dowling

Independent non-executive director

Tenure

Appointed 3 February 2012

Board and committee activities

Chair of the remuneration committee; member of the safety, ethics and environment assurance, nomination and chairman s committees

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, Energy and Industrial Strategy (BEIS)

Age 64 **Nationality** British

Career

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 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 chairs BP s technical advisory committee.

Dame Ann is a fellow of the Royal Society and the Royal Academy of Engineering and a foreign associate of the US National Academy of Engineering and the French Academy of Sciences. She has honorary degrees from fifteen universities, including the University of Oxford, Imperial College London and the KTH Royal Institute of Technology, Stockholm.

She was elected President of the Royal Academy of Engineering in September 2014 and in December 2015 was appointed to the Order of Merit.

Relevant skills and experience

Dame Ann is an internationally respected leader in engineering research and the practical application of new technology in industry. Her contribution in these fields has been widely recognized by universities around the world. Her academic background provides balance to the board and brings a different perspective to the SEEAC and nomination committee.

Dame Ann became chair of the remuneration committee in 2015 and worked tirelessly over the past year to understand key issues with a large number of major shareholders and their advisers.

Brendan Nelson

Independent non-executive director

Tenure

Appointed 8 November 2010

Board and committee activities

Chair of the audit committee; member of the chairman s committee

Outside interests

- Non-executive director and chairman of the group audit committee of The Royal Bank of Scotland Group plc
- Member of the Financial Reporting Review Panel

Age 67 **Nationality** British

Career

Brendan Nelson is a chartered accountant. He was made a partner of KPMG in 1984. He served as a member of the UK board of KPMG from 2000 to 2006, subsequently being appointed vice chairman until his

retirement in 2010. At KPMG International he held a number of senior positions including global chairman, banking and global chairman, financial services.

He served 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

Over the course of his career, Brendan Nelson has completed a wide variety of audit, regulatory and due-diligence engagements. He played a significant role in the development of the profession s approach to the audit of banks in the UK with particular emphasis on establishing auditing standards. He continues to contribute in his role as a member of the Financial Reporting Review Panel.

This wide experience makes him ideally suited to chair the audit committee and to act as its financial expert and he brings related input from his role as the chair of the audit committee of a major bank. His specialism in the financial services industry allows him to contribute insight into the challenges faced by global businesses by regulatory frameworks.

Paula Rosput Reynolds

Independent non-executive director

Tenure

Appointed 14 May 2015

Board and committee activities

Member of the audit and chairman s committees

Outside interests

- Non-executive director of BAE Systems Ltd
- Non-executive director of TransCanada Corporation
- Non-executive director of CBRE Group

Age 60 **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 chief executive officer of AGL Resources Inc., an operator of natural gas infrastructure in the US, now a subsidiary of Southern Company. 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.

Paula was awarded the National Association of Corporate Directors (US) Lifetime Achievement Award in 2014.

Relevant skills and experience

Paula Rosput Reynolds has had a long career leading global companies in the energy and financial sectors. Her financial background makes her ideally suited to serve on the audit committee.

Her experience with international and US companies, including several restructuring processes and mergers, gives her insight into strategic and regulatory issues, which is an asset to the board.

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Sir John Sawers

Independent non-executive director

Tenure

Appointed 14 May 2015

Board and committee activities

Chair of the geopolitical committee; member of the safety, ethics and environment assurance, nomination and chairman s committees

Outside interests

Chairman and partner of Macro Advisory Partners LLP

Visiting professor at King s College London

Governor of the Ditchley Foundation

Age 61 **Nationality** British

Career

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 that advises clients on the intersection of policy, politics and markets.

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. Sir John brings a unique perspective and broad experience which makes him ideal to lead the geopolitical committee. His knowledge and skills related to analysing and negotiating on a worldwide basis are invaluable to both the board and the SEEAC.

Andrew Shilston

Independent non-executive director

Tenure

Appointed 1 January 2012

Board and committee activities

Senior independent director and member of the audit, remuneration, geopolitical, nomination and chairman s committees

Outside interests

Chairman of Morgan Advanced Materials plc

Non-executive director of Circle Holdings plc

Age 61 **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. In 2003, after the sale of Enterprise Oil to Shell in 2002, 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 in the oil and gas, energy and engineering industries. He has held several positions as a chief financial officer from which he brings detailed knowledge and skills to the audit and remuneration committees.

His deep understanding of commercial issues has assisted the board in its work in overseeing the group s strategy and his global expertise across several sectors is an asset to the geopolitical committee.

As senior independent director he oversaw the evaluation of the chairman.

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 6 April 2017.

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Executive team

As at 6 April 2017

Tufan Erginbilgic

Chief executive, Downstream
Executive team tenure

Appointed 1 October 2014

Outside interests

- Independent non-executive director of GKN plc
- Member of the Turkish-British Chamber of Commerce & Industry Board of Directors

Age 57 **Nationality** British and Turkish

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

Executive vice president,

safety and operational risk
Executive team tenure

Appointed 1 October 2010

Outside interests

No external appointments

Age 53 **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, remediation management and the environment. In this capacity, he looks after the group-wide operating management system implementation and capability programmes.

Bob has over 30 years experience in the oil and gas industry, having joined Amoco Production Company in 1985. Between 2010 and 2013, Bob was executive vice president of the production division, accountable for safe and compliant exploration and production operations and stewardship of resources across all regions.

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

Andy Hopwood

Executive vice-president,

chief operating officer,

strategy and regions, Upstream

Executive team tenure

Appointed 1 November 2010

Outside interests

No external appointments

Age 59 **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.

Bernard Looney

Chief executive, Upstream

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
- Member of the Society of Petroleum Engineers Industry Advisory Council
- Fellow of the Energy Institute

Age 46 **Nationality** Irish

Career

Bernard Looney is responsible for the Upstream segment which consists of exploration, development and production.

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 becoming head of the group chief executive s office in 2007.

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 in February 2013 became chief operating officer, production, serving in the role until April 2016.

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The executive team represents the principal executive leadership of the BP group. Its members include BP s executive directors (Bob Dudley and Dr Brian Gilvary whose biographies appear on pages 53-54) and the senior management listed on these pages. The ages of the executive team are correct as at 6 April 2017.

Lamar McKay

Deputy group chief executive

Executive team tenure

Appointed 16 June 2008

Outside interests

No external appointments

Age 58 **Nationality** American

Career

Lamar McKay is accountable for group strategy and long-term planning, safety and operational risk and group technology. In addition to supporting the group chief executive, he also focuses on various corporate governance activities including ethics and compliance.

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

During 1998 to 2000, he worked on the BP-Amoco merger and served as head of strategy and planning for the exploration and production business. In 2000 he became business unit leader for the central North Sea. In 2001 he became chief of staff for exploration and production, and subsequently for BP s deputy group chief executive. Lamar became group vice president, Russia and Kazakhstan in 2003. He served as a member of the board of directors of TNK-BP between February 2004 and May 2007.

In 2007 he was appointed executive vice president, BP America. In 2008 he became executive vice president, special projects where he led BP s efforts to restructure the governance framework for TNK-BP. In 2009 Lamar was appointed chairman and president of BP America, serving as BP s chief representative in the US. In January 2013, he became chief executive, Upstream, responsible for exploration, development and production, serving in the role until April 2016.

Eric Nitcher

Group general counsel

Executive team tenure

Appointed 1 January 2017

Outside interests

No external appointments

Age 54 **Nationality** American

Career

Eric Nitcher is responsible for legal matters across the BP group.

Eric began his career in the late 1980s working as a litigation and regulatory lawyer in Wichita, Kansas. He joined Amoco in 1990 and over the years has held a wide variety of roles, both within and outside the US.

In 2000, Eric moved to London to work in the mergers and acquisitions legal team where he played a key role in the formation of the Russian joint venture TNK-BP. Eric returned to Houston in 2007 where he served as special counsel and chief of staff to BP America s chairman and president.

Most recently he played a leading role in the settlement of the Deepwater Horizon government claims and resolution of most of the remaining private claims being litigated in New Orleans.

Dev Sanyal

Chief executive, alternative

energy and executive vice

president, 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

Age 51 **Nationality** British and Indian

Career

Dev Sanyal is responsible for alternative energy and for the Europe and Asia regions and functionally for risk management, government and political affairs, economics and policy.

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 and in June 2006 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. Until April 2016, Dev was executive vice president, strategy and regions.

Helmut Schuster

Executive vice president,

group human resources

Executive team tenure

Appointed 1 March 2011

Outside interests

Non-executive director of Ivoclar

Vivadent AG, Germany

Age 56 **Nationality** Austrian

Career

Helmut Schuster became group human resources (HR) director in March 2011. In this role he is accountable for the BP human resources function.

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 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 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 that 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.

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Executive management teams

Upstream

(Pictured from left to right)

James Dupree

Chief operating officer, developments and technology

Andy Hopwood

Chief operating officer, strategy and regions

Kerry Dryburgh

Head of human resources

Tony Brock

Head of safety and operational risk

Bernard Looney

Chief executive

(Standing, from left to right)

Murray Auchincloss

Chief financial officer

Nigel Jones

Associate general counsel

Downstream

(Standing, from left to right)

Mike O Sullivan

Chief financial officer

Mandhir Singh

Chief operating officer, lubricants

Alan Haywood

Chief executive officer, integrated supply and trading (effective 1 January 2017)

Doug Sparkman

Tufan Erginbilgic

Chief executive

Guy Moeyens

Chief operating officer, fuels, Europe and Southern Africa

Paul Reed

Chief executive officer, integrated supply

and trading (to 31 December 2016)

Rita Griffin

Chief operating officer, petrochemicals

Eva Bishop

Associate general counsel

Chief operating officer, fuels,

North America

(Seated, from left to right)

Angela Strank

Head of technology

Evelyn Gardiner

Head of human resources

Andy Holmes

Chief operating officer, fuels

ASPAC and Air BP

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Alternative energy

(Pictured from left to right)

David Anderson

Chief financial officer

Laura Folse

Chief executive officer, wind

Catherine Green

Human resources director

Nick Wayth

Chief development officer

Mario Lindenhayn

Chief executive officer, biofuels

Joan Wales

Head of safety and operational risk

Dev Sanyal

Chief executive

Functional leaders

(Pictured from left to right)

David Jardine

Group head of audit

Ashok Pillai

Vice president, group reward

(Pictured from left to right)

Jessica Mitchell

Group head of investor relations

Dominic Emery

Vice president, group strategic planning

Susan Dio

Chief executive officer, shipping

Peter Henshaw

Group head of communications and external affairs

(Pictured from left to right)

David Eyton

Group head of technology

Kate Thomson

Group treasurer

Richard Hookway

Chief operating officer of global business services and information technology and systems

Rahul Saxena

Group ethics and compliance officer

(Pictured from left to right)

Eric Nitcher

Group general counsel

Robert Lawson

Global head of mergers and acquisitions

Jan Lyons

Group head of tax

Lucy Knight

Human resources vice president, corporate business activities and functions

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Introduction from the chairman

The work of the board was challenging in 2016 as we had to focus on a number of distinct issues in a changing global environment. Despite this backdrop, it was a year however when the board continued to work well.

2015 saw the announcement of our settlement with a number of significant parties in the aftermath of the Deepwater Horizon accident. This was finally approved by the appropriate authorities in March 2016. This was a significant step that has allowed us to look forward.

Your board spent significant time in 2016 in a series of briefings to understand the challenges of the transition to a lower carbon economy. And in February 2017 we communicated our refreshed strategy to investors. It defines how we see BP s business evolving over the coming years. We are clear that a strong core business will be vital to our success in playing our part in the lower carbon transition over the coming years.

The negative vote on remuneration at the 2016 AGM sent us a clear message. At that meeting Dame Ann and I said that we would listen and make further proposals for a new remuneration policy in 2017. Dame Ann and the remuneration committee have worked hard to ensure that we fully understand the views of our shareholders. They have also make a real difference in their home markets. The board of BP has for many years seen that its task is to create long-term value for shareholders. To do this it is vital that we are responsive to all those with whom we come into contact through our business. This includes shareholders, employees, customers and communities alike.

This is a clear task of all companies and their boards. In the UK we are pleased to be able to work with the current government on their recent green paper on corporate governance reform.

In 2016 the Gulf of Mexico committee met for the last time. The geopolitical committee, now chaired by Sir John Sawers, is getting into its stride and has proved its worth as the political environment has changed in a number of countries.

It is important that we look to the future and ensure that how we work and what we discuss at our meetings is always directed at delivering BP s strategy and maximizing performance in all areas.

I am very grateful to Bob, his executive colleagues and my fellow directors for all the work that they have done over the year. And we are ready for what the future brings.

considered wider remuneration within BP and recognized the importance of engaging and retaining top executive talent throughout BP. We are putting forward the new policy at the 2017 AGM and believe it reflects a fair and balanced approach. The board recommends that shareholders approve it.

Carl-Henric Svanberg

Chairman

It has been a lesson for the board and it is important for all of us that we regain the trust of shareholders and society. BP has come through many tests in the past years, and is a company with inner strength and is ready to continue playing its part in delivering light, heat and mobility to the societies in which we work.

The role of business in society has become the focus of attention in many countries, not least the UK. BP is a global business. We cannot change that; indeed that is our strength. We believe that we can make a major contribution in demonstrating how global players can

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BP governance framework

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.

Board and committee attendance in 2016

	Board		Audit committee		SEEAC		Joint audit/ SEEAC		Remuneration committee		Geopolitical committee		Nomination committee		Chairman committe
on-executive rectors	A	B	A	B	A	B	A	B	A	B	A	B	A	B	A
rl-Henric Svanberg+	11	11									3	3	5	5	7
ls Andersen	1	1	1	1			1	1							1
ul Anderson	11	11			6	6	4	4			3	3			7
an Boeckmann+	11	11			6	6	4	4	11	11			5	5	7
ank Bowman	11	11			6	6	4	4			3	3			7
tony Burgmans	3	3			2	2	1	1			1	1	1	1	3
nthia Carroll	11	10			6	5	4	3			3	3			7
n Davis	11	11							11	11	1	1	5	5	7
an Dowling+	11	11			6	6	4	4	11	11			5	5	7
endan Nelson+	11	10	14	14			4	4							7
uthuma Nhleko	3	2	4	4			1	1			1	1			3
ula Rosput Reynolds	11	11	14	14			4	4							7
nn Sawers+	11	11			6	6	4	4			3	3	5	5	7
drew Shilston	11	11	14	14			4	4	11	10	3	3	5	5	7
ecutive directors	A	B													
b Dudley	11	11													
ian Gilvary	11	11													

A = Total number of meetings the director was eligible to attend.

B = Total number of meetings the director did attend.

+ Committee chair.

Cynthia Carroll did not attend the board meeting on 26 May as she had to attend a family event. Brendan Nelson did not attend the board meeting on 6 December due to a conflict with an RBS board meeting. Phuthuma Nhleko did not attend the board meeting on 14 April due to urgent business in South Africa.

Committee meeting attendance is noted in each committee report on pages 69-79.

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Board activity in 2016

Role of the board

The board is responsible for the overall conduct of the group s business. The directors have duties under both UK company law and BP s Articles of Association. The primary tasks of the board include:

Active consideration and direction of long-term strategy and approval of the annual plan.	Monitoring of BP s performance against the strategy and plan.	Ensuring that the principal risks and uncertainties to BP are identified and that systems of risk management and control are in place.	Board and executive management succession.

Strategy

In 2016 the board worked with the executive team to understand the potential evolution of the markets in which the company operates. It also considered the implications of a transition to a low carbon economy.

At its September meeting the board spent two days discussing with the executive team their proposals for the strategic direction of the group in the short, medium and longer term.

The board discusses progress in delivering these strategic aims on a regular basis.

The board reviewed the *BP Energy Outlook*, updated in January 2017, which looks at long-term energy trends and develops projections for world energy markets over the next two decades.

Following the approval of the Consent Decree order by the US court, the Gulf of Mexico committee was stood down at the end of the first quarter of 2016. Updates on the remaining proceedings are being given directly to the board or other committees as appropriate.

Finally, the board has had regular discussions on the development of a new remuneration policy.

During the year, the board has monitored the company s performance against the annual plan for 2016 and also set the terms for the annual plan in 2017.

Risk

The board, either directly or through its committees, regularly reviews the processes whereby risks are identified, evaluated and managed.

Activities include:

- assessing the effectiveness of the group s system of internal control and risk management
- identification and allocation of risks to the board and monitoring committees (the audit, SEEA and geopolitical committees) for 2016, and confirmation of the schedule for oversight.

Group risks reviewed by the board during 2016 included:

- financial resilience (which examines how the group is able to respond to a volatile oil and gas price environment)
- cybersecurity (with the audit committee and SEEAC reviewing elements of cybersecurity risk in their work over the year).

These remain unchanged for 2017.

The group risks allocated to the committees for review over the year are outlined in the reports of the committees on pages 69-79.

Further information on BP s system of risk management is outlined in How we manage risk on page 47.

Performance and monitoring

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. Regular reports presented to the board include:

Chief executive s report

Group performance report

Group financial outlook

Effectiveness of investment review

Quarterly and full-year results

Shareholder distributions.

The board reviews the quarterly and full-year results, including the shareholder distribution policy. Both the 2015 and 2016 annual reports were assessed in terms of the directors obligations and appropriate regulatory requirements.

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.

Succession

The board, in conjunction with the nomination and chairman s committees, reviews succession plans for executive and non- executive directors on a regular basis. The board needs to ensure that potential candidates are identified and evaluated as current directors reach the end of their recommended term of office, including in the event of a director needing to leave unexpectedly.

The board employs executive search firms when it concludes that this is an effective way of finding suitable candidates. In 2016 we appointed Russell Reynolds Associates to assist in the search for non-executive directors.

Nils Andersen joined the board in October 2016 as a non-executive director. He is a member of the audit

Antony Burgmans and Phuthuma Nhleko, both non-executive directors, retired from the board at the AGM on 14 April 2016.

Sir John Sawers took the chair of the geopolitical committee following Antony Burgmans retirement.

Alan Boeckmann took the chair of the SEEAC, succeeding Paul Anderson who served as chair for four years. Mr Anderson continues as a member of the committee.

Ian Davis joined the geopolitical committee further to the departure of Antony Burgmans and Phuthuma Nhleko.

At the start of the year, Paul Anderson and Brendan Nelson stepped down from the nomination committee and Alan Boeckmann and Sir John Sawers joined.

committee and the chairman s committee.

Cynthia Carroll and Andrew Shilston will be standing down from the board at the 2017 AGM.

The board is proposing Melody Meyer for election as a director at the 2017 AGM.

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Skills and expertise

In order to carry out its duties on behalf of the shareholders, the board needs to manage its overall membership and continuously maintain its knowledge and expertise to benefit the business. It does this through four activity sets:

Succession planning to ensure future diversity and balance	Diversity including skills, experience, gender, ethnicity and tenure	Training including site visits and induction of new directors	Evaluation

kground and diversity

ctor	Background						Diversity		
	Oil & gas/ extractives/ energy	Engineering/ technology	Financial expertise	Safety	Brand/ marketing/ reputation	Regulatory/ government affairs	Female	Non UK/US	Tenure (years
ersen									1
erson									7
n ckmann									3
k yman									6
thia oll									10
Davis									7
vling									5
ndan on									6
a out nolds									2
n Sawers									2
rew ston									5
-Henric nberg									8

Diversity

BP recognizes the importance of diversity, including gender, 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.

New diversity targets have been suggested by the Hampton-Alexander review in November 2016, to increase female representation on boards, executive committees and in the executive team direct reports by 2020. At the end of 2016, there were three female directors (2015 3, 2014 2) on our board of 14. Our nomination committee actively considers diversity in seeking potential candidates for appointment to the board.

Independence

Non-executive directors (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.

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 other 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.

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. 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 97).

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

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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 2016 the board received training on ethics and compliance and digital innovation.

NEDs are expected to visit at least one business per year as part of their learning programme. In 2016 the board visited operations in Baku and Azerbaijan, and members of the SEEAC and other directors visited operations in Alaska, Colorado and Belgium.

Newly appointed NEDs follow a structured induction process. This includes one-to-one meetings with management and the external auditors and also covers the board committees that they join.

Director induction programme

It was helpful to meet a wide range of company executives.

Nils Andersen

Non-executive director

Nils Andersen, appointed in 2016, followed a tailored induction process, also covering the audit committee that he joined. The programme of topics included:

Board and governance

BP s board governance model, directors duties, interests and potential conflicts.

Safety and operational risk (S&OR), BP s operating management system« (OMS) and environmental performance

Research and technology

Legal.

Business introduction

BP s business

Upstream (exploration, development, production, overview of our operations)

Downstream (refining, marketing and lubricants)

Strategy and planning

BP s performance relative to its competitors.

Functional input

Human resources

Ethics and compliance

Audit committee specific

Upstream and downstream finance

Tax

Oil and gas reserves accounting

Controls, accounting and reporting

External auditors and internal audit

Treasury and trading.

Board evaluation

BP undertakes an annual 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 audit

An external evaluation was carried out at the end of 2015. Following a selection process led by the senior independent director, Bvalco was engaged as the external evaluator.

The evaluation tested key areas of the board s work including:

participation in the development of strategy

succession and composition

oversight of business performance, risk and governance processes.

The effectiveness of the committees in alleviating the board s overall oversight was also tested to establish whether this added value for the board.

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

Key conclusions of the evaluation included:

- Ensuring an effective strategy process that focused on the long term and which acknowledged the important role of the board in this process.
- Continued focus on succession for the board.
- Building on the collaborative and inclusive environment to try and put more of the monitoring tasks into the committees to allow more time for broader discussions at the board.
- Further steps should be taken to ensure that where appropriate all directors can access information and attend external visits for those committees of which they were not members.

2016 evaluation

The evaluation was undertaken through a questionnaire facilitated by an external consultant (Lintstock) and individual interviews between the chairman and each director. The results of the evaluation and feedback from the interviews were collectively discussed by the board at its meeting in February 2017, with the results of the chairman s evaluation discussed by the chairman s committee.

The evaluation concluded that the board felt its work and performance during the year had been positive. There had been an effective process to develop a refreshed strategy, and board discussions remained open and constructive.

Actions arising from the evaluation in 2017 included:

- Focus on implementing the strategy, in particular the opportunities relating to the transition to a lower carbon economy.
- Continued emphasis on improving operational excellence.
- Further examination of the financial performance of the business, in particular capital allocation and returns.
- Obtaining a better understanding of the group s ability to effectively deliver the strategy, including technology, digital and big data.
- Bringing wider perspectives into the board room and gaining deeper insight into shareholder views.

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Field visits

Non-executive directors are expected to visit at least one business per year, as part of their learning programme. In 2016 the board visited operations in Baku, Azerbaijan, and members of the SEEAC and other directors visited operations in Alaska, Colorado and Belgium. The board met local management during each visit, and after each one, the board or appropriate committee was briefed on the impressions gained by the directors during the visit.

Lower 48, US

Members of the SEEAC visited operations in Durango, Colorado in October. The visit was hosted by leadership of the Lower 48 business and included detailed reviews of production efficiency, operational management and safety and risk mitigation. Members saw the Florida gas plant and a number of well sites and a produced water storage and injection facility.

There was a particular emphasis on the way in which the Lower 48 business is promoting safety through digital information sharing of incidents and leadership communications.

Geel, Belgium

Members of the SEEAC and other directors visited the petrochemicals plant in Geel, Belgium in December. They were shown key areas of the plant, in particular the paraxylene manufacturing facility. The visit also involved meetings with site leadership, and a review of safety-related incidents and trends. The outreach programme with the surrounding community was also discussed and commended.

Alaska, US

Members of the SEEAC and other directors visited Anchorage and the North Slope in August. The visit to the North Slope included reviews of operations and flow stations as well as the central gas facility. They also visited pipelines and other critical infrastructure. Directors met local business and political leaders in Anchorage, as well as local BP leadership and other staff.

Baku, Azerbaijan

The board visited the fabrication site for Shah Deniz Stage 2 topsides in Baku in May. Board members were given a tour of the topsides for the Shah Deniz Bravo production platform and the quarters and utilities platform. They reviewed progress of construction and discussed the safety record at the site in particular the fact that more than 17 million safe man hours had been worked. They were informed that almost 90% of the workforce is Azerbaijani. The jackets for the platform are being constructed separately in Azerbaijan with a projected sail away in the second half of 2017. Subsequent installation and commissioning will take place at the field.

Board members also met with site leadership and were given a detailed update on the Shah Deniz Stage 2 project as a whole.

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Shareholder engagement

Institutional investors

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 meet with shareholders each year. In 2016 there was an enhanced programme of engagement by the chairman and the chair of the remuneration committee following the AGM. This is detailed in the remuneration committee report on page 76.

Senior management regularly meets with institutional investors through roadshows, group and one-to-one meetings, events for socially responsible investors (SRIs) and oil and gas sector conferences throughout the year.

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.

Shareholder engagement cycle 2016

BP Energy Outlook presentation
Fourth quarter results

Investor roadshows with the group chief executive and chief financial officer

Chairman and board committee chairs meeting

UKSA private shareholders meeting

Institutional Investors Group on Climate Change (IIGCC) meeting

SRI roadshow following the launch of the *BP Sustainability Report 2015*, continuing into Q2

Annual general meeting

First quarter results

Meetings with members of the Church Investors Group and Charities Responsible Investment Network

Upstream field trip to Baku, Azerbaijan

BP Statistical Review of World Energy launch
IIGCC meeting
Second quarter results
Investor roadshows with the group chief executive
Third quarter results
SRI annual meeting
IIGCC meeting

More information

Engagement on remuneration continued throughout the year
See pages 76 and 80.

The chairman and members of the executive team met with SRIs as part of BP s annual SRI meeting in November. 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 and demand, operating and energy performance in the Upstream, and BP s response to the shareholder resolution.

See *bp.com/investors* for investor and strategy 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 2016. 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.

AGM

Voting levels increased slightly in 2016 to 64.28% (of issued share capital, including votes cast as withheld), compared to 62.28% in 2015 and 63.13% in 2014. All resolutions were passed at the meeting with the exception of the non-binding vote to receive the directors remuneration report. 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 2016 with the provisions of the UK Corporate Governance Code except in the following aspects:

B.3.2 Letters of appointment do not set out fixed-time commitments since the schedule of board and committee meetings is subject to change according to the demands of business and other events. 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 2016 comprised 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 in 2016 included the global economy and in particular the effects of Brexit on the rest of the world, developments in political and economic reform in China, the political situation in Latin America and Turkey and the 2016 US election.

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Committee reports

Audit committee

Chairman s introduction

The committee has focused on the financial performance of the group in a challenging external environment over the year. Issues considered included the impact of weak commodity prices on oil and gas accounting judgements and asset carrying values and how changes in key long-term price assumptions impacted investment appraisals.

A significant activity of the committee in 2016 was the tender of the external audit. I believe the tender process was thorough, open and transparent and I was pleased that the governance arrangements put in place enabled the committee to make a decision based on high quality proposals put forward by all the firms involved. Subject to approval by shareholders, we look forward to working with Deloitte as our new auditor from 2018. We thank EY for their strong professional standards and all they have done to provide assurance to the board during their time as BP s auditor.

Phuthuma Nhleko retired from the committee in April 2016. He brought thoughtfulness and challenge to the debate in the committee and I thank him for his contribution during his tenure. I welcome Nils Andersen who joined the committee in October 2016 and has commercial experience from a career in energy, shipping and consumer goods. I believe that the deep and varied experience of the committee members gives perspective and insight to our discussions with management.

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 systems of internal control and risk management.

Overseeing the appointment, remuneration, independence and performance of the external auditor and the integrity of the audit process as a whole, including the engagement of the external auditor to supply non-audit services to BP.

Reviewing the systems in place to enable those who work for BP to raise concerns about possible improprieties in financial reporting or other issues and for those matters to be investigated.

Members	
Brendan Nelson	Member since November 2010; chair since April 2011
Nils Andersen	Member since October 2016
Phuthuma Nhleko	Member from February 2011 to April 2016
Paula 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 and a member of the Financial Reporting Review Panel. 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 and competence in accounting and auditing as required by the FCA s Corporate Governance Rules in DTR7. 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, as well as competence in the oil and gas sector. 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 14 committee meetings in 2016, of which five were carried out by teleconference. All directors attended every meeting during the period in which they were committee members.

Regular attendees at the committee meetings include the chief financial officer, group controller, chief accounting officer, group head of audit and external auditor.

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Activities during the year

Financial disclosure

The committee reviewed the quarterly, half-year and annual financial statements with management, focusing on:

- Integrity and clarity of disclosure.
- Compliance with relevant legal and financial reporting standards.
- Application of critical accounting policies and judgements.

The committee considered the *BP Annual Report and Form 20-F 2016* and was delegated by the board to undertake final review and sign off of the document. The audit committee reviewed whether the Annual Report was fair, balanced and understandable and provided the information necessary for shareholders to assess the group s position and performance, business model and strategy. It made a recommendation to the board who in turn reviewed the report as a whole.

Other disclosures reviewed included:

- Oil and gas reserves.
- Pensions and post-retirement benefits assumptions.
- Viability statement.
- Tax strategy.
- Going concern.
- Risk factors.
- Legal liabilities.

Risk reviews

The principal risks allocated to the audit committee for monitoring in 2016 included those associated with:

Trading activities: including risks arising from shortcomings or failures in systems, risk management methodology, internal control processes or employees.

In reviewing this risk, the committee focused on developments in the external market and how BP s trading function had responded including new areas of activity and impacts on the control environment. The committee further considered updates in the trading function s risk management programme, including compliance with regulatory developments.

Compliance with applicable laws and regulations: including ethical misconduct or breaches of applicable laws or regulations that could damage BP s reputation, adversely affect operational results and/or shareholder value and potentially affect BP s licence to operate.

The committee reviewed key areas of BP s ethics and compliance programme, including the integration of the business integrity and ethics and compliance functions, development of the anti-bribery and corruption elements of the programme, enhanced policies, tools and training and strengthening of counterparty risk measures, including due diligence.

Security threats against BP s digital infrastructure: including inappropriate access to or misuse of information and systems and disruption of business activity.

The committee reviewed changes in the cybersecurity landscape, including events in the energy, oil and gas industry and within BP itself. The review focused on the improvements made in managing cyber risk, including the application of the three lines of defence model and the committee examined indicators associated with risk management and barrier performance.

Financial resilience: including the risk associated with external market conditions, supply and demand and prices achieved for BP s products which could impact financial performance.

The committee reviewed the key price assumptions used by the group for investment appraisal and the judgements underlying those proposals, the cost of capital and its application as a discount rate to evaluate long-term BP business projects, liquidity (including credit rating, hedging, long-term commercial commitments and credit risk) and the effectiveness and efficiency of the capital investment into major projects«. risks and financial group risks, including taxation matters and the group s process to assess, mitigate and monitor them.

BP s principal risks are listed on page 49.

The committee examined the group s information technology

For 2017, the board has agreed that the committee will continue to monitor the same four group risks as for 2016.

Other reviews

Other reviews undertaken during 2016 by the committee included:

Upstream: including financial performance, strategy and how the Upstream finance function supports the segment.

Other businesses and corporate: including the various business and functional activities which constitute Other businesses and corporate and how the group finance organization supports these activities and the broad framework of financial control.

Procurement: including BP s procurement spend profile, key risks and controls.

Asset carrying values: insight into the group s approach to reviewing asset carrying values for financial reporting purposes, particularly in the Upstream segment including IFRS requirements and BP s policies.

Financial metrics proposed for BP s new remuneration policy: consideration of potential financial metrics for inclusion in the annual bonus and long-term incentive plan elements of the new policy.

Internal control and risk management

During the year the committee received quarterly reports on the findings of group audit. It reviewed the scope, activity and effectiveness of the group audit function, with a focus on how changes in the organizational structure had been implemented. In addition, the committee met privately with the group head of audit and key members of his leadership team.

The audit committee also held private meetings with the group ethics and compliance officer during the year.

Training

The committee held learning events on the Modern Slavery Act and global trends in corporate fraud. It received technical updates from the chief accounting officer on developments in financial reporting and accounting policy, including IFRS 16, the new lease accounting standard.

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Accounting judgements and estimates

During 2016, the committee was briefed on a quarterly basis on the group s key accounting judgements and estimates and was also

briefed in detail on various items during the course of the year. Areas of significant judgement considered by the committee during the year and how these were addressed included:

Key issues/judgements in financial reporting	Audit committee review and conclusions
Oil and natural gas accounting	
BP uses judgement and estimations when accounting for oil and gas exploration, appraisal and development expenditure and in determining the group s estimated oil and gas reserves.	g The committee reviewed judgemental aspects of oil and gas accounting such as intangible asset balances relating to exploration and appraisal activities and exploration write-offs as part of the company s quarterly due-diligence process. The committee was also briefed on the year-end reserves process including governance and control activities.
Recoverability of asset carrying values	
Determination as to whether and how much an asset is impaired involves management judgement and estimates on 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.	g The committee reviewed the discount rates for impairment testing as part of its annual process and examined the assumptions for future oil and gas prices and refining margins. The committee was briefed by management on any changes made to key assumptions during the year. The majority of the Upstream segment s tangible assets were tested for impairment in 2016 and the group recorded a net impairment reversal of $1.9 billion for the year.

g The group s long-term price assumptions for Brent« oil, Henry Hub« gas and UK National Balancing Point« gas were all reduced in 2016 and the discount rate used for impairment testing was also reduced.

g The committee monitored the position on any material overdue receivables and any associated provisions.

Accounting for interests in other entities

BP exercises judgement when assessing the level of control it has as a result of its interests in other entities and when determining the fair value of assets acquired and liabilities assumed.

g The committee reviewed the judgement on whether the group has significant influence over Rosneft. The committee received reports from management and the external auditor which assessed the extent of significant influence, including BP s participation in decision making through the election of two BP directors to the Rosneft board and ongoing work on significant transactions and projects.

g The committee was briefed on the accounting for transactions during the year including the dissolution of the joint operation with Rosneft and the disposal of BP s Norwegian upstream business in exchange for an interest in Aker BP.

Derivative financial instruments

BP uses judgement when estimating the fair value of some derivative instruments in cases where there is an absence of liquid market pricing information for example, relating to integrated supply and trading (IST) activities.

g The committee received a briefing on the group s trading risks including the valuation of derivative instruments using models where observable market pricing is not available. The committee also visited the BP trading floor in London and received detailed presentations on the prevention of erroneous or fraudulent trades, carbon trading and BP s oil trading activities.

Provisions and contingencies

BP s most significant provisions relate to decommissioning, the Gulf of Mexico oil spill, environmental remediation, litigation and tax.	g Provisioning for, and the disclosure of contingent liabilities relating to the Gulf of Mexico oil spill was discussed with the committee each quarter as part of the review of the Stock Exchange Announcement.
The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. Most of these decommissioning events are in the long term and the requirements that will have to be met when a removal event occurs are uncertain. Judgement is applied by BP in relation to settlement dates, technology and legal requirements, among other factors.	g The committee discussed the provisions established in the second quarter as a result of the judgement that a reliable estimate could be made for all remaining material liabilities arising from the Gulf of Mexico oil spill. Revisions to existing provisions were also reviewed by the committee. g 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.

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.	g The committee examined the assumptions used by management as part of its annual reporting process.

Taxation

Computation of the group s tax expense and liability, the provisioning for potential tax liabilities and the level of deferred tax asset recognition are underpinned by management judgement.	g The committee reviewed the judgements exercised on tax provisioning as part of its annual review of key provisions and was briefed on any material changes to deferred tax asset recognition.

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External audit

Audit risk

The external auditor set out its audit strategy, identifying key risks to be monitored during the year. These included:

- Determining the liabilities, contingent liabilities and disclosures arising from the Gulf of Mexico oil spill.
- Estimating oil and gas reserves and resources which has significant impact on the financial statements, particularly impairment testing and the calculation of depreciation, depletion and amortization.
- Monitoring for unauthorized trading activity within the trading function and its potential impact on the group s results.
- The potential of the macroeconomic environment to materially impact the carrying value of the group s upstream non-current assets.

The committee received updates during the year on the audit process, including how the auditor had challenged the group s assumptions on these issues.

Audit fees

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 $47 million (2015 $51 million), of which 4% was for non-audit assurance work (see Financial statements Note 35). 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. Non-audit or non-audit related assurance fees were $2 million (2015 $3 million). The $1-million reduction in non-audit fees relates primarily to a reduction in the amount of fees for other assurance services and services relating to corporate finance transactions. Non-audit or non-audit related services consisted of tax compliance services and other assurance services.

Audit effectiveness

The effectiveness of the audit process was evaluated through separate surveys for the committee members and those BP personnel impacted by the audit, including chief financial officers, controllers, finance managers and individuals responsible for accounting policy and internal controls over financial reporting. The surveys used a set of criteria to measure the auditor s performance against the quality commitment set out in their annual audit plan, including:

Robustness of the audit process.

Independence and objectivity.

Quality of delivery.

Quality of people and service.

Value added advice.

Overall the 2016 evaluation concluded that the external auditor performance had either improved or remained largely constant in key areas compared to the previous year. Areas with high scores included quality of delivery of the audit and technical knowledge and expertise.

A key area of focus from 2015 regarded liaison between BP s own audit function and the external auditors. Actions taken over the year resulted in an improvement in scoring for the 2016 survey. Results of the annual assessment exercise were discussed with the external auditor who considered these themes for the 2016 audit service approach.

The committee held private meetings with the external auditor during the year and the committee chair met separately with the external auditor and group head of audit 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. The committee assesses the independence of the external auditor on an ongoing basis and the external auditor is required to rotate the lead audit partner every five years and other senior audit staff every seven years. The current lead partner has been in place since the start of 2013. No partners or senior staff associated with the BP audit may transfer to the group.

Non-audit services

The audit committee is responsible for BP s policy on non-audit services and the approval of non-audit services. Audit objectivity and independence is safeguarded through the limitation of non-audit services to tax and audit-related work which falls within defined categories. BP s policy on non-audit services states that the auditors may not perform non-audit services that are prohibited by the SEC, Public Company Accounting Oversight Board (PCAOB), UK Auditing Practices Board (APB) and the UK Financial Reporting Council (FRC).

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.

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 268.

In response to the revised regulatory guidelines of the FRC, the committee reviewed and updated its policies with effect from 1 January 2017. Changes included:

Adoption of the FRC s prohibited non-audit services list.

Prohibition of all non-audit tax services by the audit firm from 2017 onwards.

Reduction of the pre-approval requirements for non-audit services in line with FRC guidance on how non-trivial engagements with the audit firm should be pre-approved by the audit committee.

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Audit tendering

The audit committee announced its intention to launch a competitive audit tender process in BP s 2013 annual report. The tender process took place in 2016, with a view to appointing a new external auditor for the 2018 financial year.

The new audit appointment will be with effect from 2018 to facilitate an orderly and thorough handover from the existing auditor and to ensure that the new auditor meets all relevant independence criteria before the commencement of the appointment.

Governance

The audit committee was responsible for the operation of the audit tender process, for making a report on the evaluation of the proposals received during the tender process to BP s board and for recommending two firms of auditors to the board together with the audit committee s preference between those two firms and its reasons for that preference.

The governance model established by the audit committee to manage and support the tender constituted three key groups:

Responsibility	Members
Executive advisory panel	
Assess the firms proposals. Investigate aspects of capability. Present a findings report to the audit committee.	Chief financial officers of BP s business segments and heads of its financial functions and group head of audit.

Governance board	
Govern the day-to-day running of the tender process. Oversee the execution of the tender. Ensure the goals set for the tender by the audit committee are met. Gather information about the proposals and communicate to the committee.	Chaired by the group controller, with representatives from internal functions including indirect procurement, legal, group control and financial reporting.

Tender project team	
Liaison with the bidding firms. Logistical support to the tender. Support for executive advisory panel and governance board.	Representatives from the finance and procurement functions.

In delegating the day-to-day running of the tender process to the governance board, the audit committee asked that the tender be designed to implement a robust process to enable the selection of an auditor that would be the best fit for the role of external auditor based on the evaluation criteria agreed by the audit committee and provide the appropriate level of assurance to BP s shareholders.

Assessment criteria

An assessment was undertaken to identify which firms would be reasonably likely to be capable of performing the audit and invited to participate in the tender; this assessment considered:

Sector experience.

Size and geographical presence.

Extent and nature of existing non-audit services work with BP.

Based on this assessment, three firms were shortlisted to receive the formal tender request for proposal (RFP). EY, BP s existing auditor was not invited to participate due to the legal requirement for BP to rotate its auditor by 2020.

Evaluation

Prior to the RFP being formally launched, briefing meetings were held with each firm covering key BP segments, functions and geographies; in addition the audit committee held introductory meetings with the lead and senior partners from each firm.

In preparation for the tender, BP sought assurance that each firm would be capable of being independent in the time frame required by applicable law or regulation before being appointed auditor. The due-diligence activities conducted as part of the tender included a review of firm independence.

The proposals from the three firms were evaluated by the audit committee against the following criteria, as well as the combined performance as a whole:

Audit quality.

Business knowledge.

People, behaviours and cultural fit.

Planning and project management, including transition.

Innovation and insight.

Independence.

Commercial and contractual structure.

At the request of the audit committee chair, the commercial and contractual structure elements were assessed separately from the other aspects of the firms proposals. Evaluation of the proposals was conducted on a fee blind basis.

Following completion of the evaluation, the audit committee recommended two firms to the board for approval, with a stated preference for Deloitte. The audit committee believe that Deloitte has a strong team with the skills and experience to provide rigour and challenge in the audit.

After considering the audit committee s recommendation, the board selected Deloitte as BP s auditor for the financial year ending 31 December 2018 subject to the approval of shareholders at the 2018 annual general meeting.

BP has complied throughout 2016 with the Statutory Audit Services Order 2014, issued by the Competition and Markets Authority.

Committee evaluation

The audit committee undertakes an annual evaluation of its performance and effectiveness.

2016 evaluation

For 2016 an internal questionnaire was used to evaluate the work of the committee. The review concluded that the committee had performed effectively. Priorities for 2017 include a review of and visit to BP s global business service centres, focus on streamlining committee materials and further scrutiny on risk management when undertaking business or functional reviews.

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 (see page 67) as well as maintaining its schedule of regular meetings with executive management.

A particular highlight was confirmation in January that all 26 of the Bly Report recommendations had been completed across the global wells organization (GWO). At the same time, we received the final report from Carl Sandlin, the independent expert we engaged in Upstream, in which he reported to the committee that such completion had occurred. Carl had provided valuable insights and advice to the GWO around safety in wells and process safety more generally, and we were grateful to him for his work.

Paul Anderson stepped down as chair of the committee in May, having been the chair since 2012. I am grateful for the opportunity to chair the committee and we all wish to thank Paul for his service.

Alan Boeckmann

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 risks are appropriate in their 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.

The SEEAC and audit committee worked together, through their chairs and secretaries, to ensure that agendas did not overlap or omit coverage of any key risks during the year.

Members	
Alan Boeckmann	Member since September 2014 and chair since May 2016
Paul Anderson	Member since February 2010
Frank Bowman	Member since November 2010
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 2016. All directors attended every meeting for which they were eligible, with the exception of Cynthia Carroll who did not attend the committee meeting on 14 December due to a conflicting external board meeting.

In addition to the committee members, 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. The group general counsel and group ethics and compliance officer also attended some of the meetings. At the conclusion of each meeting the committee scheduled private sessions for the committee members only, without the presence of executive management, to discuss any issues arising and the quality of the meeting.

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Activities during the year

System of internal control and risk management

The review of operational risk and performance forms a large part of the committee s agenda.

Group audit provided reports on their assurance work on the system to inform the review.

The committee also received regular reports from the group chief executive on operational risk, and 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. The committee also received quarterly reports from group audit. In addition, the group ethics and compliance officer met in private with the chairman and other members of the committee over the course of the year.

During the year the committee received separate reports on the company s management of risks in:

- Marine
- Wells
- Pipelines
- Explosion or release at our facilities
- Major security incidents
- Cybersecurity (process control networks).

The committee reviewed these risks and their management and mitigation in depth with relevant executive management.

Independent expert Upstream

Mr Carl Sandlin completed his role as an independent expert in providing oversight regarding the implementation of the Bly Report recommendations. In January 2016, he reported to the committee that all 26 recommendations in the Bly Report had been completed by the end of 2015. We thank him for his work with the committee since 2012.

Field trips

In August the committee (and other directors) visited Alaska. The visit encompassed both the Anchorage office and a trip to review operations on the North Slope. In November they visited operations of the US Lower 48 business in Durango, Colorado. In December they visited the Geel petrochemicals facility in Belgium. In all cases, the visiting committee members and other directors received briefings on operations, the status of conformance with the operating management system« (OMS), key business and operational risks and risk management and mitigation. Committee members then reported back in detail about each visit to the committee and subsequently to the board. See page 67 for further details.

Corporate reporting

The committee is responsible for the overview of the *BP Sustainability Report 2016.* The committee reviewed content and presentation, and worked with the external auditor with respect to their assurance of the report.

Committee evaluation

For its 2016 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.

The evaluation results continued to be generally positive. Committee members considered that they continued to possess the right mix of skills and background, had an appropriate level of support and received open and transparent briefings from management. All committee members emphasized that field trips remained an important element of its work, particularly because they gave committee members the opportunity to examine how risk management is being embedded in businesses and facilities, including management culture. Joint meetings between the committee and the audit committee were considered important in reviewing and gaining assurance around financial and operational risks where there was overlap between the committees, particularly in relation to ethics and compliance (see below).

Joint meetings of the audit and safety, ethics and environment assurance committees

During the year it was decided to hold standalone joint meetings of the audit committee and SEEAC on a quarterly basis in order to simplify reporting of key issues which were within the remit of both committees and make more effective use of the committees time. Each committee retains full discretion to require a further presentation and discussion on any joint meeting topic at their respective meeting if deemed appropriate.

The committees jointly met four times during 2016, with chairmanship of the meetings alternating between the chairman of the audit committee and the chairman of the SEEAC.

At these meetings the committee reviewed ethics and compliance and business integrity reports (including significant investigations and allegations), together with the annual ethics certification and the 2017 forward programmes for the group audit and ethics and compliance functions.

« See Glossary.

Remuneration committee

Chair s introduction

I am pleased to report on the work of the committee in 2016. This has been a challenging year following the loss of the vote on our remuneration report at the 2016 AGM. Since then our work has focused on engaging with shareholders, reflecting on their views, developing a new remuneration policy for the board, and on determining pay outcomes for 2016. Proposals for our new policy are set out in the Directors remuneration report on pages 101-110. The policy will be put forward for approval by shareholders at the 2017 AGM.

The committee s membership and detailed activities over the year are contained in this part of the annual report.

Professor Dame Ann Dowling

Committee chair

Role of the committee

The role of the committee is to determine and recommend to the board the remuneration policy for the chairman and executive directors. In determining the policy the committee takes into account various factors, including structuring the policy to promote the long-term success of the company and linking reward and business performance.

Key responsibilities

The committee undertakes its tasks in accordance with applicable regulations, including those made from time to time under the Companies Act 2006, the UK Corporate Governance Code and the UK Listing Authority s Listing Rules in relation to the remuneration of directors of quoted companies.

Determine the policy for the chairman and the executive directors (the policy) for inclusion in the remuneration policy for all directors.

Review and determine the terms of engagement, remuneration and termination of employment of the chairman and the executive directors as appropriate and in accordance with the policy, and be responsible for compliance with all remuneration issues relating to the chairman and the executive directors.

Prepare the annual report to shareholders to show how the policy has been implemented, so far as it relates to the chairman and the executive directors.

Approve the principles of any equity plan that requires shareholder approval.

Approve the terms of the remuneration (including pension and termination arrangements) of the executive team as proposed by the group chief executive.

Approve changes to the design of remuneration, as proposed by the group chief executive, 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.

Members	
Ann Dowling	Member since July 2012 and chair since May 2015
Alan Boeckmann	Member since May 2015
Antony Burgmans	Member from May 2009 to April 2016 and chair from May 2011 to May 2015
Ian Davis	Member since July 2010
Andrew Shilston	Member since May 2015

Antony Burgmans stood down from the committee upon his retirement from the board in April 2016.

Carl-Henric Svanberg and Bob Dudley attend meetings of the committee except for matters relating to their own remuneration. Bob Dudley is consulted on the remuneration of other executive directors and the executive team. Both executive directors are consulted on matters relating to the group s performance.

The group human resources director normally attends meetings and other executives may attend where necessary. The committee consults other board committees on the group s performance and on issues relating to the exercise of judgement or discretion.

Meetings and attendance

The committee met 11 times during the year; twice before the AGM and on nine occasions since. All directors attended each meeting that they were eligible to attend, either in person or by telephone, with the following exceptions:

Antony Burgmans did not attend the meeting on 17 March due to a conflict with an external meeting.

Andrew Shilston did not attend the meeting on 21 June, scheduled at late notice, due to a prior commitment.

Activities during the year

In the months before the AGM, the committee focused on the outcomes for 2015. This involved reviewing directors salaries and the group s performance outcome which in turn determined outcomes for the annual bonus and the Executive Directors Incentive Plan (EDIP).

Following the negative vote on the Directors remuneration report (DRR), the chairman and the chair of the remuneration committee made a commitment at the 2016 AGM to be responsive to shareholder feedback and to formulate a new policy for 2017.

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For the remainder of 2016 and into early 2017, the committee has focused on developing a new policy and then determining pay outcomes for 2016 (the final year of the 2014 policy). It examined the circumstances around the adverse vote and considered feedback from the engagement with shareholders.

Committee focus after the AGM

A detailed work plan for the committee was agreed for the year. The committee chair spoke to a number of the company s larger shareholders shortly after the AGM and began a structured shareholder engagement programme in the UK and US.

The committee decided that a new remuneration adviser should be appointed to assist with its work. After a competitive tender process Deloitte was appointed and has been working with the committee since May 2016.

The committee, over the series of meetings:

- Analysed the structure and operation of remuneration and compared it with prevailing and emerging best practice.
- Considered a broad range of options in discussion with shareholders before distilling to two choices for full shareholder consultation.
- Conducted a detailed review of the number, use and combination of performance measures to assess how they could be simplified while also supporting the business strategy.
- Considered the quantum of incentives in the context of securing fair and commercial outcomes relative to senior colleagues.
- Reviewed scenarios to improve alignment of remuneration outcomes with shareholder interests.
- Conducted a final review of the proposed policy to ensure that it would continue to promote the company s long-term business strategy.

The committee has also considered the implications of the transition from the 2014 to the 2017 policies, in particular relating to share grants and pension. It also reviewed potential outcomes for 2016 at the end of the year.

In all its discussions the committee has focused on the overall quantum of executive director remuneration and has sought to reflect the views of shareholders and the broader societal context in its decisions.

Shareholder engagement

There has been substantial engagement with shareholders during the year. This has been carried out primarily by the chair of the committee, with additional dialogue by the chairman and the company secretary. Engagement by the committee chair was aimed at understanding shareholders views on the company s 2014 policy, testing proposals and seeking support for the new policy to be put to shareholders at the 2017 AGM. Meetings with proxy voting agencies have also taken place. In total, the remuneration committee chair has held 68 meetings or calls with investors and proxy advisers in the period from May 2016 to the 2017 AGM. These meetings were conducted to understand concerns, test strategic direction and present a refined policy.

Committee evaluation

An internally facilitated evaluation was undertaken in 2016 to examine the committee s performance during the year. The evaluation concluded that the committee had conducted an effective review of a wide range of options when considering the new policy and was addressing effectively the balance of commercial and societal constraints.

Focus areas for 2017 included maintaining oversight of stakeholder and investor views on remuneration, staying up to date with external developments and best practice, while managing the challenge of the transition between the 2014 and 2017 remuneration policies.

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Geopolitical committee

Chairman s introduction

I am pleased to report on the work of the geopolitical committee in 2016. I thank Antony Burgmans for his work as chair of this committee in the first part of the year.

Sir John Sawers

Committee chair

Role of the committee

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

Key responsibilities

- Monitor the company s identification and management of major and correlated geopolitical risk and 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.
- Review the company s activities in the context of political and economic developments on a regional basis and advise the board on these elements in its consideration of BP s strategy and the annual plan.

Members	

John Sawers	Member since September 2015 and chair since April 2016
Paul Anderson	Member since September 2015
Frank Bowman	Member since September 2015
Antony Burgmans	Chair from September 2015 to April 2016
Cynthia Carroll	Member since September 2015
Ian Davis	Member since September 2016
Phuthuma Nhleko	Member from September 2015 to April 2016
Andrew Shilston	Member since September 2015

In 2016 Ian Davis joined the committee, Antony Burgmans and Phuthuma Nhleko left the committee on retirement from the board, and Sir John Sawers became the new chair.

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

Meetings and attendance

The committee met three times during the year. All directors attended each meeting that they were eligible to attend.

Activities during the year

The committee developed the work it had started in 2015 by considering issues that affect all BP s key geographies, for example the continuing low oil price and BP s investment approach.

The implications of the UK referendum on Brexit and the US presidential election were discussed at each meeting.

The committee considered the impact of geopolitical events on BP s interests in the Middle East and in Egypt, Russia and Turkey.

Committee evaluation

The committee held its first review at the end of 2016, focusing on its processes and effectiveness. The review was undertaken through a questionnaire, with the committee discussing the output of the evaluation in a private session at its February 2017 meeting.

The review concluded that while the committee was still evolving in terms of coverage and content, it had performed effectively. Areas of focus for 2017 included gaining greater insight and advice from advisers with direct political experience and placing emphasis on those regions and topics that would most impact BP s business or reputation as a way of helping to ease time pressure on the committee s agenda.

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Chairman s and nomination committees

Chairman s introduction

The chairman s and nomination committees have been actively involved in the evolution of the board and its work in 2016.

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 succession plans for the group chief executive, 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 the non-executive directors. Directors join the committee immediately on their appointment to the board. The group chief executive attends meetings of the committee when requested.

Meetings and attendance

The committee met seven times in 2016. All directors attended every meeting for which they were eligible, with the exception of Cynthia Carroll who did not attend the meeting on 26 May as she had to attend a family event. The chairman did not attend the meeting on 28 January as it was for his evaluation.

Activities during the year

Evaluated the performance of the chairman and the group chief executive.

Reviewed the evolution of the company s strategy given anticipated market conditions over the coming decade and the approach adopted for the annual plan.

Assessed the prioritization of investment opportunities.

Considered succession plans for the senior executive team.

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 the mix of knowledge, skills and experience of the board under review to ensure the orderly succession of directors.

Review the outside directorship/commitments of non-executive directors.

Members	

Carl-Henric Svanberg	Member since September 2009 and chair since January 2010
Alan Boeckmann	Member since April 2016
Ann Dowling	Member since May 2015
Ian Davis	Member since August 2010
John Sawers	Member since April 2016
Andrew Shilston	Member since May 2015; attended meetings previously as senior independent director

Alan Boeckmann and Sir John Sawers joined the committee in 2016. Paul Anderson and Brendan Nelson stood down, and Antony Burgmans left on his retirement from the board.

Meetings and attendance

The committee met five times during the year. All directors attended each meeting that they were eligible to attend.

Activities during the year

The committee continued to keep the composition and skills of the board under review.

Cynthia Carroll and Andrew Shilston will be standing down from the board in 2017 and there will be further retirements in 2018. The committee focused on maintaining a strong group of current and former chief executives, while ensuring appropriate diversity in all forms.

The committee appointed Nils Andersen, the former CEO of Maersk, to the board in October 2016. A search has been initiated for further candidates with the intent of maintaining the gender diversity on the board, and as a result the board is proposing Melody Meyer for election as a director at the 2017 AGM.

The board as a whole considers succession planning and diversity as discussed on pages 64-65.

Committee evaluation

The evaluation concluded that the committee was generally working well. It was important to ensure that future work would be focused on building a board capable of governing the company as it implements its strategy towards 2021 and beyond. There should be a strong continued focus on diversity.

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Directors remuneration report

Letter from the remuneration committee chair

Dear shareholder,

Last year s AGM remuneration vote was a clear message about how we manage executive pay. We made a commitment to respond in a constructive way and have taken a comprehensive look at remuneration of our executive directors.

We have held extensive dialogue with many of our largest shareholders as well as representative bodies beginning in May 2016 and running through to this year s AGM. We have listened and sought to respond to their concerns. I would like to thank all those who took part in the process for their time and insight. It is clear that shareholders and other stakeholders would like our remuneration policy to be simpler, more transparent, and to lead to reduced levels of reward. There is also a wish to see the committee make greater use of discretion.

BP is a global company with a global management team, competing for talent in a demanding environment. The company s ability to attract and retain the high-calibre executives required to lead this complex business is important for shareholders. We are mindful of

We are proposing to make a number of significant changes to our remuneration policy for 2017 which will make it simpler, better align pay and performance, and lead to a reduced maximum award for the group chief executive (GCE) and the chief financial officer (CFO).

Although we are still working under our 2014 policy, we have used some of the principles from our new policy in making our decisions for pay in 2016. We have considered the formulaic results and outcomes for shareholders and then exercised downward discretion to reach our final decisions.

As a result in a year of good performance and progress Bob Dudley s total single figure for 2016 has been reduced by some 40% compared to last year.

Future remuneration policy

this and have tried to balance these commercial pressures with the wider social context when determining executive pay.

The proposed remuneration policy is designed to ensure a clear link between delivery of BP s strategy and pay.

Over the past year, there has been much debate in the UK regarding pay models. We appointed new independent advisers and approached our review with an open mind. We explored a number of different

Key outcomes for 2016

Bob Dudley total pay

A year of progress and performance for the company.	Total single figure in 2016 for Bob Dudley is $11.6 million 40% lower than for 2015.

Committee discretion reduced pay by $2.2 million.	Maximum opportunity for 2017 and beyond significantly reduced.

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Directors remuneration report **overview**

remuneration structures before focusing on two for further consideration restricted shares and performance shares. We consulted with shareholders and the board has reaffirmed its view that performance shares rather than restricted shares remain the appropriate structure at the current time as they align pay outcomes with long-term performance.

Key changes

From 2017, we propose a simplified approach with a significant reduction in overall remuneration levels.

- We will operate only two incentive plans a short-term annual bonus and a long-term performance share plan.
- The maximum annual bonus will only be earned where stretch performance is delivered on every measure.
- The level of bonus paid for an on-target score will be reduced by 25%.
- The bonus performance scale for executive directors will be the same as the wider professional and managerial employee population.
- The proportion of annual bonus that must be deferred into shares will be increased from 33% to 50%.
- Deferred shares will no longer be matched with additional shares.
- The maximum longer-term incentives for the GCE will be reduced from seven times salary (previously granted as matching shares on the deferred annual bonus and performance shares) to a maximum of five times salary.

Policy features

In addition, the following features of the new policy support the group s long-term strategic priorities, which are in the interests of all stakeholders:

- A simplified performance assessment providing a clear link between the delivery of BP s strategy, outcomes for shareholders and pay.

An annual bonus that rewards safety, reliable operations and financial performance during the year based on the annual plan.

For long-term performance share awards, performance will be tested and shares will vest after three years, but awards will not be released until the end of a further three-year period a six-year period in total. This lengthy period reinforces the executive s stewardship of the company.

Target ranges for total shareholder return (TSR) and return on average capital employed (ROACE) will be disclosed at the start of the performance period. For 2017 awards, these determine eighty per cent of the available performance shares.

The remainder of the performance shares will be based on strategic measures, including alignment with the company s progress towards a lower carbon transition over the longer term.

Where appropriate, the committee will exercise its discretion in determining outcomes, which will include a broader consideration of outcomes for shareholders, safety and environmental performance.

Stronger malus and clawback provisions.

Minimum shareholding requirements of five times base salary will be maintained, and a significant portion of the new package will continue to be linked to performance and delivered in BP shares. It is expected that Bob Dudley and Dr Brian Gilvary will maintain a shareholding of at least 250% of salary for two years following retirement.

How we responded to shareholders in developing our new policy

Simplification	Reduced package versus 2014 policy	Link to strategy	Stewardship
Simpler package fixed pay, bonus and long-term shares.	Maximum opportunity for long-term incentives has been significantly reduced from seven times to five times salary for the GCE.	Clearer link between strategy and incentive targets.	Five times salary shareholding requirements.
Removal of matching shares.		Review of measures for bonus and	Post-retirement shareholding.

On-target bonus reduced by 25%.	long-term incentives. TSR and ROACE targets disclosed in advance.	Safety and the environment remain important considerations.

Directors remuneration report overview

Performance and pay for 2016

Our full year results were good in the context of tough conditions; however the board recognizes the opportunity for further improvement. We have made considerable progress over the year on a number of the measures by which we judge our performance. We have executed our projects safely and more efficiently. We have driven down costs and made careful judgements about the best use of capital.

The board has worked with Bob Dudley and the executive team on BP s strategic direction. This has been a significant step forward in defining BP s pathway to sustained growth. The year closed with the announcement of a number of major additions to our portfolio, all aimed at contributing to returns over both the short and the longer term.

All of this has been reflected in an improved share price during the year and good returns for shareholders.

2016 outcomes

We determined executive pay for 2016 and have exercised downward discretion in coming to our final decision.

the award, reflecting the wider performance of the business and outcomes for shareholders over the three-year period.

A portion of the annual bonuses for 2013 was deferred and a corresponding matching award made in 2014. Vesting required satisfactory safety and environmental sustainability performance over the three years from 2014 to 2016. The committee was satisfied that this condition had been met and these awards have vested in full.

From September 2016 Bob Dudley had no further service accrual under the defined benefit pension arrangements.

In a year of good performance and progress, the total single figure for Bob Dudley in 2016 is $11.6 million, 40% lower than for 2015.

In addition to the above, the executive directors have voluntarily agreed the extension of vesting periods for certain legacy share awards as a transitional approach to the new policy.

Conclusion

The annual bonus for 2016 was based on a combination of safety and value based measures.

Overall performance has been good; however the threshold performance for loss of primary containment (LOPC) was not met, partly due to harsher winter operating conditions in our unconventional gas operations in the US.

The committee exercised discretion and applied some of the principles of our new policy early. As a result, a bonus of 81% of maximum based on the previous formulaic outcome was reduced to 61% of the maximum.

For performance shares awarded in 2014, vesting will be determined by a combination of relative TSR, financial, safety and operational performance assessed over the three years from 2014 to 2016.

Again the committee has exercised discretion to reduce the vesting outcome, which is expected to be 40% of the maximum award. This discretion was applied to the operating cash flow element of

I believe that the board has responded positively to the events of 2016 and has taken significant action. In this, we have worked collaboratively with Bob Dudley and Dr Brian Gilvary.

The committee believes that the decisions on the 2016 outcomes represent a balance between BP s performance and shareholder outcomes over the relevant periods.

I have consulted widely with shareholders and listened to and sought to act on their concerns, and have been sensitive to developments in the society in which we work. We believe that the new policy is simpler, transparent and has strategic focus.

Professor Dame Ann Dowling

Chair of the remuneration committee

6 April 2017

How did we determine 2016 outcomes?

Assess performance	Review outcomes with board committees	Align with employees	Apply discretion	
Checked performance against safety and value measures.	Sought views from the audit and safety, ethics and environmental	Considered outcomes in relation to BP s group leaders and the broader comparator group of	Used judgement to reflect the broader market environment and outcomes for	**More information**

Reviewed the measures against targets set.	assurance committees to ensure a thorough review of performance.	US and UK employees in professional and managerial roles.	shareholders.	**Single figure table** Page 90 **Annual bonus scorecard** Page 92 **2014-2016 performance shares scorecard** Page 93

Directors remuneration report **overview**

Summary of our pay and performance for 2016

Directors remuneration report **overview**

Summary of our remuneration policy and approach for 2017

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Introduction

This year the board has prepared two reports on remuneration.

First, a report on how directors will be paid in 2017 and how the 2014 policy has been implemented for 2016. This will be the subject of an advisory vote at the 2017 AGM.

Second, a report which sets out the proposed 2017 remuneration policy for the three years commencing at the 2017 AGM. This will be the subject of a binding vote.

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Directors remuneration report

Features of 2017 policy

The remuneration policy proposed for 2017 is based on a detailed review of pay and an extensive programme of shareholder engagement following the 2016 AGM.

As a result, we are proposing some fundamental changes to simplify the structure and reduce the level of pay for our 2017 policy onwards.

Clearer link between pay and strategy

BP set out an update of its strategy in February 2017. The foundations for strong performance are safe and reliable operations, a balanced portfolio and a focus on returns. Our strategic priorities include:

Shareholders have been clear that they wish to see remuneration measures that are relevant to BP s strategy and long-term performance and which are genuinely stretching.

We are putting in place a balanced set of measures to enable a rounded assessment of performance against our strategy. Weightings for each of the measures may vary over time.

The culture of long-term stewardship is reinforced by the requirement for our senior leadership to own shares in BP over the long term.

Safety

The 2014 policy used safety measures in all three of its performance elements: the annual bonus, deferred shares and performance shares. A number of shareholders considered that this placed too much reward focus on safety measures.

The new policy retains tier 1 process safety events and recordable injury frequency as measures for the annual bonus. There are no longer safety measures for performance shares, however the committee will incorporate the group s longer-term safety and environmental performance as an underpin when evaluating outcomes for performance share awards. This will include consideration of a number of measures, including LOPC and input from the safety, ethics and environment assurance committee (SEEAC) to inform the exercise of the committee s discretion.

This ensures that BP s safety performance in the short and long term remains a significant consideration in remuneration.

Climate change

In 2015 the board supported a shareholder resolution which sought disclosure around BP s evolving approach to KPIs and executive incentives, in the context of the transition to a low carbon economy, including the role

Shareholder involvement in the new policy

The new policy reflects the outcome of an intense period of engagement with shareholders beginning in May 2016 and running through to this year s AGM. There has been extensive work by the remuneration committee and the board. The committee chair has held 68 meetings or calls and the committee has met 13 times since the 2016 AGM.

The committee has sought to address a number of matters raised during this engagement.

Simplification and transparency

Many shareholders said they found our 2014 policy too complicated.

In response the committee has simplified the structure by removing the matching share element of the deferred annual bonus. We have also reduced the number of measures used to determine the vesting of performance shares and have eliminated any duplication of measures between annual and long-term plans.

We have simplified the formula used to determine the payment of the annual bonus. Outperformance on every measure is now required to achieve maximum payment, aligning executive directors with the wider professional and managerial employee population.

In addition to this simplification, to improve transparency we will disclose the threshold and outperformance levels that determine the vesting of up to eighty per cent of the available performance shares for 2017 at the beginning of the performance period.

played by the relative reserves replacement ratio (RRR) .

The committee believes that our new strategic priorities support a lower carbon future. These include the shift towards gas in our portfolio and the growth of lower carbon activities including venturing, renewable trading and alternative energy.

The new policy provides an explicit link to our strategic priorities as a longer-term measure. The committee believes that the relative RRR measure does not fit with the group s strategic focus on value over volume .

The environmental underpin for performance shares will include consideration of issues around carbon and climate change.

Remuneration in the wider group

Some shareholders have asked about the relationship between executive director pay with the wider BP employee base.

The committee has considered this relationship in a number of ways:

Any percentage increase in executive directors salaries will not exceed the wider employee population.

Pension plans for the current executive directors have been scrutinized by the committee. The committee is satisfied that these plans should remain in place on the terms set out in the report, on the basis that they are open to broader groups of employees in the same home country and any discretion (e.g. payment in lieu of pension) is also applicable to wider groups of employees below executive level.

The ratio between GCE and employee pay, see page 96.

Discretion

Discretion and judgement remain features of the new policy and the committee has a clear understanding of the views of shareholders in respect of their use.

More information

Our strategy

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Implementation of 2017 policy

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2017 proposed policy

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Directors remuneration report

Implementation of 2017 policy

Salary and benefits

The committee noted that salary increases for UK and US based employees across the group were generally between 3-4%.

Bob Dudley has informed the committee that he does not intend to accept a salary increase for 2017 and therefore his salary will remain unchanged. His salary has not been increased since 1 July 2014.

Following the AGM, Dr Brian Gilvary s salary will be increased by 3.75%, which does not exceed increases within the broader employee population. This increase reflects the changes made to his role in 2016 when he took on additional responsibilities for BP s trading and shipping functions.

Benefits for 2017 will remain broadly unchanged from prior years.

Salary increases over the last five years

	Salary with effect from AGM	Increase
Bob Dudley	$1,854,000	Nil
Dr Brian Gilvary	£759,000	3.75%

For 2017, the bonus measures will focus on three areas: safety, reliable operations and financial performance.

This approach is intended to provide a balanced assessment of how the business has performed over the course of the year against stated objectives. Targets are aligned with the annual plan and strategic and operational priorities for the year.

The safety element has been simplified to focus on measures that are robust and can be readily benchmarked against sector peers. In addition, the measures linked to reliable operations also require execution of good safety practices.

Although the detail of the targets is currently commercially sensitive, the committee intends to continue to provide retrospective disclosure following the year end.

In order to provide a fair assessment of underlying performance, changes in plan conditions (including oil and gas prices and refining margins) are considered when reviewing financial outcomes.

Awards will be subject to malus and clawback provisions as set out in the policy.

The maximum bonus opportunity is 225% of salary for a bonus scorecard of 2.0 out of 2.0. As noted in the policy, the bonus payable for performance which meets the annual plan (i.e. a bonus scorecard of 1.0 out of a maximum of 2.0) has been reduced by 25% to half of maximum.

For any bonus earned, 50% will be delivered in cash and 50% must be deferred into shares that will vest after three years.

The committee retains overall discretion to review outcomes in the context of overall performance.

Measures for 2017 annual bonus

Element					
Safety 20%		Reliable operations 30%		Financial performance 50%	
Measures include	Metric weighting for 2017	Measures include	Metric weighting for 2017	Measures include	Metric weighting for 2017
Recordable injury frequency	10%	Upstream operating efficiency	15%	Operating cash flow (excluding Gulf of Mexico oil spill payments)	20%

Tier 1 process safety events	10%	Downstream refining availability (Solomon Associates operational availability)	15%	Underlying replacement cost profit	20%
				Upstream unit production costs	10%

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Directors remuneration report **implementation of 2017 policy**

Performance shares

The measures for 2017 performance share awards now focus on shareholder value, capital discipline and future growth.

Shareholder value

The total shareholder return (TSR) element will continue to be measured on a relative basis against the oil majors: Chevron, ExxonMobil, Shell and Total. The committee has reviewed the current comparator group and believes that it remains appropriate as it is used for benchmarking across a range of activities in other parts of the group. There will be no vesting of this element if BP s TSR is positioned below third place in the group.

Capital discipline

Return on average capital employed (ROACE) will be calculated by dividing the underlying replacement cost profit (after adding back net interest) by average capital employed excluding cash and goodwill.

This assessment will be based on the final year of the three-year period.

Targets for TSR and ROACE measures for 2017 determining 80% of the performance shares available are set out below at the start of the assessment period.

Future growth

Measures for the strategic element are aligned with the company s long-term strategy, positioning the portfolio for resilience and future growth. We will be following the implementation of our strategy through the four measures relating to the strategic priorities set out below. The committee has also sought input from the board regarding the specific measures.

Details of the strategic priorities targets determining 20% of the performance shares available are commercially sensitive and are not included in this report. However, the committee intends to provide detailed retrospective disclosure after the end of the performance period so that shareholders can understand the basis of payment.

Measures for 2017 performance shares

Element			
	Relative TSR versus oil majors[a] 50%	Return on average capital employed[b] 30%	Strategic progress 20%
Threshold vesting	25% of element Third out of five	0% of element 6% return on average capital employed	Shift to gas and advantaged oil in the upstream Market led growth in the downstream Venturing and low carbon across multiple fronts Gas, power and renewables trading and marketing growth
Maximum vesting	100% of element First Place	100% of element 11% return on average capital employed	

[a] Nil vesting for fourth and fifth place. Vesting of 80% for second place.

[b] Based on performance in 2019. There will be straight-line vesting for performance between the threshold and maximum vesting level. Adjustments may be required in certain circumstances (e.g. to reflect changes in accounting standards).

Operation of the performance share plan

Prior to approving vesting outcomes the committee will additionally take into account the broader performance of the business including absolute TSR performance, together with safety and environmental factors over the three-year period.

The maximum opportunity for share awards will be 500% of salary for Bob Dudley and 450% of salary for Dr Brian Gilvary. This represents a significant reduction from the previous long-term variable pay opportunity delivered via awards of performance and matching shares on the deferred annual bonus of 700% of salary for Bob Dudley and 550% of salary for Dr Brian Gilvary.

Performance will be measured over three years, with any vested shares being subject to a mandatory holding period for a further three years.

Awards will be subject to malus and clawback provisions as set out in the policy.

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Directors remuneration report **implementation of 2017 policy**

Retirement benefits

Bob Dudley and Dr Brian Gilvary participate in the pension arrangements which are available to wider groups of employees in the US and UK, as set out below.

Bob Dudley

Bob Dudley is provided with pension benefits and retirement savings through a combination of tax-qualified and non-qualified benefit plans, consistent with applicable US tax regulations.

The BP supplemental executive retirement benefit plan (SERB) is a non-qualified pension plan which provides a pension of 1.3% of final average earnings (as defined in plan rules) for each year of service, less benefits paid under all other BP (US) tax-qualified and non-qualified pension plans. Final average earnings include base salary, cash bonus and bonus deferred into a share award under the deferred element of the EDIP. Service, including service with TNK-BP, is limited to 37 years. Bob Dudley completed 37 years of service in September 2016 and therefore will not receive any further service accrual under these arrangements. There will be no additional payment in lieu of any further service accrual.

The benefit payable under the SERB is unreduced at age 60 or above.

Bob Dudley is also a member of other tax-qualified and non-qualified pension plans. However, the benefits from those plans are offset against the SERB benefit and so his benefit entitlement is determined by his participation in the SERB.

The BP Employee Savings Plan (ESP) is a US tax-qualified section 401(k) plan to which both Bob Dudley and BP contribute. BP matches contributions by Bob Dudley 1:1 up to 7% of eligible pay up to an IRS limit. The BP Excess Compensation (Savings) Plan (ECSP) is a non-qualified retirement savings plan under which BP provides a notional match in respect of eligible pay that exceeds the IRS limit. In common with other participants, Bob Dudley does not contribute to the ESCP. From 2017 onwards, for the purposes of both plans, eligible pay for Bob Dudley is base salary only.

Under both tax-qualified and non-qualified savings plans, Bob Dudley is 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.

Benefits payable under non-qualified plans are unfunded and therefore paid from corporate assets. Benefits are generally paid as a lump sum, with any pension benefit being converted to a lump sum equivalent.

Dr Brian Gilvary

Dr Brian Gilvary participates in a UK final salary pension plan, the BP Pension Scheme (BPPS), in respect of service prior to 1 April 2011. The BPPS provides a pension of one sixtieth of final base salary for each year of service, up to a maximum of two thirds of final base salary, and a dependant s benefit of two thirds of the member s pension.

Since 1 April 2011, Dr Brian Gilvary has, along with some other participants in the BPPS, elected to receive a cash supplement in lieu of future service pension accrual in the BPPS. In 2016 Dr Brian Gilvary received a cash supplement of 35% of base salary. It has been agreed for all participants who have elected to receive a cash supplement, including Dr Brian Gilvary, that a transition will take effect from April 2021 when the level of cash supplement will progressively reduce to 15% of base salary by 2024.

Pension benefits in excess of the individual lifetime allowance set by legislation are provided to Dr Brian Gilvary via an unapproved, unfunded pension arrangement provided directly by the company.

The rules of the BPPS were amended in 2006 to introduce a normal retirement age of 65, but in common with other BPPS participants in service on 30 November 2006, Dr Brian Gilvary has a normal retirement age of 60.

If Dr Brian Gilvary were to retire between age 55 and 60, then subject to the consent of the committee, he would be entitled to an immediate pension, with a reduction (currently 3%) for each year before normal retirement age in respect of the benefit that relates to service since 1 December 2006 and no reduction in respect of the remainder of his benefit.

Irrespective of this, on leaving in circumstances of total incapacity, an immediate unreduced pension would be payable as from his leaving date.

Shareholding requirements

Both executive directors meet the share ownership requirements of five times salary.

It is expected that Bob Dudley and Dr Brian Gilvary will maintain a shareholding of at least 250% of salary for two years following retirement.

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Directors remuneration report **implementation**

Single figure for 2016 executive directors

Single figure of remuneration for executive directors in 2016 (audited)

Remuneration is reported in the currency in which the individual is paid	Bob Dudley (thousand)		Dr Brian Gilvary (thousand)	
	2016	2015	**2016**	2015
Salary	**$1,854**	$1,854	**£732**	£732
Benefits	**$74**	$119	**£67**	£53
Bonus earned	**$2,545**	$4,172	**£1,004**	£1,646
Less: amount deferred and at risk subject to future performance[a]	**($848)**	($2,781)	**(£335)**	(£1,097)
Performance shares	**$3,713[b]**	$6,890[c]	**£1,387[b]**	£2,229[c]
Legacy: deferred bonus and match[d]	**$2,015**	$2,603	**£1,046**	£1,272
Total remuneration	**$9,353**	$12,857	**£3,901**	£4,835
Pension and retirement savings value increase[e]	**$2,205**	$6,519		
Cash in lieu of future accrual			**£256**	£256
Total including pension	**$11,558**	$19,376	**£4,157**	£5,091

Bob Dudley s total including pension for 2016 is equivalent to £8.57 million based on the average dollar-sterling exchange rate for 2016.

[a] This reflects the portion of the annual bonus which is deferred into shares and will only vest subject to achievement of future performance as described below.

[b] Represents the assumed vesting of shares in 2017 following the end of the relevant performance period, based on a preliminary assessment of performance achieved under the rules of the plan and includes reinvested 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 2016 which was £4.73 for ordinary shares and $35.39 for ADSs. The final vesting will be confirmed by the committee in second quarter 2017 and provided in the 2017 directors remuneration report.

[c] In accordance with UK regulations, in the 2015 single figure table, the performance outcome value was based on an estimated vesting at an assumed share price of £3.72 for ordinary shares and $33.81 for ADSs. In April 2016, after the external data became available, the committee reviewed the relative reserves replacement ratio position. This resulted in an adjustment to the final vesting from 77.6% to 74.3%. On 28 April 2016, 205,731 ADSs for Bob Dudley and 583,571 shares for Dr Brian Gilvary vested at prices of $33.49 and £3.82 respectively. The 2015 values for the total vesting have decreased by $226,330 for Bob Dudley and increased by £6,065 for Dr Brian Gilvary.

[d] Value of vested deferred bonus and matching shares. The amounts reported for 2016 relate to the 2013 annual bonus deferred over three years, which vested on 24 February 2017 at the market price of £4.47 for ordinary shares and $33.50 for ADSs and include reinvested dividends on shares vested. There was an additional accrual of notional dividends on 31 March 2017 which will vest in 2017 and will be provided in the 2017 directors remuneration report. The amounts reported for 2015 relate to the 2012 annual bonus.

[e] Represents (1) the annual increase net of inflation in accrued pension multiplied by 20 as prescribed by UK regulations, and (2) the aggregate value of the company match under Bob Dudley s US retirement savings arrangements. Full details are set out on page 94.

Bob Dudley		Dr Brian Gilvary	
Overall pay down	Performance pay down[b]	Overall pay down	Performance pay down[b]
40%	32%	18%	23%

[b] Bonus and performance shares.

Key outcomes for 2016

Bob Dudley total pay

A year of progress and performance for the company.	Total single figure in 2016 for Bob Dudley is $11.6 million 40% lower than for 2015.

Committee discretion reduced pay by $2.2 million.	Maximum opportunity for 2017 and beyond significantly reduced.

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Directors remuneration report **implementation**

Pay and performance for 2016

Salary and benefits

Base salary
No salary increases were awarded to executive directors for 2016. The 2016 salaries therefore remained unchanged from 1 July 2014: $1,854,000 for Bob Dudley and £731,500 for Dr Brian Gilvary.

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

Annual bonus

The targets for the 2016 annual bonus were set at the start of the year based on a combination of safety and value based measures. Targets were set in the context of the group s strategy and the annual plan.

During 2016 BP s share price performed strongly and the group distributed $7.5 billion to shareholders in cash and scrip dividends. However, it has clearly been another challenging year for the industry.

Over the course of 2016, the oil price averaged $44 per barrel, and both gas prices and refining margins remained weak compared to historic levels. In this context, the group s operating cash flow was solid. Goals for reduction in controllable costs were delivered one year ahead of schedule, and there has been good discipline on capital expenditure.

Trends in safety and environmental measures continued to be positive with outperformance against targets for tier 1 process safety events and recordable injury frequency. The outcome for loss of primary containment was partly impacted by harsher winter operating conditions in our unconventional gas operations in the US, and therefore the threshold set was not met. Although there was no payment against this performance measure, the committee noted that the 2016 outcomes did not create any safety concerns and that the longer-term trend for the measure remained positive.

More generally, good progress was made during 2016 to create a platform for future growth: the remaining material uncertainties regarding Deepwater Horizon liabilities have now been clarified; visible progress has been made in a number of upstream projects; and in our downstream business we rolled out our biggest fuels launch in a decade.

When reviewing performance over the period, the committee also sought input from the chairs of the audit committee and the safety, ethics and environment assurance committee to ensure a comprehensive review of peformance.

Overall, the performance delivered during the year resulted in a scorecard outcome of 1.22. Under the policy applicable for the year, approved by shareholders in 2014, this scorecard outcome would have resulted in a bonus outcome equal to 81% of the maximum available.

The committee considered the overall outcome and noted that while performance during the second and third quarters was strong, there were some challenges during the final quarter. The committee exercised discretion and applied some of the principles of the new policy early. As a result, the bonus of 81% of maximum based on the previous formulaic outcome was reduced to 61% of the maximum annual bonus available.

Overall, the committee believes that the bonuses for 2016 fairly reflect performance over the period.

Outcome

Name	Adjusted outcome after committee discretion (thousand)	Paid in cash (thousand)	Deferred into BP shares (thousand)
Bob Dudley	$2,545[a]	$1,696	$848
Dr Brian Gilvary	£1,004	£669	£335

[a] Due to rounding, the total does not agree exactly with the sum of its component parts.

Under the terms of the existing directors remuneration policy applicable for 2016, directors mandatorily defer a third of their bonus and could volunteer to defer a further third; the deferred portion of the annual bonus is then matched with a further performance-based award. The deferred and matching awards vest subject to a safety and environmental sustainability performance hurdle.

As a transition to the new policy, for 2016 the executive directors will defer a third of their bonus but will not have the opportunity to increase the potential matching award by voluntarily increasing the proportion of their bonus to be deferred.

In addition, with the support of the committee, the executive directors have elected to extend the vesting period for their matching awards in respect of the compulsorily deferred 2016 bonus, so that vesting will not occur until after retirement rather than the normal three-year period. During this extended period, the matching award will remain subject to the performance hurdle. The committee is of the view that this is a positive step as it significantly increases the time horizons for management s incentives, and reinforces the emphasis on stewardship, safety and the environment which remain core priorities for the group.

Annual bonus continued

Scorecard

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Directors remuneration report **implementation**

Performance shares

For performance shares awarded in 2014, vesting was determined by a combination of relative TSR, safety, financial and operational performance assessed over the three years from 2014 to 2016. The results are summarized in the table below.

Measured over the three-year period, the company s TSR was in third place amongst the five oil majors. The committee noted that returns on the value of BP s shares in sterling have also risen by 22% over this period, outperforming returns on the FTSE 100 index over the same timeframe.

The group delivered positive scores for tier 1 process safety events and recordable injury frequency. As noted above, the outcome for loss of primary containment was partly impacted by harsher winter operating conditions in our unconventional gas operations in the US. While the threshold for this element was not met, the outcomes did not create any safety concerns and the longer-term trend for the measure remains positive. The nil outcome provides an indication of the stretch of the original target range set.

In respect of project delivery, the vesting outcome reflects the strong progress over the three-year period. Further details of performance are set out in the strategic report.

Preliminary assessment of relative reserves replacement ratio indicates vesting for this measure. For the purpose of this report, a forecast has been used. The final outcome for this measure will be confirmed later in the year, once competitor data is published in full.

For operating cash flow, the hurdle for full vesting was originally set at $34.9 billion, based on an assumed oil price of $105 per barrel.

Under the methodology used and disclosed in prior years, this target would have been adjusted to reflect the price environment in 2016, when the actual average oil price was $44 per barrel. The adjusted target would mean that 60% of the award would vest for $15.3 billion, with full vesting occurring at $19.3 billion. The performance in 2016 would have resulted in a vesting outcome of just over 80% of the maximum available for this part of the award.

However, in light of shareholder feedback in 2016, the committee determined that it would be appropriate to exercise its discretion on this part of the award to ensure that the overall vesting outcome fairly reflected the performance of the business and outcomes for shareholders.

The committee undertook a wider review of performance over the three-year performance period, with additional consultation with the chairs of the audit committee and the safety, ethics and environment assurance committee. Following this review of performance, the committee determined that the vesting for the 2016 award should be reduced from the formulaic outcome of 57% of maximum to 40% of maximum.

Scorecard

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Directors remuneration report **implementation**

Performance shares continued

Preliminary outcome 2014-2016 performance shares

Name	Shares awarded	Shares vesting including dividends	Value of vested shares
Bob Dudley	1,304,922	629,484	$3,712,906
Dr Brian Gilvary	605,544	293,296	£1,387,290

These values are based on forecast vesting levels. As noted above, final vesting will be determined once competitor data is published in respect of relative reserves replacement.

2013-2015 performance shares final outcome

Last year the committee made a preliminary assessment of first place for the relative RRR in the 2013-2015 performance shares element.

In April 2016 the committee reviewed the results for all comparator companies as published in their annual reports and assessed that BP was in second place relative to other oil majors and that 7.8% of shares out of a maximum of 11.1% would vest for this performance measure. This resulted in a final overall vesting of 74.3% of maximum instead of the preliminary outcome of 77.6% outlined in the 2015 directors remuneration report.

Legacy: deferred bonus and matching award

Both Bob Dudley and Dr Brian Gilvary deferred one third of their 2013 annual bonus in accordance with the terms of the deferred bonus plan.

The three-year performance period for this deferred award ended on 31 December 2016.

The committee reviewed safety and environmental sustainability performance over this period and sought the input of the safety, ethics and environment assurance committee. This included an assessment of both actual outcomes under safety and sustainability measures and also consideration of the long-term performance trend.

Over the three-year period 2014-2016 safety performance continued to demonstrate progress and improvement. The committee also noted the extent to which safety performance had become embedded into the culture of the organization and the degree to which this has supported stronger operational and financial performance. This

strengthened safety performance has also informed the committee s thinking when including safety measures in pay arrangements under the new policy.

Following the committee s review, full vesting of the deferred and matching shares in respect of the 2013 deferred bonus was approved.

Subject to approval of the new policy, which will be presented to shareholders at the 2017 AGM, the committee does not intend to grant further matching share awards under this plan.

2013 deferred bonus vesting outcome

Name	Shares deferred	Vesting agreed	Total shares including dividends	Total value at vesting
Bob Dudley	299,256	100%	360,900	$2,015,025
Dr Brian Gilvary	193,306	100%	234,070	£1,046,293

Conclusions of the safety and sustainability assessment

No systemic issues identified	No major incidents	Safety culture and values embedded within the global organization	Strong performance supports efficiency and financial results across the group

Retirement benefits

2016 outcomes

Bob Dudley participates in the US pension and retirement savings plans described on page 89. In 2016, Bob Dudley s accrued pension increased, net of inflation, by $59,000. This increase has been reflected in the single figure table on page 90 by multiplying it by a factor of 20 in accordance with the requirements of the UK regulations (giving

$1,185,000).

In relation to the retirement savings plans, Bob Dudley made contributions in 2016 to the ESP totalling $26,500. For 2016 the total value of BP matching contributions in respect of Bob Dudley to the ESP and notional matching contributions to the ECSP was $422,000, 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 90 is $1,020,000.

Dr Brian Gilvary participates in the UK pension arrangements described on page 89. In 2016 Dr Brian Gilvary s accrued pension did not increase. In accordance with the requirements of the UK regulations, the value shown in the single figure table on page 90 is zero. He has exceeded the lifetime allowance under UK pensions legislation and, in accordance with the policy, receives a cash supplement of 35% of base salary, which has been separately identified in the single figure table on page 90.

The committee continues to keep under review the increase in the value of pension benefits for individual directors.

Directors remuneration report **implementation**

Stewardship

The committee places significant emphasis on executive directors having material interests in the shares of the company. Such shareholding not only provides direct alignment with the experience of shareholders, but also encourages a longer-term focus when considering the performance of BP. Executive directors are required to build a personal shareholding of five times salary within five years of their appointment.

Both executive directors significantly exceed the minimum holding required. This ensures they are subject to any fluctuation in the share price and the wider shareholder experience.

Post-retirement share ownership interests

Given the long-term nature of the group s operations, the committee sees the merits of ensuring that executives have performance alignment beyond the timeframe of existing incentive plans. The executive directors have taken a number of steps in this respect.

Firstly, the current executive directors have indicated to the committee that they expect to maintain a shareholding of at least 250% of salary for two years following retirement.

Secondly, as noted above, for deferred awards granted in respect of the 2016 bonus, Bob Dudley and Brian Gilvary have agreed to delay vesting of awards of matching shares until after retirement, rather than the normal three-year period.

Thirdly, Bob Dudley has further voluntarily opted to delay the vesting of all outstanding deferred bonus and matching shares in respect of his 2014 and 2015 bonus (representing a total interest over 1,691,784 ordinary shares), which were originally due to vest in 2018 and 2019 respectively, so that vesting is delayed until after retirement.

These factors significantly extend the time horizons for both executive directors, and in particular Bob Dudley. The committee fully endorses the steps taken by both executive directors as they clearly demonstrate a continued commitment to the long-term stewardship of the group.

Directors shareholdings

The table below shows the status of each of the executive directors in developing the required level of share ownership. These figures include the value as at 22 March 2017 of the directors interests shown below excluding the assumed vesting of the 2014-2016 performance shares.

Current directors	Appointment date	Value of current shareholding	% of policy achieved
Bob Dudley	October 2010	$15,298,423	165
Dr Brian Gilvary	January 2012	£7,018,143	191

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 2016	Ordinary shares or equivalents at 31 Dec 2016	Changes from 31 Dec 2016 to 22 March 2017	Ordinary shares or equivalents total at 22 March 2017
Bob Dudley[a]	1,554,198	2,509,500	191,016	2,700,516
Dr Brian Gilvary	903,856	1,419,263	124,034	1,543,297

[a] Held as ADSs.

The following table shows both the performance shares and the deferred bonus element awarded under the executive directors incentive plan (EDIP) and yet to vest. 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	Ordinary shares or equivalents at 1 Jan 2016	Ordinary shares or equivalents at 31 Dec 2016	Changes from 31 Dec 2016 to 22 March 2017	Ordinary shares or equivalents total at 22 March 2017
Bob Dudley[a]	5,536,950	6,607,314	(299,256)	6,308,058
Dr Brian Gilvary	2,789,921	3,259,891	(193,306)	3,066,585

[a] Held as ADSs.

At 22 March 2017, the following directors held options under the BP group share plan schemes over ordinary shares or their calculated equivalent set out below. None of these are subject to performance conditions. Additional details regarding these plans can be found on page 100.

Current director	Share options
Dr Brian Gilvary	503,103

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 March 2017, all directors and other members of senior management as a group held interests of 13,080,536 ordinary shares or their calculated equivalent, 9,619,319 restricted share units (with or without conditions) or their calculated equivalent, 9,374,643 performance shares or their calculated equivalent and 5,513,021 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 58-59 for further information.

Further information

This graph shows the growth in value of a hypothetical £100 holding in BP p.l.c. ordinary shares over eight years, relative to a hypothetical £100 holding in the FTSE 100 Index of which the company is a constituent.

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Directors remuneration report **implementation**

History of GCE remuneration

Year	GCE	Total remuneration thousand[a]	Annual bonus % of maximum	Performance shares 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	$19,376	100	74.3
2016	Dudley	$11,558	61	40

[a] Total remuneration figures include pension. The total figure is also affected by share vesting outcomes and these amounts 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 2016, 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 GCE until October 2010.

[a] Total remuneration reflects overall employee costs. See Financial statements Note 34 for further information.

[b] Capital investment reflects organic capital expenditure. 2016 includes Abu Dhabi onshore oil concession renewal.

GCE-to-employee pay ratio

The committee wanted to understand the GCE-to-employee pay ratio at BP when developing the policy. The ratio can vary significantly depending on the calculation methodology and sample employee population used and therefore can evolve over time.

The most relevant comparator group is the professional/managerial grade employees based in the UK and US which represent some 22% of the global employee population and is used elsewhere in this report. GCE-to-median-worker pay ratio for this sample was 71 to 1 in 2016. The ratio is based on a comparison of total compensation (base salary, actual annual bonus and vested equity awards) in the year. The committee will review the progression of the pay ratio over time.

Percentage change in GCE remuneration

Comparing 2016 to 2015	Salary	Benefits	Bonus
% change in GCE remuneration	0%	-38.1%	-39.0%
% change in comparator group remuneration	3.5%[a]	3.0%	-7.6%

[a] The comparator group comprises some 22% 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.

Independence and advice

The board considers all committee members to be independent with no personal financial interest, other than as shareholders, in the committee s decisions. Further detail on the activities of the committee, including activities during the year, advice received and shareholder engagement is set out in the remuneration committee report on page 76.

During 2016 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.

Gerrit Aronson, an independent consultant, was the committee s independent adviser until April 2016. He was engaged directly 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.

Following a competitive tender process, the committee appointed Deloitte LLP as its independent adviser in May 2016. Deloitte is a member of the Remuneration Consulting Group and, as such, operates under the code of conduct in relation to executive remuneration consulting in the UK. The committee is satisfied that the advice received is objective and independent.

Both firms provide other advice in their respective areas to the group. During the year, the wider Deloitte firm also provided BP with services including consulting on HR and Upstream matters.

In October 2016, BP completed a tender of its statutory audit and selected Deloitte as BP s auditor for the financial year 2018. Consequently, Deloitte will step down as adviser to the committee during 2017.

Total fees or other charges (based on an hourly rate) for the provision of remuneration advice to the committee in 2016 (save in respect of legal advice) are as follows:

Gerrit Aronson £45,000

Willis Towers Watson £5,000

Deloitte £262,000

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Directors remuneration report **implementation**

Shareholder engagement

As set out in the committee chairman s letter, during the last year we had extensive dialogue with many of our largest shareholders as well as representative bodies on remuneration matters. We have listened and sought to respond to their concerns.

Following the vote at the 2016 AGM the committee is proposing a number of changes to our remuneration policy for future years to respond to shareholder concerns.

The table below shows the votes on the report for the last three years.

AGM directors remuneration report vote results

Year	% vote for	% vote against	Votes withheld
2016	40.7%	59.3%	464,259,340
2015	88.8%	11.2%	305,297,190
2014	83.9%	16.1%	2,218,417,773

The committee s remuneration policy was approved by shareholders at the 2014 AGM. The votes on the policy are shown below.

2014 AGM directors remuneration policy vote results

Year	% vote for	% vote against	Votes withheld
2014	96.4%	3.6%	125,217,443

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 2016 are shown below.

Director	Appointee company	Additional	Total fees

		position held at appointee company	
Bob Dudley	Rosneft[a]	Director	0
Dr Brian Gilvary	L Air Liquide	Non-executive director	47,333

[a] Bob Dudley holds this appointment as a result of the company s shareholding in Rosneft.

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 2016.

Chairman

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 car and driver, and security advice in London. He receives a contribution to an office and secretarial support as appropriate to his needs in Sweden.

	Fees £ thousand
Chairman	785

The table below shows the fees paid for the chairman for the year ended 31 December 2016.

2016 remuneration (audited)

£ thousand	Fees		Benefits[a]		Total	
	2016	2015	**2016**	2015	**2016**	2015
Carl-Henric Svanberg	**785**	785	**58**	38	**843**	823

[a] Benefits include travel and other expenses relating to 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 1,203%.

Chairman

	Ordinary shares or equivalents at 1 Jan 2016	Ordinary shares or equivalents at 31 Dec 2016	Change from 31 Dec 2016 to 22 March 2017	Ordinary shares or equivalents total at 22 March 2017
Carl-Henric Svanberg	2,076,695	2,076,695		2,076,695

Non-executive directors

Fee structure

The table below shows the fee structure for non-executive directors:

	Fees £ thousand
Senior independent director[a]	120
Board member	90
Audit, geopolitical, 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, SEEA and remuneration committees.

2016 remuneration (audited)

£ thousand	Fees		Benefits[a]		Total	
	2016	2015	**2016**	2015	**2016**	2015
Nils Andersen[b]	**23**		**6**		**29**	
Paul Anderson	**165**	177	**32**	28	**197**	205
Alan Boeckmann	**168**	178	**17**	14	**185**	192
Admiral Frank Bowman	**162**	177	**14**	12	**176**	189
Antony Burgmans[c]	**47**	149	**21**	19	**68**	168
Cynthia Carroll	**140**	127	**28**	68	**168**	195
Ian Davis	**136**	145	**2**	3	**138**	148
Professor Dame Ann Dowling[d]	**150**	141	**2**	1	**152**	142
Brendan Nelson	**130**	125	**30**	11	**160**	136
Phuthuma Nhleko[c]	**48**	167	**3**	11	**51**	178
Paula Rosput Reynolds[e]	**140**	93	**17**	8	**157**	101
Sir John Sawers	**148**	85	**19**	0	**167**	85
Andrew Shilston	**190**	165	**5**	3	**195**	168

[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] Appointed on 31 October 2016.

[c] Retired on 14 April 2016.

[d] In addition, Professor Dame Ann Dowling received £25,000 for chairing and being a member of the BP technology advisory council.

[e] The 2015 number has been restated to reflect tax treatment.

The geopolitical committee was established in late 2015. Its members received the first full year of fees in 2016.

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 2016	Ordinary shares or equivalents at 31 Dec 2016	Change from 31 Dec 2016 to 22 March 2017	Ordinary shares or equivalents total at 22 March 2017	Value of current shareholding	% of policy achieved
Nils Andersen[a]		47,855	52,145	100,000	£454,750	505
Paul Anderson	30,000[b]	30,000[b]		30,000[b]	$169,950	140
Alan Boeckmann	44,772[b]	44,772[b]		44,772[b]	$253,633	209
Admiral Frank Bowman	24,864[b]	24,864[b]		24,864[b]	$140,855	116
Antony Burgmans[c]	10,156					
Cynthia Carroll	10,500[b]	10,500[b]		10,500[b]	$59,483	49
Ian Davis	23,854	25,735		25,735	£117,030	130
Professor Dame Ann Dowling	22,320	22,320		22,320	£101,500	113
Brendan Nelson	11,040	11,040		11,040	£50,204	56
Phuthuma Nhleko[c]						
Paula Rosput Reynolds	52,200[b]	52,200[b]	6,000	58,200[b]	$329,703	271
Sir John Sawers	13,528	13,528		13,528	£61,519	68
Andrew Shilston	15,000	15,000		15,000	£68,213	57

[a] Appointed on 31 October 2016.
[b] Held as ADSs.
[c] Retired on 14 April 2016.

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 2016, he received £100,000 for this role.

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Directors remuneration report **implementation**

Executive directors

Deferred shares (audited)[a]

					Deferred share element interests			Interests vested in 20	
					Potential maximum deferred shares				
	Bonus year	Type	Performance period	Date of award of deferred shares	At 1 Jan 2016	Awarded 2016	At 31 Dec 2016	Number of ordinary shares vested	Vesting date
p	2012	Comp	2013-2015	11 Feb 2013	114,690			134,856[c]	9 Feb 2016
		Vol	2013-2015	11 Feb 2013	114,690			134,856[c]	9 Feb 2016
		Mat	2013-2015	11 Feb 2013	229,380			269,712[c]	9 Feb 2016
	2013	Comp	2014-2016	12 Feb 2014	149,628		149,628	180,450[c]	24 Feb 2017
		Mat	2014-2016	12 Feb 2014	149,628		149,628	180,450[c]	24 Feb 2017
	2014[d]	Comp	2015-2017[g]	11 Feb 2015	147,054		147,054		
		Vol	2015-2017[g]	11 Feb 2015	147,054		147,054		
		Mat	2015-2017[g]	11 Feb 2015	294,108		294,108		
	2015[e]	Comp	2016-2018[g]	4 Mar 2016		275,892	275,892		
		Vol	2016-2018[g]	4 Mar 2016		275,892	275,892		
		Mat	2016-2018[g]	4 Mar 2016		551,784	551,784		
lvary	2012	Comp	2013-2015	11 Feb 2013	78,815			95,226[c]	9 Feb 2016
		Vol	2013-2015	11 Feb 2013	78,815			95,226 [c]	9 Feb 2016
		Mat	2013-2015	11 Feb 2013	157,630			190,453[c]	9 Feb 2016
	2013	Comp	2014-2016	12 Feb 2014	96,653		96,653	117,035[c]	24 Feb 2017
		Mat	2014-2016	12 Feb 2014	96,653		96,653	117,035[c]	24 Feb 2017
	2014[d]	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		
	2015[e]	Comp	2016-2018	4 Mar 2016		159,021	159,021		
		Vol	2016-2018	4 Mar 2016		159,021	159,021		
		Mat	2016-2018	4 Mar 2016		318,042	318,042		
utive directors									
	2012	Comp	2013-2015	11 Feb 2013	80,648			97,441[c]	9 Feb 2016
		Vol	2013-2015	11 Feb 2013	80,648			97,441[c]	9 Feb 2016
		Mat	2013-2015	11 Feb 2013	107,531[f]			129,922[c]	9 Feb 2016
	2013	Comp	2014-2016	12 Feb 2014	100,563		100,563	121,770[c]	24 Feb 2017

		Mat	2014-2016	12 Feb 2014	33,521[f]	33,521[f]	40,590[c]	24 Feb 2017
rote[b]	2012	Comp	2013-2015	11 Feb 2013	97,278		114,384[c]	9 Feb 2016
		Vol	2013-2015	11 Feb 2013	97,278		114,384[c]	9 Feb 2016
		Mat	2013-2015	11 Feb 2013	32,424[f]		38,124[c]	9 Feb 2016

Comp = Compulsory.

Vol = Voluntary.

Mat = Matching.

[a] Since 2010, vesting of the deferred shares has been subject to a safety and environmental sustainability hurdle, and this will continue. If the committee assesses that there has been a material deterioration in safety and environmental performance, or there have been major incidents, either of which reveal underlying weaknesses in safety and environmental management, then it may conclude that shares should vest only in part, or not at all. In reaching its conclusion, the committee will obtain advice from the SEEAC. There is no identified minimum vesting threshold level.

[b] Bob Dudley and Dr Byron Grote received awards in the form of ADSs. The above numbers reflect calculated equivalents in ordinary shares. One ADS is equivalent to six ordinary shares.

[c] Represents vestings of shares made at the end of the relevant performance period based on performance achieved under rules of the plan and includes reinvested dividends on the shares vested. The market price of each share used to determine the total value at vesting on the vesting dates of 9 February 2016 and 24 February 2017 were £3.34 and £4.47 respectively and for ADSs on 9 February 2016 and 24 February 2017 were $28.95 and $33.50 respectively.

[d] The face value has been calculated using the market price of ordinary shares on 11 February 2015 of £4.46.

[e] The market price at closing of ordinary shares on 4 March 2016 was £3.68 and for ADSs was $31.15. The sterling value has been used to calculate the face value.

[f] 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.

[g] Bob Dudley has voluntarily agreed to defer vesting of these awards until after retirement. Therefore the performance period is expected to exceed the minimum term of three years.

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Directors remuneration report **implementation**

Executive directors

Performance shares (audited)

			Share element interests Potential maximum performance shares[a]			Interests vested in 2015 and 2016		
	Performance period	Date of award of performance shares	At 1 Jan 2016	Awarded 2016	At 31 Dec 2016	Number of ordinary shares vested	Vesting date	£ Face value of the award
Bob Dudley[b]	2013-2015	11 Feb 2013	1,384,026			1,234,386[c]	28 Apr 2016[d]	
	2014-2016	12 Feb 2014	1,304,922		1,304,922	629,484[c]	May 2017	
	2015-2017[e]	11 Feb 2015	1,501,770		1,501,770			6,697,894
	2016-2018[e]	4 Mar 2016		1,809,582	1,809,582			6,659,262
Dr Brian Gilvary	2013-2015	11 Feb 2013	637,413			583,571[c]	28 Apr 2016[d]	
	2014-2016	12 Feb 2014	605,544		605,544	293,296[c]	May 2017	
	2015-2017[e]	11 Feb 2015	685,246		685,246			3,056,197
	2016-2018[e]	4 Mar 2016		786,559	786,559			2,894,537
Former executive directors								
Iain Conn	2013-2015	11 Feb 2013	463,126			424,006[c]	28 Apr 2016[d]	
	2014-2016	12 Feb 2014	220,043		220,043[f]	106,578[c]	May 2017	
Dr Byron Grote[b]	2013-2015	11 Feb 2013	142,278			126,894[c]	28 Apr 2016[d]	

[a] For awards under the 2013-2015, 2014-2016, 2015-2017 and 2016-2018 plans, performance conditions are measured one third on TSR relative to 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 28 April 2016 was £3.82 and for ADSs was $33.49. For the assumed vestings dated May 2017 a price of £4.73 per ordinary share and $35.39 per ADS has been used. These are the average prices from the fourth quarter of 2016.

[d] The 2013-2015 award vested on 28 April 2016, which resulted in an increase in value at vesting of £4,405 for Iain Conn and a decrease of $23,233 for Byron Grote. Details for Bob Dudley and Brian Gilvary can be found in the single figure table on page 90.

[e] The market price at closing of ordinary shares on 11 February 2015 was £4.46 and for ADSs was $40.35 and on 4 March 2016 was £3.68 and for ADSs was $31.15.

[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 options plans (audited)

	Option type	At 1 Jan 2016	Granted	Exercised	At 31 Dec 2016	Option price	Market price at date of exercise	Date from which first exercisable	Expiry date
Dr Brian Gilvary	BP 2011	500,000			500,000	£3.72		07 Sep 2014	07 Sep 2021
	SAYE	4,191		4,191		£3.68	£4.35	01 Sep 2016	28 Feb 2017
	SAYE		3,103		3,103	£2.90		01 Sep 2019	28 Feb 2020

The closing market prices of an ordinary share and of an ADS on 31 December 2016 were £5.10 and $37.38 respectively.

During 2016 the highest market prices were £5.11 and $37.40 respectively and the lowest market prices were £3.10 and $27.64 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 plan.

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Directors remuneration report **policy**

Directors remuneration policy

Set out below is our directors remuneration policy (the policy) for 2017 and subsequent years. It will be presented to shareholders at the 2017 annual general meeting and, subject to shareholder approval, will take effect for the 2017 financial year. We have developed this policy following a fundamental review of remuneration arrangements and extensive consultation with our major shareholders.

Remuneration principles

BP is a global company with a global management team, competing for talent in a demanding environment. The company s ability to attract and retain the high calibre executives required to lead a global and highly complex business is important for shareholders.

The policy has been designed to reflect the global nature of BP s business and talent pool. The competitive market for top executives both within the oil and gas sector and more broadly provides an important reference point, but is only one of a number of factors considered when the company sets pay.

The following principles underpin BP s revised approach to remuneration for executive directors.

Simplification	Link to strategy	Shareholder alignment	Stewardship
Simpler, transparent and fair approach.	Substantial proportion is variable and linked to the delivery of BP s strategy.	Outcomes are intended to reflect performance.	Focus on long-term sustainable performance.

Package is intended to vary with performance.

Pay is intended to reflect shareholder experience.

Emphasis on share ownership.

Key changes

The policy is intended to provide a simplified approach with a clear link between delivery of BP s strategy and pay, while reflecting outcomes for shareholders.

The policy has been simplified and clarified in response to shareholder feedback. Certain elements have been updated to reflect developments in the UK market and best practice over the past three years. It is designed to be well-balanced and to support the priorities for BP over the short and long term.

We have made a number of important changes to executive directors remuneration which result in a significant reduction in the overall variable remuneration opportunity. These include:

Simplified and updated measures to provide a more balanced and rounded assessment of group performance and better alignment with outcomes for shareholders.

Removal of the matching arrangements for the deferred annual bonus.

A revised structure so that the annual bonus pay-out scale will be more demanding in future years. Payment for on-target performance is reduced and the maximum bonus will only be paid if there is outperformance on all targets.

A higher mandatory deferral of annual bonus awards into BP shares from one third to one half of any annual bonus earned. These will vest after three years with no voluntary deferral or match.

Reduction in the GCE s maximum opportunity for performance shares from 550% of salary to 500%.

Together with the elimination of matching shares this reduces the total maximum available under long-term remuneration (i.e. performance and matching shares) from 700% to 500% of salary for the GCE and from 550% to 450% of salary for the CFO.

Stronger malus and clawback provisions.

Removal of duplicate measures between the annual and long-term elements.

Consideration of shareholder views

In designing the policy the committee undertook a major review of remuneration, considering how pay would support BP s strategy and better align with shareholders interests.

We have valued this dialogue with shareholders and remain committed to ensuring a clear and transparent approach to pay. This policy is designed to provide a transparent framework through which shareholders can assess the basis on which the executive directors at BP are paid.

Engagement with major shareholders has been key to this review and the committee chair has consulted with shareholders beginning in May 2016 and running through to this year s AGM. This multi-stage approach was adopted for the committee to hear and reflect on shareholder feedback while developing the new policy. In direct response to the views received, the policy has been refined over a number of months.

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Directors remuneration report **policy**

Remuneration policy table executive directors

Salary and benefits

Purpose g	To provide fixed remuneration to reflect the scale and complexity of both the business and the role, and to be competitive with the external market.	
Operation and opportunity g	Salary Salary levels take into account the nature of the role, performance of the business and the individual, market positioning and pay conditions in the wider BP group. When setting salaries, the committee considers practice in other oil and gas majors as well as European and US companies of a similar size, geographic spread and business dynamic to BP. Salaries are normally set in the home currency of the executive director and are reviewed annually. They may be reviewed at other times where appropriate, for example following a major role change. Salary levels are specific to the role and individual and therefore there is no maximum	Benefits The committee expects to maintain benefits at the current level. Executive directors are entitled to receive those benefits available to all BP employees generally, such as participation in all-employee share plans, sickness pay, relocation assistance and maternity pay. Benefits are not pensionable. Executive directors may receive other benefits that are judged to be cost effective and appropriate in terms of the individual s role, time and/or security. These include car-related benefits or cash in lieu, driver, security, assistance with tax return preparation, insurance and medical benefits. The company may meet any tax charges

	salary under the policy. However, when reviewing salaries for executive directors, the committee will consider salary increases for the most senior management and for employees in relevant countries. Percentage increases for executive directors will not exceed that of the broader employee population, other than in specific circumstances identified by the committee (e.g. in response to a substantial change in responsibilities). Following the 2017 AGM, the annual salaries for the executive directors will be: Group chief executive Bob Dudley: $1,854,000. Chief financial officer Dr Brian Gilvary: £759,000.	arising on business-related benefits provided to directors, for example security. The taxable value of benefits provided may fluctuate during the period of this policy, depending on the cost of provision and a director s personal circumstances.
Performance framework g	Not applicable	

Annual bonus

Purpose g	To provide variable remuneration dependent on performance against annual financial, operational and safety measures. 50% of the bonus is paid in cash and 50% is mandatorily deferred and held in BP shares for three years to reinforce the long-term nature of the business and the importance of sustainability.

Operation and opportunity g	The bonus is based on performance against annual measures and targets set at the start of the year, evaluated over the financial year and assessed following the year end.	50% of the bonus earned is required to be deferred into BP shares for three years. Dividends (or equivalents, including the value of any reinvestment) may accrue in respect of any deferred shares.

	Typically the annual bonus earned would be 50% of the maximum available for delivery of performance in line with the annual plan. The level of bonus payable may vary depending on the nature of the performance measure and level of target set.	Awards are subject to malus and clawback provisions as described on page 105.
	Executive directors may earn a maximum annual bonus (including any deferral) of up to 225% of salary for stretching performance against the objectives set for the year. The committee intends to set demanding requirements for maximum payment.	
Performance framework g	The committee determines specific measures, weightings and targets each year to reflect the priorities in the annual plan, which is designed to deliver the group s strategy and is approved by the board.	Measures will typically include a balance of financial, operational and safety measures. Details of the measures will be reported in advance each year in the annual report on remuneration. The committee intends to disclose targets for the annual bonus retrospectively.

Performance shares

Purpose	g	To link the largest part of remuneration opportunity with the long-term performance of the business. The outcome varies with performance against measures linked directly to strategic priorities.
Operation and opportunity	g	Annual awards of shares will vest based on performance relative to measures and targets that reflect the delivery of BP s strategy. Performance will normally be measured over a period of at least three years. The maximum annual award level for the group chief executive will be 500% of salary and 450% of salary for the chief financial officer. Performance shares will only vest to the extent that performance targets are met. The level of vesting for performance will depend on the stretch of the objective set, but the threshold level would normally not be expected to exceed 25% of the maximum opportunity for the relevant element. Once performance has been measured, a proportion of the shares that will vest are subject to a holding period. The combined length of the performance and holding periods will be normally six years. Dividends (or equivalents, including the value of reinvestment) may accrue in respect of vested shares. Awards are subject to malus and clawback provisions as described on page 105.
Performance framework	g	Performance shares may vest based on a combination of total shareholder return, financial and strategic measures. Prior to granting each award the committee will review the measures, weightings and targets to ensure they remain focused on delivering the strategy and are in the interests of shareholders.

		For 2017 awards, the measures and weightings will be: total shareholder return relative to oil and gas majors (50%) return on average capital employed (30%) strategic progress (20%) Details of 2017 targets relating to the total shareholder return and return on average capital employed measures are outlined in the remuneration report. Details relating to strategic progress will be disclosed retrospectively.	At least 40% of any award will be subject to measures linked to shareholder returns and the proportion linked to strategic progress will not exceed 30%. The committee would consult appropriately with major shareholders regarding any material changes to the measures.

Shareholding requirements

Purpose	g	To provide alignment between the interests of executive directors and our other shareholders.	
Operation and opportunity	g	An executive director is expected to build up and maintain a minimum shareholding of five times their base salary within five years of their appointment.	
Performance framework	g	Not applicable.	

Retirement benefits

Purpose	g	To recognize competitive practice in home country.	
Operation and	g	Executive directors normally participate in the company retirement plans that operate	The level of this allowance is expected to reduce in future, in line with the proposed

opportunity		in their home country. Senior executives in BP have generally been employees of the group for a number of years. They often remain participants in long-standing arrangements in which other group employees continue to participate, but which are no longer offered to new employees. The maximum opportunity will vary depending on the terms of these arrangements. UK participants may remain members of the company s defined benefit plan. In common with other employees in this plan, they may choose to receive up to 35% of salary in lieu as a cash supplement but do not receive further service accrual under this plan.	reduction for other UK employees who participate in this arrangement. US executive directors participate in long-standing plans of Amoco and Arco and other BP defined benefit and retirement savings plans for US employees. For future appointments, the committee will carefully review any retirement benefits to be granted to a new director. This will take account of retirement policies across the wider group, any arrangements currently in place, local market practice and individual circumstances. The committee will consider retirement benefits in the context of the overall approach to remuneration.
Performance framework	g	Retirement benefits in the UK are not directly linked to performance. Reflecting local market practice,	legacy arrangements in the US may reference bonuses when determining the benefit level.

Directors remuneration report **policy**

Notes to the policy table

How is variable pay linked to performance under the new policy?

The three elements described above provide a balance between focus on short-term, medium-term and long-term performance, while encouraging behaviours which are in the long-term interests of shareholders.

The operation of variable pay is supported by a focus on stewardship. There is an expectation that executives will build up a holding of five times salary over a period of five years following appointment and maintain that level during employment.

How are performance measures linked to the strategy under the new policy?

Variable pay is linked to performance measures designed to deliver the BP strategy. At the start of each year, the remuneration committee reviews the measures, targets and weightings to ensure they remain consistent with the priorities in the annual plan and the group strategy. For the annual bonus and performance shares, the approach to performance measurement is intended to provide a balance of measures to assess performance reflecting the global scale of the business and unique characteristics of the oil and gas sector.

The measures for the 2017 awards are summarized below, with further detail set out in the annual report on remuneration on pages 87-88.

The annual bonus is determined based on performance against measures and targets from the annual plan, which is designed to implement BP s strategy. Performance measures include a range of financial, operating and safety metrics.

Measures for performance share awards provide alignment with shareholder returns and long-term sustainable performance.

The combination of measures provides a diverse and rounded assessment of performance with appropriate checks and balances.

The committee reviews BP s underlying performance and external market reference points, as well as performance against specific measures and targets. It also seeks input from the board s audit and safety, ethics and environmental assurance committees on relevant
aspects before determining final outcomes. For the performance share awards, the committee will consider longer-term safety and environmental performance as an underpin when evaluating outcomes. This will take into account both absolute shareholder returns and safety and environmental factors, including consideration of issues around carbon and climate change, prior to determining the actual vesting levels.

When appropriate, the committee may make adjustments, upwards or downwards, to a straight formulaic outcome based on the group s broader performance and the outcomes for shareholders. The committee considers that this informed judgement is important to establishing an overall assessment of performance.

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Directors remuneration report policy

How will we use flexibility, judgement and discretion?

The committee is empowered to make quantitative and qualitative assessments of performance in reaching its decisions. This involves the use of judgement and discretion within a transparent framework approved by shareholders. The committee continues to consider that the powers of flexibility, judgement and discretion are critical to the successful execution of the policy.

In framing the policy, the committee has taken care to ensure that these important powers continue to be available:

- Sufficient flexibility to take account of future changes in the industry environment and in remuneration practice generally. This allows the committee to respond to changes in circumstances, for example in applying particular performance measures within the plans which may need to evolve with the company s strategy, without the need for specific shareholder approval.
- Power to exercise judgement in making a qualitative assessment in certain circumstances. A number of measures are used for annual or long-term incentive awards, many of which are numerical in nature and require a quantitative assessment of performance. Others may require a qualitative assessment.
- Scope for the committee to exercise discretion, mainly where it is desirable to vary a formulaic outcome that would otherwise arise from the policy s implementation. The committee considers that the ability to exercise discretion, upwards or downwards, is important to ensure that a particular outcome is fair in light of the director s own performance, the company s overall performance and positioning under particular performance measures and outcomes for shareholders. In accordance with UK regulations, areas where the remuneration policy provides for the exercise of discretion are identified in this report.

The committee intends to provide appropriate disclosure on the use of discretion so that shareholders can understand the basis for its decisions.

How will we safeguard against payments for failure?

Performance based pay	g	A significant portion of remuneration varies with performance where performance targets are not achieved, lower or no payments will be made under the plans.

Discretion	g	The committee may vary formulaic outcomes where these do not suitably reflect performance over the relevant performance period.	
Malus and clawback	g	The malus provisions enable the committee to reduce the size of award, cancel an unvested award, or impose further conditions on an award made under this policy.	The clawback provisions enable the committee to require participants to return some or all of an award after payment or vesting. They may be applied under the following circumstances:
		The malus provisions may apply if, prior to the vesting or payment of an award, there is a negative event such as:	incorrect outcomes due to miscalculation or based on incorrect information
		material failure impacting safety or environmental sustainability	restatement due to financial reporting failure or misstatement of audited results
		incorrect award outcomes due to miscalculation or based on incorrect information	material misconduct by the participant.
		restatement due to financial reporting failure or misstatement of audited results	
		material misconduct by the participant	
		such other exceptional circumstances that the committee consider to be similar in nature.	

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Directors remuneration report policy

Illustration of application of remuneration policy

The total remuneration opportunity for executive directors is strongly performance based and weighted to the long term. The charts below provide scenarios for the total remuneration of executive directors at different levels of performance and are calculated as prescribed in UK regulations.

Bob Dudley

Dr Brian Gilvary

Component

For these illustrations base salary, benefits and pension are the same in all three scenarios

Base salary	GCE: $1,854,000 CFO: £759,000	Based on salary effective following the AGM.
Benefits and retirement benefits	GCE: $474,000	Benefits are based on the value shown in the 2016 single figure table.

CFO: £332,000

Mr Dudley s assumed pension value is based on illustrative returns from his retirement savings plans.

Dr Gilvary s retirement benefits assume an allowance of 35% of salary.

Component

Variable pay under the new policy comprises annual bonus and performance shares

[a] Note that this is an indicative figure. The average vesting level for BP performance shares between 2010-2016 was 34%.

[b] Amounts in respect of performance shares and deferred annual bonus are shown at face value excluding the impact of share price growth and dividends.

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Directors remuneration report **policy**

Recruitment policy

The committee expects any new executive director to be engaged on terms that are consistent with the policy. However it recognizes that it cannot anticipate circumstances in which any new executive director may be recruited. The committee may determine that it is in the interests of the company and shareholders to secure the services of a particular individual which may require it to take account of the terms of that individual s existing employment and/or their personal circumstances.

Accordingly, the committee will ensure that:

The salary level of any new director is appropriate to their role and the competitive environment at the time of appointment. Where appropriate it may appoint an individual on a lower salary, then gradually increase salary levels as the individual gains experience in the role.

Variable remuneration will be awarded within the parameters of the policy.

The committee may tailor the vesting criteria for initial incentive awards depending on the specific circumstances.

Where an existing employee is promoted to the board, the company may honour all existing contractual commitments including any outstanding share awards or pension entitlements.

The committee would expect any new director to participate in the company pension and benefit schemes that are open to other senior employees (where appropriate referencing the candidate s home country) but would take into account the director s existing arrangements and market norms.
Where an individual is relocating in order to take up the role, the company may provide certain one-off benefits such as reasonable relocation expenses, accommodation for a period following appointment, assistance with visa applications or other immigration issues and ongoing arrangements such as tax equalization, annual flights home and a housing allowance.

Where an individual would be forfeiting remuneration or employment terms in order to join the company, the committee may award appropriate compensation. The committee would require reasonable evidence of the nature and value of any forfeited arrangements and would, to the extent practicable, ensure any compensation was of comparable commercial value and capped as appropriate, taking into account the terms of the previous arrangement being forfeited (for example the form and structure of award, timeframe, performance criteria and likelihood of vesting). Where appropriate, the committee would have a preference for buy-outs to be delivered in the form of shares in the company.

In making any decision on the remuneration of a new director, the committee would balance shareholder expectations, current best practice and the circumstances of any new director. It would strive not to pay more than is necessary to recruit the right candidate and would give full details in the next remuneration report.

Service contract

Bob Dudley s service contract is with BP Corporation North America Inc. Dr Brian Gilvary s service contract is with BP p.l.c.

Each executive director is entitled to pension provision as outlined on page 103.

Each executive director is also entitled to the following contractual benefits:

- For security reasons, a company car and driver is provided for business and private use. The company will bear all normal servicing, insurance and running costs.
- Medical and dental benefits, sick pay during periods of absence and assistance with the preparation of tax returns.
- Indemnification in accordance with applicable law.
- Participation in bonus or incentive arrangements at the committee s sole discretion.

Each executive director may terminate their employment by giving 12 months   written notice. In this event, for business reasons, the employer may not necessarily hold the executive director to their full notice period.

The employer may lawfully terminate the executive director s employment in the following ways:

- By giving the director 12 months   written notice.
- Without compensation, in circumstances where the employer is entitled to terminate for cause, as defined for the purposes of their service contract.

Additionally, in the case of Dr Brian Gilvary, the company may lawfully terminate employment by making a lump sum payment in lieu of notice equal to 12 months   base salary or by monthly instalments rather than as a lump sum.

The lawful termination mechanisms described above are without prejudice to the employer s ability in appropriate circumstances to terminate in breach of the notice period referred to above, and thereby to be liable for damages to the executive director.

In the event of termination by the company, each executive director may have an entitlement to compensation in respect of their statutory rights under employment protection legislation in the UK and potentially elsewhere. Where appropriate the company may also meet a director s reasonable legal expenses in connection with either their appointment or termination of their appointment.

Termination payments

In determining overall termination arrangements, the committee will distinguish between types of leaver and the circumstances of their leaving.

The committee would also consider all relevant circumstances, including whether a contractual provision in the director s arrangements complied with best practice at the time of termination and the date the provision was agreed, as well as the performance of the director in certain respects.

Where appropriate, the committee may consider providing certain benefits relating to termination including the provision of outplacement support or costs associated with relocation back to an individual s home country.

Should it become necessary to terminate an executive director s employment, and therefore to determine a termination payment, the committee s policy is as follows:

Termination payments	g	The director s primary entitlement would be a termination payment in respect of their service agreement, as set out above. However the committee will consider mitigation to reduce the termination payment where appropriate to do so, taking into account the circumstances for leaving and the terms of the agreement. Mitigation would not be applicable where a contractual payment in lieu of notice is made.	If the departing director is eligible for an early retirement pension, the committee would consider, if relevant under the terms of the appropriate plan, the extent of any actuarial reduction that should be applied. UK directors who leave in circumstances approved by the committee may have a favourable actuarial reduction applied to their pensions (which to date has been 3%). Departing directors who leave in other circumstances may be subject to a greater reduction.
Annual bonus	g		

		The committee would consider whether the director should be entitled to an annual bonus in respect of the financial year in which the termination occurs.	Normally, any such bonus would be restricted to the director s actual period of service in that financial year.
Share awards	g	Share awards will be treated in accordance with the relevant plan rules. For awards granted under the Executive Directors Incentive Plan (EDIP), the treatment can only be made in accordance with the framework approved by shareholders.	In deciding whether to exercise discretion to preserve EDIP awards, the committee would also consider the proximity of the award to its maturity date.
		The committee would consider whether conditional share awards held by the director should lapse on leaving or should, at the committee s discretion, be preserved. If awards are preserved, the award would normally continue until the vesting date. Awards may be pro-rated based on service over the performance period.	

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Directors remuneration report policy

Legacy arrangements and other detailed provisions

Previously the deferred element of the annual bonus in respect of years up to and including 2016 attracted a corresponding award of matching shares. Although the committee will no longer grant matching awards in respect of future bonus awards, executives retain interests in legacy awards previously granted under this arrangement under the terms set out in the 2014 policy.

For completeness, the table below summarizes the key terms of the previous matching share element.

Legacy incentives: deferred bonus and matching shares (no further awards to be granted)

Purpose	g	To reinforce the long-term nature of the business and the importance of sustainability.	
Operation	g	Previously one third of the annual bonus was subject to compulsory deferral and a further third was subject to voluntary deferral.	Where shares vest, additional shares representing the value of reinvested dividends are added.
		These deferred shares were matched on a one-for-one basis.	All deferred shares are subject to clawback provisions if they are found to have been granted on the basis of a material misstatement of financial or other data.
Performance framework	g	Both deferred and matching 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 major incidents revealing underlying weaknesses in safety and environmental management then the committee, with advice from the board s

safety, ethics and environmental assurance committee, may conclude that shares vest in part, or not at all.

In addition to the award described above, the committee may continue to satisfy existing remuneration commitments and/or payments for loss of office, including the exercise of any discretion in connection with such payments provided that such terms were agreed:

- before 10 April 2014 when the first approved remuneration policy came into effect
- before the 2017 policy came into effect, provided that the terms of the payment were consistent with the shareholder-approved directors remuneration policy in force at the time they were agreed
- at a time when the relevant individual was not a director of the company and, in the opinion of the committee, the payment was not in consideration for the individual becoming a director.

Share awards are subject to the terms of the relevant plan rules under which the award has been granted. The committee may adjust or amend awards, but only in accordance with the provisions of the plan rules. This includes making adjustments to awards to reflect one-off corporate events, such as a change in the company s capital structure or treatment of awards in the event of a change of control. In accordance with the plan rules, awards may be settled in cash rather than shares, where the committee considers this appropriate.

The committee may make minor amendments to the policy to aid its operation or implementation without seeking shareholder approval, for example for regulatory, exchange control, tax or administrative purposes or to take account of a change in legislation provided that any such change is not to the material advantage of the directors.

Remuneration in the wider group

The committee considers employment conditions in the BP group when establishing and implementing policy for executive directors to ensure the alignment of and context for principles and approach. In particular, the committee reviews the policy for the most senior leaders.

Decisions regarding remuneration for employees outside the group leaders are the responsibility of the GCE. The committee does not consult directly with employees when formulating the policy. However, feedback from employee surveys, that are regularly reported to the board, provide views on a wide range of employee matters including pay.

The wider employee group participates in performance-based incentives. Throughout the group, base salary and benefit levels are set in accordance with the prevailing relevant market conditions and practice in the countries in which employees are based.

Differences between executive director pay policy and that of other employees reflect the senior position of the individuals, prevailing market conditions and corporate governance practices in respect of executive director remuneration. The key difference in policy for executive directors is that a greater proportion of total remuneration is delivered as performance-based incentives.

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Directors remuneration report policy

Remuneration policy table non-executive directors

Non-executive chairman

Fees

Approach	g	Remuneration is in the form of cash fees, payable monthly. The level and structure of the chairman s remuneration will primarily be compared against UK best practice.
Operation and opportunity	g	The quantum and structure of the non-executive chairman s remuneration is reviewed annually by the remuneration committee, which makes a recommendation to the board.

Benefits and expenses

Approach	g	The chairman is provided with support and reasonable travelling expenses.
Operation and opportunity	g	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 his home country as appropriate. A car and the use of a driver 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.

Non-executive directors

Fees

Approach	g	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 level and structure of non-executive directors remuneration will primarily be compared against UK best practice.

		Additional fees may be payable to reflect additional board responsibilities, for example, committee chairmanship and membership and for the role of senior independent director.
Operation and opportunity	g	The level and structure of non-executive directors remuneration is reviewed by the chairman, the GCE and the company secretary who make a recommendation to the board. Non-executive directors do not vote on their own remuneration. Remuneration for non-executive directors is reviewed annually.

Other fees and benefits

Intercontinental allowance

Approach	g	Non-executive directors receive an allowance to reflect the global nature of the company s business. The intercontinental travel allowance is payable for the purpose of attending board or committee meetings or site visits.
Operation and opportunity	g	The allowance is paid in cash following each event of intercontinental travel.

Benefits and expenses

Approach	g	Non-executive directors are provided with administrative support and reasonable travelling expenses. Professional fees are reimbursed in the form of cash, payable following the provision of advice and assistance.
Operation and opportunity	g	Non-executive directors are reimbursed for all reasonable travelling and subsistence expenses (including any relevant tax) incurred in carrying out their duties.

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 fees for non-executive directors are set in accordance with the Articles of Association.

This directors remuneration report was approved by the board and signed on its behalf by David J Jackson, company secretary on 6 April 2017.

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Pages 111-112 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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Pages 114-119 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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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 2016 and 31 December 2015, 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 2016. 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 2016 and 31 December 2015 and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2016, 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 2016, 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 6 April 2017 expressed an unqualified opinion.

/s/ Ernst & Young LLP

London, United Kingdom

6 April 2017

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 2016, 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 over financial reporting on page 267. 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 2016, 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 2016 and 2015, 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 2016, and our report dated 6 April 2017 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

London, United Kingdom

6 April 2017

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 6 April 2017, 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 2016 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, 333-207189, 333-210316 and 333-210318) of BP p.l.c.

/s/ Ernst & Young LLP

London, United Kingdom

6 April 2017

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Group income statement

For the year ended 31 December				$ million
	Note	**2016**	2015	2014
Sales and other operating revenues	5	**183,008**	222,894	353,568
Earnings from joint ventures after interest and tax	15	**966**	(28)	570
Earnings from associates after interest and tax	16	**994**	1,839	2,802
Interest and other income	6	**506**	611	843
Gains on sale of businesses and fixed assets	4	**1,132**	666	895
Total revenues and other income		**186,606**	225,982	358,678
Purchases	18	**132,219**	164,790	281,907
Production and manufacturing expenses[a]		**29,077**	37,040	27,375
Production and similar taxes	5	**683**	1,036	2,958
Depreciation, depletion and amortization	5	**14,505**	15,219	15,163
Impairment and losses on sale of businesses and fixed assets	4	**(1,664)**	1,909	8,965
Exploration expense	7	**1,721**	2,353	3,632
Distribution and administration expenses		**10,495**	11,553	12,266
Profit (loss) before interest and taxation		**(430)**	(7,918)	6,412
Finance costs[a]	6	**1,675**	1,347	1,148
Net finance expense relating to pensions and other post-retirement benefits	23	**190**	306	314
Profit (loss) before taxation		**(2,295)**	(9,571)	4,950
Taxation[a]	8	**(2,467)**	(3,171)	947
Profit (loss) for the year		**172**	(6,400)	4,003
Attributable to				
BP shareholders		**115**	(6,482)	3,780
Non-controlling interests		**57**	82	223
		172	(6,400)	4,003
Earnings per share cents				
Profit (loss) for the year attributable to BP shareholders				
Basic	10	**0.61**	(35.39)	20.55
Diluted	10	**0.60**	(35.39)	20.42
Per ADS (dollars)				
Basic	10	**0.04**	(2.12)	1.23
Diluted	10	**0.04**	(2.12)	1.23

[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	2016	2015	$ million 2014
Profit (loss) for the year		**172**	(6,400)	4,003
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**254**	(4,119)	(6,838)
Exchange gains (losses) on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**30**	23	51
Available-for-sale investments		**1**	1	
Cash flow hedges marked to market	29	**(639)**	(178)	(155)
Cash flow hedges reclassified to the income statement	29	**196**	249	(73)
Cash flow hedges reclassified to the balance sheet	29	**81**	22	(11)
Share of items relating to equity-accounted entities, net of tax		**833**	(814)	(2,584)
Income tax relating to items that may be reclassified	8	**13**	257	147
		769	(4,559)	(9,463)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	23	**(2,496)**	4,139	(4,590)
Share of items relating to equity-accounted entities, net of tax			(1)	4
Income tax relating to items that will not be reclassified	8	**739**	(1,397)	1,334
		(1,757)	2,741	(3,252)
Other comprehensive income		**(988)**	(1,818)	(12,715)
Total comprehensive income		**(816)**	(8,218)	(8,712)
Attributable to				
BP shareholders		**(846)**	(8,259)	(8,903)
Non-controlling interests		**30**	41	191
		(816)	(8,218)	(8,712)

[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 2016	**43,902**	**(19,964)**	**(7,267)**	**(823)**	**81,368**	**97,216**	**1,171**	**98,387**
Profit (loss) for the year					**115**	**115**	**57**	**172**

Other comprehensive income			**389**	**(330)**	**(1,020)**	**(961)**	**(27)**	**(988)**
Total comprehensive income			**389**	**(330)**	**(905)**	**(846)**	**30**	**(816)**
Dividends[b]					**(4,611)**	**(4,611)**	**(107)**	**(4,718)**
Share-based payments, net of tax	**2,220**	**1,521**			**(750)**	**2,991**		**2,991**
Share of equity-accounted entities changes in equity, net of tax					**106**	**106**		**106**
Transactions involving non-controlling interests					**430**	**430**	**463**	**893**
At 31 December 2016	**46,122**	**(18,443)**	**(6,878)**	**(1,153)**	**75,638**	**95,286**	**1,557**	**96,843**
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

[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	**2016**	2015
Non-current assets			
Property, plant and equipment	11	**129,757**	129,758
Goodwill	13	**11,194**	11,627
Intangible assets	14	**18,183**	18,660
Investments in joint ventures	15	**8,609**	8,412
Investments in associates	16	**14,092**	9,422
Other investments	17	**1,033**	1,002
Fixed assets		**182,868**	178,881
Loans		**532**	529
Trade and other receivables	19	**1,474**	2,216
Derivative financial instruments	29	**4,359**	4,409
Prepayments		**945**	1,003
Deferred tax assets	8	**4,741**	1,545
Defined benefit pension plan surpluses	23	**584**	2,647
		195,503	191,230
Current assets			
Loans		**259**	272
Inventories	18	**17,655**	14,142
Trade and other receivables	19	**20,675**	22,323
Derivative financial instruments	29	**3,016**	4,242
Prepayments		**1,486**	1,838
Current tax receivable		**1,194**	599
Other investments	17	**44**	219
Cash and cash equivalents	24	**23,484**	26,389
		67,813	70,024
Assets classified as held for sale	3		578
		67,813	70,602
Total assets		**263,316**	261,832
Current liabilities			
Trade and other payables	21	**37,915**	31,949
Derivative financial instruments	29	**2,991**	3,239
Accruals		**5,136**	6,261
Finance debt	25	**6,634**	6,944
Current tax payable		**1,666**	1,080
Provisions	22	**4,012**	5,154
		58,354	54,627
Liabilities directly associated with assets classified as held for sale	3		97
		58,354	54,724
Non-current liabilities			
Other payables	21	**13,946**	2,910
Derivative financial instruments	29	**5,513**	4,283
Accruals		**469**	890

Finance debt	25	**51,666**	46,224
Deferred tax liabilities	8	**7,238**	9,599
Provisions	22	**20,412**	35,960
Defined benefit pension plan and other post-retirement benefit plan deficits	23	**8,875**	8,855
		108,119	108,721
Total liabilities		**166,473**	163,445
Net assets		**96,843**	98,387
Equity			
BP shareholders equity	31	**95,286**	97,216
Non-controlling interests	31	**1,557**	1,171
Total equity	31	**96,843**	98,387

C-H Svanberg Chairman

R W Dudley Group Chief Executive

6 April 2017

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Group cash flow statement

For the year ended 31 December				$ million
	Note	**2016**	2015	2014
Operating activities				
Profit (loss) before taxation		**(2,295)**	(9,571)	4,950
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	7	**1,274**	1,829	3,029
Depreciation, depletion and amortization	5	**14,505**	15,219	15,163
Impairment and (gain) loss on sale of businesses and fixed assets	4	**(2,796)**	1,243	8,070
Earnings from joint ventures and associates		**(1,960)**	(1,811)	(3,372)
Dividends received from joint ventures and associates		**1,105**	1,614	1,911
Interest receivable		**(200)**	(247)	(276)
Interest received		**267**	176	81
Finance costs	6	**1,675**	1,347	1,148
Interest paid		**(1,137)**	(1,080)	(937)
Net finance expense relating to pensions and other post-retirement benefits	23	**190**	306	314
Share-based payments		**779**	321	379
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	23	**(467)**	(592)	(963)
Net charge for provisions, less payments		**4,487**	11,792	1,119
(Increase) decrease in inventories		**(3,681)**	3,375	10,169
(Increase) decrease in other current and non-current assets		**(1,172)**	6,796	3,566
Increase (decrease) in other current and non-current liabilities		**1,655**	(9,328)	(6,810)
Income taxes paid		**(1,538)**	(2,256)	(4,787)
Net cash provided by operating activities		**10,691**	19,133	32,754
Investing activities				
Capital expenditure		**(16,701)**	(18,648)	(22,546)
Acquisitions, net of cash acquired		**(1)**	23	(131)
Investment in joint ventures		**(50)**	(265)	(179)
Investment in associates		**(700)**	(1,312)	(336)
Proceeds from disposals of fixed assets	4	**1,372**	1,066	1,820
Proceeds from disposals of businesses, net of cash disposed	4	**1,259**	1,726	1,671
Proceeds from loan repayments		**68**	110	127
Net cash used in investing activities		**(14,753)**	(17,300)	(19,574)
Financing activities				
Net issue (repurchase) of shares				(4,589)
Proceeds from long-term financing		**12,442**	8,173	12,394
Repayments of long-term financing		**(6,685)**	(6,426)	(6,282)
Net increase (decrease) in short-term debt		**51**	473	(693)
Net increase (decrease) in non-controlling interests		**887**	(5)	9
Dividends paid				
BP shareholders	9	**(4,611)**	(6,659)	(5,850)

Non-controlling interests	**(107)**	(91)	(255)
Net cash provided by (used in) financing activities	**1,977**	(4,535)	(5,266)
Currency translation differences relating to cash and cash equivalents	**(820)**	(672)	(671)
Increase (decrease) in cash and cash equivalents	**(2,905)**	(3,374)	7,243
Cash and cash equivalents at beginning of year	**26,389**	29,763	22,520
Cash and cash equivalents at end of year	**23,484**	26,389	29,763

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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 2016 were approved and signed by the group chief executive and chairman on 6 April 2017 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 2016. 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, including trade receivables; derivative financial instruments, including the application of hedge accounting; provisions and contingencies, including provisions and contingencies related to the Gulf of Mexico oil spill; pensions and other post-retirement benefits; and income taxes.

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 control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. Intra-group balances and transactions, including unrealized profits arising from intra-group transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to BP shareholders.

Interests in other entities

Business combinations and goodwill

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are recognized at their fair values at the acquisition date.

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. See Note 13 for further information.

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. Any 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 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 classified as an associate.

Since 21 March 2013, BP has owned 19.75% of the voting shares of Rosneft Oil Company (Rosneft), a Russian oil and gas company. The Russian federal government, through its investment company JSC Rosneftegaz, owned 50% plus one share of the voting shares of Rosneft at 31 December 2016. 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

1. Significant accounting policies, judgements, estimates and assumptions continued

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 Rosneft since 2013 and he is a member of the Rosneft board s Strategic Planning Committee. A second BP-nominated director, Guillermo Quintero, has been a member of the Rosneft board and its HR and Remuneration Committee since 2015. 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, classified as an associate and accounted for using the equity method. 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.

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 recognized in a separate component of equity and reported in other 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 reported in other comprehensive income. On disposal or partial disposal of a non-US dollar functional currency subsidiary, joint venture or associate, the related accumulated exchange gains and losses recognized in equity are reclassified from equity 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

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.

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. 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 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

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1. Significant accounting policies, judgements, estimates and assumptions   continued

with estimated future capital expenditure expected to be incurred relating to as yet undeveloped reserves expected to be processed through these common facilities.

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life. The typical useful lives of the group s other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemicals plants	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

Significant judgements and estimates: estimation of oil and natural gas reserves

Significant technical and commercial judgements are required to determine the group s estimated oil and natural gas reserves. Reserves estimates 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 187, which is unaudited. Details on BP s proved reserves and production compliance and governance processes are provided on page 252.

Estimates of oil and natural gas reserves determined by applying US Securities and Exchange Commission regulations 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 estimates also have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements. If proved reserves estimates determined by applying management s assumptions are revised downwards, earnings could be affected by changes in depreciation expense or an immediate write-down of the property s carrying value.

The 2016 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 187. 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 CGUs 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

1. Significant accounting policies, judgements, estimates and assumptions continued

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.

Significant judgements and estimates: 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 the effects of inflation and deflation on operating expenses, discount rates, production profiles, reserves and resources, and future commodity prices, including the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products. Judgement is required when determining the appropriate grouping of assets into a CGU or the appropriate grouping of CGUs for impairment testing purposes. See Note 13 for details on how these groupings have been determined in relation to the impairment testing of goodwill.

As disclosed above, the recoverable amount of an asset is the higher of its value in use and its fair value less costs of disposal. 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.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in business combinations. The group carries goodwill of approximately $11.2 billion on its balance sheet (2015 $11.6 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 for an extended period, the group may need to recognize goodwill impairment charges.

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.

Specific judgements and estimates made in impairment tests in 2016 relating to discount rates, oil and gas properties and oil and gas prices are discussed below.

Discount rates

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 based upon the cost of funding the group derived from an established model, adjusted to a pre-tax basis. Fair value less costs of disposal calculations use the post-tax discount rate.

The discount rates applied in impairment tests are reassessed each year. In 2016 the discount rate used to determine recoverable amounts based on fair value less costs of disposal was revised to 6% (2015 7%). The discount rate used to determine recoverable amounts based on value in use was revised to 9% (2015 11%). In both cases, where the cash-generating unit is located in a country which is judged to be higher risk an additional 2% premium was added to the discount rate (2015 2%).

Oil and natural gas properties

For oil and natural gas properties, expected future cash flows are estimated using management s best estimate of future oil and natural gas prices and production and reserves volumes. The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

Reserves assumptions for value-in-use tests are restricted to proved and probable reserves.

When estimating the fair value of our Upstream assets, assumptions reflect all reserves and resources that a market participant would consider when valuing the asset, which in some cases are broader in scope than the reserves used in a value-in-use test. In determining a fair value, risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved. Depending upon the classification of the reserves and resources, this can result in associated forecast cash flows being reduced by a factor of between 10% and 90% from their estimated full potential value. Changing the risk factor applied will in some cases have an impact upon the carrying value of the asset concerned. A 10% increase in the risk factors used in any single test could have an impact of up to $0.4 billion upon the carrying value of that asset.

The recoverability of intangible exploration and appraisal expenditure is covered under Oil and natural gas exploration, appraisal and development expenditure above.

Oil and gas prices

During the third quarter of 2016, the price assumptions used in impairment tests were revised.

The long-term price assumptions used to determine recoverable amount based on fair value less costs of disposal from 2022 onwards are derived from $75 per barrel for Brent and $4/mmBtu for Henry Hub (both in 2015 prices) inflated for the remaining life of the asset. For 2015 the equivalent values were $80 per barrel for Brent and $5/mmBtu for Henry Hub. To determine recoverable amount based on value in use, the price assumptions were inflated to 2022 but from 2022 onwards were not inflated.

For both value-in-use and fair value less costs of disposal impairment tests, the price assumptions used for the five-year period to 2021 have been set such that there is a gradual transition from current market prices to the long-term price assumptions as noted above. For 2015,

market prices were used for the first five years ranging from $40 per barrel for Brent and $2.38/mmBtu for Henry Hub in 2016 to $56 per barrel for Brent and $3.18/mmBtu in 2020. Prices used this year were revised due to a lack of liquidity in the market beyond the very near term.

Current market prices for oil reflect the elevated level of oil stocks following strong growth in US shale and OPEC production volumes in recent years. US production fell during 2016 in response to lower prices and, towards the end of the year, OPEC and a number of non-OPEC countries announced an agreement to reduce production volumes. BP s long-term assumption for oil is higher than current market prices because prices are expected to increase as the current record level of oil inventories is gradually unwound, underpinned by solid demand growth and muted increases in supply.

US gas prices have fallen back recently in response to the unusually mild winter. BP s long-term price assumption for US gas is higher than current market prices because we expect demand for US gas to grow with increased exports of liquefied natural gas (LNG), underpinned by strong growth in the global demand for gas. We expect natural gas to be the fastest growing fossil fuel over the next 20 years, supported by increasing environmental regulation encouraging a switch from coal to cleaner, lower carbon fuels including gas, as well as renewables.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Inventories

Inventories, other than inventories held for short-term 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 short-term 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

Agreements under which payments are made to owners in return for the right to use an asset are accounted for as leases. Leases that transfer substantially all the risks and rewards of ownership are recognized as finance leases. All other leases are accounted for as operating leases.

Finance leases are capitalized at the commencement of the lease term at the fair value of the leased item or, if lower, at the present value of the minimum lease payments. Finance charges are allocated to each period so as to achieve a constant rate of interest on the remaining balance of the liability and are charged directly against income. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Operating lease payments are recognized as an expense 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 generally 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 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.

1. Significant accounting policies, judgements, estimates and assumptions continued

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices, as well as for trading purposes. These derivative financial instruments are 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. Contracts to buy or sell LNG are not accounted for as derivatives as they are not considered capable of being settled net in cash.

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 in the income statement.

For the purpose of hedge accounting, hedges are classified as:

- fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability

- cash flow hedges when hedging exposure to variability in cash flows that is 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 reported in other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts reported in 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 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 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: 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.

1. Significant accounting policies, judgements, estimates and assumptions continued

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 and contingencies

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% (2015 2.75%) or a real discount rate of 0.5% (2015 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).

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.

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

18 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 judgements and estimates: provisions

During 2016, significant progress was made in resolving outstanding claims arising from the 2010 Deepwater Horizon accident and oil spill for which, at 31 December 2015, no reliable estimate could be made. As a result, a judgement has been made that a reliable estimate can now be made for all remaining material liabilities arising from the incident. Consequently, the group s provision at 31 December 2016 for costs associated with the incident now includes the estimated cost of resolving all outstanding business economic loss claims under the Plaintiffs Steering Committee (PSC) settlement and the cost of resolving economic loss and property damage claims from individuals and businesses that opted out of the PSC settlement and/or were excluded from that settlement. The provision for outstanding business economic loss claims under the PSC settlement was determined based upon an expected value of the remaining claims and the resultant charge was recognized in the income statement. Claims are determined by the Deepwater Horizon Court Supervised Settlement Program in accordance with the PSC settlement agreement and, in addition, certain claims are settled by BP. The amounts ultimately payable may differ from the amount provided and the timing of payment is uncertain. A significant number of claims determined by the DHCSSP have been and may be appealed by BP and/or the claimants. Depending upon the resolution of these claims, the amount payable may differ from what is currently provided for.

Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group s financial performance.

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.

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 2016 was a real rate of 0.5% (2015 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 of the equity instruments on the date on which they 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.

For other equity-settled share-based payment transactions, the goods or services received and the corresponding increase in equity are measured at the fair value of the goods or services received unless their fair value cannot be reliably estimated. If the fair value of the goods and services received cannot be reliably estimated, the transaction is measured by reference to the fair value of the equity instruments granted.

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 on 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: pensions and other post-retirement benefits

Accounting for defined benefit pensions and other post-retirement benefits involves making significant estimates about uncertain events, including 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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

Assumptions about these variables 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.

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 applicable 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 judgements and estimates: 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 and estimates are required to be made of the amount of future taxable profits that will be available.

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.

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1. Significant accounting policies, judgements, estimates and assumptions continued

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.

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 short-term 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 of financial assets and hedge accounting.

IFRS 15 Revenue from Contracts with Customers provides a single model for accounting for revenue arising from contracts with customers, focusing on the identification and satisfaction of performance obligations, and is effective for annual periods beginning on or after 1 January 2018. IFRS 15 will supersede IAS 18 Revenue .

BP expects to adopt IFRS 9 and IFRS 15 on 1 January 2018. The group s evaluation of the effect of adoption of these standards is ongoing but it is not currently anticipated that either IFRS 9 or IFRS 15 will have a material effect on the financial statements.

The EU has adopted both IFRS 9 and IFRS 15.

IFRS 16 Leases provides a new model for lessee 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.

BP expects to adopt IFRS 16 on 1 January 2019 using the modified retrospective approach to transition permitted by the standard in which the cumulative effect of initially applying the standard is recognized in opening retained earnings at the date of initial application. The group s evaluation of the effect of adoption of the standard is ongoing but it is expected that it will have a material effect on the group s financial statements, significantly increasing the group s recognized assets and liabilities. It is expected that the presentation and timing of recognition of charges in the income statement will also change as the operating lease expense currently reported under IAS 17, typically on a straight-line basis, will be replaced by depreciation of the right-to-use asset and interest on the lease liability. Information on the group s leases currently classified as operating leases, which are not recognized on the balance sheet, is provided in Note 27.

The EU has not yet adopted 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. Following significant progress in resolving outstanding claims arising from the 2010 Deepwater Horizon accident and oil spill, a reliable estimate has now been determined for all remaining material liabilities arising from the incident.

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2. Significant event Gulf of Mexico oil spill continued

The cumulative pre-tax income statement charge since the incident amounts to $62.6 billion. For more information on the types of expenditure included in the cumulative income statement charge, see *Impact upon the group income statement* below. It is now possible to reliably estimate the cost of resolving outstanding business economic loss claims under the Plaintiffs Steering Committee (PSC) settlement and the cost of resolving economic loss and property damage claims from individuals and businesses that either opted out of the PSC settlement and/or were excluded from that settlement. The pre-tax income statement charge for the year of $7.1 billion is primarily attributable to the recognition of additional provisions for these claims.

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
	2016	2015	2014
Income statement			
Production and manufacturing expenses	**6,640**	11,709	781
Profit (loss) before interest and taxation	**(6,640)**	(11,709)	(781)
Finance costs	**494**	247	38
Profit (loss) before taxation	**(7,134)**	(11,956)	(819)
Less: Taxation	**3,105**	3,492	262
Profit (loss) for the period	**(4,029)**	(8,464)	(557)
Balance sheet			
Current assets			
Trade and other receivables	**194**	686	
Current liabilities			
Trade and other payables	**(3,056)**	(693)	
Accruals		(40)	
Provisions	**(2,330)**	(3,076)	
Net current assets (liabilities)	**(5,192)**	(3,123)	
Non-current assets			
Deferred tax	**2,973**		
Non-current liabilities			
Other payables	**(13,522)**	(2,057)	
Accruals		(186)	
Provisions	**(112)**	(13,431)	
Deferred tax	**5,119**	5,200	
Net non-current assets (liabilities)	**(5,542)**	(10,474)	
Net assets (liabilities)	**(10,734)**	(13,597)	
Cash flow statement			
Profit (loss) before taxation	**(7,134)**	(11,956)	(819)
Net charge for interest and other finance expense, less net interest paid	**494**	247	38
Net charge for provisions, less payments	**4,353**	11,296	939

(Increase) decrease in other current and non-current assets	**(3,210)**		(662)
Increase (decrease) in other current and non-current liabilities	**(1,608)**	(732)	(792)
Pre-tax cash flows	**(7,105)**	(1,145)	(1,296)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to an outflow of $6,892 million (2015 outflow of $1,130 million and 2014 outflow of $9 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. 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. During the first half of 2016, the remaining cash in the Trust was exhausted and BP commenced paying claims and other costs previously funded from the Trust. For certain costs, these payments are made by BP into qualified settlement funds administered by the PSC settlement programmes, which then distribute the amounts to claimants. During 2016, BP paid $3,210 million to the qualified settlement funds.

Other payables

Other payables include amounts payable under the agreements with the United States and five Gulf coast states that were approved by the federal district court in 2016, including amounts payable for natural resource damages, state claims and Clean Water Act penalties (for full details

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2. Significant event Gulf of Mexico oil spill continued

of these agreements, see *BP Annual Report and Form 20-F 2015*). Further, at 31 December 2016, $1,929 million remains in Other payables in relation to the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident, of which $739 million falls due in 2017. In addition, Other payables at 31 December 2016 includes BP s remaining 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. Amounts payable for certain economic loss and property damage claims from individuals and businesses that either opted out of the PSC settlement and/or were excluded from that settlement, as well as certain business economic loss claims under the PSC settlement, are also included in Other payables.

Provisions and contingent liabilities

Provisions

Provisions relating to the agreements with the United States and five Gulf coast states were reclassified to Other payables during 2016, upon approval of those agreements by the federal district court. Remaining provisions relating to the Gulf of Mexico oil spill relate to litigation and claims.

Movements in each class of provision during the year and cumulatively since the incident are presented in the tables below.

				$ million 2016
	Environmental	Litigation and claims	Clean Water Act	Total
At 1 January	5,919	6,459	4,129	16,507
Net increase in provision		6,440		6,440
Unwinding of discount	52	25	38	115
Reclassified to other payables	(5,970)	(4,943)	(4,167)	(15,080)
Utilization paid by BP	(1)	(2,086)		(2,087)
paid by the settlement fund or Trust		(3,453)		(3,453)
At 31 December		2,442		2,442
Of which current		2,330		2,330
non-current		112		112

				$ million Cumulative since the incident
	Environmental	Litigation and claims	Clean Water Act	Total
Net increase in provision	19,992	38,867	4,171	63,030

Unwinding of discount	159	81	106	346
Change in discount rate	(130)	(74)	(110)	(314)
Reclassified to other payables	(6,429)	(9,351)	(4,167)	(19,947)
Utilization paid by BP	(11,711)	(6,400)		(18,111)
paid by the settlement fund or Trust	(1,881)	(20,681)		(22,562)
At 31 December 2016		2,442		2,442

Environmental

The environmental provisions relating to natural resource damage costs and the early restoration framework agreement were reclassified to Other payables during 2016 following approval by the Court in April 2016 of the Consent Decree between the United States, the Gulf states and BP.

Litigation and claims

The litigation and claims provision includes amounts for the future cost of resolving 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. 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 261. The provision for the cost associated with the 2012 PSC settlement has been determined based upon an expected value of the remaining claims, including business economic loss claims. During the year, significant progress was made in resolving business economic loss claims. Claims were determined by the DHCSSP in accordance with the PSC settlement agreement and in addition, certain claims were settled by BP. The provision has been increased in the year to reflect the estimate of the cost of the remaining claims which are expected to be determined and paid by the DHCSSP or resolved by BP, and associated costs. Amounts to resolve remaining claims are expected to be substantially paid in 2017. However, the amounts ultimately payable may differ from the amount provided and the timing of payment is uncertain. A significant number of claims determined by the DHCSSP have been and may be appealed by BP and/or the claimants. Depending upon the resolution of these claims, the amount payable may differ from what is currently provided for.

Litigation and claims Other claims

An estimate of the cost of the remaining economic loss and property damage claims from individuals and businesses that either opted out of the PSC settlement and/or were excluded from that settlement, is recognized in provisions. Amounts have been reclassified to Other payables during the year where settlements were agreed.

The 31 December 2015 provision recognized for litigation and claims included amounts agreed under the agreements with the United States and five Gulf Coast states in relation to state claims, which were reclassified to Other payables during 2016. These state claims are payable over 18 years.

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2. Significant event Gulf of Mexico oil spill continued

Clean Water Act penalties

The provision previously recognized for penalties under Section 311 of the Clean Water Act, as determined by the civil settlement with the United States, was reclassified to Other payables during 2016 following approval by the Court of the Consent Decree. The amount is payable in instalments over 15 years, commencing April 2017. 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 $6,440 million. It is now possible to reliably estimate the cost of resolving outstanding business economic loss claims under the Plaintiffs Steering Committee (PSC) settlement and the cost of resolving economic loss and property damage claims from individuals and businesses that either opted out of the PSC settlement and/or were excluded from that settlement, associated claims administration costs and other items. The increase in provisions in 2016 relates primarily to the recognition of amounts for these items, which could not be reliably estimated and provided for in 2015. After deducting amounts utilized during the year totalling $5,540 million, comprising payments from the trust fund and qualifying settlement fund of $3,453 million and payments made directly by BP of $2,087 million (2015 $3,279 million, comprising payments from the trust fund of $3,022 million and payments made directly by BP of $257 million), and after adjustments for discounting, the remaining provision as at 31 December 2016 was $2,442 million (2015 $16,507 million).

Contingent liabilities

For information on Legal proceedings relating to the Deepwater Horizon oil spill, see Legal proceedings on pages 261-264.

Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group s financial performance.

Impact upon the group income statement

The group income statement for 2016 includes a pre-tax charge of $7,134 million (2015 pre-tax charge of $11,956 million) in relation to the Gulf of Mexico oil spill. The costs charged within production and manufacturing expenses in 2016 include the amounts charged for provisions for business economic loss claims and economic loss and property damage claims from individuals and businesses that either opted out of the PSC settlement and/or were excluded from that settlement, the cost of the securities claims settlement with the certified class of post-explosion ADS purchasers which was agreed in June 2016, as well as operating and other costs. Finance costs of $494 million (2015 $247 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 with the United States and five Gulf coast states that were approved by the federal district court in 2016, including amounts payable for natural resource damages, state claims and Clean Water Act penalties, operating costs, amounts charged upon initial recognition of the trust obligation, other litigation, claims, environmental and legal costs and estimated obligations for future costs, 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
	2016	2015	2014	Cumulative since the incident
Trust fund liability discounted				19,580
Change in discounting relating to trust fund liability				283
Recognition of reimbursement asset			(662)	(20,000)
Other				8
Total (credit) charge relating to the trust fund			(662)	(129)
Environmental costs		5,303	192	8,526
Spill response costs				14,304
Litigation and claims costs	**6,596**	5,758	1,137	39,134
Clean Water Act penalties		551		4,061
Other costs	**44**	97	114	1,398
Settlements credited to the income statement				(5,681)
(Profit) loss before interest and taxation	**6,640**	11,709	781	61,613
Finance costs	**494**	247	38	972
(Profit) loss before taxation	**7,134**	11,956	819	62,585

3. Non-current assets held for sale

There were no non-current assets or associated liabilities classified as held for sale as at 31 December 2016.

The assets and associated liabilities classified as held for sale at 31 December 2015 related to the dissolution of the group s German refining joint operation with Rosneft, which was completed on 31 December 2016.

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4. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments.

			$ million
	2016	2015	2014
Gains on sale of businesses and fixed assets			
Upstream	**557**	324	405
Downstream	**561**	316	474
Other businesses and corporate	**14**	26	16
	1,132	666	895

			$ million
	2016	2015	2014
Losses on sale of businesses and fixed assets			
Upstream	**169**	124	345
Downstream	**89**	98	401
Other businesses and corporate	**3**	41	3
	261	263	749
Impairment losses			
Upstream	**1,022**	2,484	6,737
Downstream	**84**	265	1,264
Other businesses and corporate	**11**	155	317
	1,117	2,904	8,318
Impairment reversals			
Upstream	**(3,025)**	(1,080)	(102)
Downstream	**(17)**	(178)	
	(3,042)	(1,258)	(102)
Impairment and losses on sale of businesses and fixed assets	**(1,664)**	1,909	8,965

Disposals

Disposal proceeds and principal gains and losses on disposals by segment are described below.

			$ million
	2016	2015	2014
Proceeds from disposals of fixed assets	**1,372**	1,066	1,820
Proceeds from disposals of businesses, net of cash disposed	**1,259**	1,726	1,671
	2,631	2,792	3,491
By business			
Upstream	**839**	769	2,533
Downstream	**1,646**	1,747	864

Other businesses and corporate	**146**	276	94
	2,631	2,792	3,491

At 31 December 2016, deferred consideration relating to disposals amounted to $255 million receivable within one year (2015 $41 million and 2014 $1,137 million) and $271 million receivable after one year (2015 $385 million and 2014 $333 million). In addition, contingent consideration receivable relating to disposals amounted to $131 million at 31 December 2016 (2015 $292 million and 2014 $454 million), see Note 29 for further information.

Upstream

In 2016, gains principally resulted from the contribution of BP s Norwegian upstream business into Aker BP ASA and from the sale of certain properties in the UK. Losses principally arose from the disposal of certain exploration licences in Australia and contract losses following asset disposals in the US.

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.

Downstream

In 2016, gains principally resulted from the disposal of certain US and non-US midstream assets in our fuels business and the dissolution of our German refining joint operation with Rosneft.

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.

Summarized financial information relating to the sale of businesses is shown in the table below. The principal transactions categorized as business disposals in 2016 were the contribution of BP s Norwegian upstream business into Aker BP ASA and the dissolution of the group s German refining joint operation with Rosneft. The principal transactions categorized as business disposals in 2015 were the sales of our

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4. Disposals and impairment continued

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.

			$ million
	2016	2015	2014
Non-current assets	**4,794**	154	1,452
Current assets	**1,202**	80	182
Non-current liabilities	**(2,558)**	(70)	(395)
Current liabilities	**(532)**	(50)	(65)
Total carrying amount of net assets disposed	**2,906**	114	1,174
Recycling of foreign exchange on disposal	**25**	16	(7)
Costs on disposal[a]	**229**	8	128
	3,160	138	1,295
Gains on sale of businesses[b]	**593**	446	280
Total consideration	**3,753**	584	1,575
Non-cash consideration[c]	**(2,698)**		
Consideration received (receivable)[d]	**223**	1,116	96
Proceeds from the sale of businesses related to completed transactions	**1,278**	1,700	1,671
Deposits[e]	**(19)**	26	
Proceeds from the sale of businesses, net of cash disposed[f]	**1,259**	1,726	1,671

[a] Includes amounts relating to the remeasurement to fair value of certain assets as a result of the dissolution of our German refining joint operation with Rosneft.

[b] 2016 gains on sale of businesses include deferred amounts not recognized in the income statement.

[c] Non-cash consideration principally relates to the contribution of BP s Norwegian upstream business into Aker BP ASA in exchange for 30% interest in Aker BP ASA and the dissolution of the group s German refining joint operation with Rosneft.

[d] Consideration received from prior year business disposals or to be received from current year disposals. 2015 included $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.

[e] 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.

[f] Proceeds are stated net of cash and cash equivalents disposed of $676 million (2015 $9 million and 2014 $32 million).

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.

Upstream

Impairment losses and reversals related primarily to producing and midstream assets.

The 2016 impairment losses of $1,022 million related to a number of different assets, with the most significant charges arising in the North Sea. Impairment losses within Upstream arose primarily as a result of revised cost estimates and decisions to dispose of certain assets. On 3 April 2017, BP announced that it has agreed to sell its Forties Pipeline System business to INEOS for a consideration of up to $250 million. The transaction will lead to an impairment charge of approximately $0.4 billion, which will be included in the group income statement for 2017.

The 2016 impairment reversals of $3,025 million primarily related to the North Sea and Angola. The largest impairment reversals related to the Andrew area cash-generating unit (CGU) in the North Sea and the PSVM and Greater Plutonio CGUs in Angola but none of these were individually significant. In addition an impairment reversal was recorded in relation to the Block KG D6 CGU in India; and exploration costs were also written back during the period (see Note 7). The impairment reversals arose following a reduction in the discount rate applied, changes to future price assumptions, and also increased confidence in the progress of the KG D6 projects in India.

See Impairment of property, plant and equipment, intangible assets and goodwill within Note 1 for information on assumptions used for impairment testing.

The 2015 impairment losses of $2,484 million included $761 million in Angola, of which $371 million related to the Greater Plutonio CGU. Impairment losses also included $830 million in relation to CGUs in the North Sea, of which $328 million related to the Andrew area CGU. 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. 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 related to producing assets. The discount rate used to determine the recoverable amount of the Greater Plutonio CGU included the 2% premium for higher-risk countries. 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 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.

Downstream

The 2016 impairment losses of $84 million principally related to certain office buildings which are expected to be vacated.

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.

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4. Disposals and impairment continued

Other businesses and corporate

Impairment losses totalling $11 million, $155 million, and $317 million were recognized in 2016, 2015 and 2014 respectively. The amount for 2015 was principally in respect of our US wind business. The amount for 2014 was principally in respect of our biofuels businesses in the UK and US.

5. Segmental analysis

The group s organizational structure reflects the various activities in which BP is engaged. At 31 December 2016, 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.

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 costs relating to the Gulf of Mexico oil spill were previously presented as a reconciling item between the sum of the results of the reportable segments and the group results. From 2016, we have reported these costs as part of Other businesses and corporate. Prior period comparatives have been amended to reflect this new presentation.

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	Consolidation adjustment and eliminations	Total group 2016
Segment revenues						
Sales and other operating revenues	33,188	167,683		1,667	(19,530)	183,008
Less: sales and other operating revenues between segments	(17,581)	(1,291)		(658)	19,530	
Third party sales and other operating revenues	15,607	166,392		1,009		183,008
Earnings from joint ventures and associates after interest and tax	723	608	647	(18)		1,960
Segment results						
Replacement cost profit (loss) before interest and taxation	574	5,162	590	(8,157)	(196)	(2,027)
Inventory holding gains (losses)[a]	60	1,484	53			1,597
Profit (loss) before interest and taxation	634	6,646	643	(8,157)	(196)	(430)
Finance costs						(1,675)
Net finance expense relating to pensions and other post-retirement benefits						(190)
Profit (loss) before taxation						(2,295)
Other income statement items						
Depreciation, depletion and amortization						
US	4,396	856		71		5,323
Non-US	7,835	1,094		253		9,182
Charges for provisions, net of write-back of unused provisions, including change in discount rate	352	758		6,719		7,829
Segment assets						
Investments in joint ventures and associates	10,968	3,035	8,243	455		22,701
Additions to non-current assets[b]	17,879	3,109		216		21,204

[a] See explanation of inventory holding gains and losses on page 142.

[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

						$ million
						2015
By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	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	(13,477)	(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	(13,477)	(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		11,781		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

[a] See explanation of inventory holding gains and losses on page 142.

[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
						2014
By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	Total group
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	(2,791)	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	(2,791)	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						
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		1,652		2,625
Segment assets						
Investments in joint ventures and associates	7,877	3,244	7,312	723		19,156
Additions to non-current assets[b]	22,587	3,121		784		26,492

[a] See explanation of inventory holding gains and losses on page 142.

[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

By geographical area	US	Non-US	$ million 2016 Total
Revenues			
Third party sales and other operating revenues[a]	**65,132**	**117,876**	**183,008**
Other income statement items			
Production and similar taxes	**155**	**528**	**683**
Results			
Replacement cost profit (loss) before interest and taxation	**(8,311)**	**6,284**	**(2,027)**
Non-current assets			
Non-current assets[b c]	**64,628**	**118,152**	**182,780**

[a] Non-US region includes UK $37,119 million.
[b] Non-US region includes UK $18,615 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	$ million 2015 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

[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.

By geographical area	US	Non-US	$ million 2014 Total
Revenues			
Third party sales and other operating revenues[a]	122,951	230,617	353,568
Other income statement items			

Production and similar taxes	690	2,268	2,958
Results			
Replacement cost profit before interest and taxation	5,251	7,371	12,622
Non-current assets			
Non-current assets[b] [c]	69,125	114,462	183,587

[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.

6. Income statement analysis

			$ million
	2016	2015	2014
Interest and other income			
Interest income	**183**	226	258
Other income	**323**	385	585
	506	611	843
Currency exchange losses charged to the income statement[a]	**698**	8	36
Expenditure on research and development	**400**	418	663
Finance costs			
Interest payable	**1,221**	1,065	1,025
Capitalized at 1.81% (2015 1.75% and 2014 1.94%)[b]	**(244)**	(179)	(185)
Unwinding of discount on provisions and other payables	**698**	461	308
	1,675	1,347	1,148

[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 $56 million (2015 $42 million and 2014 $43 million).

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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 judgements made in relation to oil and natural gas accounting see Intangible assets within Note 1.

			$ million
	2016	2015	2014
Exploration and evaluation costs			
Exploration expenditure written off[a]	**1,274**	1,829	3,029
Other exploration costs	**447**	524	603
Exploration expense for the year	**1,721**	2,353	3,632
Impairment losses	**62**		
Intangible assets exploration and appraisal expenditure	**16,960**	17,286	19,344
Liabilities	**102**	145	227
Net assets	**16,858**	17,141	19,117
Cash used in operating activities	**447**	524	603
Cash used in investing activities	**2,920**	1,216	2,786

[a] 2016 included a $601-million write-off in Brazil relating to the BM-C-34 licence and various write-offs in the Gulf of Mexico totalling $611 million and India totalling $216 million, partially offset by a write-back of $319 million in India relating to block KG D6 as a result of increased confidence in the progress of the projects. An impairment reversal of $234 million was also recorded in 2016 in relation to KG D6 in India. 2015 included a $432-million write-off in Libya as there was significant uncertainty about the timing of future drilling operations. It also included 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 was 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. For further information see Upstream Exploration on page 26.

During February 2017, following completion of drilling of certain exploration wells in Egypt, BP determined that no commercial hydrocarbons had been found. The costs incurred, totalling $269 million, will be included in the group income statement for 2017.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2016 is shown in the table below.

Carrying amount	Location
$1 - 2 billion	Angola; India; Egypt; Middle East
$2 - 3 billion	Canada; Brazil
$3 - 4 billion	US Gulf of Mexico

8. Taxation

Tax on profit

$ million

	2016	2015	2014
Current tax			
Charge for the year	**1,762**	1,910	4,444
Adjustment in respect of prior years[a]	**(123)**	(329)	48
	1,639	1,581	4,492
Deferred tax			
Origination and reversal of temporary differences in the current year	**(3,709)**	(5,090)	(3,194)
Adjustment in respect of prior years[a b]	**(397)**	338	(351)
	(4,106)	(4,752)	(3,545)
Tax charge (credit) on profit or loss	**(2,467)**	(3,171)	947

[a] The adjustments in respect of prior years reflect the reassessment of the current tax and deferred tax balances for prior years in light of changes in facts and circumstances during the year.
[b] 2016 includes the reassessment of the recognition of deferred tax assets in relation to foreign tax credits in the US.
In 2016, the total tax credit recognized within other comprehensive income was $752 million (2015 $1,140 million charge and 2014 $1,481 million credit). See Note 31 for further information. The total tax credit recognized directly in equity was $5 million (2015 $9 million charge and 2014 $36 million charge).

For information on significant estimates and judgements made in relation to taxation see Income taxes within Note 1.

Reconciliation of the effective tax rate

The following table provides a reconciliation of the group weighted average statutory corporate income tax rate to the effective tax rate of the group on profit or loss before taxation.

For 2016 and 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 reversals, and for the impacts of the Gulf of Mexico oil spill and impairment losses and reversals 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

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8. Taxation continued

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.

$ million

	2016 excluding impacts of Gulf of Mexico oil spill and impairments	**2016 impacts of Gulf of Mexico oil spill and impairments**	**2016**	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
Profit (loss) before taxation	**2,914**	**(5,209)**	**(2,295)**	4,031	(13,602)	(9,571)	13,166	(8,216)	4,950
Tax charge (credit) on profit or loss	**(117)**	**(2,350)**	**(2,467)**	945	(4,116)	(3,171)	5,036	(4,089)	947
Effective tax rate	**(4)%**	**45%**	**107%**	23%	30%	33%	38%	50%	19%
						% of profit or loss before taxation			
Tax rate computed at the weighted average statutory rate[a]	**18**	**33**	**52**	17	38	46	38	55	10
Increase (decrease) resulting from									
Tax reported in equity-accounted entities	**(15)**		**19**	(7)		3	(5)		(14)
Adjustments in respect of prior years	**5**	**13**	**23**	1			(2)		(6)
Movement in deferred tax not recognized	**26**	**3**	**(27)**	17	(5)	(14)	4	(3)	17
Tax incentives for investment	**(9)**		**11**	(8)		3	(4)		(10)
Gulf of Mexico oil spill non-deductible costs		**(2)**	**(4)**		(2)	(3)			1

Disposal impacts[b]	**(24)**		**30**	(3)		1	(1)		(1)
Foreign exchange	**1**		**(2)**	18		(8)	4		10
Items not deductible for tax purposes	**8**		**(11)**	10		(4)	4	(2)	12
Decrease in rate of UK supplementary charge[c]	**(15)**		**19**	(23)		10			
Other	**1**	**(2)**	**(3)**	1	(1)	(1)			
Effective tax rate	**(4)**	**45**	**107**	23	30	33	38	50	19

[a] Calculated based on the statutory corporate income tax rate applicable in the countries in which the group operates, weighted by the profits and losses before tax in the respective countries. It reflects the mix of profits and losses arising in higher tax rate jurisdictions (primarily the Upstream segment) and lower tax rate jurisdictions (primarily the Downstream segment).

[b] In 2016 this relates primarily to the tax impact on the contribution of BP s Norwegian upstream business into Aker BP ASA.

[c] This relates to the deferred tax impact of the reductions in the UK supplementary charge tax rate applicable to profits arising in the North Sea from 20% to 10% in 2016 and from 32% to 20% in 2015.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax liability	**2016**	2015
At 1 January	**8,054**	11,584
Exchange adjustments	**(71)**	86
Charge (credit) for the year in the income statement	**(4,106)**	(4,752)
Charge (credit) for the year in other comprehensive income	**(714)**	1,140
Charge (credit) for the year in equity	**(5)**	9
Acquisitions and disposals	**(661)**	(13)
At 31 December	**2,497**	8,054

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
	2016	2015	2014	**2016**	2015
Deferred tax liability					
Depreciation	**81**	(102)	(2,178)	**26,864**	28,712
Pension plan surpluses	**(12)**	84	(272)	**171**	878
Derivative financial instruments	**(230)**	(326)	527	**761**	961
Other taxable temporary differences	**(122)**	59	(1,805)	**1,254**	1,266
	(283)	(285)	(3,728)	**29,050**	31,817
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**98**	12	492	**(1,889)**	(1,972)
Decommissioning, environmental and other provisions	**591**	(2,513)	52	**(12,108)**	(13,737)

Derivative financial instruments	**(6)**	62	166	**(734)**	(710)
Tax credits[a]	**(5,177)**	256	589	**(5,225)**	(43)
Loss carry forward	**249**	(2,239)	(1,397)	**(5,458)**	(5,985)
Other deductible temporary differences	**422**	(45)	281	**(1,139)**	(1,316)
	(3,823)	(4,467)	183	**(26,553)**	(23,763)
Net deferred tax charge (credit) and net deferred tax liability	**(4,106)**	(4,752)	(3,545)	**2,497**	8,054
Of which deferred tax liabilities				**7,238**	9,599
deferred tax assets				**4,741**	1,545

[a] The increase in tax credits in 2016 reflects the impact of a loss carry-back claim in the US, displacing foreign tax credits utilized in prior periods which are now carried forward.

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8. Taxation continued

The recognition of deferred tax assets of $3,839 million (2015 $1,067 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. Of this amount, $2,974 million relates to the US (2015 $nil).

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	**2016**	2015
Unused US state tax losses[a]	**9.6**	9.6
Unused tax losses other jurisdictions[b]	**5.2**	2.1
Unused tax credits	**19.2**	20.4
of which arising in the UK[c]	**17.1**	17.5
arising in the US[d]	**2.0**	2.8
Deductible temporary differences[e]	**26.7**	23.2
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**3.1**	3.9

[a] These losses expire in the period 2017 2036 with applicable tax rates ranging from 4% to 12%.

[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 higher statutory corporate income tax rates than the UK. 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 in respect of overseas tax. These tax credits have no fixed expiry date.

[d] The US unused tax credits expire in the period 2017-2026.

[e] The majority comprises fixed asset temporary differences in the UK. 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	**2016**	2015	2014
Current tax benefit relating to the utilization of previously unrecognized tax credits and losses	**40**	123	171
Deferred tax benefit arising from the reversal of a previous write-down of deferred tax assets	**269**		
Deferred tax benefit relating to the recognition of previously unrecognized tax credits and losses	**394**		
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**55**	768	153

9. Dividends

The quarterly dividend paid on 31 March 2017 in respect of the fourth quarter 2016 was 10 cents per ordinary share ($0.60 per American Depositary Share (ADS)). The corresponding amount in sterling was announced on 20 March 2017. 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		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Dividends announced and paid in cash									
Preference shares							**1**	2	2
Ordinary shares									
March	**7.0125**	6.6699	5.7065	**10.00**	10.00	9.50	**1,099**	1,708	1,426
June	**6.9167**	6.5295	5.8071	**10.00**	10.00	9.75	**1,168**	1,691	1,572
September	**7.5578**	6.5488	5.9593	**10.00**	10.00	9.75	**1,161**	1,717	1,122
December	**7.9313**	6.6342	6.3769	**10.00**	10.00	10.00	**1,182**	1,541	1,728
	29.4183	26.3824	23.8498	**40.00**	40.00	39.00	**4,611**	6,659	5,850
Dividend announced, paid in March 2017				**10.00**			**1,303**		

The details of the scrip dividends issued are shown in the table below.

	2016	2015	2014
Number of shares issued (thousand)	**548,005**	102,810	165,644
Value of shares issued ($ million)	**2,858**	642	1,318

The financial statements for the year ended 31 December 2016 do not reflect the dividend announced on 7 February 2017 and paid in March 2017; this will be treated as an appropriation of profit in the year ended 31 December 2017.

10. Earnings per ordinary share

			Cents per share
Per ordinary share	**2016**	2015	2014
Basic earnings per share	**0.61**	(35.39)	20.55
Diluted earnings per share	**0.60**	(35.39)	20.42

			Dollars per share
Per ADS	**2016**	2015	2014
Basic earnings per share	**0.04**	(2.12)	1.23
Diluted earnings per share	**0.04**	(2.12)	1.23

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).

10. Earnings per ordinary share continued

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.

			$ million
	2016	2015	2014
Profit (loss) attributable to BP shareholders	**115**	(6,482)	3,780
Less: dividend requirements on preference shares	**1**	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	**114**	(6,484)	3,778

			Shares thousand
	2016	2015	2014
Basic weighted average number of ordinary shares	**18,744,800**	18,323,646	18,385,458
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**110,519**		111,836
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	**18,855,319**	18,323,646	18,497,294

			Shares thousand
	2016	2015	2014
Basic weighted average number of ordinary shares - ADS equivalent	**3,124,133**	3,053,941	3,064,243
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	**18,420**		18,639
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	**3,142,553**	3,053,941	3,082,882

The number of ordinary shares outstanding at 31 December 2016, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 19,438,990,091. Between 31 December 2016 and 16 March 2017, the latest practicable date before the completion of these financial statements, there was a net increase of 71,878,542 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 80-110.

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		2016		2015
	Number of options[a b]	**Weighted average exercise**	Number of options[a b]	Weighted average exercise
	thousand	**price $**	thousand	price $
Outstanding	**26,284**	**3.85**	70,049	8.54
Exercisable	**498**	**4.59**	46,520	10.21
Dilutive effect	**3,380**	**n/a**	2,659	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2016 the quoted market price of one BP ordinary share was £5.10 (2015 £3.54).

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	2016	2015
	Number of shares[a]	Number of shares[a]
Vesting	**thousand**	thousand
Within one year	**92,529**	78,823
1 to 2 years	**94,760**	76,779
2 to 3 years	**102,342**	89,654
3 to 4 years	**680**	41,479
4 to 5 years	**319**	695
	290,630	287,430
Dilutive effect	**113,012**	101,984

[a] Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

There has been a net decrease of 28,236,653 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2016 and 16 March 2017.

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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 2016	**3,194**	**2,877**	**215,566**	**45,744**	**2,866**	**14,038**	**8,418**	**292,703**
Exchange adjustments	**(119)**	**(37)**		**(342)**	**(127)**	**(9)**	**(375)**	**(1,009)**
Additions	**106**	**24**	**12,036**	**1,699**	**192**	**156**	**568**	**14,781**
Acquisitions	**46**			**793**				**839**
Remeasurements[b]				**(1,505)**				**(1,505)**
Transfers			**1,629**					**1,629**
Deletions	**(161)**	**(629)**	**(13,667)**	**(2,664)**	**(261)**	**(185)**	**(988)**	**(18,555)**
At 31 December 2016	**3,066**	**2,235**	**215,564**	**43,725**	**2,670**	**14,000**	**7,623**	**288,883**
Depreciation								
At 1 January 2016	**642**	**1,157**	**123,831**	**20,652**	**2,084**	**9,439**	**5,140**	**162,945**
Exchange adjustments	**(9)**	**(44)**		**(264)**	**(96)**	**(6)**	**(218)**	**(637)**
Charge for the year	**40**	**166**	**11,213**	**1,740**	**214**	**397**	**384**	**14,154**
Remeasurements[b]				**(1,319)**				**(1,319)**
Impairment losses	**9**	**123**	**518**	**11**	**79**	**256**	**4**	**1,000**
Impairment reversals	**(2)**		**(2,923)**	**(12)**		**(101)**	**(4)**	**(3,042)**
Transfers			**5**					**5**
Deletions	**(96)**	**(340)**	**(10,216)**	**(2,122)**	**(259)**	**(162)**	**(785)**	**(13,980)**
At 31 December 2016	**584**	**1,062**	**122,428**	**18,686**	**2,022**	**9,823**	**4,521**	**159,126**
Net book amount at 31 December 2016	**2,482**	**1,173**	**93,136**	**25,039**	**648**	**4,177**	**3,102**	**129,757**
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
Assets held under finance leases at net book amount included above								
At 31 December 2016		**2**	**21**	**266**		**241**		**530**
At 31 December 2015		2	84	297		242		625
Assets under construction included above								
At 31 December 2016								**29,177**
At 31 December 2015								27,755

[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.

[b] Relates to the remeasurement to fair value of previously held interests in certain assets as a result of the dissolution on 31 December 2016 of the group s German refining joint operation with Rosneft.

12. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2016 amounted to $11,207 million (2015 $10,379 million). BP s share of capital commitments of joint ventures amounted to $522 million (2015 $586 million).

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13. Goodwill and impairment review of goodwill

		$ million
	2016	2015
Cost		
At 1 January	**12,236**	12,482
Exchange adjustments	**(544)**	(237)
Acquisitions	**247**	5
Deletions	**(134)**	(14)
At 31 December	**11,805**	12,236
Impairment losses		
At 1 January	**609**	614
Exchange adjustments	**5**	
Deletions	**(3)**	(5)
At 31 December	**611**	609
Net book amount at 31 December	**11,194**	11,627
Net book amount at 1 January	**11,627**	11,868

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2016**	2015
Upstream	**7,726**	7,812
Downstream	**3,401**	3,761
Other businesses and corporate	**67**	54
	11,194	11,627

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
	2016	2015
Goodwill	**7,726**	7,812
Excess of recoverable amount over carrying amount	**26,035**	12,894

The table above shows the carrying amount of goodwill for the segment at year-end and the excess of the recoverable amount, based upon a fair value less costs of disposal calculation, over the carrying amount (the headroom) at the date of the test.

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 for the purposes of goodwill impairment testing. 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. 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.

The 2016 review for impairment was carried out during the third quarter following the change in price assumptions and discount rate as disclosed in Note 1. In prior years the review was carried out during the fourth quarter. In the absence of any indicators of impairment in other quarters, the review will be carried out in the third quarter in future years. 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. 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.

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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 price 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 2022 onwards) was approximately $13 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 $2 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 889mmboe per year (2015 911mmboe per year). It is estimated that if production volume were to be reduced by approximately 4% for this period, 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 post-tax discount rate was approximately 9% for the entire portfolio, an increase of 3% for all countries not considered higher risk and 1% for countries considered higher risk , this would cause the recoverable amount to be equal to the carrying amount of goodwill and related net non-current assets of the segment.

Downstream

						$ million
			2016			2015
	Lubricants	**Other**	**Total**	Lubricants	Other	Total
Goodwill	**2,571**	**830**	**3,401**	3,109	652	3,761

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 2016 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

	2016			2015		
	Exploration and appraisal expenditure[a]	**Other intangibles**	**Total**	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	**19,856**	**4,055**	**23,911**	21,723	4,268	25,991
Exchange adjustments		**(149)**	**(149)**		(187)	(187)
Acquisitions		**15**	**15**			
Additions	**2,896**	**251**	**3,147**	1,197	234	1,431
Transfers	**(1,629)**		**(1,629)**	(1,039)		(1,039)
Reclassified as assets held for sale					(18)	(18)
Deletions	**(2,599)**	**(137)**	**(2,736)**	(2,025)	(242)	(2,267)
At 31 December	**18,524**	**4,035**	**22,559**	19,856	4,055	23,911
Amortization						
At 1 January	**2,570**	**2,681**	**5,251**	2,379	2,705	5,084
Exchange adjustments		**(96)**	**(96)**		(75)	(75)
Charge for the year	**1,274**	**351**	**1,625**	1,829	296	2,125
Impairment losses	**62**		**62**			
Transfers	**(5)**		**(5)**	(21)		(21)
Reclassified as assets held for sale					(15)	(15)
Deletions	**(2,337)**	**(124)**	**(2,461)**	(1,617)	(230)	(1,847)
At 31 December	**1,564**	**2,812**	**4,376**	2,570	2,681	5,251
Net book amount at 31 December	**16,960**	**1,223**	**18,183**	17,286	1,374	18,660
Net book amount at 1 January	**17,286**	**1,374**	**18,660**	19,344	1,563	20,907

[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
	2016	2015[a]	2014
Sales and other operating revenues	**10,081**	9,588	12,208
Profit before interest and taxation	**1,612**	785	1,210
Finance costs	**156**	188	125
Profit before taxation	**1,456**	597	1,085
Taxation	**490**	625	515
Profit (loss) for the year	**966**	(28)	570
Other comprehensive income	**5**	(1)	(15)
Total comprehensive income	**971**	(29)	555
Non-current assets	**10,874**	11,163	
Current assets	**3,257**	2,515	
Total assets	**14,131**	13,678	
Current liabilities	**2,087**	1,855	
Non-current liabilities	**3,520**	3,500	
Total liabilities	**5,607**	5,355	
Net assets	**8,524**	8,323	
Group investment in joint ventures			
Group share of net assets (as above)	**8,524**	8,323	
Loans made by group companies to joint ventures	**85**	89	
	8,609	8,412	

[a] The loss for 2015 shown in the table above included $711 million relating to BP`s share of impairment losses recognized by joint ventures, a significant element of which related to the Angola LNG plant.

Transactions between the group and its joint ventures are summarized below.

Sales to joint ventures		**2016**		2015		$ million 2014
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	**2,760**	**291**	2,841	245	3,148	300

Purchases from joint ventures	**2016**	2015	$ million 2014
Product	**Purchases**	Purchases	Purchases

		Amount payable at 31 December		Amount payable at 31 December		Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**943**	**120**	861	104	907	129

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	
	2016	2015	2014	**2016**	2015
Rosneft	**647**	1,330	2,101	**8,243**	5,797
Other associates	**347**	509	701	**5,849**	3,625
	994	1,839	2,802	**14,092**	9,422

The associate that is material to the group at both 31 December 2016 and 2015 is Rosneft.

BP owns 19.75% of the voting shares of Rosneft which 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 JSC Rosneftegaz, owned 50.0% plus one share of the voting shares of Rosneft at 31 December 2016.

BP classifies its investment in Rosneft as an associate because, in management s judgement, BP has significant influence over Rosneft; see Interests in other entities within Note 1 for further information. The group s investment in Rosneft is a foreign operation whose functional

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16. Investments in associates continued

currency is the Russian rouble. The increase in the group`s equity-accounted investment balance for Rosneft at 31 December 2016 compared with 31 December 2015 principally relates to foreign exchange effects 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 $6.50 per share (2015 $3.48 per share) was $13,604 million at 31 December 2016 (2015 $7,283 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 2016, 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
	2016	2015	2014
Sales and other operating revenues	**74,380**	84,071	142,856
Profit before interest and taxation	**7,094**	12,253	19,367
Finance costs	**1,747**	3,696	5,230
Profit before taxation	**5,347**	8,557	14,137
Taxation	**1,797**	1,792	3,428
Non-controlling interests	**273**	30	71
Profit for the year	**3,277**	6,735	10,638
Other comprehensive income	**4,203**	(4,111)	(13,038)
Total comprehensive income	**7,480**	2,624	(2,400)
Non-current assets	**129,403**	84,689	
Current assets	**37,914**	34,891	
Total assets	**167,317**	119,580	
Current liabilities	**46,284**	25,691	
Non-current liabilities	**71,980**	63,554	
Total liabilities	**118,264**	89,245	
Net assets	**49,053**	30,335	
Less: non-controlling interests	**7,316**	982	
	41,737	29,353	

The group received dividends, net of withholding tax, of $332 million from Rosneft in 2016 (2015 $271 million and 2014 $693 million).

Summarized financial information for the group s share of associates is shown below.

									$ million BP share
			2016			2015			2014
	Rosneft[a]	**Other**	**Total**	Rosneft[a]	Other	Total	Rosneft	Other	Total
Sales and other operating revenues	**14,690**	**5,377**	**20,067**	16,604	6,000	22,604	28,214	9,724	37,938
Profit before interest and taxation	**1,401**	**525**	**1,926**	2,420	661	3,081	3,825	938	4,763
Finance costs	**345**	**22**	**367**	730	6	736	1,033	7	1,040
Profit before taxation	**1,056**	**503**	**1,559**	1,690	655	2,345	2,792	931	3,723
Taxation	**355**	**156**	**511**	354	146	500	677	230	907
Non-controlling interests	**54**		**54**	6		6	14		14
Profit for the year	**647**	**347**	**994**	1,330	509	1,839	2,101	701	2,802
Other comprehensive income	**830**	**(2)**	**828**	(812)	(2)	(814)	(2,575)	10	(2,565)
Total comprehensive income	**1,477**	**345**	**1,822**	518	507	1,025	(474)	711	237
Non-current assets	**25,557**	**7,848**	**33,405**	16,726	3,914	20,640			
Current assets	**7,488**	**2,002**	**9,490**	6,891	1,621	8,512			
Total assets	**33,045**	**9,850**	**42,895**	23,617	5,535	29,152			
Current liabilities	**9,141**	**1,827**	**10,968**	5,074	1,134	6,208			
Non-current liabilities	**14,216**	**2,934**	**17,150**	12,552	1,311	13,863			
Total liabilities	**23,357**	**4,761**	**28,118**	17,626	2,445	20,071			
Net assets	**9,688**	**5,089**	**14,777**	5,991	3,090	9,081			
Less: non-controlling interests	**1,445**		**1,445**	194		194			
	8,243	**5,089**	**13,332**	5,797	3,090	8,887			
Group investment in associates									
Group share of net assets (as above)	**8,243**	**5,089**	**13,332**	5,797	3,090	8,887			
Loans made by group companies to associates		**760**	**760**		535	535			
	8,243	**5,849**	**14,092**	5,797	3,625	9,422			

[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.

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16. Investments in associates continued

Transactions between the group and its associates are summarized below.

$ million

Sales to associates	**2016**		2015		2014	
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	**4,210**	**765**	5,302	1,058	9,589	1,258

$ million

Purchases from associates	**2016**		2015		2014	
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	**8,873**	**2,000**	11,619	2,026	22,703	2,307

In addition to the transactions shown in the table above, in 2016 the group completed the dissolution of its German refining joint operation with Rosneft. 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 $12,768 million (2015 $11,446 million), primarily in relation to contracts with its associates for the purchase of transportation capacity.

17. Other investments

$ million

	2016		2015	
	Current	**Non-current**	Current	Non-current
Equity investments[a]	**2**	**405**		397
Other	**42**	**628**	219	605

	44	**1,033**	219	1,002

[a] The majority of equity investments are unlisted.
Other non-current investments includes $628 million relating to life insurance policies (2015 $605 million) which have been designated as financial assets at fair value through profit and loss. Their valuation methodology is in level 3 of the fair value hierarchy.

18. Inventories

		$ million
	2016	2015
Crude oil	**5,531**	3,467
Natural gas	**155**	251
Refined petroleum and petrochemical products	**9,198**	7,470
	14,884	11,188
Supplies	**2,388**	2,626
	17,272	13,814
Trading inventories	**383**	328
	17,655	14,142
Cost of inventories expensed in the income statement	**132,219**	164,790

The inventory valuation at 31 December 2016 is stated net of a provision of $501 million (2015 $1,295 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 $769 million (2015 $1,507 million credit).

Trading inventories are valued using quoted benchmark bid prices adjusted as appropriate for location and quality differentials. They are predominantly categorized within level 2 of the fair value hierarchy.

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19. Trade and other receivables

$ million

	2016 Current	2016 Non-current	2015 Current	2015 Non-current
Financial assets				
Trade receivables	**13,393**		13,682	72
Amounts receivable from joint ventures and associates	**1,056**		1,303	
Other receivables	**5,352**	**815**	5,908	1,249
	19,801	**815**	20,893	1,321
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**194**		686	
Other receivables	**680**	**659**	744	895
	874	**659**	1,430	895
	20,675	**1,474**	22,323	2,216

[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

	2016 Accounts receivable	2016 Fixed asset investments	2015 Accounts receivable	2015 Fixed asset investments	2014 Accounts receivable	2014 Fixed asset investments
At 1 January	**447**	**435**	331	517	343	168
Charged to costs and expenses	**120**	**55**	243	195	127	438
Charged to other accounts[a]	**(7)**	**(2)**	(23)	(4)	(24)	(2)
Deductions	**(168)**	**(153)**	(104)	(273)	(115)	(87)
At 31 December	**392**	**335**	447	435	331	517

[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 judgements made in relation to the recoverability of trade receivables see Impairment of loans and receivables within Note 1.

21. Trade and other payables

				$ million
		2016		2015
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**21,575**		16,838	
Amounts payable to joint ventures and associates	**2,120**		2,130	
Other payables[a]	**12,079**	**13,760**	10,775	2,351
	35,774	**13,760**	29,743	2,351
Non-financial liabilities				
Other payables	**2,141**	**186**	2,206	559
	37,915	**13,946**	31,949	2,910

[a] The majority of non-current other payables relate to the Gulf of Mexico oil spill. See Note 2 for further information.
Trade and other payables, other than those relating to the Gulf of Mexico oil spill, are predominantly interest free. See Note 28 for further information.

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22. Provisions

$ million

	Decommissioning	Environmental	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2016	**18,946**	**7,557**	**7,134**	**4,129**	**3,348**	**41,114**
Exchange adjustments	**(607)**	**(3)**			**(83)**	**(693)**
Acquisitions		**6**	**4**		**32**	**42**
Increase (decrease) in existing provisions	**(804)**	**262**	**6,650**		**1,278**	**7,386**
Write-back of unused provisions		**(96)**	**(36)**		**(299)**	**(431)**
Unwinding of discount	**162**	**62**	**36**	**38**	**12**	**310**
Change in discount rate	**738**	**18**	**20**		**32**	**808**
Utilization	**(17)**	**(239)**	**(5,625)**		**(883)**	**(6,764)**
Reclassified to other payables	**(624)**	**(5,970)**	**(5,012)**	**(4,167)**	**(189)**	**(15,962)**
Deletions	**(1,352)**	**(13)**	**(9)**		**(12)**	**(1,386)**
At 31 December 2016	**16,442**	**1,584**	**3,162**		**3,236**	**24,424**
Of which current	**244**	**315**	**2,460**		**993**	**4,012**
non-current	**16,198**	**1,269**	**702**		**2,243**	**20,412**
Of which Gulf of Mexico oil spill[a]			**2,442**			**2,442**

[a] 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 2016 are provisions for deferred employee compensation of $422 million (2015 $484 million).

For information on significant estimates and judgements made in relation to provisions, including those for the Gulf of Mexico oil spill, see Provisions and contingencies 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, 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 now accrue benefits under a cash balance formula. Benefits previously accrued under final salary formulas are legally protected. Retiring 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.

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 based on the interest rate which is set out in German tax law. Retired German employees take their pension benefit typically in the form of an annuity. The German plans are 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 2016 the aggregate level of contributions was $651 million (2015 $1,066 million and 2014 $1,252 million). The aggregate level of contributions in 2017 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 $5,761 million at 31 December 2016, of which $2,410 million relates to past service. This amount is included in the group s committed cash

23. Pensions and other post-retirement benefits continued

flows relating to pensions and other post-retirement benefit plans as set out in the table of contractual obligations on page 243. 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 2016 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 2016.

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 2016. 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		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Discount rate for plan liabilities	**2.7**	3.9	3.6	**3.9**	4.0	3.7	**1.7**	2.4	2.0
Rate of increase in salaries	**4.6**	4.4	4.5	**4.2**	3.9	4.0	**3.0**	3.2	3.4
Rate of increase for pensions in payment	**3.0**	3.0	3.0				**1.5**	1.6	1.8
Rate of increase in deferred pensions	**3.0**	3.0	3.0				**0.5**	0.6	0.7
Inflation for plan liabilities	**3.2**	3.0	3.0	**1.8**	1.5	1.6	**1.6**	1.8	2.0

%

Financial assumptions used to determine benefit expense	UK			US			Eurozone		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Discount rate for plan service cost	**4.0**	3.9	4.8	**4.2**	3.8	4.6	**2.7**	2.3	3.9
Discount rate for plan other finance expense	**3.9**	3.6	4.6	**4.0**	3.7	4.3	**2.4**	2.0	3.6
Inflation for plan service cost	**3.1**	3.1	3.4	**1.5**	1.6	2.1	**1.8**	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 this approach, 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. For 2016 the assumed rate of increase for the UK plans also reflects the probability of exceeding a cap or breaching a floor for pension increases as set out in the plan rules; this change resulted in a reduction in the pension obligation of $865 million.

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 0.8% 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 applicable 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		
	2016	2015	2014	**2016**	2015	2014	**2016**	2015	2014
Life expectancy at age 60 for a male currently aged 60	**28.0**	28.5	28.3	**25.7**	25.7	25.6	**25.0**	24.9	24.7
Life expectancy at age 60 for a male currently aged 40	**30.0**	31.0	30.9	**27.5**	27.5	27.4	**27.6**	27.5	27.3
Life expectancy at age 60 for a female currently aged 60	**29.5**	29.5	29.4	**29.3**	29.2	29.1	**28.9**	28.8	28.7
Life expectancy at age 60 for a female currently aged 40	**31.9**	31.9	31.8	**31.0**	30.9	30.9	**31.3**	31.2	31.1

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligations of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, 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 2016, the UK and the US plans switched 4% and nil respectively from equities to bonds.

BP s primary plan in the UK uses a 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.

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23. Pensions and other post-retirement benefits continued

The current asset allocation policy for the major plans at 31 December 2016 was as follows:

Asset category	UK %	US %
Total equity (including private equity)	**58**	**55**
Bonds/cash (including LDI)	**35**	**45**
Property/real estate	**7**	

The amounts invested under the LDI programme as at 31 December 2016 were $423 million (2015 $329 million) of government-issued nominal bonds and $9,384 million (2015 $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 $4,450 million (2015 $2,651 million) of the corporate bond portfolio. At 31 December 2016 the fair value liability of these swaps was $144 million (2015 $17 million fair value asset) and 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 160.

					$ million
	UK[a]	**US[b]**	**Eurozone**	**Other**	**Total**
Fair value of pension plan assets					
At 31 December 2016					
Listed equities developed markets	**11,494**	**2,283**	**436**	**363**	**14,576**
emerging markets	**2,549**	**220**	**54**	**46**	**2,869**
Private equity	**2,754**	**1,442**	**1**		**4,197**
Government issued nominal bonds	**489**	**1,438**	**821**	**448**	**3,196**
Government issued index-linked bonds	**9,384**		**4**		**9,388**
Corporate bonds	**4,042**	**1,732**	**427**	**259**	**6,460**
Property	**1,970**	**6**	**45**	**28**	**2,049**
Cash	**547**	**105**	**17**	**83**	**752**
Other	**(68)**	**90**	**74**	**83**	**179**

Debt (repurchase agreements) used to fund liability driven investments	**(2,981)**				**(2,981)**
	30,180	**7,316**	**1,879**	**1,310**	**40,685**
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

[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
					2016
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit (loss) before interest and taxation					
Current service cost[a]	333	310	76	71	790
Past service cost[b]	17	(24)	7	1	1
Settlement			9	(1)	8
Operating charge relating to defined benefit plans	350	286	92	71	799
Payments to defined contribution plans	30	194	7	33	264
Total operating charge	380	480	99	104	1,063
Interest income on plan assets[a]	(1,086)	(287)	(47)	(51)	(1,471)
Interest on plan liabilities	1,005	417	159	80	1,661
Other finance expense	(81)	130	112	29	190
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	4,422	330	53	8	4,813
Change in financial assumptions underlying the present value of the plan liabilities	(6,932)	(239)	(622)	4	(7,789)
Change in demographic assumptions underlying the present value of the plan liabilities	430	9	12	(5)	446
Experience gains and losses arising on the plan liabilities	55	(62)	26	15	34
Remeasurements recognized in other comprehensive income	(2,025)	38	(531)	22	(2,496)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	28,974	10,643	6,640	2,089	48,346
Exchange adjustments	(5,688)		(282)	23	(5,947)
Operating charge relating to defined benefit plans	350	286	92	71	799
Interest cost	1,005	417	159	80	1,661
Contributions by plan participants[c]	18		2	6	26
Benefit payments (funded plans)[d]	(1,192)	(821)	(78)	(117)	(2,208)
Benefit payments (unfunded plans)[d]	(6)	(284)	(301)	(24)	(615)
Acquisitions			4		4
Disposals				(399)	(399)
Remeasurements	6,447	292	584	(14)	7,309
Benefit obligation at 31 December[a e]	29,908	10,533	6,820	1,715	48,976
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,223	7,510	1,874	1,531	42,138
Exchange adjustments	(5,916)		(76)	15	(5,977)
Interest income on plan assets[a f]	1,086	287	47	51	1,471
Contributions by plan participants[c]	18		2	6	26
Contributions by employers (funded plans)	539	10	57	45	651

Benefit payments (funded plans)[d]	**(1,192)**	**(821)**	**(78)**	**(117)**	**(2,208)**
Disposals				**(229)**	**(229)**
Remeasurements[f]	**4,422**	**330**	**53**	**8**	**4,813**
Fair value of plan assets at 31 December[g]	**30,180**	**7,316**	**1,879**	**1,310**	**40,685**
Surplus (deficit) at 31 December	**272**	**(3,217)**	**(4,941)**	**(405)**	**(8,291)**
Represented by					
Asset recognized	**530**		**22**	**32**	**584**
Liability recognized	**(258)**	**(3,217)**	**(4,963)**	**(437)**	**(8,875)**
	272	**(3,217)**	**(4,941)**	**(405)**	**(8,291)**
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	**519**	**(36)**	**(316)**	**(83)**	**84**
Unfunded	**(247)**	**(3,181)**	**(4,625)**	**(322)**	**(8,375)**
	272	**(3,217)**	**(4,941)**	**(405)**	**(8,291)**
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	**(29,661)**	**(7,352)**	**(2,195)**	**(1,393)**	**(40,601)**
Unfunded	**(247)**	**(3,181)**	**(4,625)**	**(322)**	**(8,375)**
	(29,908)	**(10,533)**	**(6,820)**	**(1,715)**	**(48,976)**

[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 charges for special termination benefits representing the increased liability arising as a result of early retirements mostly in the UK and Eurozone. The UK also includes $12 million of cost resulting from benefit harmonization within the primary plan.

[c] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[d] The benefit payments amount shown above comprises $2,754 million benefits and $14 million settlements, plus $55 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $7,902 million for pension liabilities and $2,631 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,289 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 159.

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23. Pensions and other post-retirement benefits continued

	UK	US	Eurozone	Other	$ million 2015 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 f]	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 159.

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23. Pensions and other post-retirement benefits continued

	UK	US	Eurozone	Other	$ million 2014 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)

[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.

At 31 December 2016, reimbursement balances due from or to other companies in respect of pensions amounted to $28 million reimbursement assets (2015 $377 million) and $13 million reimbursement liabilities (2015 $13 million). These balances are not included as part of the pension surpluses and deficits, but are reflected within other receivables and other payables in the group balance sheet.

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 2016 for the group s plans would have had the effects shown in the table below. The effects shown for the expense in 2017 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 2017	**(360)**	**308**
Effect on pension and other post-retirement benefit obligation at 31 December 2016	**(7,515)**	**9,888**
Inflation rate[b]		
Effect on pension and other post-retirement benefit expense in 2017	**279**	**(232)**
Effect on pension and other post-retirement benefit obligation at 31 December 2016	**5,805**	**(5,048)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2017	**104**	**(91)**
Effect on pension and other post-retirement benefit obligation at 31 December 2016	**1,300**	**(1,165)**

[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 2017 pension and other post-retirement benefit expense by $55 million and the pension and other post-retirement benefit obligation at 31 December 2016 by $1,558 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 2026 and the weighted average duration of the defined benefit obligations at 31 December 2016 are as follows:

					$ million
Estimated future benefit payments	**UK**	**US**	**Eurozone**	**Other**	**Total**
2017	**906**	**912**	**341**	**107**	**2,266**
2018	**949**	**889**	**327**	**108**	**2,273**
2019	**986**	**861**	**321**	**111**	**2,279**
2020	**1,005**	**846**	**309**	**110**	**2,270**
2021	**1,041**	**848**	**300**	**110**	**2,299**
2022-2026	**5,586**	**3,869**	**1,420**	**561**	**11,436**
					Years
Weighted average duration	**20.3**	**9.9**	**14.9**	**13.3**	

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24. Cash and cash equivalents

		$ million
	2016	2015
Cash	**5,592**	4,653
Term bank deposits	**15,947**	16,749
Cash equivalents	**1,945**	4,987
	23,484	26,389

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 2016 includes $2,059 million (2015 $2,439 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $3,649 million (2015 $4,329 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
			2016			2015
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**6,592**	**51,074**	**57,666**	6,898	45,567	52,465
Net obligations under finance leases	**42**	**592**	**634**	46	657	703
	6,634	**51,666**	**58,300**	6,944	46,224	53,168

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 $5,587 million (2015 $5,942 million) and issued commercial paper of $971 million (2015 $869 million). Finance debt does not include accrued interest, which is reported within other payables.

The following table shows the weighted average interest rates achieved through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures.

		Fixed rate debt		**Floating rate debt**		**Total**
	Weighted average interest	**Weighted average time**	**Amount $ million**	**Weighted average interest**	**Amount $ million**	**Amount $ million**

	rate %	for which rate is fixed Years		rate %		2016
US dollar	**3**	**4**	**8,693**	**2**	**47,749**	**56,442**
Other currencies	**7**	**16**	**809**	**1**	**1,049**	**1,858**
			9,502		**48,798**	**58,300**
						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

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 2016, 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

		2016		2015
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**1,006**	**1,006**	956	956
Long-term borrowings	**57,723**	**56,660**	51,404	51,509
Net obligations under finance leases	**1,097**	**634**	1,178	703
Total finance debt	**59,826**	**58,300**	53,538	53,168

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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 manage the net debt ratio within a 20-30% band while weak market conditions remain and maintain a significant liquidity buffer. At 31 December 2016, the net debt ratio was 26.8% (2015 21.6%).

		$ million
At 31 December	**2016**	2015
Gross debt	**58,300**	53,168
Less: fair value asset (liability) of hedges related to finance debt[a]	**(697)**	(379)
	58,997	53,547
Less: cash and cash equivalents	**23,484**	26,389
Net debt	**35,513**	27,158
Equity	**96,843**	98,387
Net debt ratio	**26.8%**	21.6%

[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 $1,962 million (2015 liability of $1,617 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
		2016				2015
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	**(53,547)**	**26,389**	**(27,158)**	(52,409)	29,763	(22,646)
Exchange adjustments	**80**	**(820)**	**(740)**	1,065	(672)	393

Net cash flow	**(5,808)**	**(2,085)**	**(7,893)**	(2,220)	(2,702)	(4,922)
Other movements	**278**		**278**	17		17
At 31 December	**(58,997)**	**23,484**	**(35,513)**	(53,547)	26,389	(27,158)

[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 $5,113 million (2015 $6,008 million and 2014 $6,324 million).

The future minimum lease payments at 31 December 2016, before deducting related rental income from operating sub-leases of $186 million (2015 $166 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	**2016**	2015
Payable within		
1 year	**3,315**	4,144
2 to 5 years	**6,651**	7,743
Thereafter	**4,289**	3,535
	14,255	15,422

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 some 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 international oil and gas ships managed by the BP Shipping function and drilling rigs used in the Upstream segment. At 31 December 2016, the future minimum lease payments relating to these amounted to $3,582 million (2015 $3,036 million) and $2,969 million (2015 $4,783 million) respectively.

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27. Operating leases continued

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.

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 2016	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**		**407**					**407**
other	**17**		**42**		**628**			**670**
Loans		**791**						**791**
Trade and other receivables	**19**	**20,616**						**20,616**
Derivative financial instruments	**29**				**6,490**	**885**		**7,375**
Cash and cash equivalents	**24**	**21,539**	**1,749**	**196**				**23,484**
Financial liabilities								
Trade and other payables	**21**						**(49,534)**	**(49,534)**
Derivative financial instruments	**29**				**(6,507)**	**(1,997)**		**(8,504)**
Accruals							**(5,605)**	**(5,605)**
Finance debt	**25**						**(58,300)**	**(58,300)**
		42,946	**2,198**	**196**	**611**	**(1,112)**	**(113,439)**	**(68,600)**
At 31 December 2015								
Financial assets								
Other investments								
equity shares	17		397					397
	17		219		605			824

other								
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)

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.

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28. Financial instruments and financial risk factors continued

(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.

(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 fixes the US dollar cost of non-US dollar supplies by using currency forwards. The exposures are sterling, euro, Australian dollar and Norwegian krone. At 31 December 2016 the most significant open contracts in place were for $1,204 million sterling (2015 $627 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 2016, the open positions relating to cylinders consisted of receive sterling, pay US dollar cylinders for $1,885 million (2015 $2,479 million); receive euro, pay US dollar cylinders for $585 million (2015 $560 million); receive Australian dollar, pay US dollar cylinders for $274 million (2015 $312 million).

In addition, most of the group s borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2016, the total foreign currency borrowings not swapped into US dollars net of those hedged with cash in the same currency expected to be held until the maturity of those borrowings amounted to $809 million (2015 $826 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 2016 was 84% of total finance debt outstanding (2015 79%). The weighted average interest rate on finance debt at 31 December 2016 was 2% (2015 2%) and the weighted average maturity of fixed rate debt was five years (2015 five years).

The group s earnings are sensitive to changes in interest rates on the floating rate element of the group s finance debt. If the interest rates applicable to floating rate instruments were to have increased by one percentage point on 1 January 2017, it is estimated that the group s finance costs for 2017 would increase by approximately $488 million (2015 $419 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 2016 was $309 million (2015 $35 million) in respect of liabilities of joint ventures and associates and $370 million (2015 $163 million) in respect of liabilities of other third parties.

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28. Financial instruments and financial risk factors continued

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 2016, the group had in place credit enhancements designed to mitigate approximately $11.6 billion of credit risk (2015 $10.9 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.

Management information used to monitor credit risk indicates that 79% (2015 81%) of total unmitigated credit exposure relates to counterparties of investment-grade credit quality.

		$ million
Trade and other receivables at 31 December	**2016**	2015
Neither impaired nor past due	**19,459**	21,064
Impaired (net of provision)	**71**	22
Not impaired and past due in the following periods		
within 30 days	**446**	414
31 to 60 days	**116**	75
61 to 90 days	**56**	118
over 90 days	**468**	521
	20,616	22,214

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

At 31 December 2016	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Related amounts not set off in the balance sheet Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	**9,025**	**(1,882)**	**7,143**	**(1,058)**	**(133)**	**5,952**
Derivative liabilities	**(10,236)**	**1,882**	**(8,354)**	**1,058**		**(7,296)**
Trade and other receivables	**8,815**	**(4,468)**	**4,347**	**(1,039)**	**(118)**	**3,190**
Trade and other payables	**(9,664)**	**4,468**	**(5,196)**	**1,039**		**(4,157)**
At 31 December 2015						
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 and other receivables	7,091	(3,689)	3,402	(322)	(161)	2,919
Trade and other payables	(5,720)	3,689	(2,031)	322		(1,709)

(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 the treasury function, 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 (positive outlook).

During 2016, $12 billion of long-term taxable bonds were issued with terms ranging from three to twelve 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 $23.5 billion at 31 December 2016 (2015 $26.4 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2016, 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 are 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 $6,750 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 2016 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.

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

	2016				2015			
	Trade and other payables[a]	**Accruals**	**Finance debt**	**Interest**	Trade and other payables[a]	Accruals	Finance debt	Interest
Within one year	**35,774**	**5,136**	**6,634**	**1,217**	29,743	6,261	6,944	928
1 to 2 years	**2,005**	**186**	**5,973**	**1,083**	971	380	5,796	812
2 to 3 years	**1,278**	**91**	**6,734**	**942**	1,231	138	6,208	704
3 to 4 years	**1,239**	**53**	**6,301**	**801**	56	98	6,103	592
4 to 5 years	**1,229**	**33**	**6,780**	**658**	17	74	6,354	478
5 to 10 years	**5,826**	**75**	**22,378**	**1,843**	38	167	17,651	1,068
Over 10 years	**7,248**	**31**	**3,500**	**816**	38	33	4,112	402
	54,599	**5,605**	**58,300**	**7,360**	32,094	7,151	53,168	4,984

[a] 2016 includes $21,644 million and 2015 includes $2,750 million in relation to Gulf of Mexico oil spill.

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 $18,014 million at 31 December 2016 (2015 $15,706 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

Cash outflows for derivative financial instruments at 31 December	**2016**	2015
Within one year	**2,677**	2,959
1 to 2 years	**1,505**	2,685

2 to 3 years	**1,700**	1,505
3 to 4 years	**1,678**	1,700
4 to 5 years	**2,384**	1,678
5 to 10 years	**9,985**	5,500
Over 10 years	**1,413**	2,739
	21,342	18,766

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
		2016		2015
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**167**	**(2,000)**	144	(1,811)
Oil price derivatives	**1,543**	**(952)**	2,390	(1,257)
Natural gas price derivatives	**3,780**	**(2,845)**	3,942	(2,536)
Power price derivatives	**768**	**(560)**	920	(434)
Other derivatives	**232**		292	
	6,490	**(6,357)**	7,688	(6,038)
Embedded derivatives				
Commodity price contracts		**(50)**	12	(101)
Other embedded derivatives		**(100)**		
		(150)	12	(101)
Cash flow hedges				
Currency forwards, futures and cylinders	**32**	**(451)**	9	(71)
Cross-currency interest rate swaps		**(154)**		(147)
	32	**(605)**	9	(218)
Fair value hedges				
Currency forwards, futures and swaps	**22**	**(1,159)**	33	(1,108)
Interest rate swaps	**831**	**(233)**	909	(57)
	853	**(1,392)**	942	(1,165)
	7,375	**(8,504)**	8,651	(7,522)
Of which current	**3,016**	**(2,991)**	4,242	(3,239)
non-current	**4,359**	**(5,513)**	4,409	(4,283)

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
							2016
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**102**	**34**	**20**	**2**	**7**	**2**	**167**
Oil price derivatives	**1,178**	**201**	**91**	**49**	**22**	**2**	**1,543**
Natural gas price derivatives	**1,238**	**647**	**424**	**313**	**267**	**891**	**3,780**
Power price derivatives	**305**	**164**	**114**	**58**	**53**	**74**	**768**
Other derivatives	**132**					**100**	**232**
	2,955	**1,046**	**649**	**422**	**349**	**1,069**	**6,490**

							$ 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

At 31 December 2016 and 2015 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 2016
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**(379)**	**(36)**	**(402)**	**(101)**	**(338)**	**(744)**	**(2,000)**
Oil price derivatives	**(787)**	**(105)**	**(40)**	**(11)**	**(3)**	**(6)**	**(952)**
Natural gas price derivatives	**(947)**	**(421)**	**(257)**	**(258)**	**(197)**	**(765)**	**(2,845)**
Power price derivatives	**(201)**	**(126)**	**(81)**	**(39)**	**(31)**	**(82)**	**(560)**
	(2,314)	**(688)**	**(780)**	**(409)**	**(569)**	**(1,597)**	**(6,357)**

							$ million 2015
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	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)

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 2016
	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 2	**3,962**	**1,035**	**509**	**208**	**117**	**189**	**6,020**
Level 3	**448**	**265**	**249**	**243**	**241**	**906**	**2,352**
	4,410	**1,300**	**758**	**451**	**358**	**1,095**	**8,372**
Less: netting by counterparty	**(1,455)**	**(254)**	**(109)**	**(29)**	**(9)**	**(26)**	**(1,882)**

	2,955	**1,046**	**649**	**422**	**349**	**1,069**	**6,490**
Fair value of derivative liabilities							
Level 2	**(3,610)**	**(778)**	**(701)**	**(249)**	**(401)**	**(872)**	**(6,611)**
Level 3	**(159)**	**(164)**	**(188)**	**(189)**	**(177)**	**(751)**	**(1,628)**
	(3,769)	**(942)**	**(889)**	**(438)**	**(578)**	**(1,623)**	**(8,239)**
Less: netting by counterparty	**1,455**	**254**	**109**	**29**	**9**	**26**	**1,882**
	(2,314)	**(688)**	**(780)**	**(409)**	**(569)**	**(1,597)**	**(6,357)**
Net fair value	**641**	**358**	**(131)**	**13**	**(220)**	**(528)**	**133**

$ million

							2015
	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	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

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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.

	Oil price	Natural gas price	Power price	Other	Total
					$ million
Fair value of contracts at 1 January 2016	**169**	**214**	**91**	**292**	**766**
Gains (losses) recognized in the income statement	**(37)**	**1**	**(82)**	**139**	**21**
Settlements	**(63)**	**(51)**	**(145)**	**(200)**	**(459)**
Transfers out of level 3	**(1)**	**(19)**	**(11)**		**(31)**
Net fair value of contracts at 31 December 2016	**68**	**145**	**(147)**	**231**	**297**
Deferred day-one gains (losses)					**427**
Derivative asset (liability)					**724**

	Oil price	Natural gas price	Power price	Other	Total
					$ million
Fair value of contracts at 1 January 2015	146	74	109	389	718
Gains (losses) recognized in the income statement	44	288	76	92	500
Settlements	(20)	(40)	(72)	(189)	(321)
Transfers out of level 3	(1)	(108)	(22)		(131)
Net fair value of contracts at 31 December 2015	169	214	91	292	766
Deferred day-one gains (losses)					459
Derivative asset (liability)					1,225

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2016 was a $253-million loss (2015 $293-million gain related to derivatives still held at 31 December 2015).

Derivative gains and losses

Gains and losses relating to derivative contracts are included within sales and other operating revenues 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 $1,435 million (2015 $5,508 million net gain and 2014 $6,154 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 a gain of $32 million (2015 gain of $120 million, 2014 gain of $430 million).

Cash flow hedges

At 31 December 2016, 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 2016 in relation to these cash flow hedges consist of deferred losses of $343 million maturing in 2017, deferred losses of $71 million maturing in 2018 and deferred losses of $22 million maturing in 2019 and beyond.

Fair value hedges

At 31 December 2016, 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 2016 was $316 million (2015 $788 million loss and 2014 $14 million loss) offset by a gain on the fair value of the finance debt of $270 million (2015 $833 million gain and 2014 $8 million gain).

The interest rate and cross-currency interest rate swaps mature within one to twelve years, and have the same maturity terms as the debt that they are hedging. They are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar, Norwegian krone and Hong Kong dollar denominated fixed rate borrowings into floating rate debt. Note 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:

		2016		2015		2014
Issued	**Shares thousand**	**$ million**	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,108,771**	**5,028**	20,005,961	5,002	20,426,632	5,108
Issue of new shares for the scrip dividend programme	**548,005**	**137**	102,810	26	165,644	41
Issue of new shares for employee share-based payment plans[b]					25,598	6
Issue of new shares other[c]	**392,920**	**98**				
Repurchase of ordinary share capital[d]					(611,913)	(153)
At 31 December	**21,049,696**	**5,263**	20,108,771	5,028	20,005,961	5,002
		5,284		5,049		5,023

[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.

[c] Relates to the issue of new ordinary shares in consideration for a 10% interest in the Abu Dhabi onshore oil concession. See Note 31 for further information.

[d] In 2014 shares were repurchased for a total consideration of $4,796 million, including transaction costs of $26 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]

	2016		2015		2014	
		Nominal value		Nominal value		
	Shares thousand	**$ million**	Shares thousand	$ million	Shares thousand	Nominal value $ million
At 1 January	**1,756,327**	**439**	1,811,297	453	1,833,544	458
Purchases for settlement of employee share plans	**9,631**	**2**	51,142	13	49,559	12
Shares re-issued for employee share-based payment plans	**(151,339)**	**(38)**	(106,112)	(27)	(71,806)	(17)
At 31 December	**1,614,619**	**403**	1,756,327	439	1,811,297	453
Of which shares held in treasury by BP	**1,576,411**	**394**	1,727,763	432	1,771,103	443
shares held in ESOP trusts	**21,432**	**5**	18,453	4	34,169	9
shares held by BP s US share plan administrator[b]	**16,814**	**4**	10,111	3	6,025	1

[a] See Note 31 for definition of treasury shares.
[b] Held 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 8.6% (2015 8.9% and 2014 8.8%) of the called-up ordinary share capital of the company.

During 2016, the movement in shares held in treasury by BP represented less than 0.8% (2015 less than 0.2% and 2014 less than 0.1%) 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 2016	**5,049**	**10,234**	**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)					
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					
Total comprehensive income					
Dividends	**137**	**(137)**			
Share-based payments, net of tax[b c]	**98**	**2,122**			**2,220**
Share of equity-accounted entities changes in equity, net of tax					
Transactions involving non-controlling interests					
At 31 December 2016	**5,284**	**12,219**	**1,413**	**27,206**	**46,122**

	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[c]					
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[d]	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

[a] Principally foreign exchange effects relating to the Russian rouble.
[b] Includes ordinary shares issued to the government of Abu Dhabi in consideration for a 10% interest in the Abu Dhabi onshore oil concession. The share-based payment transaction was valued at the fair value of the interest in the assets, with reference to a market transaction for an identical interest.
[c] Movements in treasury shares relate to employee share-based payment plans.
[d] New share issues and movements in treasury shares 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
(19,964)	**(7,267)**	**2**	**(825)**	**(823)**	**81,368**	**97,216**	**1,171**	**98,387**
					115	**115**	**57**	**172**
	389					**389**	**(27)**	**362**
		1		**1**		**1**		**1**
			(331)	**(331)**		**(331)**		**(331)**
					833	**833**		**833**
					(96)	**(96)**		**(96)**
					(1,757)	**(1,757)**		**(1,757)**
	389	**1**	**(331)**	**(330)**	**(905)**	**(846)**	**30**	**(816)**
					(4,611)	**(4,611)**	**(107)**	**(4,718)**
1,521					**(750)**	**2,991**		**2,991**
					106	**106**		**106**
					430	**430**	**463**	**893**
(18,443)	**(6,878)**	**3**	**(1,156)**	**(1,153)**	**75,638**	**95,286**	**1,557**	**96,843**

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

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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) and BP s US share plan administrator 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. It includes $651 million relating to the acquisition of an 18.5% interest in Rosneft in 2013 which will only be reclassified to the income statement if the investment in Rosneft is either sold or impaired. For further information on the accounting for cash flow hedges 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
			2016
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	**284**	**78**	**362**
Available-for-sale investments (including recycling)	**1**		**1**
Cash flow hedges (including recycling)	**(362)**	**31**	**(331)**
Share of items relating to equity-accounted entities, net of tax	**833**		**833**
Other		**(96)**	**(96)**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**(2,496)**	**739**	**(1,757)**
Other comprehensive income	**(1,740)**	**752**	**(988)**

			$ 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			
	(4,590)	1,334	(3,256)

Remeasurements of the net pension and other post-retirement benefit liability or asset			
Share of items relating to equity-accounted entities, net of tax	4		4
Other comprehensive income	(14,196)	1,481	(12,715)

32. Contingent liabilities

Contingent liabilities related to the Gulf of Mexico oil spill

See Note 2 for information on contingent liabilities related to the Gulf of Mexico oil spill.

Contingent liabilities not related to the Gulf of Mexico oil spill

There were contingent liabilities at 31 December 2016 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 on financial guarantees 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.

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. BP is not currently aware of any such cases that have a greater than remote chance of reverting to the Group. Furthermore, as described in Provisions and contingencies 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.

33. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2016	2015	2014
Total for all directors			
Emoluments	**10**	10	14
Amounts received under incentive schemes[a]	**14**	14	10
Total	**24**	24	24

[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 2016 one executive director participated in a non-contributory pension scheme established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. One executive director participated in 2016 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 80.

Remuneration of directors and senior management

			$ million
	2016	2015	2014
Total for all senior management and non-executive directors			
Short-term employee benefits	**28**	33	34
Pensions and other post-retirement benefits	**3**	4	3
Share-based payments	**39**	36	34
Total	**70**	73	71

Senior management comprises members of the executive team, see pages 58-59 for further information.

Short-term employee benefits

These amounts comprise fees and benefits paid to the non-executive chairman and non-executive directors, as well as salary, benefits and cash bonuses for senior management. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short term employee benefits includes compensation for loss of office of $2.2 million in 2016 (2015 $nil and 2014 $1.5 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	**2016**	2015	2014
Wages and salaries[a]	**8,456**	9,556	10,710
Social security costs	**760**	879	983
Share-based payments[b]	**764**	833	689
Pension and other post-retirement benefit costs	**1,253**	1,660	1,554
	11,233	12,928	13,936

			2016			2015			2014
Average number of employees[c]	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Upstream	**6,700**	**13,500**	**20,200**	7,900	15,100	23,000	9,100	15,600	24,700
Downstream[d e]	**6,600**	**36,600**	**43,200**	7,800	38,200	46,000	8,200	39,900	48,100
Other businesses and corporate[e f]	**1,900**	**12,100**	**14,000**	1,700	11,900	13,600	1,800	10,100	11,900
	15,200	**62,200**	**77,400**	17,400	65,200	82,600	19,100	65,600	84,700

[a] Includes termination payments of $545 million (2015 $857 million and 2014 $527 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 15,800 (2015 15,000 and 2014 14,200) service station staff.

[e] Around 800 centralized function employees were reallocated from Upstream and Downstream to Other businesses and corporate during 2016, and around 2,000 employees from the global business services organization were reallocated from Downstream to Other businesses and corporate during 2015.

[f] Includes 4,900 (2015 5,300 and 2014 5,100) agricultural, operational and seasonal workers in Brazil.

35. Auditor s remuneration

			$ million
Fees Ernst & Young	**2016**	2015	2014
The audit of the company annual accounts[a]	**25**	27	27
The audit of accounts of subsidiaries of the company	**12**	13	13
Total audit	**37**	40	40
Audit-related assurance services[b]	**7**	7	7
Total audit and audit-related assurance services	**44**	47	47
Taxation compliance services	**1**	1	1
Taxation advisory services			1
Services relating to corporate finance transactions		1	1

Total non-audit and other assurance services	**1**	1	2
Total non-audit or non-audit-related assurance services	**2**	3	5
Services relating to BP pension plans[c]	**1**	1	1
	47	51	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 $nil (2015 $0.4 million and 2014 $0.4 million).
2016 includes $1 million of additional fees for 2015 and 2015 includes $2 million of additional fees for 2014.
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 $47 million (2015 $51 million and 2014 $53 million) is required to be presented as follows: audit $37 million (2015 $40 million and 2014 $40 million); other audit-related $7 million (2015 $7 million and 2014 $7 million); tax $1 million (2015 $1 million and 2014 $2 million); and all other fees $2 million (2015 $3 million and 2014 $4 million).

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36. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2016 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 14 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
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
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	Germany	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	
	100	US	

Exploration and production, refining and marketing pipelines and petrochemicals

BP America Production Company			
BP Company North America	100	US	
BP Corporation North America	100	US	
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

Associates	%	Country of incorporation	Principal activities
Russia			
Rosneft	20	Russia	Integrated oil operations

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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					**2016**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**2,740**		**182,999**	**(2,731)**	**183,008**
Earnings from joint ventures after interest and tax			**966**		**966**
Earnings from associates after interest and tax			**994**		**994**
Equity-accounted income of subsidiaries after interest and tax		**862**		**(862)**	
Interest and other income	**94**	**343**	**899**	**(830)**	**506**
Gains on sale of businesses and fixed assets			**1,132**		**1,132**
Total revenues and other income	**2,834**	**1,205**	**186,990**	**(4,423)**	**186,606**
Purchases	**888**		**134,062**	**(2,731)**	**132,219**
Production and manufacturing expenses	**1,171**		**27,906**		**29,077**
Production and similar taxes	**102**		**581**		**683**
Depreciation, depletion and amortization	**673**		**13,832**		**14,505**
Impairment and losses on sale of businesses and fixed assets	**(147)**		**(1,517)**		**(1,664)**
Exploration expense			**1,721**		**1,721**
Distribution and administration expenses		**808**	**9,797**	**(110)**	**10,495**
Profit (loss) before interest and taxation	**147**	**397**	**608**	**(1,582)**	**(430)**
Finance costs	**103**	**311**	**1,981**	**(720)**	**1,675**

Net finance (income) expense relating to pensions and other post-retirement benefits		**(82)**	**272**		**190**
Profit (loss) before taxation	**44**	**168**	**(1,645)**	**(862)**	**(2,295)**
Taxation	**(41)**	**53**	**(2,479)**		**(2,467)**
Profit (loss) for the year	**85**	**115**	**834**	**(862)**	**172**
Attributable to					
BP shareholders	**85**	**115**	**777**	**(862)**	**115**
Non-controlling interests			**57**		**57**
	85	**115**	**834**	**(862)**	**172**

Statement of comprehensive income

					$ million
For the year ended 31 December					**2016**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Profit (loss) for the year	**85**	**115**	**834**	**(862)**	**172**
Other comprehensive income		**(1,505)**	**517**		**(988)**
Equity-accounted other comprehensive income of subsidiaries		**544**		**(544)**	
Total comprehensive income	**85**	**(846)**	**1,351**	**(1,406)**	**(816)**
Attributable to					
BP shareholders	**85**	**(846)**	**1,321**	**(1,406)**	**(846)**
Non-controlling interests			**30**		**30**
	85	**(846)**	**1,351**	**(1,406)**	**(816)**

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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. [a]	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	2015 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	176		1,733		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	(266)	(6,313)	(6,515)	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	(301)	(6,369)	(8,274)	5,373	(9,571)
Taxation	(129)	82	(3,124)		(3,171)
Profit (loss) for the year	(172)	(6,451)	(5,150)	5,373	(6,400)
Attributable to					
BP shareholders	(172)	(6,451)	(5,232)	5,373	(6,482)
Non-controlling interests			82		82
	(172)	(6,451)	(5,150)	5,373	(6,400)

[a] Minor amendments have been made to previously reported amounts.

Statement of comprehensive income continued

					$ 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	(172)	(6,451)	(5,150)	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	(172)	(8,228)	(8,831)	9,013	(8,218)
Attributable to					
BP shareholders	(172)	(8,228)	(8,872)	9,013	(8,259)
Non-controlling interests			41		41
	(172)	(8,228)	(8,831)	9,013	(8,218)

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37. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

					$ million
For the year ended 31 December					2014
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	6,227		353,529	(6,188)	353,568
Earnings from joint ventures after interest and tax			570		570
Earnings from associates after interest and tax			2,802		2,802
Equity-accounted income of subsidiaries after interest and tax		4,531		(4,531)	
Interest and other income	2	193	910	(262)	843
Gains on sale of businesses and fixed assets	19		876		895
Total revenues and other income	6,248	4,724	358,687	(10,981)	358,678
Purchases	2,375		285,720	(6,188)	281,907
Production and manufacturing expenses	1,779		25,596		27,375
Production and similar taxes	554		2,404		2,958
Depreciation, depletion and amortization	545		14,618		15,163
Impairment and losses on sale of businesses and fixed assets	153		8,812		8,965
Exploration expense			3,632		3,632
Distribution and administration expenses	48	929	11,364	(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

$ million

For the year ended 31 December					2014
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (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

Balance sheet

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2016 BP group
Non-current assets					
Property, plant and equipment	7,405		122,352		129,757
Goodwill			11,194		11,194
Intangible assets	578		17,605		18,183
Investments in joint ventures			8,609		8,609
Investments in associates		2	14,090		14,092
Other investments			1,033		1,033
Subsidiaries equity-accounted basis		156,864		(156,864)	
Fixed assets	7,983	156,866	174,883	(156,864)	182,868
Loans	9		34,941	(34,418)	532
Trade and other receivables		2,951	1,474	(2,951)	1,474
Derivative financial instruments			4,359		4,359
Prepayments			945		945
Deferred tax assets			4,741		4,741
Defined benefit pension plan surpluses		528	56		584
	7,992	160,345	221,399	(194,233)	195,503
Current assets					
Loans			259		259
Inventories	249		17,406		17,655
Trade and other receivables	2,583	487	24,660	(7,055)	20,675
Derivative financial instruments			3,016		3,016
Prepayments	7		1,479		1,486
Current tax receivable			1,194		1,194
Other investments			44		44
Cash and cash equivalents		50	23,434		23,484
	2,839	537	71,492	(7,055)	67,813
Total assets	10,831	160,882	292,891	(201,288)	263,316
Current liabilities					
Trade and other payables	722	4,096	40,152	(7,055)	37,915
Derivative financial instruments			2,991		2,991
Accruals	116	129	4,891		5,136
Finance debt			6,634		6,634
Current tax payable	11		1,655		1,666
Provisions	2		4,010		4,012

	851	**4,225**	**60,333**	**(7,055)**	**58,354**
Non-current liabilities					
Other payables	**20**	**34,389**	**16,906**	**(37,369)**	**13,946**
Derivative financial instruments			**5,513**		**5,513**
Accruals		**43**	**426**		**469**
Finance debt			**51,666**		**51,666**
Deferred tax liabilities	**1,279**	**179**	**5,780**		**7,238**
Provisions	**1,390**		**19,022**		**20,412**
Defined benefit pension plan and other post-retirement benefit plan deficits		**219**	**8,656**		**8,875**
	2,689	**34,830**	**107,969**	**(37,369)**	**108,119**
Total liabilities	**3,540**	**39,055**	**168,302**	**(44,424)**	**166,473**
Net assets	**7,291**	**121,827**	**124,589**	**(156,864)**	**96,843**
Equity					
BP shareholders equity	**7,291**	**121,827**	**123,032**	**(156,864)**	**95,286**
Non-controlling interests			**1,557**		**1,557**
	7,291	**121,827**	**124,589**	**(156,864)**	**96,843**

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37. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

$ million

At 31 December					2015
	Issuer BP Exploration (Alaska) Inc.[a]	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	8,345		121,413		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	8,884	128,236	169,995	(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
	8,891	130,752	186,540	(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	18,862	131,814	256,959	(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	1,255	877	7,467		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
	3,589	7,845	104,006	(6,719)	108,721
Total liabilities	4,646	8,057	168,311	(17,569)	163,445
Net assets	14,216	123,757	88,648	(128,234)	98,387
Equity					
BP shareholders equity	14,216	123,757	87,477	(128,234)	97,216
Non-controlling interests			1,171		1,171
	14,216	123,757	88,648	(128,234)	98,387

[a] Minor amendments have been made to previously reported amounts.

37. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

				$ million
For the year ended 31 December				**2016**
	Issuer	**Guarantor**		
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**BP group**
Net cash provided by operating activities	**699**	**4,661**	**5,331**	**10,691**
Net cash provided by (used in) investing activities	**(699)**		**(14,054)**	**(14,753)**
Net cash provided by (used in) financing activities		**(4,611)**	**6,588**	**1,977**
Currency translation differences relating to cash and cash equivalents			**(820)**	**(820)**
Increase (decrease) in cash and cash equivalents		**50**	**(2,955)**	**(2,905)**
Cash and cash equivalents at beginning of year			**26,389**	**26,389**
Cash and cash equivalents at end of year		**50**	**23,434**	**23,484**

				$ million
For the year ended 31 December				2015
	Issuer	Guarantor		
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	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

				$ million
For the year ended 31 December				2014
	Issuer	Guarantor		
	BP Exploration (Alaska)	BP p.l.c.	Other subsidiaries	BP group

	Inc.			
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

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Supplementary information on oil and natural gas (unaudited)

The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities), in accordance with SEC and FASB requirements.

Oil and gas reserves certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
  (A) The area identified by drilling and limited by fluid contacts, if any; and
  (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
  (A) Successful testing by a pilot project in an area of the reservoir with properties no more favourable than in the reservoir as a whole, the operation of an installed programme in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or programme was based; and
  (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.
(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.
(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared 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 251-256.

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Oil and natural gas exploration and production activities

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2016 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	**34,171**		**81,633**	**3,622**	**12,624**	**46,892**		**30,870**	**5,752**	**215,564**
Unproved properties	**483**		**4,712**	**2,377**	**2,450**	**3,808**		**4,132**	**562**	**18,524**
	34,654		**86,345**	**5,999**	**15,074**	**50,700**		**35,002**	**6,314**	**234,088**
Accumulated depreciation	**21,745**		**44,988**	**272**	**6,764**	**31,456**		**15,942**	**2,826**	**123,993**
Net capitalized costs	**12,909**		**41,357**	**5,727**	**8,310**	**19,244**		**19,060**	**3,488**	**110,095**
Costs incurred for the year ended 31 December[a] [b]										
Acquisition of properties[c]										
Proved	**215**		**314**					**703**	**207**	**1,439**
Unproved			**38**	**10**	**10**	**181**		**1,728**		**1,967**
	215		**352**	**10**	**10**	**181**		**2,431**	**207**	**3,406**
Exploration and appraisal costs[d]	**165**	**5**	**391**	**70**	**123**	**297**	**10**	**252**	**89**	**1,402**
Development	**1,284**	**3**	**2,372**	**28**	**1,519**	**2,957**		**2,788**	**194**	**11,145**
Total costs	**1,664**	**8**	**3,115**	**108**	**1,652**	**3,435**	**10**	**5,471**	**490**	**15,953**
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[e]										
Third parties	**244**	**26**	**640**	**74**	**747**	**1,215**		**97**	**1,042**	**4,085**

Sales between businesses	**1,387**	**421**	**6,204**	**2**	**103**	**3,391**		**3,908**	**309**	**15,725**
	1,631	**447**	**6,844**	**76**	**850**	**4,606**		**4,005**	**1,351**	**19,810**
Exploration expenditure	**133**	**3**	**693**	**61**	**672**	**87**	**10**	**(27)**	**89**	**1,721**
Production costs	**619**	**208**	**2,524**	**114**	**476**	**1,220**		**691**	**154**	**6,006**
Production taxes	**(351)**		**155**		**38**			**800**	**41**	**683**
Other costs (income)[f]	**(215)**	**37**	**1,687**	**25**	**115**	**597**	**34**	**115**	**153**	**2,548**
Depreciation, depletion and amortization	**1,002**	**209**	**3,940**	**66**	**591**	**2,937**		**2,179**	**289**	**11,213**
Net impairments and (gains) losses on sale of businesses and fixed assets	**(809)**	**(345)**	**(627)**	**(5)**	**(77)**	**(765)**		**(182)**	**63**	**(2,747)**
	379	**112**	**8,372**	**261**	**1,815**	**4,076**	**44**	**3,576**	**789**	**19,424**
Profit (loss) before taxation[g]	**1,252**	**335**	**(1,528)**	**(185)**	**(965)**	**530**	**(44)**	**429**	**562**	**386**
Allocable taxes[h]	**(286)**	**(287)**	**(402)**	**(40)**	**(194)**	**670**	**(10)**	**(74)**	**288**	**(335)**
Results of operations	**1,538**	**622**	**(1,126)**	**(145)**	**(771)**	**(140)**	**(34)**	**503**	**274**	**721**

Upstream and Rosneft segments replacement cost profit (loss) before interest and tax

Exploration and production activities subsidiaries (as above)	**1,252**	**335**	**(1,528)**	**(185)**	**(965)**	**530**	**(44)**	**429**	**562**	**386**
Midstream and other activities subsidiaries[i]	**(417)**	**54**	**(14)**	**(137)**	**187**	**(142)**	**(2)**	**(81)**	**13**	**(539)**
Equity-accounted entities[j] [k]		**(1)**	**20**		**447**	**(12)**	**597**	**266**		**1,317**
Total replacement cost profit (loss) before interest and tax	**835**	**388**	**(1,522)**	**(322)**	**(331)**	**376**	**551**	**614**	**575**	**1,164**

[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] Rest of Asia amounts include BP s participating interest in the Abu Dhabi ADCO concession.

[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $32 million. The UK region includes a $454-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 $152 million which is included in finance costs in the group income statement.

[h] UK region includes the 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 20% to 10%.

[i] Midstream and other activities excludes inventory holding gains and losses.

[j] The profits of equity-accounted entities are included after interest and tax.

[k] Includes the results of BP s 30% interest in Aker BP ASA from 1 October 2016.

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Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2016 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		**2,702**			**10,211**		**19,818**	**3,009**		**35,740**
Unproved properties		**296**			**6**		**369**	**26**		**697**
		2,998			**10,217**		**20,187**	**3,035**		**36,437**
Accumulated depreciation		**48**			**4,615**		**4,379**	**3,035**		**12,077**
Net capitalized costs		**2,950**			**5,602**		**15,808**			**24,360**
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved							**1,956**			**1,956**
Unproved							**70**			**70**
							2,026			**2,026**
Exploration and appraisal costs[d]		**18**			**7**		**105**	**1**		**131**
Development		**54**			**559**		**2,014**	**371**		**2,998**
Total costs		**72**			**566**		**4,145**	**372**		**5,155**
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties		**162**			**1,865**			**876**		**2,903**
Sales between businesses							**8,129**	**16**		**8,145**
		162			**1,865**		**8,129**	**892**		**11,048**
Exploration expenditure		**13**					**50**			**63**
Production costs		**36**			**559**		**1,106**	**145**		**1,846**
Production taxes					**335**		**3,391**	**352**		**4,078**
Other costs (income)		**(13)**			**(429)**		**368**	**3**		**(71)**
		48			**499**		**1,072**	**386**		**2,005**

Depreciation, depletion and amortization							
Net impairments and losses on sale of businesses and fixed assets			164		25		189
	84		1,128		6,012	886	8,110
Profit (loss) before taxation	78		737		2,117	6	2,938
Allocable taxes	75		319		433	3	830
Results of operations[g]	3		418		1,684	3	2,108

Upstream and Rosneft segments replacement cost profit (loss) before interest and tax from equity-accounted entities

Exploration and production activities equity-accounted entities after tax (as above)	3		418		1,684	3	2,108
Midstream and other activities after tax[h]	(4)	20	29	(12)	(1,087)	263	(791)
Total replacement cost profit (loss) after interest and tax	(1)	20	447	(12)	597	266	1,317

[a] Amounts reported for Russia in this table include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia.

[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. 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 the results of BP s 30% interest in Aker BP ASA from 1 October 2016.

[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

										2015
	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	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
	1,149	718	7,427	2	33	4,005		4,028	340	17,702

Sales between businesses	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 (loss) 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 (loss) 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

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2015 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 (loss) 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 (loss) after interest and tax	(7)	19	370	(552)	1,326	363	1,519

[a] Amounts reported for Russia in this table include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia.

[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. 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
	1,069	1,662	14,894	15	450	6,289		6,951	624	31,954

Sales between businesses	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 (loss) 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 (loss) 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 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

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2014 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
					25					25

Net impairments and losses on sale of businesses and fixed assets									
				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 (loss) 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 (loss) after interest and tax	62	23		480	(33)	2,125	557		3,214

[a] Amounts reported for Russia in this table include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia.

[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. 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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Movements in estimated net proved reserves

million barrels

Crude oil[a b]										2016
	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	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
Changes attributable to										
Revisions of previous estimates[d]	13		(30)		(2)	22		543	2	548
Improved recovery			1			3		70		74
Purchases of reserves-in-place	3		3					25	1	32
Discoveries and extensions	2			4						6
Production[e]	(29)	(9)	(119)	(5)	(4)	(96)		(75)	(6)	(341)
Sales of reserves-in-place		(97)	(1)					(1)	(2)	(102)
	(11)	(106)	(145)	(1)	(6)	(71)		562	(5)	218
At 31 December[f]										
Developed	155		826	42	9	317		1,107	32	2,487
Undeveloped	274		497	209	11	42		245	14	1,291
	429		1,322	251	20	358		1,352	46	3,778
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed					311	2	2,844	68		3,225
Undeveloped					311		1,981			2,292
					622	2	4,825	68		5,517
Changes attributable to										
Revisions of previous estimates					(2)		33	13		45
Improved recovery					1		4			5
Purchases of reserves-in-place		116			36		456			609
					16		285			301

Discoveries and extensions										
Production		**(3)**			**(28)**		**(305)**	**(37)**		**(373)**
Sales of reserves-in-place							**(2)**	**(1)**		**(2)**
		114			**24**		**471**	**(25)**		**584**
At 31 December[h]										
Developed		**45**			**321**	**1**	**3,162**	**43**		**3,573**
Undeveloped		**69**			**325**		**2,134**	**1**		**2,529**
		114			**646**	**1**	**5,296**	**44**		**6,101**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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**
At 31 December										
Developed	**155**	**45**	**826**	**42**	**330**	**318**	**3,162**	**1,150**	**32**	**6,060**
Undeveloped	**274**	**69**	**497**	**209**	**336**	**42**	**2,134**	**246**	**14**	**3,819**
	429	**114**	**1,322**	**251**	**666**	**360**	**5,296**	**1,395**	**46**	**9,879**

[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 9 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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[e] Includes 6 million barrels of crude oil 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 347 million barrels of crude oil in respect of the 6.58% non-controlling interest in Rosneft, including 28 mmbbl held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[h] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,330 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 62 million barrels in Venezuela and 5,268 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	2016 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	5	11	269		7	5			9	308
Undeveloped	4	1	70		28	10			2	115
	10	12	339		35	15			12	422
Changes attributable to										
Revisions of previous estimates	7		(24)			1				(14)
Improved recovery			3							3
Purchases of reserves-in-place	1		4							6
Discoveries and extensions										
Production[c]	(2)	(1)	(24)		(2)	(2)			(1)	(34)
Sales of reserves-in-place		(10)								(10)
	7	(12)	(40)		(2)	(1)			(1)	(49)
At 31 December[d]										
Developed	13		226		5	13			9	266
Undeveloped	3		73		28	1			2	107
	16		299		33	14			11	373
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed						13	32			45
Undeveloped							15			15
						13	47			60
Changes attributable to										
Revisions of previous estimates						(2)	18			16
Improved recovery										
Purchases of reserves-in-place		5								5
Discoveries and extensions										
Production										

Sales of reserves-in-place								
		5			(2)	18		21
At 31 December[f]								
Developed		3			11	50		65
Undeveloped		2				15		17
		5			11	65		81
Total subsidiaries and equity-accounted entities (BP share)								
At 1 January								
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
At 31 December								
Developed	13	3	226	5	24	50	9	331
Undeveloped	3	2	73	28	1	15	2	123
	16	5	299	33	25	65	11	454

[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 3 thousand barrels per day for equity-accounted entities.

[d] Includes 10 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 65 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 65 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	2016 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	147	98	1,159	46	15	346		598	45	2,453
Undeveloped	303	20	647	205	46	99		192	18	1,529
	449	117	1,806	252	61	444		790	63	3,982
Changes attributable to										
Revisions of previous estimates[d]	20		(54)		(2)	23		543	3	533
Improved recovery			5			3		70		78
Purchases of reserves-in-place	5		7					25	1	38
Discoveries and extensions	2			4						6
Production[e]	(31)	(10)	(143)	(5)	(6)	(98)		(75)	(7)	(375)
Sales of reserves-in-place		(108)	(1)					(1)	(2)	(112)
	(4)	(117)	(185)	(1)	(8)	(72)		562	(5)	168
At 31 December[f]										
Developed	168		1,051	42	14	330		1,107	42	2,753
Undeveloped	277		569	209	39	43		245	16	1,398
	445		1,621	251	53	372		1,352	57	4,151
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed					311	14	2,876	68		3,270
Undeveloped					312		1,996			2,307
					622	14	4,872	68		5,577
Changes attributable to										
Revisions of previous estimates					(2)	(2)	51	13		61
Improved recovery					1		4			5
		122			36		456			614

Purchases of reserves-in-place										
Discoveries and extensions					16		285			301
Production		(3)			(28)		(305)	(37)		(374)
Sales of reserves-in-place							(2)	(1)		(2)
		119			24	(2)	489	(25)		605
At 31 December[h i]										
Developed		48			321	12	3,213	43		3,637
Undeveloped		71			325		2,148	1		2,545
		119			646	12	5,361	44		6,183
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	168	48	1,051	42	335	342	3,213	1,150	42	6,390
Undeveloped	277	71	569	209	364	43	2,148	246	16	3,943
	445	119	1,621	251	699	385	5,361	1,395	57	10,333

[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 9 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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 3 thousand barrels per day for equity-accounted entities.

[f] Also includes 16 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 347 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.

[i] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,395 million barrels, comprising less than 1 million barrels in Canada, 62 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,333 million barrels in Russia.

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Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a b]	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2016 Total
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	133		(231)	3	(1,042)	(19)		548	396	(211)
Improved recovery			469		42	1		22		534
Purchases of reserves-in-place	95		91						252	438
Discoveries and extensions			1		355	43				399
Production[c]	(71)	(33)	(676)	(4)	(624)	(219)		(152)	(306)	(2,085)
Sales of reserves-in-place		(256)	(2)		(37)			(17)	(439)	(750)
	158	(288)	(348)		(1,306)	(194)		401	(97)	(1,675)
At 31 December[d]										
Developed	499		5,447		1,784	767		1,890	3,012	13,398
Undeveloped	350		2,567		4,970	2,191		3,769	1,643	15,490
	848		8,014		6,755	2,958		5,659	4,654	28,888
Equity-accounted entities (BP share)[e]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates					62	34	736	5		836
Improved recovery					1		10			11

Purchases of reserves-in-place		**115**			**19**		**81**			**216**
Discoveries and extensions					**128**		**343**			**471**
Production[c]		**(4)**			**(190)**	**(8)**	**(461)**	**(15)**		**(680)**
Sales of reserves-in-place							**(1)**	**(8)**		**(8)**
		110			**20**	**26**	**709**	**(18)**		**846**
At 31 December[f g]										
Developed		**89**			**1,546**	**412**	**5,544**	**26**		**7,617**
Undeveloped		**21**			**534**		**6,304**	**4**		**6,863**
		110		**1**	**2,080**	**412**	**11,847**	**30**		**14,480**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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**
At 31 December										
Developed	**499**	**89**	**5,447**		**3,330**	**1,179**	**5,544**	**1,916**	**3,012**	**21,015**
Undeveloped	**350**	**21**	**2,567**		**5,505**	**2,191**	**6,304**	**3,772**	**1,643**	**22,353**
	848	**110**	**8,014**		**8,835**	**3,370**	**11,847**	**5,688**	**4,654**	**43,368**

[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 176 billion cubic feet of natural gas consumed in operations, 145 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities.

[d] Includes 2,026 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 300 billion cubic feet of natural gas in respect of the 2.53% non-controlling interest in Rosneft including 3 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 11,900 billion cubic feet, comprising 1 billion cubic feet in Canada, 33 billion cubic feet in Venezuela, 23 billion cubic feet in Vietnam and 11,843 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	2016 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates[e]	43		(94)	1	(181)	20		637	71	497
Improved recovery			86		7	3		74		170
Purchases of reserves-in-place	21		23					25	44	113
Discoveries and extensions	2			4	61	8				75
Production[f g]	(43)	(16)	(260)	(5)	(114)	(136)		(101)	(60)	(735)
Sales of reserves-in-place		(152)	(1)		(7)			(4)	(78)	(241)
	23	(167)	(245)	(1)	(233)	(105)		631	(22)	(121)
At 31 December[h]										
Developed	254		1,990	42	321	462		1,433	561	5,063
Undeveloped	338		1,012	209	896	420		895	299	4,068
	592		3,002	251	1,217	882		2,327	860	9,131
Equity-accounted entities (BP share)[i]										
At 1 January										
Developed					563	81	3,732	76		4,452
Undeveloped					415		3,061	1		3,476
					978	81	6,792	77		7,928
Changes attributable to										
Revisions of previous estimates					9	4	178	14		205
Improved recovery					1		6			7

Purchases of reserves-in-place		142			39		470			652
Discoveries and extensions					38		344			382
Production[g]		(3)			(61)	(2)	(385)	(40)		(491)
Sales of reserves-in-place							(2)	(2)		(4)
		138			27	2	611	(28)		751
At 31 December[j k]										
Developed		63			588	83	4,168	47		4,951
Undeveloped		75			417		3,235	1		3,729
		138			1,005	83	7,404	49		8,679
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	254	63	1,990	42	909	545	4,168	1,480	561	10,014
Undeveloped	338	75	1,012	209	1,313	420	3,235	896	299	7,797
	592	138	3,002	251	2,222	966	7,404	2,376	860	17,810

[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 9 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] Rest of Asia includes additions from Abu Dhabi ADCO concession.

[f] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 3 thousand barrels per day for equity-accounted entities.

[g] 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.

[h] Includes 366 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[j] Includes 402 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 29 mmboe held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[k] Total proved reserves held as part of our equity interest in Rosneft is 7,447 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 68 million barrels of oil equivalent in Venezuela, 4 million barrels of oil equivalent in Vietnam and 7,375 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	2015 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia[d]		
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[e]	(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[f]										
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)[g]										
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[h]										
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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2015 proved reserves totals.

[e] Includes 8 million barrels of crude oil 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 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.

[h] 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]										2015
			North		South					Total
						Africa			Australasia	
	Europe		America		America		Asia			
	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[d]		
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[e]	(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[f]										
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)[g]										
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[h i]										
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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2015 proved reserves totals.

[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] Also includes 19 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 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.

[i] 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]										2015
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	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[e]		
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[f g]	(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[h]										
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)[i]										
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
							29			29

Purchases of reserves-in-place										
Discoveries and extensions					45		215			260
Production[g]					(60)		(369)	(39)		(467)
Sales of reserves-in-place							(1)			(1)
				(1)	12	(5)	129	(36)		100
At 31 December[j k]										
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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2015 proved reserves totals.

[f] 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.

[g] 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.

[h] Includes 425 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[j] 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.

[k] 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 UK	Europe Rest of Europe	North America US[c]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia[d]	Australasia	2014 Total
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[e]	(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[f]										
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)[g]										
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[h]										
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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2014 proved reserves totals.

[e] Includes 10 million barrels of crude oil 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 of crude oil in respect of the 0.15% non-controlling interest in Rosneft.

[h] 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

Natural gas liquids[a b]										million barrels 2014 Total
	Europe		North America		South America	Africa	Asia		Australasia	
	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[d]		
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[e]	(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[f]										
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)[g]										
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[h i]										
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 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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2014 proved reserves totals.

[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] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[h] Includes 38 million barrels in respect of the non-controlling interest in Rosneft.

[i] 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 UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2014 Total
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 equivalent[c]

Total hydrocarbons[a] [b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia[e]		
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[f] [g]	(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[h]										
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)[i]										
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[g]					(56)	(1)	(365)	(39)		(460)
Sales of reserves-in-place					(29)	3	130	(29)		75
At 31 December[j k]										
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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There was no impact on 2014 proved reserves totals.

[f] 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.

[g] 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.

[h] Includes 456 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[j] Includes 54 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

[k] 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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Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group s estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2016 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	**21,600**		**72,400**	**4,500**	**11,700**	**23,600**		**78,100**	**24,000**	**235,900**
Future production cost[b]	**13,900**		**43,100**	**3,500**	**6,600**	**10,000**		**42,600**	**9,400**	**129,100**
Future development cost[b]	**3,000**		**14,300**	**1,100**	**3,700**	**5,100**		**15,400**	**3,500**	**46,100**
Future taxation[c]	**1,700**		**500**		**100**	**2,000**		**17,800**	**3,400**	**25,500**
Future net cash flows	**3,000**		**14,500**	**(100)**	**1,300**	**6,500**		**2,300**	**7,700**	**35,200**
10% annual discount[d e]	**900**		**4,900**		**200**	**2,800**		**(600)**	**4,100**	**12,300**
Standardized measure of discounted future net cash flows[e f]	**2,100**		**9,600**	**(100)**	**1,100**	**3,700**		**2,900**	**3,600**	**22,900**
Equity-accounted entities (BP share)[g]										

Future cash inflows[a]		**5,400**			**34,400**		**159,900**	**1,900**		**201,600**
Future production cost[b]		**3,000**			**16,500**		**84,300**	**1,200**		**105,000**
Future development cost[b]		**700**			**3,800**		**13,200**	**700**		**18,400**
Future taxation[c]		**1,300**			**3,600**		**10,100**			**15,000**
Future net cash flows		**400**			**10,500**		**52,300**			**63,200**
10% annual discount[d]		**200**			**6,100**		**30,700**			**37,000**
Standardized measure of discounted future net cash flows[h i]		**200**			**4,400**		**21,600**			**26,200**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	**2,100**	**200**	**9,600**	**(100)**	**5,500**	**3,700**	**21,600**	**2,900**	**3,600**	**49,100**

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

$ million

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	**(15,200)**	**(5,400)**	**(20,600)**
Development costs for the current year as estimated in previous year	**13,100**	**3,500**	**16,600**
Extensions, discoveries and improved recovery, less related costs	**700**	**900**	**1,600**
Net changes in prices and production cost	**(25,500)**	**(5,900)**	**(31,400)**
Revisions of previous reserves estimates	**12,200**	**1,200**	**13,400**
Net change in taxation	**(2,500)**	**900**	**(1,600)**
Future development costs	**4,900**	**(2,500)**	**2,400**
Net change in purchase and sales of reserves-in-place	**1,800**	**2,900**	**4,700**
Addition of 10% annual discount	**3,000**	**2,800**	**5,800**
Total change in the standardized measure during the year[j]	**(7,500)**	**(1,600)**	**(9,100)**

[a] The marker prices used were Brent $42.82/bbl, Henry Hub $2.46/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 with reference to 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] In certain situations, revenues and costs are included in the standardized measure of discounted future net cash flows valuation and excluded from the determination of proved reserves and vice versa. This can result in the standardized measure of discounted future net cash flows being negative. Depending on the timing of those cash flows the effect of discounting may be to increase the discounted future net cash flows.

[f] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $300 million.

[g] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

[h] Non-controlling interests in Rosneft amounted to $1,608 million in Russia.

[i] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[j] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within Net changes in prices and production cost .

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Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves continued

$ million

										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
					10,500		57,700	100		68,300

Future net cash flows 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 with reference to 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 with reference to 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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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 2016, 2015 and 2014.

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[d]		
Subsidiaries[e]										
Crude oil[f]										thousand barrels per day
2016	**79**	**24**	**335**	**13**	**10**	**263**		**204**	**16**	**943**
2015	72	38	323	3	12	270		199	17	933
2014	46	41	347		13	222		147	19	834
Natural gas liquids										thousand barrels per day
2016	**6**	**4**	**56**		**8**	**5**			**3**	**82**
2015	7	5	56		11	7		1	3	88
2014	2	5	63		12	5			3	91
Natural gas[g]										million cubic feet per day
2016	**170**	**82**	**1,656**	**10**	**1,689**	**513**		**363**	**820**	**5,302**
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
Equity-accounted entities (BP share)										
Crude oil[f]										thousand barrels per day
2016		**7**			**65**		**840**	**102**		**1,015**
2015					68		809	97		974
2014					65		816	98		979
Natural gas liquids										thousand barrels per

						day
2016		**1**	**4**	**4**		**8**
2015		3	3	4		10
2014		3	4	5		12
Natural gas[g]						million cubic feet per day
2016	**12**	**449**	**18**	**1,279**	**15**	**1,773**
2015		435		1,195	21	1,651
2014		402	7	1,084	21	1,515

[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] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq was simplified in 2016 to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods.

[e] All of the oil and liquid production from Canada is bitumen.

[f] Crude oil includes condensate.

[g] Natural gas production excludes gas consumed in operations.

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Operational and statistical information continued

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 2016. A gross well or acre is one in which a whole or fractional working interest is owned, while the number of net wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

		Europe		North America		South America	Africa	Asia		Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Number of productive wells at 31 December 2016											
Oil wells[c]	gross	**126**	**47**	**2,472**	**150**	**4,994**	**678**	**45,585**	**2,002**	**12**	**56,06**
	net	**80**	**14**	**849**	**33**	**2,736**	**462**	**9,003**	**425**	**2**	**13,60**
Gas wells[d]	gross	**55**	**1**	**23,608**	**302**	**902**	**160**	**788**	**42**	**66**	**25,92**
	net	**23**		**10,064**	**149**	**343**	**67**	**156**	**11**	**14**	**10,82**
Oil and natural gas acreage at 31 December 2016										thousands of acre	
Developed	gross	**133**	**37**	**6,462**	**166**	**1,330**	**705**	**5,024**	**1,536**	**173**	**15,56**
	net	**76**	**11**	**3,452**	**75**	**412**	**277**	**941**	**273**	**41**	**5,55**
Undeveloped[e]	gross	**1,383**	**1,360**	**5,883**	**12,806**	**20,757**	**31,345**	**380,441**	**10,018**	**11,617**	**475,61**
	net	**978**	**517**	**4,318**	**6,353**	**6,404**	**21,801**	**74,103**	**2,501**	**6,340**	**123,31**

[a] Based on information received from Rosneft as at 31 December 2016.

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

[c] Includes approximately 8,367 gross (1,632 net) multiple completion wells (more than one formation producing into the same well bore).

[d] Includes approximately 2,825 gross (1,437 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.

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		
2016										
Exploratory										
Productive	**0.3**	**0.4**	**0.5**		**0.6**	**2.1**	**3.4**	**1.6**		**8.9**
Dry	**1.0**	**0.3**	**4.7**			**1.5**		**0.3**		**7.8**
Development										
Productive	**3.4**	**1.4**	**145.6**		**99.8**	**20.2**	**88.5**	**55.2**	**0.5**	**414.6**
Dry	**0.8**				**0.6**	**2.0**		**1.0**		**4.4**
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

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

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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 2016. 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 2016										
Exploratory										
Gross	**1.0**	**0.1**	**7.0**	**1.0**	**2.0**	**4.0**		**2.0**		**17.1**
Net	**0.9**		**4.1**	**0.4**	**1.6**	**2.5**		**1.3**		**10.8**
Development										
Gross	**7.0**	**1.0**	**266.0**	**14.0**	**22.0**	**39.0**		**41.0**	**5.0**	**395.0**
Net	**2.8**	**0.3**	**113.9**	**7.0**	**14.3**	**19.1**		**13.5**	**0.8**	**171.7**

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

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Pages 215-238 have been removed as they do not form part of BP s Annual Report on Form 20-F as filed with the SEC.

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Selected financial information

This information, insofar as it relates to 2016, has been extracted or derived from the audited consolidated financial statements of the BP group presented on page 114. 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				
	2016	2015	2014	2013	2012
Income statement data					
Sales and other operating revenues	**183,008**	222,894	353,568	379,136	375,765
Profit (loss) before interest and taxation	**(430)**	(7,918)	6,412	31,769	19,769
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,865)**	(1,653)	(1,462)	(1,548)	(1,638)
Taxation	**2,467**	3,171	(947)	(6,463)	(6,880)
Non-controlling interests	**(57)**	(82)	(223)	(307)	(234)
Profit (loss) for the year[a]	**115**	(6,482)	3,780	23,451	11,017
Inventory holding (gains) losses*, before tax	**(1,597)**	1,889	6,210	290	594
Taxation charge (credit) on inventory holding gains and losses	**483**	(569)	(1,917)	(60)	(183)
RC profit (loss)* for the year	**(999)**	(5,162)	8,073	23,681	11,428
Net (favourable) unfavourable impact of non-operating items* and fair value accounting effects*, before tax	**6,746**	15,067	8,234	(9,244)	6,110
Taxation charge (credit) on non-operating items and fair value accounting effects	**(3,162)**	(4,000)	(4,171)	(1,009)	(467)
Underlying RC profit* for the year	**2,585**	5,905	12,136	13,428	17,071
Earnings per share[b] cents					
Profit (loss) for the year[a] per ordinary share					
Basic	**0.61**	(35.39)	20.55	123.87	57.89
Diluted	**0.60**	(35.39)	20.42	123.12	57.50
RC profit (loss) for the year per ordinary share*	**(5.33)**	(28.18)	43.90	125.08	60.05
Underlying RC profit for the year per ordinary share*	**13.79**	32.22	66.00	70.92	89.70
Dividends paid per share cents	**40.00**	40.00	39.00	36.50	33.00
pence	**29.418**	26.383	23.850	23.399	20.852
Additions to non-current assets[c]	**21,204**	20,080	26,492	36,916	29,268
Capital expenditure on an accruals basis*[b d]					
Organic capital expenditure*[e]	**18,440**	18,748	22,892	24,600	23,950
Inorganic capital expenditure*	**939**	710	601	12,007	1,097
	19,379	19,458	23,493	36,607	25,047
Balance sheet data (at 31 December)					
Total assets	**263,316**	261,832	284,305	305,690	300,466
Net assets	**96,843**	98,387	112,642	130,407	119,752
Share capital	**5,284**	5,049	5,023	5,129	5,261
BP shareholders equity	**95,286**	97,216	111,441	129,302	118,546
Finance debt due after more than one year	**51,666**	46,224	45,977	40,811	38,767

Net debt to net debt plus equity*	**26.8%**	21.6%	16.7%	16.2%	18.7%
Ordinary share data[f]					Share million
Basic weighted average number of shares	**18,745**	18,324	18,385	18,931	19,028
Diluted weighted average number of shares	**18,855**	18,324	18,497	19,046	19,158

[a] Profit attributable to BP shareholders.
[b] A reconciliation to GAAP information is provided on page 285.
[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures*; and investments in associates*.
[d] The definitions of capital expenditure on an accruals basis and inorganic capital expenditure have been revised to exclude asset exchanges as they are non-cash transactions. Previously reported amounts have been amended. Previously reported amounts for organic capital expenditure are unchanged.
[e] 2016 includes amounts relating to the renewal of a 10% interest in the Abu Dhabi onshore oil concession for which new ordinary shares in BP were issued.
[f] The number of ordinary shares shown has been used to calculate the per share amounts.

* See Glossary.

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Additional information

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
	2016	2015	2014
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**2,391**	(1,204)	(6,576)
Environmental and other provisions	**(8)**	(24)	(60)
Restructuring, integration and rationalization costs	**(373)**	(410)	(100)
Fair value gain (loss) on embedded derivatives	**32**	120	430
Other[b c]	**(289)**	(717)	8
	1,753	(2,235)	(6,298)
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**405**	131	(1,190)
Environmental and other provisions	**(73)**	(108)	(133)
Restructuring, integration and rationalization costs	**(300)**	(607)	(165)
Fair value gain (loss) on embedded derivatives			
Other	**(56)**	(6)	(82)
	(24)	(590)	(1,570)
Rosneft			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**62**		225
Environmental and other provisions			
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other	**(39)**		
	23		225
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets[a]		(170)	(304)
Environmental and other provisions	**(134)**	(151)	(180)
Restructuring, integration and rationalization costs	**(90)**	(71)	(176)
Fair value gain (loss) on embedded derivatives			
Gulf of Mexico oil spill response[d]	**(6,640)**	(11,709)	(781)
Other[c]	**(55)**	(155)	(10)
	(6,919)	(12,256)	(1,451)
Total before interest and taxation	**(5,167)**	(15,081)	(9,094)
Finance costs[d]	**(494)**	(247)	(38)
Taxation credit (charge)	**2,833**	4,056	4,512
Total after taxation	**(2,828)**	(11,272)	(4,620)

[a] See Financial statements Note 4 for further information on impairments.

[b] 2016 includes the write-off of $147 million in relation to the value ascribed to licences in the deepwater Gulf of Mexico, and $334 million in relation to the value ascribed to the BM-C-34 licence in Brazil, both as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. 2016 also includes a $319-million reversal relating to Block KG D6 in India. 2014 includes a $395-million write-off relating to Block KG D6 in India.

[c] 2015 principally relates to BP s share of impairment losses recognized by equity-accounted entities.

[d] See Financial statements Note 2 for further details regarding costs relating to the Gulf of Mexico oil spill.

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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 operating cash flow excluding amounts related to the Gulf of Mexico oil spill* and a strong focus on capital discipline, providing a sound platform to grow shareholder distributions. The initial priority is to address the dilution that arises from the undiscounted scrip dividend alternative we currently have in place. We would then aim to balance disciplined investment for even stronger growth with our objective of growing distributions to shareholders over the long term. 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.

While maintaining safe and reliable operations, preserving core growth activities and with an ongoing commitment to sustaining the dividend, our principal objective in the near term is to re-establish a balance in our financial framework. This rebalanced framework is underpinned by the resetting of both the capital and cash cost base of the group in response to the lower price environment, as well as the growth in operating cash flow we anticipate in our businesses. The group s controllable cash costs reduction target was reached a year ahead of schedule in 2016 and, including the impact of deals announced at the end of 2016, we expect organic capital expenditure in 2017 to be between $15-17 billion.

We aim to manage gearing* within a 20-30% band while weak market conditions remain and maintain a significant liquidity buffer. As the portfolio additions are assimilated into our plans during 2017 and we maintain our focus on both capital and costs, we expect to continue to optimize our overall spend driving down the organic cash rebalance point through the year. Operating cash flow excluding amounts related to the Gulf of Mexico oil spill is expected to cover organic capital expenditure and the dividend at around $60 per barrel by the end of 2017. As we further assimilate recently announced deals into our plans and maintain our focus on both capital and costs, we will continue to optimize our overall spend driving the balance point closer to $55 per barrel by the end of 2017. Based on our current planning assumptions we would expect our cash balance point to reduce to around $35-40 per barrel over the next five years.

Deepwater Horizon cash payments are expected to be in the range of $4.5-5.5 billion in 2017 with the larger part of the outflow in the first half of the year. With amounts to resolve the remaining business economic loss claims expected to be substantially paid this year we expect the total Deepwater Horizon cash payments to fall to around $2 billion in 2018, and then to step down to a little over $1 billion per annum from 2019. In 2017 we expect divestment proceeds to be in the range of $4.5-5.5 billion, weighted towards the second half of the year, and from 2018 to average the historical norm of around $2-3 billion per annum.

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 2017 and beyond.

Dividends and other distributions to shareholders

The dividend is determined in US dollars, the economic currency of BP, and the dividend level is regularly reviewed by the board. The quarterly dividend was increased to 10 cents per share for the third quarter of 2014 and has been maintained at this level in each subsequent quarter.

The total dividend distributed to BP shareholders in 2016 was $7.5 billion (2015 $7.3 billion). Shareholders have the option to receive a scrip dividend in place of receiving cash. In 2016 the total dividend paid in cash was $4.6 billion (2015 $6.7 billion).

Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 278. There were no other buyback programmes conducted during 2016.

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 49 for further information on risks associated with prices and markets and Financial statements Note 28.

The group s gross debt at 31 December 2016 amounted to $58.3 billion (2015 $53.2 billion). Of the total gross debt, $6.6 billion is classified as short term at the end of 2016 (2015 $6.9 billion). See Financial statements Note 25 for more information on the short-term balance. Net debt* was $35.5 billion at the end of 2016, an increase of $8.3 billion from the 2015 year-end position of $27.2 billion. The ratio of gross debt to gross debt plus equity at 31 December 2016 was 37.6% (2015 35.1%). The ratio of net debt to net debt plus equity* was 26.8% at the end of 2016 (2015 21.6%). 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 $23.5 billion at 31 December 2016 (2015 $26.4 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.

Standard & Poor s Ratings long-term credit rating for BP is A negative (stable outlook) and the Moody s Investors Service rating is A2 (positive outlook).

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.

During 2016 significant progress was made in resolving outstanding claims arising from the 2010 Deepwater Horizon accident and oil spill. As a result, a judgement has been made that a reliable estimate can now be made for all remaining material liabilities arising from the incident. Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group s financial performance. See Financial statements Note 2 for further information.

Off-balance sheet arrangements

At 31 December 2016, the group s share of third-party finance debt of equity-accounted entities was $14.6 billion (2015 $11.8 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 2016 were $309 million (2015 $35 million) in respect of liabilities of joint ventures* and associates* and $370 million (2015 $163 million) in respect of liabilities of other third parties. Of these amounts, $298 million (2015 $22 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $338 million (2015 $119 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 269 and Risk factors on page 49, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

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Contractual obligations

The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2016 and the proportion of that expenditure for which contracts have been placed.

							$ million Payments due by period
Capital expenditure	Total	2017	2018	2019	2020	2021	2022 and thereafter
Committed	32,377	12,823	9,060	4,568	2,588	1,328	2,010
of which is contracted	11,207	5,868	3,462	1,070	427	106	274

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 2016, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $2,318 million. Contracts were in place for $2,083 million of this total.

The following table summarizes the group s principal contractual obligations at 31 December 2016, 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	2017	2018	2019	2020	2021	2022 and thereafter
Balance sheet obligations							
Borrowings[a]	63,508	7,755	6,962	7,586	7,015	7,353	26,837
Finance lease future minimum lease payments[b]	1,321	96	94	90	87	85	869
Decommissioning liabilities[c]	18,119	287	303	258	321	319	16,631
Environmental liabilities[c]	1,626	316	311	177	154	134	534
Gulf of Mexico oil spill liabilities[d]	21,644	3,056	1,853	1,272	1,225	1,200	13,038
Pensions and other post-retirement benefits[e]	24,288	1,619	1,792	1,772	1,761	1,759	15,585
	130,506	13,129	11,315	11,155	10,563	10,850	73,494
Off-balance sheet obligations							
Operating lease future minimum lease payments[f]	14,255	3,315	2,194	1,915	1,520	1,022	4,289
Unconditional purchase obligations[g]	140,490	64,743	16,155	10,624	7,512	5,536	35,920
	154,745	68,058	18,349	12,539	9,032	6,558	40,209
Total	285,251	81,187	29,664	23,694	19,595	17,408	113,703

[a] Expected payments include interest totalling $5,842 million ($1,162 million in 2017, $1,032 million in 2018, $895 million in 2019, $757 million in 2020, $618 million in 2021 and $1,378 million thereafter).

[b] Expected payments include interest totalling $687 million ($54 million in 2017, $52 million in 2018, $47 million in 2019, $44 million in 2020, $40 million in 2021 and $450 million thereafter).

[c] The amounts are undiscounted.

[d] The amounts presented are undiscounted. Gulf of Mexico oil spill liabilities are included in the group balance sheet, on a discounted basis, within other payables. See Financial statements Note 2 for further information.

[e] 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.

[f] 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.

[g] 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 2017 include purchase commitments existing at 31 December 2016 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	2017	2018	2019	2020	2021	2022 and thereafter
Crude oil and oil products	63,034	41,953	7,312	4,103	2,964	2,020	4,682
Natural gas	26,041	14,619	4,544	2,326	1,558	1,097	1,897
Chemicals and other refinery feedstocks	5,801	2,576	1,413	1,467	229	38	78
Power	4,624	2,747	856	407	159	90	365
Utilities	486	151	137	68	61	18	51
Transportation	21,814	1,218	1,028	919	1,300	1,286	16,063
Use of facilities and services	18,690	1,479	865	1,334	1,241	987	12,784
Total	140,490	64,743	16,155	10,624	7,512	5,536	35,920

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Upstream analysis by region

Our upstream operations are set out below by geographical area, with associated significant events for 2016. 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) processing 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 new field developments. BP s production is generated from three key areas: the Shetland area, comprising the Magnus, Clair, Foinaven and Schiehallion fields; the central area, comprising the Bruce, Andrew and ETAP fields; and Norway, through our equity accounted 30% interest in Aker BP established in 2016 (see below).

We announced that we doubled our interest in the Culzean development in the UK Central North Sea in May, following the acquisition of an additional 16% interest from JX Nippon. The acquisition increases our interest in the development from 16% to 32%. The Maersk-operated Culzean field development was sanctioned at the end of August 2015, and we expect production to start in 2019 and continue into the 2030s.

BP and Det norske oljeselskap announced the creation of an independent oil and gas company in June, with the transaction completing at the end of September. It combines the assets and expertise from the Norwegian exploration and production operations of both companies to form the largest Norwegian independent oil and gas producer. Under the terms of the transaction, the BP Norge and Det norske businesses have combined and been renamed Aker BP ASA. Aker BP is independently operated and listed on the Oslo Stock Exchange. It is owned by the former Det norske shareholder Aker (40%), BP (30%) and independent shareholders (including other former Det norske shareholders) (30%). Aker BP is an equity-accounted associate over which BP has significant influence. Aker BP benefits from the combined strength of Det norske s efficient, streamlined operating model and BP s long experience in Norwegian offshore operations, asset knowledge, technical skills and international experience. BP received a cash payment of $250 million including working capital and interest adjustments as part of the transaction.

On 2 October, 95 tonnes of oil in water was released to the sea from the Clair platform, as a result of a technical issue with the system designed to separate the mixed production fluids of water, oil and gas. The release was stopped within an hour of the issue being identified and Clair production was taken offline. Production restarted on 25 October, resulting in a full-year production impact of 0.5mboe/d BP net.

Operations at the Rhum gas field in the North Sea continue under a licence issued by the US Office of Foreign Asset Control, which licenses US persons and US owned and controlled companies to support Rhum activities. This expires on 30 September 2017. Work is ongoing to reduce BP s reliance on US persons ahead of a new licence application expected in the second quarter of 2017. The field is owned by BP (50%) and the Iranian Oil Company (IOC) under a joint operating agreement. EU sanctions and certain US secondary sanctions in respect of Iran have been lifted or suspended as part of the Joint Comprehensive Plan of Action. See International trade sanctions on page 265.

We made strong progress on the Quad 204 project in the Schiehallion and Loyal fields, West of Shetland in 2016. Glen Lyon, the replacement floating production, storage and offloading vessel (FPSO) arrived on station in June 2016 and all 21 risers are now attached. Final commissioning activities are underway with first oil expected in 2017.

On 24 January 2017 BP announced that it has agreed to sell 25% of its 100% stake in Magnus, a 25% interest in a number of associated pipelines and a 3% interest in the Sullom Voe Terminal (SVT) on Shetland to EnQuest. The sale price of $85 million is expected to be met by EnQuest from the sharing of future cash flows from the assets and the agreement will not include any upfront payment to BP. Under the terms of the agreement, EnQuest has an option, exercisable between 1 July 2018 and 15 January 2019, to purchase BP s remaining 75% interest in Magnus, a further 9% interest in SVT and the remainder of BP s interests in the associated pipelines for a consideration of $300 million. The deal remains subject to regulatory and other third-party approvals.

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 2016 of 439mboe/d. On 3 April 2017 BP announced that it had agreed to sell the FPS business to INEOS for a consideration of up to $250 million, subject to partner, regulatory and other third-party approvals. BP also operates the Sullom Voe oil and gas terminal in Shetland.

North America

Our upstream activities in North America take place in five areas: deepwater Gulf of Mexico, the Lower 48 states, Alaska, Canada and Mexico.

BP has around 300 lease blocks in the deepwater Gulf of Mexico, making us one of the largest portfolio owners, and operates four production hubs.

In the first quarter of 2016 we completed evaluation of the Kepler 3 discovery well, drilled in late 2015, and this was tied into the Na Kika platform and began production in the fourth quarter of 2016. BP is the operator (50%), with Shell holding the other 50%.

Also in the first quarter, a successful exploration well on the Chevron-operated Guadalupe prospect (BP 50%) was completed. Further appraisal drilling commenced in the fourth quarter. In addition, an appraisal well in the Chevron-operated Tiber prospect (BP 31%) was completed in the second quarter and a Suspension of Production request was filed in September 2016. This notice is used in situations where the licence is approaching expiry without immediate plans for further drilling activity but where there are plans for further development of the prospect.

We completed drilling operations on two wells that commenced in the fourth quarter of 2015; the Chevron-operated Gibson prospect and the appraisal well on the Hopkins discovery. In the third quarter of 2016 BP disposed of 33.3% of its working interest in the Hopkins discovery to Anadarko, along with operatorship. BP s remaining working interest in the Hopkins discovery is 66.7%. In the fourth quarter costs of $276 million were written off in relation to Hopkins upon reclassification of the project to the development phase. The Hopkins discovery is being renamed Constellation.

In May we announced the start-up of the water injection major project at the Thunder Horse platform (BP 75%). The project is expected to extend the production life of the field and boost recovery of oil and natural gas from one of the field s three main reservoirs. The project follows on from improvement work over the last three years, including refurbishment of the platform s existing topsides and subsea equipment.

We announced the start-up of the South Expansion major project at our Thunder Horse platform in January 2017. Two producing wells came online at start-up and two more will be delivered in the near future. The project scope includes a new subsea production system two miles to the south of the existing Thunder Horse platform. The system is a collection point for four wells connected to the platform by two lines installed on the seabed.
In the fourth quarter of 2016 BP sanctioned the Mad Dog Phase 2 project, which will include a new floating production platform with the capacity to produce up to 140,000 gross barrels of crude oil per day from up to 14 production wells. Oil production is expected to

begin in late 2021. In 2013 BP (60.5% and operator) and co-owners, BHP Billiton and Union Oil Company of California, an affiliate of Chevron U.S.A. Inc., decided to re-evaluate the Mad Dog Phase 2 project after an initial design proved too complex and costly. Since then, BP has worked with co-owners and contractors to simplify and standardize the platform s design, reducing the overall project cost by about 60%. Today, the leaner $9-billion project, which also includes capacity for water injection, is projected to be profitable at much lower oil prices. The second Mad Dog platform will be moored approximately six miles to the southwest of the existing platform. All partners in the project have announced that they have taken a final investment decision (FID) on Mad Dog Phase 2.

During the year $233 million was written off in connection with unsuccessful exploration activity on the Silvergate and Sweetwater prospects.

See also Significant judgement: oil and natural gas accounting on page 128 for further information on exploration leases.

The US Lower 48 onshore business has significant activities across Arkansas, Colorado, New Mexico, Oklahoma, Texas and Wyoming producing natural gas, oil, NGLs and condensate. It is organized into five geographic business units, with a 1.4 billion boe proved reserve base as at 31 December 2016, predominantly in unconventional reservoirs (tight gas*, shale gas and coalbed methane). This resource spans 3.1 million net developed acres and has approximately 9,700 operated gross wells, with daily net production around 300mboe/d.

Since the beginning of 2015, our US Lower 48 onshore business has been operating as a separate business 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.

For further information on the use of hydraulic fracturing in our shale gas assets see page 45. BP s onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment.

In Alaska BP Exploration (Alaska) Inc. (BPXA) operated nine North Slope oilfields in the Greater Prudhoe Bay area at the end of 2016. 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 2016 included compressor replacements, fire and gas system upgrades, safety system upgrades, pipeline renewal and facility siting projects. BP s daily net production in Alaska in 2016 was 107.9mboe/d. Production decline is being managed through annual drilling programmes and rig and non-rig wellwork programmes. BP also owns significant interests in eight producing fields operated by others, as well as a non-operating interest in the Liberty prospect.

In April the Point Thomson major project commenced production. BP holds a 32% working interest in the field and ExxonMobil is the operator.

The Alaska LNG project concept includes a planned three train North Slope gas treatment plant, approximately 800 miles of pipeline to tidewater and a three-train liquefaction facility, with an estimated capacity of 3bcf/d (up to 18.5 million tonnes per annum) supplied from the Prudhoe Bay and Point Thomson fields. In early 2016, all co-venturers agreed that the current project cost of supply is not competitive in the market. Furthermore, a study prepared by WoodMackenzie in August 2016 confirmed this and identified commercial levers that could enable the project to compete. In December 2016 the producer parties agreed to terminate the existing governance agreement and transition the project to be led by the Alaska Gasline Development Corporation, a state entity. In 2017 the State of Alaska will progress the US Federal Energy Regulatory Commission (FERC) permitting work, identify commercial structure alternatives that deliver a competitive cost of supply, and define a financing plan for future stages of the project. On 22 January 2017 BP Alaska LNG LLC (BPAL) and AGDC executed a Cooperation Agreement detailing BPAL s commitment to helping the state further its 2017 priorities, detailed above. Future project milestones will be updated following the 2017 project re-definition and transition.

BP Pipelines (Alaska) Inc. (BPPA) 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 BPPA, 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.

In November 2015, the FERC issued an order to BPPA addressing the TAPS tariff rate filings for years 2009 and 2010 reducing the approved tariff rate. As a result of the order, BPPA refunded impacted shipping costs to BPXA and third-party shippers in 2016. Due to these lower shipping costs, BPXA subsequently paid material incremental production tax and royalty payments to the State of Alaska in 2016 and January 2017 for the years 2009 and 2010 as well as 2011 to 2015.

In Canada, BP is focused on oil sands development as well as pursuing offshore exploration opportunities. For our oil sands development we use in-situ steam-assisted gravity drainage (SAGD) technology, which uses the injection of steam into the reservoir to warm the bitumen so that it can flow to the surface through producing wells. We hold interests in three oil sands leases through the Sunrise Oil Sands and Terre de Grace partnerships and the Pike Oil Sands joint operation*. In addition, we have significant offshore exploration licences in the Canadian Beaufort Sea, Nova Scotia as well as Newfoundland and Labrador.

Following the start of oil production in March 2015 at the Sunrise Phase 1 in-situ oil sands project in Alberta (BP 50%), production is expected to ramp-up to 52,000 barrels per day (gross) in 2018.

In 2016 BP (50%) and partner Hess (50%) submitted an environmental impact statement for a drilling programme offshore Nova Scotia which is planned to commence in 2018.

In January 2016 BP was awarded three exploration licences in partnership with Statoil and ExxonMobil in the Flemish Pass Basin offshore of Newfoundland and Labrador, Canada (BP 33%) with Statoil operating all three licences. Additionally, BP acquired interests in two exploration licences from Statoil in the same basin (BP 10%). Finally, in January 2017 BP was also the successful bidder in a further four exploration blocks, of which three are in the West Orphan Basin offshore of Newfoundland and Labrador (BP 50% and operator with partners Hess and Noble Energy), and one in the East Orphan Basin (BP 60% and operator with partner Noble Energy).

In Mexico, BP (33.3%) as a member of a consortium with Statoil and Total was awarded two exploration blocks in the Deepwater bid round 1.4 held on 5 December 2016, Block 1 (2,381km^2 in 2,437m water depth) and Block 3 (3,287km^2 in 1,763m water depth) in the Saline Basin.

BP also conducts activity in Mexico through Pan American Energy LLC (PAE), an equity-accounted joint venture* with Bridas Corporation, in which BP has a 60% interest.

On 30 October 2016, PAE, via its wholly owned subsidiary, Hokchi S.A., became the first privately owned company to spud a well in Mexico post Mexico s reform of its energy industry. This is the first of four commitment wells that will be drilled under the terms of the licence agreement. In addition, on 12 December 2016, Hokchi S.A. agreed to increase its working interest in the block from 60% to 80% in a transaction with its partner, E&P Hydrocarboros y Servicios, S.A.

South America

BP has upstream activities in Brazil and Trinidad & Tobago, and through PAE, in Argentina and Bolivia. In February 2016 ANCAP, the Uruguayan oil and gas regulator, approved the relinquishment of all of our blocks in Uruguay.

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In Brazil BP has interests in 21 exploration concessions across five basins.

Our partner Anadarko took over from BP as operator of block BM-C-32 (Itaipu) located in the Campos Basin. This transfer is expected to facilitate the realization of development efficiencies for this and the adjacent block, BM-C-30 (Wahoo), where Anadarko is also the operator. BP continues to consider options for a potential joint development of Itaipu/Wahoo or tie-back. A decision to move into front-end engineering for a potential long- term test is planned in 2017.

In the third quarter of 2016 BP completed its analysis of the prospectivity of block BM-C-34 and concluded that there were no commercially viable prospects resulting in a write-off of $601 million ($334 million as a non-operating item*). Asset relinquishment is pending regulatory approval.

After disappointing exploration results, BP and Petrobras relinquished their interests in block BM-CE-2 in the Ceara basin. All assets associated with the block have been written off between 2014 and 2016.

In the fourth quarter of 2016 BP completed its seismic acquisition programme in block BAR-M-346 in the Barreirinhas basin. The seismic processing and prospect inventory development will be progressed in 2017. An extension request was submitted to the Brazilian National Petroleum Agency (ANP) and approved for the block extending the licence until the end of 2019.

BP continued to progress the preparatory activities for drilling exploration wells in the Foz de Amazonas basin, with a BP-operated well situated in block FZA-M-59, scheduled to spud in early 2018. Additionally, BP expects drilling activity to commence on its other non-operated interests in Foz de Amazonas in 2017 (BP 30%). An extension request was submitted to ANP and approved for the five non-operated blocks extending the licence until the third quarter of 2020.

In the South Campos basin, Petrobras notified BP in August 2016 of their decision to exit from block BM-C-35. BP has taken over operatorship and has a 100% working interest post Petrobras exit. A revised appraisal plan was submitted to ANP and approved, the decision to move into the second stage of the appraisal plan and commit to an additional pre-salt well or end the appraisal plan is expected in the third quarter of 2017.

In Argentina and Bolivia BP conducts activity through PAE.

On 13 December 2016 the Bolivian Branch of PAE, E&P Bolivia Limited, entered into, jointly with the other members of the Caipipendi Consortium and Yacimientos Petroliferos Fiscales Bolivianos, an addendum to the Caipipendi Operation Contract for an extension of up to 15 years from the expiration of the original term (2 May 2031) subject to certain investment and operational conditions being met over the next five years. The addendum is subject to the authority of the Bolivian National Congress and approval is expected to be received in the first half of 2017.

PAE signed an agreement on 7 December 2016 to acquire a 55% working interest and operatorship in the Coiron Amargo Sur Este Block located in the Vaca Muerte area of Neuquen, Argentina from Madalena Energy, Inc.

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 the Atlantic LNG (ALNG) liquefaction plant, BP s shareholding 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.

In July BP Trinidad and Tobago LLC and ALNG announced the sanction of the Trinidad onshore compression project. The project is 100% funded and owned by BP Trinidad and Tobago and will be operated by ALNG. It is designed to increase production from low-pressure wells in existing acreage in the Columbus Basin using an additional inlet compressor at the Point Fortin Atlantic LNG plant. The majority of the construction work will be undertaken by ALNG with BP and other shareholder representation. The project is 95% complete and start-up is planned for the second quarter of 2017.

Africa

BP s upstream activities in Africa are located in Algeria, Angola, Egypt, Libya, Mauritania and Senegal.

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.

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.

The In Salah Southern Fields major project start-up was announced in February 2016. The project is the latest stage in the development of the In Salah Gas joint venture, which commenced production in 2004.

In July train 3 at In Amenas restarted following the completion of repairs after the terrorist attack in January 2013.

In November the start of testing and ramp-up activities at the In Amenas compression project was announced. This project is designed to enhance production in order to fill the capacity of all three processing trains at the facility.

In Angola BP is present in seven major deepwater licences offshore and is operator in three of these, blocks 18 and 31 that are producing oil and block 24 that is in the exploration phase. BP s block 19 exploration licence expired on 31 December 2016 and the block has now been relinquished. BP also has an equity interest in the Angola LNG plant (BP 13.6%).

The Angola LNG plant, which had been shut down for planned repairs since April 2014 restarted in 2016 and is producing and supplying LNG and liquid cargoes to the global market.

During the year, BP was involved in two discoveries in Angola, Golfinho and Zalophus, the latter being a condensate discovery. Further assessment of their potential commerciality is underway.

In Egypt BP and its partners currently produce 10% of Egypt s liquids* production and almost 30% of its gas production.

On 26 February an exploration discovery was announced on the Nooros East prospect in Egypt by the operator Eni who has now tied it back for production. Eni holds a 75% interest in the Abu Madi West concession, while BP holds a 25% interest. The well was developed and commenced production in April 2016. Additionally, a successful discovery in Nooros West was made in the third quarter of 2016. Two wells are currently on production from the West segment. This combined with further development well drilling in the Nooros main segment, which was discovered in July 2015, led to the total Nooros production increasing to 850mmscf/d of gas, and 7,000 barrels of condensate (154,000 barrels of oil equivalent gross per day), less than 18 months after first gas.

In June we announced the Baltim SW-1 gas discovery in the Baltim South Development Lease in the East Nile Delta. The discovery, which is located 12 kilometres from shoreline, is situated along the same trend as the Nooros field discovered in July 2015. Following appraisal of the discovery, BP and its partner Eni are working on the development options for this discovery.

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Also in June we announced, together with the Egyptian Natural Gas Holding Company (EGAS), that we had sanctioned development of the Atoll Phase 1 project. The project is an early production scheme involving the conversion of the existing exploration well to a producing well, the drilling of two additional wells and the installation of the necessary tie-ins and facilities required to produce from the field, and is expected to bring gas to the Egyptian domestic gas market starting in the first half of 2018. BP has a 100% interest in the concession. BP recently completed multiple transportation and processing agreements to accelerate the development of the Atoll field. Onshore processing will be handled by the existing West Harbour gas processing facilities. BP announced the Atoll discovery in March 2015.

In September we announced we had signed concession amendments for the Temsah (BP 50%), Ras El Barr (BP 50%) and Nile Delta offshore (BP 25%) concessions in Egypt. These amendments allow for the economic development of the Nooros field in the Nile Delta offshore concession.

Following the devaluation of the Egyptian pound on 3 November 2016, the IMF approved a $12 billion extended fund facility, S&P upgraded its outlook for Egypt to Stable and Egypt s foreign currency reserves increased from $19 billion in October 2016 to $23 billion in December 2016.

In November BP announced that it had agreed to buy a 10% interest in the Shorouk concession offshore Egypt, which contains the Zohr gas field from Eni, for $375 million plus reimbursement of Eni s past expenditure from 1 January 2016 up to completion of the deal. The deal completed on 23 February. The transaction also includes the option to buy an additional 5% interest on the same terms by 31 December 2017. First gas is expected in 2017.

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 and the LIA served the National Oil Corporation (NOC) with notices of force majeure in August 2014 as a result of underlying circumstances which rendered the delivery of the EPSA obligations impossible. BP and the NOC signed an Interim Arrangement Agreement in January 2016 under which the EPSA did not terminate automatically in August 2016 (two years from the notice of force majeure). BP wrote off all balances associated with the Libya EPSA in 2015.

In December BP announced that it had signed agreements with Kosmos Energy to acquire a 62% working interest, including operatorship, of Kosmos exploration blocks in Mauritania and a 32.49% effective working interest in Kosmos Senegal exploration blocks. Together these blocks cover approximately 33,000km^2. BP intends to invest nearly $1 billion, mostly in the form of a multi-year exploration and development carry to acquire a 62% interest and operatorship of offshore Blocks C-6, C-8, C-12 and C-13 in Mauritania and an effective 32.49% interest in the Saint-Louis Profond and Cayar Profond blocks in Senegal. Under the terms of the agreements, BP and Kosmos have also agreed that Kosmos will remain the technical operator for the exploration phase of the project and drill three new exploration wells beginning in 2017. In addition to the existing blocks, the companies have agreed to co-operate in areas of mutual interest in offshore Mauritania, Senegal and the Gambia with Kosmos acting as the exploration operator and BP as the development operator. The Mauritania agreement completed in December and the Senegal agreement in February 2017.

In June 2016 BP s non-operated Tarhazoute offshore (BP 45%) and Foum Assaka offshore (BP 26.3%) licences in Morocco were not extended and lapsed. This was in agreement with partners and followed a detailed review of the prospects. Exit is in progress on BP s third licence in Morocco the Essaouira offshore licence (BP 45%).

Asia

BP has activities in Western Indonesia, China, Azerbaijan, Oman, Abu Dhabi, India, Iraq, Russia and Kuwait.

In November BP completed the sale of all of its interests in the Sanga-Sanga PSA (BP 38%) in Western Indonesia operated by Virginia Indonesia Company LLC (VICO) to subsidiaries of PT. Saka Energi Indonesia by a share sale.

In China BP has a 30% equity stake in the Guangdong LNG regasification terminal and trunkline project with a total storage capacity of 640,000m^3, making it the first and only international oil company invested in China s LNG import infrastructure. The project is supplied under a long-term contract with Australia s North West Shelf venture (BP 16.67%).

- In March BP and China National Petroleum Corporation (CNPC) signed a production-sharing contract for shale gas exploration, development and production in the Neijiang-Dazu block in the Sichuan Basin, China. The contract is BP s first shale gas PSC in China and covers an area of approximately 1,500km^2. CNPC will be operator for this project.
- In September we announced that we had signed a second PSC for shale gas exploration, development and production with CNPC. The PSC covers an area of approximately 1,000km^2 at Rong Chang Bei in the Sichuan Basin.

In Azerbaijan, BP operates two PSAs, Azeri-Chirag-Gunashli (ACG) (BP 35.8%) and Shah Deniz (BP 28.83%) and also holds a number of other exploration leases.

- In 2012 certain EU and US regulations concerning restrictive measures against Iran were issued, which impact the Shah Deniz joint venture in which Naftiran Intertrade Co Ltd (NICO), a subsidiary of the National Iranian Oil Company, holds a 10% interest. The EU sanctions and certain US secondary sanctions in respect of Iran have been lifted or suspended as part of the Joint Comprehensive Plan of Action. For further information see International trade sanctions on page 265.
- In May BP and the State Oil Company of the Republic of Azerbaijan (SOCAR) signed a memorandum of understanding, followed by a heads of agreement in November, to jointly explore potential prospects in Block D230 in the North Absheron basin in the Azerbaijan sector of the Caspian Sea.
- Implementation of the Shah Deniz Stage 2 project continues successfully. In May, the Shah Deniz consortium announced the award of a $1.5 billion contract for the transport and installation of the deeperwater subsea production systems for Shah Deniz Stage 2. In September the jacket for one of the Shah Deniz Stage 2 platforms commenced its journey for offshore installation. The Shah Deniz Stage 2 project is now more than 83% complete in terms of engineering, procurement and construction, and remains on target for first gas in 2018.
- In December the Azerbaijan International Operating Company and the ACG Joint Operating Company operated by BP, signed a non-binding letter of intent with SOCAR covering the future development of the AGC field in the Azerbaijan sector of the Caspian Sea. The agreement will cover the development of the field until the end of 2049. The letter of intent agrees the key commercial terms for the contract extension and enables the parties to proceed with negotiations and finalize fully-termed agreements.

BP holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768km 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 pipeline has a capacity of 1mmboe/d with an average throughput in 2016 of 694mboe/d.

BP is technical operator of, and currently holds a 28.83% interest in, the 693km South Caucasus Pipeline (SCP). The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 143mboe/d with average throughput in 2016 of 121mboe/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 an average throughput of 83mboe/d in 2016.

BP also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline that will transport Shah Deniz gas across Turkey, and a 20% interest in the Trans Adriatic Pipeline that will take gas through Greece and Albania into Italy.

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In Oman, BP is continuing with development activity on the BP-operated Khazzan field in block 61 (BP 60%).

As at 31 December 2016 the Khazzan major project was 92.5% complete and on track to deliver first gas in the second half of 2017. The vast majority of the infrastructure is already in place including roads, power lines and a 60km water pipeline from Hanya. The two-train central gas processing facility has also progressed well and is 97% complete. Mechanical completion and handover to commissioning has commenced. The water treatment plant, waste management area and electricity substation have also been completed along with accommodation units for the workforce of up to 13,000. The Khazzan drilling programme is also on track with 45 of the 50 wells needed by first gas already drilled. Thirty well sites are mechanically completed and connection to the central gas processing facility via the duplex gathering system is on track for the second quarter of 2017.

In November BP and Oman Oil Company Exploration & Production signed an agreement, announced in February, with the government of the Sultanate of Oman amending the Oman Block 61 exploration and production-sharing agreement (EPSA) to extend the licence area, paving the way for further development of the Khazzan field. The extension adds more than 1,000km^2 to the south and west of the original 2,700km^2 of Block 61. The extension will allow a second phase of development, accessing additional gas in the area already identified by drilling activity within the original block. Development of this additional resource is subject to final approval of the government of Oman and of BP both expected in 2017.

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 approximately 5.9 million tonnes of LNG (306bcfe regasified).

In December BP signed an agreement with the Supreme Petroleum Council of the Emirate of Abu Dhabi, in its capacity as representative of the government, and the Abu Dhabi National Oil Company (ADNOC) that grants BP a 10% interest in the Abu Dhabi ADCO onshore oil concession. In addition to the interest in the ADCO concession, BP becomes a 10% shareholder in OPCO, the Abu Dhabi Company for Onshore Petroleum Operations Limited, which operates the concession. The agreement includes BP becoming asset leader for the Bab asset group within the concession. The other partners in this concession are ADNOC (60%), Total (10%), INPEX (5%), and GS Energy (3%). Renewal of the ADCO concession interest (covering materially the same acreage as BP s prior interest that expired in 2014) to 31 December 2054 provides BP with long-term access to significant and competitive production and reserves.

In March 2016 we announced that BP and Kuwait Petroleum Corporation have signed a framework agreement to explore possible joint opportunities for investment and co-operation in future oil, gas, trading and petrochemicals ventures. In addition to enhancing oil and gas recovery from Kuwait s existing resource base, the agreement also includes the intention to study opportunities for joint investment in future oil and gas exploration both inside Kuwait and globally. Other elements of the agreement cover possible future oil and gas trading deals including LNG trading and related ventures. In March 2016 BP also signed an Enhanced Technical Service Agreement for south and east Kuwait conventional oilfields, which includes the Burgan field, with Kuwait Oil Company.

In India, we have a 30% participating interest in three oil and gas PSAs operated by Reliance Industries Limited (RIL), and have a stake with RIL in a 50:50 joint venture (India Gas Solution Private Limited) for the sourcing and marketing of gas in India.

On 21 March 2016, the government of India issued a natural gas pricing policy which allows pricing and marketing freedom for new discoveries in deep water, ultra deep water, and high pressure high temperature reservoirs. In light of this, BP and its partners are progressing the investment plans to develop the discovered resources.
In the fourth quarter of 2016 we recorded a $234-million impairment reversal and a $319-million reversal of exploration write-off relating to Block KG D6 in India. This reversal is mainly driven by an increased confidence in the progress of projects by BP and its partners.
Block CYD5 was relinquished in 2016 due to lack of material accumulations and poor future exploration prospectivity, resulting in an exploration write-off of $216 million.

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. Despite continued instability and sectarian violence in the north and west of the country, BP operations continued as planned in the south.

In Russia, in addition to its 19.75% equity interest in Rosneft, BP holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas), a joint venture with Rosneft that is developing the Srednebotuobinskoye oil and gas condensate field in East Siberia (see Rosneft on page 35 for further details).

In October 2016 Rosneft and BP completed a transaction to create a new joint venture, Yermak Neftegaz LLC, to conduct onshore exploration in the West Siberian and Yenisei-Khatanga basins. Yermak Neftegaz is 51% owned by Rosneft and 49% by BP, and currently holds seven exploration and production licences. The venture will also carry out further appraisal work on the Baikalovskoye field, an existing Rosneft discovery in the Yenisei-Khatanga area of mutual interest.

Australasia

BP has activities 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 year.

BP is also one of five participants in the Browse LNG venture (operated by Woodside) and holds a 17.33% interest.

In March 2016, following substantial completion of front-end engineering and design (FEED) work, the Browse joint venture participants decided not to progress with the floating LNG development at that time due to the economic and market environment. The Browse joint venture participants are evaluating and narrowing a range of alternative development options, and will select one in 2018.
The NWS Persephone project (BP 16.67%) is on schedule to deliver first gas in the second half of 2017 and is the second of the NWS 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.
In October BP announced it had taken the decision not to progress an exploration drilling programme in the Great Australian Bight (GAB), offshore South Australia. The decision follows the review and refresh of BP s upstream strategy earlier this year. BP has determined that the GAB project would not be able to compete for capital

investment with other upstream opportunities in its global portfolio in the foreseeable future and the related assets have been written off.

BP s 5.375% interest in the Jansz-lo field and its 12.5% interests in the Geryon, Orthrus, Maenad, Urania and Eurytion fields (which are part of the Greater Gorgon project) were sold in June 2016.

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In Papua Barat, Eastern Indonesia, BP operates the Tangguh LNG plant. In 2016 BP increased its interest in Tangguh from 37.16% to 40.22%. 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.

In July BP announced that the FID for the development of the Tangguh expansion project had been approved. The FID allows the project to continue with the planned investment to build a third LNG processing train (train 3), adding 3.8 million tonnes per annum of production capacity to the existing facility, bringing total plant capacity to 11.4 million tonnes per annum. The project also includes two offshore platforms, 13 new production wells, an expanded LNG loading facility, and supporting infrastructure. This will enable BP to play an important role in supporting Indonesia s growing energy demand, with 75% of its annual LNG production sold to the Indonesian state electricity company PT. PLN (Persero). First production from train 3 is expected in 2020.

In November BP received approval from the government of Indonesia to relinquish its 100% interests in the West Aru I and II PSAs. Approval to relinquish its 32% interests in the Chevron-operated West Papua I and Ill PSAs is still pending.

Downstream plant capacity

The following table summarizes BP group s interests in refineries and average daily crude distillation capacities as at 31 December 2016.

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	236
US East of Rockies		Whiting	100	430
		Toledo	50	80
				746
Europe				
Rhine	Germany[c]	Bayernoil[d]	10	22
		Gelsenkirchen	100	265
		Lingen	100	95
	Netherlands	Rotterdam	100	377
Iberia	Spain	Castellón	100	110
				869

Rest of world				
Australia	Australia	Kwinana	100	149
New Zealand	New Zealand	Whangarei[d]	21.2	26
Southern Africa	South Africa	Durban[d]	50	90
				265
Total BP share of capacity at 31 December 2016				1,880

[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] On 31 December 2016 we completed the dissolution of our German refining joint operation* with Rosneft. The capacities reported here reflect BP s share of capacities after the dissolution.

[d] 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 2016.

			BP share of capacity thousand tonnes per annum[b]				
		Group interest[c]			Acetic	Olefins and	Product
Geographical area	Site	(%)	PTA	PX	acid	derivatives	Others
US							
	Cooper River	100	1,400				
	Texas City	100		900	600[d]		100
			1,400	900	600		100
Europe							
UK	Hull[e]	100			500		200
Belgium	Geel	100	1,300	700			
Germany	Gelsenkirchen[f]	100				3,300	
	Mülheim[f]	100					300
			1,300	700	500	3,300	500
Rest of world							
Trinidad & Tobago	Point Lisas	36.9					700
China	Caojing	50				3,500	
	Chongqing	51			200		100
	Nanjing	50			300		
	Zhuhai[g]	85	2,500				
Indonesia	Merak	100	500				
South Korea	Ulsan	34-51			300[h]		100[h]
Malaysia	Kertih	70			400		
Taiwan	Mai Liao	50			200		
	Taichung	61.4	500				
			3,500		1,400	3,500	900
			6,200	1,600	2,500	6,800	1,500
Total BP share of capacity at 31 December 2016							18,600

[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 non-operated equity-accounted entities, as indicated.

[d] Group interest is quoted at 100%, reflecting the capacity entitlement, which is marketed by BP.

[e] The site has capacity under 100,000 tonnes per annum for a speciality product (e.g. naphthalene dicarboxylate and ethylidene diacetate).

[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. On 31 December 2016 we completed the dissolution of our German refining joint operation with Rosneft. The capacities reported here reflect BP s share of capacities after the dissolution.

[g] BP Zhuhai Chemical Company Ltd is a subsidiary* of BP, the capacity of which is shown above at 100%.

[h] Group interest varies by product.

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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 of the transaction. 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 2016 BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad, the North Sea, Egypt, Canada 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% (18% for 2015 five-year average) 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.

Proved reserves as estimated at the end of 2016 meet BP s criteria for project sanctioning and SEC tests for proved reserves. We have not halted or changed our commitment to proceed with any material project to which proved undeveloped reserves have been attributed in light of lower oil and gas prices. BP has responded to the downturn in prices by enhancing the efficiency and productivity of our operations.

In 2016 we progressed 1,134mmboe of proved undeveloped reserves (586mmboe 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 $14,143 million in 2016 ($11,145 million for subsidiaries and $2,998 million for equity-accounted entities). The major areas with progressed volumes in 2016 were Argentina, Iraq, Trinidad, Russia and the 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; there were no individually material revisions during the year. 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 2016	7,687
Revisions of previous estimates	376
Improved recovery	177
Discoveries and extensions	457
Purchases	271
Sales	(59)
Total in year proved undeveloped reserves changes	1,222
Proved developed reserves reclassified as undeveloped	22
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(1,134)
Proved undeveloped reserves at 31 December 2016	7,797

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2016	4,211
Revisions of previous estimates	185
Improved recovery	170
Discoveries and extensions	75
Purchases	54
Sales	(57)
Total in year proved undeveloped reserves changes	427
Proved developed reserves reclassified as undeveloped	17
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(586)
Proved undeveloped reserves at 31 December 2016	4,068

[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:

well data used to assess the local characteristics and conditions of reservoirs and fluids

* See Glossary.

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- field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control
- data from relevant analogous fields.

Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

BP s centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

- Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.
- Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group s business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.
- Group audit, whose role is to consider whether the group s system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to BP.
- Approval hierarchy, whereby proved reserves changes above certain threshold volumes require 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 are estimated or assured 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 2016, 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 2016. The net proved reserves estimates prepared by D&M were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve

some degree of uncertainty. BP has filed D&M s independent report on its reserves estimates as an exhibit to this 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

86% of our total proved reserves of subsidiaries at 31 December 2016 were held through joint operations* (84% in 2015), and 31% of the proved reserves were held through such joint operations where we were not the operator (34% in 2015).

Estimated net proved reserves of crude oil at 31 December 2016[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	155	274	429
Rest of Europe			
US	826	497	1,322
Rest of North America[d]	42	209	251
South America	9	11	20
Africa	317	42	358
Rest of Asia	1,107	245	1,352
Australasia	32	14	46

Subsidiaries	2,487	1,291	3,778
Equity-accounted entities	3,573	2,529	6,101
Total	6,060	3,819	9,879

Estimated net proved reserves of natural gas liquids at 31 December 2016[a b]

			million barrels
	Developed	Undeveloped	Total
UK	13	3	16
Rest of Europe			
US	226	73	299
Rest of North America			
South America	5	28	33
Africa	13	1	14
Rest of Asia			
Australasia	9	2	11
Subsidiaries	266	107	373
Equity-accounted entities	65	17	81
Total	331	123	454

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Estimated net proved reserves of liquids*

			million barrels
	Developed	Undeveloped	Total
Subsidiaries	2,753	1,398	4,151[e f]
Equity-accounted entities	3,637	2,545	6,183[g]
Total	6,390	3,943	10,333

Estimated net proved reserves of natural gas at 31 December 2016[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	499	350	848
Rest of Europe			
US	5,447	2,567	8,014
Rest of North America			
South America	1,784	4,970	6,755
Africa	767	2,191	2,958
Rest of Asia	1,890	3,769	5,659
Australasia	3,012	1,643	4,654
Subsidiaries	13,398	15,490	28,888[h]
Equity-accounted entities	7,617	6,863	14,480[i]
Total	21,015	22,353	43,368

Estimated net proved reserves on an oil equivalent basis

			million barrels of oil equivalent
	Developed	Undeveloped	Total
Subsidiaries	5,063	4,068	9,131
Equity-accounted entities	4,951	3,729	8,679
Total	10,014	7,797	17,810

[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 2016 marker prices used were Brent* $42.82/bbl (2015 $54.17/bbl and 2014 $101.27/bbl) and Henry Hub* $2.46 /mmBtu (2015 $2.59/mmBtu and 2014 $4.31/mmBtu).

[c] Includes condensate.

[d] All of the reserves in Canada are bitumen.

[e] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 9 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.

[f] Includes 16 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Includes 347 million barrels of liquids in respect of the non-controlling interest in Rosneft held assets in Russia including 28 million barrels held through BP s equity-accounted interest in Taas-Yuryakh Neftegazodobycha.

[h] Includes 2,026 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[i] Includes 300 billion cubic feet of natural gas in respect of the non-controlling interest in Rosneft held assets in Russia including 3 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 2016, on an oil equivalent basis including equity-accounted entities, increased by 4% (decrease of 1% for subsidiaries and increase of 9% for equity-accounted entities) compared with 31 December 2015. Natural gas represented about 42% (55% for subsidiaries and 29% for equity-accounted entities) of these reserves. The change includes a net increase from acquisitions and disposals of 520mmboe (decrease of 128mmboe within our subsidiaries and increase of 648mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in Abu Dhabi (increase of interest in the ADCO onshore concession from 9.5% to 10%), Indonesia, the US and the UK, and divestment activity in our subsidiaries in Norway, Indonesia, Australia, Trinidad and the US. In our equity-accounted entities the most significant items were purchases in Russia, Norway and Venezuela.

The proved reserves replacement ratio* (RRR) 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 2016, the proved reserves replacement ratio

excluding acquisitions and disposals was 109% (61% in 2015 and 63% in 2014) for subsidiaries and equity-accounted entities, 101% for subsidiaries alone and 121% for equity-accounted entities alone. There were material reductions (162mmboe) of reserves due to accelerations of the date of cessation of production in the US due to lower oil and gas prices, but these were largely offset by increases (157mmboe) in PSAs, principally in Azerbaijan, Indonesia and Iraq resulting from increased cost recovery volumes due to lower oil and gas prices. The 2016 RRR was impacted to a significant degree by the renewal of the ADCO concession in Abu Dhabi. Excluding the impact of the renewal, the total RRR would have been 70%.

In 2016 net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1336mmboe (742mmboe for subsidiaries and 594mmboe for equity-accounted entities), through revisions to previous estimates, improved recovery from, and extensions to, existing fields and discoveries of new fields. These additions include volumes associated with the renewal of the 9.5% interest in the ADCO onshore concession. 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 2016 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 Indonesia, Iraq, UAE and the US. We had material reductions in our proved reserves in the US principally due to lower oil and gas prices. The principal reserves additions in our equity-accounted entities were in Argentina and Russia.

16% of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2016 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia and Oman. In addition, the technical service contract (TSC) governing our investment in the Rumaila field in Iraq functions as a PSA.

Our Abu Dhabi offshore concessions are due to expire in 2018, we have no proved reserves associated with these concessions beyond their expiry date. 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 194.

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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		
	2016	2015	2014	**2016**	2015	2014
Subsidiaries						
UK[c d]	**79**	72	46	**6**	7	2
Norway[c]	**24**	38	41	**4**	5	5
Total Rest of Europe	**24**	38	41	**4**	5	5
Total Europe	**102**	110	87	**10**	11	7
Alaska[c]	**107**	107	127			
Lower 48 onshore[c]	**12**	14	14	**36**	37	45
Gulf of Mexico deepwater	**216**	203	206	**20**	19	18
Total US	**335**	323	347	**56**	56	63
Canada[e]	**13**	3				
Total Rest of North America	**13**	3				
Total North America	**347**	327	347	**56**	56	63
Trinidad & Tobago[c]	**10**	12	13	**8**	11	12
Total South America	**10**	12	13	**8**	11	12
Angola	**219**	221	181			
Egypt[c]	**39**	42	37			
Algeria	**5**	6	5	**5**	7	5
Total Africa	**263**	270	222	**5**	7	5
Azerbaijan[c]	**105**	111	98			
Western Indonesia[c]	**2**	2	2			
Iraq[f]	**96**	85	46			
India	**1**	1	2			
Total Rest of Asia	**204**	199	147		1	
Total Asia	**204**	199	147		1	
Australia[c]	**15**	15	17	**3**	3	3
Eastern Indonesia[c]	**2**	2	2			
Total Australasia	**16**	17	19	**3**	3	3
Total subsidiaries	**943**	933	834	**82**	88	91
Equity-accounted entities (BP share)						
Rosneft (Russia, Canada, Venezuela, Vietnam)	**836**	809	816	**4**	4	5
Abu Dhabi[g]	**101**	96	97			
Argentina	**62**	65	62	**1**	3	3
Bolivia	**4**	4	3			
Egypt				**3**	3	4

Norway[c]	**7**					
Russia[c]	**4**					
Other	**1**	1	1	**1**		
Total equity-accounted entities	**1,015**	974	979	**8**	10	12
Total subsidiaries and equity-accounted entities[h]	**1,958**	1,908	1,813	**90**	99	104

[a] Includes condensate.

[b] Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

[c] In 2016, BP increased its interests in Tangguh in Indonesia and the Culzean asset in the UK North Sea, and in certain US onshore assets. It disposed of its interests in the Valhall, Skarv and Ula assets in the Norwegian North Sea and in return received an interest in Aker BP ASA, which operates in Norway. It also disposed of its interests in the Jansz-Io asset in Australia, and the Sanga Sanga conventional concession in Indonesia. It also decreased its interests in certain Trinidad and US onshore assets. 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 and 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.

[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] All of the production from Canada in Subsidiaries is bitumen.

[f] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq has been simplified to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There is no impact on the financial results.

[g] BP holds interests, through associates, in offshore concessions in Abu Dhabi which expire in 2018.

[h] Includes 3 net mboe/d of NGLs from processing plants in which BP has an interest (2015 4mboe/d and 2014 7mboe/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]		
	2016	2015	2014
Subsidiaries			
UK[b]	**170**	155	71
Norway[b]	**82**	111	102
Total Rest of Europe	**82**	111	102
Total Europe	**252**	266	173
Lower 48 onshore[b]	**1,476**	1,353	1,350
Gulf of Mexico deepwater	**173**	168	159
Alaska	**6**	7	11
Total US	**1,656**	1,528	1,519
Canada	**10**	10	10
Total Rest of North America	**10**	10	10
Total North America	**1,666**	1,538	1,529
Trinidad & Tobago[b]	**1,689**	1,922	2,147
Total South America	**1,689**	1,922	2,147
Egypt[b]	**305**	402	406
Algeria	**208**	187	107
Total Africa	**513**	589	513
Azerbaijan[b]	**245**	219	230
Western Indonesia[b]	**35**	48	47
India	**84**	113	131
Total Rest of Asia	**363**	380	408
Total Asia	**363**	380	408
Australia[b]	**451**	447	450
Eastern Indonesia[b]	**369**	354	364
Total Australasia	**820**	801	814
Total subsidiaries[c]	**5,302**	5,495	5,585
Equity-accounted entities (BP share)			
Rosneft (Russia, Canada, Venezuela, Vietnam)	**1,279**	1,195	1,084
Argentina	**354**	341	323
Bolivia	**95**	93	80
Norway[b]	**12**		
Angola	**18**		7
Western Indonesia[b]	**15**	21	21
Total equity-accounted entities[c]	**1,773**	1,651	1,515
Total subsidiaries and equity-accounted entities	**7,075**	7,146	7,100

[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 2016, BP increased its interests in Tangguh in Indonesia and the Culzean asset in the UK North Sea, and in certain US onshore assets. It disposed of its interests in the Valhall, Skarv and Ula assets in the Norwegian North Sea and in return received an interest in Aker BP ASA, which operates in Norway. It also disposed of its interests in the Jansz-Io asset in Australia, and the Sanga Sanga concession in Indonesia. It also decreased its interests in certain Trinidad and US onshore assets. 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.

[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.

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 (realizations*)[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[b]			Russia	Rest of Asia		
Subsidiaries										
2016										
Crude oil[c]	**42.80**	**40.16**	**39.65**	**26.11**	**45.64**	**40.83**		**39.29**	**41.52**	**39.99**
Natural gas liquids	**25.70**	**20.16**	**14.71**		**21.40**	**21.30**			**32.70**	**17.31**
Gas	**4.50**	**4.19**	**1.90**		**1.72**	**3.89**		**3.39**	**5.71**	**2.84**
2015										
Crude oil[c d]	52.42	50.68	49.84	26.71	53.19	49.09		49.33	50.64	49.72
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 d]	96.02	97.77	93.66		96.85	93.99		97.07	94.04	94.74
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
Equity-accounted entities[e]										
2016										
Crude oil[c]		**50.71**			**48.88**		**36.36**	**12.92**		**34.04**
Natural gas liquids					**34.51**		**n/a[f]**			**34.51**
Gas		**5.16**			**4.21**		**1.39**	**6.11**		**2.20**
2015										
Crude oil[c]					54.24		44.78	16.87		41.49
Natural gas liquids					13.17		n/a[f]			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[f]			15.75
Gas					4.73		2.18	12.83		3.01

Average production cost per unit of production[g]

$ 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	Rest of Asia		
Subsidiaries										
2016	**14.80**	**13.72**	**10.20**	**21.79**	**4.21**	**9.34**		**7.08**	**2.62**	**8.46**
2015[d]	22.95	13.80	11.84	43.56	5.44	11.02		11.22	2.88	10.46
2014[d]	44.67	18.85	14.22		5.43	13.37		16.24	3.92	12.75
Equity-accounted entities										
2016		**10.41**			**10.66**		**2.46**	**3.67**		**3.57**
2015					12.10		2.60	4.59		3.93
2014					11.28		3.82	4.34		4.75

[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] All of the production from Canada in Subsidiaries is bitumen.

[c] Includes condensate.

[d] Production volume recognition methodology for our Technical Service Contract arrangement in Iraq has been simplified to exclude the impact of oil price movements on lifting imbalances. A minor adjustment has been made to comparative periods. There is no impact on the financial results.

[e] In certain countries 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.

f Crude oil includes natural gas liquids.

[g] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

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Environmental expenditure

			$ million
	2016	2015	2014
Environmental expenditure relating to the Gulf of Mexico oil spill		5,452	190
Operating expenditure	**487**	521	624
Capital expenditure	**564**	733	590
Clean-ups	**27**	34	33
Additions to environmental remediation provision	**262**	305	371
Increase (decrease) in decommissioning provision	**(804)**	972	2,216

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 $487 million in 2016 (2015 $521 million) showed an overall decrease of 7% which was due to price deflations and reduced environmental expenditure following the divestment of our petrochemicals site in Decatur, partially offset by a higher level of activity at Whiting refinery.

Environmental capital expenditure in 2016 was lower overall than in 2015, largely due to lower spend as a result of the completion of the installation of a dissolved nitrogen floatation unit at Whiting refinery s wastewater treatment plant in the previous year. 2015 also included higher spend relating to the upgrade to our latest generation PTA technology at some of our petrochemicals sites. These reductions were partially offset by an increased spend on a new LPG refrigeration plant for the North Sea forties pipeline system.

Clean-up costs decreased to $27 million in 2016 compared with $34 million in 2015, primarily due to decreased contractual rates, currency devaluation in certain regions and overall cost reductions.

In addition to operating and capital expenditure, we also establish provisions for future environmental remediation work. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

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

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

Additions to our environmental remediation provision was similar to prior years and also reflects scope reassessments of the remediation plans of a number of our sites in the US and Canada. The charge for environmental remediation provisions in 2016 included $7 million in respect of provisions for new sites (2015 $6 million and 2014 $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 2016 the net decrease in the decommissioning provision occurred as a result of detailed reviews of expected future costs, partially offset by increases to the asset base. The increases in 2015 and 2014 were driven by detailed reviews of expected future costs and increases to the asset base.

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

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

Further details of decommissioning and environmental provisions appear in Financial statements Note 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.

Upstream contractual and regulatory framework

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 (alone or with other contracting companies) 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

* See Glossary.

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 reservoirs 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.

Greenhouse gas regulation

In December 2015, nearly 200 nations at the United Nations climate change conference in Paris (COP21) agreed the Paris Agreement, for implementation post-2020. The agreement came into force on 4 November 2016. For the first time this agreement applies to all countries, both developing and developed, although in some instances allowances or flexibilities are provided for developing nations. The Paris Agreement aims to hold global average temperature rise to well below 2°C above pre-industrial levels and to pursue efforts to limit temperature rise to 1.5°C above pre-industrial levels. There is no quantitative long-term emissions goal. However, countries aim to reach global peaking of greenhouse gas (GHG) emissions as soon as possible and to undertake rapid reductions thereafter, so as to achieve a balance between human caused emissions by sources and removals by sinks of GHGs in the second half of this century. The Paris

Agreement commits all parties to submit Nationally Determined Contributions (NDCs) (i.e. pledges or plans of climate action) 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 to report on their emissions and progress made on their NDCs and to undergo international review of collective progress. It also requires countries to submit revised NDCs every five years, which are expected to be more ambitious with each revision. Global assessments of progress will occur every five years, starting in 2023. In the decision adopting the Paris Agreement, an earlier commitment by developed countries to mobilize $100 billion a year by 2020 was extended through 2025, with a further goal with a floor of $100 billion to be set before 2025.

The United Nations climate change conference in Marrakech (COP22), held in November 2016, agreed a deadline of 2018 for countries to agree on the guidelines and rules that are needed to support implementation of the Paris Agreement.

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:

United States

In the US, the Obama administration adopted its Climate Action Plan in 2013 and had been using existing statutory authority to implement that plan, including the Clean Air Act (CAA) and the Mineral Leasing Act (MLA). On 28 March 2017 the Trump administration issued an Executive Order (EO) rescinding major elements of the Climate Action Plan, and instructing the Environmental Protection Agency (EPA) to review and then commence the process of suspending, revising or rescinding certain regulations, including the Clean Power Plan and the EPA new source methane rule. The EO also instructs the Department of Interior to review and possibly suspend, revise or rescind the Bureau of Land Management (BLM) methane rule.

GHG emissions are currently regulated in a number of ways under the CAA, though some of these regulations may be suspended, revised or rescinded as noted above.

- Stricter GHG regulations, stricter limits on sulphur in fuels, recent emissions regulations in the refinery sector and a revised lower ambient air quality standard for ozone, finalized by the EPA in October 2015, will affect our US operations in the future.
- EPA regulations aimed at methane emissions are in place for new and modified sources and the BLM has issued methane regulations for existing sites located on federal lands.
- It is possible that EPA will be required by statute to propose regulations on existing sources of methane from onshore oil and natural gas sector activities, unless the EPA new source methane rule is rescinded.
- States may also have separate, stricter air emission laws in addition to the CAA and in some cases are considering joining carbon trading markets (e.g. California).

The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 impose a renewable fuel mandate (the federal Renewable Fuel Standard) as well as state initiatives that impose low GHG emissions thresholds for transportation fuels (currently adopted in California, through the California Low Carbon Fuel Standard and Oregon).

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. The Trump administration has announced that it will reconsider these standards.

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 GHG products are required to report product volumes and notional GHG emissions as if these products were fully combusted.

In October 2015 the EPA published its final Clean Power Plan (CPP) which was an important element of the Obama administration s Climate Action Plan. Legal challenges have been filed and the US Supreme Court has stayed the rule until the litigation is resolved, which is not expected until later in 2017 or 2018. The US Appellate Court heard arguments on the case in September 2016 and it is anticipated that its decision will be the subject of a request for review by the US Supreme Court. 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. As noted above, the Trump administration has instructed the EPA to review certain regulations including the CPP and may decline to defend certain legal challenges to the CPP in court.

In January 2015 the Obama administration announced plans to reduce methane emissions from the oil and gas sector by 40-45% from 2012 levels by 2025. In June 2016 the EPA finalized rules aimed at limiting methane emissions from new and modified sources in the oil and natural gas sector in the US. The EPA has announced its intent to adopt a regulation that would apply to existing sources in the sector. In January 2017 the BLM s methane rule, aimed at limiting methane emissions on federal lands from new, modified and existing sources in the oil and gas sector, came into effect. These EPA and BLM rules will require further actions by our US upstream businesses to manage methane emissions. As above, the Trump administration s March 2017 EO instructs the Department of Interior to review and possibly suspend, revise or rescind the BLM and EPA methane rules.

A number of additional state and regional initiatives in the US will affect our operations. The California cap and trade programme started in January 2012 and expanded to cover emissions from transportation fuels in 2015. The state of Washington recently adopted a carbon cap rule that is planned to begin in 2017.

European Union

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 Emissions Trading System (EU ETS) Directive; 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 under the Renewable Energy Directive (a revision to which was proposed by the European Commission in November 2016); 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 sector benchmarked free allocation for all other installations, with sharply declining allocation for sectors deemed not exposed to carbon leakage. EU ETS revisions also included the adoption of a Market Stability Reserve to adjust 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 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.

In October 2014 the EU 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. While the

European Commission has made legislative proposals,
including proposed amended targets, specific EU legislation and agreements required to achieve these goals are still under discussion in the European Council and European Parliament.

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.

In addition, the Energy Efficiency Directive (EED), Industrial Emissions Directive (IED) 2010, Medium Combustion Plants Directive (MCPD) 2015 and EU regulation on ozone depleting substances 2009 (ODS Regulation) referenced below under Other environmental regulation will also directly or indirectly require reductions in GHG emissions.

Other

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 C$30/tonne in 2017. In addition, a new policy direction was announced by the Alberta government including an economy-wide price of carbon that covers emissions not in the scope of the existing regulations for large final emitters (C$20/tonne in 2017; C$30/tonne in 2018 then escalating in real terms), targeted changes to electricity generation sources, a limit on overall oil sands emissions, and sector specific performance standards (currently being developed) to determine the volume of emissions subject to charges, or use of other compliance mechanisms, including offsets. The Canadian federal government has announced a number of climate change policy goals including a national carbon price starting at C$10/tonne and escalating to C$50/tonne by 2022 (or equivalent system for provinces with cap-and-trade systems), with implementation of the price, use of any funds generated and outcome reporting being managed by each province.

In the November 2014 US-China joint announcement on climate change addressing post-2020 actions, which was reaffirmed by the countries respective presidents in September 2015 and March 2016, 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 are likely to 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. In the March 2016 US-China joint presidential statement both countries agreed to ratify the Paris Agreement including submission of their domestic reduction commitments detailed above.

China is operating emission trading pilot programmes in five cities and two provinces. Two of BP s joint venture* companies in China are participating in these schemes. A nationwide carbon emissions trading market is expected to be launched in 2017 which will supersede the above seven pilot programmes. It is also proposed to carry out pilot programmes on compensation for and trading of energy quotas in four provinces in 2017 which may be expanded to nationwide in or after 2020.

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.

For information on the steps that BP is taking in relation to climate change issues and for details of BP s GHG reporting, see Sustainability Climate change on page 43.

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Other 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 257.

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

Since taking office in January, the Trump administration has issued a number of EOs intended to reform the federal permitting and rulemaking processes to reduce regulatory burdens placed on manufacturing generally and the energy industry specifically. These EOs immediately rescind certain policies and procedures and order the commencement of a broad process to identify other actions that may be taken to further reduce these regulatory requirements. It is not clear how much or how quickly these regulatory requirements will be reduced given statutory and rulemaking constraints and the likely opposition to some of these initiatives.

The National Environmental Policy Act (NEPA) requires that the federal government gives proper consideration to the environment prior to undertaking any major federal action that significantly affects the environment, which includes the issuance of federal permits. The environmental reviews required by NEPA can delay projects. In August 2016, the White House Council on Environmental Quality issued guidance to federal agencies requiring that climate impact be considered under NEPA. These requirements could further delay projects that require federal action such as exploration and production plans. States law analogues to NEPA could also limit or delay our projects.

The CAA regulates air emissions, permitting, fuel specifications and other aspects of our production, distribution and marketing activities.

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 the limitations discussed above under Greenhouse gas regulation . California also imposes Low Emission Vehicle (LEV) and Zero Emission Vehicle (ZEV) standards 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 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 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 (TSCA) regulates BP s manufacture, import, export, sale and use of chemical substances and products. In June 2016, the US enacted legislation to modernize and reform TSCA (the Frank R. Lautenberg Chemical Safety for the 21st Century Act). The EPA has begun to develop proposed rules, processes and guidance to implement the reforms. Key components of the reform legislation include: (1) a reset of the TSCA chemical inventory, (2) new chemical management prioritization efforts expanding risk assessment and risk management practices, (3) new confidentiality provisions, and (4) new authority for the EPA to impose a fee structure.

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, refining and other regulated facilities. In 2016 the Obama administration announced that the US Occupational Safety and Health Administration (OSHA) would implement a National Emphasis Program set of inspections aimed at refineries and petrochemical facilities. The Trump administration has not made any announcement regarding its intentions for this program.

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

The Maritime Transportation Security Act and the DOT Hazardous Materials (HAZMAT) regulations impose security compliance regulations on certain 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, the MLA and other statutes give the Department of Interior (DOI) and the 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. In addition, in 2016 the DOI proposed to regulate methane emissions from onshore oil and natural gas sector operations.

The Endangered Species Act and Marine Mammal Protection Act protect certain species from adverse human impacts. The species and their habitat may be protected thereby restricting operations or development at certain times and in certain places. With an increasing number of species being protected, we have increasing restrictions on our activities.

European Union

The 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. A revision to the EED was proposed by the European Commission in November 2016, which includes a new energy efficiency target for 2030.

The IED provides the framework for granting permits for major industrial sites. It lays down rules on integrated prevention and control of air, water and soil pollution arising from industrial activities. 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, for combustion as well as petrochemicals production. These may result in requirements for BP to further reduce its emissions, particularly its air and water emissions.

The MCPD came into force on 18 December 2015 and must be implemented by member states by 19 December 2017. It applies to air emissions of sulphur dioxide (SO_2), nitrogen oxides (NOx) and particulates from the combustion of fuels in plants with a rated thermal input between one and 50MW. It also includes requirements to monitor emissions of carbon monoxide (CO) from such plant. Its requirements will be phased in the emission limit values set in the Directive will apply from 20 December 2018 for new plants and by 2025 or 2030 for existing plants, depending on their size.

The National Emission Ceiling Directive 2001 has been revised to introduce stricter emissions limits from 2030, with new indicative national targets applying from 2025. Formal adoption of the revised Directive is pending.

The ODS Regulation requires BP to reduce the use of ozone depleting substances (ODSs) and phase out use of certain ODSs. BP continues to replace ODSs 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 GHGs 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.

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 manufacturing or trading/import operations in the EU. Since coming into force in 2007, REACH implementation has followed a phase-in schedule defined by the EU. The final phase-in implementation deadline requires registration of substances manufactured or imported in the tonnage-band of 1-100 tonnes per annum per legal entity by 31 May 2018. BP is in the process of preparing and submitting registration dossiers to meet this final REACH implementation milestone. For higher tonnage-band substances, BP maintains compliance by checking whether imports are covered by the registrations of non-EU suppliers representatives, preparing and submitting registration dossiers to cover new manufactured and imported substances, and updating 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.

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 Water Framework Directive (WFD) published in 2000 aims to protect the quantity and quality of ground and surface waters of the EU member states. The ongoing implementation of the WFD and the related Environmental Quality Standards Directive 2008 as well as the planned revision of the WFD in 2019 is likely to require additional compliance efforts and increased costs for managing freshwater withdrawals and discharges from BP s 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).

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:

- Liability and spill prevention and planning requirements governing, among others, tankers, barges and offshore facilities are imposed by OPA in US waters. 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 (IMO), including the International Convention on Civil Liability for Oil Pollution Damage, the International Convention for the Prevention of Pollution from Ships (MARPOL), 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 31 December 2016, as the required minimum number of contracting states had not been achieved, the HNS Convention had not entered into force.
- A global sulphur cap of 0.5% will apply to marine fuel from January 2020 under MARPOL. In order to comply, ships will either need to consume low sulphur marine fuels or implement approved abatement technology to enable them to meet the low sulphur emissions requirements whilst continuing to use higher sulphur fuel. This new global cap will not alter the lower limits that apply in the sulphur oxides Emissions Control Areas established by the IMO.
- Ships will be required to have ballast water treatment systems in place within the time frame prescribed by the International Convention for the Control and Management of Ships Ballast Water and Sediments 2004, which is due to enter into force in September 2017.

To meet its financial responsibility requirements, BP Shipping maintains marine pollution liability 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.

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). Lawsuits and claims arising from the Incident have generally been brought in US federal and state courts.

Many of the lawsuits in federal court relating to the Incident 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 lawsuits and claims arising from the Incident, are discussed below.

Federal and state claims

MDL 2179 Department of Justice (DoJ) Action, State and local authority claims consolidated into MDL 2179 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 the Oil Pollution Act of 1990 (OPA 90) for natural resources damages and civil penalties under the Clean Water Act (CWA).

Between 2010 and 2013, the states of Alabama, Florida, Louisiana, Mississippi and Texas (the five Gulf Coast states) filed lawsuits seeking declaratory and injunctive relief, and punitive damages, as a result of the Incident. Each of these actions was consolidated with MDL 2179.

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 but following the settlement between the US and BPXP (discussed below), on 19 October 2016 BP and the PSC filed a joint stipulation to dismiss the appeals. Both appeals have now been dismissed but BP could appeal the rulings in the future if a claimant was successful in an action against BP that includes a final judgment that incorporates the district court s rulings on these trial phases.

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. No decision was entered by the district court with respect to BPXP following this phase of the trial in light of the subsequent settlement between the US and BPXP.

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 the five Gulf Coast states to settle all federal and state claims arising from the Incident. In addition, 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 five Gulf Coast states and BP to fully and finally resolve any and all natural resource damages claims of the United States, the five Gulf Coast states and their respective natural resource trustees and all CWA penalty claims, and certain other claims of the United States and the five Gulf Coast states. Concurrently, BP entered into a definitive Settlement Agreement with the five Gulf Coast states (Settlement Agreement) with respect to state claims for economic, property and other losses. On 4 April 2016 (the Effective Date), the court entered the Consent Decree and also entered a final judgment in the DoJ Action on the terms set forth in the Consent Decree, at which time the Consent Decree and Settlement Agreement became effective.

For further details of the Consent Decree and Settlement Agreement, including details of the principal payments, see Legal proceedings in *BP Annual Report and Form 20-F 2015*.

OPA Test Case Proceedings

A number of lawsuits were brought, primarily by business claimants, under OPA 90 in relation to the 2010 federal deepwater drilling moratoria. Six test cases, consolidated with MDL 2179, were scheduled to address certain OPA 90 liability questions focusing on,

among other issues, whether the plaintiffs alleged losses tied to the moratoria and whether federal permit delays are compensable. On 10 March 2016, the court ruled that BPXP is not, as a Responsible Party under OPA 90, liable for economic losses that resulted from the 2010 deepwater drilling moratoria. The court s order dismissed the plaintiffs claims with prejudice. On 19 March 2016, the plaintiffs appealed the court s ruling to the Fifth Circuit. Subsequently, BPXP settled the claims of each of the test case plaintiffs and their cases and the pending appeals to the Fifth Circuit have been dismissed.

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. BP completed the final payment for the $1 billion early restoration funds in April 2016.

Under the Consent Decree, Trustees will 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 resolved certain economic and property damage claims, and included a $2.3 billion BP commitment to help resolve economic loss claims related to the Gulf seafood industry (the Seafood Compensation Program) and a $57-million fund to support advertising to promote Gulf Coast tourism. It also resolved 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 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 final deadline for filing all claims other than those that fall into the Seafood Compensation Program was 8 June 2015.

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 and in further orders extended the stay until 7 September 2016. That stay has now expired and the oral argument took place on 8 March 2017.

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) 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, and also includes provisions regarding class members pursuing claims for later-manifested physical conditions (LMPCs).

The deadline for submitting SPC and PMCP claims was 12 February 2015. The Medical Claims Administrator has reported the total number of claims submitted is approximately 37,250. As of 3 March 2017, approximately 22,300 SPC claims, totalling approximately $64.2 million, have been approved for compensation. In addition, approximately 26,200 claimants have been determined eligible for the PMCP and there are six pending lawsuits brought by class members claiming LMPCs.

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For further details of the Medical Settlement, see Legal proceedings in *BP Annual Report and Form 20-F 2015*.

MDL 2185 and other securities-related litigation

Since the Incident, shareholders have sued BP and various of its current and former officers and directors asserting shareholder derivative claims and class and individual securities fraud claims. Many of these lawsuits have been consolidated or co-ordinated in federal district court in Houston (MDL 2185).

Securities class action

On 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. 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 2 May 2016, the Supreme Court denied the pre-explosion ADS purchasers final petition.

Following various legal proceedings, on 2 June 2016, BP announced that it had agreed with plaintiffs representatives to settle the class claims of the post-explosion ADS purchasers for the amount of $175 million, payable during 2017, subject to approval by the court. The parties filed the settlement agreement and other papers in support of approval with the court on 15 September 2016 and a class notice was issued on 14 November 2016. On 13 February 2017 the court granted final approval of the class settlement.

Individual securities litigation

From April 2012 to April 2016, 38 cases were filed in state and federal courts by pension funds, 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 and/or holdings of BP ordinary shares and, in certain 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 and holdings of BP ordinary shares and/or ADSs. All of the cases, with the exception of one case that has been stayed, have been transferred to MDL 2185. On 4 January 2016, the district court dismissed two of those cases and some of the claims of a third case. Plaintiffs in the two dismissed cases filed amended complaints on 19 January 2016. On 8 July 2016, the district court granted leave for these plaintiffs to file amended complaints. On 28 September 2016, defendants filed a motion to dismiss certain claims against certain defendants in 20 of the individual securities cases and briefing is expected to be completed on that motion in April 2017.

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. Following an unsuccessful claim by the plaintiff in Texas federal court, on 26 February 2016, the plaintiff filed a motion in the Court of Appeal for Ontario to lift the stay on the Canadian action, which was granted on 29 July 2016. On 19 January 2017 the Supreme Court of Canada denied BP s motion for leave to appeal from the Court of Appeal s decision.

ERISA

On 15 January 2015, in an ERISA case related to BP share funds in several employee benefit savings plans, the federal district court in Houston allowed the plaintiffs to amend their complaint to allege some of their proposed claims against certain defendants. On 26 September 2016, the Fifth Circuit reversed the decision of the district court, holding that the amended complaint is insufficient to state a claim against defendants, that the district court erred in granting the plaintiffs motion to amend, and remanding the case to

the district court for further proceedings. On 22 November 2016, plaintiffs filed a motion to file an amended complaint, and on 8 March 2017, that motion was denied.

Other Deepwater Horizon oil spill related claims

Other civil complaints economic loss

On 29 March 2016, the district court in MDL 2179 issued an order dismissing in its entirety the master complaint raising claims for economic loss by private plaintiffs (the March 2016 Order). The court ordered that all private plaintiffs who had filed a timely claim for economic loss against BP in MDL 2179 and had not released those claims must file and serve on BP a sworn statement disclosing information regarding their claims by 2 May 2016. In addition, the court required plaintiffs who had not filed an individual complaint (defined as a complaint not joined in by other plaintiffs) against BP to file a new individual complaint by 2 May 2016. Plaintiffs who failed to comply with the sworn statement requirement or the new individual complaint requirement by 2 May 2016 (which deadline was extended by 14 days for some of the plaintiffs) were to have their claims deemed dismissed with prejudice without further notice. The court issued a supplemental order confirming that all new complaints filed would be stayed until further direction by the court.

On 7 June 2016, the court issued an order requiring private plaintiffs who had not complied with the March 2016 Order to show cause in writing by 28 June 2016 why their claims should not be dismissed with prejudice. The court also dismissed all joinders by plaintiffs in the master complaint for private plaintiff economic loss and property damages claims. On 14 July 2016 the federal district court issued an order listing those 962 plaintiffs who complied with the March 2016 Order and those plaintiffs whose compliance with the March 2016 Order remained to be determined by the court. The court dismissed with prejudice any remaining claims by private plaintiffs for economic loss and property damage. Accordingly the vast majority of economic loss and property damage claims from individuals and businesses that either opted out of the 2012 settlement with the Plaintiffs Steering Committee and/or were excluded from that settlement have either been resolved or dismissed.

On 16 December 2016, the district court issued a ruling on the show cause submissions filed by plaintiffs whose compliance with the March 2016 Order remained to be determined by the court. The court s ruling held another 61 plaintiffs to be noncompliant with the March 2016 Order and dismissed their claims. It found an additional 57 plaintiffs to have complied with the March 2016 Order and to be subject to further proceedings in MDL 2179.

On 22 February 2017 the district court in MDL 2179 ordered that any remaining plaintiffs who wish to pursue a general maritime law claim must file and serve on BP a sworn statement as to their proprietary interest in property physically damaged by oil, and whether they worked as commercial fishermen, by 5 April 2017.

Other civil complaints personal injury

On 22 February 2017 the district court in MDL 2179 issued an order dismissing in its entirety the master complaint raising claims for post-explosion clean-up, medical monitoring and personal injury claims occurring after the explosion and fire of 20 April 2010. The court ordered that all plaintiffs who had filed a timely claim for such personal injury cases against BP in MDL 2179 and had not released those claims must file and serve on BP a sworn statement disclosing information regarding their claims by 12 April 2017. In addition, the court required plaintiffs who had not filed an individual complaint (defined as a complaint not joined in by other plaintiffs) against BP to file a new individual complaint by 12 April 2017. Plaintiffs who failed to comply with the sworn statement requirement or the new individual complaint requirement by 12 April 2017 were to have their claims deemed dismissed with prejudice without further notice.

Non-US government lawsuits

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 where it remains pending.

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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. BPXP has since been dismissed. The plaintiffs, who allegedly are fishermen, 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. BP has not been formally served with the action. However, after learning that the Mexican Federal District Court issued a resolution in the class action that impacted BP s rights, BP filed a constitutional challenge (amparo) in Mexico asserting that BP has never been formally served with process in the class action. This amparo was denied and is now on appeal.

On 3 December 2015 and 29 March 2016, Acciones Colectivas de Sinaloa (ACS) filed two class actions (which have since been consolidated) in a Mexican Federal District Court on behalf of several Mexican states. In these class actions, plaintiffs seek an order requiring the BP defendants to repair the damage to the Gulf of Mexico, to pay penalties, and to compensate plaintiffs for damage to property, to health and for economic loss. BP has not been formally served with the action.

False Claims Act actions

On 17 December 2012, the court ordered one complaint to be unsealed 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 and the court subsequently stayed the action. Following the Effective Date, under the terms of the Consent Decree, the United States and Gulf states covenanted not to pursue claims against BP under the FCA. On 3 February 2017 the plaintiff in the False Claims Act case voluntarily dismissed the action.

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 Consent Decree with the United States (see above), BP withdrew its appeals on 18 April 2016, and the INCs have been fully and finally resolved.

Pending investigations and reports relating to the Deepwater Horizon oil spill CSB investigation

On 13 April 2016, the US Chemical Safety and Hazard Investigation Board (CSB) released the final two volumes of its four-volume report on its investigation into the Incident. The final two volumes primarily concern the role of the regulator in the oversight of the offshore industry and organizational and cultural factors. They include proposed recommendations to the US Department of Interior s Bureau of Safety and Environmental Enforcement, the American Petroleum Institute, the Ocean Energy Safety Institute and the Sustainability Accounting Standards Board.

Other legal proceedings

FERC and CFTC matters

Following an investigation by the US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) of several BP entities, the Administrative Law Judge of the FERC 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. On 11 July 2016 the FERC issued an Order affirming the initial decision and directing BP to pay a civil penalty of $20.16 million and to disgorge $207,169 in unjust profits. On 10 August 2016, BP filed a request for rehearing with the FERC. BP strongly disagrees with the FERC s decision and will ultimately appeal to the US Court of Appeals if necessary.

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 BP Texas City refinery. The report contained recommendations to the BP Texas City refinery and to the board of directors of BP. On 25 May 2016, the CSB closed its last open recommendation to BP. The CSB has now accepted that all of BP s responses to its recommendations have been satisfactorily addressed.

OSHA matters

On 8 March 2010, the US Occupational Safety and Health Administration (OSHA) issued 65 citations to BP Products North America Inc. (BP Products) and BP-Husky Refining LLC (BP-Husky) for alleged violations of the Process Safety Management (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 granted OSHA s petition for review and briefing was completed in the first half of 2014. Timing for the issuance of a decision by the Review Commission is currently uncertain. Depending on the outcome of this review, BP may also pay a penalty not to exceed $1 million in respect of similar issues at the BP Texas City refinery.

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, and briefing was completed on that appeal on 14 October 2016.

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

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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 an FCA 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 28 August 2014, the court entered final judgment in favour of BP and on 14 March 2017, this was affirmed by the Fifth Circuit Court of Appeals.

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. Trial is scheduled to commence in the second half of 2017.

Scharfstein v. BP West Coast Products, LLC

A 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* sites in Oregon failed to provide sufficient notice of the 35 cents per transaction debit card fee. In January 2014, the jury rendered a verdict against BP and awarded statutory damages of $200 per class member. On 25 August 2015, the trial court determined the size of the class to be slightly in excess of two million members. On 31 May 2016 the trial court entered a judgment for the amount of $417.3 million. On 1 June 2016 BP filed a notice of appeal. No provision has been made for damages arising out of this class action.

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 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, together with the EU, agreed the Joint Comprehensive Plan of

Action (JCPOA).

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 or suspended certain nuclear related sanctions, with the EU lifting nuclear related primary sanctions and the United States suspending nuclear related secondary sanctions. Following Implementation Day, BP has considered and developed possible business opportunities in relation to Iran, engaged in discussions with Iranian government officials and other Iranian nationals and attended conferences, and will continue to do so.

During the second half of 2016, BP Iran Limited leased and refurbished an office in Tehran.

In December 2016, BP purchased condensate from National Iranian Oil Company (NIOC). The condensate was loaded in Iran on 23 December 2016 and delivered to BP s Rotterdam refinery on 15 January 2017. BP intends to continue to explore commercial opportunities with NIOC (or its subsidiaries).

BP has a 50% interest in and operates the North Sea Rhum field (Rhum). Iranian Oil Company (U.K.) Limited (IOC UK) holds a 50% interest in Rhum. Production was suspended at Rhum in November 2010. Under a temporary management scheme, the UK government assumed control of and managed IOC UK s interest in the Rhum field, thereby permitting Rhum operations to recommence in mid-October 2014 in accordance with applicable EU regulations and in compliance with a licence from the US Office of Foreign Assets Control. Following Implementation Day, the temporary management scheme ceased, with control and management of IOC UK s interest passing back to IOC UK, and BP obtained an updated OFAC licence in relation to the continued operation of Rhum on 29 September 2016.

BP has a 28.8% interest in and operates the Azerbaijan Shah Deniz field (Shah Deniz) and a related gas pipeline entity, South Caucasus Pipeline Company Limited (SCPC), and has a 23% non-operated interest in a related gas marketing entity, Azerbaijan Gas Supply Company Limited (AGSC). Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) have a 10% non-operating interest in each of Shah Deniz and SCPC and an 8% non-operating interest in AGSC. Shah Deniz, SCPC and AGSC continue in operation as they 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 holds an interest in a non-BP operated Indian joint venture* and sold produced crude oil to an Indian entity in which NICO holds a minority, non-controlling stake.

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.

BP has registered and paid required fees to maintain registrations of 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.

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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) was a 50:50 joint operation* with Rosneft, operated by BP, which held interests in a number of refineries in Germany. These sanctions have had no material adverse impact on BP or ROG. On 31 December 2016, the previously-announced dissolution of ROG was completed.

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 Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA) Section 219, with the following possible exceptions:

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. The Rhum joint arrangement was originally formed in 1974. 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 2016, BP recorded gross revenues of $67.2 million related to its interests in Rhum. BP had a net profit of $31.6 million for the year ended 31 December 2016, including an impairment reversal of $48.9 million in the third quarter of 2016. BP currently intends to continue to hold its ownership stake in the Rhum joint arrangement and act as operator.

In December 2016, BP Singapore Pte. Limited (BPS) purchased a shipment of South Pars condensate from NIOC, which was loaded in Iran on 23 December 2016 and delivered to BP s Rotterdam refinery on 15 January 2017. BPS made a payment ($52 million equivalent) in consideration for the condensate on 19 January 2017. Upon delivery, the condensate was comingled with other products for refining, and therefore BP is unable to ascertain an amount of gross revenue or gross profit attributable to it. BP intends to continue to explore commercial opportunities with NIOC (or its subsidiaries).

BP Iran Limited leased and refurbished an office in Tehran during 2016. The office is used for administrative activities. In 2016, rental tax payments associated with the Tehran office, with an aggregate US dollar equivalent value of approximately $6,000, were paid from a BP trust account held with Tadvin Co. to Iranian public entities. No gross revenues or net profits were attributable to these activities. BP intends to continue to maintain an office in Tehran.

During 2016, certain BP employees visited Iran for the purpose of meetings with Iranian government officials and other Iranian nationals and attending conferences. Payments were made to Iranian public entities for visas and taxes in relation to such visits with an aggregate US dollar equivalent value of approximately $18,730. No gross revenues or net profits were attributable to these activities, save where otherwise disclosed, and BP intends to continue visits to Iran in connection with various business opportunities.

During 2016, BP Iran Limited entered into a number of confidentiality agreements for the purpose of sharing information with potential local Iranian partners. Two of these confidentiality agreements are with exploration and production companies in which the Iranian-state holds an interest. No gross revenues or net profits were attributable to these activities. BP s intention to continue to explore commercial opportunities with one, both or neither of these E&P companies is dependent upon the specific outcome of the potential commercial opportunities with NIOC (or its subsidiaries).

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.

On 4 April 2016 the district court approved the Consent Decree among 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) which fully and finally resolves 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.

Concurrently, the definitive Settlement Agreement that BP entered into with the Gulf states (Settlement Agreement) with respect to State claims for economic, property and other losses became effective.

BP has filed the Consent Decree and the Settlement Agreement as exhibits to its *Annual Report on Form 20-F 2016* filed with the SEC. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings on page 261.

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 2016 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 2016 to 16 March 2017.

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.

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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 69-79). BP has not, therefore, adopted separate charters for each committee.

Under US securities law and the listing standards of the NYSE, BP is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. BP s audit committee complies with these requirements. The BP audit committee does not have direct responsibility for the appointment, reappointment or removal of the independent auditors instead, it follows the UK Companies Act 2006 by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE s additional requirements for the audit committee states that at least one member of the audit committee is to have accounting or related financial management expertise . The board determined that Brendan Nelson possesses 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 69). 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, group head of audit 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 2016 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 2016 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 2016 has been audited by Ernst & Young, an independent registered public accounting firm, as stated in their report appearing on page 120 of *BP Annual Report and Form 20-F 2016.*

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.

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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. The policy has been updated such that all non-audit tax services provided by the audit firm from 2017 onwards are prohibited. In 2016 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; provision of the independent third party audit in accordance with US Generally Accepted Government Auditing Standards, over the company s Conflict Minerals Report where such a report is required under the SEC rule Conflict Minerals , issued in accordance with Section 1502 of the Dodd Frank Act; 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. In response to the revised regulatory guidelines of the FRC, the audit committee reviewed and updated its policies with effect from 1 January 2017. The defined maximum level for pre-approval will be reduced in 2017 in line with Financial Reporting Council guidance on non-trivial engagements. 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 69 for details of fees for services provided by auditors.)

Directors report information

This section of *BP Annual Report and Form 20-F 2016* 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 2016. During the year, a review of the terms and scope of the policy was undertaken. The policy was renewed during 2016 and continued into 2017. 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 How we manage risk on page 47, Liquidity and capital resources on page 242 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 Using technology on page 12.

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 Sustainability Our people on page 46.

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. On

4 April 2016, the district court approved the Consent Decree, at which time the Consent Decree and Settlement Agreement became effective. 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 Consent Decree and the Settlement Agreement, see Legal proceedings on page 261.

Greenhouse gas emissions

The disclosures in relation to greenhouse gas emissions are included in Sustainability Climate change on page 43.

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	145
(2) (11)	Not applicable
(12), (13) Dividend waivers	268
(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 4-5), the Group chief executive s letter (pages 6-7), the Strategic report (inside cover and pages 2-50), Additional disclosures (pages 239-270) and Shareholder information (pages 271-279), including but not limited to statements under the headings The changing world of energy , How we run our business , Our strategy and Challenging global energy markets and including but not limited to statements regarding plans and prospects relating to future value creation, near and long-term growth, capital discipline and growth in sustainable free cash flow and shareholder distributions; future dividend and optional scrip dividend payments; expectations regarding world energy demand through 2035, including the growth in relative demand for renewables, oil and gas; expectations regarding the use of electric vehicles and the expansion of BP s global business services organization; expectations regarding future emissions and carbon policies and the share of BP s direct emissions subject to such policies; plans and expectations regarding future capital expenditure, reduction in BP s cash costs, Other businesses and corporate annual charges (excluding non-operating items), proceeds from divestments, non-operating restructuring charges, net debt levels, and the timing and amount of future payments relating to the Gulf of Mexico oil spill; statements that PSC settlement claims are expected to be substantially paid in 2017; plans and expectations regarding sales commitments of BP and its equity-accounted entities; expectations regarding underlying production and capital investment in 2017; expectations regarding oil prices and their impact on BP s return on average capital employed; expectations regarding organic capital expenditure and the cash balance point in 2017; plans regarding gearing; plans and expectations for operating cash flow excluding payments relating to the Gulf of Mexico oil spill to cover organic capital expenditure and the dividend at an oil price of around $60 per barrel by the end of 2017 and plans and expectations for driving the balance point closer to $55 per barrel by the end of 2017; expectations that the cash balance point will reduce over the next five years; expectations regarding the effective tax rate in 2017; plans and expectations regarding future levels of BP production through 2020, including increases in production from new projects; plans and expectations regarding investment, development, and production levels and the timing thereof with respect

to projects and partnerships in Abu Dhabi, Alaska, Argentina, Australia, Azerbaijan, Bolivia, Brazil, Canada, China, Egypt, Georgia, India, Indonesia, Kuwait, Mauritania, Mexico, Oman, Russia, Senegal, Trinidad & Tobago, Turkey, the UK North Sea, and the United States; plans and expectations regarding plant reliability; plans and expectations regarding the share of LNG production from the Tangguh gas facility sold to the Indonesian state electricity company, the number of jobs the facility will create and the share of the Papuan workforce at the facility; expectations regarding refining margins and refining turnarounds; plans to undertake joint exploration and research with Rosneft; plans and expectations with regard to the strategic aims of Air BP and the lubricants business; plans to retain our carbon neutral accreditation at certain Air BP-operated facilities and to reduce emissions by 5% over the next 10 years; plans and expectations regarding the upgrades at plants in Belgium and South Carolina and the resulting increase in manufacturing efficiency at those facilities; plans and expectations regarding additions to BP s fleet of oil tankers and LNG tankers; expectations regarding the actions of contractors and partners and their terms of service; BP s 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 plans to address employee engagement; plans and expectations to reduce BP s reliance on US persons at the Rhum gas field; plans regarding activities, dealings and transactions relating to Iran; plans and expectations regarding the sale of stakes in Magnus and certain associated pipelines and the Sullom Voe Terminal; plans and projections regarding oil and gas reserves, including the turnover time of proved undeveloped reserves to proved developed reserves; plans and expectations regarding the renewal of leases; expectations regarding the future value of assets; expectations regarding future regulations and policy, their impact on BP s business and plans regarding compliance with such regulations; 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 timing of such proceedings and BP s intentions in respect thereof; and (ii) certain statements in Corporate governance (pages 51-79) and the Directors remuneration report (pages 80-110) 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 the appointment of Deloitte as auditor from 2018; plans regarding the implementation of a new remuneration policy; plans and expectations with regard to the remuneration, pensions and other benefits of executive directors; and goals and areas of focus of board 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; delays in the processes for resolving claims; 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 49-50). In addition to factors set forth elsewhere in this report, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

Statements regarding competitive position

Statements referring to BP s competitive position are based on the company s belief and, in some cases, rely on a range of sources, including investment analysts reports, independent market studies and BP s internal assessments of market share based on publicly available information about the financial results and performance of market participants.

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Share prices and listings

Markets and market prices

The primary market for BP s ordinary shares is the London Stock Exchange (LSE). BP s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP s ordinary shares are also traded on the Frankfurt Stock Exchange in Germany.

Trading of BP s shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent electronically to the exchange by any firm that is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a buy and a sell order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8.00am to 4.30pm UK time but, in the event of a 20%

movement in the share price either way, the LSE may impose a temporary halt in the trading of that company s shares in the order book to allow the market to re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market maker, via a member firm, outside the electronic order book.

In the US BP s securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs, for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary s principal office is 4 New York Plaza, Floor 12, New York, NY, 10004, US. Each ADS represents six ordinary shares. ADSs are listed on the NYSE. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The following table sets forth, for the periods indicated, the highest and lowest market prices 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				
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	487.50	319.90	43.85	29.35
2016	**513.24**	**309.10**	**37.68**	**27.01**
Year ended 31 December				
2015: First quarter (January-March)	463.10	376.70	42.10	34.93
Second quarter (April-June)	487.50	420.15	43.85	39.27
Third quarter (July-September)	445.05	319.90	41.52	29.35
Fourth quarter (October-December)	411.50	328.80	37.53	29.90
2016: First quarter (January-March)	**381.80**	**309.10**	**32.38**	**27.01**
Second quarter (April-June)	**438.15**	**335.07**	**35.59**	**28.67**

Third quarter (July-September)	**464.40**	**408.63**	**37.28**	**32.50**
Fourth quarter (October-December)	**513.24**	**432.15**	**37.68**	**32.53**
2017: First quarter (to 16 March)	**521.20**	**440.80**	**38.68**	**33.10**
Month of				
September 2016	**453.25**	**411.60**	**35.39**	**33.06**
October 2016	**498.45**	**459.30**	**36.83**	**35.55**
November 2016	**483.70**	**432.15**	**35.27**	**32.53**
December 2016	**513.24**	**458.95**	**37.68**	**35.29**
January 2017	**521.20**	**472.80**	**38.68**	**35.73**
February 2017	**482.95**	**440.80**	**36.20**	**33.33**
March 2017 (to 16 March)	**474.55**	**448.00**	**34.55**	**33.10**

[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 March 2017 923,167,362 ADSs (equivalent to approximately 5,539,010,217 ordinary shares or some 28.32% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 88,594 ADS holders. Of these, about 87,560 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 1,031,491 underlying holders.

On 16 March 2017 there were approximately 248,855 ordinary shareholders. Of these shareholders, around 1,570 had registered addresses in the US and held a total of some 4,001,956 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 49 and other matters that may affect the business of the group set out in Our strategy on page 14 and in Liquidity and capital resources on page 242.

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
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
2016	**UK pence**	**42.08**	**41.50**	**45.35**	**47.59**	**176.52**
	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.

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 (1) a citizen or resident of the US, (2) a US domestic corporation, (3) an estate whose income is subject to US federal income taxation regardless of its source, or (4) 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 under the terms of the deposit agreement relating to BP ADSs 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.

From 6 April 2016 the Dividend Tax Credit was replaced by a new tax-free Dividend Allowance and dividends paid by the Company on or after 6 April 2016 do not carry a UK tax credit. A Dividend Allowance has been introduced whereby there is no UK tax due on the first £5,000 of dividends received. Dividends above this level are subject to tax at 7.5% for basic tax payers, 32.5% for higher rate tax payers and 38.1% for additional rate tax payers.

Although the first £5,000 of dividend income is not subject to UK income tax, it does not reduce the total income for tax purposes. Dividends within the Dividend Allowance still count towards basic or higher rate bands, and may therefore affect the rate of tax paid on dividends received in excess of the £5,000 allowance. For instance, if an individual has £2,000 of the basic rate band remaining after earning non-dividend income, and receives £6,000 of dividend income, they will be subject to the following scenario. The Dividend Allowance will cover the first £2,000 of dividends which fall into the remaining basic rate band, leaving the remaining £3,000 of the allowance to use in the higher rate band. The first £5,000 dividend income is therefore covered by the allowance and is not subject to tax. The remaining £1,000 of dividend income falls into the higher rate band and is taxed at the rate of 32.5%.

How the shareholder pays the tax arising on the dividend income depends on the amount of dividend income they receive in the tax year. If less than £5,000 they will not need to report anything or pay any tax. If between £5,000 and £10,000, the shareholder can pay what they owe by: contacting the helpline; asking HMRC to change their tax code the tax will be taken from their wages or pension or through completion of the Dividends section of their tax return, where one is being filed. If over £10,000 they will be required to file a self-assessment tax return and should complete the Dividends section with details of the amounts received.

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

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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 adviser 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.

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 (1) resident for tax purposes in the United Kingdom at the date of disposal, (2) if he or she 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, (3) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (4) 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

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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 advisers regarding the applicability of the Medicare tax to your income and gains in respect of your investment in the shares or ADSs.

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 Guidance and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

Register of members holding BP ordinary shares as at 31 December 2016

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	54,634	21.81	0.01
201-1,000	86,631	34.58	0.24
1,001-10,000	97,136	38.78	1.55
10,001-100,000	10,729	4.28	1.12
100,001-1,000,000	731	0.29	1.44
Over 1,000,000[a]	647	0.26	95.64
Totals	250,508	100.00	100.00

[a] Includes JPMorgan Chase Bank, N.A. holding 28.31% 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 2016[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	52,478	58.76	0.31
201-1,000	23,687	26.52	1.23
1,001-10,000	12,532	14.03	3.55
10,001-100,000	618	0.69	1.11
100,001-1,000,000	8	0.00	0.15
Over 1,000,000[b]	1	0.00	93.65
Totals	89,324	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.
[b] One holder of ADSs represents 1,006,596 underlying shareholders.
As at 31 December 2016 there were also 1,376 preference shareholders. Preference shareholders represented 0.43% and ordinary shareholders represented 99.57% 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 2016 BlackRock, Inc. held 6.39% and The Capital Group Companies, Inc held 3.22% of the voting rights of the issued share capital of the company. As at 16 March 2017 BlackRock, Inc. held 6.14% and The Capital Group Companies, Inc held 2.91% 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 March 2017:

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	5,539,010,217	28.32
BlackRock, Inc.	1,201,121,362	6.14

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 March 2017:

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

Hargreaves Lansdown Asset Management Ltd.	489,641	6.77

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
Barclays Wealth	317,546	5.80
Bank J. Safra Sarasin	294,000	5.37

In accordance with DTR 5, Smith and Williamson Holdings Limited notified the company that it disposed of its interest in 32,500 8% cumulative first preference shares and BlackRock, Inc. notified the company that its indirect interest in ordinary shares decreased below 5%, during 2014 respectively.

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.

During 2016 and 2017, BlackRock, Inc. notified the company that its indirect interest in ordinary shares moved as follows: decreased below the previously disclosed threshold of 5% on 28 April 2016; increased above 5% on 9 May 2016; decreased below 5% on 29 July 2016; increased above 5% on 8 August 2016; decreased below 5% on 4 November 2016; increased above 5% on 14 November 2016; decreased below 5% on 9 February 2017; and increased above 5% on 22 February 2017.

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As at 16 March 2017, the total preference shares in issue comprised only 0.43% of the company s total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Annual general meeting

The 2017 AGM will be held on Wednesday 17 May 2017 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 2017*.

BP intends to propose to shareholders at its 2018 AGM, that Deloitte LLP be appointed as the company s auditor for the financial year 2018.

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 279.

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 a public company limited by shares, 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.

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 above 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 2016 are set out in Financial statements Note 30. At the AGM on 14 April 2016, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $3,081 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 $462 million, without having to offer such shares to existing shareholders. These authorities were given for the period until the next AGM in 2017 or 14 July 2017, 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 14 April 2016, authorization was given to the company to repurchase up to 1.8 billion ordinary shares for the period until the

next AGM in 2017 or 14 July 2017, 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 by the company during 2016. 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 $
2016		
January 10 January 11	**1,190,000**	**5.08**
May 3	**1,650,000**	**5.65**
September 7	**1,480,908**	**5.82**
November 7 November 16	**30,412**	**5.63**
December 19	**5,280,000**	**6.09**
2017		
January 3 January 31	**Nil**	
February 7	**250,000**	**5.80**
March 1 March 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.

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 associated with administering the ADS programme.	$0.005 per BP ADS per quarter per cash distribution.

Global Invest Direct (GID) Plan	New investors and existing ADS holders can buy or sell BP ADSs by enrolling in BP s GID Plan, sponsored and administered by the Depositary.	Cost per transaction is $2.00 for recurring, $2.00 for one-time automatic investments, and $5.00 for investment made by check, plus $0.12 commission per share.

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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 2016. The Depositary reimbursed to the company, or paid amounts on the company s behalf to third parties, or waived its fees and expenses, of $15,621,791.96 for the year ended 31 December 2016.

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 2016.

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 2016 $
Fees for delivery and surrender of BP ADSs	874,061.17
Dividend fees[a]	14,747,730.79
Total	15,621,791.96

[a] 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 2016 is 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@issuerdirect.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 266) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

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 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

The BP ADS Depositary, 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	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 2009.
** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2010.
*** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2011.
**** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2012.
***** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2013.
****** 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 2015.
# 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.

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Glossary

Abbreviations

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.

$MteCO_2$

Million tonnes of CO_2 equivalent.

NGLs

Natural gas liquids.

PSA

Production-sharing agreement.

PTA

Purified terephthalic acid.

RC

Replacement cost.

SEC

The United States Securities and Exchange Commission.

Definitions

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

Adjusted effective tax rate (ETR)

Non-GAAP measure. The adjusted ETR is calculated by dividing taxation on an underlying replacement cost (RC) basis excluding the impact of reductions in the rate of the UK North Sea supplementary charge (in 2016 and 2015) by underlying RC profit or loss before tax. Taxation on an underlying RC basis is taxation on a RC basis for the period adjusted for taxation on non-operating items and fair value accounting effects. Information on underlying RC profit or loss is provided below. BP believes it is helpful to disclose the adjusted ETR because this measure 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, period on period. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period, and a reconciliation to GAAP information is provided on page 285.

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.

Capital expenditure on an accruals basis

Non-GAAP measure. It comprises additions to property, plant and equipment, intangible assets and investments in joint ventures and associates, and reflects consideration payable in business combinations. It does not include additions arising from asset exchanges and certain other non-cash items. The nearest equivalent measure on an IFRS basis for the group is Additions to non-current assets. BP believes that Capital expenditure on an accruals basis provides useful information for investors as it is the measure used by management to plan and prioritize the group s investment of its resources and allows investors to understand how the group balances funds between shareholder distributions and investment for the future. Further information and a reconciliation to GAAP information is provided on page 285.

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. A reconciliation to GAAP information is provided on page 285.

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 24 and in Downstream on page 30. 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.

Effective tax rate (ETR) on replacement cost (RC) profit or loss

Non-GAAP measure. The ETR on RC profit or loss is calculated by dividing taxation on a RC basis by RC profit or loss before tax. Information on RC profit or loss is provided below. BP believes it is helpful to disclose the ETR on RC profit or loss because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is the ETR on profit or loss for the period, and a reconciliation to GAAP information is provided on page 285.

Fair value accounting effects

Non-GAAP adjustments to IFRS profit or loss. 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 physical 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. In addition, derivative instruments are used to manage the price risk associated with certain future natural gas sales. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

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

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

The way BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management s internal measure of performance. Under management s internal measure of performance the inventory and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. The fair values of certain derivative instruments used to risk manage certain LNG and oil and gas contracts and gas sales 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.

Inorganic capital expenditure

A subset of Capital expenditure on an accruals basis and is a non-GAAP measure. Inorganic capital expenditure comprises consideration in business combinations and certain other significant investments made by the group. It is reported on an accruals basis. BP believes that this measure provides useful information as it allows investors to understand how BP s management invests funds in projects which expand the group s activities through acquisition. A reconciliation of capital expenditure on an accruals basis to GAAP information is provided on page 285. See also page 240.

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 per barrel

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 shareholders 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.

We are unable to present reconciliations of forward-looking information for net debt ratio to gross debt ratio, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable GAAP forward-looking financial measure. These items include fair value asset (liability) of hedges related to finance debt and cash and cash equivalents, that are difficult to predict in advance in order to include in a GAAP estimate.

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 28% effective tax rate and dividing the result by the group s total refining capacity. BP uses this measure to assess performance relative to peer companies.

Net generating 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 240.

Operating cash flow

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 cash flow excluding amounts related to the Gulf of Mexico oil spill

Non-GAAP measure. It is calculated by excluding post-tax operating cash flows relating to the Gulf of Mexico oil spill as reported in Financial statements Note 2 from net cash provided by operating activities as reported in the group cash flow statement. The nearest equivalent measure on an IFRS basis is net cash provided by operating activities.

Operating cash margin

Operating cash margin is operating cash flow divided by the applicable number of barrels of oil equivalent produced.

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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

A subset of Capital expenditure on an accruals basis and is a non-GAAP measure. Organic capital expenditure comprises capital expenditure on an accruals basis less inorganic capital expenditure. BP believes that this measure provides useful information as it allows investors to understand how BP s management invests funds in developing and maintaining the group s assets. An analysis of additions to non-current assets by segment, and a reconciliation of capital expenditure on an accruals basis to GAAP information is provided on page 285. See also page 240.

We are unable to present reconciliations of forward-looking information for organic capital expenditure to additions to non-current assets, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to present a meaningful comparable GAAP forward-looking financial measure. These items include changes in decommissioning assets and asset exchanges, that are difficult to predict in advance in order to include in a GAAP estimate.

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.

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.

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. For the Upstream segment, realizations include transfers between businesses.

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 a non-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. The nearest equivalent measure on an IFRS basis is profit or loss attributable to BP shareholders. See Financial statements Note 5, and a reconciliation to GAAP information is provided on page 240.

RC profit or loss per share

Non-GAAP measure. Earnings per share is defined in Financial statements Note 10. RC profit or loss per share is calculated using the same denominator. The numerator used is RC profit or loss attributable to BP shareholders rather than profit or loss attributable to BP shareholders. BP believes it is helpful to disclose the RC profit or loss per share because this measure excludes the impact of price changes on the replacement of inventories and allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to BP shareholders, and a reconciliation to GAAP information is provided on page 285.

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.

Return on average capital employed

Non-GAAP measure. Return on average capital employed (ROACE) is underlying replacement cost profit, after adding back non-controlling interest and interest expense net of notional tax at an assumed 35%, divided by average capital employed, excluding cash and cash equivalents and goodwill. BP believes it is helpful to disclose the ROACE because this measure gives an indication of the company s capital efficiency. The nearest GAAP measures of the numerator and denominator are profit or loss for the period attributable to BP shareholders and average capital employed respectively. The reconciliation of the numerator and denominator is provided on page 285.

We are unable to present forward-looking information of the nearest GAAP measures of the numerator and denominator for ROACE, because without unreasonable efforts, we are unable to forecast accurately certain adjusting items required to calculate a meaningful comparable GAAP forward-looking financial measure. These items include inventory holding gains or losses and interest net of tax, that are difficult to predict in advance in order to include in a

GAAP estimate.

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. 2017 underlying production does not include the Abu Dhabi onshore concession renewal.

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Underlying RC profit or loss

Non-GAAP measure. RC profit or loss after adjusting for non-operating items and fair value accounting effects. See pages 240 and 285 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. A reconciliation to GAAP information is provided on page 240.

Underlying RC profit or loss per share

Non-GAAP measure. Earnings per share is defined Financial statements Note 10. Underlying RC profit or loss per share is calculated using the same denominator. The numerator used is underlying RC profit or loss attributable to BP shareholders rather than profit or loss attributable to BP shareholders. BP believes it is helpful to disclose the underlying RC profit or loss per share because this measure 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, period on period. The nearest equivalent measure on an IFRS basis is basic earnings per share based on profit or loss for the period attributable to BP shareholders and a reconciliation to GAAP information is provided on page 285.

Trade marks

Trade marks of the BP group appear throughout this report.
They include:

ACTIVE	Albert Heijn to go is a registered trade mark of Albert Heijn.
Aral	Fulcrum BioEnergy is a registered trade mark of Fulcrum BioEnergy, Inc.
ARCO	M&S Simply Food is a registered trade mark of Marks & Spencer plc.
BP	REWE to go is a registered trade mark of REWE.
Castrol	RocketRoute is a registered trade mark of RocketRoute Limited.
DUALOCK	Pick n Pay is a registered trade mark of Pick n Pay Stores Limited.
EDGE	
GTX	
MAGNATEC	

PTAir

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Non-GAAP measures reconciliations

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 280.

$ million

	2016	2015	2014
Upstream			
Unrecognized (gains) losses brought forward from previous period[a]	**263**	191	160
Favourable (unfavourable) impact relative to management s measure of performance	**(637)**	105	31
Exchange translation gains (losses) on fair value accounting effects	**(19)**		
Unrecognized (gains) losses carried forward	**(393)**	296	191
Downstream[b]			
Unrecognized (gains) losses brought forward from previous period[a]	**377**	188	(679)
Favourable (unfavourable) impact relative to management s measure of performance	**(448)**	156	867
Unrecognized (gains) losses carried forward	**(71)**	344	188
Favourable (unfavourable) impact relative to management s measure of performance by region			
Upstream			
US	**(379)**	(66)	23
Non-US	**(258)**	171	8
	(637)	105	31
Downstream[b]			
US	**(321)**	102	914
Non-US	**(127)**	54	(47)
	(448)	156	867
	(1,085)	261	898
Taxation credit (charge)	**329**	(56)	(341)
	(756)	205	557

[a] 2016 brought forward fair value accounting effect balances include a $33-million adjustment between Upstream and Downstream as part of the transfer of certain emission trading balances between these segments.

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

Reconciliation of non-GAAP information

$ million

	2016	2015	2014

Upstream			
RC profit (loss) before interest and tax adjusted for fair value accounting effects	**1,211**	(1,042)	8,903
Impact of fair value accounting effects	**(637)**	105	31
RC profit (loss) before interest and tax	**574**	(937)	8,934
Downstream			
RC profit before interest and tax adjusted for fair value accounting effects	**5,610**	6,955	2,871
Impact of fair value accounting effects	**(448)**	156	867
RC profit before interest and tax	**5,162**	7,111	3,738
Total group			
Profit (loss) before interest and tax adjusted for fair value accounting effects	**655**	(8,179)	5,514
Impact of fair value accounting effects	**(1,085)**	261	898
Profit (loss) before interest and tax	**(430)**	(7,918)	6,412

Reconciliation of production and manufacturing expenses and distribution and administration expenses to cash costs

			$ million
	2016	2015	2014
Income statement data			
Production and manufacturing expenses	**29,077**	37,040	27,375
Distribution and administration expenses	**10,495**	11,553	12,266
Total costs	**39,572**	48,593	39,641
Adjusted for certain non-operating items			
Gulf of Mexico oil spill	**6,640**	11,709	781
Restructuring, integration and rationalization costs	**763**	1,088	441
Other items	**(59)**	(121)	19
	32,228	35,917	38,400
Adjusted for certain variable costs			
Transportation and shipping costs	**8,179**	8,945	8,777
Other variable costs	**3,892**	3,181	2,445
Cash costs	**20,157**	23,791	27,178

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Reconciliation of basic earnings per ordinary share to RC profit (loss) per share and to underlying RC profit per share

			Per ordinary share		cents
	2016	2015	2014	2013	2012
Profit (loss) for the year[a]	**0.61**	(35.39)	20.55	123.87	57.89
Inventory holding (gains) losses, before tax	**(8.52)**	10.31	33.78	1.53	3.12
Taxation charge (credit) on inventory holding gains and losses	**2.58**	(3.10)	(10.43)	(0.32)	(0.96)
RC profit (loss) for the year	**(5.33)**	(28.18)	43.90	125.08	60.05
Net (favourable) unfavourable impact of non-operating items and fair value accounting effects, before tax	**35.99**	82.23	44.79	(48.83)	32.11
Taxation charge (credit) on non-operating items and fair value accounting effects	**(16.87)**	(21.83)	(22.69)	(5.33)	(2.45)
Underlying RC profit for the year	**13.79**	32.22	66.00	70.92	89.71

[a] Profit attributable to BP shareholders.

Reconciliation of additions to non-current assets to capital expenditure on an accruals basis

					$ million
	2016	2015	2014	2013	2012
Additions to non-current assets[b]					
Upstream	**17,879**	17,635	22,587	19,499	22,603
Downstream	**3,109**	2,130	3,121	4,449	5,246
Rosneft				11,941	
Other businesses and corporate	**216**	315	784	1,027	1,419
	21,204	20,080	26,492	36,916	29,268
Additions to other investments	**48**	35	160	41	33
Element of business combinations not related to non-current assets	**(4)**	(31)	(366)	39	(72)
(Additions to) reductions in decommissioning asset	**656**	(553)	(2,505)	(384)	(4,025)
Asset exchanges[c]	**(2,525)**	(73)	(288)	(5)	(157)
Capital expenditure on an accruals basis	**19,379**	19,458	23,493	36,607	25,047

[b] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

[c] 2016 principally relates to the contribution of BP s Norwegian upstream business into Aker BP ASA in exchange for a 30% interest in Aker BP ASA and the dissolution of the group s German refining joint operation with Rosneft.

Reconciliation of effective tax rate (ETR) to ETR on RC profit or loss and adjusted ETR

Taxation (charge) credit

					$ million
	2016	2015	2014	2013	2012
Taxation on profit or loss for the year	**2,467**	3,171	(947)	(6,463)	(6,880)
Adjusted for taxation on inventory holding gains and losses	**(483)**	569	1,917	60	183
Taxation on a RC profit or loss basis	**2,950**	2,602	(2,864)	(6,523)	(7,063)
Adjusted for taxation on non-operating items and fair value accounting effects	**3,162**	4,000	4,171	1,009	467
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	**434**	915			
Adjusted taxation	**(646)**	(2,313)	(7,035)	(7,532)	(7,530)

Effective tax rate

					%
	2016	2015	2014	2013	2012
ETR on profit or loss for the year	**107**	33	19	21	38
Adjusted for inventory holding gains and losses	**(31)**	1	7		
ETR on RC profit or loss	**76**	34	26	21	38
Adjusted for non-operating items and fair value accounting effects	**(69)**	(15)	10	14	(8)
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	**16**	12			
Adjusted ETR	**23**	31	36	35	30

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Return on average capital employed (ROACE)

$ million

	2016	2015	2014	2013	2012
Profit (loss) for the year attributable to BP shareholders	**115**	(6,482)	3,780	23,451	11,017
Inventory holding (gains) losses, net of tax	**(1,114)**	1,320	4,293	230	411
Non-operating items and fair value accounting effects, net of tax	**3,584**	11,067	4,063	(10,253)	5,643
Underlying RC profit	**2,585**	5,905	12,136	13,428	17,071
Interest expense, net of tax[a]	**635**	576	546	549	549
Non-controlling interests	**57**	82	223	307	234
Adjusted underlying RC profit	**3,277**	6,563	12,905	14,284	17,854
Total equity	**96,843**	98,387	112,642	130,407	119,752
Gross debt	**58,300**	53,168	52,854	48,192	48,800
Capital employed (2016 average $153,349 million)	**155,143**	151,555	165,496	178,599	168,552
Less: Goodwill	**11,194**	11,627	11,868	12,181	12,190
Cash and cash equivalents	**23,484**	26,389	29,763	22,520	19,635
	120,465	113,539	123,865	143,898	136,727
Average capital employed excluding goodwill and cash and cash equivalents	**117,002**	118,702	133,882	140,313	133,457
ROACE	**2.8%**	5.5%	9.6%	10.2%	13.4%

[a] Calculated on a post-tax basis using a notional tax rate of 35%.

The Directors report on pages 51-79, 187-214 and 239-287 was approved by the board and signed on its behalf by David J Jackson, company secretary on 6 April 2017.

BP p.l.c.

Registered in England and Wales No. 102498

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Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.

(Registrant)

/s/ David J Jackson

Company secretary

6 April 2017

Cross reference to Form 20-F

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Information about this report

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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 2016. A cross reference to Form 20-F requirements is included on page 289.

This document contains the Strategic report on the inside front cover and pages 2-50 and the Directors report on pages 51-79, 187-214 and 239-287. 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 Guidance and Transparency Rules. The Directors remuneration report is on pages 80-110. The consolidated financial statements of the group are on pages 113-186 and the corresponding reports of the auditor are on pages 120-121.

Registered in England and Wales

No. 102498.

London Stock Exchange symbol BP.

BP Annual Report and Form 20-F 2016 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 2016*, forms any part of this document. 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.

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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 272 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.

* See Glossary.

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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 2016

Details of our financial and operating performance in print and online.

bp.com/annualreport

Sustainability Report 2016

Details of our sustainability performance with additional information online.

bp.com/sustainability

BP Energy Outlook 2017 edition

Provides our projections of future energy trends and factors that could affect them out to 2035.

bp.com/energyoutlook

Financial and Operating Information 2012-2016

Five-year financial and operating data in PDF and Excel format.

bp.com/financialandoperating

Statistical Review of World Energy 2017

An objective review of key global energy trends.

bp.com/statisticalreview

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