GENESCO INC
Form SC 13G/A
February 11, 2013

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

SCHEDULE 13G

Under the Securities Exchange Act of 1934

(Amendment No. 2)*

GENESCO INC

(Name of Issuer)

Common Stock

(Title of Class of Securities)

371532102

(CUSIP Number)

December 31, 2012

(Date of Event Which Requires Filing of this Statement)

Check the appropriate box to designate the rule pursuant to which this Schedule is filed:

x Rule 13d-1(b)

¨ Rule 13d-1(c)

¨ Rule 13d-1(d)

* The remainder of this cover page shall be filled out for a reporting person s initial filing on this form with respect to the subject class of securities, and for any subsequent amendment containing information which would alter the disclosures provided in a prior cover page.

The information required in the remainder of this cover page shall not be deemed to be filed for the purpose of Section 18 of the Securities Exchange Act of 1934 (Act) or otherwise subject to the liabilities of that section of the Act but shall be subject to all other provisions of the Act (however, see the Notes).

CUSIP No. 371532102

1. Names of Reporting Persons.

   I.R.S. Identification Nos. of above persons (entities only).

   Dimensional Fund Advisors LP (Tax ID: 30-0447847)

2. Check the Appropriate Box if a Member of a Group (See Instructions)

   (a) ¨

   (b) x

3. SEC Use Only

4. Citizenship or Place of Organization

   Delaware Limited Partnership

Number of Shares Beneficially Owned by Each Reporting Person With	5. Sole Voting Power	601099 **see Note 1**
	6. Shared Voting Power	0
	7. Sole Dispositive Power	614903 **see Note 1**
	8. Shared Dispositive Power	

0

9. Aggregate Amount Beneficially Owned by Each Reporting Person

614903 **see Note 1**

10. Check if the Aggregate Amount in Row (9) Excludes Certain Shares (See Instructions)

N/A

11. Percent of Class Represented by Amount in Row (9)

2.5%

12. Type of Reporting Person (See Instructions)

IA

Item 1.

(a) Name of Issuer

GENESCO INC

(b) Address of Issuer s Principal Executive Offices

1415 Murfreesboro Rd, Nashville,TN 37217-2895

Item 2.

(a) Name of Person Filing

Dimensional Fund Advisors LP

(b) Address of Principal Business Office or, if none, Residence

Palisades West, Building One, 6300 Bee Cave Road, Austin, Texas, 78746

(c) Citizenship

Delaware Limited Partnership

(d) Title of Class of Securities

Common Stock

(e) CUSIP Number

371532102

Item 3. If this statement is filed pursuant to §§240.13d-1(b) or 240.13d-2(b) or (c), check whether the person filing is a:

(a) ¨ Broker or dealer registered under section 15 of the Act (15 U.S.C. 78o).

(b) ¨ Bank as defined in section 3(a)(6) of the Act (15 U.S.C. 78c).

(c) ¨ Insurance company as defined in section 3(a)(19) of the Act (15 U.S.C. 78c).

(d) ¨ Investment company registered under section 8 of the Investment Company Act of 1940 (15 U.S.C 80a-8).

(e) x An investment adviser in accordance with §240.13d-1(b)(1)(ii)(E);

(f) ¨ An employee benefit plan or endowment fund in accordance with §240.13d-1(b)(1)(ii)(F);

(g) ¨ A parent holding company or control person in accordance with § 240.13d-1(b)(1)(ii)(G);

(h) ¨ A savings associations as defined in Section 3(b) of the Federal Deposit Insurance Act (12 U.S.C. 1813);

(i) ¨ A church plan that is excluded from the definition of an investment company under section 3(c)(14) of the Investment Company Act of 1940 (15 U.S.C. 80a-3);

(j) ¨ A non-U.S. institution in accordance with §240.13d-1(b)(1)(ii)(J).

(k) ¨ Group, in accordance with §240.13d-1(b)(1)(ii)(J).

Item 4. Ownership.

Provide the following information regarding the aggregate number and percentage of the class of securities of the issuer identified in Item 1.

(a) Amount beneficially owned:

614903 **see Note 1**

(b) Percent of class:

2.5%

(c) Number of shares as to which the person has:

(i) Sole power to vote or to direct the vote:

601099 **see Note 1**

(ii) Shared power to vote or to direct the vote:

0

(iii) Sole power to dispose or to direct the disposition of:

614903 **see Note 1**

(iv) Shared power to dispose or to direct the disposition of:

0

** Note 1 ** Dimensional Fund Advisors LP, an investment adviser registered under Section 203 of the Investment Advisors Act of 1940, furnishes investment advice to four investment companies registered under the Investment Company Act of 1940, and serves as investment manager to certain other commingled group trusts and separate accounts (such investment companies, trusts and accounts, collectively referred to as the Funds). In certain cases, subsidiaries of Dimensional Fund Advisors LP may act as an adviser or sub-adviser to certain Funds. In its role as investment advisor, sub-adviser and/or manager, neither Dimensional Fund Advisors LP or its subsidiaries (collectively, Dimensional) possess voting and/or investment power over the securities of the Issuer that are owned by the Funds, and may be deemed to be the beneficial owner of the shares of the Issuer held by the Funds. However, all securities reported in this schedule are owned by the Funds. Dimensional disclaims beneficial ownership of such securities. In addition, the filing of this Schedule 13G shall not be construed as an admission that the reporting person or any of its affiliates is the beneficial owner of any securities covered by this Schedule 13G for any other purposes than Section 13(d) of the Securities Exchange Act of 1934.

Item 5. Ownership of Five Percent or Less of a Class

If this statement is being filed to report the fact that as of the date hereof the reporting person has ceased to be the beneficial owner of more than five percent of the class of securities, check the following [X].

Item 6. Ownership of More than Five Percent on Behalf of Another Person.

The Funds described in Note 1 above have the right to receive or the power to direct the receipt of dividends from, or the proceeds from the sale of the securities held in their respective accounts. To the knowledge of Dimensional, the interest of any one such Fund does not exceed 5% of the class of securities. Dimensional Fund Advisors LP disclaims beneficial ownership of all such securities.

Item 7. Identification and Classification of the Subsidiary Which Acquired the Security Being Reported on By the Parent Holding Company or Control Person.

N/A

Item 8. Identification and Classification of Members of the Group

N/A

Item 9. Notice of Dissolution of Group

N/A

Item 10. Certification

By signing below I certify that, to the best of my knowledge and belief, the securities referred to above were acquired and are held in the ordinary course of business and were not acquired and are not held for the purpose of or with the effect of changing or influencing the control of the issuer of the securities and were not acquired and are not held in connection with or as a participant in any transaction having that purpose or effect, other than activities solely in connection with a nomination under §240.14a-11.

SIGNATURE

After reasonable inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

DIMENSIONAL FUND ADVISORS LP

February 8, 2013

Date

By: Dimensional Holdings Inc., General Partner

/s/ Christopher Crossan

Signature

Global Chief Compliance Officer

Title

to those who work for BP to ewing financial statements and other andfinancialother disclosures and financialewing statements ewing the effectiveness of the group audit function, BP's igation of financial risks is appropriately addressed by the group group the by addressed appropriately is risks financial of igation raise concerns about possible improprieties in financial reporting or financial in improprieties possible about concerns raise other issues and for those matters be to investigated. Monitoring and obtaining assurance that the management or the obtaining assurance that and Monitoring mit 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 principles. governance Revi requirements. listing and legal relevant with compliance monitoring Revi Overs performance of the external auditor and the integrity of the audit process as a whole, including the engagement of the external auditor supplyto non-audit services BP. to Revi internal financial controls and systems of internal control and risk management. Members NelsonBrendan Nils Andersen Alison Carnwath Pamela Daley Reynolds Paula Meetings and attendance and Meetings There were nine committee meetings in 2018, of which three were by teleconference. All directors attended every meeting during the period in which they were committee members, except for Nils Andersen, Alison Carnwath and Paula Reynolds who all missed a meeting each due pre-existing to external commitments. Regular attendees at the meetings include the chief financial officer,group controller, chief accounting officer, group head of audit, group general counsel and auditor. external Role of the committee The committee monitors the effectiveness of the financial group's reporting, systems of internal control and risk managementand the processes. audit internal and external group's the of integrity Key responsibilities • • • • • 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 Financialthe Reporting Panel. The Review board satisfied is is he that financial relevant committee audit and the member with recent experience as outlined in the UK Corporate Governance Code and competence in accounting and auditing as required by the FCA's Corporate Governance Rules It considers in DTR7. that thecommittee as a whole has an appropriate and experienced blend of commercial, financial and auditexpertise to assess the issues it requiredis to address, as well as competence in the oil and gas The sector. board also determined that the audit committee meets the independence criteria provisions of Rule 10A-3 of the US Securities Exchange Act of 1934 and that Brendan may be regarded as an audit committee financialexpert as defined16A in Item of Form 20-F. Brendan Nelson is chair of the audit committee. He was formerly BP Annual Report and Form 20-F 2018 Audit committee The committee continued theto monitor system ofgroup's internal control, risk management functions and work of key as as well reviewing as and challenging appropriate the disclosures and key judgements made by management. BP’s financialreporting is balanced‘fair, and understandable’. In the 2018 committee focused on the effectiveness of a number of procurement, trading, and supply integrated including functions group tax, information technology and security, and shipping. We also received presentations regarding, and reviewed performance the Upstream of, segment and the lubricants business. These reviews were valuable in not only informing the committee of the work and future plans of those functions and businesses but also examining the risks key (and associated mitigations) faced by each of them. In addition, the committee carried out reviews the into group risks of financial liquidity, regulations. business with cyber compliance security and The transition Deloitte to from EY was completed in 2018. We met with both EY and Deloitte during as 2018 the transition occurred and oversaw and monitored Deloitte’s work as they settled their into role. We meet lead partner. regularly audit with the Nils Andersen retired from the committee in September as 2018 he joined the SEEAC. I would thank to like Nils for his service the to committee, and for the challenge and perspective he provided as a member. We were very pleased welcome to Dame Alison Carnwath Chairman’s introductionChairman’s As in previous years, the committee has continued review to the integrity of the financial group’s reporting by challenging and debating the judgements made by management, including the estimates which are made.We receive reports from management and the external and issues accounting significant highlighting quarter each auditor judgements and have used these informto our debate on whether to theto committee in May with 2018 Pamela Daley also joining in October 2018. Each of them bring excellent financial and otherrelevant skillsto committee.the Nelson Brendan Committee chair Committee reports

Activities during the year Financial disclosure and compliance functions, Financial liquidity: including the development of the anti-bribery risk associated with external The committee reviewed the considered whether the period and corruption elements of market conditions, supply and quarterly, half-year and annual covered by the company's viability the programme, enhanced demand and prices achieved for financial statements with statement was appropriate. policies, tools and training and BP's products which could impact management, focusing on the: The committee considered the strengthening of counter-party risk financial performance. measures, including due diligence. • Integrity of the group's BP Annual Report and Form 20-F The committee reviewed the key The committee also reviewed key financial reporting process. 2017 and assessed whether the price assumptions used by the areas of BP's legal function that • Clarity of disclosure. report was fair, balanced and group for investment appraisal and advise on compliance matters. • Compliance with relevant legal understandable and provided the judgements underlying those and financial reporting standards. the information necessary for Cyber security risk: including proposals, the cost of capital and its • Application of accounting shareholders to assess the inappropriate access to or misuse application as a discount rate to policies and judgements. group's position and performance, of information and systems and evaluate long-term BP business business model and strategy. In As part of its review, the disruption of business activity. projects, liquidity (including credit making this assessment, the committee received quarterly rating, hedging, long-term committee examined disclosures The committee reviewed ongoing updates from management and commercial commitments and during the year, discussed the developments in the cyber the external auditor in relation to credit risk) and the effectiveness requirement with senior security landscape, including accounting judgements and and efficiency of the capital management, confirmed that events in the oil and gas industry estimates including those relating investment into major projects . representations to the external and within BP itself. The review to the Gulf of Mexico oil spill, These assumptions also impacted auditors had been evidenced and focused on the improvements recoverability of asset carrying financial reporting (see page 79). reviewed reports relating to made in managing cyber risk, values and other matters. internal control over financial including the application of the BP's principal risks are listed on The committee keeps under reporting. The committee made three lines of defence model and page 55. examining the indicators review the frequency of results a recommendation to the board, For 2019, the board has agreed associated with risk management reporting during the year. who in turn reviewed the report that the committee will continue and barrier performance. The committee reviewed the as a whole, confirmed the to monitor the same four group assessment and reporting of assessment and approved the risks as for 2018. longer-term viability, risk report's publication. management and the system of Other disclosures reviewed internal control, including the included: Other reviews reporting and categorization of risk • Oil and gas reserves. across the group and the Other reviews undertaken in 2018 performance, risk management • Pensions and post-retirement examination of what might by the committee included: and controls, audit findings, key benefits assumptions. litigation and ethics and constitute a significant failing or • Lubricants: including strategy • Risk factors. compliance findings. weakness in the system of and strategic progress, financial • Legal liabilities. internal control. It also examined performance, risk management • Capability and succession in • Tax strategy. the group's modelling for stress and controls, audit findings, key BP's finance function, including • Going concern. testing different financial and litigation and ethics and the group's finance • IFRS 16 (lease accounting). operational events, and compliance findings. modernization programme. • Upstream: including vision and • Assessment of financial metrics Risk reviews priorities, structure and for executive remuneration: portfolio, financial controls and consideration of financial The principal risks allocated to the integrated supply and trading the balance sheet, an overview performance for the group's audit committee for monitoring in function's risk management of tangible and intangible assets 2018 annual cash bonus 2018 included those associated programme, including and a review of the segment's scorecard and performance with: compliance with regulatory finance organization. share plan, including developments and activities in adjustments to plan conditions Trading activities: including risks • Shipping: including an overview response to cyber threats. and NOIs. arising from shortcomings or failures of BP shipping's role and in systems, risk management Compliance with applicable operating model, financial • Auditor transition: regular methodology, internal control laws and regulations: including performance, strategy, risk reports from the external processes or employees. ethical misconduct or breaches of management and controls and auditor regarding its transition applicable laws or regulations that the impact of IFRS 16 (lease into the role including detailed In reviewing this risk, the could damage BP's reputation, accounting standard). updates on issues identified by committee focused on external adversely affect operational results the external auditor. market developments and how • Tax: including strategy and and/or shareholder value and BP's trading function had strategic progress, key • Internal controls: assessments potentially affect BP's licence responded – including new areas drivers of the group's effective of management's plans to to operate. of activity, such as emissions tax rate, the global indirect tax remediate the external auditors trading and impacts on the The committee reviewed the environment and the tax findings in relation to IT access control environment. group's ethics and compliance modernization programme. risks. programme, including the work of The committee further • Procurement: including strategy the business integrity and ethics considered updates in the and strategic progress, financial 76 See Glossary BP Annual Report and Form 20-F 2018

Corporate governance 77 usions/outcomes ecember 2018. ignificant number of BEL claim aining uncertainties.aining e recognized during the year. f of Mexico licences and believes it is -tax charge billion of $1.2 in relation the to Concl settlements the in the degree year, of judgement necessary determine to the year-end provision had reduced significantly. the capitalize to continue to appropriate costs. The group income statement includes a pre GulfMexico of oil spill. on information includes Disclosure rem The audit committee noted that following the s billion Exploration write-offs $1.1 totalling wer BP remains committed developing to the Gul billion $16.0 totalled Exploration intangibles at D 31 BP Annual Report and Form 20-F 2018 Training The committee held a review on reserves and pensions. It received technical updates from the chief accounting officer on developments in financialreporting and accounting policy, in particularregarding the introduction of IFRS ‘Leases’ 16 accounting from the start 2019. of visit trading and supply Integrated In October, the committee held its meeting at BP’s integrated supply and trading (IST) business in London and conducted its annual tour of the business which covered oil and gas market fundamentals, finance and risk, IST’s strategy, and presentations on oil products LNGand trading. ommittee activityommittee eam intangibleeam including the assets, ision related business to economic loss losure of uncertainties the of losure to relating ual intangible asset certification process group’s quarterly due diligence process. diligence due quarterly group’s delines for compliance with oil and gas Audit c Audit Received the output of management’s ann (BEL) and other claims related the to Gulf of continuing the including spill, oil Mexico effect of the Fifth Circuit opinion May 2017 on the matching of revenues with expenses claims. BEL when evaluating Held an in-depth review of BP’s policy and gui reserves regulation, disclosure including the reservesgroup’s governance framework controls. and Reviewed exploration write-offs as part of the Received briefings on the status of upstr used ensure to accounting criteria to intangible carry exploration to the continue balance are met. A review of the provisioning for and disc Particular focus was given updates to the to prov status of items on the intangibles assets ‘watch-list’, including certain Gulf of Mexico licences which expired and in 2013 2014. GulfMexico of oil spill was undertaken each quarter as part of the review of the stock announcement. exchange The the committee reviewed effectiveness internal of audit. The audit committee held also private meetings with the group ethics and compliance officer year. the during rnal control rnal risk and management Inte Oil and natural gas accounting, including reserves BP uses technical and commercial judgements exploration, gas and oil for accounting when in and expenditure appraisal development and determining the estimated group’s oil and gas reserves. management’s based on Reserves estimates commodity have prices future for assumptions a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements. Judgement is required determine to whether it is appropriate continue to carry to intangible assets related exploration to costs on the sheet. balance Gulf of Mexico oil spill BP uses judgement in relation the to recognition of provisions relating the to Gulf of Mexico oil spill. The timing and amounts of the remaining cash flows subjectare to uncertainty and estimation is required to determine the amounts provided for. Key judgements and estimates Key in financialreporting The committee received quarterly reports on the findings of group audit in 2018. The committee met privately with the group head audit of and key members his of leadership team. Accounting judgements and estimates Areas of significant judgement considered by the committee in and 2018 how these were addressed included:

Key judgements and estimates Audit committee activity Conclusions/outcomes in financial reporting Recoverability of asset carrying values Determination as to whether and how much Reviewed the group's oil and gas price The group's long-term price assumptions for an asset, cash generating unit (CGU) or group assumptions. Brent oil, and Henry Hub gas were of CGUs containing goodwill is impaired unchanged from 2017. Reviewed the group's discount rates for involves management judgement and impairment testing purposes. The group's discount rates used for estimates on uncertain matters such as future impairment testing were also unchanged. commodity pricing, discount rates, production Upstream impairment charges, reversals profiles, reserves and the impact of inflation on and 'watch-list' items were reviewed as Impairments of $0.1 billion were recorded in operating expenses. part of the quarterly due diligence process. the year, net of impairment reversals. Investment in Rosneft Judgement is required in assessing the level of Reviewed the judgement on whether the BP has retained significant influence over control or influence over another entity in group continues to have significant Rosneft throughout 2018 as defined by which the group holds an interest. influence over Rosneft. IFRS. BP uses the equity method of accounting for Considered IFRS guidance on evidence its investment in Rosneft and BP's share of participation in policy-making processes. Rosneft's oil and natural gas reserves is Received reports from management which included in the group's estimated net proved assessed the extent of significant influence, reserves of equity-accounted entities. including BP's participation in decision The equity-accounting treatment of BP's making. 19.75% interest in Rosneft continues to be dependent on the judgement that BP has significant influence over Rosneft. Derivative financial instruments For its level 3 derivative financial instruments, Received a briefing on the group's trading BP has assets and liabilities of $3.6 billion and BP estimates their fair value using internal risks and reviewed the system of risk $3.1 billion respectively recognized on the models due to the absence of quoted market management and controls in place, balance sheet for level 3 derivative financial pricing or other observable, market- including those covering the valuation of instruments at 31 December 2018, mainly corroborated data. level 3 derivative financial instruments, relating to the activities of the integrated Judgement may also be required to determine using models where observable market supply and trading function (IST). pricing is not available. whether contracts to buy or sell commodities BP's use of internal models to value certain meet the definition of a derivative. The committee annually reviews the control of these contracts has been disclosed in process and risks relating to the trading Note 30 in the financial statements. business. 78 See Glossary BP Annual Report and Form 20-F 2018

Corporate governance 79 usions/outcomes ptions remained largely unchanged remained ptions from eficits of $8.4 billion wererecognized on alance sheet obligation at the end of losed. e recognized on the balance sheet at Concl 2018 was2018 a nominal rate – based of 3% on long-dated bonds. government US The method for determining the group's assum The values these of 2017. assumptions and a sensitivity analysis of the impact of possible changes on the benefitexpense and obligation are provided in Note 24. December At31 2018, surpluses of $6.0 billion and d Decommissioning provisions of $13.6 billion wer The discount rate used by BP determine to the b The impact of this revised rate has been disc the balance sheet in relation pensions to and benefits. post-retirement other 31 December31 2018. BP Annual Report and Form 20-F 2018 The committee received updates during the year on the audit process, on assumptions group's the challenged had auditor the how including issues.these Audit fees The audit committee reviews the fee structure, resourcing and terms of engagement for the external auditor annually; in addition it reviews the non-audit services that the auditor provides the to group on a quarterly basis. Fees paid the to external auditor for the year were $42 million $47 (2017 million), of which was for 5% non-audit assurance work (see Financial statements – Note 36). 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 $3 (2017 million). Non-audit or non-audit related services consisted of other assurance services. ommittee activityommittee ulating provisions, including the change the including provisions, ulating ironmental, asbestos and litigation and asbestos ironmental, ermine the projected benefitermine the obligation Audit c Audit Reviewed the assumptions group's used to det at the year end, including the discount rate, rate of inflation, salary growth and mortality levels. Received briefings on decommissioning, decommissioning, on briefings Received env Reviewedthe discount group's rates for calc useto the nominal discount rate (i.e. taking account of expected inflation) from the second quarter of 2018. provisions, including requirements, the governance and controls for the development and approval of cost estimates and provisions in the financial statements. ts ts fi rrying value of certain exploration and appraisal assets where gement override of controls. sk of impairment in certain cash-generating units which are 3 of derivative financial instruments valuations within the financial derivative valuations within instruments of 3 unting for structured commodity transactions in the integrated ounting for pensions and other post- particularly sensitive changes to in the assumptions, key in particular assumptions. price gas long-term and the oil there could be potential indicators of impairment through licence expiry and/or partner withdrawal. Acco function. trading and supply Level integrated supply and trading function which involve using bespoke modelsvaluation and/or unobservable inputs. Mana The ri The ca retirement benefits involves making estimates estimates making benefitsinvolves retirement pension plan group's the measuring when deficits. and surpluses estimates These require assumptions be to made about rates, discount including uncertain events, inflation andexpectancy. life Pensions and other post-retirement bene post-retirement other and Pensions Acc Key judgements and estimates Key in financialreporting Provisions BP's most significant provisionsrelate to remediation environmental decommissioning, litigation.and The group holds provisions for the future decommissioning oil of and natural gas production facilities and pipelines at the end of their economic lives. Most of these decommissioning events are many years in the future and the exact requirements that will have be to met when a removal event occurs are uncertain. Assumptions are made by BP in relation settlement to dates, technology, legal requirements and discount rates. The timing and amounts of future cash flows subjectare significantto uncertainty and estimation is required in determining the amounts of provisions be to recognized. Following a regular review of 30 from estimates, cost decommissioning June the 2018 present value of the decommissioning provision was determined by discounting the estimated cash flows expressed in expected future prices, i.e. taking accountexpected of inflation. Priorto 30 June 2018, the group estimated future cash flows in terms. real • • • • External audit Audit risk The external auditor set out its audit strategy for 2018, identifying significant audit risksto be addressed during the course of the audit. These included: •

Audit effectiveness Auditor appointment and independence The effectiveness, performance and integrity of the external audit The committee considers the reappointment of the external auditor process was evaluated through separate surveys completed by each year before making a recommendation to the board. The committee members and those BP personnel impacted by the audit, committee assesses the independence of the external auditor on an including chief financial officers, controllers, finance managers and ongoing basis and the external auditor is required to rotate the lead audit individuals responsible for accounting policy and internal controls over partner every five years and other senior audit staff every seven years. financial reporting. No partners or senior staff associated with the BP audit may transfer to the group. The survey sent to management comprised questions across five main criteria to measure the auditor's performance: Non-audit services The audit committee is responsible for BP's policy on non-audit • Robustness of the audit process. services and the approval of non-audit services. Audit objectivity and • Independence and objectivity. independence is safeguarded through the prohibition of non-audit tax • Quality of delivery. services and the limitation of audit-related work which falls within defined categories. BP's policy on non-audit services states that the • Quality of people and service. auditor may not perform non-audit services that are prohibited by the • Value added advice. SEC, Public Company Accounting Oversight Board (PCAOB), UK Auditing Practices Board (APB) and the UK Financial Reporting The 2018 evaluation was the last of EY as the outgoing auditor. It also Council (FRC). included certain questions about the effectiveness of the transition to the incoming auditor, Deloitte. The results of the survey indicated that The audit committee approves the terms of all audit services as well as the external auditor's performance had remained largely consistent in permitted audit-related and non-audit services in advance. The external key areas compared with the previous year. Areas with high scores and auditor is considered for permitted non-audit services only when its favourable comments included quality of accounting and auditing expertise and experience of the company is important. judgement and the working relationship with management. Areas for Approvals for individual engagements of pre-approved permitted improvement were identified but none impacted on the effectiveness services below certain thresholds are delegated to the group controller of the audit. The results of the questions regarding auditor transition or the chief financial officer. Any proposed service not included in the indicated that management were confident that Deloitte would be permitted services categories must be approved in advance either by effective in their role. The results of the survey were discussed with the audit committee chairman or the audit committee before Deloitte for consideration in their 2018 audit approach. engagement commences. The audit committee, chief financial officer The committee held private meetings with the external auditor during and group controller monitor overall compliance with BP's policy on the year and the committee chair met separately with the external audit-related and non-audit services, including whether the necessary auditor and group head of audit at least quarterly. pre-approvals have been obtained. The categories of permitted and pre-approved services are outlined in Principal accountant's fees and The effectiveness of the external auditor is evaluated by the audit services on page 301. The committee's policies were updated in 2018 committee. The committee assessed the new auditor's approach to to clarify the engagement of the incoming auditor, Deloitte, and the providing audit services as the team undertook its first audit. On the outgoing auditor (and auditor of Rosneft) EY. basis of such assessment, the committee concluded that the audit team was providing the required quality in relation to the provision of the services. The audit team had shown the necessary commitment and Committee evaluation ability to provide the services together with a demonstrable depth of The audit committee undertakes an annual evaluation of its performance knowledge, robustness, independence and objectivity as well as an and effectiveness. appreciation of complex issues. The team had posed constructive 2018 evaluation challenge to management where appropriate. For 2018, an external assessment was used to evaluate the work of the Audit transition committee as part of a wider review of the operation of the board as a Deloitte was appointed for the statutory audit, with effect from 2018 whole. The review concluded that it had performed effectively. following a tender process in 2016. The committee monitored the Areas of focus for 2019 include succession planning for membership of transition of BP's statutory auditor from EY to Deloitte. This included: the committee, a site visit to global business services Kuala Lumpur and • Receiving reports from the audit transition team, including an integrated supply and trading Singapore and a further review of capital overview of operational activities and the termination of non-audit spending. services being provided by Deloitte to BP – which would be prohibited when Deloitte became the group's statutory auditor. This included Deloitte stepping down as independent adviser to BP's remuneration committee. • Requiring management to report to the committee on any services undertaken by the statutory auditor in line with the group's policies relating to non-audit services. • Requiring confirmation of Deloitte's compliance with BP's independence and ethics and compliance rules. Deloitte confirmed its independence to the committee in October 2017. EY resigned on 29 March 2018 following completion of the 2017 audit. The committee also received reports from the external auditor's transition team in April, May and July 2018 and an update to their plan in December 2018. 80 BP Annual Report and Form 20-F 2018

Corporate governance 81 Member since September and 2014 chair since May 2016 Member since December 2018 Member since February 2010; resigned May 2018 Member since November 2010 Member since February 2012 Member since May 2017 Member since July 2015 Members Alan Boeckmann Nils Andersen AndersonPaul Frank Bowman Ann Dowling Meyer Melody John Sawers Role of the committee The role of the SEEAC is look to at the processes adopted by BP's executive management identify to and mitigate significant non-financial process and personal of management the monitoring includes This risk. safety and receiving assurance that processes identify to and mitigate in effective and design their in appropriate are non-financial such risks implementation. their Meetings and attendance and Meetings There were six committee meetings in 2018. All directors attended every meeting for which they were eligible, apart from Alan Boeckmann who missed two meetings due unforeseen to personal circumstances. In addition the to 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 has access the to chair and secretary the to committee as required. The group general counsel and group ethics and compliance officer also attended some of the meetings. At the conclusion of each meeting the committee members the for sessions committee scheduled private withoutonly, the presence of executive management, discuss to any issues arising and the quality of the meeting. The group chief executive receives invitations join to the private meetings on an ad hoc basis and at least once a year the head of group audit and at least twice a year the group ethics and compliance officer are invitedto a private meeting with the committee. Key responsibilities segments business the reportsfrom specific receives committee The as well as cross-business information from the functions. These include, but are not limited the to, safety and operational risk function, group group and integrity business compliance, and ethics group audit, security. The SEEAC can access any other independent adviceand counsel it requires on an unrestricted basis. The SEEAC and audit committee worked together, through their chairs and secretaries, ensure to that agendas did not overlap or omit coverage risksof any key during the year. BP Annual Report and Form 20-F 2018 ronment envi . BP Sustainability Report 2017 assurance committee (SEEAC) At everyAt site visit, we engage with the local leadership who help to embed a culture focused on operational risk mitigation. Safety, ethicsSafety, and The committee made two site visits in the year (see page 73). In July members of the committee visited the Thunder Horse platform in the Gulf of Mexico, and in September members visited Cooper River petrochemicals plant in South Carolina. The level of access the into operations on such visits gives the directors first hand and direct insight. This framework provides an opportunity for meaningful and open dialogue with the local site teams, allowing the committee to better fulfil its obligations. In May 2018, Paul Anderson retired from the board and the committee. In preparation for stepping my down from the BP board at the annual general meeting in May 2019, Nils Andersen, who was appointed the to committee in December 2018, will assume the role of the chair of SEEAC from April 2019. BoeckmannAlan Committee chair Act (MSA) statement in 2018, the committee again reviewed related work practices in BP and will continue review to progress in developing and embedding those practices. In it 2018 also reviewed the The committee's focus continued be to on working with executive management drive to safe, ethical and reliable operations. It continued provide to constructive challenge as part of its review of the executives' management of the highest priority non-financial group risks assigned SEEAC. to The risks under our remit remained the marine, same as for 2017: wells, pipelines, explosion or release at facilities, major security incidents and cyber security in the process control network. The committee receives reports on each of these risks and monitors their management and mitigation. Modern second Slavery company's the of publication Following Chairman's introductionChairman's

Activities during the year Committee evaluation In 2018, the committee examined its performance and effectiveness System of internal control and risk management through an externally facilitated evaluation which included individual interviews. Discussion focused on the responsibilities of the committee, The review of operational risk and compliance officer and the group the balance of skills and experience among its members, the quality and performance forms a large part of auditor met in private with the timeliness of information the committee receives, the level of challenge the committee's agenda. chairman and other members of between committee members and management and how well the the committee over the course of Group audit provided quarterly committee communicates its activities and findings to the board to both the year. During the year the reports on their assurance work inform and drive discussion. committee received separate and their annual review of the reports on the company's The evaluation results continued to be positive. Committee members system of internal control and risk management of risks relating to: considered that they continued to possess the right mix of skills and management. background, had an appropriate level of support and received open and • Marine. The committee also received transparent briefings from management. The committee agreed to • Wells. regular reports from the group review its remit in 2019. • Pipelines. chief executive and vice president • Explosion or release Site visits remained an important element of the committee's work, for S&OR on operational risk, at our facilities. acknowledged through the responses in the evaluation process. These including regular reports prepared • Major security incidents. gave members the opportunity to examine and witness risk on the group's health, safety and • Cyber security (process management processes embedded in businesses and facilities, environmental performance and control networks). including the right management culture. Joint meetings between the operational integrity. These SEEAC and the audit committee were considered important in included meeting-by-meeting The committee reviewed these reviewing and gaining assurance around financial and operational risks measures of personal and process risks and their management and where there was overlap between the committees, particularly in safety, environmental and mitigation in depth with relevant relation to ethics and compliance (see below). regulatory compliance, security executive management. and cyber risk analysis, as well as quarterly reports from group audit. In addition, the group ethics and Site visits In July members of the visited the petrochemicals plant, committee, and other directors, Cooper River, in South Carolina. visited the Houston office and During the visit, directors were went offshore to Thunder Horse able to discuss business in the Gulf of Mexico. The continuity planning and Houston visit included time with emergency response which had various teams understanding the been in effect just prior to the effects of Hurricane Harvey, how visit as a result of Hurricane central office-based functions Florence. For all visits, committee support the offshore community members and other directors and other group monitoring received briefings on operations, teams. In preparation for the the status of conformance with offshore visit to Thunder Horse BP's operating management the directors met with the Gulf of system, key business and Mexico leadership. Offshore, operational risks and risk there was a full tour of the asset management and mitigation. Joint meetings of the audit and safety, ethics and including control room, topsides Committee members reported environment assurance committees and drilling rig and plenty of back in detail about each visit to The audit committee and SEEAC hold joint meetings on a quarterly opportunity was provided to the committee and subsequently basis to simplify reporting of key issues that are within the remit converse with employees on the to the board. See page 73 for of both committees and to make more effective use of the rig. In September, committee further details. committees' time. Each committee retains full discretion to require members, and other directors, a full presentation and discussion on any joint meeting topic at their respective meeting if deemed appropriate. The committees jointly met four times in 2018, with the chairmanship of the meetings Corporate reporting alternating between the chairman of the audit committee and chairman of the SEEAC. Topics discussed at the joint meetings The committee was responsible worked with the external auditor were the quarterly ethics and compliance reports (including for the overview of the BP with respect to their assurance significant investigations and allegations) and the 2019 forward Sustainability Report 2017. The of the report. programmes for the group audit and ethics and compliance committee reviewed content and functions. 82 BP Annual Report and Form 20-F 2018

Corporate governance 83 Member since September and chair 2017 since May 2018 Member since May 2015 Member since January 2019 Member since July 2010 Member since July and chair 2012 since May resigned2015; May 2018 Member since May 2017 mine the terms of engagement, benefits of remuneration, and terms the mine tor the alignment of incentives and remuneration for all ive, and take account into as appropriate, regular updates on ge independent consultants or other advisers as the committee tain appropriate dialogue with shareholders on remuneration remuneration on shareholders with dialogue appropriate tain re terminationre terms and payments executive to directors and insightre from data sources on pay ratio, gender pay gap and hairman and the executive directorswhile considering policies ove theove principles of any equity plan that requires shareholder changesove the to design of remuneration for BP group leaders, are the annual remuneration report shareholders to show to how ew the relevant remuneration principles policies and remuneration for relevant the ew for employees below the board. the below employees for Ensu Appr Rece Ensu Main matters. Moni employees below the executive team with the expected values and behaviours. Enga may from time time to deem necessary, at the expense of the company. Recommend the to board the remuneration principlesand policy for the c Deter termination of employment for the chairman and the executive directors, executive team and the company secretary in accordance with the policy. Revi team. executive the below employees Prep the policy has been implemented. Appr approval. the executive team are fair. as proposed by the group chief executive. workforce views and engagement initiatives related remuneration. to considered as are outcomes workforce remuneration other appropriate. Members Reynolds Paula Alan Boeckmann Pamela Daley Ian Davis Ann Dowling NelsonBrendan • • • Role of the committee The role of the committee is determine to and recommend the to board the remuneration policy for the chairman and executive directors. In determining the policy, the committee takes account into various factors, including structuring the policy promote to the long-term success of thecompany and linkingreward business to performance. The committee recognizes the remuneration principles applicable all to level. board below employees Key responsibilities • • • • • • • • • BP Annual Report and Form 20-F 2018 Remuneration committee As the new committee I took chair, the opportunity in the autumn to engage with some of our institutional shareholders. In a changing governance landscape, it has been important ensure to our stakeholders continue be to heard. We have reviewed the responsibilities of the committee and have extended the scope include to oversight of remuneration below board level. We have continued operate to under the policy approved by shareholders Our focus will for 2019 of course in 2017. be the preparation new of a Policy for approval by shareholders at the 2020 AGM. Pamela Daley has joined the remuneration committee from 1 January 2019. We welcome Pamela the to committee and look contribution. valuable her to forward PricewaterhouseCoopers independent LLP our as continued has adviser following their PwC appointment has in other 2017. engagements with the company provide to certain services none of which are deemed material in this context. Paula Rosput Reynolds Chair’s introduction Committee chair

Meetings and attendance The chairman and the group chief executive attend meetings of the committee except for matters relating to their own remuneration. The group chief executive is consulted on the remuneration of the chief financial officer, the executive team and more broadly on remuneration across the wider employee population. Both the group chief executive and chief financial officer are consulted on matters relating to the group's performance. The group human resources director 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. The committee met seven times during the year. All directors attended each meeting that they were eligible to attend, either in person or by telephone, except Alan Boeckmann who was not able to attend two Geopolitical committee meetings due to unforeseen personal circumstances. Activities during the year Chairman's introduction In the period before the 2018 AGM, the committee focused on the outcomes for 2017. This involved reviewing directors' salaries and the I am pleased to report on the work of the geopolitical committee in group's performance outcome which in turn determined the annual 2018, which continued to develop and evolve during the year. During bonus and the performance share plan. 2018 I also joined discussions of the international advisory board. PwC has continued as independent adviser during 2018. The committee Paul Anderson stood down in May 2018. I want to thank Paul for his continued to monitor developments in potential regulation and legislation valuable contribution. We welcomed Nils Andersen to the committee and resulting implications. It also considered the company's disclosure in August 2018 and his experience is invaluable given he was CEO of on the UK gender pay gap. major companies, such as Carlsberg and Mærsk, which had operations in many jurisdictions with significant political risk In each of its meetings, the committee focused on the overall quantum considerations. Other board members joined our meetings from time of executive director remuneration and its alignment to the broader to time. group of employees in BP. It has sought to reflect the views of shareholders and the broader societal context in its decisions. Sir John Sawers Committee chair Shareholder engagement There was engagement with shareholders and proxy voting agencies ahead of the 2018 AGM, carried out by the chair of the committee, the Role of the committee chairman and company secretary as required. The new committee chair The committee monitors the company's identification and management continued engagement throughout the year, primarily with larger of geopolitical risk. shareholders and representative bodies, in light of evolving regulation and related remuneration issues. Key responsibilities Committee evaluation • Monitor the company's identification and management of major and correlated geopolitical risk and consider reputational as well as An externally facilitated evaluation was undertaken to examine the financial consequences: committee's performance in 2018. The evaluation concluded that the committee had worked well and had responded to the previous – Major geopolitical risks are those brought about by social, evaluation by increasing its remit to take on oversight of economic or political events that occur in countries where BP has remuneration below board level. material investments. Focus areas for 2019 include responding to regulation and – Correlated geopolitical risks are those brought about by social, governance reform and planning for the new remuneration policy economic or political events that occur in countries where BP may to be brought to shareholders for approval in 2020. The commitment or may not have a presence but that can lead to global political to stay focused on external developments and emerging 'best instability. practice' and improving remuneration reporting remained. See • Review BP's activities in the context of political and economic page 87 for the Directors' remuneration report. developments on a regional basis and advise the board on these elements in its consideration of BP's strategy and the annual plan. 84 BP Annual Report and Form 20-F 2018

Corporate governance 85 rmine any other matter that is appropriate be to considered by e on any matter referred it to by the chairman of any committees utive. ew theew structure and effectiveness of the business organization. theew systems for senior executive development and determine Chairman's and nominationChairman's and governance committees Evaluate the performance and the effectiveness of the group chief exec Revi Revi succession plans for the group chief executive, executive directors and other senior members of executive management. Dete non-executive directors. Opin non-executive directors. of solely comprised • Members the join Directors non-executive directors. all comprises The committee committee immediately on their appointment the to board. The group chief executive attends meetings of the committee when requested. BP Annual Report and Form 20-F 2018 Chairman's committeeChairman's Role of the committee provide a forumTo for matters be to discussed by the non-executive directors. Key responsibilities • • • • Chairman's introductionChairman's The chairman's and the nomination and governance committees were actively involved in the evolution of the board in 2018. In October, Carl-Henric Svanberg stood down as chairman of both committees and I pay tribute his to exceptional service since 2010. The board expanded the nomination committee's remit in September help to 2018 fulfilrequirements provided in the new UK Corporate Governance Code and it was re-named the nomination and governance committee. It also continues focus to on board renewal and diversity as well as the talent in the senior levels of executive management and development of future leaders. Lund Helge Chair of the committees Member since September and 2015 chair since April 2016 Member since August2018 Member since September resigned 2015; May 2018 Member since September 2015 Member since September 2016 Member since May 2017 NilsAndersen AndersonPaul FrankBowman Ian Davis Meyer Melody Members John Sawers The committee reviewed its performance through feedback from the external evaluation of its work and of the work of the board as a whole. The evaluation concluded that the committee was working well and considering the right issues. The committee currently meets four times meetings. additional considering is and year a The committee and board felt that there should be greater integration between the work of the board, the committee and the international advisory board. This is being further considered during 2019. Committee evaluation The committee developed and broadened its work It over the year. discussed BP's involvement in the countries key where it has existing investments or isconsidering investment in detail. These included the US, Russia, Mexico, Brazil, India and China. It considered broader policy issues such as the US domestic and foreign policy and the political and economic impact of a low oil price on countries. producing We reviewed the geopolitical background BP's to global investments and the politics around climate change. Activities during the year The chairman and group chief executive regularly attend committee meetings. The executive vice president, regions and the vice president, government and political affairs attend meetings as required. The committee met four times during All the year. directors attended each meeting that they were eligible attend. to Meetings and attendance and Meetings

Meetings and attendance Nomination and governance committee The committee met six times in 2018. All directors attended all the Role of the committee meetings for which they were eligible, except that Nils Andersen was excused from two meetings due to a potential conflict of interest and The committee ensures an orderly succession of candidates for Alan Boeckmann missed two meetings due to unforeseen personal directors and the company secretary and oversees corporate circumstances. governance matters for the group. Bob Dudley and Brian Gilvary joined meetings where the chairman's Key responsibilities succession was discussed. Matters relating to the business of the nomination and governance committee were also discussed at some • Identify, evaluate and recommend candidates for appointment or meetings. reappointment as directors. • Review the outside directorships/commitments of the NEDs. Activities during the year • Review the mix of knowledge, skills experience and diversity of the • Evaluated the performance of the chairman and the group chief Board to ensure the orderly succession of directors. executive. • Identify, evaluate and recommend candidates for appointment as • Considered the composition of and the succession plans for the company secretary. executive team. • Review developments in law, regulation and best practice relating to • Discussed the strategy options for the company, including the corporate governance and make recommendations to the board on transition to a lower carbon future. appropriate actions to allow compliance. Committee evaluation Members The committee continues to work well. The balance of skills and experience amongst its non-executive director membership ensures it is Helge Lund Member since July 2018 and chair since best able to support and challenge the company as it implements its September 2018 strategy. Carl-Henric Member since September 2009 and chair Svanberg since January 2010; resigned as chair September 2018 and from committee December 2018 Alan Boeckmann Member since April 2016 Ian Davis Member since August 2010 Ann Dowling Member since May 2015 and resigned May 2018 Brendan Nelson Member since September 2018 Paula Reynolds Member since May 2018 John Sawers Member since April 2016 Meetings and attendance The committee met three times in 2018. During the second half of the year, matters relating to the appointment of new directors were considered jointly with the chairman's committee. All directors attended each meeting that they were eligible to attend, except Paula Reynolds due to pre-existing external commitments. Activities during the year The committee continued to monitor the composition and skills of the board. The committee will continue to focus on ensuring that the board's composition is strong and diverse. During the year, it was agreed that the committee would assume oversight of governance. Committee evaluation Following the board evaluation, it was agreed that the committee would also focus on governance requirements arising from the new UK Corporate Governance Code. 86 BP Annual Report and Form 20-F 2018

Corporate governance 87 Results and progress 2018 in BP delivered another year of disciplined execution in 2018, alongside further progress against our five-year strategyto 2021. for growth. We delivered a further six major projects in 2018, bringing the over total 19 to the 2016-18 cycle. Strong operating performance across all all performance across operating Strong doubled than more has businesses our underlyingour to cost replacement profit billion,$12.7 with operating cash flow excluding Gulf of Mexico oilspill payments of $26.1 billion. BP distributed $8.1 billion in dividends in 2018, and continued the share buyback programme started offset to in 2017 the dilutive effects of the scrip shares. BP continues play to an active role in relation theto energy transition. We are carefully considering our mix of natural gas and oil, while investing in new technology and businesses that have the potential contribute to a lower to carbon world through our ‘reduce, improve, framework. create’ Our acquisitionChargemaster, of the UK’s (see company charging electric vehicle largest page 42), and further expansion of the solar company Lightsource BP (see page 47), are among the most promising investments advancing to commitment with our consistent a lowercarbon future. At the same time we continue sustain to our traditional reserves Our organic business. replacement ratio for the year was 100%, and our acquisition of BHP assets provides us with reserves opportunitiesand significantnew BP Annual Report and Form 20-F 2018 Chair of the remuneration committee Chair of the remuneration Targets are strongly aligned withTargets are strongly priorities,the company’s strategic and requirethey are ambitious achieve outcomes. material effort to Paula Rosput Reynolds Dear shareholder, Following shareholder extensive consultation led by board my colleague Professor Dame Ann Dowling, BP introduced our current remuneration Thus policy 2018 in 2017. was our second year using this policy. The committeeremuneration the believes structure remains fitfor purpose, the targets are strongly aligned with the company’s ambitious and are priorities, they strategic require material effort achieve to outcomes, and the rewards conferred date to align with progress. strategic and results financial our Please the to refer ‘Remuneration at a glance’ table for an overview. The policy delivers remuneration in three parts: a market-aligned foundation of base salary, benefits andretirement provision; annual reflect that our based measures on incentives assessed against targets require that strategy, progressive improvement year-on-year; and a materialopportunity earn to shares at the end of a three-year performance period, which is accompanied by a shareholding requirement ensureto our executive directors’ interests align with your own. Of course it is not enough relyto on a purely formulaic application of policy. Therefore the committee engages in a dialogue with Bob Dudley, Brian Gilvary and particularly colleagues, board onour those assurance environment and ethics safety, the committee (SEEAC) and the main board audit committee (MBAC) test to the reasonableness of the outcomes. This dialogue ensures we are well equipped apply to and explain discretion and judgement as needed. isclosures nnual bonus outcome xecutive director director xecutive xecutive director director xecutive tive director director tive tive directors’ pay directors’ tive r workforce in 2018 ardship and executive executive and ardship -18 performance share -18 ment with strategy with ment outcomes remuneration policy for 2019 Execu policy andremuneration 2019 for implementation Non-e Stew Non-e interests and outcomes Other d director interests for 2018 Wide 2018 a 2018 2016 outcome plan Align Execu 2018 performance2018 and pay Contents 105 109 104 102 95 97 100 91 92 94 90 Directors’ remuneration report remuneration Directors’ report remuneration Directors’

Directors' remuneration report Remuneration at a glance Key features Purpose and link to strategy Outcomes for 2018 Implementation in 2019 • Salary is reviewed annually and, if • Fixed remuneration reflecting • Bob Dudley's salary unchanged • Bob Dudley's salary appropriate, increased following the scale and complexity of our at $1,854,000. to remain at $1,854,000. the AGM. business, enabling us to attract • Brian Gilvary's salary increased • Brian Gilvary's salary increased and keep the highest calibre • Relates to market and our wider by 2% to £775,000. by 2% to £790,500. global talent. benefits workforce. Salary and • Benefits remain unchanged. • Benefits remain unchanged. • Bob is a member of both US • To recognize competitive • Bob's defined benefit pension • Arrangements for Bob will pension (defined benefit) and practice in home country. did not increase in 2018. His continue unchanged. retirement savings (defined actual and notional company • Brian has offered to accelerate contribution) plans. contributions were more than the scheduled reductions in offset by investment losses • Brian is a member of a UK final his cash allowance. These will within his retirement savings salary defined benefit pension now reduce by 5% of salary at plans, hence he received no plan, and receives a cash each of 1 June 2019, 2020 and net benefit in 2018. allowance in lieu of further 2021, and a further 5% of service accrual. • Brian's accrued defined benefit salary at 1 June 2023, taking pension increase was below his cash allowance to 15% inflation. He received a cash of salary. benefits allowance at 35% of salary, • These proposed changes Retirement Retirement which is included in the single reduce Brian's cash figure table. supplement sooner than the transition for other members of the BP UK defined benefits plan. He will not receive any form of compensation related to the reductions. • 112.5% of salary at target, and • To incentivize delivery of our • Against our scorecard of safety • We will include an 225% at maximum. annual and strategic goals. and operational risk (20%), environmental target, weighted reliable operations (30%) and at 10%, in our performance • 50% of the bonus is paid in cash • The 50% deferral reinforces financial performance (50%), scorecard for 2019. and 50% is mandatorily deferred the long-term nature of our our performance score is 81% bonus Annual and held in BP shares for three business and the importance of target (40.5% of maximum). years. of sustainability. • Annual grant of performance • To link the largest part of • Against our balanced scorecard • Awards granted in 2017 at shares, representing the remuneration opportunity with of financial measures (67%), 500% (group chief executive) maximum outcome. the long-term performance of and strategic imperatives (33%), and 450% (chief financial the business. The outcome our 2016-18 performance score officer) of salary will vest in —500% of salary for group chief varies with performance against is 90.5% of maximum. proportion to success against executive. measures linked directly to the measures of our 2017-19 • The committee has exercised —450% of salary for chief financial returns and strategic scorecard. discretion to reduce the actual financial officer. priorities. vesting outcome to 80%. • Awards granted in 2019 will be • Shares only vest to the extent granted at 500% (group chief performance conditions are met. executive) and 450% (chief shares financial officer) of salary. Performance Performance • For awards granted in 2019, strategic priorities will be weighted at 30% (previously 20%) with return on average capital employed reducing to 20%. • Executive directors are required • To provide alignment between • Both executive directors • In 2019 we will engage with to maintain a shareholding the interests of executive materially exceed the share stakeholders to review and equivalent to at least five times directors and our shareholders. ownership requirements. revise, as appropriate, our post their salary. employment shareholding • The executive directors maintain policy for 2020 onwards. • Additionally, they are expected to their commitment to retain maintain shareholdings of at least shareholdings of at least two two and a half times salary for two and a half times salary for two requirement Shareholding years post employment. years post employment. 88 BP Annual Report and Form 20-F 2018

Corporate governance 89 In this Directors' remuneration report RC profit (loss), underlying RC profit,return on average capital employed, operating cash flowexcluding Gulf of Mexico oil spill payments are non-GAAP refining reliability, plant upstream and These measures measures. availability, major projects and underlying production and reserves replacement ratio are defined in the Glossary on page315. Paula Rosput Reynolds Chair of the remuneration committee 29 March 2019 Looking ahead to 2019 We recently announced our support for a shareholder resolution at the annual 2019 general meeting that would broaden our corporate reporting describe to how our strategy is consistent with the goals of the Paris Agreement.We welcome this resolution as an opportunity provideto further detail onour strategy and on our attractiveness as an investment proposition in the energy transition, and for continued investor engagement. We believe that all constituencies will be well served byour increasing the target financialrewards relating to how a greenhouse gas emissions reduction measure for our bonus 2019 scorecard. This means that of the outcome 10% will now reflect our progress in emissions reduction (consequently reducing slightly the relative weighting of other customary measures in our bonus plan). The 2019-21 performance share plan scorecard will continue focus to on relative total shareholder return, absolute returns on average capital employed over the three years, and a focused suite of strategic progress measures. better reflect To the importance of strategic progress, we navigate the low-carbon transition. this end, we have To introduced which includes BP's role in the energy transition, we are increasing the weighting of this measure from 20% 30%, to while reducing the returns measure from 30% 20%. to Following our review of their total remuneration, we have decided to keep Bob's salary unchanged, and propose increase to salary Brian's fromby 2% the date of the AGM. We have also agreed accelerate to the reductions the to cash supplement Brian receives in lieu of further defined benefit pension service accrual, which will now startfrom 1 June 2019. More broadly, our committee activity has in 2019 included a review of the committee charter, approving remuneration decisions in respect of the executive team, deepening our understanding of wider workforce appropriate under the as measures adopting and other remuneration revised UK Corporate Governance Code, including an examination of the implications of pay and benefits differences across the workforce. We will be reviewing BP's strategic progress in the context of share programmes approved under policy, the in particular 2017 progress related the to challenges a lower of carbon world. These evaluations will take time and thoughtful discussion and will lead the in to important business of engaging with our major shareholders and representative bodies ahead of our new policy approval in 2020. In that regard, we will be consulting widely on the ways in which we reflect the strategic imperatives of the company within a competitive global remuneration structure. BP Annual Report and Form 20-F 2018 set stretching targets for the annual 2018 bonus scorecard. Therefore, despite the strong business results we assessed for the year, 2018 performance as below of target plan, (40.5% at 81% of maximum). Following our discussions with SEEAC and MBAC, we found no reason adjustto this formulaic scorecard outcome. Half of the bonus for the executive directors will be delivered as shares and held for three years. was2018 the finalyear of the 2016-18 performance share award, the measures with financial strategic and policy, 2014 under our grant last Performance and remuneration outcomes 2018 in As we seek incentivize to year-on-year improvement, the committee Directors' remuneration report remuneration Directors' as shown in the table on page 93. BP again ranked first place relativeon TSR, delivered robust operating cash and flow, exceeded maximum expectations for major project delivery. These strong results across the range of measures led a formulaic to vesting outcome of 90.5% of maximum. execution, project and TSR, flow, including cash results, The foregoing were delivered alongside an almost 50% return shareholders to over the same three-year between period. directional alignment is Thus, there executives and shareholders. the formula However, from which the outcome was calculated originated in the plan 2014 which we substantially The committee revised in 2017. recognized that merely applying a dated formula might not best serve the interests of the to delivered clear value the despite stakeholders. Therefore, shareholders and the relatively muted annual bonus outcome, we concluded we should apply downward discretion on theexecutive directors' long term award outcomes. We will vest the 2016-18 performance shares at 80% rather than at the 90.5% formulaic outcome. scorecard In exercising our judgement we have opted apply to the more challenging scales policy of our 2017 in measuring performance outcomes relating operating to cash flow, major project delivery and safety and operational risk. This adjustment brings the vintage 2016 EDIP outcome harmony into with the policy that was approved by shareholders This adjustment in 2017. reduced incentive 2018 pay by $1.45 million for Bob and £0.54 million for Brian. In addition, the committee has again acted on Bob's request re-base to his 2016-18 award from its original 550% grant level the to 500% of salary grant level established policy. in the This 2017 adjustment reduces Bob's vesting outcome million, by a further thus reducing $1.10 his incentive pay by $2.70 million overall. The single figurestotal of remuneration for Bob and Brian $14.67are million and £7.98 million respectively, as reported on page 95. This represents decrease a 3% for Bob, reflecting significant reductions in both his annual bonus and the investment return on his retirement savings, partly offset by an increase attributable share to price growth. For Brian, this represents increase,a 12% largely due vesting to of deferred awards from bonus, his 2015 and the increase attributable to share price growth. In our committee deliberations, we considered these outcomes and believe they are appropriate given the operational and financial performance of BP thisyear and the tremendousrecovery that BP has made over the past three years.

Directors’ remuneration report 2018 performance and pay outcomes 2018 A year of exceptional operational performance, with record plant reliability in the Upstream and refining throughput in Business the Downstream. Improvement across virtually all safety measures, growth in our retail business and delivery of six performance major projects. Profits have more than doubled, with an 11.2% return on capital, and strong foundations for continuing returns over the near and long term. Key strategic highlights • $12.7 billion underlying replacement cost profit. 1st $26.1bn $8.1bn • Transformation of our US onshore business. Among peers for total Operating cash flow Dividends paid, shareholder return for excluding Gulf of Mexico including scrip. • Six new major projects delivered. 2016-18. oil spill payments. Performance outcomes Robust results for the year fell short of our stretching targets, particularly on cash flow. On a three-year basis, 2018 concluded a remarkable period of delivery and preparation for the future. Annual bonus Performance shares 40.5% 0% 40.5% 90.5% -10.5% 80% Formulaic outcome Committee judgement, Final outcome Formulaic outcome Committee judgement Expected outcome after (% of maximum) no adjustment (% of maximum) (% of maximum) to reduce vesting committee discretiona (% of maximum) Performance measures Nil Maximum Performance measures Nil Maximum (% weighting) (% weighting) &#0;&#0;&#0;&#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0; Tier 1 process safety events (10%) &#0;&#0;&#0; Relative TSR (33.3%) &#0;&#0;&#0; Recordable injury frequency (10%) &#0;&#0;&#0; Cumulative operating cash flow (33.3%) &#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0; &#0;&#0;&#0; Reserves replacement ratioa (11.1%) &#0;&#0;&#0; Downstream refining availability (15%) BP-operated upstream plant &#0;&#0;&#0; Major project delivery (11.1%) &#0;&#0;&#0; reliability (15%) Safety and operational risk &#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0; – Tier 1 process safety events &#0;&#0;&#0; (11.1%) Operating cash flow (excluding Gulf – Recordable injury frequency &#0;&#0;&#0; of Mexico oil spill payments) (20%) &#0;&#0;&#0; Underlying replacement cost profit (20%) &#0;&#0;&#0; a The final outcome for part of this award is based on BP’s relative RRR ranking. This is forecast at second place but cannot be confirmed until after publication of our peers’ reports. This final Upstream unit production costs (10%) &#0;&#0;&#0; outcome will be reported in our 2019 report. KPI This symbol denotes remuneration measures that directly relate to the key performance indicators of our investor proposition – see page 16. Remuneration outcomes Reduced annual bonus and pension, partly offset by increases in performance share vesting, lead to a reduction for Bob. The increase for Brian reflects increases in the values of performance and deferred share vesting. &#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0; &#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0;&#0; Brian Gilvary, chief financial officer &#0;ota&#0; remunerat&#0;on &#0;ota&#0; remunerat&#0;on 2018 &#0;1&#0;&#0;&#0;&#0; 2018 £8.0m 201&#0; &#0;1&#0;&#0;1m 201&#0; &#0;&#0;&#0;1m 201&#0; &#0;11&#0;&#0;m 201&#0; &#0;&#0;&#0;2m 201&#0; &#0;1&#0;&#0;&#0;m 201&#0; &#0;&#0;&#0;1m 201&#0; &#0;1&#0;&#0;&#0;m 201&#0; &#0;&#0;&#0;&#0;m Salary and benefits Retirement benefits Annual bonus Performance shares Discontinued plans (see page 96 for descriptions) Share ownership This is a key means by which the interests of executive directors are aligned with those of shareholders. Both directors have holdings in BP which significantly exceeded our shareholding policy requirement of five times salary. Bob Dudley, group chief executive 14.66 times salary, 3,718,074 sharesa, as at 15 March 2019 Brian Gilvary, chief financial officer 15.80 times salary, 2,248,905 shares, as at 15 March 2019 &#0;o&#0;&#0;cy re&#0;u&#0;rements &#0;&#0;&#0;&#0; &#0;ctua&#0; aHeld as ADSs 90 BP Annual Report and Form 20-F 2018

Corporate governance 91 y performancey cators on page 16. indi See ke See out of 2.0 a KPI out of 2.0 a Formulaic score 0.81 0.10 0.81 0.11 0.03 0.18 0 0.33 0.07 $26.1bn 0.00 $12.7bn $7.15/bbl 0.40 0.198/200k hrs 0.21 94.9% 95.7% 0.21 16 events16 Outcome Outcome 40.5% of maximum bonus $31.4bn 0.4 $13.0bn 0.4 $6.61/bbl 0.2 0.164/200k hrs 0.2 95.8% 0.3 97.3% 0.3 12 events 0.2 Maximum (2) Final scorecard outcome 2.0 of out 0.81 Financial performance 0.40 To avoid windfallTo outcomes in our financial measures, and drive genuine year-on-year improvement, we adjust our financial targetsreflectto any pricing impacts, i.e. the stronger oil price environment led of 2018 a to proportionalincrease in our profit and cash flow targets. This is the fourth occasion in the last seven years in which we have adjusted our and price positive out strip environments performance to measurement better reflect financial improvement in underlying terms. Unadjusted, the scores would all have been significantly higher, leadingto remuneration outcomes greater than we would have intended. Consequently, and despite another strong year of results and delivery for shareholders, our bonus of target, outcome or is for 81% 2018 40.5% of maximum, compared with 143% of target, of or 71.5% maximum, in 2017. BP Annual Report and Form 20-F 2018 16 events $28.9bn $28.9bn 0.2 $12.2bn 0.2 $7.01/bbl 0.1 0.200/200k hrs 0.1 95.3% 0.15 95.3% 0.15 0.1 Target (1) No adjustment MBAC discretion 19 events 0 $26.4bn 0 $11.4bn 0 $7.41/bbl 0 0.219/200k hrs 0 94.8% 0 93.3% 0 Threshold (0) Reliable operations 0.21 10% 20% 20% 10% 10% 15% 15% Weighting No adjustment SEEAC SEEAC discretion KPI KPI KPI KPI KPI KPI KPI (20% weight) Measures used for the 2017 remuneration policy. ating cash flow flow cash ating Safety 0.21 REM cost profit costs frequency (Solomon Associates'(Solomon operational availability) (defined by API) (excluding Gulf of Mexico spilloil payments) Formulaic Formulaic scorecard outcome 2.0 of out 0.81 Financial performance weight) (50% Reliable operations weight) (30% Safety Underlying replacement replacement Underlying production unit Upstream Financial performance outcome Safety outcomeSafety BP-operated upstream reliability plant outcome operations Reliable Recordable injury Downstream refining availability Measures Tier 1 process safety events 2018 annual bonus annual 2018 Oper Formulaic score Annual bonus Due to rounding, the total does not agree exactly with the sum of its component parts. a Scorecard For the 2018 committee established a bonus scorecard of seven measures across three areas of focus: safetyand operational risk, operations financialreliable and performance.align measures These with our strategy and, in particular, reflect the annual plan. Six of the seven measures are identical scorecard. our to 2017 The seventh 'BP-operatedmeasure, replaces 'Upstream reliability', plant upstream operating efficiency' bringing unplanned from 2017, downtime into account which provides closer a comparison with the equivalent Downstream. the for measure In order build to the on the committee strong results set of 2017, notably stretching targets for each of these measures. For instance, our 2018 thresholdoutcomes for safety performance were set at the level our of outcomes,2017 meaning we had results exceed to 2017 achieve to even a minimum contribution the to bonus. 2018 Directors' remuneration report remuneration Directors' bonus annual outcome 2018

Directors' remuneration report Shareholders will note that the most significant divergence from our Notwithstanding this outcome, we discussed and agreed Bob's decision 2018 targets is in operating cash flow. Even though the 2018 outcome to adjust the group performance element of annual bonus for the wider of $26.1 billion is 8% higher than 2017, it fell marginally short of the workforce (employees below senior leadership level) and consequently threshold level of $26.4 billion on an adjusted basis. This meant a score these 32,600 employees received 2018 annual bonus based on an of zero on an element that contributes 20% of the overall bonus target. adjusted group performance score of 100%, rather than 81%, of target. We feel this is a reflection of the rigor in our policy and target-setting The annual bonus outcome is unrelated to the BP share price, and process, delivering a nil outcome even in a year which saw underlying therefore no part of the bonus is attributable to share price appreciation. profit more than double, and returns almost double. As shown below, half of the bonus is paid in cash after year end, and As in previous years, in order to confirm the final bonus score we have half is deferred into shares that will vest in three years, according to 2017 discussed the formulaic score with the chairs of the safety, ethics and policy terms. The full value of the 2018 bonus, including the deferred environment assurance committee (SEEAC) and the main board audit shares, is included in the 2018 single figure table. This differs from committee (MBAC). This year, neither of these committees raised reporting in respect of the 2014 policy, under which deferred shares issues for which we felt any need to adjust. On this basis, and in view are included in the single figure for the year in which they vest. of the demanding target levels we had set for 2018 performance, we believe that the formulaic score, and the annual bonuses that result, Deferred fairly reflect and reward 2018 performance for the executive directors Adjusted Paid into BP and senior leadership of BP. Accordingly we have made no discretionary Name outcome in cash shares adjustments to the formulaic scorecard outcome, which applies to the Bob Dudley $1,689,458 $844,729 $844,729 executive directors and BP's senior leadership (approximately 4,400 Brian Gilvary £706,219a £353,109 £353,109 employees). a Due to rounding, the total does not agree exactly with the sum of its component parts. 2016-18 performance share plan outcome Vesting levels for the 2016-18 performance share awards we granted ratio over the period, which yields vesting at 80% of maximum for this in 2016 are determined under the terms of the 2014 policy, in line with element. We will confirm our final outcome for this measure once the performance measures and outcomes shown on the scorecard on competitor data is published in full later in the year. page 93. As before, we have assessed performance against the safety and Assessed against these scorecard measures, the group's performance for operational risk measure by looking back at tier 1 process safety the three years from 2016 to 2018 is strong. Notably, we placed first on incidents and recordable injury frequency over the three-year period. relative total shareholder return (with 49.3%) which measures us against This is a detailed assessment looking at year-on-year performance our super-major peers, Chevron, ExxonMobil, Shell and Total. We also for which we sought input from the SEEAC. Based on continuing placed first in the 2015-17 performance cycle. Total shareholder return reductions in tier 1 events and in recordable injury frequency, and the represents the change in value of a shareholding over a three-year period, SEEAC overview, we assessed a score of 88% of maximum for this assuming that dividends are re-invested to purchase additional shares. element of the performance shares scorecard. BP's standard practice is to calculate this change in value based on the While the scorecard provides a balanced view of longer-term results, average US market prices over the fourth quarter immediately before, as a committee we wish to take a broader view of performance in order and at the end of, the three-year performance cycle. Using a three- to ensure reward outcomes are proportional and appropriate. Our first month period average helps to counter the impact of share price concern is to ensure outcomes align with shareholders' own experience volatility. of both returns, and of the company's positioning to generate value into the future. In this regard we believe the scorecard has worked well. The choice of basis period for calculating share price growth can be a material factor in the ranking result. This generally explains why our Clearly there are also broader societal views to consider, together with peers who use relative TSR in their remuneration plans can arrive at a the general experience of the wider workforce as a key stakeholder different result. For example, in the three year scorecard period just group. These broader considerations create a compelling case for ended, BP and Shell showed different relative TSR rankings because restraint on quantum, even as they emphasize the need to align to unlike BP's average of the calendar quarter approach, Shell's standard performance. basis is to use a 90-day averaging period around the start and end of the Therefore while we believe that 2016-18 performance has been performance period. exemplary, and that the business is both operationally and strategically We have again made strong progress in major project delivery, well positioned for the future, the committee has nonetheless decided exceeding the top of the measurement scale (13) with 19 major to reduce vesting of the performance share award from the formulaic projects delivered over the three-year period, allowing maximum 90.5% to a discretionary 80% of maximum. In applying this judgement vesting for this element. and making this reduction the committee decided to apply the more challenging measurement scales of our 2017 policy. The committee Our $68 billion cumulative operating cash flow excluding the Gulf studied the impact of share price appreciation on pay outcomes and is of Mexico oil spill payments for the period exceeds the threshold satisfied that the gains arising are an appropriate and necessary design performance level of $61.2 billion, following adjustments for oil price feature of a long-term incentive. We believe there should be no routine in line with the 2014 policy. For the purposes of this report, we have adjustment, either for gains that in part reflect low grant prices, or for forecast a second place outcome for our relative reserves replacement shortfalls that reflect the opposite. 92 BP Annual Report and Form 20-F 2018

Corporate governance 93 y performancey cators on page 16. c b indi See ke See KPI 33.3% 27.3% 8.9% 11.1% 5.0% 90.5% 4.8% 29.8% 60.7% Outcome First $67.8bn Second 19 80% final vesting after committee discretion Formulaic vesting 90.5% First $73.2bn First 13 Maximum performance BP Annual Report and Form 20-F 2018 The value of vested shares reflects the share price appreciation all three-year the shareholders experienced over period. 2016-18 For this award cycle, the original grant was calculated based on ordinary share and American depositary share (ADS) prices of £3.72 and $33.81 fourth-quarter 2018 the while respectively, £5.33 prices are average and $41.48. Consequently, share price appreciation accounts for $2.04 million of the value (18.5%) of Bob's vested shares, and for £1.23 million (30.2%) of the value vested of Brian's shares. The committee did not regard this as a direct reason exercise to discretion, although overall pay outcomes have been a partour of consideration of downward discretion. Third 9 Assessment of improvement over the three years Third $61.2bn Threshold performance £535,863 and re-basingand $2,698,677 due to discretion discretion to due Reduction in value value in Reduction a Strategic imperatives 29.8% shares vested Value of Committee review of stakeholder context and experience over three-year period of plan 33.3% 33.3% 11.1% 11.1% 11.1% Weighting £4,082,769 $11,043,179 KPI KPI KPI Shares vesting KPI including KPI dividends 765,998 1,597,374 b KPI Shares awarded 786,559 1,809,582 a Measures used for the 2014 remuneration policy. Formulaic Formulaic vesting 90.5% Financial 60.7% Total formulaicTotal vesting REM Financial Cumulative operating cash flow Major project delivery Safety and operational risk: – Process safety tier 1 events – Recordable injury frequency Relative reserves replacement ratio reserves replacement Relative Measures Relative total shareholder return 2016-18 performance2016-18 shares Strategic imperatives Performance shares Performance Due to rounding, the total does not agree exactly with the sum of its component parts. Due to rounding, the sum of the weightings does not agree with the actual total, which is 100%. This original award was based on 550% of salary, according to the terms of the 2014 policy. Bob Dudley's award is granted in respect of American depositary shares (ADSs). The numbers in this table reflect calculated equivalents in ordinary shares. One ADS equates to ordinarysix shares. Forecast position, to be confirmed after external data becomes available later in 2019. Scorecard a b c a b Name Bob Dudley Directors' remuneration report remuneration Directors' Brian Gilvary In addition, and in line with treatment last the committee year, has agreed Bob's to request re-base to his original grant from 550% of salary 500% to salary, of recognizing the change from the policy 2014 to the 2017 policy. theto The 2017 impact these decisions have on pay outcomes for Bob and Brian are detailed below.

Directors' remuneration report Alignment with strategy The strategy we set in 2017 commits us to a balance of short-term Our longer-term view is explicitly covered in the strategic progress goals and long-term ambitions, encompassing both conventional element for our performance shares, alongside measures that focus and emerging sources of energy. To help the board and executive on shareholder returns and return on average capital employed (ROACE) management assess delivery against this strategy, we track progress over each three-year cycle. These are the measures we established two against a number of key performance indicators (KPIs) – see page 16. years ago with our 2017 policy, and we will see the first cycle of results This strategy and these KPIs represent the foundation of our investor under that policy when we report the 2017-19 performance shares proposition. Importantly the majority of our KPIs translate directly into outcome in next year's report. Looking ahead, the committee has the measures we use to assess our annual bonus and performance decided to increase the weighting of the strategic progress measure share awards. This helps us align the focus of our board and executive from 20% to 30% to better reflect its importance. This will apply for the management with the interests of our shareholders. To maintain this performance shares we grant in 2019 as part of the 2019-21 cycle. As a alignment over time, we will adjust our bonus and performance share result, we will reduce the weighting on ROACE from 30% to 20%. measures as and when BP's strategy evolves or finds new areas To ensure we take a rounded view in our performance assessment, the of focus. performance share plan also features an underpin to bring absolute TSR, The annual bonus rewards activities that assure our success in the near safety and environmental factors into account. This underpin allows the term, with measures focused on safety, reliable operations, financial committee to embrace the energy transition in a way that enhances our performance and, from 2019, a new emissions reduction target. investor proposition and allows us to be competitive at a time when Ensuring our near-term health is a critical building block for the longer prices, policy, technology and customer preferences are volatile and term, providing the funds for us to invest, innovate, pursue new evolving, while managing the alignment between remuneration opportunities and enhance our productivity. For instance, the reliable outcomes and our strategic progress. operations measure in our annual plan has a strong and direct bearing on the financial measures for our three-year performance share Reducing our Improving Creating outcomes. Our new sustainable emissions reduction measure, with a emissions in our low carbon 10% weighting for 2019, connects bonus outcomes directly with the our operations products businesses progress we make under the reduce element of our 'reduce, improve, create' (RIC) framework for a low carbon transition. See our low carbon ambitions on page 46. BP set out an update of its strategy in 2017, which was reinforced in the results announcements in February 2018 and 2019. The foundations for strong performance are safe and reliable operations, a balanced portfolio, and a focus on returns. How we align Safer Fit for Focused on Growing our strategy and future returns sustainable free remuneration cash flow and measures distributions to Safe, reliable A distinctive Value based, shareholders over and efficient portfolio fit for a disciplined the long term execution changing world investment and cost focus Annual bonus Safety Environment Reliable operations Financial performance Performance shares Total shareholder return Return on average capital employed Strategic priorities Underpin: absolute TSR and safety/ environmental factors 94 BP Annual Report and Form 20-F 2018

Corporate governance c e 95 £38 2017 £611 £611 £186 £752 £263 £936 £7,115 £1,060 £3,595 (thousand) Brian Gilvary e b £0 2018 £67 £769 £269 £353 £353 £7,977 £1,876 £2,083 £4,083 c d – – 2017 $70 $746 $1,491 $1,491 $1,854 $1,349 $9,455 $15,108 (thousand) Bob Dudley Bob d b – – $0 2018 $79 $845 $845 $1,854 $2,042 $11,043 $14,666 BP Annual Report and Form 20-F 2018 a g Shares – deferred for three years Cash bonus Performance shares Deferred share awards from bonuses prior-year Salary retirement and Pension savings value – increase Benefits Cash in lieu of future accrual f 38 for ordinary shares and include accrued dividends on shares vested. Brian Gilvary has voluntarily agreed defer to performance assessment 01 for01 ordinary shares and $39.85 for ADSs. In May 2018, after the external data became available, the committee reviewed the relative ear after retirement, therefore the performance period is expected exceed to the minimum term of three years. As stated in the 2017 pensation (Savings) Plan (ECSP) account under Bob's US retirement savings arrangements. In Bob 2018 incurred investment losses formance achieved under the rules of the plan and includes accrued dividends on shares vested. In accordance with UK regulations, the vesting iods. This additional line shows the value of those awards that is directly attributable share to price appreciation,being the number of shares directors' remuneration report, Bob voluntarily deferred performance assessment and vesting of the deferred 2014 and matching awards until at least one year after retirement – see the Deferred shares table on page for further 101 details on these awards. The values shown for performance shares and deferred share awards include the share price appreciation experienced over the three-year vesting per vesting, including accrued dividends, multiplied by the increase in share price from grant date vesting to date. Bob Dudley has voluntarily agreed defer to performance assessment and vesting of the awards related annual his to 2015 bonus until at least one y Represents the assumed vesting of shares following in 2019 the end of the relevant performance period, based on a preliminary assessment of per price of the assumed vesting is the average market price for the fourth quarter which of 2018 was £5.33 for ordinary shares and $41.48 for ADSs. The finalvesting will be confirmed by the committee in the second quarter ofand2019 provided in the directors'2019 remuneration report. by less than inflation, hence the net increase reportedis zero as perregulations. Full details are set out on page 96. For Brian Gilvary this represents the annual increase in accrued pension, net of inflation, multiplied by 20. In Brian's salary2018 increased of $193,910 in this account, hence this aggregate value is negative and reported as per zero regulations. Full details are set out on page 96. and vesting of the matching awards related annual his to 2015 bonus for a further two years – see the Deferred shares table on page for further 101 details on these awards. The amounts reported relate the annual to for 2014 2017 bonus and have been adjusted from the number provided in the directors'2017 remuneration report include to the accrual and vesting of accrued dividends. The amounts reported relate for 2018 the annual to 2015 bonus deferred over three years, which vested February on 19 at the 2019 market price of £5. For Bob Dudley this represents the aggregate value of the company match and investment gains on the accumulating unfunded BP Excess Com Remuneration is reported in the currency in which the individual is paid

In accordance with UK regulations, single in the 2017 figure table, the performance outcome values were based fourth-quarteron average prices reserves replacement ratio position, and this resulted in no adjustment the to finalvesting of 70%. On 22 198,306May 2018, ADSsfor Bob Dudley and 603,831 ordinary shares for Brian Gilvary vested at prices of $47.09 and £5.88 respectively. On July 31 an additional 2019 2,599 ADS and 7,795 ordinary shares vested, representing accrued dividends at prices of $45.09 and £5.73 for Bob and Brian respectively. The reported 2017 values for the total vesting have therefore thousand increased for by Bob $1,168 and by £614 thousand for Brian. of £5. Total remuneration Total Performance shares Discontinued plans Retirement benefits Retirement Annual bonus Value attributable to share price appreciation price share to attributable Value Due rounding, to the total does not agree exactly with the sum of its component parts. Salary and benefits g f e d c b a Single figure table – executive directors(audited) Directors' remuneration report remuneration Directors' Executive directors' pay for 2018 for pay directors' Executive

Directors' remuneration report Overview of single figure outcomes Bob has requested that the committee delay the performance assessment and hence the vesting of his 2015 deferred and matching The single figures of total remuneration for Bob Dudley and Brian Gilvary awards. This reflects his commitment to the long-term success of BP are $14.67 million and £7.98 million respectively. This is a 3% decrease and adds to his alignment with shareholders' interests. These awards for Bob, and a 12% increase for Brian. In both cases 2018 remuneration will now vest, subject to an assessment against the original safety and includes material value from share price appreciation over the 2016 to environmental sustainability conditions, after his retirement. Similarly, 2018 period. Both individuals pay a majority of their taxes in the UK. After Brian has requested a two-year extension to the performance these tax and social security liabilities on this BP income, the net values assessment and vesting date of his 2015 matching award. of 2018 total remuneration are approximately $7.77 million for Bob, and approximately £4.23 million for Brian. For the 2015 deferred award for Brian, the committee considered operational and financial performance and reviewed safety and Salary and benefits environmental sustainability performance over the 2016-18 period, Bob Dudley's salary remained at $1,854,000 throughout 2018. Brian seeking input from the SEEAC on safety and sustainability measures. Gilvary's salary was increased by 2% to £775,000 with effect from The committee concluded that safety performance continues to show 21 May 2018. Both executive directors received car-related benefits, improvement, with safety embedded in the culture of the organization assistance with tax return preparation, security assistance, insurance and supporting strong operational and financial performance. The and medical benefits. In 2018 BP reimbursed Brian for holiday committee concluded that the deferred award should vest in full. curtailment costs incurred due to BP commitments. Part of this reimbursement is considered non-business related, hence is subject 2015 bonus – deferred and matching awards to tax and included as a benefit in the single figure table. Total shares vesting, 2018 annual bonus and 2016-18 performance shares Shares Vesting including Total value at Please refer to pages 91-93 for details of the performance measures, Name granted agreed dividends vesting targets, and outcomes, and the related reward outcomes Bob Dudleya for annual bonus and performance shares. Deferred award 551,784 –a – – Discontinued plans: deferral of 2015 bonus – deferred and Matching award 551,784 –a – – matching awards of shares Brian Gilvaryb In accordance with 2014 policy, Bob Dudley and Brian Gilvary deferred Deferred award 318,042 100% 387,160 £2,082,921c two thirds of their 2015 annual bonus. As a result, they each received Matching award 318,042 –b – – an equivalent value deferred award of BP shares, together with a a matching award of BP shares. Both the deferred and matching awards Vesting of deferred and matching awards deferred until at least one year after retirement, subject to conditions. were subject to a three-year performance period which ended on b Vesting of matching award deferred for two years, subject to conditions. 31 December 2018. c Based on a vesting share price of £5.38. Conclusions of the safety and sustainability assessment No systemic No major incidents Safety culture and values Strong safety performance issues identified embedded within the supports efficiency and financial global organization results across the group Retirement benefits This cash allowance is a feature of the UK pension arrangement, and Bob Dudley is a member of the US pension and retirement savings plans will transition down to 15% of salary by 1 June 2023 – see page 105 described on page 108. His normal retirement age is 60. In 2018 Bob's for more detail. The committee continues to review the value of pension accrued defined benefit pension did not increase. In accordance with the benefits for individual directors and its alignment to the broader workforce. requirements of the UK regulations, the amount included in the single History of group chief executive remuneration figure table on page 95 is therefore zero. In 2018 Bob made contributions to the BP Employee Savings Plan (ESP) totalling $27,000 and BP made Total Annual bonus Performance Group chief remuneration % of shares vesting matching contributions to the ESP, and notional contributions to the BP Year executive thousanda maximum % of maximum Excess Compensation (Savings) Plan (ECSP), totalling $129,780. 2009 Tony Hayward £6,753 88.9b 17.5 However, investment losses of $193,910 in his unfunded ECSP account 2010c Tony Hayward £3,890 0 0 (aggregating the unfunded arrangements relating to his overall service Bob Dudley $8,057 0 0 with BP and TNK-BP), exceeded the sum of these contributions, hence the amount included in the single figure table is zero. 2011 Bob Dudley $8,439 66.7 16.7 2012 Bob Dudley $9,609 64.9 0 Brian Gilvary is a member of the UK pension arrangement described on 2013 Bob Dudley $15,086 88.0 45.5 page 108 in common with more than 3,800 UK employees employed 2014 Bob Dudley $16,390 73.3 63.8 prior to 2010 (or before 2014 in the North Sea). His normal retirement age is 60, although benefits accrued before 1 December 2006 may be 2015 Bob Dudley $19,376 100.0 74.3 paid from age 55 with BP's consent. Brian's 2018 salary increase was 2016 Bob Dudley $11,904 61.0 40.0 below inflation, and his accrued defined benefit pension increase was 2017 Bob Dudley $15,108 71.5 70.0 therefore likewise below inflation. In accordance with the requirements 2018 Bob Dudley $14,666 40.5 80.0 of the UK regulations, the amount included in the single figure table is a Total remuneration figures include pension. The total figure is also affected by share vesting therefore zero. 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 Brian has exceeded the lifetime allowance under UK pension legislation for EDIP was made. For 2018 the preliminary assessment has been reflected. and now receives a cash allowance of 35% of base salary in lieu of b 2009 annual bonus did not have an absolute maximum and so is shown as a percentage of the maximum established in 2010. further service accrual. This amount has been separately identified c 2010 figures show full-year total remuneration for both Tony Hayward and Bob Dudley, in the single figure table on page 95. although Bob Dudley did not become GCE until October 2010. 96 BP Annual Report and Form 20-F 2018

Corporate governance 97 Performance shares for our executive directors performance group same the assessed using are leader performance group the for scorecard used weightings. the to adjustment some with shares, Annual bonus for executive directors is directly performance group same the measures to related without but workforce, wider the as outcomes and individual and performance area business element. the Other than the addition of security-related addition of the Other than benefits, our executive director benefit packages are broadly aligned with other employees who joined BP in the same country at the same time. The salaries of our executive directors and executive team form the basis of their total remuneration, and salaries these annually. review we The primary purpose of the review is stay to aligned ensure comparators, we although market relevant with any increases are kept within the budgets set for our wider workforce salary review. Comparison with executive director remuneration director executive Comparison with 4,000); and all BP Annual Report and Form 20-F 2018 Looking beyond much pay, the of workforce experience atBP is centred on a disciplined approach performance to management, for which employees set annual priorities related both to safety and value creation, balanced with behavioural objectives that give focus the to importance of good conduct. This deeply embedded programme has served to develop the management skills of team leaders and drives quality dialogue between employees and their managers. We agree with the executive view that team's the time invested in managing performance both aligns individual effort corporate to goals and allows employees to understand the value of their own contribution. The benefit of this approach is largely qualitative, through direction and feedback, but the individual contribution is also measured and then rewarded as part of the annual bonus. For a more immediate impact, BP is also encouraging more 'in the moment' feedback through our new global recognition introducedprogramme in 'energize!', 2018. Energize! has been well received in all business areas and locations, with 77% of employees recognized at least once, at a frequency of around 1,500 recognition moments every day by year end. With strong emphasis on diversity and inclusion create to teams that reflect their communities, and with the enduringfoundation of BP's values and behaviours build to respect, we believe BP employees work in a supportive, meritocratic and progressive environment. This positive environment is reflected in being the highest-ranked recruiterUK in the oil and gas sector in the Times newspaper's 100 Graduate Top Employer 2018. rankings other professional employees (approximately 35,000 potential participants, of whom 20% will participate). Vesting is subject group to performance outcomes for the group only. population leader We operate a performance share plan with three-year vesting for employees from our professional entry level and above. Operation varies based on seniority in three broad (approximately 400); leaders senior (approximately leaders group tiers: Approximately half of our global workforce participate in an annual cash bonus plan that multiplies a target bonus amount by a performance factor in the range 2. 0 to The performance factor is an average of performance outcomes measured at a group, business area and individual level. This structure places equal emphasis on the team, broad their of success the contribution, personal employee's an importance of and the results achieved by BP. where parts business distinct our those of for plans bonus different operate We and trading our as such different, markedly are market the models in remuneration businesses. marketing We offer market-aligned benefits packages reflecting normal practice in each country in which we operate. Where appropriate, and subject scale, to we offer significant elements of personal benefit choiceto our employees. Our salary is the basis for a competitive total reward package for all employees, and we conduct an annual salary review for all non-unionized employees. non-unionized employees. all for salary review annual an conduct we and As we determine salaries in this review, we take account of comparable pay rates at other relevant employers, the skills, knowledge and experience of each individual, relativitypeers to individual within BP, performance, and the overall budget we set for each country. In setting the budget each we year, assess how employee pay is currently positioned business and increases, further market any of forecasts rates, market to relative context related such to things as growth plans, workforce turnover and affordability. Policy features forthe wider workforce shares benefits Salary Performance Performance Annual bonus bonus Annual Pensions and and Pensions Summary of remuneration structure for employees below the board Element Directors' remuneration report remuneration Directors' Widerin workforce 2018 Workforce experience Delivery our of strategy, both near and long term, depends upon BP's success in attracting and engaging a highly talented workforce, and on equipping our people with the skills for the future. While the board is currently considering ways engage to more deeply with the workforce, and about the workplace in its broadest sense, the remuneration committee continues receive to and review information on pay outcomes and processes for our wider workforce. We are building insight the into remuneration models used in different BP entities and stay informed on the pay structures and typical salary budgets for the core areas of the business. group's For example, we have looked at data from the organization's gender pay reporting, at progression of reward across the hierarchyjob of levels, and reviewed the reward structures and processes in BP's trading business. Overall we observe a well-balanced and structured approach reward to (summarized in the table below), and the to 'non-financial'reward engaged an productive and environment. to contribute that elements This context has informed our decision making on executive director pay and our views on incentive outcomes across the group. In our consideration the of annual bonus scorecard for 2018, for instance, while we felt the formulaic result delivered appropriate outcomes for BP's senior leadership, we agreed with Bob's decision apply to a more generous outcome the to wider workforce on the basis that, individually, they have limited influence over financial outcomes such as cash flow.

Directors’ remuneration report Group chief executive-to-employee pay ratio Percentage change comparisons: GCE remuneration versus professional workforce In 2016 and 2017 we disclosed the ratio between our group chief executive’s (GCE) total remuneration and the median (P50) Comparing remuneration of a comparator group of our UK and US professional 2018 to 2017 Salary Benefits Bonus workforce (representing 38% of our global professional workforce). % change in GCE We believe this representation offers a valuable data point, highlighting remuneration 0% 8.0% -43.4% relevant pay differentials within BP. On this basis, our 2018 GCE % change in comparator group to median pay ratio is 106:1. remuneration 4.4% 0% -7.8% GCE pay ratios The comparator group used here is the same as used in our voluntary P50 pay pay ratio disclosures since 2017, i.e. our professional and managerial ratio on total P50 total grade staff in the UK and US. This group is employed on readily Year Method remuneration P50 salary remuneration comparable terms to the group chief executive, and represents a 2017 BP voluntary 105:1 $112,100 $136,865 approximately one third of our total employee base. 2018 BP voluntary 106:1 $114,800 $138,101 Relative importance of spend on pay ($ million) a Re-based from original 92:1 to reflect final value at vesting of 2015-17 performance shares. &#0;&#0;&#0;tr&#0;&#0;ut&#0;on&#0; to Remunerat&#0;on pa&#0;d to &#0;ap&#0;tal &#0;n&#0;e&#0;tment With effect from year ending 31 December 2019, the UK government &#0;&#0;are&#0;older&#0; all emplo&#0;ee&#0; will require that we calculate the total remuneration of the three BP UK employees whose remuneration represents the 25th, 50th and 75th 1&#0;&#0;&#0;01 percentile of our entire UK workforce. We are then required to disclose &#0;&#0;&#0;&#0;&#0;&#0; the ratio of our group chief executive’s total remuneration against each of those three representative employees. &#0;&#0;&#0;&#0;&#0;&#0; 10&#0;20&#0; &#0;&#0;&#0;&#0;&#0;&#0; 8&#0;210a &#0;&#0;&#0;&#0; 201&#0; &#0;&#0;&#0;&#0; 201&#0; &#0;&#0;&#0;&#0; 201&#0; a Distributions to shareholders comprise dividend payments of $8,080 million ($7,867 million in 2017) and share buybacks at a cost of $355 million ($343 million in 2017). See page 275 for details. 98 BP Annual Report and Form 20-F 2018

Corporate governance 99 8% 12% 17% 37% 37% 38% 52% 58% Men Women BP ExplorationBP Limited OperatingCompany ExplorationBP activities upstream covers in the UK, principally North Sea operations. ExpressBP Shopping Limited BP Express Shopping is our largest UK employing business, concerned with retail operations concernedbusiness, retail with supporting our UK-wide network of forecourts. 92% 88% 83% 63% 63% 62% 48% 42% The illustration below, from our UK 2018 gender pay gap reporting, highlights the representation issue and how it relates the to gender pay gap for each entity. For instance, our larger gender pay gaps relate BP to Exploration and BP p.l.c. where we have the largest differential between female representation in the top and bottom pay quartiles. By contrast, we reported negative a pay gap in BP Chemicals, where male female to consistent. more is representation BP Annual Report and Form 20-F 2018 Lower Lower Upper Upper 7% 15% 18% 24% 31% 32% 37% 56% 29% 30% 40% 64% 60% 36% corporate in employees covers predominantly p.l.c. BP BP Oil represents our downstream our represents Oil BP lubricants businesses. and fuels BP p.l.c. 71% 70% integrated our including functions, and business businesses. BP Air and trading and supply BP Chemicals is our petrochemicals business our Chemicals is BP in the UK, principally our operations in Hull. 69% 68% 44% 85% 82% 76% BP Chemicals Limited 93% BP Oil UK Limited 63% Lower Lower Lower Proportion of females and males in each quartile band These charts show how men and women are represented in each pay band. An even distribution across the quartiles would tend minimize to the gender pay gap. Equal pay and UK gender pay gap reporting As well as looking at pay structures,the committee hasspent time understanding how effectively current pay policies and processes manage fairness and avoid bias in payoutcomes. noted We the February UK 2018 gender pay gapreporting for the five legal entities covered by the regulations, and the explanations provided in the reporting. BP's accompanied that narrative anti-discrimination the Overall that committeeassured the feels Directors' remuneration report remuneration Directors' controls written pay into policies, and the quality of processes behind individual pay decision making, are effective in delivering an equal pay environment (like pay work) for like for the wider workforce. While the UK gender pay gap reporting showed pay gaps in favourmen of for four out of the five entities, we understand that these gapsresult largely from the relative under-representation of women in senior roles, and that the primary group's focus should therefore be on improving female representation, rather than adjusting pay practices. Thereforewe have reviewed the various initiatives taken by management address to these representation concerns and will continue monitor to progress in issues. underlying the addressing Upper Upper Upper

Stewardship and executive director interests We believe that our executive directors should have a material interest Multiple of in the company, both during their tenure and after they leave BP. Our Value of salary achieved shareholding policy therefore requires executive directors to build a Director Appointment date current shareholding (policy requires 5x) personal shareholding of five times their salary within five years of their Bob Dudley October 2010 $27,185,318 14.66 x salary appointment. They are expected to maintain personal shareholdings of Brian Gilvary January 2012 £12,256,532 15.80 x salary at least two and a half times salary for two years post employment. The executive directors have interests in both performance shares and deferred bonus shares under the executive directors' incentive plan Directors' shareholdings (audited) (EDIP). The share interests are shown in aggregate and by plan in the The tables below detail the personal shareholdings of each executive tables below. These figures show the maximum possible vesting levels. director, and demonstrate that both significantly exceed the policy The actual number of shares/ADSs that vest will depend on the extent requirement as at 15 March 2019. These figures include all beneficial and to which performance conditions are satisfied. non-beneficial ownership of shares of BP (or calculated equivalents) that have been disclosed to the company and exclude the anticipated vesting Unvested Unvested Unvested of the 2016-18 performance shares. ordinary shares ordinary shares Changes from ordinary shares or equivalents or equivalents as 31 Dec 2018 to or equivalents at Director at 1 Jan 2018 31 Dec 2018 15 Mar 2019 15 Mar 2019 Ordinary Ordinary shares Ordinary shares shares or Changes from or equivalents Bob Dudleya 6,569,010b 6,825,606b 1,459,350 8,284,956 or equivalents equivalents at 31 Dec 2018 to total at Director at 1 Jan 2018 31 Dec 2018 15 Mar 2019 15 Mar 2019 Brian Gilvary 3,329,274 3,291,614 400,709 3,692,323 Bob Dudleya 3,065,520 3,718,284 -210b 3,718,074 a Held as ADSs. b This shareholding has been re-based to reflect the 500% of salary grant level of the 2017 Brian Gilvary 1,709,243 2,043,899 205,006 2,248,905 policy, in place of the original 550% per the 2014 policy. a Held as ADSs. b This reflects change in the equivalent value of BP ADRs under the BP Employee Savings Plan ('ESP'), due to the BP ADR price movement. See page 108 for explanation of the ESP. Performance shares (audited) Share element interests Interests vested in 2018 and 2019 Date of award Potential maximum performance sharesa Number of of performance At 1 Jan Awarded At 31 Dec ordinary shares Face value of Performance period shares 2018 2018 2018 vested Vesting date the award, £ Bob Dudleyb 2015-17 11 Feb 2015 1,365,240 – – 1,205,430c 22 May 2018d – 2016-18 4 Mar 2016 1,645,074 – 1,645,074 e 1,597,374 f 2019f – 2017-19 g 19 May 2017 1,571,628h – 1,571,628 – – 7,418,084 2018-20i 22 May 2018 – 1,395,600 1,395,600 – – 8,206,128 Brian Gilvary 2015-17 11 Feb 2015 685,246 – – 611,626 c 22 May 2018d – 2016-18 4 Mar 2016 786,559 – 786,559 765,998f 2019f – 2017-19 g 19 May 2017 722,093 – 722,093 – – 3,408,279 2018-20i 22 May 2018 – 696,705 696,705 – – 4,096,625 a For awards under the 2015-17 and 2016-18 plans, performance conditions are measured one third on TSR relative to Chevron, ExxonMobil, Shell and Total ('comparator companies'); one third on operating cash flow; and one third on a balanced scorecard of strategic imperatives. 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, each of the strategic imperatives and strategic progress reaching the minimum threshold, has been calculated. For awards under the 2017-19 plan, performance conditions are measured 50% on TSR relative to Chevron, ExxonMobil, Shell and Total over three years; 30% on ROACE based on performance in 2019 and 20% on strategic progress assessed over the performance period. For awards under the 2018-20 plan, performance conditions are measured on the same basis as the 2017-19 plan, except ROACE which will be based on performance in the last two years of the performance period (i.e. 2019 and 2020). Each performance period ends on 31 December of the third year. b Bob Dudley 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 22 May 2018 was £5.88 and for ADSs was $47.09. These totals include the additional accrual of dividends which vested on 31 July 2018. d The 2015-17 award vested on 22 May 2018. Details can be found in the single figure table on page 95. e Bob Dudley has requested that the EDIP performance shares vesting in respect of the performance period 2016-18 is based on the 500% maximum annual award level which applies under the 2017 directors' remuneration policy, rather than the 550% maximum annual award level which applies under the 2014 directors' remuneration policy. The number reported here has been re-based to 500%. f For the assumed vestings in the second quarter of 2019 a price of £5.33 per ordinary share and $41.48 per ADS has been used. These are the average prices from the fourth quarter of 2018. g The face value has been calculated using the market price of ordinary shares on 19 May 2017 of £4.72. h In our 2017 report, the 31 December 2017 value for this award was incorrectly stated as 1,428,750. i The face value has been calculated using the market price of ordinary shares on 22 May 2018 of £5.88. 100 BP Annual Report and Form 20-F 2018

Corporate governance – – – – 101 787,529 749,447 655,861 655,861 696,870 696,870 344,890 344,890 the award, £ award, the 1,311,722 1,170,395 1,015,283 1,015,283 Face value of 1,330,268 2,030,565 28 Feb 2020 – – – – – – – – – – – – – – rcisable Expiry date imum vesting threshold level. Vesting date Vesting rst exe 19 Feb 20 Feb 2019 20 Feb 2018 20 Feb 2018 fi 01 Sep 2019 07 Sep 2014 07 Sep 2021 Date from which j j h h ed min – – – – – – – – – – – – – – fi – vested Interests vested in 2018 and 111,161 111,161 £5.27 Number of 193,580 193,580 ordinary shares Market price at date of exercise rs with a further one-year retention period. The face values 2018 ve yea 73,070 73,070 At 31Dec fi £3.72 £2.90 147,642 147,642 147,054 147,054 551,784 176,576 294,108 159,021 159,021 318,042 275,892 275,892 Option price — – – – – – – – – – – – – – – – – – a 2018 c Awarded Awarded 2018 127,457 127,457 226,236 226,236 3,103 At 31 De – – Share element interests element Share 2 Annual Report and Form 20-F 2018 Post employment share ownership interests As we reported last maintain to year, their alignment with shareholders and in keeping with the long-term nature of our business, our executive directors will retain significant interests in BP post employment. These ongoing interests are centred on a) the personal commitment by each executive director maintain to actual holdings equivalent two to and a half times salary for two years post employment, and b) their anticipated interests in share awards under group plans which remain subject to vesting and/or holding periods at the time they leave BP. At 1 Jan 73,070 73,070 Potential maximum deferred shares maximum deferred Potential 88,288 88,288 147,642 147,642 147,054 147,054 551,784 176,576 294,108 159,021 159,021 318,042 275,892 275,892 Exercised 100,000 400,000 i – – – lculated equivalents in ordinary shares. One ADS is equivalent to six ordinary shares. Granted ect ca fl 4 Mar 2016 4 Mar 2016 4 Mar 2016 4 Mar 2016 4 Mar 2016 4 Mar 2016 deferred shares deferred 11 Feb2015 11 11 Feb 2015 11 11 Feb2015 11 Feb2015 11 Feb2015 11 11 Feb2015 11 Date of awardDate of of 19 May19 2017 19 May19 2017 19 May19 2017 19 May19 2017 22 May2018 22 May 2018 k d d d d d d d i i 3,103 period 500,000 2017-19 2017-19 2015-17 2015-17 2015-17 2017-19 2017-19 2015-17 2015-17 2015-17 2016-18 2016-18 2016-18 2016-18 2016-18 2018-20 2018-20 2016-18 b Performance SAYE BP 2011 Vol Vol Vol Vol Type Option type At 1 Jan 2018 Mat Mat Mat Mat Mat Mat Comp Comp Comp Comp Comp Comp Comp Comp a f f c e g g year 2015 2016 2016 2014 2017 2017 2014 Bonus 2015 b 2011' means 2011' the BP plan. 2011 These options were granted to Brian Gilvary prior to his appointment as a director and are not subject to performance conditions. Represents vesting of shares at the end of the relevant performance period based on performance achieved under rules of the plan.Includes reinvested dividends on the shares vested. Brian Gilvary has voluntarily agreed to defer the performance assessment and vesting of these awardsperformance until the later of three period years post is expected award or one to exceed year post the minimum employment, term of three years. therefore the Bob Dudley has voluntarily agreed to defer the performance assessment and vesting of these awards untilexceed at least the minimum one year after term of three retirement, years. therefore the performance period is expected to The face value has been calculated using the market price of ordinary shares on 4 March 2016 of £3.68.The market price at closing of ordinary shares on May 19 2017 was £4.72 and for ADSs was $36.94. TheThe sterling market price value has at closing been used of ordinary to calculate the shares face on value. 22 May 2018 was £5.88 and for ADSs was $47.09. TheRepresents sterling value vestings has been of shares used to made calculate at the end the of the face relevant value. performance period based on performancevested. achieved The market under price rules of each of the plan share and used includes to determine reinvested the total value dividends at vesting on on the the shares vesting date of 20 Februarywhich 2018 vested was £4.75. on 22 May These 2018 and totals 31 July include 2018. the additional accrual of dividends Brian Gilvary has voluntarily agreed to defer the performance assessment and vesting of these matching awards for a total of Since 2010, vesting of the deferred shares has been subject to a safety and environmental sustainabilitydeterioration hurdle, and this will in safety continue. and environmental If the committee performance, assesses that there or there has have been been a material major incidents, eitherconclude of which reveal that underlying shares should vest weaknesses only in part, in safety or not and at all. environmental In reaching its management, conclusion, then the itcommittee may Bob will Dudley obtain received advice awards from the in the SEEAC. form of ADSs. There The is no above identi numbers re The face value has been calculated using the market price of ordinary shares February on 11 2015 of £4.46. have been calculated using the market prices of £4.46 per ordinary share February on 11 2015 and £3.68 per ordinary share on 4 March 2016. The market price of each shareused to determine the total value on the vesting date February of 19 2019 was £5.38. 'BP The closing market price of an ordinary share on 31 December 2018 was £4.96. During 2018 the highest market price was £5.98 and the lowest market price was £4.60. Neither Bob Dudley or Brian Gilvary have any interest in BP preference shares, debentures or option plans (other than as listed above), and neither have interests in shares or loan stock of any subsidiary company. No directors or other executive team members (see page 63) own more of the ordinarythan 1% shares in issue. MarchAt 15 2019, our directors and other executive team members collectively held interests of 17,436,602 ordinary shares or their calculated equivalents, 5,978,567 restricted share units (with or without performance 11,977,279 equivalents, calculated their or conditions) shares or their calculated options over equivalents and 4,417,149 ordinary shares or their calculated equivalents, under BP group share schemes. option Brian Gilvary Brian a b In common with many of our UK employees, Brian Gilvary holds options under the BP group save as you earn (SAYE) schemes as shown below. These options are not subject performance to conditions. Share interests in share options plans (audited) i j k f g h b c d e a Bob Dudley Bob Deferred shares (audited) Directors' remuneration report remuneration Directors' Brian Gilvary Brian

Non-executive director outcomes and interests The board's remuneration policy for the chairman and non-executive Non-executive directors fee structure directors (NEDs) was approved at the 2017 AGM and implemented The table below shows the fee structure for non-executive directors. during 2017. There has been no variance of the fees or allowances for the chairman and the NEDs since approval in 2017. Fees £ thousand a Chairman Senior independent director 120 Board member 90 The fee structure for the chairman, which has been in place since May Audit, geopolitical, remuneration and 2013, is £785,000 per year. The chairman is not eligible for committee SEEA committees chairmanship feesb 30 chairmanship and membership fees or intercontinental travel allowance. Committee membership feec 20 As chairman throughout 2018, Carl-Henric Svanberg had the use of a Intercontinental travel allowance 5 fully maintained office for company business, a car and driver, and a The senior independent director is eligible for committee chairmanship fees and security advice in London. He received a contribution to an office and intercontinental travel allowance plus any committee membership fees. secretarial support as appropriate to his needs in Sweden. The table b Committee chairmen do not receive an additional membership fee for the committee they chair. below shows the fees paid for the year ended 31 December 2018. c For members of the audit, geopolitical, SEEA and remuneration committees. 2018 remuneration (audited) 2018 remuneration (audited) £ thousand Fees Benefitsa Total £ thousand Fees Benefitsa Totalb 2018 2017 2018 2017 2018 2017 2018 2017 2018 2017 2018 2017 Carl-Henric Svanberg 785 785 24 35 809 820 Nils Andersen 132 115 11 17 144 132 a Benefits include travel and other expenses relating to attendance at board and other Paul Andersonc 69 155 6 27 76 182 meetings. Amounts disclosed have been grossed up using a tax rate of 45%, where relevant, as an estimation of tax due. Alan Boeckmann 155 165 10 11 165 176 Admiral Frank Bowman 160 155 14 15 174 170 The figures below include all the beneficial and non-beneficial interests Dame Alison Carnwathd 74 – 47 – 121 – of the chairman in shares of BP (or calculated equivalents) that have e been disclosed according to the disclosure guidance and transparency Pamela Daley 55 – 42 – 97 – rules in the Financial Conduct Authority handbook ('the DTRs') as at the Ian Davis 170 154 2 2 172 156 applicable dates. The chairman's holdings as at 31 December 2018, as a Professor Dame Ann percentage of the shareholding policy, were 1,312%. Dowlingf 158 145 2 5 159 150 Helge Lunde 46 – 122g – 169 – Ordinary Melody Meyerh 160 86 26 23 186 109 Ordinary Ordinary Change from shares or shares or shares or 31 Dec 2018 equivalents Brendan Nelson 150 138 12 14 162 152 equivalents at equivalents at to total at Paula Rosput Reynolds 166 146i 33 8 200 154i Chairman 1 Jan 2018 31 Dec 2018 15 Mar 2019 15 Mar 2019 Sir John Sawers 150 145 1 5 151 150 Carl-Henric Svanberga 2,076,695 2,076,695 – – 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, a Resigned on 31 December 2018. as an estimation of tax due. b Due to rounding, the totals may not agree exactly with the sum of its component parts. Helge Lund assumed the role of chairman with effect from 1 January c Resigned on 21 May 2018. d Appointed on 21 May 2018. 2019. His share interests are disclosed on page 103. e Appointed on 26 July 2018. f Fee includes £25 thousand for chairing and being a member of the BP technology advisory council. g Benefits include relocation expenses. h Appointed on 17 May 2017. i Amended from £140 thousand (fees) and £148 thousand (total) as originally disclosed in our 2017 report. 102 BP Annual Report and Form 20-F 2018

Corporate governance – 103 91% 67% 151% 417% 107% 107% 126% 135% 757% 273% 305% 446% achieved % of policy a – £81,914 £60,168 £60,168 £96,465 £274,113 $181,797 $181,797 £121,644 shareholding $128,627 $150,957 $327,358 £681,250 $535,214 Value of current £3,270,000 £3,270,000 c c c c c – 17,700 17,592 11,040 44,772 15,030 73,200 24,864 20,646 50,296 125,000 600,000 15 Mar 15 2019 equivalents at equivalents Ordinary shares or – 22,320 – – – – – – – – – – – – 15 15 2019 Changes from from Changes 31 Dec 2018 to c c c c c – BP Annual Report and Form 20-F 2018 17,700 17,592 44,772 15,030 73,200 24,864 20,646 50,296 600,000 31 Dec 2018 Ordinary shares or equivalents at c c c c c – – – 14,198 11,040 11,040 47,500 44,772 22,320 22,320 24,864 20,646 30,000 58,200 125,000 125,000 1 Jan 2018 Ordinary shares or equivalents at threshold for such d b e f Resigned on 21 May 2018. Appointed on 21 May 2018. policy achieved based on annual equivalent fee for role of chairman. Based on share and ADS prices March at 15 2019 of £5.45 and $43.87. Appointed on 26 July 2018. Held as ADSs. Appointed 26 July 2018. Became chairman with effect from 1 January 2019. Percentage of Helge Lund Professor Dame Ann Dowling Paul AndersonPaul Alan Boeckmann Ian Davis Admiral Frank Bowman Payments for loss of office and payments to past directors (audited) We made no payments for loss of office during or respectin to of 2018 directors. former or current 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 Limited Trustees on 1 October 2010. During 2018, he received £100,000 for this role. Other than this, we made no payment any past to director of BP during (we 2018 have no minimis de a disclosures). NilsAndersen Non-executive directors' interests (audited) The figures below indicate and include all the beneficial and Directors' remuneration report remuneration Directors' non-beneficial interestsof each non-executive director of the company in shares of BP (or calculated equivalents) that have been disclosed the to company under the DTRs as at the applicable dates. d e f b c Pamela Daley Brendan NelsonBrendan Dame Alison Carnwath Sir John Sawers Melody Meyer Melody Paula Rosput Reynolds Rosput Paula

Other disclosures Historical TSR performance Shareholder engagement F&#0;&#0;&#0; 100 &#0;&#0; Throughout 2018 we continued to discuss remuneration policy and approach with many of our largest shareholders, as well as investor &#0;2&#0;0 representative bodies. We plan to continue this dialogue in 2019, as we consider updates to our remuneration and minimum shareholdings policies for 2020. &#0;200 The table below shows the votes on the report for the last three years. AGM directors' remuneration report vote results &#0;1&#0;0 Year % vote 'for' % vote 'against' Votes withheld et&#0;&#0;al &#0;100 &#0;old&#0;n&#0; &#0;100 t&#0; et&#0;&#0;al 2018 96.42% 3.58% 42,741,541 &#0;100 2017 97.05% 2.95% 63,453,383 2016 40.70% 59.30% 464,259,340 &#0;alue o&#0; &#0;&#0;po o&#0; &#0;alue &#0;&#0;0 The remuneration policy was approved by shareholders at the 2017 AGM on 17 May 2017. The votes on the policy are shown below. 200&#0; 2010 2011 2012 201&#0; 201&#0; 201&#0; 201&#0; 201&#0; &#0;&#0;&#0;&#0; 2017 AGM directors' remuneration policy vote results Year % vote 'for' % vote 'against' Votes withheld This graph shows the growth in value of hypothetical £100 investments 2017 97.28% 2.72% 36,563,886 in BP p.l.c. ordinary shares, and in the FTSE 100 Index (of which BP is a constituent), over 10 years from 31 December 2008 to External appointments 31 December 2018. The board supports executive directors taking up appointments Independence and advice outside the company to broaden their knowledge and experience. Each executive director is permitted to retain any fee from their external The board considers all committee members to be independent appointments. Such external appointments are subject to agreement by with no personal financial interest, other than as shareholders, in the the chairman and reported to the board. Any external appointment must committee's decisions. Further detail on the activities of the committee, not conflict with a director's duties and commitments to BP. Details of advice received and shareholder engagement is set out in the appointments as non-executive directors of publicly listed companies remuneration committee report on page 83. during 2018 are shown below. During 2018 David Jackson, the then company secretary, and Appointee Additional position subsequently Hannah Ashdown, both of whom were employed by the Director company held at appointee company Total fees company and reported to the chairman of the board, acted as secretary Bob Dudley Rosnefta Director 0 to the remuneration committee. Brian Gilvary Air Liquide Non-executive director Euros 70,500 The committee also received advice on various matters relating to the a Bob Dudley holds this appointment as a result of the company's shareholding in Rosneft. remuneration of executive directors' and senior management from Helmut Schuster, executive vice president, group human resources, and Ashok Pillai, vice president, group reward. Committee membership Please refer to the committee report on page 83 for details of PricewaterhouseCoopers LLP ('PwC') continued to provide membership of the remuneration committee during 2018. independent advice to the committee in 2018, following its appointment as independent adviser to the committee in September 2017, following a competitive tender process. PwC 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. Freshfields Bruckhaus Deringer LLP provided legal advice on specific compliance matters to the committee. PwC and Freshfields provide other advice in their respective areas to the group. During the year, PwC provided BP with services including subsidiary company secretarial support. Total fees or other charges (based on an hourly rate) for the provision of remuneration advice to the committee in 2018 (save in respect of legal advice) were £179,200 to PwC. 104 BP Annual Report and Form 20-F 2018

Corporate governance 105 ial performance – 50%. performance – ial onment – 10% ty – 20% able operations – 20% 19, performance will be assessed against: mmittee holds discretionadjust to outcomes reflect to ition, the executive directors have voluntarily elected to rpin – the committee will then review broader fits will remain unchangedfor 2019. These include e changes reduce Brian's cash supplement sooner supplement cash Brian's reduce changes e ting from 1 June 2019, we agreed reduce to Brian's cash Safe Envir Reli Financ impacting safety environmental or sustainability, by the committee. Bonus is subject malus to and clawback provisions or restatement misconduct, as such events following Malus miscalculation. and results, of misstatement may also be applied following a material failure decided as circumstances exceptional other or Performance shares are subject malus to and clawback misconduct, as such events following provisions and results, of misstatement or restatement miscalculation. applied be also following Malus may a material failure impacting safety or environmental as circumstances exceptional other or sustainability, decided by the committee. – – – – defer the vesting date of certain other share awards, with performanceassociated otherwise conditions, would which unrestricted. been have In add For 20 Unde TSR, and safety absolute including performance, environmental factors in order determine to the final outcome. vesting Bene car-relatedpreparation, benefits,return assistance tax with security medical and benefits. assistance, insurance Star supplement of by salary 5% each year reach to 20% of salary with effect from 1 June 2021, with a further reduction, 5% Thes to 15% of salary,15% to with effect from September 1 2023. The co than the transition for other members of the BP UK defined UK BP the members of other for transition the than benefits plan, and Brian will not receive anyform of normal His reductions. the to related compensation retirement age is 60, although benefits accrued before 1 December 2006 may be paid from age 55 with BP's consent. performance considerations. broader • • • • • • BP Annual Report and Form 20-F 2018 lative oil to and gas majors – 50% weighting. E – averaged over the full period – 20% weighting. onus earned is paid in cash, 50% is deferred into ress against our strategic objectives – 30% es aligned to BP strategy and shareholders' interests. interests. shareholders' and strategy BP to aligned es d Brian are expected maintain to a holding of at least orecard measures for the bonus are set annually to ffect from the AGM, Brian Gilvary's salary will increase ecard outcome of 1.0, reflecting target on each e 2019-21 cycle, vesting level will first be assessed on ompares an to average increase of over 3.5% our to UK surement scale on every measurea scorecard – n is a member of the BP UK defined benefits pension ROAC Prog TSR re weighting. rual under his defined his benefitarrangements. under rual pension ding of five times salary. ee-year holding period.ee-year holding – – – The table below shows how the remuneration policy approved by shareholders at the 2017 AGM by shareholders at the 2017 policy approved shows how the remuneration The table below . go to bp.com/remuneration full remuneration policy, please in 2019. For the will be implemented Continuing requirement for executive directors maintain to a hol Bob an two and a half times salary for two years post employment. outcome of 2.0. scales measurement sets priorities. reflect committee The year-on-year require that (disclosed retrospectively) improvement. Three-year performance further by period, followed thr Measur For th areas: these in years three performance the over future years. His normal retirement age is 60. Maximum bonus requires performance at the top of the mea A scor maximum bonus. of half delivers scale, measurement 50% of b shares for three years. The sc Bob Dudley's salary will remain at $1,854,000 for 2019. With e by £790,500. to 2% This c salaried staff, effective on our annual salary review date 1 April. Since September 2016, Bob has had no further service acc The 401(k) benefits have been partially cappedfor Bria plan and he receives a cash supplement in lieu of further participants other service as in terms same accrual the on the plan, currently 35% of salary. • • • • • • • • • • • • • • Directly linked long-term to performance and represents the largest part of total remuneration. Reinforces alignment with shareholder interests, and stewardship of the enterprise. Salary and benefitsreflect the scale and complexity of the role, and competitive practice in the market. The bonus links variable pay safety, to environmental goals, reliable operations and financial performance for the year. 2019 CFO – 450% of salary reflects Vesting three-year performance GCE – 500% Share ownership Long-term shareholding obligation Performance shares Annual bonus Reflectshome country market Reflectsrole and home country market benefits Retirement Salary and benefits Up 225% to of salary annual with Aligned objectives Executive director remuneration policyremuneration director Executive Directors' remuneration report remuneration Directors' 2019 for and implementation

Salary and benefits Bob's annual salary will remain at $1,854,000 for 2019. Brian's salary Salary increases over the last five years will increase by 2% to £790,500 from the date of the 2019 AGM. For Bob Dudley Brian Gilvary reference, the April 2019 annual pay review of our salaried employees in the UK was subject to a budget in excess of 3.5%. 2019 Nil 2019 2.0% We expect to maintain benefits at the current level. 2018 &#0;&#0;l 2018 2&#0;0&#0; 201&#0; &#0;&#0;l 201&#0; &#0;&#0;&#0;&#0;&#0;&#0; 201&#0; &#0;&#0;l 201&#0; &#0;&#0;l 201&#0; &#0;&#0;l 201&#0; &#0;&#0;l Salary with effect from AGM Increase Bob Dudley $1,854,000 Nil Brian Gilvary £790,500 2.0% Annual bonus For 2019 we have amended our bonus measures to include an changes in plan conditions (including oil and gas prices and refining environmental measure (10%) alongside safety (20%), reliable margins) when reviewing financial outcomes at year end, and retains operations (20%) and financial performance (50%). This approach discretion to review outcomes in the context of overall performance. will provide a balanced assessment of how the business has performed Awards will be subject to malus and clawback provisions as described over the course of the year and of our progress in addressing emissions in the 2017 policy. reduction. We are also changing downstream refining availability to BP-operated downstream refining availability to more closely align to our The maximum bonus opportunity remains 225% of salary, for a BP-operated upstream plant reliability measure. maximum bonus score of 2.0. In accordance with the 2017 policy, the bonus payable for performance which meets the annual plan The committee has set the 2019 targets after consultation on the safety (i.e. a bonus score of 1.0 out of a maximum of 2.0) is half of maximum, targets with the SEEAC and on the financial targets with the MBAC. 112.5% of salary. Although the detail of these targets is currently commercially sensitive, the committee will provide retrospective disclosure following the year For any bonus earned, 50% will be delivered in cash and 50% will be end, as with previous cycles. As before, the committee will consider deferred into shares that will vest after three years. Measures for 2019 annual bonus Element Safety Environment Financial performance Reliable operations 20% 10% 50% 20% Measures Weighting Measures Weighting Measures Weighting Measures Weighting include for 2019 include for 2019 include for 2019 include for 2019 Recordable injury 10% Sustainable emissions 10% Operating cash 20% BP-operated upstream 10% frequency KPI reduction KPI flow xcludinge Gulf of plant reliability KPI Tier 1 and tier 2 process 10% Mexico oil spill payments KPI BP-operated 10% safety events KPI Underlying 20% downstream refining replacement availability (Solomon cost profit KPI Associates' operational Upstream unit 10% availability) KPI production costs KPI 106 BP Annual Report and Form 20-F 2018

Corporate governance 107 t-led downstream growth the in ower and renewables trading renewables and ower ing gas and advantaged oil in the uring and low carbon across multiple fronts Grow upstream Marke Vent Gas, p growth marketing and • Strategic progress 30% • • • KPI b BP Annual Report and Form 20-F 2018 Future growthFuture Measures for the strategic element are directly focused on deliveryof resilience portfolio the for positioning long-term strategy, company's the and future growth. We will be following the implementation of our strategy through the four measures relating the to strategic priorities set out below. The committee has also sought input from the board specific the regarding measures. Detailsthe of strategic progress targets – which carry a 30% weighting in the vesting calculation – are commercially sensitive and are not included in this report. the committee However, intends provide to detailed retrospective disclosure after the end of the performance period so that shareholders will be able review to the basis of our assessment.The board regularly reviews progress on the strategic quarterly BP's announcement and year priorities results the throughout progress. strategic group's the on updates includes Broader performance assessment – the underpin Prior approving to vesting outcomes, the committee will also consider the broader performance of the business including absolute TSR (including factors performance, environmental with safety and together consideration issues of around greenhouse gases) over the three-year period. this to We refer as the underpin. The underpin will be applied after the formulaic outcome for the performance shares but before the finalvesting outcome has been determined. In looking at environmental factors, the committee will consider the improving emissions, reducing as such issues on progress group's our products and creating low carbon businesses – see page 46. Return average capital on employed 20% 12.5% return on average12.5% capital employed 0% of element 8.5% return on average capital employed 100% of element KPI a 25% of element25% Third out five of 100% of element place First 50% Threshold vesting Maximum vesting Relative TSR versus oil majors Based on the average of performance over 2019, 2020 and 2021. There will be straight-line vesting for performance between the threshold and maximum vesting level. Adjustments may Element be required in certain circumstances (e.g. to reflect changes in accounting standards). Nil vesting for fourth and fifth place.Vesting of 80% for second place. Measures performance for 2019-21 shares a b Performance shares Performance Directors' remuneration report remuneration Directors' In line with policy, our the2017 performance share awards for our 2019-21 cycle will be granted at in the 2019 level of 500% of salary for Bob and 450% of salary for Brian. Performance will then be measured over three years, with any vested shares being subject a mandatory to holding period further of a three years. These awards are subject to malus and clawback provisions as set out in the policy. The measures for the 2019-21 cycle of performance shares focus on shareholder value, capital discipline and future growth. Shareholder value The TSR element is measured on a relative basis against the oil majors: Chevron, ExxonMobil, Shell We maintain and Total. our belief that the current comparator group remains appropriate as it is used for benchmarking across a range of activities in otherparts of the group. This measure carries a 50% weighting in the vesting calculation, with targets shown below. disciplineCapital ROACE is calculated by dividing the underlying replacement cost profit (after adding back net interest) by average capital employed excluding cash and goodwill (see Glossary on page for full definition). 315 ROACE is measured based on the actual price environmentfor each of the years in question; there will be no adjustments for changes plan to conditions. For the 2019-21 performance shares award, this assessment will be averaged over the full three-year period. This ROACE measure carries a 20% weighting in the vesting calculation, and targets are shown in the table below.

Retirement benefits Bob Dudley Bob is provided with pension benefits and retirement savings through a provided directly by the company rather than through the BPPS. The combination of tax-qualified and non-qualified benefit plans. His normal rules of this non-qualified arrangement are designed to mirror the design retirement age is 60. of the approved BPPS. The BP Supplemental Executive Retirement Benefit Plan (SERB) is a The BPPS is closed to new hires, but for existing participants the plan non-qualified defined benefit pension plan which provides a pension of continues to provide a pension of one sixtieth of final base salary for 1.3% of final average earnings for each year of service, less benefits each year of service, up to a maximum of two thirds of final base salary, paid under all other BP (US) tax-qualified and non-qualified pension and a dependant's benefit of two thirds of the member's pension. plans. In 2016 Bob reached the SERB service limit of 37 years of service On 1 April 2011, Brian elected to stop future service accrual and instead and therefore no longer builds up further service accrual under these receive a cash allowance. His accrued benefits in the approved and pension plans. However the accrued benefit remains linked to highest unapproved plans remain linked to his final base pay. average earnings within the final 10 years. The benefit payable under the The rules of the BPPS were amended in 2006 to introduce a normal SERB is unreduced at age 60 or older. retirement age of 65, but in common with other BPPS participants in The BP Employee Savings Plan (ESP) is a US tax-qualified defined service on 30 November 2006, Brian has a normal retirement age of 60. contribution plan to which both Bob and BP contribute. BP matches Subject to the consent of the committee, Brian may retire between age Bob's salary contributions to a maximum of 7% of base salary, up 55 and 60 and be entitled to an immediate pension, with a reduction to the IRS limit. The BP Excess Compensation (Savings) Plan (ECSP) (currently 3%) for each year before normal retirement age in respect of is a non-qualified, unfunded, retirement savings plan to which BP the benefit that relates to service since 1 December 2006 and no notionally contributes 7% of base salary above the annual IRS limit. reduction in respect of the remainder of his benefit. In common with around 2,000 other participants, Bob does not Irrespective of this, on leaving in circumstances of total incapacity, an contribute to the ECSP. immediate unreduced pension would be payable from his leaving date. Under both savings plans, Bob is entitled to make investment elections, BPPS members can elect to stop accrual and instead receive a cash involving the actual investment holdings in the case of the ESP, allowance of 35% of salary until March 2021, then progressively and the notional investment holdings in the case of the ECSP. Benefits reducing to 15% of salary by March 2024 (or such earlier date that they payable under the ECSP are unfunded and will therefore be paid from would have accrued a maximum two-thirds pension under the BPPS corporate assets. Accordingly annual investment returns on the ECSP had they not opted out). As noted above, on 1 April 2011 Brian elected are recognized as income for the single figure table, in addition to the to stop future service accrual and receive this cash allowance. Currently notional contributions themselves. Conversely, annual investment over 650 employees have elected to stop future service accrual under losses are offset against the value of contributions and notional the final salary plan and instead receive the 35% cash allowance. Brian contributions by BP and therefore reduce the amount recognized as has offered to accelerate the schedule of this progressive reduction. income for the single figure table. Accordingly reductions to 30%, 25% and 20% will be made with effect Brian Gilvary from 1 June 2019, 2020 and 2021 respectively, and a final reduction to 15% with effect from 1 September 2023 being the date on which Brian Brian is provided with pension benefits and retirement savings through would have reached a maximum two-thirds pension under the BPPS a combination of tax-qualified and non-qualified benefit plans and a had he not opted out. cash allowance. His normal retirement age is 60, although benefits accrued before 1 December 2006 may be paid from age 55 with BP's consent. Brian is a member of a UK final salary defined benefit pension plan, the BP Pension Scheme (BPPS), along with over 3,800 other UK employees. Pension benefits that have been accrued in the BPPS in excess of the individual lifetime tax allowance set by legislation are provided to Brian via a non-qualified, unfunded pension arrangement Shareholding requirements Both executive directors remain subject to the share ownership requirement of five-times salary, which they currently exceed. Based on the commitments each director has made to the committee, we expect that Bob and Brian will each maintain shareholdings of at least 250% of salary for two years post employment. 108 BP Annual Report and Form 20-F 2018

Corporate governance 109 . BP Annual Report and Form 20-F 2018 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. 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 level and structure of non-executive directors' remuneration is reviewed by the chairman, the GCE and the company secretary who make a recommendation the to board. Non-executive directors do not on vote their own remuneration. Remuneration for non-executive directors is reviewed annually. Non-executive directors receive an allowance reflect to 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. The allowance is paid in cash following each event of intercontinental travel. The chairman is provided with an office and full-time secretarial and administrative support in London and a contribution an to 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. 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 reflect to additional boardresponsibilities, forexample, committee chairmanship and membership and for the role of senior independent director. Remuneration is in the form cash of fees, payable monthly. The level and structure of the chairman's remuneration will practice. best UK against compared be primarily The quantum and structure of the non-executive chairman's remuneration is reviewed annually by the remuneration committee, which makes a recommendation the to board. The chairman is provided with support and reasonable travelling expenses The table below shows the remuneration policy approved by shareholders at policy approved by shareholders shows the remuneration The table below . policy, please go to bp.com/remuneration For the full remuneration the 2017 AGM. Operation and Operation opportunity Operation and Operation opportunity Operation and Operation opportunity Operation and Operation opportunity Operation and Operation opportunity Approach Approach Benefitsexpenses and Other fees and benefits allowance Intercontinental Non-executive directors Fees Approach Benefits and expenses Approach Approach Non-executive chairman Fees The maximum fees for non-executive directors are set in accordance with the Articles of Association. Directors' remuneration report remuneration Directors' policyNon-executive 2019 for remuneration director This directors' remuneration report was approved by the board and signed on its behalf by Jens Bertelsen, company secretary on 29 March 2019.

Pages 110-111 have been removed as they do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Financial statements

Consolidated financial statements of the BP group

Pages 114-125 have been removed as they do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

This page does not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Consolidated financial statements of the BP group
Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of BP p.l.c.

Opinion on the financial statements
We have audited the accompanying group balance sheet of BP p.l.c. and subsidiaries (the Company) as at 31 December 2018, the related group income statement, statements of comprehensive income and changes in equity, and group cash flow statement, for the year ended 31 December 2018, and the related notes (collectively referred to as the 'financial statements'). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of 31 December 2018, and the results of its operations and its cash flows for the year ended 31 December 2018, in conformity with International Financial Reporting Standards (IFRS) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board.
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of 31 December 2018, based on criteria established in the UK Financial Reporting Council’s Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting and our report dated 29 March 2019 expressed an unqualified opinion on the Company's internal control over financial reporting.
Basis for opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Deloitte LLP

London
United Kingdom
29 March 2019

The first accounting period we audited was the 12 months ended 31 December 2018. In 2017, we commenced our audit planning procedures.

Consolidated financial statements of the BP group
Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of BP p.l.c.

Opinion on internal control over financial reporting
We have audited the internal control over financial reporting of BP p.l.c. and subsidiaries (the Company) as at 31 December 2018, based on the criteria established in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting (UK FRC Guidance). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of 31 December 2018, based on the criteria established in the UK FRC Guidance.
We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as at and for the year ended 31 December 2018, of the Company and our report dated 29 March 2019, expressed an unqualified opinion on those financial statements.
As described in Management's report on internal control over financial reporting on page 301, management excluded from its assessment the internal control over financial reporting at Petrohawk Energy Corporation, which was acquired on 31 October 2018 and whose financial statements constitute 10.3% and 4.0% of net and total assets, respectively, 0.2% of total revenues and other income, and 0.05% of profit for the year of the consolidated financial statement amounts as at and for the year ended 31 December 2018. Accordingly, our audit did not include the internal control over financial reporting at Petrohawk Energy Corporation.
Basis for opinion
The Company'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. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audit in accordance with the standards of the PCAOB. 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.
Definition and limitations of internal control over financial reporting
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.

/s/ Deloitte LLP

London, United Kingdom
29 March 2019

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 29 March 2019, relating to the consolidated financial statements of BP p.l.c. (the 'company'), and the effectiveness of the company's internal control over financial reporting, appearing in the Annual Report on Form 20-F of the company for the year ended 31 December 2018, in the following Registration Statements:

Registration Statements on Form F-3 (File Nos. 333-226485, 333-226485-01 and 333-226485-02) of BP p.l.c., BP Capital Markets p.l.c. and BP Capital Markets America Inc.; 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, 333-210318) of BP p.l.c.

/s/ Deloitte LLP
London, United Kingdom
29 March 2019

Consolidated financial statements of the BP group
Report of Independent Registered Public Accounting Firm
To the shareholders and board of directors of BP p.l.c.

Opinion on the financial statements
We have audited the accompanying group balance sheets of BP p.l.c. (the Company) as of 31 December 2017, 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 two years in the period ended 31 December 2017, and the related notes (collectively referred to as the "group financial statements"). In our opinion, the group financial statements present fairly, in all material respects, the financial position of BP p.l.c. at 31 December 2017 and the results of its operations and its cash flows for each of the two years in the period ended 31 December 2017, in conformity with International Financial Reporting Standards (IFRS) as adopted by the European Union and IFRS as issued by the International Accounting Standards Board.
Basis for opinion
These financial statements are the responsibility of BP p.l.c.'s management. Our responsibility is to express an opinion on these financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to BP p.l.c. in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP
We served as the Company's auditor from 1909 to 2018.
London, United Kingdom
29 March 2018

Note that the report set out above is included for the purposes of BP p.l.c.’s Annual Report on Form 20-F for 2018 only and does not form part of BP p.l.c.’s Annual Report and Accounts for 2017.

Group income statement

For the year ended 31 December

	Note	2018	2017	2016
				$ million
Sales and other operating revenues	5	298,756	240,208	183,008
Earnings from joint ventures – after interest and tax	16	897	1,177	966
Earnings from associates – after interest and tax	17	2,856	1,330	994
Interest and other income	7	773	657	506
Gains on sale of businesses and fixed assets	4	456	1,210	1,132
Total revenues and other income		303,738	244,582	186,606
Purchases	19	229,878	179,716	132,219
Production and manufacturing expenses[a]		23,005	24,229	29,077
Production and similar taxes	5	1,536	1,775	683
Depreciation, depletion and amortization	5	15,457	15,584	14,505
Impairment and losses on sale of businesses and fixed assets	4	860	1,216	(1,664)
Exploration expense	8	1,445	2,080	1,721
Distribution and administration expenses		12,179	10,508	10,495
Profit (loss) before interest and taxation		19,378	9,474	(430)
Finance costs[a]	7	2,528	2,074	1,675
Net finance expense relating to pensions and other post-retirement benefits	24	127	220	190
Profit (loss) before taxation		16,723	7,180	(2,295)
Taxation[a]	9	7,145	3,712	(2,467)
Profit (loss) for the year		9,578	3,468	172
Attributable to				
BP shareholders		9,383	3,389	115
Non-controlling interests		195	79	57
		9,578	3,468	172
Earnings per share				
Profit (loss) for the year attributable to BP shareholders				
Per ordinary share (cents)				
Basic	11	46.98	17.20	0.61
Diluted	11	46.67	17.10	0.60
Per ADS (dollars)				
Basic	11	2.82	1.03	0.04
Diluted	11	2.80	1.03	0.04

[a] See Note 2 for information on the impact of the Gulf of Mexico oil spill on these income statement line items.

Group statement of comprehensive income[a]

For the year ended 31 December				$ million
	Note	2018	2017	2016
Profit (loss) for the year		9,578	3,468	172
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		(3,771)	1,986	254
Exchange (gains) losses on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		—	(120)	30
Available-for-sale investments		—	14	1
Cash flow hedges marked to market	30	(126)	197	(639)
Cash flow hedges reclassified to the income statement	30	120	116	196
Cash flow hedges reclassified to the balance sheet	30	—	112	81
Costs of hedging marked to market	30	(244)	—	—
Costs of hedging reclassified to the income statement	30	58	—	—
Share of items relating to equity-accounted entities, net of tax	16, 17	417	564	833
Income tax relating to items that may be reclassified	9	4	(196)	13
		(3,542)	2,673	769
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	24	2,317	3,646	(2,496)
Cash flow hedges that will subsequently be transferred to the balance sheet	30	(37)	—	—
Income tax relating to items that will not be reclassified	9	(718)	(1,303)	739
		1,562	2,343	(1,757)
Other comprehensive income		(1,980)	5,016	(988)
Total comprehensive income		7,598	8,484	(816)
Attributable to				
BP shareholders		7,444	8,353	(846)
Non-controlling interests		154	131	30
		7,598	8,484	(816)

[a] See Note 32 for further information.

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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 31 December 2017	46,122	(16,958)	(5,156)	(743)	75,226	98,491	1,913	100,404
Adjustment on adoption of IFRS 9, net of tax	—	—	—	(54)	(126)	(180)	—	(180)
At 1 January 2018	46,122	(16,958)	(5,156)	(797)	75,100	98,311	1,913	100,224
Profit (loss) for the year	—	—	—	—	9,383	9,383	195	9,578
Other comprehensive income	—	—	(3,746)	(216)	2,023	(1,939)	(41)	(1,980)
Total comprehensive income	—	—	(3,746)	(216)	11,406	7,444	154	7,598
Dividends[b]	—	—	—	—	(6,699)	(6,699)	(170)	(6,869)
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	26	—	26	—	26
Repurchase of ordinary share capital	—	—	—	—	(355)	(355)	—	(355)
Share-based payments, net of tax	230	1,191	—	—	(718)	703	—	703
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	14	14	—	14
Transactions involving non-controlling interests, net of tax	—	—	—	—	—	—	207	207
At 31 December 2018	46,352	(15,767)	(8,902)	(987)	78,748	99,444	2,104	101,548
At 1 January 2017	46,122	(18,443)	(6,878)	(1,153)	75,638	95,286	1,557	96,843
Profit (loss) for the year	—	—	—	—	3,389	3,389	79	3,468
Other comprehensive income	—	—	1,722	410	2,832	4,964	52	5,016
Total comprehensive income	—	—	1,722	410	6,221	8,353	131	8,484

Dividends[b]	—	—	—	—	(6,153)	(6,153)	(141)	(6,294)
Repurchase of ordinary share capital	—	—	—	—	(343)	(343)	—	(343)
Share-based payments, net of tax	—	1,485	—	—	(798)	687	—	687
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	215	215	—	215
Transactions involving non-controlling interests, net of tax	—	—	—	—	446	446	366	812
At 31 December 2017	46,122	(16,958)	(5,156)	(743)	75,226	98,491	1,913	100,404
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, net of tax	—	—	—	—	430	430	463	893
At 31 December 2016	46,122	(18,443)	(6,878)	(1,153)	75,638	95,286	1,557	96,843

[a] See Note 32 for further information.
[b] See Note 10 for further information.

Group balance sheet

At 31 December			$ million
	Note	2018	2017
Non-current assets			
Property, plant and equipment	12	135,261	129,471
Goodwill	14	12,204	11,551
Intangible assets	15	17,284	18,355
Investments in joint ventures	16	8,647	7,994
Investments in associates	17	17,673	16,991
Other investments	18	1,341	1,245
Fixed assets		192,410	185,607
Loans		637	646
Trade and other receivables	20	1,834	1,434
Derivative financial instruments	30	5,145	4,110
Prepayments		1,179	1,112
Deferred tax assets	9	3,706	4,469
Defined benefit pension plan surpluses	24	5,955	4,169
		210,866	201,547
Current assets			
Loans		326	190
Inventories	19	17,988	19,011
Trade and other receivables	20	24,478	24,849
Derivative financial instruments	30	3,846	3,032
Prepayments		963	1,414
Current tax receivable		1,019	761
Other investments	18	222	125
Cash and cash equivalents	25	22,468	25,586
		71,310	74,968
Total assets		282,176	276,515
Current liabilities			
Trade and other payables	22	46,265	44,209
Derivative financial instruments	30	3,308	2,808
Accruals		4,626	4,960
Finance debt	26	9,373	7,739
Current tax payable		2,101	1,686
Provisions	23	2,564	3,324
		68,237	64,726
Non-current liabilities			
Other payables	22	13,830	13,889
Derivative financial instruments	30	5,625	3,761
Accruals		575	505
Finance debt	26	56,426	55,491
Deferred tax liabilities	9	9,812	7,982
Provisions	23	17,732	20,620
Defined benefit pension plan and other post-retirement benefit plan deficits	24	8,391	9,137
		112,391	111,385
Total liabilities		180,628	176,111
Net assets		101,548	100,404
Equity			
BP shareholders’ equity	32	99,444	98,491

Non-controlling interests	32	2,104	1,913
Total equity	32	101,548	100,404

Helge Lund Chairman
R W Dudley Group chief executive
29 March 2019

Group cash flow statement

For the year ended 31 December

	Note	2018	2017	$ million 2016
Operating activities				
Profit (loss) before taxation		16,723	7,180	(2,295)
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	8	1,085	1,603	1,274
Depreciation, depletion and amortization	5	15,457	15,584	14,505
Impairment and (gain) loss on sale of businesses and fixed assets	4	404	6	(2,796)
Earnings from joint ventures and associates		(3,753)	(2,507)	(1,960)
Dividends received from joint ventures and associates		1,535	1,253	1,105
Interest receivable		(468)	(304)	(200)
Interest received		348	375	267
Finance costs	7	2,528	2,074	1,675
Interest paid		(1,928)	(1,572)	(1,137)
Net finance expense relating to pensions and other post-retirement benefits	24	127	220	190
Share-based payments		690	661	779
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	24	(386)	(394)	(467)
Net charge for provisions, less payments		986	2,106	4,487
(Increase) decrease in inventories		672	(848)	(3,681)
(Increase) decrease in other current and non-current assets		(2,858)	(4,848)	(1,172)
Increase (decrease) in other current and non-current liabilities		(2,577)	2,344	1,655
Income taxes paid		(5,712)	(4,002)	(1,538)
Net cash provided by operating activities		22,873	18,931	10,691
Investing activities				
Expenditure on property, plant and equipment, intangible and other assets		(16,707)	(16,562)	(16,701)
Acquisitions, net of cash acquired	3	(6,986)	(327)	(1)
Investment in joint ventures		(382)	(50)	(50)
Investment in associates		(1,013)	(901)	(700)
Total cash capital expenditure		(25,088)	(17,840)	(17,452)
Proceeds from disposals of fixed assets	4	940	2,936	1,372
Proceeds from disposals of businesses, net of cash disposed	4	1,911	478	1,259
Proceeds from loan repayments		666	349	68
Net cash used in investing activities		(21,571)	(14,077)	(14,753)
Financing activities				
Repurchase of shares		(355)	(343)	—
Proceeds from long-term financing		9,038	8,712	12,442
Repayments of long-term financing		(7,210)	(6,276)	(6,685)
Net increase (decrease) in short-term debt		1,317	(158)	51
Net increase (decrease) in non-controlling interests		—	1,063	887
Dividends paid				
BP shareholders	10	(6,699)	(6,153)	(4,611)
Non-controlling interests		(170)	(141)	(107)
Net cash provided by (used in) financing activities		(4,079)	(3,296)	1,977
Currency translation differences relating to cash and cash equivalents		(330)	544	(820)
Increase (decrease) in cash and cash equivalents		(3,107)	2,102	(2,905)
Cash and cash equivalents at beginning of year[a]		25,575	23,484	26,389

Cash and cash equivalents at end of year	22,468	25,586	23,484

[a] See Note 1 for further information.

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 BP p.l.c and its subsidiaries (collectively referred to as BP or the group) for the year ended 31 December 2018 were approved and signed by the group chief executive and chairman on 29 March 2019 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 as applicable to companies reporting under IFRS. 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 2018. The accounting policies that follow have been consistently applied to all years presented, except where otherwise indicated.

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 consolidated 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 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 the investment in Rosneft; oil and natural gas accounting, including the estimation of reserves; the recoverability of asset carrying values; derivative financial instruments; provisions and contingencies; and pensions and other post-retirement benefits. Where an estimate has a significant risk of resulting in a material adjustment to the carrying amounts of assets and liabilities within the next financial year this is specifically noted within the boxed text. The group no longer considers the recoverability of trade receivables to represent one of its significant accounting judgements following the adoption of IFRS 9 'Financial Instruments´ and resulting recognition of expected credit losses, see Impact of new International Financial Reporting Standards for more information. The group does not consider income taxes to represent a significant estimate or judgement for 2018, see Income taxes for more information.

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 14 for further information.

Goodwill may 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.

Goodwill may also arise upon acquisition of interests in joint operations that meet the definition of a business. The amount of goodwill separately recognized is the excess of the consideration transferred over the group's share of the net fair value of the identifiable assets and liabilities.

Interests in joint arrangements

The results, assets and liabilities of joint ventures are incorporated in these consolidated 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 consolidated financial statements using the equity method of accounting as described below.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Significant judgement: investment in Rosneft

Judgement is required in assessing the level of control or influence over another entity in which the group holds an interest. For BP, the judgement that the group has significant influence over Rosneft Oil Company (Rosneft), a Russian oil and gas company is significant. As a consequence of this judgement, BP uses the equity method of accounting for its investment and BP's share of Rosneft's oil and natural gas reserves is included in the group's estimated net proved reserves of equity-accounted entities. If significant influence was not present, the investment would be accounted for as an investment in an equity instrument measured at fair value as described under 'Financial assets' below and no share of Rosneft's oil and natural gas reserves would be reported.

Significant influence is defined in IFRS as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those policies. Significant influence is presumed when an entity owns 20% or more of the voting power of the investee. Significant influence is presumed not to be present when an entity owns less than 20% of the voting power of the investee.

BP owns 19.75% of the voting shares of Rosneft. The Russian federal government, through its investment company JSC Rosneftegaz, owned 50% plus one share of the voting shares of Rosneft at 31 December 2018. 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 chairman 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. BP's management consider, therefore, that the group has significant influence over Rosneft, as defined by IFRS.

The equity method of accounting

Under the equity method, an 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 in the accounting policies used by the equity-accounted entity and those used by BP, 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 there is objective evidence that the investment is impaired. If any such objective evidence 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 if the borrowings form part of the net investment in the subsidiary, joint venture or associate. On disposal or for certain partial disposals 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.

Significant 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.

1. Significant accounting policies, judgements, estimates and assumptions – continued

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 are carried initially at cost unless acquired as part of a business combination. Any such asset is measured at fair value at the date of the business combination and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life, other than capitalized exploration and appraisal costs as described below, are amortized on a straight-line basis over their expected useful lives. For patents, licences and trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to fifteen years. Computer software costs generally have a useful life of three to five years.

The expected useful lives of assets and the amortization method are reviewed on an annual basis and, if necessary, changes in useful lives or the amortization method 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.

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 or appraisal work in the area, remain capitalized on the balance sheet as long as such work is under way or firmly planned.

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

Judgement is required to determine whether it is appropriate to continue to carry costs associated with exploration wells and exploratory-type stratigraphic test wells on the balance sheet. This includes costs relating to exploration licences or leasehold property acquisitions. It is not unusual to have such costs 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 circumstances that indicate 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 that were scheduled to expire at the end of 2013 and some with terms that 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. The carrying amount of capitalized costs is included in Note 8.

1. Significant accounting policies, judgements, estimates and assumptions – continued

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, directly attributable general or specific finance costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes, and all other maintenance costs are expensed as incurred.

Oil and natural gas properties, including related pipelines, are depreciated using a unit-of-production method. The cost of producing wells is amortized over proved developed reserves. Licence acquisition, common facilities and future decommissioning costs are amortized over total proved reserves. The unit-of-production rate for the depreciation of common facilities takes into account expenditures incurred to date, together with estimated future capital expenditure expected to be incurred relating to as yet undeveloped reserves expected to be processed through these common facilities. 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 12 and Note 5 respectively.

Estimates of oil and natural gas reserves determined by applying US Securities and Exchange Commission regulations including the determination of prices using 12-month historical data 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.

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 210, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 286. The 2018 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 210.

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 and depreciation method of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives or the depreciation method 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.

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.

1. Significant accounting policies, judgements, estimates and assumptions – continued
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 that are not reflected in the discount rate and are discounted to their present value typically 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 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. For example, certain oil and gas properties with shared infrastructure may be grouped together to form a single CGU. Alternative groupings of assets or CGUs may result in a different outcome from impairment testing. See Note 14 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 expected sales proceeds or similar recent market transaction data or, where recent market transactions 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, estimates 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.

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 12, Note 14 and Note 15.

The estimates for assumptions made in impairment tests in 2018 relating to discount rates, oil and gas properties and oil and gas prices are discussed below. Changes in the economic environment or other facts and circumstances may necessitate revisions to these assumptions and could result in a material change to the carrying values of the group's assets within the next financial year.

Discount rates

For discounted cash flow calculations, future cash flows are adjusted for risks specific to the cash-generating unit. Value-in-use calculations are typically discounted using a pre-tax discount rate 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 2018 the post-tax discount rate was 6% (2017 6%) and the pre-tax discount rate was 9% (2017 9%). 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 (2017 2%). The judgement of classifying a country as higher risk takes into account various economic and geopolitical factors.

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.

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

The long-term price assumptions used to determine recoverable amount based on value-in-use impairment tests from 2024 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 (2017 $75 per barrel and $4/mmBtu, both in 2015 prices, from 2023 onwards).

The price assumptions used for the five-year period to 2023 have been set such that there is a gradual transition from current market prices to the long-term price assumptions as noted above, with the rate of increase reducing in the later years.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Oil prices rebounded in 2018 in the face of cooperative production restraint from OPEC and some non-OPEC producers, but weakened late in the year as production restraint eased and US supply recorded record growth. BP's long-term assumption for oil prices is higher than recent market prices, reflecting the judgement that recent prices are not consistent with the market being able to produce sufficient oil to meet global demand sustainably in the longer term, especially given the financial requirements of key low-cost oil producing economies.

US gas prices remained relatively low for much of 2018, before increasing temporarily in the final quarter due to a combination of low storage and cold weather. Strong growth of low-cost supply helped to moderate prices through much of the year. BP's long-term price assumption for US gas is higher than recent market prices as US gas demand is expected to grow strongly, both domestic demand as well as exports of liquefied natural gas, absorbing the lowest cost resources from the sweet spots, and forcing producers to go to more expensive/drier gas, as well as requiring increased investment in infrastructure.

Oil and natural gas reserves

In addition to oil and gas prices, significant technical and commercial assessments 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 and drilling of new wells 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.

Reserves assumptions for value-in-use and fair value tests reflect the reserves and resources that management currently intend to develop. The recoverable amount of oil and gas properties is determined using a combination of inputs including reserves, resources and production volumes. Risk factors may be applied to reserves and resources which do not meet the criteria to be treated as proved.

The interdependency of these inputs, risk factors and the wide diversity of our oil and gas properties limits the practicability of estimating the probability or extent to which the overall recoverable amount is impacted by changes to one or more of the underlying assumptions. The recoverable amount of oil and gas properties is primarily sensitive to changes in the long-term oil and gas price assumptions. Management do not expect a change in these long-term price assumptions within the next financial year that would result in a material impairment charge. However, sensitivity analysis may be performed if a specific oil and gas property is identified to have low headroom above its carrying amount. In 2018, the group identified oil and gas properties with carrying amounts totalling $22,000 million where the headroom, as at the dates of the last impairment test performed on those assets, was less than or equal to 20% of the carrying value, including $1,345 million in relation to equity-accounted entities. A change in the discount rate, reserves, resources or the oil and gas price assumptions in the next financial year may result in the recoverable amount of one or more of these assets falling below the current carrying amount.

Goodwill

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 $12.2 billion on its balance sheet (2017 $11.6 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. If there are low oil or natural gas prices for an extended period or the long-term price outlook weakens, the group may need to recognize goodwill impairment charges against its Upstream segment goodwill. Sensitivities relating to impairment testing of goodwill in the Upstream segment are provided in Note 14.

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 a specific 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 except where capitalized as exploration or appraisal expenditure. See significant accounting policy: Exploration and appraisal expenditure.

Financial assets

Financial assets are recognized initially at fair value, normally being the transaction price. In the case of financial assets not at fair value through profit or loss, directly attributable transaction costs are also included. The subsequent measurement of financial assets depends on their classification, as set out below. The group derecognizes financial assets when the contractual rights to the cash flows expire or the financial asset is transferred to a third party. This includes the derecognition of receivables for which discounting arrangements are entered into.

From 1 January 2018, the group classifies its financial asset debt instruments as measured at amortized cost, fair value through other comprehensive income or fair value through profit or loss. The classification depends on the business model for managing the financial assets and the contractual cash flow characteristics of the financial asset.

Financial assets measured at amortized cost

Financial assets are classified as measured at amortized cost when they are held in a business model the objective of which is to collect contractual cash flows and the contractual cash flows represent solely payments of principal and interest. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in profit or loss when the assets are derecognized or impaired and when interest is recognized using the effective interest method. This category of financial assets includes trade and other receivables.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Financial assets measured at fair value through other comprehensive income

Financial assets are classified as measured at fair value through other comprehensive income when they are held in a business model the objective of which is both to collect contractual cash flows and sell the financial assets, and the contractual cash flows represent solely payments of principal and interest. The group does not have any financial assets classified in this category.

Financial assets measured at fair value through profit or loss

Financial assets are classified as measured at fair value through profit or loss when the asset does not meet the criteria to be measured at amortized cost or fair value through other comprehensive income. Such assets 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 included in this category.

Investments in equity instruments

Investments in equity instruments are subsequently measured at fair value through profit or loss unless an election is made on an instrument-by-instrument basis to recognise fair value gains and losses in other comprehensive income.

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.

Cash equivalents

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. Cash equivalents are classified as financial assets measured at amortized cost or fair value through profit or loss.

Impairment of financial assets measured at amortized cost

The group assesses on a forward looking basis the expected credit losses associated with financial assets classified as measured at amortized cost at each balance sheet date. Expected credit losses are measured based on the maximum contractual period over which the group is exposed to credit risk. Since this is typically less than 12 months there is no significant difference between the measurement of 12-month and lifetime expected credit losses for the group's in-scope financial assets. The measurement of expected credit losses is a function of the probability of default, loss given default and exposure at default. The expected credit loss is estimated as the difference between the asset’s carrying amount and the present value of the future cash flows the group expects to receive discounted at the financial asset’s original effective interest rate. The carrying amount of the asset is adjusted, with the amount of the impairment gain or loss recognized in the income statement.

A financial asset or group of financial assets classified as measured at amortized cost is considered to be credit-impaired if there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset (or group of financial assets) have occurred. Financial assets are written off where the group has no reasonable expectation of recovering amounts due.

Financial liabilities

The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities measured at fair value through profit or loss

Financial liabilities that meet the definition of held for trading are classified as measured at fair value through profit or loss. Such liabilities 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 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 directly attributable transaction costs. For interest-bearing loans and borrowings this is typically equivalent to 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.

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices, as well as for trading purposes. These derivative financial instruments are recognized initially at fair value on the date on which a derivative contract is entered into and subsequently remeasured at fair value. Derivatives are carried as assets when the fair value is positive and as liabilities when the fair value is negative.

Contracts to buy or sell a non-financial item (for example, oil, oil products, gas or power) that can be settled net in cash, with the exception of contracts that were entered into and continue to be held for the purpose of the receipt or delivery of a non-financial item in accordance with the group’s expected purchase, sale or usage requirements, are accounted for as financial instruments. Gains or losses arising from changes in the fair value of derivatives that are not designated as effective hedging instruments are recognized in the income statement.

If, at inception of a contract, the valuation cannot be supported by observable market data, any gain or loss determined by the valuation methodology is not recognized in the income statement but is deferred on the balance sheet and is commonly known as ‘day-one gain or loss’. This deferred gain or loss is recognized in the income statement over the life of the contract until substantially all the remaining contract term can be valued using observable market data at which point any remaining deferred gain or loss is recognized in the income statement. Changes in valuation subsequent to the initial valuation at inception of a contract are recognized immediately in the income statement.

1. Significant accounting policies, judgements, estimates and assumptions – continued
For the purpose of hedge accounting, hedges are classified as:

- Fair value hedges when hedging exposure to changes in the fair value of a recognized asset or liability.
- Cash flow hedges when hedging exposure to variability in cash flows that is attributable to either a particular risk associated with a recognized asset or liability or a highly probable forecast transaction.

Hedge relationships are formally designated and documented at inception, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, the existence at inception of an economic relationship and subsequent measurement of the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item’s fair value or cash flows attributable to the hedged risk, the hedge ratio and sources of hedge ineffectiveness. 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, where it offsets. The group applies fair value hedge accounting when hedging interest rate risk and certain currency risks on fixed rate finance debt.

Fair value hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the risk management objective changes or when the hedging instrument is sold, terminated or exercised. The accumulated adjustment to the carrying amount of a hedged item at such time is then amortized prospectively to profit or loss as finance interest expense over the hedged item's 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 highly probably forecast transaction that results in the recognition of 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 transferred 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.

Cash flow hedge accounting is discontinued only when the hedging relationship or a part thereof ceases to meet the qualifying criteria. This includes when the designated hedged forecast transaction or part thereof is no longer considered to be highly probable to occur, or when the hedging instrument is sold, terminated or exercised without replacement or rollover. When cash flow hedge accounting is discontinued amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to profit or loss or transferred to the initial carrying amount of a non-financial asset or liability as above. If the forecast transaction is no longer expected to occur, amounts previously recognized within other comprehensive income will be immediately reclassified to profit or loss.

Costs of hedging

Time value of options and the foreign currency basis spread of cross-currency interest rate swaps are excluded from hedge designations and accounted for as costs of hedging. Changes in fair value of the time-value component of option contracts and the foreign currency basis spread of cross-currency interest rate swaps are recognized in other comprehensive income to the extent that they relate to the hedged item. For transaction-related hedged items, the amount recognized in other comprehensive income is reclassified to profit or loss when the hedged transaction affects profit or loss. For time-period related hedged items, the amount recognized in other comprehensive income is amortized to profit or loss on a straight line over the term of the hedging relationship.

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 judgement and estimate: derivative financial instruments

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 historical and long-term pricing relationships. Price volatility is also an input for options models. Changes in the key assumptions, in particular price curves, could have a material impact on the carrying amounts of derivative assets and liabilities in the next financial year. The impact on net assets and the Group income statement would be limited as a result of offsetting movements on derivative assets and liabilities. For more information see Note 30.

In some cases, judgement is required to determine whether contracts to buy or sell commodities meet the definition of a derivative. In particular longer -term contracts to buy and sell LNG are not considered to meet the definition as they are not considered capable of being net settled due to a lack of liquidity in the LNG market and so are accounted for on an accruals basis.

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.

1. Significant accounting policies, judgements, estimates and assumptions – continued
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. Provisions are discounted using a nominal discount rate of 3.0% (2017 2.5%).
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 consolidated 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 future prices, depending on the expected timing of the activity, and discounted using the nominal 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 where that asset is generating or is expected to generate future economic benefits.
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 future prices and discounted using a nominal discount rate. The weighted-average period over which these costs are generally expected to be incurred is estimated to be approximately six years.
Significant judgements and estimates: provisions

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations facing BP relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event occurs are uncertain. Decommissioning technologies and costs are constantly changing, as are political, environmental, safety and public expectations. The timing and amounts of future cash flows are subject to significant uncertainty and estimation is required in determining the amounts of provisions to be recognized. Any changes in the expected future costs are reflected in both the provision and the asset.

If oil and natural gas production facilities and pipelines are sold to third parties, judgement is required to assess whether the new owner will be unable to meet their decommissioning obligations, whether BP would then be responsible for decommissioning, and if so the extent of that responsibility.

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 current estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

The timing and amount of future expenditures relating to decommissioning and environmental liabilities are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligations at the end of 2018 was a nominal rate of 3.0% (2017 a real rate of 0.5% and a nominal rate of 2.5%), which was based on long-dated US government bonds.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Further information about the group's provisions is provided in Note 21. Changes in assumptions in relation to the group's provisions could result in a material change in their carrying amounts within the next financial year. A 0.5% change in the nominal discount rate could have an impact of approximately $1.3 billion on the value of the group's provisions, excluding those relating to the Gulf of Mexico oil spill. The impact on the group income statement would not be significant as the majority of the group's provisions relate to decommissioning costs.

As described in Note 33, the group is subject to claims and actions for which no provisions have been recognized. 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.

Change in significant estimate - decommissioning provision

Decommissioning provision cost estimates are reviewed regularly and such a review was undertaken in the second quarter of 2018. The timing and amount of estimated future expenditures were re-assessed and discounted to determine the present value. From 30 June 2018 the present value of the decommissioning provision is determined by discounting the estimated cash flows expressed in expected future prices, i.e. taking account of expected inflation, at a nominal discount rate of 2.5% as at 30 June 2018. Prior to 30 June 2018, the group estimated future cash flows in real terms i.e. at current prices and discounted them using a real discount rate of 0.5% as at 31 December 2017.

The impact of the review was a reduction in the provision of $1.5 billion as at 30 June 2018, with a similar reduction in the carrying amount of property, plant and equipment. There was no significant impact on the income statement for the first half of 2018. The impact on the income statement for the second half of 2018 was a decrease in depreciation, depletion and amortization of approximately $80 million and an increase in finance costs of approximately $80 million.

The nominal discount rate applied to provisions was revised at 31 December 2018 to 3.0%. The impact of this increase was a further $1.3- billion reduction in the decommissioning provision, with a similar reduction in the carrying amount of property, plant and equipment.

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, either by way of a refund from the plan or reductions in future contributions to the plan.

Contributions to defined contribution plans are recognized in the income statement in the period in which they become payable.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Significant estimate: pensions and other post-retirement benefits

Accounting for defined benefit pensions and other post-retirement benefits involves making significant estimates when measuring the group's pension plan surpluses and deficits. These estimates require assumptions to be made about many uncertainties.

Pensions 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 that are the most significant to the amounts reported are the discount rate, inflation rate, salary growth and mortality levels. Assumptions about these variables are based on the environment in each country. The assumptions used vary from year to year, with resultant effects on future net income and net assets. Changes to some of these assumptions, in particular the discount rate and inflation rate, could result in material changes to the carrying amounts of the group's pension and other post-retirement benefit obligations within the next financial year, in particular for the UK, US and Eurozone plans. Any differences between these assumptions and the actual outcome will also affect future net income and net assets.

The values ascribed to these assumptions and a sensitivity analysis of the impact of changes in the assumptions on the benefit expense and obligation used are provided in Note 24.

Income taxes

Income tax expense represents the sum of current tax and deferred tax.

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 or increased to the extent that it is 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.
Where tax treatments are uncertain, if it is considered probable that a taxation authority will accept the group's proposed tax treatment, income taxes are recognized consistent with the group's income tax filings. If it is not considered probable, the uncertainty is reflected using either the most likely amount or an expected value, depending on which method better predicts the resolution of the uncertainty.
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 whether provisions for income taxes are required and, if so, estimation is required of the amounts that could be payable.
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.
Management do not assess there to be a significant risk of a material change to the group’s tax provisioning or recognition of deferred tax assets within the next financial year, however the tax position remains inherently uncertain and therefore subject to change. 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 9 and Note 33.

1. Significant accounting policies, judgements, estimates and assumptions – continued

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 in accordance with the applicable accounting policy such as Provisions and contingencies. No new significant judgements were made in 2018 in this regard.

Customs duties and sales taxes

Customs duties and sales taxes that are passed on or charged 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 consolidated financial statements as treasury shares. Consideration, if any, received for the sale of such shares is also recognized in equity. 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 and other income

Revenue from contracts with customers is recognized when or as the group satisfies a performance obligation by transferring control of a promised good or service to a customer. The transfer of control of oil, natural gas, natural gas liquids, LNG, petroleum and chemical products, and other items usually coincides with title passing to the customer and the customer taking physical possession. The group principally satisfies its performance obligations at a point in time; the amounts of revenue recognized relating to performance obligations satisfied over time are not significant.

When, or as, a performance obligation is satisfied, the group recognizes as revenue the amount of the transaction price that is allocated to that performance obligation. The transaction price is the amount of consideration to which the group expects to be entitled. The transaction price is allocated to the performance obligations in the contract based on standalone selling prices of the goods or services promised.

Contracts for the sale of commodities are typically priced by reference to quoted prices. Revenue from term commodity contracts is recognized based on the contractual pricing provisions for each delivery. Certain of these contracts have pricing terms based on prices at a point in time after delivery has been made. Revenue from such contracts is initially recognized based on relevant prices at the time of delivery and subsequently adjusted as appropriate.

Physical exchanges with counterparties in the same line of business in order to facilitate sales to customers are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange.

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.

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.

Interest income is recognized as the interest accrues (using the effective interest rate, that is, the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset).

Dividend income from investments is recognized when the shareholders' right to receive the payment is established.

Finance costs

Finance costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use, are added to the cost of those assets until such time as the assets are substantially ready for their intended use. All other finance costs are recognized in the income statement in the period in which they are incurred.

1. Significant accounting policies, judgements, estimates and assumptions – continued
Impact of new International Financial Reporting Standards
BP adopted two new accounting standards issued by the IASB with effect from 1 January 2018, IFRS 9 'Financial instruments' and IFRS 15 'Revenue from contracts with customers'. There are no other new or amended standards or interpretations adopted during the year that have a significant impact on the consolidated financial statements.
IFRS 9 'Financial Instruments'
IFRS 9 'Financial Instruments' was issued in July 2014 and replaced IAS 39 'Financial Instruments: Recognition and Measurement.' BP adopted IFRS 9 and the related consequential amendments to other IFRSs in the financial reporting period commencing 1 January 2018. The group has applied the new standard in accordance with the transition provisions of IFRS 9. Comparatives have not been restated and adjustments on transition have been reported in opening retained earnings at 1 January 2018.
The group's revised accounting policies in relation to financial instruments are provided above.
The overall impact on transition to IFRS 9, including the impact upon the group's share of equity-accounted entities, was a reduction of $180 million in net assets, net of tax. This adjustment mainly related to an increase in the loss allowance for financial assets in the scope of IFRS 9's impairment requirements. As comparatives have not been restated the closing balance at 31 December 2017 for certain line items in the balance sheet differ from the opening balance at 1 January 2018 (as summarized below). Cash and cash equivalents at the beginning of 2018 in the Group cash flow statement are the 1 January 2018 amounts included in the table below.

			$ million
	31 December 2017	1 January 2018	Adjustment on adoption of IFRS 9
Non-current			
Investments in equity-accounted entities	24,985	24,903	(82)
Loans, trade and other receivables	2,080	2,069	(11)
Deferred tax liabilities	(7,982)	(7,946)	36
Current			
Loans, trade and other receivables	25,039	24,927	(112)
Cash and cash equivalents	25,586	25,575	(11)
Net assets	100,404	100,224	(180)
Reserves			
Available-for-sale investments	17	—	(17)
Costs of hedging	—	(37)	(37)
Profit and loss account	75,226	75,100	(126)
	75,243	75,063	(180)

Classification and measurement
IFRS 9 provides a single classification and measurement approach for financial assets that reflects the business model in which they are managed and their cash flow characteristics. For financial liabilities the existing classification and measurement requirements of IAS 39 are largely retained.
The table below illustrates the classification and carrying amounts of financial assets under IFRS 9 and IAS 39 at the date of initial application, 1 January 2018. There were no differences in classification or carrying amounts for financial liabilities and no differences in the measurement of liabilities for financial guarantee contracts.

						$ million
At 1 January 2018	Classification under IAS 39	Classification under IFRS 9	Carrying amount under IAS 39	Measurement category adjustment on transition	Measurement attribute adjustment on transition	Carrying amount under IFRS 9
Financial assets						
			433	—	—	433

Other investments – equity shares	Available-for-sale financial assets	Fair value through profit or loss				
– other	Available-for-sale financial assets	Fair value through profit or loss	275	—	—	275
– other	At fair value through profit or loss	Fair value through profit or loss	662	—	—	662
Loans	Loans and receivables	Amortized cost	836	(100	)—	736
Loans	Loans and receivables	Fair value through profit or loss	—	100	(8	)92
Trade and other receivables	Loans and receivables	Amortized cost	24,361	—	(115	)24,246
Derivative financial instruments	At fair value through profit or loss	Fair value through profit or loss	6,454	—	—	6,454
Derivative financial instruments	Derivative hedging instruments	Derivative hedging instruments	688	—	—	688
Cash and cash equivalents	Loans and receivables	Amortized cost	21,916	—	(11	)21,905
Cash and cash equivalents	Available-for-sale financial assets	Amortized cost	2,270	(2,058	)—	212
Cash and cash equivalents	Available-for-sale financial assets	Fair value through profit or loss	—	2,058	—	2,058
Cash and cash equivalents	Held-to-maturity investments	Amortized cost	1,400	—	—	1,400
			59,295	—	(134	)59,161

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1. Significant accounting policies, judgements, estimates and assumptions – continued

Other investments existing on transition that were classified as available-for-sale financial assets under IAS 39 are classified as mandatorily measured at fair value through profit or loss (FVTPL) under IFRS 9. The contractual terms of these assets do not give rise to cash flows that are solely payments of principal and interest. Fair value gains and losses will be recognized in profit or loss rather than in other comprehensive income as was the case under IAS 39. An adjustment to the 2018 opening balance sheet was made to transfer $17 million of fair value gains net of related tax from the available-for-sale investments reserve to the profit and loss account reserve.

Certain loans that were classified as loans and receivables under IAS 39 have been classified as mandatorily measured at FVTPL under IFRS 9 as a result of the business model in which they are held. The adjustment of $8m to the carrying amount of these assets on transition reflects the difference between amortized cost measurement under IAS 39 and fair value measurement under IFRS 9.

Cash and cash equivalents that were classified as available-for-sale and held-to-maturity financial assets under IAS 39 have been classified as either measured at amortized cost or measured at FVTPL under IFRS 9. Cash and cash equivalents measured at FVTPL comprise money market funds that do not give rise to cash flows that are solely payments of principal and interest. For cash and cash equivalents that have been reclassified to measured at amortized cost, the carrying amount of those assets at the end of the reporting period approximate their fair value. The fair value gain or loss that would have been recognized in other comprehensive income in the reporting period if those financial assets had not been reclassified to amortized cost is immaterial.

Adjustments to the carrying amount of financial assets classified as measured at amortized cost under IFRS 9 relate entirely to the additional loss allowance required by the new standard's expected credit loss model.

There were no financial assets or financial liabilities which the group had previously designated as at FVTPL under IAS 39 that were required to be reclassified, or which the group has elected to reclassify upon the application of IFRS 9. The group did not elect to designate at FVTPL any financial assets or financial liabilities at the date of initial application of IFRS 9.

Under IFRS 9 the group has elected to apply hedge accounting prospectively to certain of its commodity price risk management activities for which hedge accounting was not possible under IAS 39. Certain derivatives that were previously classified as at FVTPL have therefore been reclassified to derivative hedging instruments at 1 January 2018. As the hedging instruments are exchange traded derivatives, the value transferred on transition was nil.

Impairment

The financial asset impairment requirements of IFRS 9 introduce a forward-looking expected credit loss model that results in earlier recognition of credit losses than the incurred loss model of IAS 39. The adjustment to the 2018 opening balance sheet relating to expected credit loss reduced both the carrying amounts of financial assets and the profit and loss account reserve.

The table below reconciles the ending impairment allowances in accordance with IAS 39 and the provisions in accordance with IAS 37 to the opening loss allowances determined in accordance with IFRS 9.

						$ million
At 1 January 2018	Classification under IAS 39	Classification under IFRS 9	IAS 39 loss allowance	Measurement category effect on transition	Measurement attribute adjustment on transition	IFRS 9 loss allowance
Financial assets						
Other investments – equity shares	Available-for-sale financial assets	Fair value through profit or loss	91	(91)	—	—
Trade and other receivables	Loans and receivables	Amortized cost	335	—	115	450
Cash and cash equivalents	Loans and receivables	Amortized cost	—	—	11	11
Total loss allowance on financial assets			426	(91)	126	461

Loans that form part of the net investment in equity-accounted entities	37	—	6	43
Total loss allowance	463	(91	)132	504

Impairment allowances on available-for-sale assets represent amounts provided against investments in equity instruments that were held at cost under IAS 39. Under IFRS 9 these assets are classified as measured at fair value through profit or loss and therefore no loss allowance exists on these assets under IFRS 9.

The increase in the loss allowances for financial assets classified as measured at amortized cost under IFRS 9 and loans that form part of the net investment in equity-accounted entities represent the additional loss allowance required by the new standard's expected credit loss model.

Hedge accounting

Under IFRS 9 all existing hedging relationships qualified as continuing hedging relationships and the group has applied hedge accounting prospectively to certain of its commodity price risk management activities for which hedge accounting was not possible under IAS 39.

1. Significant accounting policies, judgements, estimates and assumptions – continued

IFRS 9 also introduces a new way of treating fair value movements on the time value and foreign currency basis spreads of certain hedging instruments. Whereas under IAS 39 these movements were recognized in profit or loss, the group is either required, or has elected to initially recognize these movements within equity to the extent that they relate to the hedged item. An adjustment to the 2018 opening balance sheet was made to transfer $37 million of losses net of related tax from the profit and loss account reserve to the costs of hedging reserve for relevant hedging instruments existing on transition.

Under IAS 39 the effective portion of the gain or loss on a cash flow hedging instrument is reported in other comprehensive income and is reclassified to the balance sheet as part of the initial carrying amount of the corresponding non-financial asset or liability. Under IFRS 9 the effective portion of the gain or loss continues to be reported in the statement of other comprehensive income but the transfer to the balance sheet is shown in the statement of changes in equity.

IFRS 15 ‘Revenue from Contracts with Customers’

IFRS 15 ‘Revenue from Contracts with Customers’ was issued in May 2014 and replaced IAS 18 ‘Revenue’ and certain other standards and interpretations. IFRS 15 provides a single model for accounting for revenue arising from contracts with customers, focusing on the identification and satisfaction of performance obligations. BP adopted IFRS 15 from 1 January 2018 and applied the ‘modified retrospective’ transition approach to implementation.

The group’s revised accounting policy in relation to revenue is provided above. A disaggregation of revenue from contracts with customers is provided in note 5.

The group identified certain minor changes in accounting relating to its revenue from contracts with customers but the new standard had no material effect on the group’s net assets as at 1 January 2018 and so no transition adjustment is presented.

The most significant change identified is the accounting for revenues relating to oil and natural gas properties in which the group has an interest with joint operation partners. From 1 January 2018, BP ceased using the entitlement method of accounting under which revenue was recognized in relation to the group's entitlement to the production from oil and gas properties based on its working interest, irrespective of whether the production was taken and sold to customers. In its 2018 consolidated financial statements the group has recognized revenue when sales are made to customers; production costs have been accrued or deferred to reflect differences between volumes taken and sold to customers and the group's ownership interest in total production volumes. Compared to the group’s previous accounting policy this may result in timing differences in respect of revenues and profits recognized in each period, but there will be no change in the total revenues and profits over the duration of the joint operation. The impact on the consolidated financial statements for the year ended 31 December 2018 was not material.

In addition, BP has made determinations about presentation and disclosure relating to its revenue from contracts with customers as follows:

Derivative contracts resulting in physical delivery to a customer

Certain contracts entered into by the group that result in physical delivery to a counterparty of products such as crude oil, natural gas and refined products are required by IFRS to be accounted for as financial instruments. These contracts are within the scope of IFRS 9 rather than IFRS 15. The group’s counterparties in these transactions, however, may meet the IFRS 15 definition of a customer. Revenue recognized relating to such contracts when physical delivery occurs is, therefore, presented together with revenue from contracts with customers in the group’s consolidated financial statements. Changes in the fair value of derivative assets and liabilities prior to physical delivery are excluded from revenue from contracts with customers and are presented as other operating revenues. Additionally, where forward sales and purchase contracts for oil, natural gas or power have been determined to be for short-term trading purposes, the associated sales and purchases continue to be reported net within other operating revenues consistent with the group’s practice prior to implementation of IFRS 15.

Contracts with post-delivery pricing terms

Contracts entered into by the group for the sale of oil, natural gas (including LNG), NGLs and refined products are typically priced by reference to quoted prices. In line with market practice, certain of these contracts are based on average prices over a period that is partially or entirely after delivery. Revenue relating to such contracts is recognized initially based on relevant prices at the time of delivery and subsequently adjusted as prices are finalized, consistent with the group's practice prior to implementation of IFRS 15. Whilst these post-delivery adjustments are changes in the value of receivables within the scope of IFRS 9, not IFRS 15, the distinction between revenue recognized at the time of delivery and revenue recognized as a result of post-delivery changes in quoted commodity prices relating to the same transaction is not considered to be significant. All revenue from these contracts, both that recognized at the time of delivery and that from post-delivery price adjustments, is disclosed as revenue from contracts with customers.

Disclosure of the amount of the transaction price allocated to unsatisfied performance obligations

The disclosures required by IFRS 15 include the amount of the contract transaction price allocated to performance obligations that are unsatisfied at the balance sheet date. Many of BP's commodity sales are made under term contracts in which sales are made based on quoted prices at or near the time of delivery, meaning the consideration for future deliveries is entirely variable. In these arrangements, each delivery is considered to be a separate performance obligation and the transaction price is the amount of revenue expected to be earned from all sales that are contracted to be made in future periods, which can be up to 20 years from the balance sheet date.

BP does not consider the disclosure of the amount of the transaction price allocated to contracted future deliveries of commodities within the scope of IFRS 15 to be relevant information. This disclosure has not, therefore, been provided in these consolidated financial statements. The consideration in many such contracts is entirely variable so would be subject to the requirement of IFRS 15 relating to constraining estimates of variable consideration. Applying the constraint for the purposes of this disclosure requirement would provide an indication only of contracted revenues based on estimated future minimum market prices. Such commodities are regularly sold in liquid markets on a spot basis, using similar pricing bases to sales made under term contracts, meaning that disclosure of contracted sales would have little predictive value. Furthermore, as described above, a significant proportion of the group's commodity sales contracts are within the scope of IFRS 9, not IFRS 15. Derivative assets or liabilities representing the difference between contracted price and forward price are recognized on the group balance sheet for these contracts.

Contract assets and liabilities

The group does not have material contract asset or contract liability balances and so these amounts are included within amounts presented for trade receivables and other payables.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Not yet adopted

The IASB has issued IFRS 16 'Leases' which will become effective from financial reporting periods beginning on or after 1 January 2019 and has been adopted by the EU. The group has not adopted IFRS 16 in these consolidated financial statements and will adopt it from 1 January 2019. 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.

IFRS 16 'Leases'

IFRS 16 'Leases' provides a new model for lessee accounting in which the majority of leases will be accounted for by the recognition on the balance sheet of a right-of-use asset and a lease liability. The subsequent amortization of the right-of-use asset and the interest expense related to the lease liability will be recognized in profit or loss over the lease term. IFRS 16 replaces IAS 17 'Leases' and IFRIC 4 'Determining whether an arrangement contains a lease' and will be effective for financial reporting periods beginning on or after 1 January 2019.

BP will adopt IFRS 16 in the financial reporting period commencing 1 January 2019 and has elected to apply the modified retrospective transition approach in which the cumulative effect of initial application is recognized in opening retained earnings at the date of initial application with no restatement of comparative periods' financial information.

IFRS 16 introduces a revised definition of a lease. As permitted by the standard, BP has elected not to reassess the existing population of leases under the new definition and will only apply the new definition for the assessment of contracts entered into after the transition date. On transition the standard permits, on a lease-by-lease basis, the right-of-use asset to be measured either at an amount equal to the lease liability (as adjusted for prepaid or accrued lease payments), or on an historical basis as if the standard had always applied. BP has elected to use the historical asset measurement for its more material leases and to use the asset equals liability approach for the remainder of the population. In addition, BP has also elected the option to adjust the carrying amounts of the right-of-use assets as at 1 January 2019 for onerous lease provisions that had been recognized on the group balance sheet as at 31 December 2018, rather than the alternative of performing impairment tests on transition.

The group's evaluation of the effect of adoption of the standard is substantially complete and a material effect on the group's balance sheet is expected, as set out further below. 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-of-use asset and interest on the lease liability. In the cash flow statement operating lease payments are currently presented within cash flows from operating activities but under IFRS 16 payments will be presented as financing cash flows, representing repayments of debt, and as operating cash flows, representing payments of interest. Variable lease payments that do not depend on an index or rate are not included in the lease liability and will continue to be presented as operating cash flows.

Information on the group's leases classified as operating leases under IAS 17, which are not recognized on the balance sheet as at 31 December 2018, is presented in Note 28. The following table provides a reconciliation of the operating lease commitments disclosed in Note 28 to the total lease liability expected to be recognized on the group balance sheet in accordance with IFRS 16 as at 1 January 2019, with explanations below.

	$ million
Operating lease commitments at 31 December 2018	11,979
Leases not yet commenced	(1,372)
Leases below materiality threshold	(86)
Short-term leases	(91)
Effect of discounting	(1,512)
Impact on leases in joint operations	836
Variable lease payments	(58)
Redetermination of lease term	(252)
Other	(22)

Total additional lease liabilities expected to be recognized on adoption of IFRS 16	9,422
Finance lease obligations at 31 December 2018	667
Adjustment for finance leases in joint operations	(189)
Total expected lease liabilities at 1 January 2019	9,900

Leases not yet commenced: The operating lease commitments disclosed in Note 28 include amounts relating to leases entered into by the group that had not yet commenced as at 31 December 2018. In accordance with IFRS 16 assets and liabilities will not be recognized on the group balance sheet in relation to these leases until the dates of commencement of the leases. Such commitments will continue to be disclosed in future under IFRS 16.

Short-term leases and leases below materiality threshold: As part of the transition to IFRS 16, BP has elected not to recognize assets and liabilities relating to short-term leases i.e. leases with a term of less than 12 months and has also applied a materiality threshold for the recognition of assets and liabilities related to leases. The disclosed operating lease commitments as at 31 December 2018 in Note 28 includes amounts related to such leases.

Effect of discounting: The amount of the lease liability recognized in accordance with IFRS 16 will be on a discounted basis whereas the operating lease commitments information in Note 28 is presented on an undiscounted basis. The discount rates used on transition are incremental borrowing rates as appropriate for each lease based on factors such as the lessee legal entity, lease term and currency. The weighted average discount rate to be used on transition is expected to be around 3.5%, with a weighted average remaining lease term of around 9 years. For new leases commencing after 1 January 2019 the discount rate used will be the interest rate implicit in the lease, if this is readily determinable, or the incremental borrowing rate if the implicit rate cannot be readily determined.

1. Significant accounting policies, judgements, estimates and assumptions – continued

Impact on leases in joint operations: The operating lease commitments for leases within joint operations are included on the basis of BP's net working interest for the information provided in Note 28, irrespective of whether BP is the operator and whether the lease has been co-signed by the joint operators or not. However, for transition to IFRS 16, the facts and circumstances of each lease in a joint operation have been assessed to determine the group's rights and obligations and to recognize assets and liabilities on the group balance sheet accordingly. This relates mainly to leases of drilling rigs within joint operations in the Upstream segment. Where all parties to a joint operation jointly have the right to control the use of the identified asset and all parties have a legal obligation to make lease payments to the lessor, the group's share of the right-of-use asset and its share of the lease liability will be recognized on the group balance sheet. This may arise in cases where the lease is signed by all parties to the joint operation. However, in cases where BP is the only party with the legal obligation to make lease payments to the lessor, the full lease liability will be recognized on the group balance sheet. This may be the case if for example BP, as operator of the joint operation, is the sole signatory to the lease. If, however, the underlying asset is jointly controlled by all parties to the joint operation BP will recognize its net share of the right-of-use asset on the group balance sheet along with a receivable representing the amounts to be recovered from the other parties. If BP is not legally obliged to make lease payments to the lessor but jointly controls the asset, the net share of the right-of-use asset will be recognized on the group balance sheet along with a payable representing amounts to be paid to the other parties.

Variable lease payments: Where there are lease payments that vary depending on an index or rate, the measurement of the operating lease commitments in Note 28 is based on the variable factor as at inception of the lease and is not updated to reflect subsequent changes in the variable factor. Such subsequent changes in the lease payments are currently treated as contingent rentals and charged to profit or loss as and when paid. Under IFRS 16 the lease liability will be adjusted whenever the lease payments are changed in response to changes in the variable factor, and for transition the liability is measured on the basis of the prevailing variable factor on 1 January 2019.

Redetermination of lease term: Under the transition provisions of IFRS 16, the remaining terms of certain leases have been redetermined with the benefit of hindsight, on the basis that BP is now reasonably certain to exercise its option to terminate those leases before the full term.

Under IAS 17 finance leases are recognized on the group balance sheet and will continue to be recognized in accordance with IFRS 16. The amounts recognized on the group balance sheet as at 1 January 2019 in relation to the right-of-use assets and liabilities for existing finance leases within joint operations will be on a net or gross basis as appropriate as described above.

In addition to the lease liability, which will be presented within finance debt, other line items on the group balance sheet expected to be adjusted on transition to IFRS 16 include property, plant and equipment, prepayments, receivables, accruals, payables, provisions and deferred tax balances, as set out below.

			$ million
	31 December 2018	1 January 2019	Adjustment on adoption of IFRS 16
Non-current assets			
Property, plant and equipment	135,261	143,950	8,689
Trade and other receivables	1,834	2,159	325
Prepayments	1,179	849	(330)
Deferred tax assets	3,706	3,736	30
Current assets			
Trade and other receivables	24,478	24,673	195
Prepayments	963	872	(91)
Current liabilities			
Trade and other payables	46,265	46,209	(56)
Accruals	4,626	4,578	(48)
Finance debt and leases	9,373	11,525	2,152
Provisions	2,564	2,547	(17)
Non-current liabilities			
Other payables	13,830	14,013	183

Accruals	575	548	(27)
Finance debt and leases	56,426	63,507	7,081
Deferred tax liabilities	9,812	9,767	(45)
Provisions	17,732	17,657	(75)
Net assets	101,548	101,218	(330)
Equity			
BP shareholders' equity	99,444	99,115	(329)
Non-controlling interests	2,104	2,103	(1)
	101,548	101,218	(330)

The total expected adjustments to the group's lease liabilities at 1 January 2019 may be reconciled as follows:

	$ million
Total additional lease liabilities expected to be recognized on adoption of IFRS 16	9,422
Less: adjustment for finance leases in joint operations	(189)
Total expected adjustment to lease liabilities	9,233
Of which – current	2,152
– non-current	7,081

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.

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
	2018	2017	2016
Income statement			
Production and manufacturing expenses	714	2,687	6,640
Profit (loss) before interest and taxation	(714)	(2,687)	(6,640)
Finance costs	479	493	494
Profit (loss) before taxation	(1,193)	(3,180)	(7,134)
Less: Taxation	174	(2,222)	3,105
Profit (loss) for the period	(1,019)	(5,402)	(4,029)
Balance sheet			
Current assets			
Trade and other receivables	214	252	
Current liabilities			
Trade and other payables	(2,279)	(2,089)	
Provisions	(333)	(1,439)	
Net current assets (liabilities)	(2,398)	(3,276)	
Non-current assets			
Deferred tax	1,563	2,067	
Non-current liabilities			
Other payables	(11,922)	(12,253)	
Provisions	(12)	(1,141)	
Deferred tax	3,999	3,634	
Net non-current assets (liabilities)	(6,372)	(7,693)	
Net assets (liabilities)	(8,770)	(10,969)	
Cash flow statement			
Profit (loss) before taxation	(1,193)	(3,180)	(7,134)
Net charge for interest and other finance expense, less net interest paid	479	493	494
Net charge for provisions, less payments	240	2,542	4,353
(Increase) decrease in other current and non-current assets	(485)	(1,738)	(3,210)
Increase (decrease) in other current and non-current liabilities	(2,572)	(3,453)	(1,608)
Pre-tax cash flows	(3,531)	(5,336)	(7,105)

Income statement

The group income statement for 2018 includes a pre-tax charge of $1,193 million (2017 pre-tax charge of $3,180 million, 2016 pre-tax charge of $7,134 million) in relation to the Gulf of Mexico oil spill. The charge within production and manufacturing expenses in 2018 of $714 million (2017 $2,687 million, 2016 $6,640 million) relates mainly to business economic loss (BEL) and other claims associated with the Deepwater Horizon Court Supervised Settlement Program (DHCSSP). Finance costs of $479 million (2017 $493 million, 2016 $494 million) reflect the unwinding of the discount on payables and, for 2016, 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 2012 agreement with the US government to resolve all federal criminal claims arising from the incident, amounts charged for the 2016 consent decree and settlement agreement with the United States and the five Gulf coast states 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 cumulative pre-tax income statement charge since the incident amounts to $67.0 billion and is analysed in the table below.

	2018	2017	2016	$ million Cumulative since the incident
Environmental costs	—	—	—	8,526
Spill response costs	—	—	—	14,304
Litigation and claims costs	629	2,647	6,596	42,410
Clean Water Act penalties	—	—	—	4,061
Other costs	85	40	44	1,394
Settlements credited to the income statement	—	—	—	(5,681)
(Profit) loss before interest and taxation	714	2,687	6,640	65,014
Finance costs	479	493	494	1,944
(Profit) loss before taxation	1,193	3,180	7,134	66,958

2. Significant event – Gulf of Mexico oil spill – continued
Provisions and contingent liabilities
Provisions
Movements during the year in the remaining provision, which relates to litigation and claims, are presented in the table below.

	$ million
	2018
	Litigation and claims
At 1 January	2,580
Increase in provision	629
Reclassified to other payables	(2,045)
Utilization	(819)
At 31 December	345
Of which – current	333
– non-current	12

Litigation and claims – PSC settlement
The Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) with the Plaintiffs' Steering Committee (PSC) provides for a court-supervised settlement programme, the DHCSSP, which commenced operation on 4 June 2012. A separate claims administrator was 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 296.
The litigation and claims provision reflects the latest estimate for the remaining costs associated with the PSC settlement. These costs relate predominantly to BEL claims and associated administration costs. The amounts ultimately payable may differ from the amount provided and the timing of payments is uncertain.
The DHCSSP's determination of BEL claims was substantially completed by the end of 2017 and remaining claims continued to be processed throughout 2018 with only a very small number of claims remaining to be determined by the end of 2018. However certain BEL claims determined by the DHCSSP have been and continue to be appealed by BP and/or the claimants.
During 2018 settlement agreements were reached with claimants for a significant proportion of the provision existing at the beginning of the year. Amounts payable under these settlement agreements have been reclassified from provisions to other payables. The remaining amount provided for includes the latest estimate of the amounts that are expected ultimately to be paid to resolve outstanding BEL claims. Claims under appeal will ultimately only be resolved once the full judicial appeals process has been concluded, including appeals to the Federal District Court and Fifth Circuit, as may be the case, or when settlements are reached with individual claimants. Depending upon the ultimate resolution of these claims, the amounts payable may differ from those currently provided.
Payments to resolve outstanding claims under the PSC settlement are expected to be made over a number of years. The timing of payments, however, is uncertain, and, in particular, will be impacted by how long it takes to resolve claims that have been appealed and may be appealed in the future.
Contingent liabilities
For information on legal proceedings relating to the Deepwater Horizon oil spill, see Legal proceedings on pages 296-298. Any further outstanding Deepwater Horizon related claims are not expected to have a material impact on the group's financial performance.
Other payables
Other payables include amounts payable under the 2016 consent decree and settlement agreement with the United States and five Gulf coast states, including amounts payable for natural resource damages, state claims and Clean Water Act penalties. On a discounted basis the amounts included in other payables for these elements of the agreements are $5,485 million payable over 14 years, $2,897 million payable over 15 years and $4,010 million payable over 14 years respectively at 31 December 2018. For full details of these agreements, see BP Annual Report and Form 20-F 2015.

In addition, other payables at 31 December 2018 also includes amounts payable for settled economic loss and property damage claims which are payable over a period of up to nine years.

Cash flow statement

The impact on net cash provided by operating activities on a pre-tax basis amounted to an outflow of $3,531 million (2017 outflow of $5,336 million, 2016 outflow of $7,105 million). On a post-tax basis, the amounts were an outflow of $3,218 million (2017 outflow of $5,167 million and 2016 outflow of $6,892 million).

Cash outflows in 2018, 2017 and 2016 include payments made under the 2012 agreement with the US government to resolve all federal criminal claims arising from the incident and the 2016 consent decree and settlement agreement with the United States and the five Gulf coast states.

3. Business combinations and other significant transactions

Business combinations

BP undertook a number of business combinations in 2018. For the full year, total consideration paid in cash amounted to $7,100 million, offset by cash acquired of $114 million.

On 31 October 2018, BP acquired from BHP Billiton Petroleum (North America) Inc. 100% of the issued share capital of Petrohawk Energy Corporation, a wholly owned subsidiary of BHP that holds a portfolio of unconventional onshore US oil and gas assets.

The acquisition brings BP extensive oil and gas production and resources in the liquids-rich regions of the Permian and Eagle Ford basins in Texas and in the Haynesville gas basin in Texas and Louisiana.

The total consideration for the transaction, after customary closing adjustments and the effect of discounting deferred payments, is $10,302 million, which will all be paid in cash. As at 31 December 2018, $6,788 million of the consideration had been paid. The remaining discounted amount of $3,514 million is included within other payables on the group balance sheet and will be paid in four instalments, with the final instalment being paid in April 2019.

The transaction has been accounted for as a business combination using the acquisition method. The provisional fair values of the identifiable assets and liabilities acquired, as at the date of acquisition, are shown in the table below. No goodwill has been recognized on the acquisition.

	$ million
	2018
Assets	
Property, plant and equipment	10,845
Intangible assets	21
Inventories	27
Trade and other receivables	493
Cash	104
Liabilities	
Trade and other payables	(659)
Provisions	(323)
Non-controlling interest	(206)
Total consideration	10,302

The acquisition-date fair values of the assets and liabilities acquired are provisional. As we gain further understanding of the acquired properties and development options, these fair values may be adjusted.

An analysis of the cash flows relating to the acquisition included within the cash flow statement for 2018 is provided below.

	$ million
	2018
Transaction costs of the acquisition (included in cash flows from operating activities)	62
Interest on deferred payments (included in cash flows from operating activities)	21
Cash consideration paid, net of cash acquired (included in cash flows from investing activities)	6,684
Total net cash outflow for the acquisition	6,767

From the date of acquisition to 31 December 2018, the acquired activities generated revenues of $472 million and profit before tax of $49 million. If the business combination had taken place on 1 January 2018, it is estimated that the acquired activities would have generated revenues of $2,798 million and profit before tax of $431 million.

In addition to the BHP transaction described above, BP undertook a number of other individually insignificant business combinations in 2018.

Other significant transactions

On 18 December 2018, BP purchased an additional 16.5% interest in the Clair field in the North Sea, as part of the agreements with ConocoPhillips in which ConocoPhillips simultaneously purchased BP's entire 39.2% interest in the Greater Kuparuk Area on the North Slope of Alaska. The purchase gives BP a 45.1% interest in Clair in total. Gross payments made and received of $1,739 million and $1,490 million are included in Capital expenditure and Proceeds from disposals of businesses, net of cash acquired, respectively, in the group cash flow statement. Goodwill of $804 million, resulting from the recognition of a deferred tax liability as part of the transaction accounting, has been recognized on the purchase of the interest in the Clair field.

4. Disposals and impairment

The following amounts were recognized in the income statement in respect of disposals and impairments.

			$ million
	2018	2017	2016
Gains on sale of businesses and fixed assets			
Upstream	437	526	557
Downstream	15	674	561
Other businesses and corporate	4	10	14
	456	1,210	1,132

			$ million
	2018	2017	2016
Losses on sale of businesses and fixed assets			
Upstream	707	127	169
Downstream	59	88	89
Other businesses and corporate	11	—	3
	777	215	261
Impairment losses			
Upstream	400	1,138	1,022
Downstream	12	69	84
Other businesses and corporate	254	32	11
	666	1,239	1,117
Impairment reversals			
Upstream	(580)	(176)	(3,025)
Downstream	(2)	(62)	(17)
Other businesses and corporate	(1)	—	—
	(583)	(238)	(3,042)
Impairment and losses on sale of businesses and fixed assets	860	1,216	(1,664)

Disposals

Disposal proceeds and principal gains and losses on disposals by segment are described below.

			$ million
	2018	2017	2016
Proceeds from disposals of fixed assets	940	2,936	1,372
Proceeds from disposals of businesses, net of cash disposed	1,911	478	1,259
	2,851	3,414	2,631
By business			
Upstream	2,145	1,183	839
Downstream	120	2,078	1,646
Other businesses and corporate	586	153	146
	2,851	3,414	2,631

At 31 December 2018, deferred consideration relating to disposals amounted to $35 million receivable within one year (2017 $259 million and 2016 $255 million) and $304 million receivable after one year (2017 $268 million and 2016 $271 million). In addition, contingent consideration receivable relating to disposals amounted to $893 million at 31 December 2018 (2017 $237 million and 2016 $131 million). These amounts of contingent consideration are reported within Other investments on the group balance sheet - see Note 18 for further information.

Upstream

In 2018, gains principally resulted from the disposal of interests in the Bruce, Keith and Rhum fields in the UK North Sea, from the disposal of certain properties in the US, and from adjustments to disposals in prior periods. Losses included $335 million resulting from the disposal of our interest in the Magnus field and associated assets in the UK North Sea, $221 million from the disposal of our interest in the Greater Kuparuk Area in the US (see Note 3 for

further information), and adjustments to disposals in prior periods.
In 2017, gains principally resulted from the disposal of a portion of our interest in the Perdido offshore hub in the US, and further gains associated with disposals in the UK.
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.
Downstream
In 2017, gains principally resulted from the disposal of our interest in the SECCO joint venture and the disposal of certain midstream assets in Europe.
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.
Other businesses and corporate
In 2018 proceeds from disposals were principally in respect of life insurance policies in the US and wind farms within our US wind business.

4. Disposals and impairment – continued

Summarized financial information relating to the sale of businesses is shown in the table below. The principal transaction categorized as a business disposal in 2018 was the disposal of our interest in the Greater Kuparuk Area in the US - see Note 3 for further information. The principal transaction categorized as a business disposal in 2017 was the disposal of our interest in the Forties Pipeline System in the North Sea. 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.

			$ million
	2018	2017	2016
Non-current assets	3,274	735	4,794
Current assets	173	57	1,202
Non-current liabilities	(250)	(173)	(2,558)
Current liabilities	(97)	(86)	(532)
Total carrying amount of net assets disposed	3,100	533	2,906
Recycling of foreign exchange on disposal	—	—	25
Costs on disposal[a]	3	3	229
	3,103	536	3,160
Gains (losses) on sale of businesses[b]	(221)	44	593
Total consideration	2,882	580	3,753
Non-cash consideration[c]	(282)	(216)	(2,698)
Consideration received (receivable)	(689)	114	204
Proceeds from the sale of businesses, net of cash disposed[d]	1,911	478	1,259

[a] 2016 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] 2016 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] Proceeds are stated net of cash and cash equivalents disposed of $15 million (2017 $25 million and 2016 $676 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. See also Note 12, Note 15 and Note 21 for further information on impairments by asset category.

Upstream

Impairment losses and reversals related primarily to producing and midstream assets.

The 2018 impairment losses of $400 million related to a number of different assets, with the most significant charges arising in Australia and the US. Impairment losses arose primarily as a result of changes to project activity, asset obsolescence and the decision to dispose of certain assets. The 2018 impairment reversals of $580 million related to a number of different assets, with the most significant reversals arising in the North Sea and Angola following a change to decommissioning cost estimates.

The 2017 impairment losses of $1,138 million related to a number of different assets, with the most significant charges arising in BPX Energy (previously known as the US Lower 48 business) and the North Sea. Impairment losses within Upstream arose primarily as a result of changes in reserves estimates and the decision to dispose of certain assets, including the Forties Pipeline System business.

The 2017 impairment reversals of $176 million related to a number of different assets, with the most significant reversals arising in the North Sea.

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.

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 8). 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.

Downstream

Impairment losses totalling $12 million, $69 million, and $84 million were recognized in 2018, 2017 and 2016 respectively.

Other businesses and corporate

Impairment losses totalling $254 million, $32 million, and $11 million were recognized in 2018, 2017 and 2016 respectively. The amount for 2018 is in respect of assets within our US wind business in advance of their disposal in December 2018.

5. Segmental analysis
The group's organizational structure reflects the various activities in which BP is engaged. At 31 December 2018, 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 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.

5. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	$ million 2018 Total group
Segment revenues						
Sales and other operating revenues	56,399	270,689	—	1,678	(30,010)	298,756
Less: sales and other operating revenues between segments	(28,565)	(574)	—	(871)	30,010	—
Third party sales and other operating revenues	27,834	270,115	—	807	—	298,756
Earnings from joint ventures and associates – after interest and tax	951	589	2,283	(70)	—	3,753
Segment results						
Replacement cost profit (loss) before interest and taxation	14,328	6,940	2,221	(3,521)	211	20,179
Inventory holding gains (losses)[a]	(6)	(862)	67	—	—	(801)
Profit (loss) before interest and taxation	14,322	6,078	2,288	(3,521)	211	19,378
Finance costs						(2,528)
Net finance expense relating to pensions and other post-retirement benefits						(127)
Profit (loss) before taxation						16,723
Other income statement items						
Depreciation, depletion and amortization						
US	4,211	900	—	59	—	5,170
Non-US	8,907	1,177	—	203	—	10,287
Charges for provisions, net of write-back of unused provisions, including change in discount rate	355	834	—	1,557	—	2,746
Segment assets						
Investments in joint ventures and associates	12,785	2,772	10,074	689	—	26,320
Additions to non-current assets[b]	11,533	2,862	—	245	—	14,640

[a] See explanation of inventory holding gains and losses on page 156.

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

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	$ million 2017 Total group

Segment revenues						
Sales and other operating revenues	45,440	219,853	—	1,469	(26,554)	240,208
Less: sales and other operating revenues between segments	(24,179)	(1,800)	—	(575)	26,554	—
Third party sales and other operating revenues	21,261	218,053	—	894	—	240,208
Earnings from joint ventures and associates – after interest and tax	930	674	922	(19)	—	2,507
Segment results						
Replacement cost profit (loss) before interest and taxation	5,221	7,221	836	(4,445)	(212)	8,621
Inventory holding gains (losses)[a]	8	758	87	—	—	853
Profit (loss) before interest and taxation	5,229	7,979	923	(4,445)	(212)	9,474
Finance costs						(2,074)
Net finance expense relating to pensions and other post-retirement benefits						(220)
Profit (loss) before taxation						7,180
Other income statement items						
Depreciation, depletion and amortization						
US	4,631	875	—	65	—	5,571
Non-US	8,637	1,141	—	235	—	10,013
Charges for provisions, net of write-back of unused provisions, including change in discount rate	220	304	—	2,902	—	3,426
Segment assets						
Investments in joint ventures and associates	12,093	2,349	10,059	484	—	24,985
Additions to non-current assets[b]	14,500	2,677	—	275	—	17,452

a See explanation of inventory holding gains and losses on page 156.

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

5. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Consolidation adjustment and eliminations	$ million 2016 Total group
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

[a] See explanation of inventory holding gains and losses on page 156.

By geographical area	US	Non-US	$ million 2018 Total
Revenues			
Third party sales and other operating revenues[a]	98,066	200,690	298,756
Other income statement items			
Production and similar taxes	369	1,167	1,536
Results			
Replacement cost profit (loss) before interest and taxation	3,041	17,138	20,179
Non-current assets			
Non-current assets[b c]	68,188	124,060	192,248

[a] Non-US region includes UK $65,630 million

[b] Non-US region includes UK $19,426 million

c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

			$ million
			2017
By geographical area	US	Non-US	Total
Revenues			
Third party sales and other operating revenues[a]	83,269	156,939	240,208
Other income statement items			
Production and similar taxes	52	1,723	1,775
Results			
Replacement cost profit (loss) before interest and taxation	(266)	8,887	8,621
Non-current assets			
Non-current assets[b c]	61,828	123,646	185,474

a Non-US region includes UK $48,837 million.

b Non-US region includes UK $18,004 million.

c Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Segmental analysis – continued

			$ million 2016
By geographical area	US	Non-US	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)

[a] Non-US region includes UK $37,119 million.

6. Revenue from contracts with customers

The amounts shown in the table below are included in Sales and other operating revenues in the group income statement. An analysis of total sales and other operating revenues by segment and region is provided in Note 5.

Revenue from contracts with customers, by product

			$ million
	2018	2017	2016
Crude oil	65,276	49,670	32,284
Oil products	195,466	159,821	126,465
Natural gas, LNG and NGLs	21,745	16,196	11,337
Non-oil products and other revenues from contracts with customers	13,768	12,538	11,487
Revenues from contracts with customers	296,255	238,225	181,573

The group's sales to customers of crude oil and oil products were substantially all made by the Downstream segment. The group's sales to customers of natural gas, LNG and NGLs were made by the Upstream segment. A significant majority of the group's sales of non-oil products and other revenues from contracts with customers were made by the Downstream segment.

7. Income statement analysis

			$ million
	2018	2017	2016
Interest and other income			
Interest income from			
Financial assets measured at amortized cost	421	288	183
Financial assets measured at fair value through profit or loss	39	—	—
Other income	313	369	323
	773	657	506
Currency exchange losses charged to the income statement[a]	368	83	698
Expenditure on research and development	429	391	400
Finance costs			
Interest payable on liabilities measured at amortized cost	2,198	1,718	1,221
Capitalized at 3.56% (2017 2.25% and 2016 1.81%)[b]	(419)	(297)	(244)
Unwinding of discount on provisions	210	150	310
Unwinding of discount on other payables measured at amortized cost	539	503	388
	2,528	2,074	1,675

[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 $55 million (2017 $64 million and 2016 $56 million).

8. 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 in Note 1.

			$ million
	2018	2017	2016
Exploration and evaluation costs			
Exploration expenditure written off[a]	1,085	1,603	1,274
Other exploration costs	360	477	447
Exploration expense for the year	1,445	2,080	1,721
Impairment losses	137	—	62
Intangible assets – exploration and appraisal expenditure[b]	15,989	17,026	16,960
Liabilities	60	82	102
Net assets	15,929	16,944	16,858
Cash used in operating activities	360	477	447
Cash used in investing activities	1,119	1,901	2,920

[a] 2018 includes $447 million in the deepwater Gulf of Mexico principally relating to licence expiries. 2017 included a write-off in Angola of $574 million in relation to licence relinquishment, and Egypt of $208 million following a determination that no commercial hydrocarbons had been found. 2017 also included a $145-million write-off in relation to the value ascribed to certain licences in the deepwater Gulf of Mexico as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. 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. For further information see Upstream – Exploration on page 25.

[b] 2018 includes $2.3 billion relating to licences in the Gulf of Mexico that have expired and approximately $1.6 billion relating to certain licences elsewhere that are due to expire in the next financial year. BP remains committed to developing these prospects. See Note 1 for further information.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2018 is shown in the table below.

Carrying amount	Location
$1 - 2 billion	Angola; India; Egypt; Middle East
$2 - 3 billion	US - Gulf of Mexico; Canada; Brazil

9. Taxation

Tax on profit

			$ million
	2018	2017	2016
Current tax			
Charge for the year	6,217	4,208	1,762
Adjustment in respect of prior years[a]	(221)	58	(123)
	5,996	4,266	1,639
Deferred tax[b]			
Origination and reversal of temporary differences in the current year	907	(503)	(3,709)
Adjustment in respect of prior years	242	(51)	(397)
	1,149	(554)	(4,106)
Tax charge (credit) on profit or loss	7,145	3,712	(2,467)

[a] The adjustments in respect of prior years reflect the reassessment of the current tax balances for prior years in light of changes in facts and circumstances during the year.

[b] Origination and reversal of temporary differences in the current year include the impact of tax rate changes on deferred tax balances. 2018 includes a credit of $121 million (2017 $859 million charge) in respect of the reduction in the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018. The adjustments in respect of prior years reflect the reassessment of deferred tax balances for prior periods in light of all other changes in facts and circumstances during the year.

In 2018, the total tax charge recognized within other comprehensive income was $714 million (2017 $1,499 million charge and 2016 $752 million credit), primarily comprising the deferred tax impact of the remeasurements of the net pension and other post-retirement benefit liability or asset. See Note 32 for further information.

The total tax charge recognized directly in equity was $17 million (2017 $263 million charge and 2016 $5 million credit).

For information on significant estimates and judgements made in relation to taxation see Income taxes in 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, 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.

9. Taxation – continued

					$ million
	2018	2017	2016 excluding impacts of Gulf of Mexico oil spill and impairments	2016 impacts of Gulf of Mexico oil spill and impairments	2016
Profit (loss) before taxation	16,723	7,180	2,914	(5,209)	(2,295)
Tax charge (credit) on profit or loss	7,145	3,712	(117)	(2,350)	(2,467)
Effective tax rate	43%	52%	(4)%	45%	107%

		% of profit or loss before taxation			
Tax rate computed at the weighted average statutory rate[a]	43	44	18	33	52
Increase (decrease) resulting from					
Tax reported in equity-accounted entities	(5)	(7)	(15)	—	19
Adjustments in respect of prior years	—	—	5	13	23
Deferred tax not recognized	2	9	26	3	(27)
Tax incentives for investment	(2)	(6)	(9)	—	11
Gulf of Mexico oil spill non-deductible costs	—	1	—	(2)	(4)
Disposal impacts[b]	—	(1)	(24)	—	30
Foreign exchange	3	(4)	1	—	(2)
Items not deductible for tax purposes	1	5	8	—	(11)
Impact of US tax reform[c]	(1)	12	—	—	—
Decrease in rate of UK supplementary charge[d]	—	—	(15)	—	19
Other	2	(1)	1	(2)	(3)
Effective tax rate	43	52	(4)	45	107

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.

b In 2016 this related primarily to the tax impact on the contribution of BP's Norwegian upstream business into Aker BP ASA.

c Relates to the deferred tax impact of the reduction in the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018.

d Relates to the deferred tax impact of the reduction in the UK supplementary charge rate applicable to profits arising in the North Sea from 20% to 10% in 2016.

Deferred tax

		$ million
Analysis of movements during the year in the net deferred tax liability	2018	2017
At 31 December	3,513	2,497
Adjustment on adoption of IFRS 9[a]	(36)	—
At 1 January	3,477	2,497
Exchange adjustments	(68)	12
Charge (credit) for the year in the income statement	1,149	(554)

Charge for the year in other comprehensive income	734	1,503
Charge for the year in equity	17	1
Acquisitions and other additions[b]	797	54
At 31 December	6,106	3,513

[a] 2018 reflects the deferred tax impact of adjustments recorded by the group on adoption of IFRS 9. See Note 1 for further information.

[b] 2018 relates primarily to the purchase of an additional 16.5% interest in the Clair field. See Note 3 - Other significant transactions for further information.

9. Taxation – continued

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[a]			Balance sheet[a]
	2018	2017	2016	2018	2017
Deferred tax liability					
Depreciation	(1,297)	(3,971)	81	22,565	23,045
Pension plan surpluses	65	(12)	(12)	1,956	1,319
Derivative financial instruments	(36)	(27)	(230)	—	623
Other taxable temporary differences	(57)	(64)	(122)	1,224	1,317
	(1,325)	(4,074)	(283)	25,745	26,304
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	(6)	340	98	(1,319)	(1,386)
Decommissioning, environmental and other provisions	1,505	3,503	591	(7,126)	(8,618)
Derivative financial instruments	(25)	(50)	(6)	(144)	(672)
Tax credits[b]	123	1,476	(5,177)	(3,626)	(3,750)
Loss carry forward	559	(964)	249	(5,900)	(6,493)
Other deductible temporary differences	318	(785)	422	(1,524)	(1,872)
	2,474	3,520	(3,823)	(19,639)	(22,791)
Net deferred tax charge (credit) and net deferred tax liability	1,149	(554)	(4,106)	6,106	3,513
Of which – deferred tax liabilities				9,812	7,982
– deferred tax assets				3,706	4,469

[a] The 2017 and 2018 income statement and balance sheet are impacted by the reduction in US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018.

[b] The 2016 income statement reflected the impact of a loss carry-back claim in the US, displacing foreign tax credits utilized in prior periods which are now carried forward.

The recognition of deferred tax assets of $2,758 million (2017 $3,503 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. For 2018, $1,563 million relates to the US (2017 $2,067 million) and $1,108 million relates to India (2017 $1,336 million).

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	2018	2017
Unused US state tax losses[a]	6.6	6.8
Unused tax losses – other jurisdictions[b]	4.3	4.5
Unused tax credits	22.5	20.1
of which – arising in the UK[c]	18.7	16.3
– arising in the US[d]	3.8	3.8
Deductible temporary differences[e]	37.3	31.4
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	1.5	1.6

[a] For 2018 these losses expire in the period 2019-2038 with applicable tax rates ranging from 3% 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] For 2018 the US unused tax credits expire in the period 2019-2028.

[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 tax charge	2018	2017	2016
Current tax benefit relating to the utilization of previously unrecognized deferred tax assets	83	22	40
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 deferred tax assets	112	436	394
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	169	78	55

10. Dividends

The quarterly dividend paid on 29 March 2019 in respect of the fourth quarter 2018 was 10.25 cents per ordinary share ($0.615 per American Depositary Share (ADS)). The corresponding amount in sterling was announced on 18 March 2019. 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		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Dividends announced and paid in cash									
Preference shares							1	1	1
Ordinary shares									
March	7.1691	8.1587	7.0125	10.00	10.00	10.00	1,828	1,303	1,099
June	7.4435	7.7563	6.9167	10.00	10.00	10.00	1,727	1,546	1,168
September	7.9296	7.6213	7.5578	10.25	10.00	10.00	1,409	1,676	1,161
December	8.0251	7.4435	7.9313	10.25	10.00	10.00	1,734	1,627	1,182
	30.5673	30.9798	29.4183	40.50	40.00	40.00	6,699	6,153	4,611
Dividend announced, paid in March 2019				10.25			1,435		

The details of the scrip dividends issued are shown in the table below.

	2018	2017	2016
Number of shares issued (thousand)	195,305	289,789	548,005
Value of shares issued ($ million)	1,381	1,714	2,858

The financial statements for the year ended 31 December 2018 do not reflect the dividend announced on 5 February 2019 and paid in March 2019; this will be treated as an appropriation of profit in the year ending 31 December 2019.

11. Earnings per share

			Cents per share
Per ordinary share	2018	2017	2016
Basic earnings per share	46.98	17.20	0.61
Diluted earnings per share	46.67	17.10	0.60

		Dollars per share	
Per American Depositary Share (ADS)	2018	2017	2016
Basic earnings per share	2.82	1.03	0.04
Diluted earnings per share	2.80	1.03	0.04

Basic earnings per ordinary share amounts are calculated by dividing the profit (loss) for the year attributable to BP ordinary shareholders by the weighted average number of ordinary shares outstanding during the year.

The average number of shares outstanding includes certain shares that will be issuable in the future under employee share-based payment plans and excludes treasury shares, which includes shares held by the Employee Share Ownership Plan trusts (ESOPs).

For the diluted earnings per share calculation, the weighted average number of shares outstanding during the year is adjusted for the average number of shares that are potentially issuable in connection with employee share-based payment plans. 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.

			$ million
	2018	2017	2016
Profit (loss) attributable to BP shareholders	9,383	3,389	115
Less: dividend requirements on preference shares	1	1	1
Profit (loss) for the year attributable to BP ordinary shareholders	9,382	3,388	114

	2018	2017	Shares thousand 2016
Basic weighted average number of ordinary shares	19,970,215	19,692,613	18,744,800
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	132,278	123,829	110,519
Weighted average number of ordinary shares outstanding used to calculate diluted earnings per share	20,102,493	19,816,442	18,855,319

	2018	2017	Shares thousand 2016
Basic weighted average number of ordinary shares – ADS equivalent	3,328,369	3,282,102	3,124,133
Potential dilutive effect of ordinary shares (ADS equivalent) issuable under employee share-based payment plans	22,046	20,638	18,420
Weighted average number of ordinary shares (ADS equivalent) outstanding used to calculate diluted earnings per share	3,350,415	3,302,740	3,142,553

11. Earnings per share – continued

The number of ordinary shares outstanding at 31 December 2018, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 20,101,658,664. Between 31 December 2018 and 11 March 2019, the latest practicable date before the completion of these financial statements, there was a net increase of 143,038,241 in the number of ordinary shares outstanding primarily 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 87-109.

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	2018		2017	
	Number of options[ab] thousand	Weighted average exercise price $	Number of options[ab] thousand	Weighted average exercise price $
Outstanding	19,437	4.28	22,399	4.34
Exercisable	481	4.69	1,112	4.46
Dilutive effect	6,123	n/a	5,145	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

[b] At 31 December 2018 the quoted market price of one BP ordinary share was £4.96 (2017 £5.23).

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	2018	2017
Vesting	Number of shares[a] thousand	Number of shares[a] thousand
Within one year	108,934	101,550
1 to 2 years	106,337	108,373
2 to 3 years	71,407	85,878
3 to 4 years	588	413
Over 4 years	799	166
	288,065	296,380
Dilutive effect	127,165	126,122

[a] Numbers of shares shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).

There has been a net decrease of 56,796,490 in the number of potential ordinary shares relating to employee share-based payment plans between 31 December 2018 and 11 March 2019.

12. Property, plant and equipment

								$ million
	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fittings, fixtures and office equipment	Transportation[b]	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2018	3,474	1,573	226,054	46,662	2,853	10,774	8,748	300,138
Exchange adjustments	(168)	(58)	—	(892)	(73)	(43)	(501)	(1,735)
Additions	233	40	9,712	2,323	204	(112)	736	13,136
Acquisitions	163	4	10,882	9	1	2	36	11,097
Remeasurements	—	—	17	—	—	—	—	17
Transfers from intangible assets	—	—	901	—	—	—	—	901
Deletions	(140)	(45)	(14,699)	(1,810)	(238)	(128)	(146)	(17,206)
At 31 December 2018	3,562	1,514	232,867	46,292	2,747	10,493	8,873	306,348
Depreciation								
At 1 January 2018	683	818	133,326	20,996	2,136	7,523	5,185	170,667
Exchange adjustments	(25)	(24)	—	(460)	(52)	(27)	(279)	(867)
Charge for the year	92	52	12,342	1,820	189	252	384	15,131
Impairment losses	2	—	86	253	—	178	2	521
Impairment reversals	—	—	(564)	(1)	—	(17)	—	(582)
Deletions	(126)	(139)	(11,333)	(1,733)	(232)	(75)	(145)	(13,783)
At 31 December 2018	626	707	133,857	20,875	2,041	7,834	5,147	171,087
Net book amount at 31 December 2018	2,936	807	99,010	25,417	706	2,659	3,726	135,261
Cost								
At 1 January 2017	3,066	2,235	215,564	43,725	2,670	14,000	7,623	288,883
Exchange adjustments	264	42	—	1,251	91	28	772	2,448
Additions	264	94	12,366	1,890	240	347	575	15,776
Acquisitions	—	—	—	41	—	228	1	270
Transfers from intangible assets	—	—	451	—	—	—	—	451
Deletions	(120)	(798)	(2,327)	(245)	(148)	(3,829)	(223)	(7,690)
At 31 December 2017	3,474	1,573	226,054	46,662	2,853	10,774	8,748	300,138
Depreciation								
At 1 January 2017	584	1,062	122,428	18,686	2,022	9,823	4,521	159,126
	33	27	—	647	67	19	466	1,259

Exchange adjustments								
Charge for the year	90	94	12,385	1,764	185	381	350	15,249
Impairment losses	3	35	624	35	—	479	17	1,193
Impairment reversals	—	—	(135)	—	—	(72)	—	(207)
Deletions	(27)	(400)	(1,976)	(136)	(138)	(3,107)	(169)	(5,953)
At 31 December 2017	683	818	133,326	20,996	2,136	7,523	5,185	170,667
Net book amount at 31 December 2017	2,791	755	92,728	25,666	717	3,251	3,563	129,471
Assets held under finance leases at net book amount included above								
At 31 December 2018	—	2	12	207	—	295	6	522
At 31 December 2017	—	2	16	238	—	233	7	496
Assets under construction included above								
At 31 December 2018								22,522
At 31 December 2017								23,789

[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] Includes adjustments to decommissioning provisions see Note 1 for further information.

13. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2018 amounted to $8,319 million (2017 $11,340 million). BP has capital commitments amounting to $1,227 million (2017 $1,451 million) in relation to associates. BP's share of capital commitments of joint ventures amounted to $619 million (2017 $483 million).

14. Goodwill and impairment review of goodwill

	$ million	
	2018	2017
Cost		
At 1 January	12,163	11,805
Exchange adjustments	(210)	336
Acquisitions and other additions[a]	1,046	83
Deletions	(184)	(61)
At 31 December	12,815	12,163
Impairment losses		
At 1 January	612	611
Exchange adjustments	—	1
Deletions	(1)	—
At 31 December	611	612
Net book amount at 31 December	12,204	11,551
Net book amount at 1 January	11,551	11,194

[a] 2018 principally relates to the purchase of an additional 16.5% share in the Clair field in the North Sea. See Note 3 - Other significant transactions for further information.

Impairment review of goodwill

	$ million	
Goodwill at 31 December	2018	2017
Upstream	8,346	7,728
Downstream	3,802	3,758
Other businesses and corporate	56	65
	12,204	11,551

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, intangible assets and goodwill in Note 1.

Upstream

	$ million	
	2018	2017
Goodwill	8,346	7,728
Excess of recoverable amount over carrying amount	53,391	27,705

The table above shows the carrying amount of goodwill for the segment and the excess of the recoverable amount, based upon a post-tax value-in-use calculation, over the carrying amount (headroom) at the date of the test. The increase in headroom principally arises from acquisitions, new activity and changes in US tax. In the prior year, the recoverable amount was estimated using a fair value less costs of disposal calculation and was based on cash flows estimated for the impairment test performed in 2016 as permitted by IAS 36.

The value in use is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field, based on current estimates of reserves and resources, appropriately risked. Midstream and supply and trading activities and equity-accounted entities are generally not included in the impairment review of goodwill, because they are not part of the grouping of cash-generating units to which the goodwill relates and which is used to monitor the goodwill for internal management purposes. Where such activities form part of a wider Upstream cash-generating unit, they are reflected in the test. As the production profile and related cash flows can be estimated from BP's past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment. The estimated date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP management. Capital expenditure, operating costs and expected hydrocarbon production profiles are derived from the business segment plan adjusted for assumptions reflecting the price environment at the time that the test was performed. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis are 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.

The most recent review for impairment was carried out in the fourth quarter. The key assumptions used in the value-in-use calculation are oil and natural gas prices, production volumes and the discount rate. Oil and gas price assumptions for the first five years are based on management's best estimate of prices over those five years, with the long-term price applied from year 6 onwards. Price assumptions and discount rate assumptions used were as disclosed in Note 1. The value-in-use calculation has 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. 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.

14. Goodwill and impairment review of goodwill – continued

It is estimated that if the oil price assumption for all future years was approximately $14 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 no reasonable fall in the gas price assumption 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 829mmboe per year (2017 889mmboe per year). It is estimated that if production volumes were to be reduced by approximately 13% 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 11% for the entire portfolio, an increase of 5% for all countries not considered ‘higher risk’ and 3% 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
			2018			2017
	Lubricants	Other	Total	Lubricants	Other	Total
Goodwill	2,692	1,110	3,802	2,849	909	3,758

Cash flows for each cash-generating unit are derived from the business segment plans, which cover a period of up 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 as the basis for the tests in 2014-2017 as the criteria of IAS 36 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 is remote. IAS 36 does not specify for how many years such an approach is appropriate and management determined that a re-performance of the test was appropriate in 2018 given the passage of time since 2013. There was no significant change in the outcome of this test compared to that in 2013.

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. Operating margin and sales volumes assumptions used in the detailed impairment review of goodwill calculation are consistent with the assumptions used in the Lubricants unit’s business plan and values assigned to these key assumptions reflect past experience. No reasonably possible change in any of these key assumptions would cause the unit’s carrying amount to exceed its recoverable amount. Cash flows beyond the plan period are extrapolated using a nominal 2.8% growth rate (2013 3%).

15. Intangible assets

						$ million
			2018			2017
	Exploration and appraisal expenditure[a]	Other intangibles	Total	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	17,886	4,488	22,374	18,524	4,035	22,559
Exchange adjustments	—	(128)	(128)	—	197	197
Acquisitions	—	25	25	—	41	41
Additions	1,095	318	1,413	2,128	310	2,438
Transfers to property, plant and equipment	(901)	—	(901)	(451)	—	(451)
Deletions	(1,027)	(199)	(1,226)	(2,315)	(95)	(2,410)

At 31 December	17,053	4,504	21,557	17,886	4,488	22,374
Amortization						
At 1 January	860	3,159	4,019	1,564	2,812	4,376
Exchange adjustments	—	(77)	(77)	—	107	107
Charge for the year	1,085	326	1,411	1,603	335	1,938
Impairment losses	137	—	137	—	—	—
Deletions	(1,018)	(199)	(1,217)	(2,307)	(95)	(2,402)
At 31 December	1,064	3,209	4,273	860	3,159	4,019
Net book amount at 31 December	15,989	1,295	17,284	17,026	1,329	18,355
Net book amount at 1 January	17,026	1,329	18,355	16,960	1,223	18,183

[a] For further information see Intangible assets within Note 1 and Note 8.

16. Investments in joint ventures

The following table provides aggregated summarized financial information relating to the group's share of joint ventures.

			$ million
	2018	2017	2016
Sales and other operating revenues	13,258	11,380	10,081
Profit before interest and taxation	1,396	1,394	1,612
Finance costs	85	100	156
Profit before taxation	1,311	1,294	1,456
Taxation	414	117	490
Profit for the year	897	1,177	966
Other comprehensive income	6	8	5
Total comprehensive income	903	1,185	971
Non-current assets	10,399	10,139	
Current assets	2,935	2,419	
Total assets	13,334	12,558	
Current liabilities	1,715	1,687	
Non-current liabilities	3,017	2,927	
Total liabilities	4,732	4,614	
Net assets	8,602	7,944	
Group investment in joint ventures			
Group share of net assets (as above)	8,602	7,944	
Loans made by group companies to joint ventures	45	50	
	8,647	7,994	

Transactions between the group and its joint ventures are summarized below.

						$ million
Sales to joint ventures		2018		2017		2016
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	4,603	251	3,578	352	3,327	291

						$ million
Purchases from joint ventures		2018		2017		2016
Product	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	1,336	300	1,257	176	943	120

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.

17. 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			Balance sheet	
	Earnings from associates - after interest and tax			Investments in associates	
	2018	2017	2016	2018	2017
Rosneft	2,283	922	647	10,074	10,059
Other associates	573	408	347	7,599	6,932
	2,856	1,330	994	17,673	16,991

The associate that is material to the group at both 31 December 2018 and 2017 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 2018.

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 currency is the Russian rouble. The increase in the group's equity-accounted investment balance for Rosneft at 31 December 2018 compared with 31 December 2017 principally relates to earnings from Rosneft offset by dividends distribution and foreign exchange effects which have been recognized in other comprehensive income.

17. Investments in associates – continued

The value of BP’s 19.75% shareholding in Rosneft based on the quoted market share price of $6.18 per share (2017 $4.99 per share) was $12,934 million at 31 December 2018 (2017 $10,444 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 2018, as shown in the table below, compared with the amounts reported in Rosneft's IFRS financial statements. In particular, in 2018 these adjustments resulted in BP reporting a lower amount relating to impairment charges of downstream goodwill than the equivalent amounts reported by Rosneft.

			$ million Gross amount
	2018	2017	2016
Sales and other operating revenues	131,322	103,028	74,380
Profit before interest and taxation	18,886	9,949	7,094
Finance costs	2,785	2,228	1,747
Profit before taxation	16,101	7,721	5,347
Taxation	2,957	1,742	1,797
Non-controlling interests	1,585	1,311	273
Profit for the year	11,559	4,668	3,277
Other comprehensive income	2,086	2,810	4,203
Total comprehensive income	13,645	7,478	7,480
Non-current assets	137,038	158,719	
Current assets	43,438	39,737	
Total assets	180,476	198,456	
Current liabilities	41,311	66,506	
Non-current liabilities	78,754	70,704	
Total liabilities	120,065	137,210	
Net assets	60,411	61,246	
Less: non-controlling interests	9,403	10,314	
	51,008	50,932	

The group received dividends, net of withholding tax, of $620 million from Rosneft in 2018 (2017 $314 million and 2016 $332 million).

Summarized financial information for the group’s share of associates is shown below.

									$ million BP share
			2018			2017			2016
	Rosneft[a]	Other	Total	Rosneft[a]	Other	Total	Rosneft[a]	Other	Total
Sales and other operating revenues	25,936	9,134	35,070	20,348	7,600	27,948	14,690	5,377	20,067
Profit before interest and taxation	3,730	1,150	4,880	1,965	626	2,591	1,401	525	1,926
Finance costs	550	78	628	440	54	494	345	22	367
Profit before taxation	3,180	1,072	4,252	1,525	572	2,097	1,056	503	1,559
Taxation	584	499	1,083	344	164	508	355	156	511
Non-controlling interests	313	—	313	259	—	259	54	—	54
Profit for the year	2,283	573	2,856	922	408	1,330	647	347	994
Other comprehensive income	412	(1)	411	555	1	556	830	(2)	828
Total comprehensive income	2,695	572	3,267	1,477	409	1,886	1,477	345	1,822
Non-current assets	27,065	10,787	37,852	31,347	9,261	40,608			
Current assets	8,579	2,398	10,977	7,848	2,645	10,493			

Total assets	35,644	13,185	48,829	39,195	11,906	51,101
Current liabilities	8,159	2,232	10,391	13,135	2,501	15,636
Non-current liabilities	15,554	3,817	19,371	13,964	3,308	17,272
Total liabilities	23,713	6,049	29,762	27,099	5,809	32,908
Net assets	11,931	7,136	19,067	12,096	6,097	18,193
Less: non-controlling interests	1,857	—	1,857	2,037	—	2,037
	10,074	7,136	17,210	10,059	6,097	16,156
Group investment in associates						
Group share of net assets (as above)	10,074	7,136	17,210	10,059	6,097	16,156
Loans made by group companies to associates	—	463	463	—	835	835
	10,074	7,599	17,673	10,059	6,932	16,991

[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.

17. Investments in associates – continued

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		2018		2017		2016
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	2,064	393	1,612	216	3,643	765

						$ million
Purchases from associates		2018		2017		2016
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	14,112	2,069	11,613	1,681	8,873	2,000

In addition to the transactions shown in the table above, in 2018 BP acquired a 49% stake in LLC Kharampurneftegaz, a Rosneft subsidiary, which will develop subsoil resources within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets Autonomous Okrug in northern Russia. BP's interest in LLC Kharampurneftegaz is accounted for as an associate.

The terms of the outstanding balances receivable from associates are typically 30 to 45 days. The balances are unsecured and will be settled in cash. There are no significant provisions for doubtful debts relating to these balances and no significant expense recognized in the income statement in respect of bad or doubtful debts. Dividends receivable are not included in the table above.

The majority of the sales to and purchases from associates relate to crude oil and oil products transactions with Rosneft.

BP has commitments amounting to $11,303 million (2017 $13,932 million), primarily in relation to contracts with its associates for the purchase of transportation capacity. For information on capital commitments in relation to associates see Note 13.

18. Other investments

				$ million
		2018		2017
	Current	Non-current	Current	Non-current
Equity investments[a]	1	482	15	418
Other	221	859	110	827
	222	1,341	125	1,245

[a] The majority of equity investments are unlisted.

Other investments includes $893 million relating to contingent consideration amounts arising on disposals (2017 $237 million) which are financial assets classified as measured at fair value through profit or loss. The fair value is determined using an estimate of discounted future cash flows that are expected to be received and is considered a level 3 valuation under the fair value hierarchy. Future cash flows are estimated based on inputs including oil and natural gas prices, production volumes and operating costs related to the disposed operations. The discount rate used is based on a risk-free rate adjusted for asset-specific risks.

19. Inventories

		$ million
	2018	2017
Crude oil	4,878	5,692

Natural gas	322	119
Refined petroleum and petrochemical products	10,419	10,694
	15,619	16,505
Trading inventories	282	295
	15,901	16,800
Supplies	2,087	2,211
	17,988	19,011
Cost of inventories expensed in the income statement	229,878	179,716

The inventory valuation at 31 December 2018 is stated net of a provision of $1,009 million (2017 $474 million) to write down inventories to their net realizable value, of which $604 million (2017 $62 million) relates to hydrocarbon inventories. The net charge to the income statement in the year in respect of inventory net realizable value provisions was $552 million (2017 $27 million credit), of which $553 million (2017 $31 million credit) related to hydrocarbon inventories.

Trading inventories are valued using quoted benchmark prices adjusted as appropriate for location and quality differentials. They are predominantly categorized within level 2 of the fair value hierarchy.

20. Trade and other receivables

				$ million
		2018		2017
	Current	Non-current	Current	Non-current
Financial assets				
Trade receivables	19,414	7	18,912	4
Amounts receivable from joint ventures and associates	642	2	566	2
Other receivables	3,275	740	4,206	671
	23,331	749	23,684	677
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset	214	—	252	—
Sales taxes and production taxes	790	482	746	276
Other receivables	143	603	167	481
	1,147	1,085	1,165	757
	24,478	1,834	24,849	1,434

In both 2018 and 2017 the group entered into non-recourse arrangements to discount certain receivables in support of supply and trading activities and the management of credit risk.

Trade and other receivables are predominantly non-interest bearing. See Note 29 for further information.

21. Valuation and qualifying accounts

								$ million
				2018		2017		2016
	Not credit-impaired	Credit impaired	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments	Trade and other receivables	Fixed asset investments
At 1 January – IAS 39	—	335	335	314	392	335	447	435
Adjustment on adoption of IFRS 9	115	—	115	(85)	—	—	—	—
At 1 January – IFRS 9	115	335	450	229	392	335	447	435
Charged to costs and expenses	(26)	56	30	10	68	47	120	55
Charged to other accounts[a]	—	(12)	(12)	(1)	13	3	(7)	(2)
Deductions	—	(52)	(52)	(3)	(138)	(71)	(168)	(153)
At 31 December	89	327	416	235	335	314	392	335

[a] Principally exchange adjustments.

Valuation and qualifying accounts relating to trade and other receivables comprise expected credit loss allowances in 2018 and impairment provisions recognized on an incurred loss basis in comparative periods. The adjustment on adoption of IFRS 9 relates to the additional loss allowance required by the new standard's expected credit loss model. There were no significant changes to the gross carrying amounts of trade and other receivables during the year that affected the estimation of the loss allowance at 31 December 2018.

Valuation and qualifying accounts relating to fixed asset investments comprise impairment provisions for investments in equity-accounted entities in 2018. This includes expected credit loss allowances of $44 million (1 January 2018 $43 million) relating to loans that form part of the net investment in equity-accounted entities. The adjustment on adoption of IFRS 9 primarily relates to amounts provided against investments in equity instruments that were held at cost less impairment losses under IAS 39 but that are classified as measured at fair value through profit or loss under IFRS 9.
In addition to the amounts presented above, expected loss allowances on cash and cash equivalents classified as measured at amortized cost totalled $11 million (1 January 2018 $11 million). For further information on the group's credit risk management policies and how the group recognizes and measures expected losses see Note 29.
Valuation and qualifying accounts are deducted in the balance sheet from the assets to which they apply.
For further information on the adjustments on adoption of IFRS 9 see Note 1.

22. Trade and other payables

				$ million
	2018		2017	
	Current	Non-current	Current	Non-current
Financial liabilities				
Trade payables	26,252	—	26,983	—
Amounts payable to joint ventures and associates	2,369	—	1,857	—
Payables for capital expenditure and acquisitions[a]	7,325	1,345	3,810	1,269
Payables related to the Gulf of Mexico oil spill[b]	2,279	11,922	2,089	12,253
Other payables	4,980	318	5,733	60
	43,205	13,585	40,472	13,582
Non-financial liabilities				
Sales taxes, customs duties, production taxes and social security	2,272	35	2,586	50
Other payables	788	210	1,151	257
	3,060	245	3,737	307
	46,265	13,830	44,209	13,889

[a] Includes $3,514 million deferred consideration relating to the acquisition of Petrohawk Energy Corporation from BHP Billiton Petroleum (North America) Inc. See Note 3 for further information.

[b] See Note 2 for further information.

Materially all of BP's trade payables have payment terms in the range of 30 to 60 days and give rise to operating cash flows. The active management of supplier payment terms within this range enables BP to optimize and reduce volatility in cash flow.

Trade and other payables, other than those relating to the Gulf of Mexico oil spill, are predominantly interest free. See Note 29 (c) for further information.

23. Provisions

					$ million
	Decommissioning	Environmental	Litigation and claims	Other	Total
At 1 January 2018	16,100	1,516	3,334	2,994	23,944
Exchange adjustments	(135)	(9)	(3)	(84)	(231)
Acquisitions	295	12	24	5	336
Increase (decrease) in existing provisions	137	428	1,492	1,303	3,360
Write-back of unused provisions	(2)	(115)	(21)	(255)	(393)
Unwinding of discount	162	22	9	17	210
Change in discount rate[a]	(2,377)	(38)	(31)	(17)	(2,463)
Utilization	(9)	(245)	(1,034)	(528)	(1,816)
Reclassified to other payables	(270)	(4)	(2,051)	(37)	(2,362)
Deletions	(288)	—	(1)	—	(289)
At 31 December 2018	13,613	1,567	1,718	3,398	20,296
Of which – current	257	300	798	1,209	2,564
– non-current	13,356	1,267	920	2,189	17,732
Of which – Gulf of Mexico oil spill[b]	—	—	345	—	345

[a] Includes the impact of changing from a real to nominal discount rate. See Note 1 for further information.

[b] Further information on the financial impacts of the Gulf of Mexico oil spill is provided in Note 2.

The decommissioning provision comprises the future cost of decommissioning oil and natural gas wells, facilities and related pipelines. The environmental provision includes provisions for costs related to the control, abatement, clean-up or elimination of environmental pollution relating to soil, groundwater, surface water and sediment contamination. The litigation and claims category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2018 are provisions for deferred employee compensation of $338 million (2017 $391 million).

For information on significant estimates and judgements made in relation to provisions, see Provisions and contingencies within Note 1.

24. 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 in 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.

24. Pensions and other post-retirement benefits – continued

In the US, all pension benefits now accrue 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 2018 the aggregate level of contributions was $610 million (2017 $637 million and 2016 $651 million). The aggregate level of contributions in 2019 is expected to be approximately $700 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 is agreed covering the next five years. Contractually committed funding amounted to $1,275 million at 31 December 2018, all of which relates to future service. This amount is included in the group's committed cash flows relating to pensions and other post-retirement benefit plans as set out in the table of contractual obligations on page 278.

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. No contributions were made into the primary US pension plan in 2018 and no statutory funding requirement is expected in the next 12 months.

The surplus relating to the primary US fund is recognized on the balance sheet on the basis that economic benefit can be gained from the surplus through a reduction in future contributions.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2018.

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 2018. 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 2017. A valuation of the US plan and largest Eurozone plans are 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.

									%
		UK			US				Eurozone
Financial assumptions used to determine benefit obligation	2018	2017	2016	2018	2017	2016	2018	2017	2016

Discount rate for plan liabilities	2.9	2.5	2.7	4.1	3.5	3.9	2.0	1.9	1.7
Rate of increase in salaries	3.8	4.1	4.6	3.9	4.1	4.2	3.1	3.0	3.0
Rate of increase for pensions in payment	3.0	2.9	3.0	—	—	—	1.5	1.4	1.5
Rate of increase in deferred pensions	3.0	2.9	3.0	—	—	—	0.5	0.6	0.5
Inflation for plan liabilities	3.1	3.1	3.2	1.5	1.7	1.8	1.7	1.6	1.6

Financial assumptions used to determine benefit expense		UK			US				% Eurozone
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Discount rate for plan service cost	2.6	2.7	4.0	3.6	4.1	4.2	2.4	2.1	2.7
Discount rate for plan other finance expense	2.5	2.7	3.9	3.5	3.9	4.0	1.9	1.7	2.4
Inflation for plan service cost	3.1	3.2	3.1	1.7	1.8	1.5	1.6	1.6	1.8

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.

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 an allowance for promotion-related salary growth, of up to 0.8% depending on country.

24. Pensions and other post-retirement benefits – continued

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		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Life expectancy at age 60 for a male currently aged 60	27.4	27.4	28.0	25.1	25.1	25.7	25.6	25.1	25.0
Life expectancy at age 60 for a male currently aged 40	28.9	29.0	30.0	26.9	26.8	27.5	28.1	27.6	27.6
Life expectancy at age 60 for a female currently aged 60	28.8	28.8	29.5	28.5	28.4	29.3	29.0	29.0	28.9
Life expectancy at age 60 for a female currently aged 40	30.6	30.5	31.9	30.1	30.0	31.0	31.2	31.4	31.3

Pension plan assets are generally held in trusts, the primary objective of which is to accumulate assets sufficient to meet the obligations of the 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.

The trustee's long-term investment objective for the primary UK plan as it matures is to invest in assets whose value changes in the same way as the plan liabilities, in order to reduce the level of funding risk. To move towards this objective, the UK plan uses a liability driven investment (LDI) approach for part of the portfolio, investing primarily in government bonds to achieve this matching effect for the most significant plan liability assumptions of interest rate and inflation rate. This is partly funded by short-term sale and repurchase agreements, whereby the plan borrows money using existing bonds as security and which will be bought back at a specified price at an agreed future date. The funds raised are used to invest in further bonds to increase the proportion of assets which match the plan liabilities. The borrowings are shown separately in the analysis of pension plan assets in the table below.

For the primary UK pension plan there is an agreement with the trustee to increase the proportion of assets with liability matching characteristics over time primarily by reducing the proportion of plan assets held as equities and increasing the proportion held as bonds. There is a similar agreement in place for the primary US plan. During 2018, the UK and the US plans switched 12.5% and 10% of plan assets respectively from equities to bonds.

The current asset allocation policy for the major plans at 31 December 2018 was as follows:

	UK	US
Asset category	%	%
Total equity (including private equity)	30	40
Bonds/cash (including LDI)	63	60
Property/real estate	7	—

The amounts invested under the LDI programme by the primary UK pension plan as at 31 December 2018 were $4,197 million (2017 $2,588 million) of government-issued nominal bonds and $17,491 million (2017 $16,177 million) of index-linked bonds.

Some of the group's pension plans in the Eurozone and other countries use derivative financial instruments as part of their asset mix to manage the level of risk. The fair value of these instruments are included in other assets in the table below. The UK and US plans do not use derivative financial instruments.

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 176.

24. Pensions and other post-retirement benefits – continued

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2018					
Listed equities – developed markets	5,191	1,238	413	306	7,148
– emerging markets	950	63	65	56	1,134
Private equity[c]	2,792	1,495	—	4	4,291
Government issued nominal bonds[d]	4,263	2,072	895	533	7,763
Government issued index-linked bonds[d]	17,491	—	102	—	17,593
Corporate bonds[d]	4,606	2,184	506	243	7,539
Property[e]	2,311	6	57	25	2,399
Cash	376	73	42	83	574
Other	116	64	32	40	252
Debt (repurchase agreements) used to fund liability driven investments	(6,011)	—	—	—	(6,011)
	32,085	7,195	2,112	1,290	42,682
At 31 December 2017					
Listed equities – developed markets	9,548	2,158	537	376	12,619
– emerging markets	2,220	220	83	53	2,576
Private equity[c]	2,679	1,461	—	—	4,140
Government issued nominal bonds[d]	2,663	1,777	941	545	5,926
Government issued index-linked bonds[d]	16,177	—	2	—	16,179
Corporate bonds[d]	4,682	2,024	546	272	7,524
Property[e]	2,211	6	71	30	2,318
Cash	390	80	21	98	589
Other	104	53	23	45	225
Debt (repurchase agreements) used to fund liability driven investments	(5,583)	—	—	—	(5,583)
	35,091	7,779	2,224	1,419	46,513
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[c]	2,754	1,442	1	—	4,197
Government issued nominal bonds[d]	489	1,438	821	448	3,196
Government issued index-linked bonds[d]	9,384	—	4	—	9,388
Corporate bonds[d]	4,042	1,732	427	259	6,460
Property[e]	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

[a] Bonds held by the UK pension plans are 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.

[c] Private equity is valued at fair value based on the most recent third-party net asset valuation.

[d] Bonds held by pension plans are valued using quoted prices in active markets. Where quoted prices are not available, quoted prices for similar instruments in active markets are used.

[e] Properties are valued based on an analysis of recent market transactions supported by market knowledge derived from third-party valuers.

24. Pensions and other post-retirement benefits – continued

	UK	US	Eurozone	Other	$ million 2018 Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	295	299	84	43	721
Past service cost[b]	15	—	9	4	28
Settlement[b]	—	—	17	—	17
Operating charge relating to defined benefit plans	310	299	110	47	766
Payments to defined contribution plans	38	178	5	40	261
Total operating charge	348	477	115	87	1,027
Interest income on plan assets[a]	(868)	(262)	(44)	(45)	(1,219)
Interest on plan liabilities	774	369	136	67	1,346
Other finance (income) expense	(94)	107	92	22	127
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	(722)	(256)	(69)	(36)	(1,083)
Change in financial assumptions underlying the present value of the plan liabilities	1,770	945	14	65	2,794
Change in demographic assumptions underlying the present value of the plan liabilities	123	(9)	(42)	7	79
Experience gains and losses arising on the plan liabilities	520	41	(43)	9	527
Remeasurements recognized in other comprehensive income	1,691	721	(140)	45	2,317
Movements in benefit obligation during the year					
Benefit obligation at 1 January	31,513	10,820	7,275	1,873	51,481
Exchange adjustments	(1,589)	—	(303)	(113)	(2,005)
Operating charge relating to defined benefit plans	310	299	110	47	766
Interest cost	774	369	136	67	1,346
Contributions by plan participants[c]	21	—	2	7	30
Benefit payments (funded plans)[d]	(1,780)	(597)	(84)	(83)	(2,544)
Benefit payments (unfunded plans)[d]	(6)	(218)	(301)	(17)	(542)
Disposals	—	—	—	(14)	(14)
Remeasurements	(2,413)	(977)	71	(81)	(3,400)
Benefit obligation at 31 December[a e]	26,830	9,696	6,906	1,686	45,118
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	35,091	7,779	2,224	1,419	46,513
Exchange adjustments	(1,883)	—	(93)	(73)	(2,049)
Interest income on plan assets[a f]	868	262	44	45	1,219
Contributions by plan participants[c]	21	—	2	7	30
Contributions by employers (funded plans)	490	7	88	25	610
Benefit payments (funded plans)[d]	(1,780)	(597)	(84)	(83)	(2,544)
Disposals	—	—	—	(14)	(14)
Remeasurements[f]	(722)	(256)	(69)	(36)	(1,083)
Fair value of plan assets at 31 December[g]	32,085	7,195	2,112	1,290	42,682
Surplus (deficit) at 31 December	5,255	(2,501)	(4,794)	(396)	(2,436)
Represented by					
Asset recognized	5,473	418	29	35	5,955
Liability recognized	(218)	(2,919)	(4,823)	(431)	(8,391)
	5,255	(2,501)	(4,794)	(396)	(2,436)

The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	5,473	396	(152)	(97)	5,620
Unfunded	(218)	(2,897)	(4,642)	(299)	(8,056)
	5,255	(2,501)	(4,794)	(396)	(2,436)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(26,612)	(6,799)	(2,264)	(1,387)	(37,062)
Unfunded	(218)	(2,897)	(4,642)	(299)	(8,056)
	(26,830)	(9,696)	(6,906)	(1,686)	(45,118)

[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 and settlements have arisen from restructuring programmes and represent 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 $3,046 million benefits and $2 million settlements, plus $38 million of plan expenses incurred in the administration of the benefit.

[e] The benefit obligation for the US is made up of $7,290 million for pension liabilities and $2,406 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,328 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 174.

24. Pensions and other post-retirement benefits – continued

	UK	US	Eurozone	Other	$ million 2017 Total
Analysis of the amount charged to profit or loss					
Current service cost[a]	357	292	85	46	780
Past service cost[b]	12	—	5	(1)	16
Settlement[b]	—	—	13	—	13
Operating charge relating to defined benefit plans	369	292	103	45	809
Payments to defined contribution plans	31	191	7	38	267
Total operating charge	400	483	110	83	1,076
Interest income on plan assets[a]	(845)	(266)	(37)	(48)	(1,196)
Interest on plan liabilities	831	393	121	71	1,416
Other finance (income) expense	(14)	127	84	23	220
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,396	826	30	43	3,295
Change in financial assumptions underlying the present value of the plan liabilities	(236)	(514)	336	(47)	(461)
Change in demographic assumptions underlying the present value of the plan liabilities	734	72	—	(23)	783
Experience gains and losses arising on the plan liabilities	91	(40)	(36)	14	29
Remeasurements recognized in other comprehensive income	2,985	344	330	(13)	3,646
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,908	10,533	6,820	1,715	48,976
Exchange adjustments	2,886	—	915	89	3,890
Operating charge relating to defined benefit plans	369	292	103	45	809
Interest cost	831	393	121	71	1,416
Contributions by plan participants[c]	16	—	2	6	24
Benefit payments (funded plans)[d]	(1,903)	(641)	(75)	(89)	(2,708)
Benefit payments (unfunded plans)[d]	(5)	(239)	(302)	(20)	(566)
Acquisitions	—	1	—	—	1
Disposals	—	(1)	(9)	—	(10)
Remeasurements	(589)	482	(300)	56	(351)
Benefit obligation at 31 December[a e]	31,513	10,820	7,275	1,873	51,481
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	30,180	7,316	1,879	1,310	40,685
Exchange adjustments	3,048	—	264	72	3,384
Interest income on plan assets[a f]	845	266	37	48	1,196
Contributions by plan participants[c]	16	—	2	6	24
Contributions by employers (funded plans)	509	12	87	29	637
Benefit payments (funded plans)[d]	(1,903)	(641)	(75)	(89)	(2,708)
Remeasurements[f]	2,396	826	30	43	3,295
Fair value of plan assets at 31 December[g]	35,091	7,779	2,224	1,419	46,513
Surplus (deficit) at 31 December	3,578	(3,041)	(5,051)	(454)	(4,968)
Represented by					
Asset recognized	3,838	260	43	28	4,169
Liability recognized	(260)	(3,301)	(5,094)	(482)	(9,137)
	3,578	(3,041)	(5,051)	(454)	(4,968)

The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	3,838	238	(106)	(101)	3,869
Unfunded	(260)	(3,279)	(4,945)	(353)	(8,837)
	3,578	(3,041)	(5,051)	(454)	(4,968)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(31,253)	(7,541)	(2,330)	(1,520)	(42,644)
Unfunded	(260)	(3,279)	(4,945)	(353)	(8,837)
	(31,513)	(10,820)	(7,275)	(1,873)	(51,481)

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 and settlements have arisen from restructuring programmes and represent 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 $3,235 million benefits and $2 million settlements, plus $37 million of plan expenses incurred in the administration of the benefit.

e The benefit obligation for the US is made up of $8,085 million for pension liabilities and $2,735 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,586 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 174.

24. Pensions and other post-retirement benefits – continued

					$ million 2016
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit or loss					
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 (income) 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)

[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.

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 2018 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2019 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 2019	(337)	295
Effect on pension and other post-retirement benefit obligation at 31 December 2018	(6,179)	8,153
Inflation rate[b]		
Effect on pension and other post-retirement benefit expense in 2019	227	(187)
Effect on pension and other post-retirement benefit obligation at 31 December 2018	4,919	(4,225)
Salary growth		
Effect on pension and other post-retirement benefit expense in 2019	64	(55)
Effect on pension and other post-retirement benefit obligation at 31 December 2018	653	(595)

[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 2019 pension and other post-retirement benefit expense by $52 million and the pension and other post-retirement benefit obligation at 31 December 2018 by $1,432 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 2028 and the weighted average duration of the defined benefit obligations at 31 December 2018 are as follows:

					$ million
Estimated future benefit payments	UK	US	Eurozone	Other	Total
2019	1,030	787	350	101	2,268
2020	1,036	755	339	97	2,227
2021	1,056	806	331	97	2,290
2022	1,088	749	326	100	2,263
2023	1,120	741	317	98	2,276
2024-2028	5,777	3,476	1,501	498	11,252
					Years
Weighted average duration	17.8	9.5	14.2	13.0	

25. Cash and cash equivalents

	$ million	
	2018	2017
Cash	6,148	4,592
Term bank deposits	13,105	17,324
Cash equivalents (excluding term bank deposits)	3,215	3,670
	22,468	25,586

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 2018 includes $1,350 million (2017 $1,488 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $4,693 million (2017 $3,638 million) of cash and cash equivalents outside the UK and it is not expected that any significant tax will arise on repatriation.

26. Finance debt

						$ million
			2018			2017
	Current	Non-current	Total	Current	Non-current	Total
Borrowings	9,329	55,803	65,132	7,701	54,873	62,574
Net obligations under finance leases	44	623	667	38	618	656
	9,373	56,426	65,799	7,739	55,491	63,230

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 $7,175 million (2017 $6,849 million) and issued commercial paper of $2,040 million (2017 $744 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 rate %	Weighted average time for which rate is fixed Years	Amount $ million	Weighted average interest rate %	Amount $ million	Amount $ million
						2018
US dollar	4	4	17,593	4	47,465	65,058
Other currencies	7	18	657	8	84	741
			18,250		47,549	65,799
						2017
US dollar	4	4	18,090	3	44,212	62,302
Other currencies	6	16	895	3	33	928
			18,985		44,245	63,230

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 2018, whereas in the group balance sheet the amount is reported within current finance debt.

The carrying amount of the group’s short-term borrowings, comprising mainly of 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 analysis 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
		2018		2017
	Fair value	Carrying amount	Fair value	Carrying amount
Short-term borrowings	2,153	2,153	852	852
Long-term borrowings	63,106	62,979	63,182	61,722
Net obligations under finance leases	1,087	667	1,131	656
Total finance debt	66,346	65,799	65,165	63,230

27. 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 and maintain a significant liquidity buffer. At 31 December 2018, the net debt ratio was 30.3% (2017 27.4%).

		$ million
At 31 December	2018	2017
Gross debt	65,799	63,230
Less: fair value asset (liability) of hedges related to finance debt[a]	(813)	(175)
	66,612	63,405
Less: cash and cash equivalents	22,468	25,586
Net debt	44,144	37,819
Equity	101,548	100,404
Net debt ratio	30.3%	27.4%

[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 $827 million (2017 liability of $634 million, 2016 liability of $1,962 million) are not included in the calculation of net debt shown above as hedge accounting was not applied for these instruments. The movement in the year is attributable to a net cash flow of $nil (2017 net cash outflow $242 million) and fair value losses of $193 million (2017 fair value gains of $1,086 million).

An analysis of changes in net debt is provided below.

								$ million
				2018				2017
Movement in net debt	Finance debt	Hedge-accounted derivatives	Cash and cash equivalents	Net debt	Finance debt	Hedge-accounted derivatives	Cash and cash equivalents	Net debt
At 1 January	(63,230)	(175)	25,586	(37,819)	(58,300)	(697)	23,484	(35,513)
Adjustment on adoption of IFRS 9	—	—	(11)	(11)	—	—	—	—
Exchange adjustments	259	—	(330)	(71)	(1,324)	—	544	(780)
Net financing cash flow	(3,505)	360	(2,777)	(5,922)	(2,236)	(284)	1,558	(962)
Fair value gains (losses)	856	(998)	—	(142)	(1,314)	1,282	—	(32)
Other movements	(179)	—	—	(179)	(56)	(476)	—	(532)
At 31 December	(65,799)	(813)	22,468	(44,144)	(63,230)	(175)	25,586	(37,819)

[a] The adjustment on adoption of IFRS 9 reflects the creation of a credit loss allowance for cash and cash equivalents as a result of the new standard`s expected credit loss impairment model.

28. Operating leases

The cost recognized in relation to minimum lease payments for the year was $3,514 million (2017 $4,423 million and 2016 $5,113 million).

The future minimum lease payments at 31 December 2018, before deducting related rental income from operating sub-leases of $120 million (2017 $188 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	2018	2017
Payable within		
1 year	2,511	2,969
2 to 5 years	5,359	6,387
Thereafter	4,109	4,614
	11,979	13,970

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 ten years for leases of plant and machinery, up to fifteen years for leases of ships and commercial vehicles and up to forty years for leases of land and buildings.

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Upstream segment. At 31 December 2018, the future minimum lease payments relating to these amounted to $1,378 million (2017 $2,088 million).

28. Operating leases – continued

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 future minimum lease payments relating to operating leases for international oil and gas ships managed by the BP Shipping function amounted to $3,032 million (2017 $3,172 million). Commercial vehicles hired under operating leases are primarily railcars.

Retail service station sites and office accommodation are the main items in the land and buildings category. At 31 December 2018, the future minimum lease payments relating to land and buildings amounted to $1,914 million (2017 $2,167 million).

The terms and conditions of these operating leases do not impose any significant financial restrictions on the group. Some of the leases of rigs, ships and buildings allow for renewals at BP's option, and some of the group's operating leases contain escalation clauses.

BP will adopt IFRS 16 'Leases' in the financial reporting period commencing 1 January 2019. See Note 1 for further details.

29. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments and their carrying amounts are set out below. Current year amounts are presented based on the classification, measurement and impairment requirements of IFRS 9. Comparatives are presented based on the classification, measurement and impairment requirements of IAS 39.

					$ million
At 31 December 2018	Note	Measured at amortized cost	Mandatorily measured at fair value through profit or loss	Derivative hedging instruments	Total carrying amount
Financial assets					
Other investments	18	—	1,563	—	1,563
Loans		839	124	—	963
Trade and other receivables	20	24,080	—	—	24,080
Derivative financial instruments	30	—	8,564	427	8,991
Cash and cash equivalents	25	20,366	2,102	—	22,468
Financial liabilities					
Trade and other payables	22	(56,790)	—	—	(56,790)
Derivative financial instruments	30	—	(7,685)	(1,248)	(8,933)
Accruals		(5,201)	—	—	(5,201)
Finance debt	26	(65,799)	—	—	(65,799)
		(82,505)	4,668	(821)	(78,658)

								$ million
At 31 December 2017	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	18	—	433	—	—	—	—	433
– other	18	—	275	—	662	—	—	937
Loans		836	—	—	—	—	—	836
Trade and other receivables	20	24,361	—	—	—	—	—	24,361
Derivative financial instruments	30	—	—	—	6,454	688	—	7,142
Cash and cash equivalents	25	21,916	2,270	1,400	—	—	—	25,586
Financial liabilities								
Trade and other payables	22	—	—	—	—	—	(54,054)	(54,054)
Derivative financial instruments	30	—	—	—	(5,705)	(864)	—	(6,569)
Accruals		—	—		—	—	(5,465)	(5,465)
Finance debt	26	—	—	—	—	—	(63,230)	(63,230)
		47,113	2,978	1,400	1,411	(176)	(122,749)	(70,023)

The fair value of finance debt is shown in Note 26. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Information on gains and losses on derivative financial assets and financial liabilities classified as measured at fair value through profit or loss is provided in the derivative gains and losses section of Note 30. Fair value gains and losses related to other assets and liabilities classified as measured at fair value through profit or loss totalled a net loss of $78 million. Dividend income of $8 million from investments in equity instruments classified as measured at fair value through profit or loss is presented within other income - see Note 7.

Interest income and expenses arising on financial instruments are disclosed in Note 7.

29. Financial instruments and financial risk factors – continued

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including market risks relating to commodity prices, foreign currency exchange rates 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. Treasury holds foreign exchange and interest-rate products in the financial markets to hedge group exposures related to debt issuance; the compliance, control, and risk management processes for these activities are managed within the treasury function. All other foreign exchange and interest rate activities within financial markets are performed within the integrated supply and trading function and are also underpinned by the compliance, control and risk management infrastructure common to the activities of BP's 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 approves value-at-risk delegations, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves the trading of new products, instruments and strategies and material commitments.

In addition, the integrated supply and trading function undertakes derivative activity for risk management purposes under a control framework as described more fully below.

(a) Market risk

Market risk is the risk or uncertainty arising from possible market price movements and their impact on the future performance of a business. The primary commodity price risks that the group is exposed to include oil, natural gas and power prices that could adversely affect the value of the group's financial assets, liabilities or expected future cash flows. The group enters into derivatives in a well-established entrepreneurial trading operation. In addition, the group has developed a control framework aimed at managing the volatility inherent in certain of its natural business exposures. In accordance with the control framework the group enters into various transactions using derivatives for risk management purposes.

The major components of market risk are commodity price risk, foreign currency exchange risk and interest rate risk, each of which is discussed below.

(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

Since BP has global operations, fluctuations in foreign currency exchange rates can have a significant effect on the group's reported results and future expenditure commitments. 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.

Most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2018, the total foreign currency borrowings not swapped into US dollars amounted to $741 million (2017 $928 million).

The group manages the net residual foreign currency 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. A continuous assessment is made in respect to the group's foreign currency exposures to capture hedging requirements.

During the year, hedge accounting was applied to foreign currency exposure to highly probable forecast capital expenditure commitments. The group fixes the US dollar cost of non-US dollar supplies by using currency forwards for the highly probable forecast capital expenditure; the exposures are in sterling, euro, Australian dollar, Norwegian krone and Korean won. At 31 December 2018 the most significant open contracts in place were for $434 million sterling (2017 $437 million sterling).

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 in (i) commodity price risk above.

29. Financial instruments and financial risk factors – continued

(iii) Interest rate risk

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 2018 was 72% of total finance debt outstanding (2017 70%). The weighted average interest rate on finance debt at 31 December 2018 was 4% (2017 3%) and the weighted average maturity of fixed rate debt was five years (2017 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 changed by one percentage point on 1 January 2019, it is estimated that the group's finance costs for 2019 would change by approximately $475 million (2017 $442 million).

(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 2018 was $696 million (2017 $656 million) in respect of liabilities of joint ventures and associates and $432 million (2017 $382 million) in respect of liabilities of other third parties.

The group has a credit policy, approved by the CFO that is designed to ensure that consistent processes are in place throughout the group to measure and control credit risk. Credit risk is considered as part of the risk-reward balance of doing business. On entering into any business contract the extent to which the arrangement exposes the group to credit risk is considered. Key requirements of the policy include segregation of credit approval authorities from any sales, marketing or trading teams authorized to incur credit risk; the establishment of credit systems and processes to ensure that all counterparty exposure is rated and that all counterparty exposure and limits can be monitored and reported; and the timely identification and reporting of any non-approved credit exposures and credit losses. While each segment is responsible for its own credit risk management and reporting consistent with group policy, the treasury function holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

For the purposes of financial reporting the group calculates expected loss allowances based on the maximum contractual period over which the group is exposed to credit risk. Since this is typically less than 12 months for the group's in-scope financial assets there is no significant difference between the measurement of 12-month and lifetime expected credit losses. The group has no significant financial guarantee liabilities measured on an expected loss basis. Financial assets are considered to be credit-impaired when there is reasonable and supportable evidence that one or more events that have a detrimental impact on the estimated future cash flows of the financial asset have occurred. This includes observable data concerning significant financial difficulty of the counterparty; a breach of contract; concession being granted to the counterparty for economic or contractual reasons relating to the counterparty's financial difficulty, that would not otherwise be considered; it becoming probable that the counterparty will enter bankruptcy or other financial re-organization or an active market for the financial asset disappearing because of financial difficulties. The group also applies a rebuttable presumption that an asset is credit-impaired when contractual payments are more than 30 days past due. Where the group has no reasonable expectation of recovering a financial asset in its entirety or a portion thereof for example where all legal avenues for collection of amounts due have been exhausted, the financial asset (or relevant portion) is written off.

The measurement of expected credit losses is a function of the probability of default, loss given default (i.e. the magnitude of the loss after recovery if there is a default) and the exposure at default (i.e. the asset's carrying amount). The group allocates a credit risk rating to exposures based on data that is determined to be predictive of the risk of loss, including but not limited to external ratings. Probabilities of default derived from historical, current and future-looking market data are assigned by credit risk rating with a loss given default based on historical experience

and relevant market and academic research applied by exposure type. Experienced credit judgement is applied to ensure probabilities of default are reflective of the credit risk associated with the group's exposures. Credit enhancements that would reduce the group's credit losses in the event of default are reflected in the calculation when they are considered integral to the related asset.
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 2018, the group had in place credit enhancements designed to mitigate approximately $7.3 billion of credit risk, of which $6.7 billion relates to assets in the scope of IFRS 9's impairment requirements. Credit enhancements include standby and documentary letters of credit, bank guarantees, insurance and liens which are typically taken out with financial institutions who have investment grade credit ratings, or are liens over assets held by the counterparty of the related receivables. 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, which reflects the impact of credit enhancements, indicates that the risk profile of financial assets which are subject to review for impairment under IFRS 9 is as set out below.

	%	
As at 31 December	2018	
AAA to AA-	22	%
A+ to A-	41	%
BBB+ to BBB-	16	%
BB+ to BB-	8	%
B+ to B-	11	%
CCC+ and below	2	%

For the comparative period an analysis of the ageing of trade and other receivables reported under IAS 39 is provided.

29. Financial instruments and financial risk factors – continued

	$ million
Trade and other receivables at 31 December	2017
Neither impaired nor past due	22,858
Impaired (net of provision)	53
Not impaired and past due in the following periods	
within 30 days	637
31 to 60 days	130
61 to 90 days	114
over 90 days	569
	24,361

Movements in the impairment provision for trade and other receivables are shown in Note 21.

Financial instruments subject to offsetting, enforceable master netting arrangements and similar agreements

The following table shows the amounts recognized for financial assets and liabilities which are subject to offsetting arrangements on a gross basis, and the amounts offset in the balance sheet.

Amounts which cannot be offset under IFRS, but which could be settled net under the terms of master netting agreements if certain conditions arise, and collateral received or pledged, are also presented in the table to show the total net exposure of the group.

						$ million
				Related amounts not set off in the balance sheet		
At 31 December 2018	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	11,502	(2,511)	8,991	(2,079)	(299)	6,613
Derivative liabilities	(11,337)	2,511	(8,826)	2,079	—	(6,747)
Trade and other receivables	11,296	(5,390)	5,906	(1,020)	(169)	4,717
Trade and other payables	(10,797)	5,390	(5,407)	1,020	—	(4,387)
At 31 December 2017						
Derivative assets	8,522	(1,380)	7,142	(1,554)	(321)	5,267
Derivative liabilities	(7,818)	1,380	(6,438)	1,554	—	(4,884)
Trade and other receivables	11,648	(5,311)	6,337	(2,156)	(114)	4,067
Trade and other payables	(12,543)	5,311	(7,232)	2,156	—	(5,076)

(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.

BP utilizes various arrangements in order to manage its working capital including discounting of receivables and, in the supply and trading business, the active management of supplier payment terms, inventory and collateral. In line with normal industry practice some supplier arrangements utilize letter of credit (LC) facilities. In certain of those arrangements BP's payments are made to the provider of the LC rather than the supplier.

Standard & Poor's Ratings long-term credit rating for BP is A- (stable outlook) and Moody's Investors Service rating is A1 (stable outlook).

During 2018, $9 billion of long-term taxable bonds were issued with terms ranging from four to ten years. Commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, amounting to $22.5 billion at 31 December 2018 (2017 $25.6 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2018, the group had substantial amounts of undrawn borrowing facilities available, consisting of $7,625 million of standby facilities, all of which is available to draw and repay up to the first half of 2022. These facilities are with 25 international banks, and borrowings under them would be at pre-agreed rates.

The group has committed LC facilities totalling $12,175 million with a number of banks, allowing LCs to be issued for a maximum 24-month duration. There were also uncommitted secured LC facilities in place at 31 December 2018 for $4,190 million, which are secured against inventories or receivables when utilized. The facilities only terminate by either party giving a stipulated termination notice to the other.

The amounts shown for finance debt in the table below include future minimum lease payments with respect to finance leases. The table also shows the timing of cash outflows relating to trade and other payables and accruals.

29. Financial instruments and financial risk factors – continued

								$ million
			2018					2017
	Trade and other payables[a]	Accruals	Finance debt	Interest on finance debt	Trade and other payables[a]	Accruals	Finance debt	Interest on finance debt
Within one year	43,230	4,626	9,301	2,404	40,472	4,960	7,626	1,757
1 to 2 years	2,232	146	6,788	1,955	1,693	135	7,331	1,537
2 to 3 years	1,662	95	6,805	1,700	1,413	83	7,068	1,321
3 to 4 years	1,484	64	8,057	1,422	1,378	70	6,766	1,114
4 to 5 years	1,406	89	7,058	1,138	1,368	54	7,986	894
5 to 10 years	6,058	113	25,356	2,390	6,181	115	24,162	1,951
Over 10 years	5,001	68	1,243	320	6,125	48	2,089	390
	61,073	5,201	64,608	11,329	58,630	5,465	63,028	8,964

[a] 2018 includes $18,360 million (2017 $18,918 million) in relation to the 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 30. 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 finance 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 $22,453 million at 31 December 2018 (2017 $21,484 million) to be received on the same day as the related cash outflows. For further information on our derivative financial instruments, see Note 30.

		$ million
Cash outflows for derivative financial instruments at 31 December	2018	2017
Within one year	1,700	1,505
1 to 2 years	1,678	1,700
2 to 3 years	2,384	1,678
3 to 4 years	2,838	2,384
4 to 5 years	2,906	2,838
5 to 10 years	11,475	11,238
Over 10 years	724	724
	23,705	22,067

30. 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 29. 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 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. Exchange traded derivatives are typically considered settled through the (normally daily) payment or receipt of variation margin.

Over-the-counter (OTC) financial swaps and physical commodity sale and purchase contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are categorized within level 2 of the fair value hierarchy.

In certain less liquid markets, or for longer-term contracts, forward prices are not as readily available. In these circumstances, OTC financial swaps and physical commodity sale and purchase contracts are valued using internally developed methodologies that consider historical relationships between various commodities, and that result in management's best estimate of fair value. These contracts are categorized within level 3 of the fair value hierarchy.

Financial OTC and physical commodity options are valued using industry standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and contractual prices for the underlying instruments, as well as other relevant economic factors. The degree to which these inputs are observable in the forward markets determines whether the option is categorized within level 2 or level 3 of the fair value hierarchy.

30. Derivative financial instruments – continued

				$ million
		2018		2017
	Fair value asset	Fair value liability	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	69	(898)	237	(756)
Oil price derivatives	2,361	(1,849)	1,637	(1,281)
Natural gas price derivatives	4,787	(3,888)	3,580	(2,844)
Power price derivatives	1,240	(943)	885	(693)
Other derivatives	107	—	115	—
	8,564	(7,578)	6,454	(5,574)
Embedded derivatives				
Commodity price contracts	—	—	—	(16)
Other embedded derivatives	—	(107)	—	(115)
	—	(107)	—	(131)
Cash flow hedges				
Currency forwards, futures and cylinders	5	(14)	35	(35)
Gas price futures	2	—	—	—
	7	(14)	35	(35)
Fair value hedges				
Currency forwards, futures and swaps	158	(789)	460	(523)
Interest rate swaps	262	(445)	193	(306)
	420	(1,234)	653	(829)
	8,991	(8,933)	7,142	(6,569)
Of which – current	3,846	(3,308)	3,032	(2,808)
– non-current	5,145	(5,625)	4,110	(3,761)

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 29.

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
							2018
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	48	12	9	—	—	—	69
Oil price derivatives	1,916	363	53	25	4	—	2,361
Natural gas price derivatives	1,333	708	542	452	352	1,400	4,787
Power price derivatives	540	276	158	79	55	132	1,240
Other derivatives	—	—	—	—	107	—	107
	3,837	1,359	762	556	518	1,532	8,564

$ million
2017

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	186	31	8	5	3	4	237
Oil price derivatives	1,280	177	99	66	14	1	1,637
Natural gas price derivatives	1,122	609	428	328	288	805	3,580
Power price derivatives	420	188	81	60	38	98	885
Other derivatives	—	—	—	—	—	115	115
	3,008	1,005	616	459	343	1,023	6,454

30. Derivative financial instruments – continued

Derivative liabilities held for trading have the following fair values and maturities.

							$ million 2018
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(299)	(71)	(256)	(171)	(3)	(98)	(898)
Oil price derivatives	(1,560)	(232)	(43)	(12)	(2)	—	(1,849)
Natural gas price derivatives	(1,030)	(557)	(391)	(338)	(285)	(1,287)	(3,888)
Power price derivatives	(401)	(213)	(95)	(54)	(47)	(133)	(943)
	(3,290)	(1,073)	(785)	(575)	(337)	(1,518)	(7,578)

							$ million 2017
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(92)	(232)	(66)	(188)	(99)	(79)	(756)
Oil price derivatives	(1,120)	(118)	(33)	(4)	(6)	—	(1,281)
Natural gas price derivatives	(973)	(410)	(334)	(224)	(194)	(709)	(2,844)
Power price derivatives	(337)	(134)	(63)	(39)	(29)	(91)	(693)
	(2,522)	(894)	(496)	(455)	(328)	(879)	(5,574)

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 2018
	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	111	14	3	—	—	—	128
Level 2	5,000	1,362	504	262	120	72	7,320
Level 3	491	385	353	331	427	1,640	3,627
	5,602	1,761	860	593	547	1,712	11,075
Less: netting by counterparty	(1,765)	(402)	(98)	(37)	(29)	(180)	(2,511)
	3,837	1,359	762	556	518	1,532	8,564
Fair value of derivative liabilities							
Level 1	(156)	(11)	(2)	(2)	—	—	(171)
Level 2	(4,562)	(1,161)	(576)	(308)	(67)	(163)	(6,837)
Level 3	(337)	(303)	(305)	(302)	(299)	(1,535)	(3,081)
	(5,055)	(1,475)	(883)	(612)	(366)	(1,698)	(10,089)
Less: netting by counterparty	1,765	402	98	37	29	180	2,511
	(3,290)	(1,073)	(785)	(575)	(337)	(1,518)	(7,578)
Net fair value	547	286	(23)	(19)	181	14	986

							$ million 2017
	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	3,663	1,003	438	244	140	135	5,623

Level 3	386	258	231	226	211	899	2,211	
	4,049	1,261	669	470	351	1,034	7,834	
Less: netting by counterparty	(1,041	)(256	)(53	)(11	)(8	)(11	)(1,380	)
	3,008	1,005	616	459	343	1,023	6,454	
Fair value of derivative liabilities								
Level 2	(3,338	)(953	)(358	)(289	)(163	)(166	)(5,267	)
Level 3	(225	)(197	)(191	)(177	)(173	)(724	)(1,687	)
	(3,563	)(1,150	)(549	)(466	)(336	)(890	)(6,954	)
Less: netting by counterparty	1,041	256	53	11	8	11	1,380	
	(2,522	)(894	)(496	)(455	)(328	)(879	)(5,574	)
Net fair value	486	111	120	4	15	144	880	

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30. Derivative financial instruments – continued

Level 3 derivatives

The following table shows the changes during the year in the net fair value of derivatives held for trading purposes within level 3 of the fair value hierarchy.

					$ million
	Oil price	Natural gas price	Power price	Other	Total
Fair value contracts at 1 January 2018	67	65	(226)	115	21
Gains (losses) recognized in the income statement	58	(26)	209	(8)	233
Settlements	(107)	(32)	(97)	—	(236)
Transfers out of level 3	5	(20)	(34)	—	(49)
Net fair value of contracts at 31 December 2018	23	(13)	(148)	107	(31)
Deferred day-one gains (losses)					577
Derivative asset (liability)					546

					$ million
	Oil price	Natural gas price	Power price	Other	Total
Fair value contracts at 1 January 2017	68	145	(147)	231	297
Gains (losses) recognized in the income statement	76	161	61	15	313
Settlements	(68)	(35)	(113)	(131)	(347)
Transfers out of level 3	(9)	(206)	(27)	—	(242)
Net fair value of contracts at 31 December 2017	67	65	(226)	115	21
Deferred day-one gains (losses)					503
Derivative asset (liability)					524

The amount recognized in the income statement for the year relating to level 3 held-for-trading derivatives still held at 31 December 2018 was a $123-million gain (2017 $234-million gain related to derivatives still held at 31 December 2017).

Derivative gains and losses

The group enters into derivative contracts including futures, options, swaps and certain forward sales and forward purchases contracts, relating 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. These gains and losses are included within sales and other operating revenues in the income statement. Also included within this line item 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 $2,504 million (2017 $1,983 million net gain and 2016 $1,435 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 amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

The group also enters into derivative contracts including futures, options, swaps and certain forward sales and forward purchase contracts primarily relating to foreign currency risk management activities. Gains and losses on these contracts are included within production and manufacturing expenses in the income statement. The change in the unrealized value of these contracts was a net loss of $351 million (2017 $1,420 million net gain and 2016 $154 million net loss), however the gains and losses in each year are largely offset by opposing net foreign exchange differences on retranslation of the associated non-US dollar debt. The net amounts for actual gains and losses relating to these derivative contracts and all related items therefore differ significantly from the amounts disclosed above.

Cash flow hedges

(i) Foreign currency risk of highly probable forecast capital expenditure

At 31 December 2018, the group held currency forwards designated as hedging instruments in cash flow hedge relationships of highly probable forecast non-US dollar capital expenditure. Note 29 outlines the group's approach to foreign currency exchange risk management. When the highly probable forecast capital expenditure designated as a hedged item occurs, a non-financial asset is recognized and is presented within the fixed asset section of the balance sheet.

The group claims hedge accounting only for the spot value of the currency exposure in line with the strategy to fix the volatility in the spot exchange rate element. The fair value on the instrument attributable to forward points is taken immediately to the income statement.

The group applies hedge accounting where there is an economic relationship between the hedged item and hedging instrument. The existence of an economic relationship is determined at inception and prospectively by comparing the critical terms of the hedging instrument and those of the hedged item. The group enters into hedging derivatives that match the currency and notional of the hedged items on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional designated on the forecast transaction. The group determines the extent to which it hedges highly probable forecast capital expenditures on a project by project basis.

The group has identified the following sources of ineffectiveness, which are not expected to be material:

- counterparty's credit risk, the group mitigates counterparty credit risk by entering into derivative transactions with high credit quality counterparties; and
- differences in settlement timing between the derivative and hedged items. The latter impacts the discount factor used in the calculation of the hedge ineffectiveness. The group mitigates differences in timing between the derivatives and hedged items by applying a rolling strategy and by hedging currency pairs from stable economies (i.e. sterling/US dollar, Euro/US dollar, Norwegian krone/US dollar, Korean won/US dollar). The group's cash flow hedge designations are highly effective as the sources of ineffectiveness identified are expected to result in minimal hedge ineffectiveness.

The group has not designated any net positions as hedged items in cash flow hedges of foreign currency risk.

30. Derivative financial instruments – continued

(ii) Commodity price risk of highly probable forecast sales

At 31 December 2018, the group held Henry Hub NYMEX futures designated as hedging instruments in cash flow hedge relationships of certain highly probable forecast future sales.

The group is exposed to the variability in the gas price, but only applies hedge accounting to the risk of Henry Hub price movements for a percentage of future gas sales from its BPX Energy business (previously known as US Lower 48 business). Hedge accounting may be applied to such sales for up to the following two calendar years.

The group applies hedge accounting in relation to these highly probable future sales where there is an economic relationship between the hedged item and hedging instrument. The existence of an economic relationship is determined at inception and prospectively by comparing the critical terms of the hedging instrument and those of the hedged item. The group enters into hedging derivatives that match the notional amounts of the hedged items on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional amount designated on the forecast transaction.

The hedge is expected to be highly effective due to the price index of the hedging instruments matching the price index of the hedged item and the derivative assets or liabilities recognized in respect of exchange-traded instruments reflect the impact of daily margin payments and receipts.

The group has not designated any net positions as hedged items in cash flow hedges of commodity price risk.

The table below summarizes the change in the fair value of hedging instruments and the hedged item used to calculate ineffectiveness in the period.

			$ million
At 31 December 2018	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
Cash flow hedges			
Foreign exchange risk			
Highly probable forecast capital expenditure	(5)	5	—
Commodity price risk			
Highly probable forecast sales	(126)	126	—

The table below summarizes the carrying amount and nominal amount of the derivatives designated as hedging instruments in cash flow hedge relationships at 31 December 2018.

	Carrying amount of hedging instrument		Nominal amounts of hedging instruments	
	Assets	Liabilities		
At 31 December 2018	$ million	$ million	$ million	mmBtu
Cash flow hedges				
Foreign exchange risk				
Highly probable forecast capital expenditure	5	(14)	386	
Commodity price risk				
Highly probable forecast sales	2	—		145

All hedging instruments are presented within derivative financial instruments on the group balance sheet.

Of the nominal amount of hedging instruments relating to highly probable forecast capital expenditure $304 million matures in 2019 and $82 million matures in 2020. All of the hedging instruments relating to highly probable forecast sales mature in 2019.

The table below summarizes the weighted average exchange rates and the weighted average sales price in relation to the derivatives designated as hedging instruments in cash flow hedge relationships at 31 December 2018.

	Weighted average price/rate	
At 31 December 2018	Forecast capital expenditure	Forecast sales
Sterling/US dollar	1.34	
Euro/US dollar	1.14	
Australian dollar/US dollar	0.72	
Norwegian krone/US dollar	8.67	
Korean won/US dollar	1,107.90	
Henry Hub $/mmBtu		2.86

30. Derivative financial instruments – continued

Fair value hedges

At 31 December 2018, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk and foreign currency risk arising from group fixed rate debt issuances. The interest rate swaps are used to convert US dollar denominated fixed rate borrowings into floating rate debt. The cross-currency interest rate swaps are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar and Norwegian krone denominated fixed rate borrowings into US dollar floating rate debt. The group manages all risks derived from debt issuance, such as credit risk, however, the group applies hedge accounting only to certain components of interest rate and foreign currency risk in order to minimize hedge ineffectiveness. Note 29 outlines the group's approach to interest rate and foreign currency exchange risk management.

The interest rate and foreign currency exposures are identified and hedged on an instrument-by-instrument basis. For interest rate exposures, the group designates as a fair value hedge the benchmark interest rate component only. This is an observable and reliably measurable component of interest rate risk. For foreign currency exposures, the group excludes from the designation the foreign currency basis spread component implicit in the cross-currency interest rate swaps. This is separately calculated at hedge designation, is recognized in other comprehensive income over the life of the hedge and amortized to the income statement on a straight-line basis, in accordance with the group's policy on costs of hedging.

The group applies hedge accounting where there is an economic relationship between the hedged item and the hedging instrument. The existence of an economic relationship is determined initially by comparing the critical terms of the hedging instrument and those of the hedged item and it is prospectively assessed using linear regression analysis. The group issues fixed rate debt and enters into interest rate and cross-currency interest rate swaps with critical terms that match those of the debt and on a 1:1 hedge ratio basis. The hedge ratio is determined by comparing the notional amount of the derivative with the notional amount of the debt. The hedge relationship is designated for the full term and notional value of the debt. Both the hedging instrument and the hedged item are expected to be held to maturity.

The group has identified the following sources of ineffectiveness, which are not expected to be material:

- derivative counterparty's credit risk which is not offset by the hedged item. This risk is mitigated by entering into derivative transactions only with high credit quality counterparties; and
- sensitivity to interest rate between the hedged item and the derivatives. This is driven by differences in payment frequencies between the instrument and the bond.

The table below summarizes the change in the fair value of hedging instruments and the hedged item used to calculate ineffectiveness in the period.

			$ million
At 31 December 2018	Change in fair value of hedging instrument used to calculate ineffectiveness	Change in fair value of hedged item used to calculate ineffectiveness	Hedge ineffectiveness recognized in profit or (loss)
Fair value hedges			
Interest rate risk on finance debt	(70)	69	(1)
Interest rate and foreign currency risk on finance debt	812	(809)	3

The table below summarizes the carrying amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December 2018.

			$ million
	Carrying amount of hedging instrument		Nominal amounts of hedging instruments
At 31 December 2018	Assets	Liabilities	
Fair value hedges			

Interest rate risk on finance debt	262	(445)	24,513
Interest rate and foreign currency risk on finance debt	158	(789)	16,580

All hedging instruments are presented within derivative financial instruments on the group balance sheet.
Ineffectiveness arising on fair value hedges is included within the production and manufacturing expenses section of the income statement.
The table below summarizes the profile by tenor of the nominal amount of the derivatives designated as hedging instruments in fair value hedge relationships at 31 December 2018. The weighted average floating interest rate of these interest rate swaps and cross-currency interest rate swaps was 3.04% and 4.07% respectively.

								$ million
At 31 December 2018	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	5-10 years	Over 10 years	Total
Fair value hedges								
Interest rate risk on finance debt	2,694	2,324	2,597	4,923	1,700	10,275	—	24,513
Interest rate and foreign currency risk on finance debt	—	1,245	1,167	707	2,921	10,254	286	16,580

30. Derivative financial instruments – continued

The table below summarizes the carrying amount, and the accumulated fair value adjustments included within the carrying amount, of the hedged items designated in fair value hedge relationships at 31 December 2018.

					$ million
	Carrying amount of hedged item		Accumulated fair value adjustment included in the carrying amount of hedged items		
At 31 December 2018	Assets	Liabilities	Assets	Liabilities	Discontinued hedges
Fair value hedges					
Interest rate risk on finance debt	—	(24,747)	175	—	(360)
Interest rate and foreign currency risk on finance debt	—	(16,883)	—	(62)	—

The hedged item for all fair value hedges is presented within finance debt on the group balance sheet.

Movement in reserves related to hedge accounting

The table below provides a reconciliation of the cash flow hedge and costs of hedging reserves on a pre-tax basis by risk category. The signage convention of this table is consistent with that presented in Note 32.

					$ million
	Cash flow hedge reserve			Costs of hedging reserve	
	Highly probable forecast capital expenditure	Highly probable forecast sales	Purchase of equity[a]	Interest rate and foreign currency risk on finance debt	Total
At 31 December 2017	(10)	—	(651)	—	(661)
Adjustment on adoption of IFRS 9	—	—	—	(37)	(37)
At 1 January 2018	(10)	—	(651)	(37)	(698)
Recognized in other comprehensive income					
Cash flow hedges marked to market	(37)	(126)	—	—	(163)
Cash flow hedges reclassified to the income statement - hedged item affected profit or loss	—	120	—	—	120
Costs of hedging marked to market	—	—	—	(244)	(244)
Costs of hedging reclassified to the income statement	—	—	—	58	58
	(37)	(6)	—	(186)	(229)
Cash flow hedges transferred to the balance sheet	26	—	—	—	26
At 31 December 2018	(21)	(6)	(651)	(223)	(901)

[a] See Note 32 for further information on the cash flow hedge reserve relating to the purchase of equity

Substantially all of the cash flow hedge reserve balances and all of the amounts reclassified into profit or loss during the year relate to continuing hedge relationships. Amounts deferred in the cash flow hedge reserve that have been reclassified to profit or loss are presented in sales and other operating revenues in the income statement.

Costs of hedging relates to the foreign currency basis spreads of hedging instruments used to hedge the group's interest rate and foreign currency risk on debt which is a time-period related item.

31. Called-up share capital

The allotted, called up and fully paid share capital at 31 December was as follows:

Issued	2018 Shares thousand	2018 $ million	2017 Shares thousand	2017 $ million	2016 Shares thousand	2016 $ 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	21,288,193	5,322	21,049,696	5,263	20,108,771	5,028
Issue of new shares for the scrip dividend programme	195,305	49	289,789	72	548,005	137
Issue of new shares for employee share-based payment plans	92,168	23	—	—	—	—
Issue of new shares – other[b]	—	—	—	—	392,920	98
Repurchase of ordinary share capital	(50,202)	(13)	(51,292)	(13)	—	—
At 31 December	21,525,464	5,381	21,288,193	5,322	21,049,696	5,263
		5,402		5,343		5,284

[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] 2016 relates to the issue of new ordinary shares in consideration for a 10% interest in the Abu Dhabi onshore oil concession. See Note 32 for further information.

Voting on substantive resolutions tabled at a general meeting is on a poll. On a poll, shareholders present in person or by proxy have two votes for every £5 in nominal amount of the first and second preference shares held and one vote for every ordinary share held. On a show-of-hands vote on other resolutions (procedural matters) at a general meeting, shareholders present in person or by proxy have one vote each.

In the event of the winding up of the company, preference shareholders would be entitled to a sum equal to the capital paid up on the preference shares, plus an amount in respect of accrued and unpaid dividends and a premium equal to the higher of (i) 10% of the capital paid up on the preference shares and (ii) the excess of the average market price of such shares on the London Stock Exchange during the previous six months over par value.

During 2018 the company repurchased 50 million ordinary shares for a total consideration of $355 million, including transaction costs of $2 million, as part of the share repurchase programme announced on 31 October 2017. All shares purchased were for cancellation. The repurchased shares represented 0.2% of ordinary share capital.

Treasury shares[a]

	2018 Shares thousand	2018 Nominal value $ million	2017 Shares thousand	2017 Nominal value $ million	2016 Shares thousand	2016 Nominal value $ million
At 1 January	1,482,072	370	1,614,657	403	1,756,327	439
Purchases for settlement of employee share plans	757	—	4,423	1	9,631	2
Issue of new shares for employee share-based payment plans	92,168	23	—	—	—	—
Shares re-issued for employee share-based payment plans	(148,732)	(37)	(137,008)	(34)	(151,301)	(38)
At 31 December	1,426,265	356	1,482,072	370	1,614,657	403
Of which – shares held in treasury by BP	1,264,732	316	1,472,343	368	1,576,411	394
– shares held in ESOP trusts	161,518	40	9,705	2	21,432	5

– shares held by BP's US share plan administrator[b]	15	—	24	—	16,814	4

[a] See Note 32 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 6.9% (2017 7.5% and 2016 8.6%) of the called-up ordinary share capital of the company. During 2018, the movement in shares held in treasury by BP represented less than 1.0% (2017 less than 0.5% and 2016 less than 0.8%) of the ordinary share capital of the company.

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32. Capital and reserves

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 31 December 2017	5,343	12,147	1,426	27,206	46,122
Adjustment on adoption of IFRS 9, net of tax	—	—	—	—	—
At 1 January 2018	5,343	12,147	1,426	27,206	46,122
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Cash flow hedges and costs of hedging (including reclassifications)	—	—	—	—	—
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	—	—	—	—	—
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	—	—	—
Total comprehensive income	—	—	—	—	—
Dividends	49	(49)	—	—	—
Cash flow hedges transferred to the balance sheet, net of tax	—	—	—	—	—
Repurchases of ordinary share capital	(13)	—	13	—	—
Share-based payments, net of tax[b]	23	207	—	—	230
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax	—	—	—	—	—
At 31 December 2018	5,402	12,305	1,439	27,206	46,352

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2017	5,284	12,219	1,413	27,206	46,122
Profit (loss) for the year	—	—	—	—	—
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including reclassifications)	—	—	—	—	—
Available-for-sale investments (including reclassifications)	—	—	—	—	—
Cash flow hedges (including reclassifications)	—	—	—	—	—
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	72	(72)	—	—	—
Repurchases of ordinary share capital	(13)	—	13	—	—
Share-based payments, net of tax[b]	—	—	—	—	—
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—

Transactions involving non-controlling interests, net of tax[c]	—	—	—	—	—
At 31 December 2017	5,343	12,147	1,426	27,206	46,122

	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 reclassifications)[a]	—	—	—	—	—
Available-for-sale investments (including reclassifications)	—	—	—	—	—
Cash flow hedges (including reclassifications)	—	—	—	—	—
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 d]	98	2,122	—	—	2,220
Share of equity-accounted entities' changes in equity, net of tax	—	—	—	—	—
Transactions involving non-controlling interests, net of tax	—	—	—	—	—
At 31 December 2016	5,284	12,219	1,413	27,206	46,122

[a] Principally foreign exchange effects relating to the Russian rouble.

[b] Movements in treasury shares relate to employee share-based payment plans.

32. Capital and reserves – continued

$ million

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(16,958)	(5,156)	17	(760)	—	(743)	75,226	98,491	1,913	100,404
—	—	(17)	—	(37)	(54)	(126)	(180)	—	(180)
(16,958)	(5,156)	—	(760)	(37)	(797)	75,100	98,311	1,913	100,224
—	—	—	—	—	—	9,383	9,383	195	9,578
—	(3,746)	—	—	—	—	—	(3,746)	(41)	(3,787)
—	—	—	(6)	(173)	(179)	—	(179)	—	(179)
—	—	—	—	—	—	417	417	—	417
—	—	—	—	—	—	7	7	—	7
—	—	—	—	—	—	1,599	1,599	—	1,599
—	—	—	(37)	—	(37)	—	(37)	—	(37)
—	(3,746)	—	(43)	(173)	(216)	11,406	7,444	154	7,598
—	—	—	—	—	—	(6,699)	(6,699)	(170)	(6,869)
—	—	—	26	—	26	—	26	—	26
—	—	—	—	—	—	(355)	(355)	—	(355)
1,191	—	—	—	—	—	(718)	703	—	703
—	—	—	—	—	—	14	14	—	14
—	—	—	—	—	—	—	—	207	207
(15,767)	(8,902)	—	(777)	(210)	(987)	78,748	99,444	2,104	101,548

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Costs of hedging	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(18,443)	(6,878)	3	(1,156)	—	(1,153)	75,638	95,286	1,557	96,843
—	—	—	—	—	—	3,389	3,389	79	3,468
—	1,722	—	—	—	—	(3)	1,719	52	1,771
—	—	14	—	—	14	—	14	—	14
—	—	—	396	—	396	—	396	—	396
—	—	—	—	—	—	564	564	—	564
—	—	—	—	—	—	(72)	(72)	—	(72)
—	—	—	—	—	—	2,343	2,343	—	2,343
—	1,722	14	396	—	410	6,221	8,353	131	8,484
—	—	—	—	—	—	(6,153)	(6,153)	(141)	(6,294)
—	—	—	—	—	—	(343)	(343)	—	(343)
1,485	—	—	—	—	—	(798)	687	—	687
—	—	—	—	—	—	215	215	—	215
—	—	—	—	—	—	446	446	366	812
(16,958)	(5,156)	17	(760)	—	(743)	75,226	98,491	1,913	100,404

Treasury	Foreign	Available-			Total		BP	Non-	

shares	currency translation reserve	for-sale investments	Cash flow hedges	Costs of hedging	fair value reserves	Profit and loss account	shareholders' equity	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

[c] Principally relates to the initial public offering of common units in BP Midstream Partners LP for which net proceeds of $811 million were received.

[d] 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.

32. Capital and reserves – continued

Share capital

The balance on the share capital account represents the aggregate nominal value of all ordinary and preference shares in issue, including treasury shares.

Share premium account

The balance on the share premium account represents the amounts received in excess of the nominal value of the ordinary and preference shares.

Capital redemption reserve

The balance on the capital redemption reserve represents the aggregate nominal value of all the ordinary shares repurchased and cancelled.

Merger reserve

The balance on the merger reserve represents the fair value of the consideration given in excess of the nominal value of the ordinary shares issued in an acquisition made by the issue of shares.

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 reclassified to the income statement.

Available-for-sale investments

This reserve recorded the changes in fair value of investments classified as available-for-sale under IAS 39 except for impairment losses, foreign exchange gains or losses, or changes arising from revised estimates of future cash flows. On adoption of IFRS 9 the balance in this reserve was transferred to the profit and loss account reserve. Under the new standard the group recognizes fair value gains and losses on these investments in profit or loss.

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.

Costs of hedging

This reserve records the change in fair value of the foreign currency basis spread of financial instruments to which cost of hedge accounting has been applied. The accumulated amount relates to time-period related hedged items and is amortized to profit or loss over the term of the hedging relationship.

Prior to the group's adoption of IFRS 9 changes in the fair value of such foreign currency basis spreads were recognized in profit or loss. On adoption of the new standard a transfer from the profit and loss account reserve to the costs of hedging reserve was made in order to reflect the opening reserves position for relevant hedging instruments existing on transition. For further information on the accounting for costs of hedging 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.

32. Capital and reserves – continued

The pre-tax amounts of each component of other comprehensive income, and the related amounts of tax, are shown in the table below.

			$ million
			2018
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	(3,771)	(16)	(3,787)
Cash flow hedges (including reclassifications)	(6)	—	(6)
Costs of hedging (including reclassifications)	(186)	13	(173)
Share of items relating to equity-accounted entities, net of tax	417	—	417
Other	—	7	7
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	2,317	(718)	1,599
Cash flow hedges that will subsequently be transferred to the balance sheet	(37)	—	(37)
Other comprehensive income	(1,266)	(714)	(1,980)

			$ million
			2017
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	1,866	(95)	1,771
Available-for-sale investments (including reclassifications)	14	—	14
Cash flow hedges (including reclassifications)	425	(29)	396
Share of items relating to equity-accounted entities, net of tax	564	—	564
Other	—	(72)	(72)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	3,646	(1,303)	2,343
Other comprehensive income	6,515	(1,499)	5,016

			$ million
			2016
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including reclassifications)	284	78	362
Available-for-sale investments (including reclassifications)	1	—	1
Cash flow hedges (including reclassifications)	(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)

33. 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 2018 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 29.

In the normal course of the group’s business, legal and regulatory 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 health, safety and 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 and regulatory proceedings on the group‘s results of operations, liquidity or financial position will not be material.

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 including the tax deductibility of certain intercompany charges. The resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete and the amounts could be significant and could be material to the group’s results of operations, financial position or liquidity. 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.

33. Contingent liabilities – continued

The group is subject to numerous national and local health, safety and 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, commodities extraction sites, 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 impact on the group’s results of operations, 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. While the amounts associated with decommissioning provisions reverting to the group could be significant and could be material, 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.

See also Legal proceedings on pages 296-298.

34. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2018	2017	2016
Total for all directors			
Emoluments	8	9	10
Amounts received under incentive schemes[a]	16	9	14
Total	24	18	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 2018 one executive director participated in a UK final salary pension plan in respect of service prior to 1 April 2011. During 2018, one executive director participated in retirement savings plans established for US employees and in a US defined benefit pension plan in respect of service prior to 1 September 2016.

Further information

Full details of individual directors’ remuneration are given in the Directors’ remuneration report on page 87. See also Related-party transactions on page 300.

Remuneration of directors and senior management

			$ million
	2018	2017	2016
Total for all senior management and non-executive directors			
Short-term employee benefits	25	29	28
Pensions and other post-retirement benefits	2	2	3
Share-based payments	32	29	39
Total	59	60	70

Senior management comprises members of the executive team, see pages 63-65 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 $nil in 2018 (2017 $nil and 2016 $2.2 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’.

35. Employee costs and numbers

		$ million	
Employee costs	2018	2017	2016
Wages and salaries[a]	7,931	7,572	8,456
Social security costs	743	711	760
Share-based payments[b]	669	624	764
Pension and other post-retirement benefit costs	1,154	1,296	1,253
	10,497	10,203	11,233

		2018			2017			2016	
Average number of employees[c]	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Upstream	5,900	11,500	17,400	6,200	12,200	18,400	6,700	13,500	20,200
Downstream[d e]	6,000	36,300	42,300	6,100	35,900	42,000	6,600	36,600	43,200
Other businesses and corporate[e f]	1,900	12,100	14,000	1,900	12,400	14,300	1,900	12,100	14,000
	13,800	59,900	73,700	14,200	60,500	74,700	15,200	62,200	77,400

[a] Includes termination costs of $493 million (2017 $189 million and 2016 $545 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 17,100 (2017 16,500 and 2016 15,800) service station staff.
[e] Around 800 centralized function employees were reallocated from Upstream and Downstream to Other businesses and corporate during 2016.
[f] Includes 4,000 (2017 4,700 and 2016 4,900) agricultural, operational and seasonal workers in Brazil.

36. Auditor’s remuneration

			$ million
Fees	2018	2017	2016
The audit of the company annual accounts[a]	25	26	25
The audit of accounts of subsidiaries of the company	10	11	12
Total audit	35	37	37
Audit-related assurance services[b]	4	7	7
Total audit and audit-related assurance services	39	44	44
Taxation compliance services	—	—	1
Non-audit and other assurance services	2	3	1
Total non-audit or non-audit-related assurance services	2	3	2
Services relating to BP pension plans	1	—	1
	42	47	47

[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 audit of internal control over financial reporting and non-statutory audit services.

With effect from 2018, following a competitive tender process, Deloitte LLP (Deloitte) was appointed as auditor of the Company, replacing Ernst & Young LLP (EY). In the table above, auditor’s remuneration for services provided during the year ended 31 December 2018 thus relates to Deloitte and for the years ended 31 December 2017 and 31 December 2016 to EY.
In addition to the amounts shown in the table above, in 2018 $0.75 million of additional fees were paid to EY in respect of their audit for 2017. 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 Deloitte to render audit and certain assurance and other services. The audit fees payable to Deloitte were considered as part of the audit

tender process in 2016 and challenged by the audit committee through comparison with the audit pricing proposals of the other bidding firms, before being approved. Deloitte performed further assurance services that were not prohibited by regulatory or other professional requirements and were pre-approved by the Committee. Deloitte is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit-related or assurance nature.

Under SEC regulations, the remuneration of the auditor of $42 million (2017 $47 million and 2016 $47 million) is required to be presented as follows: audit $35 million (2017 $37 million and 2016 $37 million); other audit-related $4 million (2017 $7 million and 2016 $7 million); tax $nil (2017 $nil and 2016 $1 million); and all other fees $3 million (2017 $3 million and 2016 $2 million).

37. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2018 and the group percentage of ordinary share capital (to nearest whole number) are set out below. There are no individually significant incorporated joint arrangements. The group's share of the assets and liabilities of the more important unincorporated joint arrangements are held by subsidiaries listed in the table below. Those subsidiaries 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	Exploration and production, refining and marketing
BP America	100	US	
BP America Production Company	100	US	
BP Company North America	100	US	
BP Corporation North America	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 Oil Company	19.75	Russia	Integrated oil operations

38. 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 2018
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,315	—	298,620	(4,179)	298,756
Earnings from joint ventures - after interest and tax	—	—	897	—	897
Earnings from associates - after interest and tax	—	—	2,856	—	2,856
Equity-accounted income of subsidiaries - after interest and tax	—	10,942	—	(10,942)	—
Interest and other income	42	373	2,081	(1,723)	773
Gains on sale of businesses and fixed assets	—	—	456	—	456
Total revenues and other income	4,357	11,315	304,910	(16,844)	303,738
Purchases	1,507	—	232,550	(4,179)	229,878
Production and manufacturing expenses	1,015	—	21,990	—	23,005
Production and similar taxes	282	—	1,254	—	1,536
Depreciation, depletion and amortization	377	—	15,080	—	15,457
Impairment and losses on sale of businesses and fixed assets	66	—	794	—	860
Exploration expense	—	—	1,445	—	1,445
Distribution and administration expenses	22	642	11,673	(158)	12,179
Profit (loss) before interest and taxation	1,088	10,673	20,124	(12,507)	19,378
Finance costs	8	1,326	2,759	(1,565)	2,528
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(95)	222	—	127
Profit (loss) before taxation	1,080	9,442	17,143	(10,942)	16,723

Taxation	164	59	6,922	—	7,145
Profit (loss) for the year	916	9,383	10,221	(10,942	)9,578
Attributable to					
BP shareholders	916	9,383	10,026	(10,942	)9,383
Non-controlling interests	—	—	195	—	195
	916	9,383	10,221	(10,942	)9,578

38. Condensed consolidating information on certain US subsidiaries – continued
Statement of comprehensive income

	Issuer	Guarantor			$ million 2018
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	916	9,383	10,221	(10,942)	9,578
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	(296)	(3,475)	—	(3,771)
Cash flow hedges (including reclassifications)	—	—	(6)	—	(6)
Costs of hedging (including reclassifications)	—	—	(186)	—	(186)
Share of items relating to equity-accounted entities, net of tax	—	—	417	—	417
Income tax relating to items that may be reclassified	—	—	4	—	4
	—	(296)	(3,246)	—	(3,542)
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	1,689	628	—	2,317
Cash flow hedges that will subsequently be transferred to the balance sheet	—	—	(37)	—	(37)
Income tax relating to items that will not be reclassified	—	(511)	(207)	—	(718)
	—	1,178	384	—	1,562
Other comprehensive income	—	882	(2,862)	—	(1,980)
Equity-accounted other comprehensive income of subsidiaries	—	(2,821)	—	2,821	—
Total comprehensive income	916	7,444	7,359	(8,121)	7,598
Attributable to					
BP shareholders	916	7,444	7,205	(8,121)	7,444
Non-controlling interests	—	—	154	—	154
	916	7,444	7,359	(8,121)	7,598

Income statement continued

	Issuer	Guarantor			$ million 2017
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	3,264	—	240,177	(3,233)	240,208
	—	—	1,177	—	1,177

Earnings from joint ventures - after interest and tax					
Earnings from associates - after interest and tax	—	—	1,330	—	1,330
Equity-accounted income of subsidiaries - after interest and tax	—	4,436	—	(4,436)	—
Interest and other income	11	369	1,470	(1,193)	657
Gains on sale of businesses and fixed assets	71	9	1,139	(9)	1,210
Total revenues and other income	3,346	4,814	245,293	(8,871)	244,582
Purchases	1,010	—	181,939	(3,233)	179,716
Production and manufacturing expenses	1,156	—	23,073	—	24,229
Production and similar taxes[a]	(18)	—	1,793	—	1,775
Depreciation, depletion and amortization	735	—	14,849	—	15,584
Impairment and losses on sale of businesses and fixed assets	—	—	1,216	—	1,216
Exploration expense	—	—	2,080	—	2,080
Distribution and administration expenses	19	616	10,022	(149)	10,508
Profit (loss) before interest and taxation	444	4,198	10,321	(5,489)	9,474
Finance costs	6	826	2,286	(1,044)	2,074
Net finance (income) expense relating to pensions and other post-retirement benefits	—	(15)	235	—	220
Profit (loss) before taxation	438	3,387	7,800	(4,445)	7,180
Taxation	(392)	(11)	4,115	—	3,712
Profit (loss) for the year	830	3,398	3,685	(4,445)	3,468
Attributable to					
BP shareholders	830	3,398	3,606	(4,445)	3,389
Non-controlling interests	—	—	79	—	79
	830	3,398	3,685	(4,445)	3,468

[a] Includes revised non-cash provision adjustments; actual cash payments for Production and similar taxes remain in line with prior year.

38. Condensed consolidating information on certain US subsidiaries – continued

Statement of comprehensive income continued

					$ million 2017
	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	830	3,398	3,685	(4,445)	3,468
Other comprehensive income					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	166	1,820	—	1,986
Exchange (gains) losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	—	—	(120)	—	(120)
Available-for-sale investments marked to market	—	—	14	—	14
Cash flow hedges marked to market	—	—	197	—	197
Cash flow hedges reclassified to the income statement	—	—	116	—	116
Cash flow hedges reclassified to the balance sheet	—	—	112	—	112
Share of items relating to equity-accounted entities, net of tax	—	—	564	—	564
Income tax relating to items that may be reclassified	—	—	(196)	—	(196)
	—	166	2,507	—	2,673
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	2,984	662	—	3,646
Income tax relating to items that will not be reclassified	—	(1,169)	(134)	—	(1,303)
	—	1,815	528	—	2,343
Other comprehensive income	—	1,981	3,035	—	5,016
Equity-accounted other comprehensive income of subsidiaries	—	2,983	—	(2,983)	—
Total comprehensive income	830	8,362	6,720	(7,428)	8,484
Attributable to					
BP shareholders	830	8,362	6,589	(7,428)	8,353
Non-controlling interests	—	—	131	—	131
	830	8,362	6,720	(7,428)	8,484

Income statement continued

			$ million 2016
	Issuer	Guarantor BP p.l.c.	

	BP Exploration (Alaska) Inc.		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

38. Condensed consolidating information on certain US subsidiaries – continued
Statement of comprehensive income continued

					$ million 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					
Items that may be reclassified subsequently to profit or loss					
Currency translation differences	—	(236)	490	—	254
Exchange (gains) losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	—	—	30	—	30
Available-for-sale investments marked to market	—	—	1	—	1
Cash flow hedges marked to market	—	—	(639)	—	(639)
Cash flow hedges reclassified to the income statement	—	—	196	—	196
Cash flow hedges reclassified to the balance sheet	—	—	81	—	81
Share of items relating to equity-accounted entities, net of tax	—	—	833	—	833
Income tax relating to items that may be reclassified	—	—	13	—	13
	—	(236)	1,005	—	769
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	—	(2,019)	(477)	—	(2,496)
Income tax relating to items that will not be reclassified	—	750	(11)	—	739
	—	(1,269)	(488)	—	(1,757)
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)

38. Condensed consolidating information on certain US subsidiaries – continued
Balance sheet

					$ million 2018
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	4,445	—	130,816	—	135,261
Goodwill	—	—	12,204	—	12,204
Intangible assets	598	—	16,686	—	17,284
Investments in joint ventures	—	—	8,647	—	8,647
Investments in associates	—	2	17,671	—	17,673
Other investments	—	—	1,341	—	1,341
Subsidiaries - equity-accounted basis	—	166,311	—	(166,311	)—
Fixed assets	5,043	166,313	187,365	(166,311	)192,410
Loans	—	—	32,402	(31,765	)637
Trade and other receivables	—	2,600	1,834	(2,600	)1,834
Derivative financial instruments	—	—	5,145	—	5,145
Prepayments	—	—	1,179	—	1,179
Deferred tax assets	—	—	3,706	—	3,706
Defined benefit pension plan surpluses	—	5,473	482	—	5,955
	5,043	174,386	232,113	(200,676	)210,866
Current assets					
Loans	—	—	326	—	326
Inventories	302	—	17,686	—	17,988
Trade and other receivables	2,536	151	38,931	(17,140	)24,478
Derivative financial instruments	—	—	3,846	—	3,846
Prepayments	7	—	956	—	963
Current tax receivable	—	—	1,019	—	1,019
Other investments	—	—	222	—	222
Cash and cash equivalents	—	13	22,455	—	22,468
	2,845	164	85,441	(17,140	)71,310
Total assets	7,888	174,550	317,554	(217,816	)282,176
Current liabilities					
Trade and other payables	413	14,634	48,358	(17,140	)46,265
Derivative financial instruments	—	—	3,308	—	3,308
Accruals	89	31	4,506	—	4,626
Finance debt	—	—	9,373	—	9,373
Current tax payable	310	—	1,791	—	2,101
Provisions	1	—	2,563	—	2,564
	813	14,665	69,899	(17,140	)68,237
Non-current liabilities					
Other payables	—	31,800	16,395	(34,365	)13,830
Derivative financial instruments	—	—	5,625	—	5,625
Accruals	—	—	575	—	575
Finance debt	—	—	56,426	—	56,426
Deferred tax liabilities	586	1,907	7,319	—	9,812
Provisions	670	—	17,062	—	17,732

Defined benefit pension plan and other post-retirement benefit plan deficits	—	184	8,207	—	8,391
	1,256	33,891	111,609	(34,365)	112,391
Total liabilities	2,069	48,556	181,508	(51,505)	180,628
Net assets	5,819	125,994	136,046	(166,311)	101,548
Equity					
BP shareholders' equity	5,819	125,994	133,942	(166,311)	99,444
Non-controlling interests	—	—	2,104	—	2,104
	5,819	125,994	136,046	(166,311)	101,548

38. Condensed consolidating information on certain US subsidiaries – continued
Balance sheet continued

					$ million 2017
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	6,973	—	122,498	—	129,471
Goodwill	—	—	11,551	—	11,551
Intangible assets	585	—	17,770	—	18,355
Investments in joint ventures	—	—	7,994	—	7,994
Investments in associates	—	2	16,989	—	16,991
Other investments	—	—	1,245	—	1,245
Subsidiaries - equity-accounted basis	—	161,840	—	(161,840)	—
Fixed assets	7,558	161,842	178,047	(161,840)	185,607
Loans	1	—	32,401	(31,756)	646
Trade and other receivables	—	2,623	1,434	(2,623)	1,434
Derivative financial instruments	—	—	4,110	—	4,110
Prepayments	—	—	1,112	—	1,112
Deferred tax assets	—	—	4,469	—	4,469
Defined benefit pension plan surpluses	—	3,838	331	—	4,169
	7,559	168,303	221,904	(196,219)	201,547
Current assets					
Loans	—	—	190	—	190
Inventories	274	—	18,737	—	19,011
Trade and other receivables	2,206	293	34,991	(12,641)	24,849
Derivative financial instruments	—	—	3,032	—	3,032
Prepayments	2	—	1,412	—	1,414
Current tax receivable	—	—	761	—	761
Other investments	—	—	125	—	125
Cash and cash equivalents	—	10	25,576	—	25,586
	2,482	303	84,824	(12,641)	74,968
Total assets	10,041	168,606	306,728	(208,860)	276,515
Current liabilities					
Trade and other payables[a]	673	10,143	46,034	(12,641)	44,209
Derivative financial instruments	—	—	2,808	—	2,808
Accruals	115	60	4,785	—	4,960
Finance debt	—	—	7,739	—	7,739
Current tax payable	—	—	1,686	—	1,686
Provisions	1	—	3,323	—	3,324
	789	10,203	66,375	(12,641)	64,726
Non-current liabilities					
Other payables[a]	—	31,804	16,464	(34,379)	13,889
Derivative financial instruments	—	—	3,761	—	3,761
Accruals	—	—	505	—	505
Finance debt	—	—	55,491	—	55,491
Deferred tax liabilities	838	1,337	5,807	—	7,982
Provisions	1,222	—	19,398	—	20,620

Defined benefit pension plan and other post-retirement benefit plan deficits	—	221	8,916	—	9,137
	2,060	33,362	110,342	(34,379)	111,385
Total liabilities	2,849	43,565	176,717	(47,020)	176,111
Net assets	7,192	125,041	130,011	(161,840)	100,404
Equity					
BP shareholders’ equity	7,192	125,041	128,098	(161,840)	98,491
Non-controlling interests	—	—	1,913	—	1,913
	7,192	125,041	130,011	(161,840)	100,404

[a] For BP plc, an amount of $2,300 million has been reclassified from non-current other payables to current trade and other payables, with consequential amendments to the eliminations and reclassifications column.

38. Condensed consolidating information on certain US subsidiaries – continued
Cash flow statement

	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2018 BP group
Operating activities					
Profit (loss) before taxation	1,080	9,442	17,143	(10,942)	16,723
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,085	—	1,085
Depreciation, depletion and amortization	377	—	15,080	—	15,457
Impairment and (gain) loss on sale of businesses and fixed assets	66	—	338	—	404
Earnings from joint ventures and associates	—	—	(3,753)	—	(3,753)
Dividends received from joint ventures and associates	—	—	1,535	—	1,535
Equity accounted income of subsidiaries - after interest and tax	—	(10,942)	—	10,942	—
Dividends received from subsidiaries	—	3,490	—	(3,490)	—
Interest receivable	(42)	(215)	(1,776)	1,565	(468)
Interest received	42	215	1,656	(1,565)	348
Finance costs	8	1,326	2,759	(1,565)	2,528
Interest paid	(8)	(1,326)	(2,159)	1,565	(1,928)
Net finance expense relating to pensions and other post-retirement benefits	—	(95)	222	—	127
Share-based payments	—	671	19	—	690
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(183)	(203)	—	(386)
Net charge for provisions, less payments	33	—	953	—	986
(Increase) decrease in inventories	(62)	—	734	—	672
(Increase) decrease in other current and non-current assets	(72)	165	(951)	(2,000)	(2,858)
Increase (decrease) in other current and non-current liabilities	(491)	4,509	(6,595)	—	(2,577)
Income taxes paid	(133)	—	(5,579)	—	(5,712)
Net cash provided by (used in) operating activities	798	7,057	20,508	(5,490)	22,873
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(273)	—	(16,434)	—	(16,707)
Acquisitions, net of cash acquired	—	—	(6,986)	—	(6,986)
Investment in joint ventures	—	—	(382)	—	(382)
Investment in associates	—	—	(1,013)	—	(1,013)

Total cash capital expenditure	(273)	—	(24,815)	—	(25,088)
Proceeds from disposals of fixed assets	—	—	940	—	940
Proceeds from disposals of businesses, net of cash disposed	1,475	—	436	—	1,911
Proceeds from loan repayments	—	—	666	—	666
Net cash provided by (used in) investing activities	1,202	—	(22,773)	—	(21,571)
Financing activities					
Repurchase of shares	—	(355)	—	—	(355)
Proceeds from long-term financing	—	—	9,038	—	9,038
Repayments of long-term financing	—	—	(7,210)	—	(7,210)
Net increase (decrease) in short-term debt	—	—	1,317	—	1,317
Dividends paid					
BP shareholders	(2,000)	(6,699)	(3,490)	5,490	(6,699)
Non-controlling interests	—	—	(170)	—	(170)
Net cash provided by (used in) financing activities	(2,000)	(7,054)	(515)	5,490	(4,079)
Currency translation differences relating to cash and cash equivalents	—	—	(330)	—	(330)
Increase (decrease) in cash and cash equivalents	—	3	(3,110)	—	(3,107)
Cash and cash equivalents at beginning of year	—	10	25,565	—	25,575
Cash and cash equivalents at end of year	—	13	22,455	—	22,468

38. Condensed consolidating information on certain US subsidiaries – continued
Cash flow statement continued

	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2017 BP group
Operating activities					
Profit (loss) before taxation	438	3,387	7,800	(4,445)	7,180
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,603	—	1,603
Depreciation, depletion and amortization	735	—	14,849	—	15,584
Impairment and (gain) loss on sale of businesses and fixed assets	(71)	(9)	77	9	6
Earnings from joint ventures and associates	—	—	(2,507)	—	(2,507)
Dividends received from joint ventures and associates	—	—	1,253	—	1,253
Equity accounted income of subsidiaries - after interest and tax	—	(4,436)	—	4,436	—
Dividends received from subsidiaries	—	3,183	—	(3,183)	—
Interest receivable	(11)	(220)	(1,117)	1,044	(304)
Interest received	11	220	1,188	(1,044)	375
Finance costs	6	826	2,286	(1,044)	2,074
Interest paid	(6)	(826)	(1,784)	1,044	(1,572)
Net finance expense relating to pensions and other post-retirement benefits	—	(15)	235	—	220
Share-based payments	—	595	66	—	661
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(145)	(249)	—	(394)
Net charge for provisions, less payments	(128)	—	2,234	—	2,106
(Increase) decrease in inventories	(25)	—	(823)	—	(848)
(Increase) decrease in other current and non-current assets	108	522	(5,478)	—	(4,848)
Increase (decrease) in other current and non-current liabilities	(830)	3,374	(200)	—	2,344
Income taxes paid	—	—	(4,002)	—	(4,002)
Net cash provided by operating activities	227	6,456	15,431	(3,183)	18,931
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(321)	—	(16,241)	—	(16,562)
Acquisitions, net of cash acquired	—	—	(327)	—	(327)
Investment in joint ventures	—	—	(50)	—	(50)
Investment in associates	—	—	(901)	—	(901)
Total cash capital expenditure	(321)	—	(17,519)	—	(17,840)

Proceeds from disposals of fixed assets	94	—	2,842	—	2,936
Proceeds from disposals of businesses, net of cash disposed	—	—	478	—	478
Proceeds from loan repayments	—	—	349	—	349
Net cash provided by (used in) investing activities	(227)	—	(13,850)	—	(14,077)
Financing activities					
Net issue (repurchase) of shares	—	(343)	—	—	(343)
Proceeds from long-term financing	—	—	8,712	—	8,712
Repayments of long-term financing	—	—	(6,276)	—	(6,276)
Net increase (decrease) in short-term debt	—	—	(158)	—	(158)
Net increase (decrease) in non-controlling interests	—	—	1,063	—	1,063
Dividends paid					
BP shareholders	—	(6,153)	(3,183)	3,183	(6,153)
Non-controlling interests	—	—	(141)	—	(141)
Net cash provided by (used in) financing activities	—	(6,496)	17	3,183	(3,296)
Currency translation differences relating to cash and cash equivalents	—	—	544	—	544
Increase (decrease) in cash and cash equivalents	—	(40)	2,142	—	2,102
Cash and cash equivalents at beginning of year	—	50	23,434	—	23,484
Cash and cash equivalents at end of year	—	10	25,576	—	25,586

38. Condensed consolidating information on certain US subsidiaries – continued
Cash flow statement continued

	Issuer	Guarantor			$ million 2016
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Operating activities					
Profit (loss) before taxation	44	168	(1,645)	(862)	(2,295)
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	—	—	1,274	—	1,274
Depreciation, depletion and amortization	673	—	13,832	—	14,505
Impairment and (gain) loss on sale of businesses and fixed assets	(148)	—	(2,648)	—	(2,796)
Earnings from joint ventures and associates	—	—	(1,960)	—	(1,960)
Dividends received from joint ventures and associates	—	—	1,105	—	1,105
Equity accounted income of subsidiaries - after interest and tax	—	(862)	—	862	—
Dividends received from (paid to) subsidiaries	(7,000)	372	—	6,628	—
Interest receivable	(94)	(233)	(593)	720	(200)
Interest received	94	233	660	(720)	267
Finance costs	103	311	1,981	(720)	1,675
Interest paid	(103)	(311)	(1,443)	720	(1,137)
Net finance expense relating to pensions and other post-retirement benefits	—	(82)	272	—	190
Share-based payments	—	780	(1)	—	779
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	—	(192)	(275)	—	(467)
Net charge for provisions, less payments	77	—	4,410	—	4,487
(Increase) decrease in inventories	(3)	—	(3,678)	—	(3,681)
(Increase) decrease in other current and non-current assets	6,985	(156)	(1,001)	(7,000)	(1,172)
Increase (decrease) in other current and non-current liabilities	(33)	4,634	(2,946)	—	1,655
Income taxes paid	104	(1)	(1,641)	—	(1,538)
Net cash provided by operating activities	699	4,661	5,703	(372)	10,691
Investing activities					
Expenditure on property, plant and equipment, intangible and other assets	(699)	—	(16,002)	—	(16,701)
Acquisitions, net of cash acquired	—	—	(1)	—	(1)
Investment in joint ventures	—	—	(50)	—	(50)
Investment in associates	—	—	(700)	—	(700)

Total cash capital expenditure	(699)	—	(16,753)	—	(17,452)
Proceeds from disposals of fixed assets	—	—	1,372	—	1,372
Proceeds from disposals of businesses, net of cash disposed	—	—	1,259	—	1,259
Proceeds from loan repayments	—	—	68	—	68
Net cash provided by (used in) investing activities	(699)	—	(14,054)	—	(14,753)
Financing activities					
Proceeds from long-term financing	—	—	12,442	—	12,442
Repayments of long-term financing	—	—	(6,685)	—	(6,685)
Net increase (decrease) in short-term debt	—	—	51	—	51
Net increase (decrease) in non-controlling interests	—	—	887	—	887
Dividends paid					
BP shareholders	—	(4,611)	(372)	372	(4,611)
Non-controlling interests	—	—	(107)	—	(107)
Net cash provided by (used in) financing activities	—	(4,611)	6,216	372	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

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 285-290.

Oil and natural gas exploration and production activities

$ million
2018

	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	29,730	—	89,069	3,385	14,269	51,980	—	38,315	6,119	232,867
Unproved properties	451	—	3,602	2,667	2,742	3,870	—	3,153	568	17,053
	30,181	—	92,671	6,052	17,011	55,850	—	41,468	6,687	249,920
Accumulated depreciation	16,809	—	47,051	420	8,517	38,324	—	20,173	3,626	134,920
Net capitalized costs	13,372	—	45,620	5,632	8,494	17,526	—	21,295	3,061	115,000
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	1,933	—	10,650	—	—	(1)	—	36	—	12,618
Unproved	—	—	35	—	100	50	—	(5)	—	180
	1,933	—	10,685	—	100	49	—	31	—	12,798
Exploration and appraisal costs[c]	238	—	216	139	245	283	5	148	24	1,298
Development	817	—	3,429	46	591	2,340	—	2,458	236	9,917
Total costs	2,988	—	14,330	185	936	2,672	5	2,637	260	24,013
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	619	—	1,306	105	2,074	3,228	—	1,430	1,410	10,172
Sales between businesses	2,255	—	11,656	1	195	3,928	—	7,793	665	26,493
	2,874	—	12,962	106	2,269	7,156	—	9,223	2,075	36,665
Exploration expenditure	105	—	509	146	252	405	5	20	3	1,445
Production costs	646	—	2,729	120	430	1,066	—	951	138	6,080
Production taxes	(269)	—	369	—	357	—	—	1,010	69	1,536
Other costs (income)[e]	(331)	(2)	2,379	43	165	133	42	94	223	2,746
Depreciation, depletion and amortization	1,199	—	3,921	101	1,023	3,635	—	2,165	298	12,342
Net impairments and (gains) losses on sale of businesses and fixed assets	(226)	—	203	10	—	(141)	—	21	136	3
	1,124	(2)	10,110	420	2,227	5,098	47	4,261	867	24,152
Profit (loss) before taxation[f]	1,750	2	2,852	(314)	42	2,058	(47)	4,962	1,208	12,513
Allocable taxes[g]	446	—	454	(95)	314	1,184	13	3,509	508	6,333
Results of operations	1,304	2	2,398	(219)	(272)	874	(60)	1,453	700	6,180

Upstream and Rosneft segments replacement cost profit (loss) before interest and tax

Exploration and production activities – subsidiaries (as above)	1,750	2	2,852	(314)	42	2,058	(47)	4,962	1,208	12,513
Midstream and other activities – subsidiaries[h]	(20)	265	188	(111)	135	(58)	5	463	6	873
Equity-accounted entities[i j]	(2)	130	28	—	209	207	2,346	245	—	3,163
Total replacement cost profit (loss) before interest and tax	1,728	397	3,068	(425)	386	2,207	2,304	5,670	1,214	16,549

[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, Asia and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

[b] Costs of decommissioning 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 $17 million. The UK region includes a $384-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 $208 million which is included in finance costs in the group income statement.

[g] US region includes the deferred tax impact of the reduction in the US Federal corporate income tax rate from 35% to 21% enacted in December 2017.

[h] Midstream and other activities excludes inventory holding gains and losses.

[i] The profits of equity-accounted entities are included after interest and tax.

[j] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation.

Oil and natural gas exploration and production activities – continued

										$ million 2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	—	3,439	—	—	9,643	—	24,052	3,646	—	40,780
Unproved properties	—	657	—	—	86	—	828	26	—	1,597
	—	4,096	—	—	9,729	—	24,880	3,672	—	42,377
Accumulated depreciation	—	670	—	—	4,665	—	6,749	3,672	—	15,756
Net capitalized costs	—	3,426	—	—	5,064	—	18,131	—	—	26,621
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	425	—	—	425
Unproved	—	137	—	—	—	—	148	—	—	285
	—	137	—	—	—	—	573	—	—	710
Exploration and appraisal costs[d]	—	67	—	—	25	—	207	—	—	299
Development	—	251	—	—	575	—	3,255	212	—	4,293
Total costs	—	455	—	—	600	—	4,035	212	—	5,302
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	1,114	—	—	1,792	—	—	353	—	3,259
Sales between businesses	—	—	—	—	—	—	15,901	—	—	15,901
	—	1,114	—	—	1,792	—	15,901	353	—	19,160
Exploration expenditure	—	89	—	—	7	—	112	—	—	208
Production costs	—	207	—	—	438	—	1,487	39	—	2,171
Production taxes	—	—	—	—	361	—	7,634	94	—	8,089
Other costs (income)	—	21	—	—	127	—	638	—	—	786
Depreciation, depletion and amortization	—	290	—	—	416	—	1,627	212	—	2,545
Net impairments and losses on sale of businesses and fixed assets	—	6	—	—	—	—	47	1	—	54
	—	613	—	—	1,349	—	11,545	346	—	13,853
Profit (loss) before taxation	—	501	—	—	443	—	4,356	7	—	5,307
Allocable taxes	—	350	—	—	279	—	849	—	—	1,478
Results of operations[g]	—	151	—	—	164	—	3,507	7	—	3,829
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)	—	151	—	—	164	—	3,507	7	—	3,829
Midstream and other activities after tax[h]	(2)	(21)	28	—	45	207	(1,161)	238	—	(666)
Total replacement cost profit (loss) after interest and tax	(2)	130	28	—	209	207	2,346	245	—	3,163

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities.
[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 and Pan American Energy Group are excluded.
[c] Costs of decommissioning 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] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation.
[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities – continued

										$ million 2017
	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	34,208	—	83,449	3,518	13,581	49,795	—	35,519	5,984	226,054
Unproved properties	481	—	3,957	2,561	2,905	4,013	—	3,407	562	17,886
	34,689	—	87,406	6,079	16,486	53,808	—	38,926	6,546	243,940
Accumulated depreciation	21,793	—	48,462	367	7,495	34,870	—	18,007	3,192	134,186
Net capitalized costs	12,896	—	38,944	5,712	8,991	18,938	—	20,919	3,354	109,754
Costs incurred for the year ended 31 December[a b]										
Acquisition of properties										
Proved	—	—	22	—	—	564	—	1,187	—	1,773
Unproved	13	—	13	—	330	374	—	228	—	958
	13	—	35	—	330	938	—	1,415	—	2,731
Exploration and appraisal costs[c]	336	—	102	52	264	682	11	190	18	1,655
Development	995	—	2,776	58	911	2,972	—	2,760	223	10,695
Total costs	1,344	—	2,913	110	1,505	4,592	11	4,365	241	15,081
Results of operations for the year ended 31 December[a]										
Sales and other operating revenues[d]										
Third parties	204	—	724	171	1,134	2,211	—	1,276	967	6,687
Sales between businesses	1,745	—	9,117	2	327	4,022	—	6,394	487	22,094
	1,949	—	9,841	173	1,461	6,233	—	7,670	1,454	28,781
Exploration expenditure	331	—	282	39	83	1,346	11	(29)	17	2,080
Production costs	629	—	2,256	116	573	979	—	904	157	5,614
Production taxes	(37)	—	52	—	86	—	—	1,618	56	1,775
Other costs (income)[e]	(272)	2	1,655	34	71	280	39	311	349	2,469
Depreciation, depletion and amortization	1,190	—	4,258	96	742	3,586	—	2,147	366	12,385
Net impairments and (gains) losses on sale of businesses and fixed assets	133	(12)	87	(1)	(31)	—	—	(10)	13	179
	1,974	(10)	8,590	284	1,524	6,191	50	4,941	958	24,502
Profit (loss) before taxation[f]	(25)	10	1,251	(111)	(63)	42	(50)	2,729	496	4,279
Allocable taxes[g]	(104)	—	(1,811)	(28)	155	788	(19)	1,505	146	632
Results of operations	79	10	3,062	(83)	(218)	(746)	(31)	1,224	350	3,647

Upstream and Rosneft segments replacement cost profit (loss) before interest and tax

Exploration and production activities – subsidiaries (as above)	(25)	10	1,251	(111)	(63)	42	(50)	2,729	496	4,279
Midstream and other activities – subsidiaries[h]	(185)	97	(176)	(111)	140	(80)	3	315	11	14
Equity-accounted entities[i j]	—	71	25	—	381	205	837	245	—	1,764
Total replacement cost profit (loss) before interest and tax	(210)	178	1,100	(222)	458	167	790	3,289	507	6,057

[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, Asia and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the South Caucasus Pipeline, the Forties Pipeline System and the Baku-Tbilisi-Ceyhan pipeline. The Forties Pipeline System was divested on 31 October 2017. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.
[b] Costs of decommissioning 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 $32 million. The UK region includes a $343-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 $120 million which is included in finance costs in the group income statement.
[g] US region includes the deferred tax impact of the reduction in the US Federal corporate income tax rate from 35% to 21% enacted in December 2017.
[h] Midstream and other activities excludes inventory holding gains and losses.
[i] The profits of equity-accounted entities are included after interest and tax.
[j] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation. Of BP's initial 60% interest in PAE, 10% was classified as held for sale on 9 September 2017. For September, only 9 days of income was reported for the full 60%. After this equity accounting continued for the 50% not classified as held for sale. BP accounted for 50% of the enlarged entity from 16 December 2017.

Oil and natural gas exploration and production activities – continued

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2017 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	—	3,187	—	—	9,096	—	24,686	3,434	—	40,403
Unproved properties	—	481	—	—	68	—	907	26	—	1,482
	—	3,668	—	—	9,164	—	25,593	3,460	—	41,885
Accumulated depreciation	—	400	—	—	4,249	—	6,207	3,460	—	14,316
Net capitalized costs	—	3,268	—	—	4,915	—	19,386	—	—	27,569
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	323	—	—	—	—	653	—	—	976
Unproved	—	152	—	—	20	—	416	—	—	588
	—	475	—	—	20	—	1,069	—	—	1,564
Exploration and appraisal costs[d]	—	49	—	—	43	—	194	—	—	286
Development	—	199	—	—	576	—	3,361	446	—	4,582
Total costs	—	723	—	—	639	—	4,624	446	—	6,432
Results of operations for the year ended 31 December[b]										
Sales and other operating revenues[f]										
Third parties	—	773	—	—	1,750	—	—	988	—	3,511
Sales between businesses	—	—	—	—	—	—	11,537	—	—	11,537
	—	773	—	—	1,750	—	11,537	988	—	15,048
Exploration expenditure	—	68	—	—	—	—	59	—	—	127
Production costs	—	157	—	—	592	—	1,424	117	—	2,290
Production taxes	—	—	—	—	336	—	5,712	426	—	6,474
Other costs (income)	—	67	—	—	11	—	409	(5)	—	482
Depreciation, depletion and amortization	—	328	—	—	458	—	1,539	446	—	2,771
Net impairments and losses on sale of businesses and fixed assets	—	6	—	—	27	—	54	—	—	87
	—	626	—	—	1,424	—	9,197	984	—	12,231
Profit (loss) before taxation	—	147	—	—	326	—	2,340	4	—	2,817
Allocable taxes	—	54	—	—	(18)	—	457	—	—	493
Results of operations[g]	—	93	—	—	344	—	1,883	4	—	2,324
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)	—	93	—	—	344	—	1,883	4	—	2,324
Midstream and other activities after tax[h]	—	(22)	25	—	37	205	(1,046)	241	—	(560)
	—	71	25	—	381	205	837	245	—	1,764

Total replacement cost profit (loss) after
interest and tax

[a] Amounts reported for Russia in this table include BP’s share of Rosneft’s worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities.

[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 and Pan American Energy Group are excluded.

[c] Costs of decommissioning 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] From 16 December 2017, BP entered into a new 50:50 joint venture Pan American Energy Group (PAEG). Prior to this, Pan American Energy (PAE) was owned 60% by BP and 40% by Bridas Corporation. Of BP's initial 60% interest in PAE, 10% was classified as held for sale on 9 September 2017. For September, only 9 days of income was reported for the full 60%. After this equity accounting continued for the 50% not classified as held for sale. BP accounted for 50% of the enlarged entity from 16 December 2017.

[h] Includes interest and adjustment for non-controlling interests. Excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities – continued

										$ million 2016
	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	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										
	1,252	335	(1,528)	(185)	(965)	530	(44)	429	562	386

Exploration and production activities – subsidiaries (as above)										
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, Asia 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] Costs of decommissioning 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.

Oil and natural gas exploration and production activities – continued

										$ million 2016
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	—	2,702	—	—	10,211	—	19,558	3,009	—	35,480
Unproved properties	—	296	—	—	6	—	383	26	—	711
	—	2,998	—	—	10,217	—	19,941	3,035	—	36,191
Accumulated depreciation	—	48	—	—	4,615	—	4,401	3,035	—	12,099
Net capitalized costs	—	2,950	—	—	5,602	—	15,540	—	—	24,092
Costs incurred for the year ended 31 December[b d e]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	1,576	—	—	1,576
Unproved	—	—	—	—	—	—	69	—	—	69
	—	—	—	—	—	—	1,645	—	—	1,645
Exploration and appraisal costs[d]	—	18	—	—	7	—	118	1	—	144
Development	—	54	—	—	559	—	2,070	371	—	3,054
Total costs	—	72	—	—	566	—	3,833	372	—	4,843
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	—	—	—	—	—	—	8,088	16	—	8,104
	—	162	—	—	1,865	—	8,088	892	—	11,007
Exploration expenditure	—	13	—	—	—	—	50	—	—	63
Production costs	—	36	—	—	559	—	1,085	145	—	1,825
Production taxes	—	—	—	—	335	—	3,393	352	—	4,080
Other costs (income)	—	(13)	—	—	(429)	—	345	3	—	(94)
Depreciation, depletion and amortization	—	48	—	—	499	—	1,082	386	—	2,015
Net impairments and losses on sale of businesses and fixed assets	—	—	—	—	164	—	59	—	—	223
	—	84	—	—	1,128	—	6,014	886	—	8,112
Profit (loss) before taxation	—	78	—	—	737	—	2,074	6	—	2,895
Allocable taxes	—	75	—	—	319	—	435	3	—	832
Results of operations[g]	—	3	—	—	418	—	1,639	3	—	2,063
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	—	1,639	3	—	2,063
Midstream and other activities after tax[h]	—	(4)	20	—	29	(12)	(1,042)	263	—	(746)
	—	(1)	20	—	447	(12)	597	266	—	1,317

Total replacement cost profit (loss) after interest and tax

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia. The amounts reported include the corresponding amounts for their equity-accounted entities. Amounts also include certain adjustments, mainly related to purchase price allocations for 2016 acquisitions.

[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.

[c] Costs of decommissioning 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.

Movements in estimated net proved reserves

Crude oil[a b]										million barrels 2018
	Europe		North America		South America	Africa	Asia		Australia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	245	—	932	54	10	281	—	1,040	31	2,592
Undeveloped	164	—	492	195	6	28	—	642	11	1,537
	409	—	1,423	248	16	309	—	1,682	42	4,129
Changes attributable to										
Revisions of previous estimates	22	—	116	(6)	1	11	—	40	(2)	183
Improved recovery	—	—	51	—	—	1	—	—	—	52
Purchases of reserves-in-place	93	—	412	—	—	—	—	—	—	504
Discoveries and extensions	15	—	17	—	—	13	—	—	—	46
Production[d]	(37)	—	(137)	(9)	(3)	(75)	—	(114)	(6)	(381)
Sales of reserves-in-place	(37)	—	(118)	—	—	—	—	—	—	(155)
	57	—	341	(15)	(2)	(50)	—	(74)	(8)	249
At 31 December[e]										
Developed	223	—	962	43	8	223	—	1,126	30	2,615
Undeveloped	243	—	802	190	5	36	—	482	5	1,763
	466	—	1,764	234	14	259	—	1,608	34	4,378
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	56	—	—	285	1	3,124	6	—	3,473
Undeveloped	—	89	—	—	263	—	2,251	—	—	2,603
	—	145	—	—	548	1	5,374	6	—	6,076
Changes attributable to										
Revisions of previous estimates	—	11	—	—	7	—	150	—	—	168
Improved recovery	—	13	—	—	—	—	—	—	—	13
Purchases of reserves-in-place	—	—	—	—	—	—	89	—	—	89
Discoveries and extensions	—	—	—	19	21	—	326	—	—	366
Production	—	(13)	—	—	(25)	—	(335)	(6)	—	(379)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	12	—	19	4	(1)	229	(6)	—	257
At 31 December[g]										
Developed	—	57	—	—	293	1	3,190	—	—	3,541
Undeveloped	—	100	—	19	259	—	2,414	—	—	2,792
	—	157	—	19	552	1	5,604	—	—	6,333
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	245	56	932	54	295	282	3,124	1,047	31	6,064
Undeveloped	164	89	492	195	269	28	2,251	642	11	4,140
	409	145	1,423	249	564	310	5,374	1,688	42	10,205
At 31 December										
Developed	223	57	962	43	302	224	3,190	1,126	30	6,156

Undeveloped	243	100	802	209	264	36	2,414	482	5	4,555
	466	157	1,764	253	566	260	5,604	1,608	34	10,711

[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 16 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Includes 4 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 344 million barrels of crude oil in respect of the 6.28% non-controlling interest in Rosneft, including 24 mmbbl held through BP's interests in Russia other than Rosneft.
[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,539 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 58 million barrels in Venezuela and 5,481 million barrels in Russia.

Movements in estimated net proved reserves - continued

Natural gas liquids[a b]

million barrels
2018

	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	11	—	177	—	2	21	—	—	5	216
Undeveloped	3	—	69	—	28	—	—	—	1	102
	14	—	246	—	30	21	—	—	6	318
Changes attributable to										
Revisions of previous estimates	1	—	20	—	—	(3)	—	—	—	17
Improved recovery	—	—	16	—	—	2	—	—	—	18
Purchases of reserves-in-place	—	—	253	—	—	—	—	—	—	253
Discoveries and extensions	3	—	1	—	—	3	—	—	—	7
Production[c]	(2)	—	(25)	—	(3)	(3)	—	—	(1)	(34)
Sales of reserves-in-place	(3)	—	—	—	—	—	—	—	—	(3)
	—	—	265	—	(3)	(2)	—	—	(1)	258
At 31 December[d]										
Developed	8	—	266	—	2	14	—	—	5	295
Undeveloped	6	—	246	—	25	4	—	—	—	280
	14	—	511	—	27	18	—	—	5	576
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	4	—	—	—	10	82	—	—	97
Undeveloped	—	4	—	—	—	—	49	—	—	53
	—	8	—	—	—	10	131	—	—	149
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	(1)	25	—	—	23
Improved recovery	—	—	—	—	—	—	—	—	—	—
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(1)	—	—	—	(3)	23	—	—	19
At 31 December[f]										
Developed	—	4	—	—	—	7	103	—	—	114
Undeveloped	—	3	—	—	—	—	51	—	—	54
	—	7	—	—	—	7	154	—	—	169
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	11	4	177	—	2	31	82	—	5	313
Undeveloped	3	4	69	—	28	—	49	—	1	154
	14	8	246	—	30	31	131	—	6	467
At 31 December										
Developed	8	4	266	—	2	22	103	—	5	409
Undeveloped	6	3	246	—	25	4	51	—	—	335

14	7	511	—	27	26	154	—	5	744

[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 8 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] Includes 12 million barrels of NGLs in respect of the 7.82% non-controlling interest in Rosneft.
[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 154 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 154 million barrels in Russia.

Movements in estimated net proved reserves - continued

Total liquids[a b]	Europe		North America		South America	Africa	Asia		Australia	million barrels 2018 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	256	—	1,108	54	12	301	—	1,040	36	2,808
Undeveloped	167	—	561	195	34	28	—	642	12	1,639
	424	—	1,669	248	46	329	—	1,682	48	4,447
Changes attributable to										
Revisions of previous estimates	23	—	136	(6)	1	8	—	40	(2)	200
Improved recovery	—	—	67	—	—	3	—	—	—	70
Purchases of reserves-in-place	93	—	665	—	—	—	—	—	—	758
Discoveries and extensions	18	—	18	—	—	16	—	—	—	52
Production[d]	(39)	—	(162)	(9)	(6)	(79)	—	(114)	(7)	(415)
Sales of reserves-in-place	(40)	—	(118)	—	—	—	—	—	—	(158)
	56	—	606	(15)	(5)	(52)	—	(74)	(9)	507
At 31 December[e]										
Developed	231	—	1,228	43	10	237	—	1,126	35	2,910
Undeveloped	249	—	1,048	190	30	40	—	482	5	2,044
	480	—	2,276	234	41	277	—	1,608	39	4,954
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	—	60	—	—	285	11	3,206	6	—	3,569
Undeveloped	—	93	—	—	263	—	2,300	—	—	2,656
	—	153	—	—	548	12	5,505	6	—	6,225
Changes attributable to										
Revisions of previous estimates	—	11	—	—	7	(2)	175	—	—	191
Improved recovery	—	13	—	—	—	—	—	—	—	13
Purchases of reserves-in-place	—	—	—	—	—	—	89	—	—	89
Discoveries and extensions	—	—	—	19	21	—	326	—	—	366
Production	—	(13)	—	—	(25)	(2)	(337)	(6)	—	(383)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	11	—	19	4	(3)	253	(6)	—	277
At 31 December[g h]										
Developed	—	60	—	—	293	8	3,293	—	—	3,655
Undeveloped	—	104	—	19	259	—	2,465	—	—	2,846
	—	164	—	19	552	8	5,758	—	—	6,502
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	256	60	1,108	54	297	313	3,206	1,047	36	6,377
Undeveloped	167	93	561	195	297	28	2,300	642	12	4,295
	424	153	1,669	249	594	341	5,505	1,688	48	10,672
At 31 December										
Developed	231	60	1,228	44	303	245	3,293	1,126	35	6,565
Undeveloped	249	104	1,048	209	289	40	2,465	482	5	4,890

480	164	2,276	253	593	285	5,758	1,608	39	11,456

[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 16 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 3 thousand barrels per day for equity-accounted entities.
[e] Also includes 12 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 356 million barrels in respect of the non-controlling interest in Rosneft, including 24 mmboe held through BP's interests in Russia other than Rosneft.
[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,693 million barrels, comprising less than 1 million barrels in Canada, 58 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,635 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]										billion cubic feet 2018
	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	523	—	5,238	(1)	2,862	1,159	—	2,755	2,730	15,266
Undeveloped	320	—	3,086	—	3,330	1,510	—	4,245	1,505	13,997
	843	—	8,323	(1)	6,193	2,670	—	7,000	4,235	29,263
Changes attributable to										
Revisions of previous estimates	84	—	10	3	(195)	(444)	—	140	(123)	(524)
Improved recovery	—	—	1,315	—	—	—	—	—	—	1,315
Purchases of reserves-in-place	40	—	2,655	—	—	—	—	—	—	2,695
Discoveries and extensions	60	—	11	—	31	578	—	—	—	680
Production[c]	(66)	—	(751)	(3)	(788)	(423)	—	(324)	(303)	(2,658)
Sales of reserves-in-place	(178)	—	(237)	—	—	—	—	—	—	(416)
	(61)	—	3,003	1	(951)	(290)	—	(184)	(426)	1,092
At 31 December[d]										
Developed	439	—	6,270	—	2,168	1,313	—	3,599	2,630	16,420
Undeveloped	343	—	5,056	—	3,073	1,067	—	3,218	1,179	13,936
	782	—	11,326	—	5,241	2,380	—	6,817	3,809	30,355
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	112	—	—	1,274	476	6,077	17	—	7,955
Undeveloped	—	69	—	—	450	146	7,173	3	—	7,841
	—	180	—	—	1,724	622	13,250	20	—	15,796
Changes attributable to										
Revisions of previous estimates	—	2	—	—	(50)	(39)	805	2	—	719
Improved recovery	—	—	—	—	1	—	—	—	—	1
Purchases of reserves-in-place	—	—	—	—	—	—	2,413	—	—	2,413
Discoveries and extensions	—	—	—	4	122	—	512	—	—	638
Production[c]	—	(22)	—	—	(145)	(48)	(464)	(6)	—	(685)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	(19)	—	3	(71)	(87)	3,267	(5)	—	3,087
At 31 December[f g]										
Developed	—	107	—	—	1,207	391	7,798	12	—	9,515
Undeveloped	—	55	—	4	446	143	8,719	4	—	9,369
	—	161	—	4	1,653	534	16,517	15	—	18,884
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	523	112	5,238	—	4,136	1,635	6,077	2,771	2,730	23,221
Undeveloped	320	69	3,086	—	3,781	1,656	7,173	4,249	1,505	21,838
	843	180	8,323	—	7,917	3,291	13,250	7,020	4,235	45,060
At 31 December										
Developed	439	107	6,270	—	3,375	1,704	7,798	3,610	2,630	25,934

Undeveloped	343	55	5,056	4	3,519	1,210	8,719	3,221	1,179	23,305
	782	161	11,326	4	6,894	2,914	16,517	6,832	3,809	49,239

[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, 139 billion cubic feet in subsidiaries, 42 billion cubic feet in equity-accounted entities.

[d] Includes 1,573 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 1,211 billion cubic feet of natural gas in respect of the 8.60% non-controlling interest in Rosneft including 480 billion cubic feet held through BP's interests in Russia other than Rosneft.

[g] Total proved gas reserves held as part of our equity interest in Rosneft is 14,325 billion cubic feet, comprising 0 billion cubic feet in Canada, 26 billion cubic feet in Venezuela, 15 billion cubic feet in Vietnam, 200 billion cubic feet in Egypt and 14,084 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

										million barrels of oil equivalent[c]
Total hydrocarbons[a b]										2018
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	347	—	2,011	54	505	501	—	1,515	507	5,440
Undeveloped	222	—	1,093	195	608	288	—	1,374	272	4,052
	569	—	3,104	248	1,114	790	—	2,889	779	9,492
Changes attributable to										
Revisions of previous estimates	38	—	138	(5)	(33)	(69)	—	64	(23)	110
Improved recovery	—	—	294	—	—	3	—	—	—	297
Purchases of reserves-in-place	100	—	1,123	—	—	—	—	—	—	1,222
Discoveries and extensions	29	—	20	—	5	116	—	—	—	169
Production[e f]	(50)	—	(292)	(9)	(142)	(152)	—	(170)	(59)	(874)
Sales of reserves-in-place	(70)	—	(159)	—	—	—	—	—	—	(229)
	46	—	1,124	(15)	(169)	(102)	—	(106)	(82)	696
At 31 December[g]										
Developed	307	—	2,309	43	384	464	—	1,746	488	5,741
Undeveloped	308	—	1,919	190	560	224	—	1,037	208	4,447
	615	—	4,228	234	944	687	—	2,783	696	10,188
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	—	80	—	—	505	93	4,254	9	—	4,941
Undeveloped	—	105	—	—	341	25	3,536	1	—	4,008
	—	184	—	—	846	119	7,790	10	—	8,949
Changes attributable to										
Revisions of previous estimates	—	11	—	—	(1)	(8)	313	—	—	315
Improved recovery	—	13	—	—	—	—	—	—	—	14
Purchases of reserves-in-place	—	—	—	—	—	—	505	—	—	505
Discoveries and extensions	—	—	—	20	42	—	414	—	—	476
Production[e]	—	(17)	—	—	(50)	(10)	(417)	(7)	—	(501)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	8	—	19	(9)	(18)	816	(7)	—	809
At 31 December[i j]										
Developed	—	79	—	—	501	76	4,638	2	—	5,296
Undeveloped	—	113	—	20	336	25	3,968	1	—	4,462
	—	192	—	20	837	101	8,605	3	—	9,757
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	347	80	2,011	54	1,010	595	4,254	1,524	507	10,381
Undeveloped	222	105	1,093	195	949	314	3,536	1,374	272	8,060
	569	184	3,104	249	1,959	908	7,790	2,899	779	18,441

At 31 December										
Developed	307	79	2,309	44	885	539	4,638	1,749	488	11,037
Undeveloped	308	113	1,919	210	896	249	3,968	1,037	208	8,908
	615	192	4,228	253	1,781	788	8,605	2,786	696	19,945

[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 16 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 3 thousand barrels per day for equity-accounted entities.

[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 24 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities.

[g] Includes 283 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[i] Includes 565 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 107 mmboe held through BP's interests in Russia other than Rosneft.

[j] Total proved reserves held as part of our equity interest in Rosneft is 8,163 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 62 million barrels of oil equivalent in Venezuela, 3 million barrels of oil equivalent in Vietnam, 35 million barrels of oil equivalent in Egypt and 8,063 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

million barrels
2017

Crude oil[a b]

	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	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
Changes attributable to										
Revisions of previous estimates	15	—	208	5	1	35	—	407	2	673
Improved recovery	—	—	12	—	—	2	—	—	—	14
Purchases of reserves-in-place	3	—	1	—	—	1	—	—	—	5
Discoveries and extensions	—	—	12	—	—	—	—	42	—	53
Production[d]	(29)	—	(131)	(7)	(5)	(88)	—	(119)	(6)	(384)
Sales of reserves-in-place	(9)	—	—	—	—	—	—	—	—	(9)
	(20)	—	101	(2)	(4)	(50)	—	330	(4)	351
At 31 December[e]										
Developed	245	—	932	54	10	281	—	1,040	31	2,592
Undeveloped	164	—	492	195	6	28	—	642	11	1,537
	409	—	1,423	248	16	309	—	1,682	42	4,129
Equity-accounted entities (BP share)[f]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	2	—	—	1	—	102	(1)	—	104
Improved recovery	—	11	—	—	4	—	—	—	—	16
Purchases of reserves-in-place	—	34	—	—	—	—	37	—	—	71
Discoveries and extensions	—	1	—	—	22	—	264	—	—	288
Production	—	(11)	—	—	(28)	—	(325)	(36)	—	(401)
Sales of reserves-in-place	—	(5)	—	—	(98)	—	—	—	—	(103)
	—	31	—	—	(98)	—	78	(37)	—	(25)
At 31 December[g]										
Developed	—	56	—	—	285	1	3,124	6	—	3,473
Undeveloped	—	89	—	—	263	—	2,251	—	—	2,603
	—	145	—	—	548	1	5,374	6	—	6,076
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	245	56	932	54	295	282	3,124	1,047	31	6,064
Undeveloped	164	89	492	195	269	28	2,251	642	11	4,140

409	145	1,423	249	564	310	5,374	1,688	42	10,205

[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] Includes 5 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 337 million barrels of crude oil in respect of the 6.31% non-controlling interest in Rosneft, including 6 mmbbl held through BP's equity-accounted interest in Taas-Yuryakh Neftegazodobycha.
[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 5,402 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 59 million barrels in Venezuela and 5,342 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas liquids[a b]

million barrels
2017

	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	13	—	226	—	5	13	—	—	9	266
Undeveloped	3	—	73	—	28	1	—	—	2	107
	16	—	299	—	33	14	—	—	11	373
Changes attributable to										
Revisions of previous estimates	2	—	(44)	—	—	11	—	—	(4)	(36)
Improved recovery	—	—	15	—	—	—	—	—	—	15
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	1	—	—	—	—	—	—	1
Production[c]	(3)	—	(24)	—	(3)	(4)	—	—	(1)	(35)
Sales of reserves-in-place	(1)	—	—	—	—	—	—	—	—	(1)
	(2)	—	(52)	—	(3)	7	—	—	(5)	(55)
At 31 December[d]										
Developed	11	—	177	—	2	21	—	—	5	216
Undeveloped	3	—	69	—	28	—	—	—	1	102
	14	—	246	—	30	21	—	—	6	318
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	—	3	—	—	—	11	50	—	—	65
Undeveloped	—	2	—	—	—	—	15	—	—	17
	—	5	—	—	—	11	65	—	—	81
Changes attributable to										
Revisions of previous estimates	—	—	—	—	—	1	68	—	—	69
Improved recovery	—	1	—	—	—	—	—	—	—	1
Purchases of reserves-in-place	—	2	—	—	—	—	—	—	—	2
Discoveries and extensions	—	—	—	—	—	—	—	—	—	—
Production	—	(1)	—	—	—	(1)	(2)	—	—	(4)
Sales of reserves-in-place	—	—	—	—	—	—	—	—	—	—
	—	3	—	—	—	(1)	66	—	—	68
At 31 December[f]										
Developed	—	4	—	—	—	10	82	—	—	97
Undeveloped	—	4	—	—	—	—	49	—	—	53
	—	8	—	—	—	10	131	—	—	149
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	11	4	177	—	2	31	82	—	5	313

Undeveloped	3	4	69	—	28	—	49	—	1	154
	14	8	246	—	30	31	131	—	6	467

[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 2 thousand barrels per day for equity-accounted entities.

[d] Includes 9 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 131 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 131 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]										2017
	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	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
Changes attributable to										
Revisions of previous estimates	17	—	164	5	1	45	—	407	(2)	637
Improved recovery	—	—	27	—	—	2	—	—	—	29
Purchases of reserves-in-place	3	—	1	—	—	1	—	—	—	5
Discoveries and extensions	—	—	12	—	—	—	—	42	—	54
Production[d]	(32)	—	(155)	(7)	(8)	(92)	—	(119)	(7)	(419)
Sales of reserves-in-place	(10)	—	—	—	—	—	—	—	—	(10)
	(22)	—	49	(2)	(7)	(43)	—	330	(9)	296
At 31 December[e]										
Developed	256	—	1,108	54	12	301	—	1,040	36	2,808
Undeveloped	167	—	561	195	34	28	—	642	12	1,639
	424	—	1,669	248	46	329	—	1,682	48	4,447
Equity-accounted entities (BP share)[f]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	2	—	—	1	1	170	(1)	—	174
Improved recovery	—	13	—	—	4	—	—	—	—	17
Purchases of reserves-in-place	—	36	—	—	—	—	37	—	—	72
Discoveries and extensions	—	1	—	—	22	—	264	—	—	288
Production	—	(12)	—	—	(28)	(2)	(327)	(36)	—	(405)
Sales of reserves-in-place	—	(6)	—	—	(98)	—	—	—	—	(104)
	—	34	—	—	(98)	(1)	144	(37)	—	43
At 31 December[g h]										
Developed	—	60	—	—	285	11	3,206	6	—	3,569
Undeveloped	—	93	—	—	263	—	2,300	—	—	2,656
	—	153	—	—	548	12	5,505	6	—	6,225
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										
Developed	256	60	1,108	54	297	313	3,206	1,047	36	6,377
Undeveloped	167	93	561	195	297	28	2,300	642	12	4,295

424	153	1,669	249	594	341	5,505	1,688	48	10,672

[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] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 2 thousand barrels per day for equity-accounted entities.
[e] Also includes 14 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 338 million barrels in respect of the non-controlling interest in Rosneft, including 6 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 5,533 million barrels, comprising less than 1 million barrels in Canada, 59 million barrels in Venezuela, less than 1 million barrels in Vietnam and 5,473 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas[a b]									billion cubic feet 2017	
	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	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
Changes attributable to										
Revisions of previous estimates	50	—	(38)	3	(677)	(450)	—	258	(129)	(983)
Improved recovery	—	—	1,002	—	—	1	—	6	—	1,009
Purchases of reserves-in-place	25	—	—	—	—	527	—	—	—	552
Discoveries and extensions	—	—	10	—	829	14	—	1,229	—	2,082
Production[c]	(77)	—	(664)	(3)	(714)	(380)	—	(152)	(291)	(2,281)
Sales of reserves-in-place	(4)	—	—	—	—	—	—	—	—	(4)
	(5)	—	309	—	(562)	(288)	—	1,342	(420)	376
At 31 December[d]										
Developed	523	—	5,238	(1)	2,862	1,159	—	2,755	2,730	15,266
Undeveloped	320	—	3,086	—	3,330	1,510	—	4,245	1,505	13,997
	843	—	8,323	(1)	6,193	2,670	—	7,000	4,235	29,263
Equity-accounted entities (BP share)[e]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	19	—	—	47	5	1,556	(2)	—	1,625
Improved recovery	—	37	—	—	55	—	—	—	—	92
Purchases of reserves-in-place	—	39	—	—	—	237	10	—	—	286
Discoveries and extensions	—	1	—	—	67	—	324	—	—	392
Production[c]	—	(19)	—	—	(178)	(32)	(488)	(8)	—	(726)
Sales of reserves-in-place	—	(6)	—	—	(347)	—	—	—	—	(353)
	—	70	—	—	(356)	210	1,403	(10)	—	1,316
At 31 December[f g]										
Developed	—	112	—	—	1,274	476	6,077	17	—	7,955
Undeveloped	—	69	—	—	450	146	7,173	3	—	7,841
	—	180	—	—	1,724	622	13,250	20	—	15,796
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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
At 31 December										

Developed	523	112	5,238	—	4,136	1,635	6,077	2,771	2,730	23,221
Undeveloped	320	69	3,086	—	3,781	1,656	7,173	4,249	1,505	21,838
	843	180	8,323	—	7,917	3,291	13,250	7,020	4,235	45,060

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Includes 180 billion cubic feet of natural gas consumed in operations, 131 billion cubic feet in subsidiaries, 49 billion cubic feet in equity-accounted entities.
[d] Includes 1,860 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 306 billion cubic feet of natural gas in respect of the 2.30% non-controlling interest in Rosneft including 2 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 13,522 billion cubic feet, comprising 0 billion cubic feet in Canada, 28 billion cubic feet in Venezuela, 19 billion cubic feet in Vietnam, 237 billion cubic feet in Egypt and 13,237 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent [c]

Total hydrocarbons[a b]									2017	
	Europe		North America		South America	Africa	Asia		Australia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	25	—	157	5	(116)	(32)	—	451	(24)	467
Improved recovery	—	—	200	—	—	2	—	1	—	203
Purchases of reserves-in-place	8	—	1	—	—	92	—	—	—	100
Discoveries and extensions	—	—	14	—	143	3	—	254	—	413
Production[e f]	(45)	—	(270)	(8)	(131)	(157)	—	(145)	(57)	(812)
Sales of reserves-in-place	(11)	—	—	—	—	—	—	—	—	(11)
	(23)	—	102	(2)	(104)	(93)	—	562	(81)	361
At 31 December[g]										
Developed	347	—	2,011	54	505	501	—	1,515	507	5,440
Undeveloped	222	—	1,093	195	608	288	—	1,374	272	4,052
	569	—	3,104	248	1,114	790	—	2,889	779	9,492
Equity-accounted entities (BP share)[h]										
At 1 January										
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
Changes attributable to										
Revisions of previous estimates	—	5	—	—	9	2	439	(1)	—	454
Improved recovery	—	19	—	—	14	—	—	—	—	33
Purchases of reserves-in-place	—	42	—	—	—	41	38	—	—	122
Discoveries and extensions	—	1	—	—	34	—	320	—	—	355
Production[e]	—	(15)	—	—	(58)	(7)	(411)	(38)	—	(530)
Sales of reserves-in-place	—	(7)	—	—	(158)	—	—	—	—	(165)
	—	46	—	—	(159)	35	386	(39)	—	269
At 31 December[i j]										
Developed	—	80	—	—	505	93	4,254	9	—	4,941
Undeveloped	—	105	—	—	341	25	3,536	1	—	4,008
	—	184	—	—	846	119	7,790	10	—	8,949
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
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

At 31 December										
Developed	347	80	2,011	54	1,010	595	4,254	1,524	507	10,381
Undeveloped	222	105	1,093	195	949	314	3,536	1,374	272	8,060
	569	184	3,104	249	1,959	908	7,790	2,899	779	18,441

[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] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 2 thousand barrels per day for equity-accounted entities.
[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 23 million barrels of oil equivalent in subsidiaries, 8 million barrels of oil equivalent in equity-accounted entities.
[g] Includes 335 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[i] Includes 391 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft, including 7 mmboe held through BP's equity accounted interest in Taas-Yuryakh Neftegazodobycha.
[j] Total proved reserves held as part of our equity interest in Rosneft is 7,864 million barrels of oil equivalent, comprising less than 1 million barrels of oil equivalent in Canada, 64 million barrels of oil equivalent in Venezuela, 3 million barrels of oil equivalent in Vietnam, 41 million barrels of oil equivalent in Egypt and 7,755 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil[a b]									million barrels 2016	
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia[d]		
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
Discoveries and extensions	—	—	—	—	16	—	285	—	—	301
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 6 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.

Movements in estimated net proved reserves – continued

Natural gas liquids[a b]									million barrels 2016	
	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	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.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]

2016

	Europe		North America		South America	Africa	Asia		Australia	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
Purchases of reserves-in-place	—	122	—	—	36	—	456	—	—	614
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 6 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.

Movements in estimated net proved reserves – continued

Natural gas[a b]

billion cubic feet
2016

	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	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 1 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.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a] [b]

2016

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	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 6 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.

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 2018
	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]	39,700	—	160,000	4,100	17,500	30,400	—	147,500	30,000	429,200
Future production cost[b]	15,000	—	57,600	3,400	7,200	8,500	—	55,800	7,600	155,100
Future development cost[b]	2,100	—	17,800	1,100	2,800	2,600	—	16,400	2,500	45,300
Future taxation[c]	8,900	—	16,600	—	3,200	5,300	—	51,100	6,900	92,000
Future net cash flows	13,700	—	68,000	(400)	4,300	14,000	—	24,200	13,000	136,800
10% annual discount[d]	5,000	—	29,900	(200)	700	3,300	—	9,400	5,800	53,900
Standardized measure of discounted future net cash flows[e f]	8,700	—	38,100	(200)	3,600	10,700	—	14,800	7,200	82,900
Equity-accounted entities (BP share)[g]										
Future cash inflows[a]	—	12,800	—	—	38,500	—	356,800	—	—	408,100
Future production cost[b]	—	4,200	—	—	16,100	—	232,100	—	—	252,400
Future development cost[b]	—	800	—	—	3,600	—	19,300	—	—	23,700
Future taxation[c]	—	5,900	—	—	4,400	—	24,000	—	—	34,300
Future net cash flows	—	1,900	—	—	14,400	—	81,400	—	—	97,700
10% annual discount[d]	—	600	—	—	8,500	—	48,100	—	—	57,200
Standardized measure of discounted future net cash flows[h i]	—	1,300	—	—	5,900	—	33,300	—	—	40,500
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	8,700	1,300	38,100	(200)	9,500	10,700	33,300	14,800	7,200	123,400

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
	(18,800)	(8,000)	(26,800)

Sales and transfers of oil and gas produced, net of production costs			
Development costs for the current year as estimated in previous year	8,500	4,300	12,800
Extensions, discoveries and improved recovery, less related costs	5,800	3,500	9,300
Net changes in prices and production cost	41,000	15,800	56,800
Revisions of previous reserves estimates	(2,100)	2,100	—
Net change in taxation	(17,000)	(7,600)	(24,600)
Future development costs	1,000	(3,500)	(2,500)
Net change in purchase and sales of reserves-in-place	7,600	400	8,000
Addition of 10% annual discount	5,200	3,100	8,300
Total change in the standardized measure during the year[j]	31,200	10,100	41,300

[a] The marker prices used were Brent $71.43/bbl, Henry Hub $3.10/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.

[f] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,100 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 $2,500 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.

[i] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within ‘Net changes in prices and production cost’.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves – continued

										$ million 2017
	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]	26,300	—	99,200	7,100	15,200	27,000	—	118,800	26,200	319,800
Future production cost[b]	13,800	—	46,700	4,100	7,100	8,600	—	52,600	8,400	141,300
Future development cost[b]	1,700	—	12,100	1,100	2,400	3,400	—	18,200	3,200	42,100
Future taxation[c]	4,200	—	6,500	—	1,700	3,800	—	33,200	4,800	54,200
Future net cash flows	6,600	—	33,900	1,900	4,000	11,200	—	14,800	9,800	82,200
10% annual discount[d]	2,100	—	13,100	1,100	500	3,400	—	5,500	4,800	30,500
Standardized measure of discounted future net cash flows[e]	4,500	—	20,800	800	3,500	7,800	—	9,300	5,000	51,700
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	—	9,000	—	—	32,900	—	205,100	400	—	247,400
Future production cost[b]	—	4,100	—	—	15,500	—	114,900	300	—	134,800
Future development cost[b]	—	800	—	—	3,400	—	17,600	100	—	21,900
Future taxation[c]	—	3,100	—	—	3,100	—	12,400	—	—	18,600
Future net cash flows	—	1,000	—	—	10,900	—	60,200	—	—	72,100
10% annual discount[d]	—	400	—	—	6,400	—	34,900	—	—	41,700
Standardized measure of discounted future net cash flows[g h]	—	600	—	—	4,500	—	25,300	—	—	30,400
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	4,500	600	20,800	800	8,000	7,800	25,300	9,300	5,000	82,100

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	(12,800)	(5,500)	(18,300)
Development costs for the current year as estimated in previous year	9,800	4,200	14,000
Extensions, discoveries and improved recovery, less related costs	2,300	1,300	3,600
Net changes in prices and production cost	33,100	7,300	40,400
Revisions of previous reserves estimates	2,800	1,000	3,800
Net change in taxation	(12,500)	(1,500)	(14,000)
Future development costs	3,000	(4,600)	(1,600)
Net change in purchase and sales of reserves-in-place	800	(600)	200
Addition of 10% annual discount	2,300	2,600	4,900
	28,800	4,200	33,000

Total change in the standardized measure during the year[i]

[a] The marker prices used were Brent $54.36/bbl, Henry Hub $2.96/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 $1,100 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 $1,963 million in Russia.

[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[i] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within ‘Net changes in prices and production cost’.

Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves – continued

										$ million 2016
	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]	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 to US dollars are included within ‘Net changes in prices and production cost’.

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 2018, 2017 and 2016.

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	
2018	101	—	385	24	7	204	—	313	17	1,051
2017	80	—	370	20	12	241	—	325	17	1,064
2016	79	24	335	13	10	263	—	204	16	943
Natural gas liquids									thousand barrels per day	
2018	5	—	60	—	9	11	—	—	2	88
2017	6	—	56	—	10	10	—	—	2	85
2016	6	4	56	—	8	5	—	—	3	82
Natural gas[g]									million cubic feet per day	
2018	152	—	1,900	7	2,136	1,061	—	826	819	6,900
2017	182	—	1,659	9	1,936	949	—	371	783	5,889
2016	170	82	1,656	10	1,689	513	—	363	820	5,302
Equity-accounted entities (BP share)										
Crude oil[f]									thousand barrels per day	
2018	—	34	—	—	55	1	933	16	—	1,040
2017	—	31	—	—	63	1	905	99	—	1,099
2016	—	7	—	—	65	—	840	102	—	1,015
Natural gas liquids									thousand barrels per day	
2018	—	2	—	—	—	6	4	—	—	12
2017	—	2	—	—	—	6	4	—	—	12
2016	—	—	—	—	1	4	4	—	—	8
Natural gas[g]									million cubic feet per day	
2018	—	59	—	—	335	80	1,286	—	—	1,760
2017	—	53	—	—	418	77	1,308	—	—	1,855

2016	—	12	—	—	449	18	1,279	15	—	1,773

[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.

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 2018. 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[b]
		UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Number of productive wells at 31 December 2018											
Oil wells[c]	– gross	116	74	2,677	169	5,356	695	66,147	1,979	12	77,225
	– net	69	22	1,097	45	2,437	466	13,151	445	2	17,734
Gas wells[d]	– gross	34	1	20,565	244	1,069	209	512	102	78	22,814
	– net	5	—	10,602	121	379	89	114	45	16	11,371
Oil and natural gas acreage at 31 December 2018										thousands of acres	
Developed	– gross	81	57	6,263	147	1,336	868	6,751	1,290	173	16,966
	– net	46	17	3,683	64	355	345	1,297	272	41	6,120
Undeveloped[e]	– gross	3,067	180	5,012	17,110	19,890	52,698	431,130	8,586	4,022	541,695
	– net	1,861	54	3,700	8,750	6,469	36,504	86,045	2,357	1,889	147,629

a Based on information received from Rosneft as at 31 December 2018.

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

c Includes approximately 7,381 gross (1,447 net) multiple completion wells (more than one formation producing into the same well bore).

d Includes approximately 2,768 gross (1,407 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		
2018										
Exploratory										
Productive	0.3	—	1.7	—	2.0	—	15.0	5.0	—	24.0
Dry	—	—	—	0.5	2.0	2.4	—	—	—	4.9
Development										

Productive	1.4	0.6	142.7	5.0	103.9	14.4	137.3	53.5	1.3	460.1
Dry	—	—	6.8	—	3.6	—	—	2.6	—	13.0
2017										
Exploratory										
Productive	2.8	0.1	1.5	1.2	3.2	2.6	9.4	1.4	—	22.2
Dry	2.4	—	—	—	—	2.9	—	1.0	—	6.3
Development										
Productive	2.5	0.5	124.0	8.0	103.7	16.5	282.7	43.6	1.1	582.6
Dry	—	—	0.5	—	1.6	2.1	—	0.8	—	5.0
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

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

Operational and statistical information – continued

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 2018. 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 2018										
Exploratory										
Gross	—	0.9	5.0	—	3.0	3.0	—	3.0	—	14.9
Net	—	0.3	2.9	—	0.8	1.3	—	3.0	—	8.3
Development										
Gross	9.0	4.6	147.0	5.0	11.0	18.0	—	108.0	—	302.6
Net	2.9	1.4	80.5	2.5	5.0	9.2	—	19.0	—	120.5

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

Pages 238-271 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 has been extracted or derived from the audited consolidated financial statements of the BP group. 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. The audited consolidated financial statements and related notes as of 31 December 2018 and 2017 and for the three years ended 31 December 2018 are presented on page 126.

	$ million except per share amounts				
	2018	2017	2016	2015	2014
Income statement data					
Sales and other operating revenues	298,756	240,208	183,008	222,894	353,568
Profit (loss) before interest and taxation	19,378	9,474	(430)	(7,918)	6,412
Finance costs and net finance expense relating to pensions and other post-retirement benefits	(2,655)	(2,294)	(1,865)	(1,653)	(1,462)
Taxation	(7,145)	(3,712)	2,467	3,171	(947)
Non-controlling interests	(195)	(79)	(57)	(82)	(223)
Profit (loss) for the year[a]	9,383	3,389	115	(6,482)	3,780
Inventory holding (gains) losses«, before tax	801	(853)	(1,597)	1,889	6,210
Taxation charge (credit) on inventory holding gains and losses	(198)	225	483	(569)	(1,917)
RC profit (loss)«for the year	9,986	2,761	(999)	(5,162)	8,073
Net (favourable) adverse impact of non-operating items« and fair value accounting effects«, before tax[b]	3,380	3,730	6,746	15,067	8,234
Taxation charge (credit) on non-operating items and fair value accounting effects	(643)	(325)	(3,162)	(4,000)	(4,171)
Underlying RC profit«for the year	12,723	6,166	2,585	5,905	12,136
Earnings per share[c] – cents					
Profit (loss) for the year[a] per ordinary share					
Basic	46.98	17.20	0.61	(35.39)	20.55
Diluted	46.67	17.10	0.60	(35.39)	20.42
RC profit (loss) for the year per ordinary share«	50.00	14.02	(5.33)	(28.18)	43.90
Underlying RC profit for the year per ordinary share«	63.70	31.31	13.79	32.22	66.00
Dividends paid per share – cents	40.50	40.00	40.00	40.00	39.00
– pence	30.568	30.979	29.418	26.383	23.850
Capital expenditure«[d]					
Organic capital expenditure«	15,140	16,501	16,675	N/A	N/A
Inorganic capital expenditure«	9,948	1,339	777	N/A	N/A
	25,088	17,840	17,452	20,202	23,192
Balance sheet data (at 31 December)					
Total assets	282,176	276,515	263,316	261,832	284,305
Net assets	101,548	100,404	96,843	98,387	112,642
Share capital	5,402	5,343	5,284	5,049	5,023
BP shareholders' equity	99,444	98,491	95,286	97,216	111,441
Finance debt due after more than one year	56,426	55,491	51,666	46,224	45,977
Net debt to net debt plus equity«	30.3%	27.4%	26.8%	21.6%	16.7%
Ordinary share data[e]	Share million				
Basic weighted average number of shares	19,970	19,693	18,745	18,324	18,385
Diluted weighted average number of shares	20,102	19,816	18,855	18,324	18,497

[a] Profit attributable to BP shareholders.

[b] See pages 276 and 320 for further analysis of these items.

[c] A reconciliation to GAAP information is provided on page 320.

[d]

From 2017 onwards BP reports organic, inorganic and total capital expenditure on a cash basis which were previously reported on an accruals basis. This aligns with BP's financial framework and is consistent with other financial metrics used when comparing sources and uses of cash. An analysis of capital expenditure on a cash basis for 2015 and 2014 is not available.

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

Additional information

Capital expenditure

	2018	2017	2016
			$ million
Capital expenditure			
Organic capital expenditure	15,140	16,501	16,675
Inorganic capital expenditure[a]	9,948	1,339	777
	25,088	17,840	17,452

	2018	2017	2016
			$ million
Organic capital expenditure by segment			
Upstream			
US	3,482	2,999	3,415
Non-US	8,545	10,764	10,929
	12,027	13,763	14,344
Downstream			
US	877	809	774
Non-US	1,904	1,590	1,328
	2,781	2,399	2,102
Other businesses and corporate			
US	54	64	32
Non-US	278	275	197
	332	339	229
	15,140	16,501	16,675
Organic capital expenditure by geographical area			
US	4,413	3,872	4,221
Non-US	10,727	12,629	12,454
	15,140	16,501	16,675

[a] On 31 October 2018, BP acquired from BHP Billiton Petroleum (North America) Inc. 100% of the issued share capital of Petrohawk Energy Corporation, a wholly owned subsidiary of BHP that holds a portfolio of unconventional onshore US oil and gas assets. As at 31 December 2018, $6,788 million of the consideration had been paid. 2018 includes $1,739 million relating to the purchase of an additional 16.5% interest in the Clair field west of Shetland in the North Sea, as part of the agreements with ConocoPhillips in which ConocoPhillips simultaneously purchased BP's entire 39.2% interest in the Greater Kuparuk Area on the North Slope of Alaska. 2018 also includes amounts relating to the 25-year extension to our ACG production-sharing agreement« in Azerbaijan. 2017 includes amounts paid to acquire interests in Mauritania and Senegal and in the Zohr gas field in Egypt.

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
	2018	2017	2016
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a b]	(90)	(563)	2,391
Environmental and other provisions	(35)	1	(8)
Restructuring, integration and rationalization costs[c]	(131)	(24)	(373)
Fair value gain (loss) on embedded derivatives	17	33	32
Other[b d]	56	(118)	(289)
	(183)	(671)	1,753
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a e]	(54)	579	405
Environmental and other provisions	(83)	(19)	(73)
Restructuring, integration and rationalization costs[c]	(405)	(171)	(300)
Fair value gain (loss) on embedded derivatives	—	—	—
Other	(174)	—	(56)
	(716)	389	(24)
Rosneft			
Impairment and gain (loss) on sale of businesses and fixed assets	(95)	—	62
Environmental and other provisions	—	—	—
Restructuring, integration and rationalization costs	—	—	—
Fair value gain (loss) on embedded derivatives	—	—	—
Other	—	—	(39)
	(95)	—	23
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	(260)	(22)	—
Environmental and other provisions[f]	(640)	(156)	(134)
Restructuring, integration and rationalization costs[c]	(190)	(72)	(90)
Fair value gain (loss) on embedded derivatives	—	—	—
Gulf of Mexico oil spill response[g]	(714)	(2,687)	(6,640)
Other	(159)	90	(55)
	(1,963)	(2,847)	(6,919)
Total before interest and taxation	(2,957)	(3,129)	(5,167)
Finance costs[g]	(479)	(493)	(494)
Total before taxation	(3,436)	(3,622)	(5,661)
Taxation credit (charge) on non-operating items[h]	510	1,172	2,833
Taxation - impact of US tax reform[i]	121	(859)	—
Total after taxation	(2,805)	(3,309)	(2,828)

[a] See Financial statements – Note 4 for further information.

[b] 2018 includes an impairment reversal for assets in the North Sea and Angola. 2017 includes an impairment charge relating to BPX Energy (previously known as the US Lower 48 business), partially offset by gains associated with asset divestments. In addition, 2017 includes an impairment charge arising following the announcement of the agreement to sell the Forties Pipeline System business to INEOS. 2016 includes a $319-million exploration write-back relating to Block KG D6 in India. In addition, an impairment reversal of $234 million was also recorded in relation to this block.

[c]

Restructuring charges are classified as non-operating items where they relate to an announced major group restructuring. A major group restructuring is a restructuring programme affecting more than one of the group's operating segments that is expected to result in charges of more than $1 billion over a defined period. Following the Gulf of Mexico oil spill in 2010 and since the fall in oil prices in late 2014, major group restructuring programmes were initiated.The group's restructuring programme, originally announced in 2014, has now been completed.

d 2018 and 2017 include exploration write-offs of $124 million and $145 million respectively in relation to the value ascribed to certain licences in the deepwater Gulf of Mexico as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011. 2017 also includes BP's share of an impairment reversal recognized by the Angola LNG equity-accounted entity, partially offset by other items. 2016 includes the write-off of $334 million in relation to the value ascribed to the licence in Brazil as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011.

e 2017 primarily reflects the disposal of our shareholding in the SECCO joint venture.

f 2018 primarily reflects charges due to the annual update of environmental provisions, including asbestos-related provisions for past operations, together with updates of non-Gulf of Mexico oil spill related legal provisions.

g See Financial statements – Note 2 for further details regarding costs relating to the Gulf of Mexico oil spill.

h 2017 includes the tax effect of the increase in the provision in the fourth quarter for business economic loss and other claims associated with the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) at the new US tax rate.

i In 2017 the US tax reform reduced the US federal corporate income tax rate from 35% to 21%, effective from 1 January 2018. The impact disclosed has been calculated as the change in deferred tax balances at 31 December 2017, excluding the increase in the provision in the fourth quarter for business economic loss and other claims associated with the DHCSSP, which arises following the reduction in the tax rate. 2018 reflects a further impact following a clarification of the tax reform. The impact of the US tax reform has been treated as a non-operating item because it is not considered to be part of underlying business operations, has a material impact upon the reported result and is substantially impacted by Gulf of Mexico oil spill charges, which are also treated as non-operating items. Separate disclosure is considered meaningful and relevant to investors.

Liquidity and capital resources
Financial framework
BP's financial framework sets a number of parameters in support of growing shareholder value, distributions and returns, while maintaining a strong balance sheet. BP's objective over time is to grow sustainable free cash flow« through a combination of operating cash flow« growth and capital discipline, in service of growing shareholder distributions over the long term.
We maintain our progressive dividend policy and the commitment to the share buyback programme and expect the impact of the scrip dilution since the third quarter of 2017 to be fully offset by the end of 2019. The shape of the buyback programme will reflect ongoing consideration of factors including changes in the environment, the underlying performance of the business, the outlook for the group financial framework, and other market factors which may vary quarter to quarter.
We expect operating cash flow excluding amounts relating to the Gulf of Mexico oil spill to continue to cover organic capital expenditure« of $15-17 billion and the full dividend« (including scrip) at around $50 per barrel. Looking further out, this balancing point is expected to steadily reduce to $35-40 per barrel by 2021, with organic capital expenditure in a range of $15-17 billion per year. In a constant price environment, surplus organic free cash flow« is expected to grow and be used to ensure the right balance between deleveraging the balance sheet, growing distributions and disciplined investment, depending on the context and outlook at the time.
Gulf of Mexico oil spill payments were just over $3 billion in 2018, are expected to step down to around $2 billion in 2019 and around $1 billion per annum thereafter. Over the next two years we plan to complete more than $10 billion of divestments and we expect divestment proceeds« subsequently to revert to the historical norm of around $2-3 billion per annum.
We continue to target a gearing« band on a pre-IFRS 16 basis of 20-30%, while maintaining strong liquidity and debt market access. Payments for the acquisition of BHP's onshore US assets using available cash moved gearing to 30.3% at the end of 2018. Gearing is expected to move towards the middle of the band in 2020 in line with the generation of free cash flow and receipt of disposal proceeds.
In 2018, the return on average capital employed« was 11.2%[a] at an average of $71 per barrel. At $55 per barrel real, return on average capital employed is targeted to improve to over 10% by 2021, as we continue to grow our underlying business.
[a] Nearest equivalent GAAP measures: Numerator – Profit attributable to BP shareholders $9.4 billion; Denominator – Average capital employed $165.5 billion.
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 10.25 cents per share from the third quarter of 2018 (2017 10 cents per share).
The total dividend distributed to BP shareholders in 2018 was $8.1 billion (2017 $7.9 billion). Shareholders have the option to receive a scrip dividend in place of receiving cash. In 2018 the total dividend paid in cash was $6.7 billion (2017 $6.2 billion).
Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 312. The share buyback programme to offset the dilutive impact of the scrip dividend purchased 50 million ordinary shares in 2018 at a cost of $355 million, including fees and stamp duty.
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. 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 cash or borrowings. Also see Risk factors on page 55 for further information on risks associated with prices and markets and Financial statements – Note 29.

The group's gross debt at 31 December 2018 amounted to $65.8 billion (2017 $63.2 billion). Of the total gross debt, $9.4 billion is classified as short term at the end of 2018 (2017 $7.7 billion). See Financial statements – Note 26 for more information on the short-term balance. Net debt« was $44.1 billion at the end of 2018, an increase of $6.3 billion from the 2017 year-end position of $37.8 billion.

The ratio of gross debt to gross debt plus equity at 31 December 2018 was 39.3% (2017 38.6%). The ratio of net debt to net debt plus equity« was 30.3% at the end of 2018 (2017 27.4%). See Financial statements – Note 27 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Cash and cash equivalents of $22.5 billion at 31 December 2018 (2017 $25.6 billion) are included in net debt. We manage our cash position to ensure the group has adequate cover to respond to potential short-term market illiquidity, and expect to maintain a robust cash position.

The group also has undrawn committed bank facilities of $7.6 billion (see Financial statements – Note 29 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 its ongoing ability to generate cash.

BP utilizes various arrangements in order to manage its working capital including discounting of receivables and, in the supply and trading business, the active management of supplier payment terms, inventory and collateral.

Standard & Poor's Ratings' long-term credit rating for BP is A- (stable outlook) and the Moody's Investors Service rating is A1 (stable outlook).

The group's sources of funding, its access to capital markets and maintaining a strong cash position are described in Financial statements – Note 25 and Note 29. On 14 December 2018, BP completed the exchange of $10.5 billion of notes previously issued by BP Capital Markets p.l.c for new notes issued by BP Capital Markets America Inc. in order to optimize the BP group's capital structure and align revenue generation to indebtedness. 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 26 and Note 29.

Off-balance sheet arrangements

At 31 December 2018, the group's share of third-party finance debt of equity-accounted entities was $16.1 billion (2017 $18.0 billion). These amounts are not reflected in the group's debt on the balance sheet. The group has issued third-party guarantees under which amounts outstanding, incremental to amounts recognized on the balance sheet, at 31 December 2018 were $696 million (2017 $656 million) in respect of liabilities of joint ventures«and associates«and $432 million (2017 $382 million) in respect of liabilities of other third parties. Of these amounts, $684 million (2017 $645 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $423 million (2017 $350 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 28.

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 303 and Risk factors on page 55, 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.

Contractual obligations

The following table summarizes the group’s capital expenditure commitments for property, plant and equipment at 31 December 2018 and the proportion of that expenditure for which contracts have been placed.

	$ million						
	Payments due by period						
Capital expenditure	Total	2019	2020	2021	2022	2023	2024 and thereafter
Committed	26,378	12,749	5,689	3,456	1,653	1,001	1,830
of which is contracted	8,319	5,646	1,742	528	157	53	193

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 2018, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $1,411 million. Contracts were in place for $1,170 million of this total.

The following table summarizes the group’s principal contractual obligations at 31 December 2018, 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 26 and more information on operating leases is given in Financial statements – Note 28.

							$ million
							Payments due by period
Expected payments by period under contractual obligations	Total	2019	2020	2021	2022	2023	2024 and thereafter
Balance sheet obligations							
Borrowings[a]	74,587	11,607	8,646	8,410	9,385	8,110	28,429
Finance lease future minimum lease payments[b]	1,350	98	97	95	94	86	880
Decommissioning liabilities[c]	23,807	290	169	107	339	96	22,806
Environmental liabilities[c]	1,663	300	303	219	173	136	532
Gulf of Mexico oil spill liabilities[d]	18,360	2,302	1,569	1,343	1,267	1,219	10,660
Pensions and other post-retirement benefits[e]	19,114	1,237	1,211	1,149	1,084	1,067	13,366
	138,881	15,834	11,995	11,323	12,342	10,714	76,673
Off-balance sheet obligations							
Operating lease future minimum lease payments[f]	11,979	2,511	1,875	1,446	1,124	914	4,109
Unconditional purchase obligations[g]	144,660	69,676	16,422	11,479	8,326	6,715	32,042
	156,639	72,187	18,297	12,925	9,450	7,629	36,151
Total	295,520	88,021	30,292	24,248	21,792	18,343	112,824

a Expected payments include interest totalling $10,646 million ($2,350 million in 2019, $1,904 million in 2020, $1,653 million in 2021, $1,379 million in 2022, $1,101 million in 2023 and $2,259 million thereafter).

b Expected payments include interest totalling $683 million ($54 million in 2019, $51 million in 2020, $47 million in 2021, $43 million in 2022, $37 million in 2023 and $451 million thereafter).

c The amounts presented 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 2019 include purchase commitments existing at 31 December 2018 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 29.

The following table summarizes the nature of the group's unconditional purchase obligations.

							$ million
						Payments due by period	
Unconditional purchase obligations	Total	2019	2020	2021	2022	2023	2024 and thereafter
Crude oil and oil products	62,801	43,265	6,395	4,679	2,769	2,356	3,337
Natural gas	27,642	14,916	4,922	2,880	2,325	1,555	1,044
Chemicals and other refinery feedstocks	6,715	4,857	923	298	291	118	228
Power	5,573	3,296	1,087	494	158	113	425
Utilities	1,037	163	138	80	64	64	528
Transportation	21,682	1,740	1,480	1,580	1,412	1,412	14,058
Use of facilities and services	19,210	1,439	1,477	1,468	1,307	1,097	12,422
Total	144,660	69,676	16,422	11,479	8,326	6,715	32,042

Upstream analysis by region

Our upstream operations are set out below by geographical area, with associated significant events for 2018. 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 proved reserves and production.

In addition to exploration, development and production activities, our upstream business also includes midstream and liquefied natural gas (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 3.5 million tonnes per annum of our LNG production to IST, which uses contractual rights to access import terminal capacity in the liquid markets of Italy (Rovigo), the Netherlands (Gate), Spain (Bilbao), the UK (the Isle of Grain) and the US (Cove Point), with the remainder marketed directly to customers. LNG is supplied to customers in markets including Argentina, China, the Dominican Republic, India, Japan, Kuwait, South Korea, Taiwan and Thailand.

Europe

BP is active in the North Sea and the Norwegian Sea. In 2018 BP's production came from three key areas: the Shetland area comprising the Clair, Foinaven, Magnus and Schiehallion fields; the central area comprising the Andrew area, Bruce, ETAP, Keith, Kinnoull and Rhum fields; and Norway, through our equity accounted 30% interest in Aker BP.

- In July we announced that we had entered into an agreement with ConocoPhillips to increase our holding in the Clair field (prior to the increase BP 29% and operator) by 16.5%, while selling our non-operated interest in the Greater Kuparuk Area on the North Slope of Alaska as well as our holding in the Kuparuk Transportation Company. Clair is the largest oilfield on the UK Continental Shelf. The transaction completed in December.
- In September we received approval from the Oil and Gas Authority (OGA) to proceed with the Vorlich development (BP 66% and operator). Located 240 kilometres east of Aberdeen, in the central North Sea, Vorlich will consist of two wells tied back to the existing Ithaca Energy-operated FPF-1 floating production facility. The development is part of a programme of North Sea subsea tie-back developments that seek to access new production from fields located near to established producing infrastructure. The field is expected to come onstream in 2020.
- In October EnQuest notified BP that it would exercise its option to acquire the remaining 75% of BP's stake in the Magnus field and associated infrastructure. The disposal completed at the end of November. EnQuest acquired the initial 25% of BP's interest in the Magnus field and associated infrastructure in December 2017.
- Also in October we received approval from OGA to proceed with the Alligin development (BP 50% and operator). Located 140 kilometres west of Shetland, Alligin is part of the Greater Schiehallion area. We announced our intention to develop it in April. The development will consist of two wells tied back to the existing Schiehallion and Loyal subsea infrastructure, and is expected to come onstream in 2020.
- Development progressed at the Total-operated Culzean field (BP 32%) during the year. The field will be developed with three fixed platforms and a floating storage unit. At the end of 2018, construction activities were complete and the hook-up and commissioning activities were underway, with first production expected in 2019.
- In November 2017 we announced that we had agreed to sell a package of our interests in the North Sea comprising the Bruce (BP 37%), Keith (BP 35%) and Rhum (BP 50%) fields, three bridge-linked platforms and associated subsea infrastructure to Serica

Energy plc. We operated the assets through the year until the sale and transfer of ownership completed at the end of November 2018.

- In November as part of the sale of Rhum to Serica Energy plc the US Office of Foreign Assets Control issued a joint licence to BP and Serica permitting certain US persons and US owned and controlled companies to support Rhum activities in compliance with US primary sanctions and a letter of comfort permitting all non-US persons to support Rhum activities in compliance with US secondary sanctions. The Rhum field is now owned by Serica (50%) and the Iranian Oil Company (U.K.) Limited (IOC, 50%) under a joint operating agreement. The shares in IOC are now held in trust. See International Trade Sanctions on page 298.

- In November we announced the start-up of production at Clair Ridge – the second phase of development at the Clair field. Two new, bridge-linked platforms and oil and gas export pipelines have been constructed as part of the project. The new facilities, which required capital investment in excess of $6 billion, are designed for around 40 years of production.

North America

Our upstream activities in North America are located in five areas: deepwater Gulf of Mexico, the Lower 48 states, Alaska, Canada and Mexico.

BP has around 240 lease blocks in the deepwater Gulf of Mexico and operates four production hubs.

- In October we announced the start-up of the Northwest Expansion project at our Thunder Horse platform, under budget and ahead of schedule. The project, which achieved first oil just 16 months after being sanctioned, adds a new subsea manifold and two wells tied into existing flowlines two miles to the north of the platform. The new project is expected to boost production at Thunder Horse and is the third major field expansion there in recent years.
- We participated in lease sales 250 and 251 during the year, and were awarded 44 leases in total.
- In December BP received approval from the Bureau of Safety Environmental Enforcement of the assignment of Chevron's interest in the Tiber and Guadalupe leases. BP now has a 100% working interest in these leases.
- Exploration write-offs totalling $447 million were recognized in 2018, driven primarily by lease relinquishment ($131 million of this was recognized as a non-operating item).
- In February 2019 we announced the start-up of the Constellation project (BP 66.67%), operated by Anadarko.
- See also Financial statements – Note 1 for further information on exploration leases.

The US Lower 48 onshore new combined business, following acquisition of BHP's unconventional assets (see below), has significant operated and non-operated activities across Colorado, Louisiana, New Mexico, Oklahoma, Texas and Wyoming producing natural gas, oil, NGLs and condensate. It had a 2.4 billion boe proved reserve base as at 31 December 2018, predominantly in unconventional reservoirs (tight gas«, shale gas and coalbed methane, and newly acquired shale oil). This resource spans 3.5 million net developed acres and has approximately 12,000 operated gross wells, with daily net production around 500mboe/d.

Since the beginning of 2015, our US Lower 48 onshore business has operated as a separate business while remaining part of our Upstream segment. With its own governance, systems and processes, it was established to increase competitive performance through swift decision making and innovation, while maintaining BP's commitment to safe, reliable and compliant operations. In October 2018 we announced that we had changed the name of our Lower 48 business to BPX Energy.

- In October we completed the acquisition of BHP's US unconventional assets in a landmark deal that will significantly upgrade our US onshore oil and gas portfolio and help drive long-term growth. The acquisition, which was announced in July, adds oil and gas production of 190mboe/d in the liquids-rich regions of the Permian and Eagle Ford basins in Texas and in the Haynesville natural gas basin in East Texas and Louisiana.

- As part of the BHP acquisition announcement, BPX Energy expects to divest some existing assets to shift the organization's core focus towards the newly-acquired BHP assets. The divestment includes core positions in San Juan, Wamsutter, Anadarko, Arkoma, legacy East Texas and Southwest Oklahoma basins, as well as diversified non-operated royalty and working interests across the US Lower 48.

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 the year. For the past four years BP has slowed decline at Prudhoe Bay through wellwork and improved operating field efficiencies, with production being largely maintained. Infrastructure renewal activities in 2018 included compressor replacements, fire and gas system upgrades, safety system upgrades, pipeline renewal, and facility piping upgrade projects. BP owns significant interests in three producing fields operated by others, as well as a non-operating interest in the Liberty development project and owned significant interests in an additional five producing fields operated by others prior to the sale of our interest in the Greater Kuparuk Area (see below).

- In July we announced the sale of our non-operated 39.2% interest in the Greater Kuparuk Area on the North Slope comprising five fields, as well as our holding in the Kuparuk Transportation Company to ConocoPhillips. The transaction received all regulatory approvals and closed in December, with a retroactive effective date of 1 July 2018.
- In May 2018 BP signed a Gas Sales Precedent Agreement with the Alaska Gas Development Corporation detailing key terms for potential future gas sales to the State. In addition, in September an amendment to the Point Thomson development plan was agreed with the State to better align field milestones to those of the Alaska LNG project.

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 southcentral Alaska. In April 2012 Unocal (1.37%) gave notice to the other TAPS owners of their intention to withdraw as an owner of TAPS. The remaining owners and Unocal have not yet reached agreement regarding the terms for the transfer of Unocal's interest in TAPS.

- In 2017 the parties involved in TAPS tariff matters at the Federal Energy Regulatory Commission (FERC) and the Regulatory Commission of Alaska (RCA) reached an agreement to settle all pending legal challenges involving TAPS interstate rates at FERC for the years 2009-15 and establish a mechanism for calculating interstate rate ceilings for TAPS for the period from 2016 through 2021, as well as subsequent years unless otherwise terminated. The agreement resolved all challenges involving TAPS intrastate rates from 2008 to 2019 and established intrastate rate ceilings for the future through to 30 June 2019. RCA approval was granted in January and FERC approval in February and all associated settlement amounts and tariff refunds were paid.
- In September BP Alaska removed one of its four Alaska grade crude oil tankers from service (the vessel Frontier). Historically, BP Alaska has utilized four tankers to carry crude oil shipments from Alaska. With the reduction in volume over time, as well as new efficiencies identified in the shipping programme, Frontier has been removed from service and its carrying value impaired accordingly.

In Canada BP is focused on oil sands development as well as pursuing offshore exploration opportunities. We utilize in-situ steam-assisted gravity drainage (SAGD) technology in our oil sands developments, 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 lease areas 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 Nova Scotia, Newfoundland and Labrador and the Canadian Beaufort Sea.

- The government of Canada continued with its plans to introduce legislation to allow it to suspend any oil and gas activities in the Beaufort Sea.

In Mexico, we have interests in two exploration joint operations« in the Salina Basin with Equinor and Total, Block 1 (BP 33% and operator) and Block 3 (BP 33%), and in one exploration joint operation in the Sureste Basin with Total and Hokchi, a subsidiary of Pan American Energy Group (PAEG), Block 34 (BP 42.5% and operator). Both Salina Basin operations received exploration plan approval in March from Comisión Nacional de Hidrocarburos (CNH), the Mexican regulator. Seismic interpretation and well pre-spud activities are taking place in 2018 and 2019 with the

tentative plan to commence drilling in the first half of 2020. The Sureste Basin operation submitted an exploration plan for approval to CNH at the end of December.
South America
BP has upstream activities in Brazil and Trinidad & Tobago and through PAEG, in Argentina and Bolivia.
In Brazil BP has interests in 25 exploration concessions across five basins.

- In the North Campos basin, BP was nominated as operator following Anadarko's withdrawal from both the BM-C-30 and BM-C-32 blocks. Regulatory consent is being sought for both Anadarko's exit and the operatorship transfer. The consortium decided not to perform the previously planned extended well test during the year. Instead it elected to finalize the appraisal plans and request a postponement of up to five years to decide whether the projects are commercially feasible. During this period, the consortium will assess alternative development concepts. Approval of this request by the Brazilian National Petroleum Agency (ANP) is still pending.
- BP continues to progress the preparatory activities for drilling exploration wells in the Foz do Amazonas Basin, with a BP-operated well scheduled to start drilling in 2021. An extension request to August 2020 was approved by the ANP regarding the BP-operated Block FZA-M-59. BP is monitoring developments on its other non-operated interests in the Foz de Amazonas basin (BP 30%) to establish an expected drilling activity schedule.
- In the South Campos basin, BP's request for a contract suspension in Block BM-C-35 is under review by the ANP.
- BP won Blocks C-M-755 and C-M-793 at the 15th bid round in March in a consortium with Equinor (BP 60%).
- In June BP won the licence for the Dois Irmãos block located in the Campos basin, offshore Brazil, as a result of the fourth Pre-Salt Production Sharing Contract Bid Round (Petrobras operator 45%, BP 30%, and Equinor 25%).
- BP accessed new acreage in the Santos basin, offshore Brazil in September by winning the licence for the Pau Brasil block (BP 50% and operator). This represents BP's first operated production sharing acreage in the Santos basin.
- In October drilling commenced at the Peroba block (BP 40%). Well results are expected in the first quarter of 2019.

In Argentina and Bolivia BP conducts activity through PAEG, a joint venture that is owned by BP (50%) and Bridas Corporation (50%). PAEG also has activities in Mexico.
In Trinidad & Tobago BP holds exploration and production licences and production-sharing agreements«(PSAs) covering 1.8 million acres offshore of the east and north-east coast. Facilities include 14 offshore platforms and two onshore processing facilities. Production comprises gas and associated liquids.
BP also has a shareholding in the Atlantic LNG liquefaction plant. BP's shareholding averages 39% across four LNG trains« with a combined capacity of 15 million tonnes per annum. We sell gas to train 1, 2 and 3 and process gas in train 4. All LNG from train 1 and most of the LNG from trains 2 and 3 is sold to third parties under

long-term contracts. BP’s LNG entitlement from trains 2, 3 and 4 is marketed to the US, Europe, Asia and South America.

- In December, the Cassia compression project was sanctioned. This project involves the installation of a new compression platform (Cassia C), bridge-linked to the Cassia B processing platform and providing lowered wellhead pressures to fields served by the Cassia hub. The expected project start-up date is 2021.
- Negotiations of three historical upstream commercial issues were completed with the government of the Republic of Trinidad & Tobago at the end of 2018. This resulted in a payment of $144 million representing final settlement.
- The Atlantic LNG Train 1 gas supply contract is currently being negotiated for the period April 2019 to September 2024.
- Discussions are ongoing with partners in the Manakin project on the Unit Operating Agreement (UOA), Field Development Plan and subsurface arrangements following declaration of commerciality in January 2018. The UOA is expected to be agreed in 2019. Manakin, discovered in 1998, is a cross-border field with Venezuela.
- In October the Bongos exploration well in the deepwater Block 14 (BP 30%) was announced as a discovery. Assessment of the well results is currently in progress.
- The Angelin project, sanctioned in June 2017, involves the construction of a new platform, BP’s 15th offshore production facility, 60 kilometres off the south-east coast of Trinidad in water depths of approximately 65 metres. The development includes four wells, with gas from Angelin flowing to the Cassia B hub for processing via a new pipeline to the Serrette platform. During 2018 the jacket and topsides were installed and subsea skid and pipeline installation was also completed. The first well was completed in January 2019 and the project commenced production in February 2019.

Africa

BP’s upstream activities in Africa are located in Algeria, Angola, Côte d'Ivoire, Egypt, Libya, Madagascar, Mauritania, São Tomé & Príncipe and Senegal.

In Algeria BP, Sonatrach and Equinor 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.

- In December 2017 BP and Equinor signed an extension agreement for the In Amenas production sharing contract with Sonatrach, the Algerian state-owned energy company. The agreement was formally ratified in April 2018.

In Angola, BP owns an interest in five major deepwater offshore licences and is operator in two of these, Blocks 18 and 31, that are producing. We also have an equity interest in the Angola LNG plant (BP 13.6%).

- During the year a final investment decision (FID) on Block 17 was made by the operator, Total, to proceed with the Zinia 2 deep offshore development project (BP 16.67%).
- In December, BP announced it had taken the FID to progress the Platina project in Block 18. The agreement also extends the production licence for the Greater Plutonio operation in Block 18 to 2032, and provides for Sonangol to take an 8% equity interest in the block, all subject to government approval.
- The Block 25/11 production sharing agreement expired in January 2019. The remaining intangible asset of $42 million associated with the licence acquisition cost was written off at the start of 2018 as no further drilling activity was planned.

In Côte d’Ivoire, BP has interests in five offshore oil blocks with Kosmos Energy (KE) under agreements with the government of Côte d'Ivoire and the state oil company Société Nationale d'Operations Pétrolières de la Côte d'Ivoire (PETROCI) (BP 45%, KE 45% and operator, PETROCI approximately 10%). New 3D seismic data was acquired during the year and analysis of it is ongoing.

In Egypt, BP and its partners currently produce 10% of Egypt’s liquids« production and over 50% of its gas production.

- The Atoll field in the North Damietta concession came fully onstream at the start of 2018.
- In 2018 exploration write-offs of $236 million were recognized, the most significant being $169 million in connection with withdrawal from the Rahamat lease.
- Following concept sanction in 2017, BP continued progressing the Baltim South West field. Two wells are planned in 2019 followed by further development wells in 2020. A new nine-slot platform will be installed and tied back to existing infrastructure (Abu Madi) through a new offshore and onshore pipeline.

- In December BP announced it had acquired a 25% interest in the Nour North Sinai offshore concession area from Eni. The concession is in the East Nile Delta Basin. Eni, the operator, is currently carrying out drilling of the first exploration well and will remain the operator with a 40% stake in the concession. BP will hold a 25% interest, Mubadala Petroleum 20% and Tharwa Petroleum Company 15%.
- In February 2019 BP announced the start-up of gas production from the Giza and Fayoum fields in the West Nile Delta development (BP 82.75%). This development comprises five fields across the North Alexandria and West Mediterranean deepwater offshore blocks and is being developed as three separate projects to enable BP and its partners to accelerate gas production commitments to Egypt. The first of these three projects (Taurus and Libra) started production in 2017, Giza and Fayoum is the second, and the third project (Raven) is expected to be onstream in 2019.

In Libya, BP partners 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 wrote off all balances associated with the Libya EPSA in 2015.

- In October we announced that we had signed an agreement with the Libyan National Oil Corporation and Eni with a view to working together to resume exploration activities in Libya. The parties have agreed to work towards Eni acquiring a 42.5% interest in the BP-operated EPSA in Libya. On completion, Eni would also become operator of the EPSA. The companies are working to finalize and complete all agreements with a target of resuming exploration activities in 2019.

In Mauritania and Senegal, BP has a 62% participating interest in the C-6, C-8, C-12 and C-13 exploration blocks in Mauritania and a 60% participating interest in the Cayar Profond and St Louis Profond exploration blocks in Senegal. Together these blocks cover approximately 33,000 square kilometres. BP also has a 15% interest in the C-18 exploration block, operated by Total.

- In February KE announced that the Requin Tigre-1 well in the Saint Louis Profond Block, offshore Senegal, was fully tested but did not encounter hydrocarbons.
- In December BP and partners announced that the FID for Phase 1 of the cross-border Greater Tortue Ahmeyim development had been agreed. The decision was made following agreement between the Mauritanian and Senegalese governments and partners BP, KE and National Oil Companies, Petrosen and SMHPM. The project will produce gas from an ultra-deepwater subsea system and mid-water floating production, storage and offloading (FPSO) vessel. The gas will then be transferred to a floating liquefied natural gas (FLNG) facility at a near-shore hub located on the Mauritania and Senegal maritime border. The FLNG facility is designed to provide approximately 2.5 million tonnes of LNG per annum on average. The project, the first major gas project to reach FID in the basin, is planned to provide LNG for global export as well as making gas available for domestic use in both Mauritania and Senegal. First gas for the project is expected in 2022.

In Madagascar, BP signed four production-sharing contracts (PSC) in 2018 for exploration licences situated offshore northwest Madagascar, under agreements with the government of Madagascar represented by Office des Mines Nationales et des Industries Stratégiques (OMNIS) (BP 100%).

In São Tomé & Príncipe, BP and KE were awarded two offshore blocks in March 2018, under production-sharing agreements with the government of São Tomé & Príncipe represented by Agência Nacional do Petróleo de São Tomé e Príncipe (ANP-STP) (BP 50% (operator), KE 35% ANP-STP 15%). During the year work began on environmental baseline surveys, with completion anticipated in the second half of 2019.

Asia

BP has activities in Abu Dhabi, Azerbaijan, China, India, Iraq, Kuwait, Oman and Russia.

In China we have a 30% equity stake in the Guangdong LNG regasification terminal and trunkline project with a total storage capacity of 640,000 cubic metres. The project is supplied under a long-term contract with Australia's North West Shelf venture (BP 16.67%).

- BP has two PSCs for shale gas exploration, development and production in the Neijiang-Dazu block and Rong Chang Bei block in the Sichuan basin. The two blocks, both in the exploration phase, cover a total area of approximately 2,500 square kilometres. China National Petroleum Corporation (CNPC) is the operator. In 2018, drilling activity continued to progress in the two blocks in the Sichuan basin.

In Azerbaijan, BP operates two PSAs, Azeri-Chirag-Gunashli (ACG) (BP 30.37%) 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 were lifted or suspended as part of the Joint Comprehensive Plan of Action. However, in November the US secondary sanctions were reinstated. For further information see International trade sanctions on page 298.
- In April we announced that we had signed a new PSA with the State Oil Company of Azerbaijan Republic (SOCAR) for the joint exploration and development of Block D230 in the North Absheron basin. The block lies 135 kilometres north-east of Baku in the Caspian Sea, covering an area of 3,200 square kilometres. Under the PSA, which is for 25 years, BP will be the operator during the exploration phase and hold a 50% interest, with SOCAR holding the remaining 50%. The signing of the PSA follows the memorandum of understanding for exploration of Block D230, which was agreed in May 2016.
- In July we announced the start-up of the landmark Shah Deniz Stage 2 gas development in Azerbaijan, including its first commercial gas delivery to Turkey. The BP-operated $28 billion project is the first subsea development in the Caspian Sea and the largest subsea infrastructure operated by BP worldwide. It is also the starting point for the Southern Gas Corridor series of pipelines that will deliver natural gas from the Caspian Sea direct to European markets for the first time.

BP holds a 30.1% interest in and operates the Baku-Tbilisi-Ceyhan oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oilfield and gas condensate from the Shah Deniz gas field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The pipeline has a capacity of 1mmboe/d, with an average throughput in 2018 of 697mboe/d.

BP is technical operator of, and currently holds a 28.83% interest in, the 693 kilometre South Caucasus Pipeline. The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 143mboe/d, with average throughput in 2018 of 142mboe/d. BP (as operator of Azerbaijan International Operating Company) also operates the Western Route Export Pipeline that transports ACG oil to Supsa on the Black Sea coast of Georgia, with an average throughput of 76mboe/d in 2018.

BP also holds a 12% interest in the Trans Anatolian Natural Gas Pipeline. In the first phase, which commenced in June, gas from Shah Deniz is transported from Georgia to Eskishehir in Turkey. The

capacity of the pipeline during the first phase is 106mboe/d and the average throughput in 2018 was 30mboe/d. The second phase will take gas from Eskishehir to the connection with the Trans Adriatic Pipeline (TAP) in Greece. BP has a 20% interest in TAP, that will take gas through Greece and Albania into Italy. In December TAP entered into project financing arrangements with multiple lenders. BP's share of the funds received as a result of financing is $594 million.

In Oman BP operates the Khazzan field in Block 61 (BP 60%).

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In April BP announced that, together with its partner the Oman Oil Company Exploration & Production (OOCEP), it had approved the development of Ghazeer, the second phase of the Khazzan gas field in Oman. The Ghazeer project is expected to increase production by 50% and will involve construction of a third gas processing train to handle this. The project is currently on track to deliver first gas as planned in 2021.

- In January 2019 BP announced that together with Eni, they had signed a heads of agreement (HoA) with the Ministry of Oil and Gas of the Sultanate of Oman to work jointly towards a significant new exploration opportunity in Oman. Under the HoA, the two companies will work with the government of Oman towards the award of a new EPSA for Block 77 in central Oman. BP and Eni have entered discussions with the Ministry to finalise details of the EPSA. Block 77, with a total area of almost 3,100 square kilometres, is located in central Oman, 30 kilometres east of the BP-operated Block 61.

In Abu Dhabi, BP holds a 10% interest in the ADNOC onshore concession. We also have a 10% equity shareholding in ADNOC LNG and a 10% shareholding in the shipping company NGSCO. ADNOC LNG supplied approximately 5.4 million tonnes of LNG (729bcfe regasified) in 2018. Our interest in the ADNOC onshore concession expires at the end of 2054.

- In March 2019 ADNOC and ADNOC LNG agreed to extend the gas supply agreement to 2040. The new agreement will take effect from 1 April 2019, and replaces an existing agreement expiring on 31 March 2019.

Our interest in the ADNOC offshore concession expired in March 2018. The concession, together with all related rights and obligations, has reverted back to the government of the Emirate of Abu Dhabi.

In 2016 BP signed an enhanced technical service agreement for south and east Kuwait conventional oilfields, which includes the Burgan field, with Kuwait Oil Company. Target performance for the 2017-18 plan was delivered and implementation of the 2018-19 plan is underway.

In India we have a participating interest in two oil and gas PSAs (KG D6 30% and NEC25 33.33%) both operated by Reliance Industries Limited (RIL). We also have a stake in a 50:50 joint venture (India Gas Solutions Private Limited) with RIL for the sourcing and marketing of gas in India.

- In April BP and RIL sanctioned the Satellite Cluster project in Block KG D6. This is the second of three projects in the Block KG D6 integrated development. The first of the projects, development of the R-Series deep-water gas fields, was sanctioned in June 2017 and is currently under development. The Satellite Cluster is a dry gas development and comprises four discoveries with a five-well subsea development in Block KG D6, off the east coast of India. It is expected to come on stream in 2021.

In Iraq BP holds a 47.6% working interest and is the lead contractor in the Rumaila technical service contract in southern Iraq. The technical services contract runs to December 2034. Rumaila is one of the world's largest oil fields, comprising five producing reservoirs.

- In January 2018 BP entered into a letter of intent to work on the Kirkuk field which extends until 2019.

In Russia in addition to its 19.75% equity interest in Rosneft, BP holds a 20% interest in Taas-Yuryakh Neftegazodobycha (Taas) together with Rosneft (50.1%) and a consortium comprising Oil India Limited, Indian Oil Corporation Limited and Bharat PetroResources Limited (29.9%). Taas is developing the Srednebotuobinskoye oil and gas condensate field in East Siberia (see Rosneft on page 34 for further details). Also with Rosneft, we hold a 49% interest in Yermak

Neftegaz LLC, which conducts exploration in the West Siberian and Yenisei-Khatanga basins. Yermak Neftegaz LLC currently holds seven exploration and production licences. The venture has carried out further appraisal work on the Baikalovskoye field, an existing Rosneft discovery in the Yenisei-Khatanga area of mutual interest.

- In the second quarter, the Taas-Yuryakh expansion project completed commissioning of the main project facilities for the Srednebotuobinskoye oil and gas condensate.
- Also in the second quarter BP acquired a 49% stake in LLC Kharampurneftegaz to develop subsoil resources jointly with Rosneft within the Kharampurskoe and Festivalnoye licence areas in Yamalo-Nenets.
- In September Rosneft and BP also agreed to jointly explore two additional oil and gas licence areas located in Sakha (Yakutia). The licences are expected to be held by a Yermak subsidiary. Completion of the deal, subject to external approvals, is expected in 2019.

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 largest single source 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.

- The Browse project participants finalized evaluating a range of development options for the project and have selected to develop Browse by connecting it via a 900 kilometre pipeline to the NWS venture's Karratha gas plant. A final investment decision is expected in 2021. This decision has resulted in the write-off of $136 million in relation to previous project development costs for Browse.
- In October we announced the start-up of production at our Western Flank B project (BP 16.67%), ahead of schedule.
- During the year, the Ocean Great White rig contract was cancelled and a commercial arrangement entered into with the lessor whereby BP will utilize different rigs on projects in the future.

In Papua Barat, Eastern Indonesia, BP operates the Tangguh LNG plant (BP 40.22%). The asset currently comprises 16 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, Mexico, China, South Korea, and Japan through a combination of long, medium and short-term contracts.

- The Tangguh expansion project is progressing on schedule with the installation of two offshore platforms completed and the construction of the onshore LNG production train and supporting facilities currently ongoing. Drilling on the first of 13 new production wells commenced in early 2019, and first production is expected in 2020. The project will add 3.8 million tonnes per annum (mtpa) of production capacity to the existing facility, bringing total plant capacity to 11.4mtpa.
- In November approval from the government of Indonesia to relinquish BP's 32% interest in the Chevron-operated West Papua I was received.

Downstream plant capacity

The following table[a] summarizes BP group's interests in refineries and average daily crude distillation capacities as at 31 December 2018.

Fuels value chain	Country	Refinery	Crude distillation capacities[b] Group interest[c] (%)	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	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	152
New Zealand	New Zealand	Whangarei[d e]	10.1	33
Southern Africa	South Africa	Durban[d]	50	90
				275
Total BP share of capacity at 31 December 2018				1,890

[a] This does not include BP's interest in Pan American Energy Group, which is reported through the Upstream segment.

[b] Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

[c] BP share of equity, which is not necessarily the same as BP share of processing entitlements.

[d] Indicates refineries not operated by BP.

[e] Reflects BP share of processing entitlement, which is not the same as BP share of equity.

Petrochemicals production capacity[a]

The following table summarizes BP group's share of petrochemicals production capacities as at 31 December 2018.

					BP share of capacity thousand tonnes per annum[b]		
Geographical area	Site	Group interest[c] (%)	PTA	PX	Acetic acid	Olefins and derivatives	Product Others
US							
	Cooper River	100	1,400	—	—	—	—
	Texas City[d]	100	—	900	600	—	100
			1,400	900	600	—	100
Europe							
UK	Hull	100	—	—	500	—	200
Belgium	Geel	100	1,400	700	—	—	—
Germany	Gelsenkirchen[e]	100	—	—	—	3,300	—
	Mülheim[e]	100	—	—	—	—	200
			1,400	700	500	3,300	400
Rest of world							

Trinidad & Tobago	Point Lisas	36.9	—	—	—	—	700
China	Chongqing	51	—	—	200	—	100
	Nanjing	50	—	—	300	—	—
	Zhuhai[f]	91.9	2,500	—	—	—	—
Indonesia	Merak	100	500	—	—	—	—
South Korea	Ulsan[g]	34-51	—	—	300	—	100
Malaysia	Kertih	70	—	—	400	—	—
Taiwan	Mai Liao	50	—	—	200	—	—
	Taichung	61.4	500	—	—	—	—
			3,500	—	1,400	—	900
			6,300	1,600	2,500	3,300	1,400
Total BP share of capacity at 31 December 2018							15,100

[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] For acetic acid, group interest is quoted at 100%, reflecting the capacity entitlement which is marketed by BP.

[e] 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.

[f] BP Zhuhai Chemical Company Ltd is a subsidiary«of BP, the capacity of which is shown above at 100%.

[g] Group interest varies by product.

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 2018 BP had material volumes of proved undeveloped reserves held for more than five years in Russia, 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, or where there are significant commitments on delivery to the relevant authority.

Over the past five years, BP has annually progressed a weighted average 19% (18% for 2017 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 2018 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 2018 we progressed 1,306mmboe of proved undeveloped reserves (745mmboe 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 $14,210 million in 2018 ($9,917 million for subsidiaries and $4,293 million for equity-accounted entities). The major areas with progressed volumes in 2018 were Russia, US, Azerbaijan, UAE and Egypt. 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 material net positive revisions to our proved undeveloped resources in

Russia as a result of development drilling results and material net negative revisions in the US Lower 48 due to changes in our development plan to incorporate activity associated with the purchase of new assets. 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 2018	8,060
Revisions of previous estimates	20
Improved recovery	311
Discoveries and extensions	646
Purchases	1,174
Sales	(12)
Total in year proved undeveloped reserves changes	2,139
Proved developed reserves reclassified as undeveloped	15
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(1,306)
Proved undeveloped reserves at 31 December 2018	8,908

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2018	4,052
Revisions of previous estimates	(272)
Improved recovery	297
Discoveries and extensions	169
Purchases	945
Sales	(12)
Total in year proved undeveloped reserves changes	1,128
Proved developed reserves reclassified as undeveloped	12
Progressed to proved developed reserves by development activities (e.g. drilling/completion)	(745)
Proved undeveloped reserves at 31 December 2018	4,447

[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
- 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 35 years of diversified industry experience, with 13 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 by the group's petroleum engineers or by independent petroleum engineering consulting firms and then 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 2018, 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 2018. 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.

Netherland, Sewell & Associates (NSAI), 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 2018, of certain properties owned by BP in the US Lower 48. The properties evaluated by NSAI account for 100% of BP's net proved reserves in the US Lower 48 as of 31 December 2018. The net proved reserves estimates prepared by NSAI 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 NSAI'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

89% of our total proved reserves of subsidiaries at 31 December 2018 were held through joint operations«(88% in 2017), and 31% of the proved reserves were held through such joint operations where we were not the operator (34% in 2017).

Estimated net proved reserves of crude oil at 31 December 2018[a b c]

	million barrels		
	Developed	Undeveloped	Total
UK	223	243	466
Rest of Europe	—	—	—
US[d]	962	802	1,764
Rest of North America[e]	43	190	234
South America[f]	8	5	14
Africa	223	36	259
Rest of Asia	1,126	482	1,608
Australasia	30	5	34
Subsidiaries	2,615	1,763	4,378
Equity-accounted entities	3,541	2,792	6,333
Total	6,156	4,555	10,711

Estimated net proved reserves of natural gas liquids at 31 December 2018[a b]

	million barrels		
	Developed	Undeveloped	Total
UK	8	6	14
Rest of Europe	—	—	—
US	266	246	511
Rest of North America	—	—	—
South America	2	25	27
Africa	14	4	18
Rest of Asia	—	—	—
Australasia	5	—	5
Subsidiaries	295	280	576
Equity-accounted entities	114	54	169
Total	409	335	744

Estimated net proved reserves of liquids«

	million barrels		
	Developed	Undeveloped	Total
Subsidiaries[f]	2,910	2,044	4,954
Equity-accounted entities[g]	3,655	2,846	6,502
Total	6,565	4,890	11,456

Estimated net proved reserves of natural gas at 31 December 2018[a b]

	billion cubic feet		
	Developed	Undeveloped	Total
UK	439	343	782
Rest of Europe	—	—	—
US	6,270	5,056	11,326
Rest of North America	—	—	—
South America[h]	2,168	3,073	5,241
Africa	1,313	1,067	2,380
Rest of Asia	3,599	3,218	6,817
Australasia	2,630	1,179	3,809
Subsidiaries	16,420	13,936	30,355
Equity-accounted entities[i]	9,515	9,369	18,884
Total	25,934	23,305	49,239

Estimated net proved reserves on an oil equivalent basis

million barrels of oil equivalent

	Developed	Undeveloped	Total
Subsidiaries	5,741	4,447	10,188
Equity-accounted entities	5,296	4,462	9,757
Total	11,037	8,908	19,945

[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 2018 marker prices used were Brent« $71.43/bbl (2017 $54.36/bbl and 2016 $42.82/bbl) and Henry Hub« $3.10/mmBtu (2017 $2.96/mmBtu and 2016 $2.46/mmBtu).

[c] Includes condensate.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 16 million barrels on which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] All of the reserves in Canada are bitumen.

[f] Includes 12 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[g] Includes 356 million barrels of liquids in respect of the non-controlling interest in Rosneft held assets in Russia including 24 million barrels held through BP's interests in Russia other than Rosneft.

[h] Includes 1,573 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[i] Includes 1,211 billion cubic feet of natural gas in respect of the non-controlling interest in Rosneft held assets in Russia including 480 billion cubic feet held through BP's interests in Russia other than Rosneft.

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 2018, on an oil equivalent basis including equity-accounted entities, increased by 8% (increase of 7% for subsidiaries and increase of 9% for equity-accounted entities) compared with 31 December 2017. Natural gas represented about 43% (51% for subsidiaries and 33% for equity-accounted entities) of these reserves. The change includes a net increase from acquisitions and disposals of 1,498mmboe (increase of 993mmboe within our subsidiaries and increase of 505mmboe within our equity-accounted entities). Acquisition activity in our subsidiaries occurred in the US and UK, and divestment activity in our subsidiaries in the US and UK. In our equity-accounted entities acquisitions occurred in our Russian joint ventures other than Rosneft. There were no divestments in our equity-accounted entities.

The proved reserves replacement ratio« is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries. For 2018, the proved reserves replacement ratio excluding acquisitions and disposals was 100% (143% in 2017 and 109% in 2016) for subsidiaries and equity-accounted entities, 66% for subsidiaries alone and 161% for equity-accounted entities alone. There were increases (131mmboe) of reserves due to extension of the date of cessation of production across the group due to higher oil and gas prices, but these were more than offset by decreases (140mmboe) in PSAs, principally in Azerbaijan, Indonesia and Iraq resulting from decreased cost recovery volumes due to higher oil and gas prices.

In 2018 net additions to the group's proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 1,381mmboe (576mmboe for subsidiaries and 805mmboe for equity-accounted entities), through revisions to previous estimates, improved recovery from, and extensions to, existing fields and discoveries of new fields. The subsidiary additions were through improved recovery from, and extensions to, existing fields and discoveries of new fields where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2018 principally resulted from the application of conventional technologies and extensions of the cessation of production as a result of higher prices. The principal proved reserves additions in our subsidiaries by region were in UAE, Oman and the US. We had material reductions in our proved reserves in Iraq principally due to higher oil and gas prices. The principal reserves additions in our equity-accounted entities were in

PAE and Rosneft.

14% of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2018 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.

The group holds no 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 217.

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
	2018	2017	2016	2018	2017	2016
Subsidiaries						
UK[c d]	101	80	79	5	6	6
Norway[c]	—	—	24	—	—	4
Total Rest of Europe	—	—	24	—	—	4
Total Europe	101	80	102	5	6	10
Alaska[c]	106	109	107	—	—	—
Lower 48 onshore[c]	18	10	12	37	34	36
Gulf of Mexico deepwater	261	251	216	23	21	20
Total US	385	370	335	60	56	56
Canada[e]	24	20	13	—	—	—
Total Rest of North America	24	20	13	—	—	—
Total North America	408	390	347	60	56	56
Trinidad & Tobago[c]	7	12	10	9	10	8
Total South America	7	12	10	9	10	8
Angola	147	192	219	—	—	—
Egypt[c]	49	40	39	—	—	—
Algeria	9	9	5	11	10	5
Total Africa	204	241	263	11	10	5
Abu Dhabi[c]	169	158	—	—	—	—
Azerbaijan	72	90	105	—	—	—
Western Indonesia[c]	—	—	2	—	—	—
Iraq	54	73	96	—	—	—
India	—	1	1	—	—	—
Oman	17	2	—	—	—	—
Total Rest of Asia	313	325	204	—	—	—
Total Asia	313	325	204	—	—	—
Australia[c]	16	15	15	2	2	3
Eastern Indonesia[c]	2	1	2	—	—	—
Total Australasia	17	17	16	2	2	3
Total subsidiaries	1,051	1,064	943	88	85	82
Equity-accounted entities (BP share)						
Rosneft (Russia, Canada, Venezuela, Vietnam)	919	900	836	4	4	4
Abu Dhabi	16	99	101	—	—	—
Argentina[c]	52	60	62	—	—	1
Bolivia[c]	3	3	4	—	—	—
Egypt	—	—	—	3	2	3
Norway[c]	34	31	7	2	2	—
Russia[c]	14	5	4	—	—	—
Angola	1	1	—	3	4	1
Other	—	—	1	—	—	—
Total equity-accounted entities	1,040	1,099	1,015	12	12	8
Total subsidiaries and equity-accounted entities[f]	2,091	2,163	1,958	100	97	90

[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 2018, BP acquired various interests in the Permian Basin, Eagle Ford and Haynesville Shales in Lower 48 onshore as a result of the acquisition of BHP's US unconventional assets, increased its interest in the Clair asset in the UK North Sea, and acquired an interest in LLC Kharampurneftegaz in Russia, and in certain US offshore assets. It also disposed of its interests in the Greater Kuparuk Area in Alaska, the Magnus field in the UK North Sea, and in certain other assets in the UK North Sea and US onshore assets. In 2017, BP renewed its onshore concession of the United Arab Emirates that grants BP 10% interest in ADCO onshore concession. It also decreased its interest in Magnus field in North Sea and completed the formation of Pan American Energy Group (PAEG) (BP 50%, Bridas Corporation 50%), which is a combination of Pan American Energy and Axion Energy with an effective decrease in interest. 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.

[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] Includes 3 net mboe/d of NGLs from processing plants in which BP has an interest (2017 3mboe/d and 2016 3mboe/d).

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

BP's net production by country – natural gas

	million cubic feet per day BP net share of production[a]		
	2018	2017	2016
Subsidiaries			
UK[b]	152	182	170
Norway[b]	—	—	82
Total Rest of Europe	—	—	82
Total Europe	152	182	252
Lower 48 onshore[b]	1,705	1,467	1,476
Gulf of Mexico deepwater	190	186	173
Alaska	5	5	6
Total US	1,900	1,659	1,656
Canada	7	9	10
Total Rest of North America	7	9	10
Total North America	1,907	1,667	1,666
Trinidad & Tobago[b]	2,136	1,936	1,689
Total South America	2,136	1,936	1,689
Egypt[b]	878	745	305
Algeria	183	205	208
Total Africa	1,061	949	513
Azerbaijan	256	232	245
Western Indonesia[b]	—	—	35
India	32	60	84
Oman	538	79	—
Total Rest of Asia	826	371	363
Total Asia	826	371	363
Australia[b]	437	426	451
Eastern Indonesia[b]	382	357	369
Total Australasia	819	783	820
Total subsidiaries[c]	6,900	5,889	5,302
Equity-accounted entities (BP share)			
Rosneft (Russia, Canada, Egypt, Venezuela, Vietnam)	1,286	1,308	1,279
Argentina	264	329	354
Bolivia	71	89	95
Norway[b]	59	53	12
Angola	80	77	18
Western Indonesia	—	—	15
Total equity-accounted entities[c]	1,760	1,855	1,773
Total subsidiaries and equity-accounted entities	8,659	7,744	7,075

[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 2018, BP acquired various interests in the Permian Basin, Eagle Ford and Haynesville Shales in Lower 48 onshore as a result of the acquisition of BHP's US unconventional assets, increased its interest in the Clair asset in the UK North Sea, and acquired an interest in LLC Kharampurneftegaz in Russia, and in certain US offshore assets. It also disposed of its interests in the Greater Kuparuk Area in Alaska, the Magnus field in the UK North Sea, and in certain other assets in the UK North Sea and US onshore assets. In 2017, BP decreased its interest in Magnus field in North Sea and completed the formation of Pan American Energy Group (PAEG) (BP 50%, Bridas Corporation 50%),

which is a combination of Pan American Energy and Axion Energy with an effective decrease in interest.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.

[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.

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]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
									$ per unit of production	
	UK	Rest of Europe	US	Rest of North America[b]			Russia	Rest of Asia		
Subsidiaries										
2018										
Crude oil[c]	71.28	—	67.11	33.57	69.17	68.81	—	70.80	67.54	67.81
Natural gas liquids	31.63	—	25.81	—	35.74	39.14	—	92.47	52.14	29.42
Gas	7.71	—	2.43	—	3.08	4.82	—	3.85	7.97	3.92
2017										
Crude oil[c]	53.67	—	49.98	36.80	55.44	53.61	—	52.88	53.26	51.71
Natural gas liquids	32.77	—	22.42	—	26.79	36.48	—	—	39.39	26.00
Gas	5.09	—	2.36	—	2.25	3.82	—	3.44	6.14	3.19
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
Equity-accounted entities[d]										
2018										
Crude oil[c]	—	70.24	—	—	62.35	—	62.46	39.49	—	62.24
Natural gas liquids[e]	—	—	—	—	—	—	N/A	—	—	—
Gas	—	7.93	—	—	4.36	—	1.70	—	—	2.50
2017										
Crude oil[c]	—	55.08	—	—	49.97	—	45.66	15.61	—	42.33
Natural gas liquids[e]	—	—	—	—	—	—	N/A	—	—	—
Gas	—	5.78	—	—	4.49	—	1.63	—	—	2.47
2016										
Crude oil[c]	—	50.71	—	—	48.88	—	36.36	12.92	—	34.04
Natural gas liquids[e]	—	—	—	—	34.51	—	N/A	—	—	34.51
Gas	—	5.16	—	—	4.21	—	1.39	6.11	—	2.20

Average production cost per unit of production[f]

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
									$ per unit of production	
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
2018	13.76	—	9.63	13.10	3.08	7.31	—	5.72	2.35	7.15
2017	14.58	—	8.68	15.02	4.41	6.47	—	6.37	2.79	7.11
2016	14.80	13.72	10.20	21.79	4.21	9.34	—	7.08	2.62	8.46

Equity-accounted entities										
2018	—	12.15	—	—	10.61	—	3.09	5.92	—	4.16
2017	—	10.33	—	—	11.92	—	3.19	3.27	—	4.32
2016	—	10.41	—	—	10.66	—	2.46	3.67	—	3.57

[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] 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.

[e] Natural gas liquids for Russia are included in crude oil.

[f] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

Environmental expenditure

	$ million		
	2018	2017	2016
Operating expenditure	501	441	487
Capital expenditure	449	487	564
Clean-ups	31	22	27
Additions to environmental remediation provision	428	249	262
Increase (decrease) in decommissioning provision	137	(228)	(804)

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 $501 million in 2018 (2017 $441 million) showed an overall increase of 14% the largest element of which was due to higher expenditures associated with sustaining and increasing production volumes in the Gulf of Mexico region.

Environmental capital expenditure in 2018 was lower overall than in 2017 largely due to lower spend resulting from the divestiture of the North Sea Forties Pipeline System and lower expenditure on Arundel, Clair and Schiehallion fields.

Clean-up costs were $31 million in 2018 (2017 $22 million) representing increases in oil spill clean-up costs and other associated remediation and disposal costs as well as costs related to the replacement of underground storage tanks in the US.

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 increased in 2018 largely due to the scope reassessments of the remediation plans of a number of our sites in the US and Canada. The charge for environmental remediation provisions in 2018 included $8 million in respect of provisions for new sites (2017 $8 million and 2016 $7 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 2018, the net decrease in the decommissioning provision, similar to the decrease in 2017, was a result of detailed reviews of expected future costs, partially offset by 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 23.

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.

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, solar and shipping activities, 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 US government entities are usually by lease. Arrangements with private property owners are also usually in the form of leases.

Licences (or concessions) give the holder the right to explore for, develop and produce 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, develop and produce 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 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. This agreement applies to both developing and developed countries, although in some instances allowances or flexibilities are provided for developing countries. The Paris Agreement aims to hold the increase in the global average temperature to well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase 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 towards absolute emission reduction targets over time. 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. On 1 June 2017, the US announced that it will withdraw from the Paris Agreement. This includes suspending the implementation of the US's NDC and funding for the

Green Climate Fund. The process for withdrawal can be completed no earlier than 4 November 2020.

At the United Nations climate change conference in Poland (COP24) in December 2018, the 'Paris Rulebook' was agreed. This rulebook describes how the elements of the Paris Agreement will be implemented when it comes into force in 2020. COP24 failed to agree on rules for implementing Article 6, which could enable international carbon trading to assist in meeting NDCs. Discussions on Article 6 have now been deferred to COP25 which will take place

in Chile in 2019.
More stringent national and regional measures relating to the transition to a lower carbon economy can be expected in the future. These measures could increase BP’s production costs for certain products, increase compliance and litigation costs, increase demand for competing energy alternatives or products with lower-carbon intensity, and affect the sales and specifications of many of BP’s products. Further, such measures could lead to constraints on production and supply and access to new reserves, particularly due to the long term nature of many of BP’s projects. 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 used its existing statutory authority to implement that plan, including the Clean Air Act (CAA) and the Mineral Leasing Act (MLA). BP's operations are affected by regulation in a number of ways under the CAA, for example:

- Stricter GHG regulations, stricter limits on sulphur in fuels, emissions regulations in the refinery sector and a revised lower ambient air quality standard for ozone, finalized by the EPA in October 2015, are affecting our US operations.
- EPA regulations aimed at methane emissions are in place for new and modified sources. As discussed below, the Bureau of Land Management (BLM) has issued a new waste prevention rule which rescinded the prior rule regarding methane regulation on federal lands.
- States may also have separate, stricter air emission laws in addition to the CAA. Despite the US withdrawal from the Paris Agreement, a number of US states, cities and private organizations remain committed to meeting Paris Agreement goals. A number of states also belong to or are considering joining carbon trading markets (e.g. California).

As noted below, some of these regulations may be suspended, revised or rescinded resulting in regulatory uncertainty and complex compliance challenges for our affected businesses
On 28 March 2017, the Trump administration issued Executive Order (EO) 13783 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 (CPP) which was an important element of the Obama administration’s Climate Action Plan, and the EPA new source methane rule.
On 21 August 2018, the EPA introduced the Affordable Clean Energy (ACE) Rule, which is intended to address GHG emissions from certain stationary sources, and which is intended to replace the CPP. The CPP regulations are currently stayed pending resolution of existing legal challenges; the EPA may decline to defend certain of these legal challenges. When the ACE Rule is finalized, it is likely to face legal challenges as well. The outcome with respect to these rules may affect electricity generation practices and prices, reliability of electricity supply, and regulatory requirements affecting other GHG emission sources in other sectors and have potential impacts on combined heat and power installations.
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 by 40-45% from 2012 levels by 2025. In January 2017 the BLM's methane rule, aimed at limiting methane emissions from oil and gas operations on federal lands also came into effect. EO 13783 instructed the Department of Interior (DOI) to

review and possibly suspend, revise or rescind the BLM methane rule. In September 2018, BLM finalized a new waste prevention rule, which removed many of the provisions of the former BLM methane rule. The EPA rule and the new waste prevention rule are being challenged by states and NGOs. The final outcome of the rule revisions and legal challenges with respect to these EPA and BLM rules is uncertain.

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 in Oregon). In October 2018, President Trump directed the EPA to conduct rulemaking to extend to E15 gasoline the volatility allowance currently given to E10 gasoline under the CAA. Current law allows E15 gasoline to be sold year-round, but this rule will make it easier for E15 to meet the more stringent summer volatility standards. This rulemaking will also address "market reforms" of the RFS credit-trading programme, which is the open market for renewables credit trading. EPA has indicated it hopes to have the rulemaking finalized by the summer 2019 driving season.

Under the GHG mandatory reporting rule (GHGMRR), annual reports on GHG emissions must be filed with the EPA. 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.

A number of states, municipalities and regional organizations have responded to current and proposed federal changes in environmental regulation and 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 adopted a carbon cap rule that was to become effective 2017, but the rule has been suspended pending review before the state's supreme court.

European Union

- EU leaders in 2007 endorsed a set of measures to reduce GHG emissions and encourage renewables in the 2010 to 2020 period. These include an overall GHG reduction target of 20% by 2020. To meet this, a set of regulatory measures were adopted which include: a collective national reduction target for emissions not covered by the EU Emissions Trading System (EU ETS) Directive; binding national renewable energy targets of 20% renewable energy used in 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 legal framework to promote carbon capture and storage (CCS); and a revised EU ETS Phase 3.
- In October 2014 EU leaders adopted the climate and energy framework setting key targets for the year 2030 including at least 40% cuts in GHG emissions (from 1990 levels). 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. Measures to achieve the 2030 targets include a significant revision of the EU ETS for Phase 4 agreed in 2017, which addresses the surplus allowances in the system and the amount of free allocation for sectors prone to international competition. In mid-2018 a 32% share of renewable energy and a 32.5% increase in energy efficiency was agreed which must be met by EU Member States by 2030. The package also sets a renewable energy target of 14% for the transportation sector.
- On 28 November 2018 the European Commission presented its long-term Energy and Climate Strategy that sets a "vision" towards a net-zero GHG emissions economy by the mid-twenty first century.
- The Medium Combustion Plants Directive (MCPD) applies to air emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x) 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 are being phased in - the emission limit values set in the Directive applied from 20 December 2018 for new plants and by 2025 or 2030 for existing plants, depending on their size.

- The National Emission Ceiling Directive 2016 entered into force on 31 December 2016, replacing earlier legislation. It introduces stricter emissions limits from 2020 and 2030, with new indicative national targets applying from 2025. EU member states had to implement the Directive by 1 July 2018. NECD has been implemented in the UK by the

National Emission Ceiling Regulations 2018. Each EU Member State is also required to produce a National Air Pollution Control Programme by 31 March 2019 setting out the measures it will take to ensure compliance with the 2020 and 2030 reduction commitments.

- 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.

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 compliance obligations being based on facility performance relative to product specific benchmarks. Compliance is possible by improving emissions intensity, the purchase of offsets or the payment of C$30/tonne to the Climate Change and Emissions Management Fund. In addition, there is an economy-wide price of carbon policy that covers emissions not in the scope of the existing regulations for large final emitters (C$30/tonne in 2019; then escalating in line with Federal backstop pricing). Additional requirements are in place relating to electricity generation sources and limits on overall oil sands emissions. The Canadian federal government has announced climate change regulations, effective from January 2019, including a national backstop carbon price starting at C$20/tonne in 2019 and escalating to C$50/tonne by 2022 (or equivalent system for provinces with cap-and-trade systems), with implementation of the price and associated large emitters pricing system (modelled on the Alberta output-based-allocation system), use of any funds generated, and outcome reporting being managed by each province. Newfoundland & Labrador and Nova Scotia are implementing regulations that meet equivalency requirements of the Federal regulations via economy wide carbon taxes on fuels and large emitter programs (intensity based for Newfoundland & Labrador and cap and trade for Nova Scotia).
- China is operating emission trading pilot programmes in five cities and three provinces. One of BP's subsidiaries and one of BP's joint venture« companies in China are participating in these schemes. A plan to establish a nationwide carbon emissions trading market (initially covering the power sector only) was promulgated in December 2017 by the National Development and Reform Commission, which will not supersede the above eight pilot programmes immediately but allow those pilot schemes to be incorporated into the national scheme gradually. In 2018, the Climate Change Bureau was transferred to the newly formed Ministry for Ecology & Environment as part of the overall ministerial restructuring. The Climate Change Bureau remains in charge of the nationwide Emission Trading Scheme with no changes to the 2017 implementation plan.
- In July 2016, China carried out pilot programmes on compensation for and trading of energy quotas in four provinces which may be further expanded in or after 2020. In January 2017, a nationwide pilot scheme on the issuance and voluntary purchase and trading of renewable energy green power certificates was launched, and draft regulation issued in 2018. The scheme is expected to undergo further testing in 2019 before becoming mandatory. Generators will be able to obtain certificates, which then can be sold to the two national grid companies. No secondary trading is foreseen initially.

- 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. In addition, China has also introduced a mandate for sales of new energy vehicles (NEVs) commencing in 2020. This will accelerate NEV penetration into the light vehicle sector and impact light fuel 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 45.

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 23 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 291.

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 2017, the Trump administration has issued a number of Executive Orders (EO) 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 legal challenges to some of these initiatives which can result in regulatory uncertainty and compliance challenges for our operations.
- 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. State law analogues to NEPA could also limit or delay our projects. On 15 August 2017 the Trump administration issued EO 13807 which directs federal agencies to take certain actions to streamline the NEPA process although the effect of EO 13807 on our operations remains uncertain. In 2018 the Trump Administration started the rulemaking process to reform the NEPA regulations consistent with EO 13807.

- 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'. EPA regulations impose light, medium and heavy duty vehicle emissions standards for GHGs (both fuel economy and tailpipe standards) as well as for nonroad engines and vehicles and permitting requirements for certain large GHG stationary emission sources. California also imposes Low Emission Vehicle (LEV) and Zero Emission Vehicle (ZEV) standards on vehicle manufacturers and a number of other states impose different stricter GHG emission limits on vehicles.

These regulations may impact fuel demand and product mix in California and those states adopting LEV and ZEV standards and may impact BP's product mix and demand for particular products.

- In August 2018 the US Department of Transportation and EPA issued a joint proposed rulemaking to establish new or revised fuel economy and tailpipe carbon dioxide emissions standards for passenger cars and light trucks covering model years (MY) 2021 through 2026. The Trump administration's proposed option would lock in the 2020 standards until 2026. This would be a rollback from the Obama Administration's rules. The agencies have said they intend to finalize this rulemaking in Spring 2019. The proposal would also eliminate the waiver allowing California and other states to set their own LEV and ZEV standards. California and other states have announced their intention to litigate if such a rule is finalized.
- 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 who 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 reporting on the storage, use and releases of designated quantities of certain listed hazardous substances to federal, 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 EPA has promulgated 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. In 2017, the EPA finalized details regarding the process and requirements for execution of the TSCA inventory reset.
- 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. On 17 January 2017, the US Occupational Safety and Health Administration (OSHA) published an instruction guidance document for implementing and conducting a "National Emphasis Program" for process safety management (PSM) in covered facilities. Over the next several years OSHA will pursue inspections through the National Emphasis Program to ensure compliance with PSM requirements in both refineries and chemical plants.

- 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 imposes operational requirements, liability standards and other obligations governing the transportation of petroleum products in US waters and is implemented through regulations issued by the EPA, the US Coast Guard, the DOT, the 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, including equipment and testing, on offshore and onshore operations on federal lands subject to DOI authority.
- 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 experienced increasing restrictions on our activities.

European Union

- The Industrial Emissions Directive (IED) 2010 provides the framework for granting permits for major industrial sites. It lays down rules on integrated prevention and control of air, water and soil pollution arising from industrial activities. As part of the IED framework, additional emission limit values are informed by sector specific and cross-sector Best Available Technology (BAT) Conclusions, such as the BAT Conclusions for the refining sector, for large combustion plants as well as common waste water and waste gas treatment and management systems in the chemical sector. These may result in requirements for BP to further reduce its emissions, particularly its air and water emissions.
- The EU regulation on ozone depleting substances 2009 (ODS Regulation) requires companies 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. The Kigali Amendment to the Montreal Protocol (which aims to reduce hydrofluorocarbons) came into force on 1 January 2019. In addition, the EU regulation on fluorinated GHGs with high global warming potential (the F-gas Regulations) require a phase-out of certain hydrofluorocarbons, based on global warming potential.
- European regulations also establish passenger car performance standards for CO_2 tailpipe emissions (European Regulation (EC) No 443/2009). By 2021, the European passenger fleet emissions target for new vehicles will be 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. 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 October 2018 the European Council released an updated proposal on setting CO_2 reduction targets, from a 2021 baseline, of 15% by 2025 and 35% by 2030 for passenger cars, and 15% by 2025 and 30% by 2030 for passenger vans and heavy duty vehicles.
- The EU Registration, Evaluation Authorization and Restriction of Chemicals (REACH) Regulation 2006 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 of which was completed 31 May 2018. 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. In addition, BP's facilities and operations in several EU countries have undergone REACH compliance inspections by the competent authority for the respective EU member state. An amendment to the Annex of the Regulation on classification, labelling and packaging of substances and mixture (CLP Regulation) requires harmonized notification of information on hazardous materials (certain lubricant and fuel formations) to EU member state poison centres. The uniform notification rules will apply as of January 2020 for consumer products, from 2021 for professional and 2024 for industrial uses.

- Outside the EU, Turkey has published REACH-like regulations, known as KKDIK, as well as related implementation schedules and substance registrations. BP is compiling and preparing the requisite information to meet the pre-registration requirements for the KKDIK.
- 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 review 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.
- The "Best Available Techniques Guidance Document on upstream hydrocarbon exploration and production" seeks to document best practice in the upstream sector. The guidance defines Best Available Techniques and best risk management approaches across the upstream lifecycle, from exploration and appraisal through to decommissioning, and largely draws on experience and good practice from existing standards as well as existing regulatory regimes from Member States. While the document is non-binding, the European Commission are encouraging regulatory authorities to utilize this guidance when issuing permits. The guidance is in the final stages of review and is expected to be published in 2019.

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 is upgrading its water treatment facilities to meet consent levels agreed 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 upgraded produced water treatment systems to meet revised oil in water limits for produced water discharge under Executive Decree ED 97-14.

The Abidjan Convention has been now been ratified by more than 15 African nations, including Angola. The Convention, along with the Additional Protocol published in 2012, sets environmental quality standards for the discharge of chemicals to the marine environment. BP currently operates produced water treatment to meet these quality standards in Angola and is designing systems to meet the standard for our future gas operations in Mauritania and Senegal.

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. OPA 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 2018, 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, operate on other low sulphur fuels such as LNG or implement approved abatement technology to enable them to meet the low sulphur emissions requirements while 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. Measures to support consistent global implementation are expected to be finalized in 2019.
- Under the International Convention for the Control and Management of Ships' Ballast Water and Sediments 2004, which entered into force in September 2017, ships in international traffic are required to manage their ballast water and sediments to a certain standard, according to a ship-specific ballast water management plan.
- The Convention for the Protection of the Marine Environment of the North-East Atlantic (OSPAR), entered into force in March 1998, is an international convention which aims to protect the marine environment of the North-East Atlantic. OSPAR has 16 contracting parties, including the UK Government. Work carried out in accordance with OSPAR is managed by the OSPAR Commission, which is made up of government representatives of the 15 contracting parties and the EU. OSPAR Recommendation 2001/1 relates to the management of produced water from offshore installations in the North Sea. The 2001 recommendation set a target of a 15% reduction in the total quantity of oil in produced water discharged by 2006 compared to 2000 levels and a performance standard for dispersed oil in produced water discharged into the sea of 30 mg/l. More recently, guidelines for the implementation of a risk-based approach to the management of produced water discharges from offshore installations were adopted (OSPAR Recommendation 2012/5). This approach supports a key goal of the 2001 recommendations, that by 2020 Contracting Parties should achieve a reduction of oil in produced water discharged into the sea to a level which will adequately ensure that each of those discharges will present no harm to the marine environment.
- The EU shipping monitoring, reporting and verification (MRV) regulation entered into force in July 2015 and is aimed at gathering data on CO_2 emissions based on ships' fuel consumption. It is considered the first step of a staged approach for the inclusion of maritime transport emissions in the EU's GHG reduction commitment. In parallel, through amendments to MARPOL Annex VI, the IMO Data Collection System (DCS) for collecting and analysing fuel consumption data came into effect in March 2018.

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 explosion and fire and resulting oil spill (the Incident). Lawsuits and claims arising from the Incident were brought principally 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. All federal and state governmental claims in relation to the Incident have now been settled or dismissed and the 2014 administrative agreement with the US Environmental Protection Agency and BP's obligations thereunder ended in March 2019. The remaining proceedings arising from the Incident are discussed below.
PSC settlements
PSC settlements – Economic and Property Damages Settlement Agreement
In 2012 the Economic and Property Damages Settlement was entered into with the PSC to resolve certain economic and property damage claims. 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, which is under court supervision through the settlement claims process established by the Economic and Property Damages Settlement, continued during 2018. Only a very small number of business economic loss claims remain to be determined, although certain business economic loss claims continue to be appealed by BP and/or the claimants.
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
In 2012 the Medical Benefits Class Action Settlement (Medical Settlement) was entered into with the PSC. It 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 37,226. As of 25 January 2019, 27,607 claims (comprising 22,833 SPC and 4,774 PMCP only) have been approved for compensation totalling approximately $67 million; 9,615 claims have been denied; and 4 claims are pending determination.

In order to seek compensation from BP for an LMPC, class members must file a notice with the Medical Claims Administrator within 4 years after either (i) the date of first diagnosis of the LMPC or (ii) the effective date of the MSA (12 February 2014), whichever is later. As of 22 February 2019, there are 2,159 pending lawsuits brought by class members claiming LMPCs.

Other civil complaints – economic loss

PSC settlement - Opt out and Excluded claims

In 2016, the vast majority of economic loss and property damage claims from individuals and businesses that either opted out of the 2012 PSC settlement and/or were excluded from that settlement were either resolved or dismissed. Although several groups of plaintiffs whose claims were dismissed by the district court for noncompliance with the district court's prior orders filed appeals in the Fifth Circuit, only a small number of those individual and business plaintiffs now have pending appeals.

BP-Branded Fuel Dealers

On 23 March 2017, two plaintiffs filed an appeal to the Fifth Circuit from the district court's October 2012 ruling dismissing their claims on the grounds that alleged losses by dealers of BP-branded fuel allegedly caused by the reputation impact of the spill on the BP brand are not compensable under OPA 90. On 3 July 2018, the Fifth Circuit affirmed the district court's ruling dismissing their claims.

General Maritime Law Claims

On 19 July 2017 the district court held that maritime claims by 215 plaintiffs would be subject to further proceedings in MDL 2179 under OPA 90 and under general maritime law. The court dismissed with prejudice all other claims for economic loss brought by private plaintiffs under general maritime law. Five groups of plaintiffs filed appeals in the Fifth Circuit from the dismissal of their claims, and two of those appeals remain pending.

MDL 2179 - Other Economic Loss and Property Damage Claims

On 11 January 2018, the district court issued an order requiring all remaining plaintiffs in MDL 2179 with economic loss or property damage claims to file by 11 April 2018 a verified sworn statement regarding the actual damages each such plaintiff seeks in its pending litigation and an explanation of how those alleged damages were causally related to the Incident. On 10 July 2018 the district court issued an order on those plaintiffs' compliance with the January 2018 order and on 29 November 2018 ruled on several motions for reconsideration of its July 2018 compliance order. In those two orders, the district court identified fewer than 200 plaintiffs with economic loss or property damage claims that it deemed to have complied with its January 2018 order, and it dismissed the remaining economic loss or property damage claims with prejudice.

Other civil complaints – personal injury

The vast majority of post-explosion clean-up, medical monitoring and personal injury claims from individuals that either opted out of the 2012 PSC settlement and/or were excluded from that settlement have been dismissed.

On 9 April 2018 the district court in MDL 2179 issued an order requiring the 981 plaintiffs whose claims for post-explosion clean-up, medical monitoring and personal injury claims occurring after the Incident remain pending in MDL 2179 to file a sworn statement providing detailed information regarding their claims. On 20 September 2018, the district court issued an order requiring more than 150 plaintiffs whose responses to the 9 April 2018 order BP deemed to be materially deficient to show cause in writing by 11 October 2018 why their claims should not be

dismissed with prejudice for their failure to comply with the court's order. The district court has not yet ruled on the show cause submissions.

Individual securities litigation

Following court approval of the settlement of a securities class action brought on behalf of a class of post-explosion American depository share (ADS) holders in 2017, there remained individual cases filed in state and federal courts by pension funds, investment funds and advisers. These were 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. All of the cases, with the exception of one case that has been stayed, were transferred to MDL 2185. As at 31 December 2018, 28 actions on behalf of 113 plaintiffs remained pending in MDL 2185.

Canadian class actions

Following various legal proceedings, on 26 February 2016, a plaintiff 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 filed a motion in the Court of Appeal for Ontario to lift a stay on the action. The plaintiff's motion was granted on 29 July 2016. On 1 September 2017 the court granted in part and denied in part BP's motion for summary judgment, limiting the case to three alleged misstatements and narrowing the class period. On 3 April 2018, the Court of Appeal for Ontario affirmed that decision.

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. On 5 April 2017, BP moved to dismiss the State of Yucatan's claims, and the court granted BP's motion to dismiss on 6 March 2018.

On 19 April 2013, the Mexican federal government filed a civil action against BP and others in MDL 2179. The complaint sought a determination that each defendant was liable under OPA 90 for damages that included 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. The claims in this civil action were resolved by agreement effective 15 February 2018 and dismissed on 28 March 2018.

On 18 October 2012, before a Mexican Federal District Court located in Mexico City, a class action complaint was filed against BP America Production Company (BPAPC) and other BP subsidiaries. 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. On 15 May 2018, BP was formally served with the post-class certification complaint. On 27 June 2018, BP answered the complaint by seeking dismissal on various grounds including that no oil reached Mexican waters or land and there was no economic or environmental harm in Mexico.

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 against BPXP, BPAPC, and other purported BP subsidiaries. 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. BPXP was formally served with the action on 8 December 2017. BPXP opposed class certification and sought dismissal on 1 February 2018, principally on the basis that that no oil reached Mexican waters or land and there was no economic or environmental harm in Mexico. BPAPC was formally served with the

action in October 2018 and filed an opposition to class certification and requested dismissal on 28 December 2018.
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.
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. On 27 September 2018, the OSH Review Commission issued its decision, which reduced the citations to two remaining, and reduced the penalty to $7,000. OSHA has decided not to appeal this decision.
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. On July 31, 2018 the Ninth Circuit granted the parties' motion to dismiss the appeal voluntarily ending the litigation.
Lead paint matters
Since 1987, Atlantic Richfield Company (Atlantic Richfield), a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. The plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programmes, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be

substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences. It intends to defend such actions vigorously and believes that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group's results, financial position or liquidity will not be material.
Scharfstein v. BP West Coast Products, LLC
A class action lawsuit was filed against BP West Coast Products, LLC (BPWCP) 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 BPWCP 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 against BPWCP for the amount of $417.3 million. On 31 May 2018 the Oregon Court of Appeals affirmed the trial court's ruling. BP filed a Petition for Review to the Oregon Supreme Court which was denied on 8 November 2018. In March 2019, BP and the Plaintiffs agreed to a settlement of the class action lawsuit, subject to final court approval. BP intends to file a petition for a writ of certiorari to the US Supreme Court in order to preserve BP's appeal rights pending final court approval of the settlement. BP's provisions for litigation and claims includes a provision for this lawsuit.

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.

In May 2018, the US government announced its planned withdrawal from the Joint Comprehensive Plan of Action (JCPOA) under which the US and the EU had implemented temporary, limited and reversible relief of certain sanctions related to Iran. The US government tasked OFAC with implementing the full re-imposition of both primary and secondary sanctions in respect of Iran by the end of a wind-down period. As a result of the JCPOA, BP had considered and developed possible business opportunities in relation to Iran, engaged in discussions with Iranian government officials and other Iranian nationals and attended conferences. BP will continue to monitor and assess business opportunities in Iran which are compliant with EU and US laws applicable to BP including potentially attending meetings in connection with this purpose.

On 30 November 2018, BP completed the sale of certain of its assets in the North Sea, including its ownership stake, and the transfer of its role as operator, in the North Sea Rhum field (Rhum) joint arrangement to Serica Energy plc (Serica). Prior to that date, Rhum was owned under a 50:50 unincorporated joint arrangement between BP and Iranian Oil Company (U.K.) Limited (IOC).

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 the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA).

On 3 December 2018 BP entered into an agreement with, among others, SOCAR and NICO pursuant to which SOCAR shall pay to BP

Exploration Shah Deniz Limited (BPXSD), as the Shah Deniz Operator, an amount in respect of compensation for NICO's waiver of its right to lift its share of Shah Deniz condensate. Such amounts shall be used to cover cash calls to NICO in respect of operating costs due from NICO to BPXSD. On 30 November 2018, OFAC issued a new licence in relation to these arrangements.

BP holds an interest in a non-BP operated Indian joint venture« that 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 sells lubricants in Cuba through a 50:50 joint arrangement and trades in small quantities of lubricants.

During 2014 the US and the EU imposed sanctions on certain Russian activities, individuals and entities, including Rosneft. Certain sectoral sanctions also apply to entities in which entities on the relevant sectoral sanctions list own a certain percentage interest, being either 33% or 50% depending on certain criteria. In August 2017, Russia related sanctions were passed in the US which target among other things: (i) Russian energy export pipelines; (ii) privatisation of state owned assets in Russia; and (iii) certain international offshore Arctic, deepwater and/or shale exploration and production oil projects. We are not aware of any material adverse effect on our current income and investment in Russia or elsewhere as a consequence of those sanctions.

BP maintains bank accounts and has registered and paid required fees to maintain registrations of patents and trademarks in certain Sanctioned Countries.

BP has equity interests in non-operated joint arrangements« with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint arrangement operator or other partners may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries, without BP's involvement.

BP has no control over the activities non-controlled associates may undertake in Sanctioned Countries or with persons from Sanctioned Countries.

Disclosure pursuant to Section 219 of ITRA

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

- Prior to 30 November 2018, Rhum, located in the UK sector of the North Sea, was operated by BP Exploration Operating Company Limited (BPEOC), a non-US subsidiary of BP, and Rhum was owned under a 50:50 unincorporated joint arrangement between BPEOC and Iranian Oil Company (U.K.) Limited (IOC) which was initially established in 1974. During 2018, BP recorded gross revenues of $177.3 million related to its interests in Rhum. BP had a net profit of $87.7 million for the year ended 31 December 2018.
- BP has sought to carry out its role as operator of the Rhum joint arrangement in compliance with US sanctions and has obtained a series of specific OFAC licences relating to the ongoing operation of the Rhum field.
- In November 2017, BPEOC entered into an agreement with IOC for the sale and purchase of an IOC entitlement to Forties blend crude oil. The parties agreed to set off the purchase price - £29.89 million ($39.88 million equivalent) - against IOC's share of operating costs incurred or to be incurred by BPEOC as operator of the Rhum field under the Rhum joint operating agreement. 604,976 net barrels of Forties blend crude oil was loaded at a North Sea terminal in January 2018 and delivered to BP's Rotterdam refinery. Upon

delivery at BP's Rotterdam refinery, the Forties blend crude oil 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.

- During 2018, BPEOC received £223,693 ($298,456 equivalent) (net of tariffs) from BPEOC Forties Pipeline System in respect of monies owed to IOC in relation to the purchase of IOC's share of Onshore Raw Gas at the Kinneil terminal of the Forties Pipeline System. BP and IOC agreed to set off the £223,693 ($298,456 equivalent) against

IOC's share of operating costs incurred or to be incurred by BPEOC as operator of the Rhum field under the Rhum joint operating agreement.

- During 2018, BPEOC received £2.79 million ($3.73 million equivalent) (net of tariffs) from a non-US third party in respect of the sale to such non-US third party of certain NGLs redelivered from the St Fergus terminal. These NGLs had been acquired by BPEOC from IOC at the St. Fergus terminal. BP and IOC agreed to set off the £2.79 million ($3.73 million equivalent) against IOC's share of operating costs incurred by BPEOC as operator of the Rhum field under the Rhum joint operating agreement.
- As noted above, on 30 November 2018, BP completed the sale of its ownership stake in the Rhum joint arrangement and transferred its role as operator to Serica. Prior to the sale, on 5 October 2018, Serica and BP received a conditional licence from OFAC relating to the ongoing operation of the Rhum field. The licence was valid until 31 October 2019 and was conditional upon arrangements being put in place before 5 November 2018 relating to the interests in Rhum held by IOC. An updated licence from OFAC on substantially the same terms and a letter of comfort permitting all non-US persons to support Rhum activities in compliance with US secondary sanctions were issued on 2 November 2018. On the same date the conditions in such OFAC licence in respect of the interest in Rhum held by IOC were met in full. These conditions were satisfied through arrangements which provide that all benefits accruing from and relating to IOC's interest in Rhum will be held in escrow, by a trust and management company (Rhum Management Company) set up for this purpose, for such period as US sanctions apply. The arrangements are designed to ensure that neither IOC nor any direct or indirect parent company of IOC (including any member of the Government of Iran) will derive any economic benefit from Rhum, or exercise any decision-making powers in respect of Rhum, during that period. From satisfaction of the OFAC licence conditions on 2 November 2018, BP dealt with the Rhum Management Company in respect of Rhum joint venture matters.
- In December 2018, BP made a cash transfer of £2.69 million ($3.59 million equivalent) to Rhum Management Company. This transfer represented the net amount of IOC funds in the Rhum joint venture account which had not, to that date, been set off against IOC's share of operating costs incurred by BPEOC as operator of the Rhum field under the Rhum joint operating agreement.
- BP does not expect to enter into any further similar arrangements with IOC or any member of the Government of Iran in relation to the Rhum field. BP will continue to purchase from Serica's liftings from Rhum or provide services to Serica as the operator of Rhum.
- On 17 July 2018 BP Iran Limited terminated its lease of an office in Tehran. The office had been used for administrative activities. In 2018, taxes, including rental tax payments associated with the Tehran office, with an aggregate US dollar equivalent value of approximately $11,000, 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.
- During 2018, 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 $3,000. In addition, certain BP employees met with Iranian government officials and other Iranian nationals outside of Iran. No gross revenues or net profits were attributable to these activities, save where otherwise disclosed. BP will continue to monitor and assess business opportunities in Iran which are compliant with EU

and US laws applicable to BP including potentially attending meetings in connection with this purpose.
Material contracts
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 resolved 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 2018 filed with the SEC. For further details of the Consent Decree and the Settlement Agreement, see Legal proceedings in BP Annual Report and Form 20-F 2015.
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 2018 and the group percentage of ordinary share capital see Financial statements – Note 37. For information on significant joint ventures« and associates« of the group see Financial statements – Notes 16 and 17.
Related-party transactions
Transactions between the group and its significant joint ventures and associates are summarized in Financial statements – Note 16 and Note 17. 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 any material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2018 to 15 March 2019.
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 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 and remuneration (rather than compensation) committee. BP also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive

directors whom the board has determined to be independent, in the manner described above.
The BP board governance principles prescribe the composition, main tasks and requirements of each of the committees (see the board committee reports on pages 75-86). 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 75). 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 within the company, if any, 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 costs and benefits of possible control and procedure design options. Also, we have investments in 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 2018 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the criteria in the UK Financial Reporting Council's Guidance on Risk Management, Internal Control and Related Financial and Business Reporting relating to internal control over financial reporting. Based on this assessment, management has determined that BP's internal control over financial reporting as of 31 December 2018 was effective.

Management's assessment of the effectiveness of internal control over financial reporting excluded Petrohawk Energy Corporation, which was acquired on 31 October 2018. Petrohawk financial statements constitute 10.3% and 4.0% of net and total assets respectively, 0.2% of revenues, and 0.05% of net income of the consolidated financial statement amounts as of and for the year ended 31 December 2018. This exclusion is in accordance with the general guidance issued by the SEC that an assessment of a recent business combination may be omitted from management's report on internal control over financial reporting in the first year of consolidation.

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 2018 has been audited by Deloitte, an independent registered public accounting firm, as stated in their report appearing on page 127 of BP Annual Report and Form 20-F 2018.

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 control over financial reporting.

Principal accountant's fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Deloitte LLP, to render audit and certain assurance services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, non-audit and other services that are not prohibited by regulatory or other professional requirements. Deloitte is 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 non-audit tax services provided by the audit firm from 2017 onwards are prohibited.

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); provision of, or access to, Deloitte 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 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 UK Financial Reporting Council, the audit committee reviewed and updated its policies with effect from 1 January 2017 and in 2018 further updated its policies to clarify the engagement of the incoming auditor, Deloitte, and the outgoing auditor (and auditor of Rosneft) Ernst & Young to ensure independence. The defined maximum level for pre-approval has been reduced in line with FRC 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 auditor each year. The audit fees payable to Deloitte 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 auditor. External regulation and BP policy requires the auditor to rotate its lead audit partner every five years. See Financial statements – Note 36 and Audit committee report on page 79 for details of fees for services provided by the auditor.

Directors' report information

This section of BP Annual Report and Form 20-F 2018 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 2018. During the year, a review of the terms and scope of the policy was undertaken. The policy was renewed during 2018 and continued into 2019. 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 53, Liquidity and capital resources on page 277 and Financial statements – Notes 29 and 30.

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 29.

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 in the business of the company 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 Innovation in BP on page 40.

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 51.

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 in BP Annual Report and Form 20-F 2015.

Greenhouse gas emissions

The disclosures in relation to greenhouse gas emissions are included in Sustainability – Climate change on page 45.

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	159
(2) – (11)	Not applicable
(12), (13) Dividend waivers	302
(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') and the general doctrine of cautionary statements, 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 and circumstances - 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 likel to', 'intends', 'believes', 'anticipates', 'plans', 'we see' or similar expressions. In particular, among other statements, (i) certair statements in the Chairman's letter (pages 6-7), the Group chief executive's letter (page 8), the Strategic report (inside cover and pages 1-56), Additional disclosures (pages 273-304) and Shareholder information (pages 305-314), including but not limited to statements under the headings 'The changing energy mix', 'How we run our business', 'Our strategy' and 'Global energy markets' and including but not limited to statements regarding plans and prospects relating to near- and long-term growth, organic capital expenditure, organic growth, the strength of BP's balance sheet, maintaining a robust cash position, working capital, operating cash flow and margins, capital discipline, growth in sustainable free cash flow and shareholder distributions and future dividend and optional scrip dividend payments; plans and expectations regarding share buybacks, including to offset the impact of dilution from the scrip programme since the third quarter 2017 by the end of 2019; expectations regarding world energy demand, including the growth in relative demand for renewables, oil and gas, and the proportional growth of renewables; expectations with respect to the world energy mix, production, consumption and emissions to 2040; plans and expectations regarding BP's portfolio, including having a distinctive portfolio, BP's active management of the portfolio and the flexibility of the portfolio; plans and expectations with respect to disciplined investment; plans and expectations with respect to the Upstream, including growing advantaged oil and gas, being competitive in every basin and producing resilient and competitive barrels; plans and expectations with respect to BP's transformation agenda; plans and expectations to deliver 2021 financial targets; expectations with respect to reserves bookings from new discoveries; plans and expectations regarding BP's quality of execution, including to get more from a unit of capital compared to peers; plans and expectations with respect to BP's refining and petrochemicals portfolio; plans and expectations with respect to creating distinctive retail offers in the Downstream; plans and expectations with regard to new technologies, including their efficiency and impact on production; plans and expectations with respect to BP's investments in Chargemaster, StoreDot and FreeWire, including for BP to become the leading fuel provider for both conventional and electric vehicles and supporting electric vehicle adoption; plans and expectations with respect to BP's investment in solar energy and biofuels, including to invest $200 million in Lightsource BP over a three-year period; plans and expectations with respect to the commercial optimization programme; plans and expectations to run safe and reliable operations; plans and expectations regarding BP's acquisition of onshore-US oil and gas assets from BHP, including expectations regarding the funding and timing of further purchase price payments, future performance and operations and related divestments; plans and expectations to reduce emissions in operations and the low carbon future, including to target zero net growth in operational emissions to 2025 and the Advancing Low Carbon accreditation programme; plans and expectations with respect to evaluating the creation of a joint venture with SOCAR; plans and expectations regarding BP's low carbon businesses, including in Brazil and India; plans and expectations with respect to Fulcrum BioEnergy's commercial operations; plans to grow third-party technology licensing income; plans and expectations regarding charges in Other businesses and corporate in 2019 and proceeds from divestments and disposals, including to have more than $10 billion of divestments over the next two years; expectations regarding the determination of business economic loss claims in respect of the 2012 PSC settlement and expectations with respect to the timing and amount of future payments relating to the Gulf of Mexico oil spill

including 2012 PSC settlement payments; plans and expectations regarding sales commitments of BP and its equity-accounted entities; expectations regarding underlying production and capital investment; plans and expectations with respect to gearing including to target gearing within a 20-30% band; expectations regarding oil prices; expectations regarding the return on average capital employed; expectations with respect to the cash break even point; plans and expectations regarding the US onshore, including to increase the liquid hydrocarbon proportion and to upgrade and reposition BPX Energy; plans with regard to BP's exploration budget; plans and expectations regarding the resiliency of downstream businesses; expectations regarding the effective tax rate in 2019; plans to produce 900,000boe/d from new major projects by 2021 and expectations regarding operating cash margins of this production; plans to start up five major projects in 2019; plans and expectations with respect to expected project start-ups between 2019 and 2021; plans and expectations regarding investment, development, and production levels and the timing thereof with respect to projects and partnerships in Australia, Azerbaijan, Brazil, China, Egypt, India, Indonesia, Libya, Mexico, Mauritania, Russia, São Tomé and Príncipe, Senegal, Turkey, Trinidad & Tobago, Oman, the UK North Sea, the Gulf of Mexico, and the continental United States; expectations regarding the Trans Anatolian Natural Gas Pipeline; plans and expectations regarding social investment; plans and expectations regarding relationships with governments, customers, partners, suppliers and communities; plans and expectations regarding the dual energy challenge and the energy transition, including BP's progressive and pragmatic approach and planned investments; plans and expectations regarding shareholder resolutions; plans and expectations with respect to BP's public reporting of ambitions, plans and progress; plans and expectations regarding innovation in BP, including the development of BPme, Wolfspar, a land seismic recording system, APEX, Plant Operations Advisor and wind energy storage systems; plans and expectations regarding plant reliability and base decline, including for base decline to remain between 3-5%; plans and expectations regarding the Tangguh gas facility; expectations regarding discounts for North American heavy crude oil, refining margins and refining turnarounds; plans to undertake joint exploration and development with Rosneft, including to explore oil and gas licence areas in Sakha (Yakutia); expectations regarding pensions and other post-retirement benefits; expectations regarding payments under contractual obligations; 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; policies and goals related to risk management plans; plans regarding activities, dealings and transactions relating to Iran; plans and projections regarding oil and gas reserves, including the turnover time of proved undeveloped reserves to proved developed reserves; expectations regarding the costs of environmental restoration programmes; 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; 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 57-86) and the Directors' remuneration report (pages 87-109) with regard to the anticipated future composition of the board of directors and the effects thereof; the board's goals and areas of focus, including changes to KPIs and those goals stemming from the board's annual evaluation; plans and expectations regarding directors' share ownership and remuneration; plans regarding the governance and remuneration processes; and goals, activities 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 projects onstream; the timing, quantum and nature of certain acquisitions and 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 and policies, including related to climate change; changes in social attitudes and customer preferences; 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; amounts ultimately determined to be payable and the timing of payments relating to the Gulf of Mexico oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; our access to future credit resources; business disruption and crisis management; the impact on our reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; decisions by Rosneft’s management and board of directors; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism; cyberattacks or sabotage; and other factors discussed elsewhere in this report including under Risk factors (pages 55-56). 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.

Shareholder information

Share prices and listings

Markets and market prices

The primary market for BP’s ordinary shares is the London Stock Exchange (LSE) (trading symbol 'BP'). BP’s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index.

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 (trading symbol 'BP'), for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary’s principal office is 383 Madison Avenue, Floor 11, New York, NY, 10179, 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.

BP's securities are also traded in the form of a global depositary certificate representing BP ordinary shares on the Frankfurt, Hamburg and Dusseldorf Stock Exchanges.

On 11 March 2019, 922,206,611 ADSs (equivalent to approximately 5,533,239,666 ordinary shares or some 27.31% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 81,329 ADS holders. Of these, about 80,393 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 1,207,639 underlying holders.

On 11 March 2019 there were approximately 235,594 ordinary shareholders. Of these shareholders, around 1,540 had registered addresses in the US and held a total of some 4,112,535 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 or 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 10.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010 and was renewed for a further three years at the 2018 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 55 and other matters that may affect the business of the group set out in Our strategy on page 10 and in Liquidity and capital resources on page 277.

The following table shows dividends announced and paid by the company per ADS for the past five years.

	March	June	September	December	Total

Dividends per ADS[a]

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
2017	UK pence	48.95	46.54	45.73	44.66	185.88
	US cents	60	60	60	60	240
2018	UK pence	43.01	44.66	47.58	48.15	183.40
	US cents	60	60	61.50	61.50	243

[a] Dividends announced and paid by the company on ordinary and preference shares are provided in Financial statements – Note 10.

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, was 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. The dividend allowance was £5,000 but this has been reduced to £2,000 as of 6 April 2018.

The dividend allowance of £2,000 means there is no UK tax due on the first £2,000 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 £2,000 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 £2,000 allowance. For instance, if an individual has an annual gross salary of £50,000 and also receives a dividend of £12,000 they will be subject to the following scenario. The individual's personal allowance and the basic rate tax band will be used up by the gross salary. The remaining part of the salary and the whole of the dividend will be subject to tax at the higher rate, although the dividend allowance will reduce the amount of dividend subject to tax. The dividend of £12,000 will be reduced by the dividend allowance of £2,000 leaving taxable dividend income of £10,000. The dividend will be taxed at 32.5% so that the total tax payable on the dividends is £3,250.

How the shareholder pays the tax arising on the dividend income depends on the amount of dividend income and salary they receive in the tax year. If less than £2,000 they will not need to report anything or pay any tax. If between £2,000 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 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.

For gains on or after 23 June 2010, the UK Capital Gains Tax rate will be dependent on the level of an individual's taxable income. Where total taxable income and gains after all allowable deductions are less than the upper limit of the basic rate income tax band of £34,500 (for 2018/19), the rate of Capital Gains Tax will be 10%. For gains (and any parts of gains) above that limit the rate will be 20%.

From 6 April 2008, entitlement to the annual exemption is based on an individual's circumstances (taking into account Domicile status, remittance basis of taxation and number of years in the UK). For individuals who are entitled to the exemption for 2018/19, this has been set at £11,700. Corporation tax on chargeable gains is levied at 19 per cent for companies from 1 April 2017.

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 (PFIC) for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain 'excess distributions' would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Programme

The company has an optional Scrip Programme, wherein holders of BP ordinary shares or ADSs may elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax adviser for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual's death or on transfer during the individual's lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an

agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary's nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment, HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

US Medicare Tax

A US holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, is subject to a 3.8% tax on the lesser of (1) the US holder's 'net investment income' (or 'undistributed net investment income' in the case of an estate or trust) for the relevant taxable year and (2) the excess of the US holder's modified adjusted gross income for the taxable year over a certain threshold (which in the case of individuals is between $125,000 and $250,000, depending on the individual's circumstances). A holder's net investment income generally includes its dividend income and its net gains from the disposition of shares or ADSs, unless such dividend income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). If you are a US holder that is an individual, estate or trust, you are urged to consult your tax 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 2018

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	53,495	22.63	0.01
201-1,000	79,856	33.77	0.22
1,001-10,000	90,654	38.34	1.41
10,001-100,000	10,801	4.57	1.11
100,001-1,000,000	948	0.40	1.77
Over 1,000,000[a]	689	0.29	95.48
Totals	236,443	100.00	100.00

a Includes JPMorgan Chase Bank, N.A. holding 27.32% 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 2018[a]

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1-200	48,763	59.44	0.28
201-1,000	21,504	26.21	1.11
1,001-10,000	11,266	13.73	3.17
10,001-100,000	501	0.61	0.91
100,001-1,000,000	7	0.01	0.13
Over 1,000,000[b]	1	0.00	94.40
Totals	82,042	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.

[b] One holder of ADSs represents 1,169,280 underlying shareholders.

As at 31 December 2018 there were also 1,286 preference shareholders. Preference shareholders represented 0.42% and ordinary shareholders represented 99.58% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

As at 31 December 2018, we had been notified pursuant to DTR5 that BlackRock, Inc. held 6.84% of the voting rights attached to the issued share capital of the company.

Between 1 January 2019 and 11 March 2019, we received notification of the following interests pursuant to DTR5. On 12 February 2019, BlackRock, Inc. notified BP that it held 7.29% of the voting rights attached to the issued share capital of the company. On 19 February 2019, BlackRock, Inc. notified BP that it held 7.28% of the voting rights attached to the issued share capital of the company.

We are also aware that, as at 11 March 2019, BlackRock, Inc. held 6.61% and The Vanguard Group, Inc. held 3.45% of the ordinary issued share capital of the company.

Under the US Securities Exchange Act of 1934 BP is aware of the following interests as at 11 March 2019:

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	5,533,239,667	27.31
BlackRock, Inc.	1,339,183,607	6.61

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 11 March 2019:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society Limited	945,000	13.10
Hargreaves Lansdown Asset Management Limited	628,471	8.70
Canaccord Genuity Group Inc.	587,885	8.10
Prudential plc	528,150	7.30

Holder	Holding of 9% cumulative second preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society Limited	987,000	18.00
Prudential plc	644,450	11.80
Safra Group	320,000	5.80
Hargreaves Lansdown Asset Management Limited	317,789	5.80
Canaccord Genuity Group Inc.	283,135	5.20

As at 11 March 2019, the total preference shares in issue comprised only 0.42% of the company's total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Annual general meeting

The 2019 AGM will be held on Tuesday 21 May 2019 at 11.00am. 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. Deloitte 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 2019.

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. The Memorandum and Articles of Association are available online at bp.com/usefuldocs.

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 and shareholders voted to adopt new Articles of Association at the AGM held on 16 April 2015. At the AGM held on 21 May 2018 shareholders voted to adopt new Articles of Association to reflect developments in market practice and to provide clarification and additional flexibility where necessary or appropriate.

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 and secretary

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 subsidiary undertakings.
- 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 subsidiary undertakings.

- 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.

The Articles of Association provide entitlement to the directors' pensions and death and disability benefits to the directors' relations and dependants respectively.

The circumstances in which a director's office will automatically terminate include: when a director ceases to hold an executive office of the company and the directors resolve that he should cease to be a director; if a medical practitioner provides an opinion that a director has become incapable of acting as a director and may remain so incapable for a further three months and the directors resolve that he should cease to be a director; and if all of the other directors vote in favour of a resolution stating that the person should cease to be a director.

The company secretary has express powers to delegate any of the powers or discretions conferred on him or her.

Dividend rights; other rights to share in company profits; capital calls

If recommended by the directors of BP, shareholders of BP 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 10 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 entitlement to claim dividends or other monies unclaimed in respect of those shares will be for a period of twelve months after the sale. The company may take such steps as the directors decide are appropriate in the circumstances to trace the member entitled and the sale may be made at such time and on such terms as the directors may decide.

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 21 May 2018 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.

The directors may determine in relation to any scrip dividend plan or programme how the costs of the programme will be met, the minimum number of ordinary shares required in order to be able to participate in the programme and any arrangements to deal with legal and practical difficulties in any particular territory.

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.

Share transfers and share certificates

The directors may permit transfers to be effected other than by an instrument in writing and that share certificates will not be required to be issued by the company if they are not required by law.

The company may charge an administrative fee in the event that a shareholder wishes to replace two or more certificates representing shares with a single certificate or wishes to surrender a single certificate and replace it with two or more certificates. All certificates are sent at the member's risk.

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 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.

The directors have power to convene a general meeting which is a hybrid meeting, that is to provide facilities for shareholders to attend a meeting which is being held at a physical place by electronic means as well (but not to convene a purely electronic meeting).

The provisions of the Articles of Association in relation to satellite meetings permit facilities being provided by electronic means to allow those persons at each place to participate in the meeting.

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 2018 are set out in Financial statements – Note 31. In accordance with institutional investor guidelines, the company deems it appropriate to grant authority to the directors to allot shares and other securities and to disapply pre-emption rights by way of shareholders resolutions at each AGM in place of authority granted by virtue of the company's Articles of Association. At the AGM on 21 May 2018, authorization was given to the directors to allot shares in the company and to grant rights to subscribe for, or to convert any

security into, shares in the company up to an aggregate nominal amount as set out in the Notice of Meeting 2018. These authorities were given for the period until the next AGM in 2019 or 21 August 2019, whichever is the earlier. These authorities are renewed annually at the AGM.

Company records and service of notice

In relation to notices not covered by the Act, the reference to notice by advertisement in a national newspaper also includes advertisements via other means such as a public announcement.

Purchases of equity securities by the issuer and affiliated purchasers

In November 2017 BP began a share repurchase or buyback programme (the programme). The sole purpose of the programme is to reduce the issued share capital of the company to offset the ongoing dilutive effect of scrip dividends over time, as announced by the company on 31 October 2017. Authorization for the programme was renewed at the company’s 2018 AGM covering the period until the date of the company's 2019 AGM. The maximum number of ordinary shares to be purchased will not exceed 1.99 billion ordinary shares, which is the maximum number of ordinary shares permitted to be purchased by the company pursuant to the authority granted by shareholders at the company's 2018 AGM . The shares purchased will be cancelled.

The following table provides details of ordinary share purchases made (1) under the programme and (2) by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased[a]	Average price paid per share $	Number of shares purchased by ESOPs or for certain employee share-based plans[b]	Number of shares purchased as part of the buyback programme[c]	Maximun approximate dollar value of shares yet to be purchased under the programme $ million
2018					
January	Nil				N/A
February 6 – February 28	12,574,000	6.69	24,000	12,550,000	N/A
March 8 – March 21	5,500,000	6.62	Nil	5,500,000	N/A
April	Nil				N/A
May 1 – May 11	7,765,798	7.50	463,650	7,302,148	N/A
June 6 – June 27	3,230,500	7.66	Nil	3,230,500	N/A
July	Nil				N/A
August 3 – August 30	6,788,050	7.24	Nil	6,788,050	N/A
September 4 – September 21	12,497,354	7.22	Nil	12,497,354	N/A
October	Nil				N/A
	2,603,190	6.84	269,000	2,334,190	N/A

November 1 – November 28					
December	Nil				N/A
2019					
January	Nil				N/A
February 5 – February 21	2,753,983	7.10	120,000	2,633,983	N/A
March 11	717,995	7.14	Nil	717,995	N/A

[a] All share purchases were of ordinary shares of 25 cents each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.

[b] Transactions represent the purchase of ordinary shares by ESOPs and other purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

[c] The company announced its intent to commence the programme on 31 October 2017 and announced further details and commencement of the programme on 15 November 2017. At the AGM on 21 May 2018, authorization was given to the company to repurchase up to 1.99 billion ordinary shares, for the period ending on the date of the AGM in 2019 or 21 August 2019, whichever is the earlier. This authorization is renewed annually at the AGM. The total number of ordinary shares repurchased during 2018 under the programme was 50,202,242 at a cost of $355 million (including fees and stamp duty) representing 0.25% of BP’s issued share capital excluding shares held in treasury on 31 December 2018. All ordinary shares repurchased in 2018 under the programme were cancelled in order to reduce BP’s issued share capital.

Fees and charges payable by ADS 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.	The Deposit Agreement provides that a fee of $0.05 or less per ADS can be charged. The current fee is $0.02 per BP ADS per calendar year (equivalent to $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.

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 2018. The Depositary reimbursed to the company, or paid amounts on the company's behalf to third parties, or waived its fees and expenses, of $16,582,418.54 for the year ended 31 December 2018.

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 2018.

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 2018 $
Fees for delivery and surrender of BP ADSs	647,683.39
Dividend fees[a]	15,934,735.15
Total	16,582,418.54

[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 2018 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. The SEC maintains an internet site at http://www.sec.gov that contains reports and other information regarding issuers, including BP, that file electronically with the SEC. BP's SEC filings are also available at bp.com/sec. BP discloses in this report (see Corporate governance practices (Form 20-F Item 16G) on page 300) 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, Link Asset Services
The Registry, 34 Beckenham Road, Beckenham, Kent BR3 4TU, UK
Freephone in UK 0800 701107
From outside the UK +44 (0)371 277 1014
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

2019 shareholder calendar[a]

30 April 2019	First quarter results announced
10 May 2019	Record date (to be eligible for the first quarter interim dividend)
21 May 2019	Annual general meeting
21 Jun 2019	First quarter interim dividend payment for 2019
5 Jul 2019	8% and 9% preference shares record date
30 Jul 2019	Second quarter results announced
31 Jul 2019	8% and 9% preference shares dividend payment
9 Aug 2019	Record date (to be eligible for the second quarter interim dividend)
20 Sep 2019	Second quarter interim dividend payment for 2019
29 Oct 2019	Third quarter results announced
8 Nov 2019	Record date (to be eligible for the third quarter interim dividend)
20 Dec 2019	Third quarter interim dividend payment for 2019

[a] All future dates are provisional and may be subject to change. For the full calendar see bp.com/financialcalendar.

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 4.3	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 8	Subsidiaries (included as Note 37 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	Consent of Netherland, Sewell & Associates†
Exhibit 15.4	Report of Netherland, Sewell & Associates†

Exhibit 15.5	Consent Decree*******†
Exhibit 15.6	Gulf states Settlement Agreement*******†
Exhibit 15.7	Consent of Ernst & Young LLP†
Exhibit 15.8	Consent of Deloitte LLP (included on page 127)
Exhibit 101	Interactive data files

*	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 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 BP p.l.c. and its subsidiaries under any one instrument does not exceed 10% of their total assets on a consolidated basis.

The company agrees to furnish copies of any or all such instruments to the SEC on request.

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.
b/d
Barrels per day.
boe/d
Barrels of oil equivalent per day.
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 or Mb/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 or Mte
Million tonnes.
$MteCO_2$
Million tonnes of CO_2 equivalent.

MW
Megawatt.
NGLs
Natural gas liquids.
PSA
Production-sharing agreement.

PTA
Purified terephthalic acid.
RC
Replacement cost.
SEC
The United States Securities and Exchange Commission.
Definitions
Unless the context indicates otherwise, the definitions for the following glossary terms are given below.
Non-GAAP measures are sometimes referred to as alternative performance measures.
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. A reconciliation to GAAP information is provided on page 320.
We are unable to present reconciliations of forward-looking information for adjusted ETR to ETR on profit or loss for the period, 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 the taxation on inventory holding gains and losses, non-operating items and fair value accounting effects, that are difficult to predict in advance in order to include in a GAAP estimate.
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
Total cash capital expenditure as stated in the group cash flow statement.
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 22 and in Downstream on page 28. 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.

Divestment proceeds
Disposal proceeds as per the group cash flow statement.
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. A reconciliation to GAAP information is provided on page 320.

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 physical contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences.

BP enters into contracts for pipelines and other transportation, 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 that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management’s internal measure of performance. Under management’s internal measure of performance the inventory, transportation 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 derivative instruments used to risk manage certain oil, gas and other 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. A reconciliation to GAAP information is provided on page 320.

In addition, from 2018 fair value accounting effects include changes in the fair value of the near-term portions of LNG contracts that fall within BP’s risk management framework. LNG contracts are not considered derivatives, because there is insufficient market liquidity, and they are therefore accrual accounted under IFRS. However, oil and natural gas derivative financial instruments (used to risk manage the near-term portions of the LNG contracts) are fair valued under IFRS. The fair value accounting effect reduces timing differences between recognition of the derivative financial instruments used to risk manage the LNG contracts and the recognition of the LNG contracts themselves, which therefore gives a better representation of performance in each period. Comparative information has not been restated on the basis that the effect was not material.

Free cash flow

Operating cash flow less net cash used in investing activities, as presented in the group cash flow statement.

Full dividend

Full dividend is cash dividend plus cash equivalent value of scrip dividend.

Gearing

See Net debt and net debt ratio definition.

Gross debt ratio

Gross debt ratio is defined as the ratio of gross debt to the total of gross debt plus shareholders' equity.

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 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 a cash 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. An analysis of organic capital expenditure by segment and region, and a reconciliation to GAAP information is provided on page 275.

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 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 27 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 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 276.

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 Gulf of Mexico oil spill payments
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. BP believes net cash provided by operating activities excluding amounts related to the Gulf of Mexico oil spill is a useful measure as it allows for more meaningful comparisons between reporting periods. The nearest equivalent measure on an IFRS basis is net cash provided by operating activities.
Organic free cash flow is operating cash flow excluding Gulf of Mexico oil spill payments less organic capital expenditure.
Operating cash margin
Operating cash margin is operating cash flow divided by the applicable number of barrels of oil equivalent produced, at $52/bbl flat oil prices. Expected operating cash margins are calculated over the period 2016-2025.
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 and is a non-GAAP measure. Organic capital expenditure comprises capital expenditure 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 organic capital expenditure by segment and region, and a reconciliation to GAAP information is provided on page 275.
We are unable to present reconciliations of forward-looking information for organic capital expenditure to total cash capital expenditure, because without unreasonable efforts, we are unable to forecast accurately the adjusting item, inorganic capital expenditure, that is difficult to predict in advance in order to derive the nearest GAAP estimate.
Organic sources of cash and organic uses of cash
Non-GAAP measure. Organic sources of cash is the sum of operating cash flow, excluding Gulf of Mexico oil spill payments, and proceeds of loan repayments. Organic uses of cash is the sum of organic capital expenditure, dividends and share buybacks. The nearest equivalent measure on an IFRS basis for organic sources of cash is net cash provided by operating activities and the nearest equivalent measures on an IFRS basis for organic uses of cash are total cash capital expenditure, dividends paid to BP shareholders and net issue (repurchase) of shares.
Production-sharing agreement (PSA) / Production-sharing contract
An arrangement through which an oil and gas 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.
Readily marketable inventory (RMI)
RMI is inventory held and price risk-managed by our integrated supply and trading function (IST) which could be sold to generate funds if required. It comprises oil and oil products for which liquid markets are available and excludes inventory which is required to meet operational requirements and other inventory which is not price risk-managed. RMI is reported at fair value. Inventory held by the Downstream fuels business for the purpose of sales and marketing, and all inventories

relating to the lubricants and petrochemicals businesses, are not included in RMI. BP believes that disclosing the amounts of RMI and paid-up RMI is useful to investors as it enables them to better understand and evaluate the group's inventories and liquidity position by enabling them to see the level of discretionary inventory held by IST and to see builds or releases of liquid trading inventory.

Paid-up RMI excludes RMI which has not yet been paid for. For inventory that is held in storage, a first-in first-out (FIFO) approach is used to determine whether inventory has been paid for or not. Unpaid RMI is RMI which has not yet been paid for by BP. RMI, RMI at fair value, Paid-up RMI and Unpaid RMI are non-GAAP measures. A reconciliation of total inventory as reported on the group balance sheet to paid-up RMI is provided on page 322.

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.

Refining net cash margin per barrel

Refining 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.

Refinery utilization

Refinery utilization is calculated as annual throughput (thousands of barrels per day) divided by crude distillation capacity.

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. A reconciliation to GAAP information is provided on page 274.

RC profit or loss per share

Non-GAAP measure. Earnings per share is defined in Financial statements – Note 11. 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. A reconciliation to GAAP information is provided on page 320.

Reserves replacement ratio

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.

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 tax (for the comparative periods interest expense was net of notional tax at an assumed 35%), divided by average capital employed, excluding cash and cash equivalents and goodwill. Interest expense is finance costs excluding the unwinding of the discount on provisions and other payables before tax. 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 321.

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, costly damage to equipment or exceeding defined quantities. 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.

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 acquisitions and divestments and entitlement impacts in our production-sharing agreements.

Underlying RC profit or loss

Non-GAAP measure. RC profit or loss after adjusting for non-operating items and fair value accounting effects. See page 276 and 320 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. Underlying profit in the group chief executive's letter on page 8 refers to full year underlying RC profit for the group. A reconciliation to GAAP information is provided on page 274.

Underlying replacement cost (RC) profit or loss per share

Non-GAAP measure. Earnings per share is defined Financial statements – Note 11. 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. A reconciliation to GAAP information is provided on page 320.

Upstream plant reliability

BP-operated Upstream 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, which does not include Gulf of Mexico weather related downtime.

Upstream unit production cost

Upstream unit production cost is calculated as production cost divided by units of production. Production cost does not include ad valorem and severance taxes. Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts disclosed are for BP subsidiaries only and do not include BP's share of equity-accounted entities.

Wellwork

Activities undertaken on previously completed wells with the primary objective to restore or increase production.

West Texas Intermediate (WTI)

A light sweet crude oil, priced at Cushing, Oklahoma, which serves as a benchmark price for purchases of oil in the US.

Working capital

Movements in inventories and other current and non-current assets and liabilities as stated in the group cash flow statement.

Trade marks

Trade marks of the BP group appear throughout this report. They include: ACTIVE, Aral, ARCO, BP, BPme, BP Ultimate, Castrol, Castrol EDGE BIO-SYNTHETIC, Castrol GTX ECO, Castrol Opitgear, PTAir

Trade marks:

Butamax – a registered trade mark of Butamax Advance Biofuels LLC.

Fulcrum and Fulcrum BioEnergy – registered trade marks of Fulcrum BioEnergy, Inc.

M&S Simply Food – a registered trade mark of Marks & Spencer plc.

MyAuchan – a registered trade mark of Auchan.

REWE to Go – a registered trade mark of REWE.

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 316.

			$ million
	2018	2017	2016
Upstream			
Unrecognized (gains) losses brought forward from previous period[a]	(419)	(393)	263
Favourable (adverse) impact relative to management's measure of performance	(39)	27	(637)
Exchange translation gains (losses) on fair value accounting effects	3	2	(19)
Unrecognized (gains) losses carried forward	(455)	(364)	(393)
Downstream[b]			
Unrecognized (gains) losses brought forward from previous period[a]	(151)	(71)	377
Favourable (adverse) impact relative to management's measure of performance	95	(135)	(448)
Unrecognized (gains) losses carried forward	(56)	(206)	(71)
Favourable (adverse) impact relative to management's measure of performance – by region			
Upstream			
US	(35)	192	(379)
Non-US	(4)	(165)	(258)
	(39)	27	(637)
Downstream[b]			
US	(155)	(29)	(321)
Non-US	250	(106)	(127)
	95	(135)	(448)
	56	(108)	(1,085)
Taxation credit (charge)	12	12	329
	68	(96)	(756)

a 2018 brought forward fair value accounting effect balances include a $55-million adjustment between Upstream and Downstream as part of the transfer of the NGL business between segments. 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
	2018	2017	2016
Upstream			
RC profit (loss) before interest and tax adjusted for fair value accounting effects	14,367	5,194	1,211
Impact of fair value accounting effects	(39)	27	(637)
RC profit (loss) before interest and tax	14,328	5,221	574
Downstream			
RC profit before interest and tax adjusted for fair value accounting effects	6,845	7,356	5,610
Impact of fair value accounting effects	95	(135)	(448)
RC profit before interest and tax	6,940	7,221	5,162
Total group			
Profit (loss) before interest and tax adjusted for fair value accounting effects	19,322	9,582	655
Impact of fair value accounting effects	56	(108)	(1,085)
Profit (loss) before interest and tax	19,378	9,474	(430)

Reconciliation of basic earnings per ordinary share to RC profit (loss) per share and to underlying RC profit per share

	Per ordinary share – cents				
	2018	2017	2016	2015	2014
Profit (loss) for the year[a]	46.98	17.20	0.61	(35.39)	20.55
Inventory holding (gains) losses, before tax	4.01	(4.32)	(8.52)	10.31	33.78
Taxation charge (credit) on inventory holding gains and losses	(0.99)	1.14	2.58	(3.10)	(10.43)
RC profit (loss) for the year	50.00	14.02	(5.33)	(28.18)	43.90
Net (favourable) adverse impact of non-operating items and fair value accounting effects, before tax	16.93	18.94	35.99	82.23	44.79
Taxation charge (credit) on non-operating items and fair value accounting effects	(3.23)	(1.65)	(16.87)	(21.83)	(22.69)
Underlying RC profit for the year	63.70	31.31	13.79	32.22	66.00

[a] Profit attributable to BP shareholders.

Reconciliation of effective tax rate (ETR) to ETR on RC profit or loss and adjusted ETR
Taxation (charge) credit

	$ million				
	2018	2017	2016	2015	2014
Taxation on profit or loss for the year	(7,145)	(3,712)	2,467	3,171	(947)
Adjusted for taxation on inventory holding gains and losses	198	(225)	(483)	569	1,917
Taxation on a RC profit or loss basis	(7,343)	(3,487)	2,950	2,602	(2,864)
Adjusted for taxation on non-operating items and fair value accounting effects	522	1,184	3,162	4,000	4,171
Adjusted for the impact of US tax reform	121	(859)	—	—	—
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	—	—	434	915	—
Adjusted taxation	(7,986)	(3,812)	(646)	(2,313)	(7,035)

Effective tax rate

	%				
	2018	2017	2016	2015	2014
ETR on profit or loss for the year	43	52	107	33	19
Adjusted for inventory holding gains and losses	(1)	3	(31)	1	7
ETR on RC profit or loss	42	55	76	34	26
Adjusted for non-operating items and fair value accounting effects	(5)	(9)	(69)	(15)	10
Adjusted for the impact of US tax reform	1	(8)	—	—	—
Adjusted for the impact of the reduction in the rate of the UK North Sea supplementary charge	—	—	16	12	—
Adjusted ETR	38	38	23	31	36

Return on average capital employed (ROACE)

					$ million
	2018	2017	2016	2015	2014
Profit (loss) for the year attributable to BP shareholders	9,383	3,389	115	(6,482)	3,780
Inventory holding (gains) losses, net of tax	603	(628)	(1,114)	1,320	4,293
Non-operating items and fair value accounting effects, net of tax	2,737	3,405	3,584	11,067	4,063
Underlying RC profit	12,723	6,166	2,585	5,905	12,136
Interest expense, net of tax[a]	1,583	924	635	576	546
Non-controlling interests	195	79	57	82	223
Adjusted underlying RC profit	14,501	7,169	3,277	6,563	12,905
Total equity	101,548	100,404	96,843	98,387	112,642
Gross debt	65,799	63,230	58,300	53,168	52,854
Capital employed (2018 average $165,491 million)	167,347	163,634	155,143	151,555	165,496
Less: Goodwill	12,204	11,551	11,194	11,627	11,868
Cash and cash equivalents	22,468	25,586	23,484	26,389	29,763
	132,675	126,497	120,465	113,539	123,865
Average capital employed excluding goodwill and cash and cash equivalents	129,586	123,481	117,002	118,702	133,882
ROACE	11.2%	5.8%	2.8%	5.5%	9.6%

[a] Calculated on a post-tax basis (for 2017 interest expense was net of notional tax at an assumed 35%).

Readily marketable inventory (RMI)

Readily marketable inventory (RMI) is oil and oil products inventory held and price risk-managed by BP`s integrated supply and trading function (IST) which could be sold to generate funds if required. Details of RMI balances and a reconciliation to GAAP information is set out below. Further information on RMI, RMI at fair value, paid-up RMI and unpaid RMI is provided on page 318.

At 31 December	$ million	
	2018	2017
RMI at fair value	4,202	5,661
Paid-up RMI	1,641	2,688

Reconciliation of non-GAAP information

At 31 December		$ million
	2018	2017
Reconciliation of total inventory to paid-up RMI		
Inventories as reported on the group balance sheet	17,988	19,011
Less: (a) inventories which are not oil and oil products and (b) oil and oil product inventories which are not risk-managed by IST	(14,066)	(13,929)
RMI on IFRS basis	3,922	5,082
Plus: difference between RMI at fair value and RMI on an IFRS basis	280	579
RMI at fair value	4,202	5,661
Less: unpaid RMI at fair value	(2,561)	(2,973)
Paid-up RMI	1,641	2,688

The Directors' report on pages 57-86, 210-237 and 273-322 was approved by the board and signed on its behalf by Jens Bertelsen, company secretary on 29 March 2019.
BP p.l.c.
Registered in England and Wales No. 102498

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ Jens Bertelsen
Company secretary
29 March 2019

Cross reference to Form 20-F

Information about this report

Registered office and our worldwide headquarters:

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

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

Our agent in the US:

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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 2018. A cross reference to Form 20-F requirements is included on page 324.

This document contains the Strategic report on the inside front cover and pages 1-56 and the Directors' report on pages 57-86, 210-237 and 273-322. 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 87-109. The consolidated financial statements of the group are on pages 113-209 and the corresponding reports of the auditor are on pages 126-128.

BP Annual Report and Form 20-F 2018 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 2018, 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, Advancing the energy transition, BP Statistical Review of World Energy and BP Technology Outlook are included as an aid to their location and are not incorporated by reference into this document.

BP p.l.c. is the parent company of the BP group of companies. The company was incorporated in 1909 in England and Wales and changed its name to BP p.l.c. in 2001. Where we refer to the company, we mean BP p.l.c. Unless otherwise stated, the text does not distinguish between the activities and operations of the parent company and those of its subsidiaries«, and information in this document reflects 100% of the assets and operations of the company and its subsidiaries that were consolidated at the date or for the periods indicated, including non-controlling interests.

BP's primary share listing is the London Stock Exchange. In the US, the company's securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs (see page 306 for more details) and in Germany in the form of a global depositary certificate representing BP ordinary shares traded on the Frankfurt, Hamburg and Dusseldorf Stock Exchanges.

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.

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BP’s corporate reporting suite includes information about our financial and operating BP performance, sustainability performance and Annual Report and Form 20-F 2018 also on global energy trends and projections. Annual Report Sustainability Advancing the Financial and Operating and Form 20-F 2018 Report 2018 energy transition Information 2014-2018 Details of our financial Details of our sustainability How the energy world is Five-year financial and and operating performance performance with additional changing, our low carbon operating data in PDF in print and online. information online. ambitions and how we're and Excel format. bp.com/annualreport bp.com/sustainability helping advance the bp.com/financialandoperating transition. bp.com/energytransition BP Energy Outlook Statistical Review Technology Outlook BP social media Provides our projections of World Energy 2019 How technology could Join the conversation, of future energy trends An objective review of influence the way we meet get the latest news, see and factors that could key global energy trends. the energy challenge into photos and films from affect them out to 2040. the future. the field and find out bp.com/statisticalreview about working with us. bp.com/energyoutlook bp.com/technologyoutlook You can order BP’s UK and rest of world Feedback You can also telephone printed publications BP Distribution Services Your feedback is important +44 (0)20 7496 4000 free of charge from Tel: +44 (0)870 241 3269 to us. You can email the bp.com/papercopies bpdistributionservices@ corporate reporting team at or write to bp.com corporatereporting@bp.com Corporate reporting BP p.l.c. US and Canada 1 St James’s Square Issuer Direct London SW1Y 4PD, UK Toll-free: +1 888 301 2505 bpreports@issuerdirect.com