Financial statements

Statement of directors' responsibilities

The directors are responsible for preparing the Annual Report and the financial statements in accordance with applicable law and regulations.

The directors are required by the UK Companies Act 2006 to prepare financial statements for each financial year that give a true and fair view of the financial position of the group and the parent company and the financial performance and cash flows of the group and parent company for that period. Under that law they are required to prepare the consolidated financial statements in accordance with International Financial Reporting Standards (IFRS) as adopted by the European Union (EU) and applicable law and have elected to prepare the parent company financial statements in accordance with applicable United Kingdom law and United Kingdom accounting standards (United Kingdom generally accepted accounting practice). In preparing the consolidated financial statements the directors have also elected to comply with IFRSs as issued by the International Accounting Standards Board (IASB). In preparing those financial statements, the directors are required to:

- select suitable accounting policies and then apply them consistently.
- make judgements and estimates that are reasonable and prudent.
- present information, including accounting policies, in a manner that provides relevant, reliable, comparable and understandable information.
- provide additional disclosure when compliance with the specific requirements of IFRS is insufficient to enable users to understand the impact of particular transactions, other events and conditions on the group's financial position and financial performance.
- state that applicable accounting standards have been followed, subject to any material departures disclosed and explained in the parent company financial statements.
- prepare the financial statements on the going concern basis unless it is inappropriate to presume that the company will continue in business.

The directors are responsible for keeping proper accounting records that disclose with reasonable accuracy at any time the financial position of the group and company and enable them to ensure that the consolidated financial statements comply with the Companies Act 2006 and Article 4 of the IAS Regulation and the parent company financial statements comply with the Companies Act 2006. They are also responsible for safeguarding the assets of the group and company and hence for taking reasonable steps for the prevention and detection of fraud and other irregularities.

The directors draw attention to Note 2 on the consolidated financial statements which describes the uncertainties surrounding the amounts and timings of liabilities arising from the Gulf of Mexico oil spill.

The group's business activities, performance, position and risks are set out in this report. The financial position of the group, its cash flows, liquidity position and borrowing facilities are detailed in the appropriate sections on pages 211 to 212 and elsewhere in the notes on the consolidated financial statements. The report also includes details of the group's risk mitigation and management. Information on the Gulf of Mexico oil spill and BP's response is included on pages 36 to 38 and elsewhere in this report, including Safety on pages 39 to 41. The group has considerable financial resources, and the directors believe that the group is well placed to manage its business risks successfully. After making enquiries, the directors have a reasonable expectation that the company and the group have adequate resources to continue in operational existence for the foreseeable future. Accordingly, they continue to adopt the going concern basis in preparing the annual report and accounts.

Having made the requisite enquiries, so far as the directors are aware, there is no relevant audit information (as defined by Section 418(3) of the Companies Act 2006) of which the company's auditors are unaware, and the directors have taken all the steps they ought to have taken to make themselves aware of any relevant audit information and to establish that the company's auditors are aware of that information.

The directors confirm that to the best of their knowledge:

- the consolidated financial statements, prepared in accordance with IFRS as issued by the IASB, IFRS as adopted by the EU and in accordance with the provisions of the Companies Act 2006, give a true and fair view of the assets, liabilities, financial position and profit or loss of the group;
- the parent company financial statements, prepared in accordance with United Kingdom generally accepted accounting practice, give a true and fair view of the assets, liabilities, financial position, performance and cash flows of the company; and
- the management report, which is incorporated in the strategic report and directors' report, includes a fair review of the development and performance of the business and the position of the group, together with a description of the principal risks and uncertainties that they face.

Fair, balanced and understandable

The board considers the Annual Report and financial statements, taken as a whole, is fair, balanced and understandable and provides the information necessary for shareholders to assess the company's performance, business model and strategy.

C-H Svanberg
Chairman
3 March 2015

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

Independent auditor's report on the Annual Report and Accounts to the members of BP p.l.c.

Opinion on financial statements

In our opinion:

- the financial statements give a true and fair view of the state of the group's and of the parent company's affairs as at 31 December 2014 and of the group's profit for the year then ended;
- the group financial statements have been properly prepared in accordance with IFRS as adopted by the European Union;
- the parent company financial statements have been properly prepared in accordance with United Kingdom Generally Accepted Accounting Practice; and
- the financial statements have been prepared in accordance with the requirements of the Companies Act 2006 and, as regards the group financial statements, Article 4 of the IAS Regulation.

Emphasis of matter – significant uncertainty over provisions and contingencies related to the Gulf of Mexico oil spill

In forming our opinion on the group financial statements we have considered the adequacy of the disclosure in Note 2 to the financial statements concerning the provisions, future expenditures which cannot be reliably estimated and other contingent liabilities related to the claims, penalties and litigation arising from the Gulf of Mexico oil spill. The total amount that will ultimately be paid by BP in relation to all obligations arising from this significant event is subject to significant uncertainty and the ultimate exposure and cost to BP is dependent on many factors, including but not limited to, the determinations of the Courts and Regulatory authorities in the US. Significant uncertainty exists in relation to the amount of claims that will become payable by BP and the amount of fines that will be levied on BP (including any ultimate determination of BP's culpability based on negligence, gross negligence or wilful misconduct). The outcome of litigation and the cost of the longer term environmental consequences of the oil spill are also subject to significant uncertainty. For these reasons it is not possible to estimate reliably the ultimate cost to BP. Our opinion is not qualified in respect of these matters.

Separate opinion in relation to IFRS as issued by the International Accounting Standards Board

As explained in Note 1 to the consolidated financial statements, the group in addition to applying IFRS as adopted by the European Union, has also applied IFRS as issued by the International Accounting Standards Board (IASB). In our opinion the consolidated financial statements comply with IFRS as issued by the IASB.

What we have audited

We have audited the financial statements of BP p.l.c. for the year ended 31 December 2014 which comprise the Group income statement, the Group statement of comprehensive income, the Group statement of changes in equity, the Group and Parent Company balance sheets, the Group and Parent Company cash flow statements, the Parent Company statement of total recognized gains and losses and the related notes. The financial reporting framework that has been applied in the preparation of the group financial statements is applicable law and International Financial Reporting Standards (IFRS) as adopted by the European Union. The financial reporting framework that has been applied in the preparation of the parent company financial statements is applicable law and United Kingdom Accounting Standards (United Kingdom Generally Accepted Accounting Practice).

This report is made solely to the company's members, as a body, in accordance with Chapter 3 of Part 16 of the Companies Act 2006. Our audit work has been undertaken so that we might state to the company's members those matters we are required to state to them in an auditor's report and for no other purpose. To the fullest extent permitted by law, we do not accept or assume responsibility to anyone other than the company and the company's members as a body, for our audit work, for this report, or for the opinions we have formed.

Respective responsibilities of directors and auditor

As explained more fully in the Statement of directors' responsibilities set out on page 90, the directors are responsible for the preparation of the financial statements and for being satisfied that they give a true and fair view. Our responsibility is to audit and express an opinion on the financial statements in accordance with applicable law and International Standards on Auditing (UK and Ireland). Those standards require us to comply with the Auditing Practices Board's Ethical Standards for Auditors.

Scope of the audit of the financial statements

An audit involves obtaining evidence about the amounts and disclosures in the financial statements sufficient to give reasonable assurance that the financial statements are free from material misstatement, whether caused by fraud or error. This includes an assessment of: whether the accounting policies are appropriate to the group's and parent company's circumstances and have been consistently applied and adequately disclosed; the reasonableness of significant accounting estimates made by the directors; and the overall presentation of the financial statements. In addition, we read all the financial and non-financial information in the Annual Report to identify material inconsistencies with the audited financial statements and to identify any information that is apparently materially incorrect based on, or materially inconsistent with, the knowledge acquired by us in the course of performing the audit. If we become aware of any apparent material misstatements or inconsistencies we consider the implications for our report.

Our assessment of risks of material misstatement

We identified the following risks that have the greatest effect on the overall audit strategy; the allocation of audit resource; and in directing the efforts of the audit engagement team:

- the determination of the liabilities, contingent liabilities and disclosures arising from the significant uncertainties related to the Gulf of Mexico oil spill (See AC and AP)*;
- the significant decline in oil and gas prices since late 2014 has the potential for a material impact on the carrying value of the group's assets. We reconsidered our risk assessment at the year end to recognise this significant development (See AC and AP)*;
- the estimate of oil and gas reserves and resources which has a significant impact on impairment tests, depreciation, depletion & amortisation and decommissioning provisions (See AC and AP)*;
- unauthorized trading activity within the Integrated Supply and Trading function and the potential impact on revenue (See AC)*;
- BP's ability to exercise significant influence over Rosneft and the consequent accounting for the interest in Rosneft using the equity method (See AC and AP)*;

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* These risks are discussed in other areas of this report as noted by the following key:

AC – see Audit Committee Report on pages 64 to 67.

AP – see Financial statements—Note 1 Significant accounting policies, judgements, estimates and assumptions on pages 100 to 110.

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With the exception of the risk related to the recent significant decrease in the oil price the other risks are consistent with the prior year. The risk we identified in the prior year related to the determination of the fair value of the assets and liabilities of the Rosneft business on acquisition of the equity interest is not relevant to the current period as the acquisition was completed and accounted for in the prior year.

Our application of materiality

We quantify materiality in planning and executing the audit and in evaluating the materiality of misstatements on the financial statements and the effect they have on our audit. In determining if the financial statements are free from material error, we define materiality as the magnitude of an omission or misstatement that, individually or in the aggregate, in light of the surrounding circumstances, could reasonably be expected to influence the economic decisions of the users of the financial statements. The evaluation of materiality requires professional judgement and the consideration of both qualitative and quantitative factors.

We determined materiality for the group to be $1 billion (2013 $1 billion), which represents 5% of underlying replacement cost profit (as defined on page 255) before tax having added back charges related to the Gulf of Mexico oil spill response. We used this measure to calculate our materiality to exclude the impact of both changes in crude oil and product prices and items disclosed as non-operating items that can significantly distort the results. This provides a basis for assessing the importance of misstatements and in determining the scope of our audit procedures.

We determined, based on our risk assessment and consideration of the group's control environment, that performance materiality be set at 75% of our materiality for the group, namely at $750 million (2013 $750 million). Performance materiality is the application of materiality at an individual account or balance level and is set to reduce to an appropriately low level the probability that the aggregate of uncorrected and undetected misstatements exceeds materiality. Audit work on individual locations is undertaken using a percentage of our total performance materiality. We allocate performance materiality to the components of the group we audit based on their relative risk and size. The range of performance materiality allocated to components in 2014 was $150 million to $640 million (2013 $150 million to $640 million).

We agreed with the Audit Committee to report all audit differences in excess of $50 million (2013 $50 million).

We evaluate any uncorrected misstatements against both the quantitative measures of materiality discussed above and in the light of other relevant qualitative considerations.

An overview of the scope of our audit

Our audit scope is risk based and is designed to focus our efforts on the areas at greatest risk of material misstatement, aspects subject to significant management judgement and on the locations of greatest complexity, risk and size. We design and execute our audit based primarily on our assessment of the risks particular to this company and the industry in which it operates.

In scoping the audit we view the group as 42 Regional Performance Units ('RPUs') plus the group functions. The group audit scope focused on 19 RPUs in the US, Azerbaijan, Angola, UK, Germany, Russia, Singapore and the group functions. We designed specific procedures for these locations and functions to provide an appropriate basis for executing audit work to address the risk of material misstatement. This included the audit of all accounts that were impacted by our assessment of the risks of material misstatement (identified above). We note that for these RPUs we do not include all balances at these entities in our specific audit scope, based on our assessment of risk we exclude certain low risk, lower value balances. The specific in scope locations represent audit coverage of 71% (2013 68%) of revenue and 63% (2013 72%) of property, plant and equipment. Our procedures at the locations in group scope included assessment and testing of management's financial controls and other substantive and analytical verification procedures. For those locations and balances that are not subject to specific group scoping (there are many small, low risk locations and balances in the 23 RPUs not included in our specific scope) we assess and test management's group wide controls and undertake analytical and enquiry procedures to address the residual risk of material misstatement.

One of the key locations is Russia which includes Rosneft, a material associate not controlled by BP. We were provided with appropriate access to Rosneft's auditors in order to ensure they had completed the procedures required by ISA 600 on the financial statements of Rosneft used as the basis for BP's equity accounting.

The Group audit team continued to undertake a programme of planned visits to significant locations to ensure the audit is executed and delivered in accordance with the planned approach and to confirm the quality of the audit work undertaken.

Our response to the risks of material misstatement identified above included the following procedures:

The determination of the liabilities, contingent liabilities and disclosures arising from the significant uncertainties related to the Gulf of Mexico oil spill

We continued to assess developments in legal cases related to claims and penalties through reading the determinations and judgments made by the courts, discussions with the BP legal team and correspondence with external lawyers. The determination of liabilities related to the oil spill takes months and years to evolve and during 2014 there were some significant developments in loss claims and potential penalties, specifically related to the Economic and Property Damages Settlement Agreement and Clean Water Act penalties (see Note 2), that we considered in assessing the requirements of IFRS in relation to liabilities, contingent liabilities and disclosure. Where appropriate we deployed valuation and modelling experts to inform our assessment. There is significant uncertainty related to the ultimate liabilities and we considered the disclosures related to these uncertainties and concluded that it was appropriate to include an emphasis of matter related to these uncertainties in this report.

The significant decline in oil and gas prices since late 2014 has the potential for a material impact on the carrying value of the group's assets.

Movements in commodity prices can have a significant effect on the carrying value of the group's assets. A significant and rapid drop in prices will also quickly impact the group's operations and cash flows. We assessed the principal risk arising in relation to the financial statements to be associated with the carrying value of tangible and intangible assets, many of which are supported by an assessment of future cash flows. The assessment of the asset carrying values is further complicated as external market evidence, such as market transactions, become less reliable in a period of significant change to the price of oil. We extended the scope of our procedures to address the change in risk profile of the group's assets and to scrutinize impairment considerations. We extended the use of our own valuation experts and external data in critically assessing and corroborating the revised assumptions used in impairment testing, the most significant being future market oil prices, reserves and resources volumes and discount rates. We also performed audit procedures on the mathematical integrity of the impairment models and sensitivity analysis and procedures to ensure the completeness of the impairment charge and exploration write offs.

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The estimate of oil and gas reserves and resources which has a significant impact on impairment tests, depreciation, depletion & amortisation and decommissioning provisions
We carried out testing of controls over BP's internal certification process for technical and commercial experts who are responsible for reserves estimation. We assessed whether the significant changes in proved reserves have been made in compliance with relevant regulations. We ensured that the updated reserves and resources estimates were included appropriately in consideration of impairment, depreciation, depletion and amortization and decommissioning provisions.

Unauthorized trading activity and the potential impact on revenue
We performed testing relating to controls over unauthorized trading activity. Analytical tools were used to assist us in identifying trades which have the highest risk of unauthorized activity so as to focus our testing on these trades. We obtained confirmations directly from third parties for a sample of trades. We verified the fair value of a sample of derivatives using contract and external market prices. We tested the completeness of the amounts recorded in the financial statements through performing procedures to detect unrecorded liabilities as well as detailed cut off procedures around sales, purchases, trade receivables, and trade payables.

BP's ability to exercise significant influence over Rosneft and the consequent accounting for the interest in Rosneft using the equity method
We challenged the evidence available to support BP's continuing conclusion that Rosneft should be accounted using the equity method. We assessed the impact of sanctions imposed by the US and European Union through discussion with the BP legal team, consideration of EY internal guidance and observation of the interaction between BP and Rosneft. We also considered the adequacy of the financial and other information provided to BP to allow compliance with its reporting obligations. We ensured appropriate review was completed by BP on the information reported. We provided instruction to Rosneft's auditors who reported in accordance with our timetable and instructions.

Opinion on other matter prescribed by the Companies Act 2006
In our opinion:

- the part of the Directors' Remuneration Report to be audited has been properly prepared in accordance with the Companies Act 2006; and
- the information given in the Strategic Report and the Directors' Report for the financial year for which the financial statements are prepared is consistent with the financial statements.

Matters on which we are required to report by exception
We have nothing to report in respect of the following:
Under the ISAs (UK and Ireland), we are required to report to you if, in our opinion, information in the annual report is:

- materially inconsistent with the information in the audited financial statements; or
- apparently materially incorrect based on, or materially inconsistent with, our knowledge of the group acquired in the course of performing our audit; or
- is otherwise misleading.

In particular, we are required to consider whether we have identified any inconsistencies between our knowledge acquired during the audit and the directors' statement that they consider the annual report is fair, balanced and understandable and whether the annual report appropriately discloses those matters that we communicated to the audit committee which we consider should have been disclosed.
Under the Companies Act 2006 we are required to report to you if, in our opinion:

- adequate accounting records have not been kept by the parent company, or returns adequate for our audit have not been received from branches not visited by us; or
- the parent company financial statements and the part of the Directors' Remuneration Report to be audited are not in agreement with the accounting records and returns; or
- certain disclosures of directors' remuneration specified by law are not made; or
- we have not received all the information and explanations we require for our audit.

Under the Listing Rules we are required to review:
- the directors' statement, set out on page 90, in relation to going concern; and
- the part of the Governance and Risk section of the Annual Report relating to the company's compliance with the nine provisions of the UK Corporate Governance Code specified for our review.

John C. Flaherty (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
3 March 2015

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Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm on the Annual Report on Form 20-F

The Board of Directors and Shareholders of BP p.l.c.

We have audited the accompanying group balance sheets of BP p.l.c. as of 31 December 2014, 31 December 2013 and 1 January 2013, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the group financial position of BP p.l.c. at 31 December 2014, 31 December 2013 and 1 January 2013, and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2014, in accordance with International Financial Reporting Standards as adopted by the European Union and International Financial Reporting Standards as issued by the International Accounting Standards Board.

In forming our opinion on the group financial statements we have considered the adequacy of the disclosure in Note 2 to the financial statements concerning the provisions, future expenditures which cannot be reliably estimated and other contingent liabilities related to the claims, penalties and litigation arising from the Gulf of Mexico oil spill. The total amount that will ultimately be paid by BP in relation to all obligations arising from this significant event is subject to significant uncertainty and the ultimate exposure and cost to BP is dependent on many factors, including but not limited to, the determinations of the Courts and Regulatory authorities in the US. Significant uncertainty exists in relation to the amount of claims that will become payable by BP and the amount of fines that will be levied on BP (including any ultimate determination of BP's culpability based on negligence, gross negligence or wilful misconduct). The outcome of litigation and the cost of the longer term environmental consequences of the oil spill are also subject to significant uncertainty. For these reasons it is not possible to estimate reliably the ultimate cost to BP. Our opinion is not qualified in respect of these matters.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), BP p.l.c.'s internal control over financial reporting as of 31 December 2014, based on criteria established in Internal Control: Revised Guidance for Directors on the Combined Code as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull guidance) and our report dated 3 March 2015 expressed an unqualified opinion.

/s/ Ernst & Young LLP
London, England
3 March 2015

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2. Legislation in the United Kingdom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm on the Annual Report on Form 20-F

The Board of Directors and Shareholders of BP p.l.c.

We have audited BP p.l.c.'s internal control over financial reporting as of 31 December 2014, based on criteria established in Internal Control: Revised Guidance for Directors on the Combined Code as issued by the Institute of Chartered Accountants in England and Wales (the Turnbull guidance). BP p.l.c.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's report on internal control on page 240. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, BP p.l.c. maintained, in all material respects, effective internal control over financial reporting as of 31 December 2014, based on the Turnbull guidance.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the group balance sheets of BP p.l.c. as of 31 December 2014 and 2013, and the related group income statement, group statement of comprehensive income, group statement of changes in equity and group cash flow statement for each of the three years in the period ended 31 December 2014, and our report dated 3 March 2015 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
London, United Kingdom
3 March 2015

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 3 March 2015, with respect to the group financial statements of BP p.l.c., and the effectiveness of internal control over financial reporting of BP p.l.c., included in this Annual Report and Form 20-F for the year ended 31 December 2014 in the following Registration Statements:

Registration Statement on Form F-3 (File No. 333-201894-01) of BP Capital Markets p.l.c. and BP p.l.c.; and
Registration Statements on Form S-8 (File Nos.333-67206, 333-103924, 333-123482, 333-123483, 333-131583, 333-146868, 333-146870, 333-146873, 333-131584, 333-132619, 333-173136, 333-177423, 333-179406, 333-186463, 333-186462, 333-199015, 333-200794, 333-200795 and 333-200796) of BP p.l.c.

/s/ Ernst & Young LLP
London, England
3 March 2015

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Group income statement

For the year ended 31 December				$ million
	Note	**2014**	2013	2012
Sales and other operating revenues	4	**353,568**	379,136	375,765
Earnings from joint ventures – after interest and tax	14	**570**	447	260
Earnings from associates – after interest and tax	15	**2,802**	2,742	3,675
Interest and other income	5	**843**	777	1,677
Gains on sale of businesses and fixed assets	3	**895**	13,115	6,697
Total revenues and other income		**358,678**	396,217	388,074
Purchases	17	**281,907**	298,351	292,774
Production and manufacturing expenses[a]		**27,375**	27,527	33,926
Production and similar taxes	4	**2,958**	7,047	8,158
Depreciation, depletion and amortization	4	**15,163**	13,510	12,687
Impairment and losses on sale of businesses and fixed assets	3	**8,965**	1,961	6,275
Exploration expense	6	**3,632**	3,441	1,475
Distribution and administration expenses		**12,696**	13,070	13,357
Fair value gain on embedded derivatives	28	**(430)**	(459)	(347)
Profit before interest and taxation		**6,412**	31,769	19,769
Finance costs[a]	5	**1,148**	1,068	1,072
Net finance expense relating to pensions and other post-retirement benefits	22	**314**	480	566
Profit before taxation		**4,950**	30,221	18,131
Taxation[a]	7	**947**	6,463	6,880
Profit for the year		**4,003**	23,758	11,251
Attributable to				
BP shareholders	30	**3,780**	23,451	11,017
Non-controlling interests	30	**223**	307	234
		4,003	23,758	11,251
Earnings per share – cents				
Profit for the year attributable to BP shareholders				
Basic	9	**20.55**	123.87	57.89
Diluted	9	**20.42**	123.12	57.50

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

Group statement of comprehensive income[a]

For the year ended 31 December

	Note	2014	2013	2012
				$ million
Profit for the year		**4,003**	23,758	11,251
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(6,838)**	(1,608)	485
Exchange gains (losses) on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**51**	22	(15)
Available-for-sale investments marked to market		**(1)**	(172)	306
Available-for-sale investments reclassified to the income statement		**1**	(523)	(1)
Cash flow hedges marked to market	28	**(155)**	(2,000)	1,466
Cash flow hedges reclassified to the income statement	28	**(73)**	4	62
Cash flow hedges reclassified to the balance sheet	28	**(11)**	17	19
Share of items relating to equity-accounted entities, net of tax		**(2,584)**	(24)	(39)
Income tax relating to items that may be reclassified	7	**147**	147	(170)
		(9,463)	(4,137)	2,113
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	22	**(4,590)**	4,764	(1,572)
Share of items relating to equity-accounted entities, net of tax		**4**	2	(6)
Income tax relating to items that will not be reclassified	7	**1,334**	(1,521)	440
		(3,252)	3,245	(1,138)
Other comprehensive income		**(12,715)**	(892)	975
Total comprehensive income		**(8,712)**	22,866	12,226
Attributable to				
BP shareholders		**(8,903)**	22,574	11,988
Non-controlling interests		**191**	292	238
		(8,712)	22,866	12,226

[a] See Note 30 for further information.

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Treasury shares	Foreign currency translation reserve	Fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
At 1 January 2014	**43,656**	**(20,971)**	**3,525**	**(695)**	**103,787**	**129,302**	**1,105**	**130,407**
Profit for the year	**–**	**–**	**–**	**–**	**3,780**	**3,780**	**223**	**4,003**
Other comprehensive income	**–**	**–**	**(6,934)**	**(202)**	**(5,547)**	**(12,683)**	**(32)**	**(12,715)**
Total comprehensive income	**–**	**–**	**(6,934)**	**(202)**	**(1,767)**	**(8,903)**	**191**	**(8,712)**
Dividends	**–**	**–**	**–**	**–**	**(5,850)**	**(5,850)**	**(255)**	**(6,105)**
Repurchases of ordinary share capital	**–**	**–**	**–**	**–**	**(3,366)**	**(3,366)**	**–**	**(3,366)**
Share-based payments, net of tax	**246**	**252**	**–**	**–**	**(313)**	**185**	**–**	**185**
Share of equity-accounted entities' changes in equity, net of tax	**–**	**–**	**–**	**–**	**73**	**73**	**–**	**73**
Transactions involving non-controlling interests	**–**	**–**	**–**	**–**	**–**	**–**	**160**	**160**
At 31 December 2014	**43,902**	**(20,719)**	**(3,409)**	**(897)**	**92,564**	**111,441**	**1,201**	**112,642**
At 1 January 2013	43,513	(21,054)	5,128	1,775	89,184	118,546	1,206	119,752
Profit for the year	–	–	–	–	23,451	23,451	307	23,758
Other comprehensive income	–	–	(1,603)	(2,470)	3,196	(877)	(15)	(892)
Total comprehensive income	–	–	(1,603)	(2,470)	26,647	22,574	292	22,866
Dividends	–	–	–	–	(5,441)	(5,441)	(469)	(5,910)
Repurchases of ordinary share capital	–	–	–	–	(6,923)	(6,923)	–	(6,923)
Share-based payments, net of tax	143	83	–	–	247	473	–	473
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	73	73	–	73
Transactions involving non-controlling interests	–	–	–	–	–	–	76	76
At 31 December 2013	43,656	(20,971)	3,525	(695)	103,787	129,302	1,105	130,407
At 1 January 2012	43,454	(21,323)	4,509	267	84,661	111,568	1,017	112,585
Profit for the year	–	–	–	–	11,017	11,017	234	11,251
Other comprehensive income	–	–	619	1,508	(1,156)	971	4	975
Total comprehensive income	–	–	619	1,508	9,861	11,988	238	12,226
Dividends	–	–	–	–	(5,294)	(5,294)	(82)	(5,376)
Share-based payments, net of tax	59	269	–	–	(44)	284	–	284
Transactions involving non-controlling interests	–	–	–	–	–	–	33	33
At 31 December 2012	43,513	(21,054)	5,128	1,775	89,184	118,546	1,206	119,752

[a] See Note 30 for further information.

Group balance sheet

At 31 December			$ million
	Note	**2014**	2013
Non-current assets			
Property, plant and equipment	10	**130,692**	133,690
Goodwill	12	**11,868**	12,181
Intangible assets	13	**20,907**	22,039
Investments in joint ventures	14	**8,753**	9,199
Investments in associates	15	**10,403**	16,636
Other investments	16	**1,228**	1,565
Fixed assets		**183,851**	195,310
Loans		**659**	763
Trade and other receivables	18	**4,787**	5,985
Derivative financial instruments	28	**4,442**	3,509
Prepayments		**964**	922
Deferred tax assets	7	**2,309**	985
Defined benefit pension plan surpluses	22	**31**	1,376
		197,043	208,850
Current assets			
Loans		**333**	216
Inventories	17	**18,373**	29,231
Trade and other receivables	18	**31,038**	39,831
Derivative financial instruments	28	**5,165**	2,675
Prepayments		**1,424**	1,388
Current tax receivable		**837**	512
Other investments	16	**329**	467
Cash and cash equivalents	23	**29,763**	22,520
		87,262	96,840
Total assets		**284,305**	305,690
Current liabilities			
Trade and other payables	20	**40,118**	47,159
Derivative financial instruments	28	**3,689**	2,322
Accruals		**7,102**	8,960
Finance debt	24	**6,877**	7,381
Current tax payable		**2,011**	1,945
Provisions	21	**3,818**	5,045
		63,615	72,812
Non-current liabilities			
Other payables	20	**3,587**	4,756
Derivative financial instruments	28	**3,199**	2,225
Accruals		**861**	547
Finance debt	24	**45,977**	40,811
Deferred tax liabilities	7	**13,893**	17,439
Provisions	21	**29,080**	26,915
Defined benefit pension plan and other post-retirement benefit plan deficits	22	**11,451**	9,778
		108,048	102,471
Total liabilities		**171,663**	175,283
Net assets		**112,642**	130,407
Equity			
BP shareholders' equity	30	**111,441**	129,302
Non-controlling interests	30	**1,201**	1,105
Total equity	30	**112,642**	130,407

C-H Svanberg Chairman
R W Dudley Group Chief Executive
3 March 2015

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2014**	2013	2012
Operating activities				
Profit before taxation		**4,950**	30,221	18,131
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	6	**3,029**	2,710	745
Depreciation, depletion and amortization	4	**15,163**	13,510	12,687
Impairment and (gain) loss on sale of businesses and fixed assets	3	**8,070**	(11,154)	(422)
Earnings from joint ventures and associates		**(3,372)**	(3,189)	(3,935)
Dividends received from joint ventures and associates		**1,911**	1,391	1,763
Interest receivable		**(276)**	(314)	(379)
Interest received		**81**	173	175
Finance costs	5	**1,148**	1,068	1,072
Interest paid		**(937)**	(1,084)	(1,166)
Net finance expense relating to pensions and other post-retirement benefits	22	**314**	480	566
Share-based payments		**379**	297	156
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	22	**(963)**	(920)	(858)
Net charge for provisions, less payments		**1,119**	1,061	5,338
(Increase) decrease in inventories		**10,169**	(1,193)	(1,720)
(Increase) decrease in other current and non-current assets		**3,566**	(2,718)	2,933
Increase (decrease) in other current and non-current liabilities		**(6,810)**	(2,932)	(8,125)
Income taxes paid		**(4,787)**	(6,307)	(6,482)
Net cash provided by operating activities		**32,754**	21,100	20,479
Investing activities				
Capital expenditure		**(22,546)**	(24,520)	(23,222)
Acquisitions, net of cash acquired		**(131)**	(67)	(116)
Investment in joint ventures		**(179)**	(451)	(1,526)
Investment in associates		**(336)**	(4,994)	(54)
Proceeds from disposals of fixed assets	3	**1,820**	18,115	9,992
Proceeds from disposals of businesses, net of cash disposed	3	**1,671**	3,884	1,606
Proceeds from loan repayments		**127**	178	245
Net cash used in investing activities		**(19,574)**	(7,855)	(13,075)
Financing activities				
Net issue (repurchase) of shares		**(4,589)**	(5,358)	122
Proceeds from long-term financing		**12,394**	8,814	11,087
Repayments of long-term financing		**(6,282)**	(5,959)	(7,177)
Net increase (decrease) in short-term debt		**(693)**	(2,019)	(666)
Net increase (decrease) in non-controlling interests		**9**	32	–
Dividends paid				
BP shareholders	8	**(5,850)**	(5,441)	(5,294)
Non-controlling interests		**(255)**	(469)	(82)
Net cash used in financing activities		**(5,266)**	(10,400)	(2,010)
Currency translation differences relating to cash and cash equivalents		**(671)**	40	64
Increase in cash and cash equivalents		**7,243**	2,885	5,458
Cash and cash equivalents at beginning of year		**22,520**	19,635	14,177
Cash and cash equivalents at end of year		**29,763**	22,520	19,635

Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions

Authorization of financial statements and statement of compliance with International Financial Reporting Standards

The consolidated financial statements of the BP group for the year ended 31 December 2014 were approved and signed by the group chief executive and chairman on 3 March 2015 having been duly authorized to do so by the board of directors. BP p.l.c. is a public limited company incorporated and domiciled in England and Wales. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS) as issued by the International Accounting Standards Board (IASB), IFRS as adopted by the European Union (EU) and in accordance with the provisions of the UK Companies Act 2006. IFRS as adopted by the EU differs in certain respects from IFRS as issued by the IASB, however, the differences have no impact on the group's consolidated financial statements for the years presented. The significant accounting policies and accounting judgements, estimates and assumptions of the group are set out below.

Basis of preparation

The consolidated financial statements have been prepared in accordance with IFRS and IFRS Interpretations Committee (IFRIC) interpretations issued and effective for the year ended 31 December 2014. The accounting policies that follow have been consistently applied to all years presented.

The consolidated financial statements are presented in US dollars and all values are rounded to the nearest million dollars ($ million), except where otherwise indicated.

Significant accounting policies: use of judgements, estimates and assumptions

Inherent in the application of many of the accounting policies used in preparing the financial statements is the need for BP management to make judgements, estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual outcomes could differ from the estimates and assumptions used. The accounting judgements and estimates that could have a significant impact on the results of the group are set out in boxed text below, and should be read in conjunction with the information provided in the Notes on financial statements. The areas requiring the most significant judgement and estimation in the preparation of the consolidated financial statements are: accounting for interests in other entities; oil and natural gas accounting, including the estimation of reserves; the recoverability of asset carrying values; derivative financial instruments, including the application of hedge accounting; provisions and contingencies, in particular provisions and contingencies related to the Gulf of Mexico oil spill; pensions and other post-retirement benefits and taxation.

Basis of consolidation

The group financial statements consolidate the financial statements of BP p.l.c. and the entities it controls (its subsidiaries) drawn up to 31 December each year. Subsidiaries are consolidated from the date of their acquisition, being the date on which the group obtains control, and continue to be consolidated until the date that such control ceases. The financial statements of subsidiaries are prepared for the same reporting year as the parent company, using consistent accounting policies. Intra-group balances and transactions, including unrealized profits arising from intra-group transactions, have been eliminated. Unrealized losses are eliminated unless the transaction provides evidence of an impairment of the asset transferred. Non-controlling interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to BP shareholders.

Interests in other entities

Business combinations and goodwill

Business combinations are accounted for using the acquisition method. The identifiable assets acquired and liabilities assumed are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the aggregate of the consideration transferred, measured at acquisition-date fair value, and the amount of any non-controlling interest in the acquiree. Acquisition costs incurred are expensed and included in distribution and administration expenses.

Goodwill is initially measured as the excess of the aggregate of the consideration transferred, the amount recognized for any non-controlling interest and the acquisition-date fair values of any previously held interest in the acquiree over the fair value of the identifiable assets acquired and liabilities assumed at the acquisition date.

At the acquisition date, any goodwill acquired is allocated to each of the cash-generating units, or groups of cash-generating units, expected to benefit from the combination's synergies.

Following initial recognition, goodwill is measured at cost less any accumulated impairment losses.

Goodwill arising on business combinations prior to 1 January 2003 is stated at the previous carrying amount under UK generally accepted accounting practice, less subsequent impairments.

Goodwill may also arise upon investments in joint ventures and associates, being the surplus of the cost of investment over the group's share of the net fair value of the identifiable assets and liabilities. Such goodwill is recorded within the corresponding investment in joint ventures and associates.

Interests in joint arrangements

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

Certain of the group's activities, particularly in the Upstream segment, are conducted through joint operations. BP recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these joint operations incurred jointly with the other partners, along with the group's income from the sale of its share of the output and any liabilities and expenses that the group has incurred in relation to the joint operation.

Interests in associates

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

Significant estimate or judgement: accounting for interests in other entities

Judgement is required in assessing the level of control obtained in a transaction to acquire an interest in another entity; depending upon the facts and circumstances in each case, BP may obtain control, joint control or significant influence over the entity or arrangement. Transactions which give BP control of a business are business combinations. If BP obtains joint control of an arrangement, judgement is also required to assess whether the arrangement is a joint operation or a joint venture. If BP has neither control nor joint control, it may be in a position to exercise significant influence over the entity, which is then accounted for as an associate.

Accounting for business combinations and acquisitions of investments in equity-accounted joint ventures and associates requires judgements and estimates to be made in order to determine the fair value of the consideration transferred, together with the fair values of the assets acquired and the liabilities assumed in a business combination, or the identifiable assets and liabilities of the equity-accounted entity at the acquisition date. The group uses all available information, including external valuations and appraisals where appropriate, to determine these fair values. If necessary, the group has up to one year from the acquisition date to finalize the determinations of fair value for business combinations.

Since 21 March 2013, BP has owned 19.75% of the voting shares of OJSC Oil Company Rosneft (Rosneft), a Russian oil and gas company. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2014. BP uses the equity method of accounting for its investment in Rosneft because under IFRS it is considered to have significant influence. Significant influence is defined as the power to participate in the financial and operating policy decisions of the investee but is not control or joint control. IFRS identifies several indicators that may provide evidence of significant influence, including representation on the board of directors of the investee and participation in policy-making processes. BP's group chief executive, Bob Dudley, has been elected to the board of directors of Rosneft and he is a member of the Rosneft board's Strategic Planning Committee. Furthermore, under the Rosneft Charter, BP has the right to nominate a second director to Rosneft's nine-person board of directors for election at a general meeting of shareholders should it choose to do so in the future. In addition, BP holds the voting rights at general meetings of shareholders conferred by its 19.75% stake in Rosneft. In management's judgement, the group has significant influence over Rosneft, as defined by the relevant accounting standard, and the investment is, therefore, accounted for as an associate. BP's share of Rosneft's oil and natural gas reserves is included in the estimated net proved reserves of equity-accounted entities.

The equity method of accounting

Under the equity method, the investment is carried on the balance sheet at cost plus post-acquisition changes in the group's share of net assets of the entity, less distributions received and less any impairment in value of the investment. Loans advanced to equity-accounted entities that have the characteristics of equity financing are also included in the investment on the group balance sheet. The group income statement reflects the group's share of the results after tax of the equity-accounted entity, adjusted to account for depreciation, amortization and any impairment of the equity-accounted entity's assets based on their fair values at the date of acquisition. The group statement of comprehensive income includes the group's share of the equity-accounted entity's other comprehensive income. The group's share of amounts recognized directly in equity by an equity-accounted entity is recognized directly in the group's statement of changes in equity.

Financial statements of equity-accounted entities are prepared for the same reporting year as the group. Where material differences arise, adjustments are made to those financial statements to bring the accounting policies used into line with those of the group.

Unrealized gains on transactions between the group and its equity-accounted entities are eliminated to the extent of the group's interest in the equity-accounted entity. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in equity-accounted entities for impairment whenever events or changes in circumstances indicate that the carrying value may not be recoverable. If any such indication of impairment exists, the carrying amount of the investment is compared with its recoverable amount, being the higher of its fair value less costs of disposal and value in use. If the carrying amount exceeds the recoverable amount, the investment is written down to its recoverable amount.

The group ceases to use the equity method of accounting from the date on which it no longer has joint control over the joint venture or significant influence over the associate, or when the interest becomes classified as an asset held for sale.

Segmental reporting

The group's operating segments are established on the basis of those components of the group that are evaluated regularly by the chief operating decision maker in deciding how to allocate resources and in assessing performance.

The accounting policies of the operating segments are the same as the group's accounting policies described in this note, except that IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker. For BP, this measure of profit or loss is replacement cost profit before interest and tax which reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Note 4.

Foreign currency translation

In individual subsidiaries, joint ventures and associates, transactions in foreign currencies are initially recorded in the functional currency of those entities by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in the income statement, unless hedge accounting is applied. Non-monetary assets and liabilities, other than those measured at fair value, are not retranslated subsequent to initial recognition.

In the consolidated financial statements, the assets and liabilities of non-US dollar functional currency subsidiaries, joint ventures and associates, including related goodwill, are translated into US dollars at the rate of exchange ruling at the balance sheet date. The results and cash flows of non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars using average rates of exchange. In the consolidated financial statements, exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency subsidiaries, joint ventures and associates are translated into US dollars are taken to a separate component of equity and reported in the statement of comprehensive income. Exchange gains and losses arising on long-term intra-group foreign currency borrowings used to finance the group's non-US dollar investments are also taken to other comprehensive income. On disposal or partial disposal of a non-US dollar functional currency subsidiary, joint venture or associate, the related cumulative exchange gains and losses recognized in equity are reclassified to the income statement.

Non-current assets held for sale

Non-current assets and disposal groups classified as held for sale are measured at the lower of carrying amount and fair value less costs to sell.

Non-current assets and disposal groups are classified as held for sale if their carrying amounts will be recovered through a sale transaction rather than through continuing use. This condition is regarded as met only when the sale is highly probable and the asset or disposal group is available for immediate sale in its present condition subject only to terms that are usual and customary for sales of such assets. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification as held for sale.

Property, plant and equipment and intangible assets are not depreciated or amortized once classified as held for sale.

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

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trade marks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses.

Intangible assets acquired separately from a business are carried initially at cost. The initial cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. An intangible asset acquired as part of a business combination is measured at fair value at the date of acquisition and is recognized separately from goodwill if the asset is separable or arises from contractual or other legal rights.

Intangible assets with a finite life are amortized on a straight-line basis over their expected useful lives. For patents, licences and trade marks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to 15 years. Computer software costs generally have a useful life of three to five years.

The expected useful lives of assets are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

Oil and natural gas exploration, appraisal and development expenditure

Oil and natural gas exploration, appraisal and development expenditure is accounted for using the principles of the successful efforts method of accounting.

Licence and property acquisition costs

Exploration licence and leasehold property acquisition costs are capitalized within intangible assets and are reviewed at each reporting date to confirm that there is no indication that the carrying amount exceeds the recoverable amount. This review includes confirming that exploration drilling is still under way or firmly planned or that it has been determined, or work is under way to determine, that the discovery is economically viable based on a range of technical and commercial considerations and sufficient progress is being made on establishing development plans and timing. If no future activity is planned, the remaining balance of the licence and property acquisition costs is written off. Lower value licences are pooled and amortized on a straight-line basis over the estimated period of exploration. Upon recognition of proved reserves and internal approval for development, the relevant expenditure is transferred to property, plant and equipment.

Exploration and appraisal expenditure

Geological and geophysical exploration costs are charged against income as incurred. Costs directly associated with an exploration well are initially capitalized as an intangible asset until the drilling of the well is complete and the results have been evaluated. These costs include employee remuneration, materials and fuel used, rig costs and payments made to contractors. If potentially commercial quantities of hydrocarbons are not found, the exploration well is written off as a dry hole. If hydrocarbons are found and, subject to further appraisal activity, are likely to be capable of commercial development, the costs continue to be carried as an asset.

Costs directly associated with appraisal activity, undertaken to determine the size, characteristics and commercial potential of a reservoir following the initial discovery of hydrocarbons, including the costs of appraisal wells where hydrocarbons were not found, are initially capitalized as an intangible asset. When proved reserves of oil and natural gas are determined and development is approved by management, the relevant expenditure is transferred to property, plant and equipment.

Development expenditure

Expenditure on the construction, installation and completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including service and unsuccessful development or delineation wells, is capitalized within property, plant and equipment and is depreciated from the commencement of production as described below in the accounting policy for property, plant and equipment.

Significant estimate or judgement: oil and natural gas accounting

The determination of whether potentially economic oil and natural gas reserves have been discovered by an exploration well is usually made within one year after well completion, but can take longer, depending on the complexity of the geological structure. Exploration wells that discover potentially economic quantities of oil and natural gas and are in areas where major capital expenditure (e.g. an offshore platform or a pipeline) would be required before production could begin, and where the economic viability of that major capital expenditure depends on the successful completion of further exploration work in the area, remain capitalized on the balance sheet as long as additional exploration or appraisal work is under way or firmly planned.

It is not unusual to have exploration wells and exploratory-type stratigraphic test wells remaining suspended on the balance sheet for several years while additional appraisal drilling and seismic work on the potential oil and natural gas field is performed or while the optimum development plans and timing are established. All such carried costs are subject to regular technical, commercial and management review on at least an annual basis to confirm the continued intent to develop, or otherwise extract value from, the discovery. Where this is no longer the case, the costs are immediately expensed.

One of the facts and circumstances which indicate that an entity should test such assets for impairment is that the period for which the entity has a right to explore in the specific area has expired or will expire in the near future, and is not expected to be renewed.

BP has leases in the Gulf of Mexico making up a prospect, some with terms which were scheduled to expire at the end of 2013 and some with terms which were scheduled to expire at the end of 2014. A significant proportion of our capitalized exploration and appraisal costs in the Gulf of Mexico relate to this prospect. This prospect requires the development of subsea technology to ensure that the hydrocarbons can be extracted safely. BP is in negotiation with the US Bureau of Safety and Environmental Enforcement in relation to seeking extension of these leases so that the discovered hydrocarbons can be developed. BP remains committed to developing this prospect and expects that the leases will be renewed and, therefore, continues to carry the capitalized costs on its balance sheet.

Property, plant and equipment

Property, plant and equipment is stated at cost, less accumulated depreciation and accumulated impairment losses. The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into the location and condition necessary for it to be capable of operating in the manner intended by management, the initial estimate of any decommissioning obligation, if any, and, for assets that necessarily take a substantial period of time to get ready for their intended use, finance costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. The capitalized value of a finance lease is also included within property, plant and equipment.

Expenditure on major maintenance refits or repairs comprises the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the

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

item will flow to the group, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. Inspection costs associated with major maintenance programmes are capitalized and amortized over the period to the next inspection. Overhaul costs for major maintenance programmes, and all other maintenance costs are expensed as incurred.

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

Other property, plant and equipment is depreciated on a straight-line basis over its expected useful life. The typical useful lives of the group's other property, plant and equipment are as follows:

Land improvements	15 to 25 years
Buildings	20 to 50 years
Refineries	20 to 30 years
Petrochemicals plants	20 to 30 years
Pipelines	10 to 50 years
Service stations	15 years
Office equipment	3 to 7 years
Fixtures and fittings	5 to 15 years

The expected useful lives of property, plant and equipment are reviewed on an annual basis and, if necessary, changes in useful lives are accounted for prospectively.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in the income statement in the period in which the item is derecognized.

Significant estimate or judgement: estimation of oil and natural gas reserves

The determination of the group's estimated oil and natural gas reserves requires significant judgements and estimates to be applied and these are regularly reviewed and updated. Factors such as the availability of geological and engineering data, reservoir performance data, acquisition and divestment activity, drilling of new wells and commodity prices all impact on the determination of the group's estimates of its oil and natural gas reserves. BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements.

The estimation of oil and natural gas reserves and BP's process to manage reserves bookings is described in Supplementary information on oil and natural gas on page 167, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 219.

Estimates of oil and natural gas reserves are used to calculate depreciation, depletion and amortization charges for the group's oil and gas properties. The impact of changes in estimated proved reserves is dealt with prospectively by amortizing the remaining carrying value of the asset over the expected future production. Oil and natural gas reserves also have a direct impact on the assessment of the recoverability of asset carrying values reported in the financial statements. If proved reserves estimates are revised downwards, earnings could be affected by higher depreciation expense or an immediate write-down of the property's carrying value.

The 2014 movements in proved reserves are reflected in the tables showing movements in oil and natural gas reserves by region in Supplementary information on oil and natural gas (unaudited) on page 167. Information on the carrying amounts of the group's oil and natural gas properties, together with the amounts recognized in the income statement as depreciation, depletion and amortization is contained in Note 10 and Note 4 respectively.

Impairment of property, plant and equipment, intangible assets, and goodwill

The group assesses assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable, for example, changes in the group's business plans, changes in commodity prices leading to sustained unprofitable performance, low plant utilization, evidence of physical damage or, for oil and gas assets, significant downward revisions of estimated reserves or increases in estimated future development expenditure or decommissioning costs. If any such indication of impairment exists, the group makes an estimate of the asset's recoverable amount. Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets. An asset group's recoverable amount is the higher of its fair value less costs of disposal and its value in use. Where the carrying amount of an asset group exceeds its recoverable amount, the asset group is considered impaired and is written down to its recoverable amount.

The business segment plans, which are approved on an annual basis by senior management, are the primary source of information for the determination of value in use. They contain forecasts for oil and natural gas production, refinery throughputs, sales volumes for various types of refined products (e.g. gasoline and lubricants), revenues, costs and capital expenditure. As an initial step in the preparation of these plans, various market assumptions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates, are set by senior management. These market assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability. In assessing value in use, the estimated future cash flows are adjusted for the risks specific to the asset group and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money.

Fair value less costs of disposal is the price that would be received to sell the asset in an orderly transaction between market participants and does not reflect the effects of factors that may be specific to the entity and not applicable to entities in general.

An assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such an indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in profit or loss. After such a reversal, the depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life.

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

Goodwill is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the group of cash-generating units to which the goodwill relates should be assessed. In assessing whether goodwill has been impaired, the carrying amount of the group of CGUs (including goodwill) is compared with their recoverable amount. The recoverable amount of a group of CGUs to which goodwill is allocated is the higher of value in use and fair value less costs of disposal. Where the recoverable amount of the group of CGUs to which goodwill has been allocated is less than the carrying amount, an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

Significant estimate or judgement: recoverability of asset carrying values

Determination as to whether, and by how much, an asset or group of CGUs containing goodwill is impaired involves management estimates on highly uncertain matters such as future commodity prices, the effects of inflation on operating expenses, discount rates, production profiles and the outlook for global or regional market supply-and-demand conditions for crude oil, natural gas and refined products. For oil and natural gas properties, the expected future cash flows are estimated using management's best estimate of future oil and natural gas prices and reserves volumes.

The estimated future level of production in all impairment tests is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

Fair value less costs of disposal may be determined based on similar recent market transaction data or, where recent market transactions for the asset are not available for reference, using discounted cash flow techniques. Where discounted cash flow analyses are used to calculate fair value less costs of disposal, accounting judgements are made about the assumptions market participants would use when pricing an asset, a CGU or a group of CGUs containing goodwill and the test is performed on a post-tax basis. The discount rate used is the group's post-tax weighted average cost of capital (2014 8%), with a 2% premium added in higher-risk countries. Reserves assumptions for fair value less costs of disposal discounted cash flow tests consider all reserves that a market participant would consider when valuing the asset, which are usually broader in scope than the reserves used in a value-in-use test. Discounted cash flow analyses used to calculate fair value less costs of disposal use market prices for the first five years and long-term price assumptions that are consistent with the assumptions used by the group for investment appraisal purposes thereafter. The long-term oil price assumption used in such tests is $97 per barrel in 2020 and is inflated at a rate of 2.5% per annum for the remaining life of the asset. This long-term assumption is derived from the $80 per barrel real oil price assumption used for investment appraisal. In the current price environment, the market prices used for the first five years of both value-in-use and fair value less costs of disposal impairment tests are particularly volatile. Market prices used for the first five years of both value-in-use and fair value less costs of disposal impairment tests are shown in the table below:

					2014
	2015	**2016**	**2017**	**2018**	**2019**
Brent oil price ($/bbl)	**61**	**69**	**73**	**76**	**77**
Henry Hub natural gas price ($/mmBtu)	**3.11**	**3.53**	**3.82**	**4.00**	**4.15**

					2013
	2014	2015	2016	2017	2018
Brent oil price ($/bbl)	108	102	97	93	90
Henry Hub natural gas price ($/mmBtu)	3.86	4.02	4.10	4.17	4.27

For value-in-use calculations, future cash flows are adjusted for risks specific to the cash-generating unit and are discounted using a pre-tax discount rate. The discount rate is derived from the group's post-tax weighted average cost of capital and is adjusted where applicable to take into account any specific risks relating to the country where the cash-generating unit is located. In 2014 the discount rate used for value-in-use calculations was 12% nominal (2013 12% nominal), with a 2% premium added in higher-risk countries. The discount rates applied in assessments of impairment are reassessed each year. Reserves assumptions for value-in-use tests are confined to proved and sanctioned probable reserves. For value-in-use calculations, prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years (consistent with those shown in the table above) and the group's flat nominal long-term price assumptions thereafter. As at 31 December 2014, the group's long-term flat nominal price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2013 $90 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review and revision.

Irrespective of whether there is any indication of impairment, BP is required to test annually for impairment of goodwill acquired in a business combination. The group carries goodwill of approximately $11.9 billion on its balance sheet (2013 $12.2 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. In testing goodwill for impairment, the group uses the approach described above to determine recoverable amount. If there are low oil or natural gas prices or refining margins or marketing margins for an extended period, the group may need to recognize goodwill impairment charges.

The recoverability of intangible exploration and appraisal expenditure is covered under Oil and natural gas exploration, appraisal and development expenditure above.

Details of impairment charges recognized in the income statement are provided in Note 3 and details on the carrying amounts of assets are shown in Note 10, Note 12 and Note 13.

Inventories

Inventories, other than inventories held for trading purposes, are stated at the lower of cost and net realizable value. Cost is determined by the first-in first-out method and comprises direct purchase costs, cost of production, transportation and manufacturing expenses. Net realizable value is determined by reference to prices existing at the balance sheet date, adjusted where the sale of inventories after the reporting period gives evidence about their net realizable value at the end of the period.

Inventories held for trading purposes are stated at fair value less costs to sell and any changes in fair value are recognized in the income statement.

Supplies are valued at cost to the group mainly using the average method or net realizable value, whichever is the lower.

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

Leases

Finance leases are capitalized at the commencement of the lease term at the fair value of the leased item or, if lower, at the present value of the minimum lease payments. Finance charges are allocated to each period so as to achieve a constant rate of interest on the remaining balance of the liability and are charged directly against income. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Operating lease payments are recognized as an expense in the income statement on a straight-line basis over the lease term.

Financial assets

Financial assets are classified as loans and receivables; financial assets at fair value through profit or loss; derivatives designated as hedging instruments in an effective hedge; held-to-maturity financial assets; or as available-for-sale financial assets, as appropriate. Financial assets include cash and cash equivalents, trade receivables, other receivables, loans, other investments, and derivative financial instruments. The group determines the classification of its financial assets at initial recognition. Financial assets are recognized initially at fair value, normally being the transaction price plus, in the case of financial assets not at fair value through profit or loss, directly attributable transaction costs.

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

Loans and receivables

Loans and receivables are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in income when the loans and receivables are derecognized or impaired, as well as through the amortization process. This category of financial assets includes trade and other receivables. Cash and cash equivalents are short-term highly liquid investments that are readily convertible to known amounts of cash, are subject to insignificant risk of changes in value and have a maturity of three months or less from the date of acquisition.

Financial assets at fair value through profit or loss

Financial assets at fair value through profit or loss are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category.

Derivatives designated as hedging instruments in an effective hedge

These derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Held-to-maturity financial assets

Held-to-maturity financial assets are measured at amortized cost using the effective interest method, less any impairment.

Available-for-sale financial assets

After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income, except for impairment losses, and, for available-for-sale debt instruments, foreign exchange gains or losses and any changes in fair value arising from revised estimates of future cash flows, which are recognized in profit or loss.

Impairment of loans and receivables

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired. If there is objective evidence that an impairment loss on loans and receivables carried at amortized cost has been incurred, the amount of the loss is measured as the difference between the asset's carrying amount and the present value of estimated future cash flows discounted at the financial asset's original effective interest rate. The carrying amount of the asset is reduced, with the amount of the loss recognized in the income statement.

Significant estimate or judgement: recoverability of trade receivables

Judgements are required in assessing the recoverability of overdue trade receivables and determining whether a provision against the future recoverability of those receivables is required. Factors considered include the credit rating of the counterparty, the amount and timing of anticipated future payments and any possible actions that can be taken to mitigate the risk of non-payment. See Note 27 for information on overdue receivables.

Financial liabilities

Financial liabilities are classified as financial liabilities at fair value through profit or loss; derivatives designated as hedging instruments in an effective hedge; or as financial liabilities measured at amortized cost, as appropriate. Financial liabilities include trade and other payables, accruals, most items of finance debt and derivative financial instruments. The group determines the classification of its financial liabilities at initial recognition. The measurement of financial liabilities depends on their classification, as follows:

Financial liabilities at fair value through profit or loss

Financial liabilities at fair value through profit or loss are carried on the balance sheet at fair value with gains or losses recognized in the income statement. Derivatives, other than those designated as effective hedging instruments, are classified as held for trading and are included in this category.

Derivatives designated as hedging instruments in an effective hedge

These derivatives are carried on the balance sheet at fair value. The treatment of gains and losses arising from revaluation is described below in the accounting policy for derivative financial instruments and hedging activities.

Financial liabilities measured at amortized cost

All other financial liabilities are initially recognized at fair value. For interest-bearing loans and borrowings this is the fair value of the proceeds received net of issue costs associated with the borrowing.

After initial recognition, other financial liabilities are subsequently measured at amortized cost using the effective interest method. Amortized cost is calculated by taking into account any issue costs, and any discount or premium on settlement. Gains and losses arising on the repurchase, settlement or cancellation of liabilities are recognized respectively in interest and other income and finance costs.

This category of financial liabilities includes trade and other payables and finance debt.

Derivative financial instruments and hedging activities

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

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

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

For the purpose of hedge accounting, hedges are classified as:

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

Hedge relationships are formally designated and documented at inception, together with the risk management objective and strategy for undertaking the hedge. The documentation includes identification of the hedging instrument, the hedged item or transaction, the nature of the risk being hedged, and how the entity will assess the hedging instrument effectiveness in offsetting the exposure to changes in the hedged item's fair value or cash flows attributable to the hedged risk. Such hedges are expected at inception to be highly effective in achieving offsetting changes in fair value or cash flows. Hedges meeting the criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss. The group applies fair value hedge accounting when hedging interest rate risk on fixed rate borrowings.

If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the accumulated adjustment to the carrying amount of a hedged item at such time is then amortized to profit or loss over the remaining period to maturity.

Cash flow hedges

The effective portion of the gain or loss on a cash flow hedging instrument is recognized within other comprehensive income, while the ineffective portion is recognized in profit or loss. Amounts taken to other comprehensive income are reclassified to the income statement when the hedged transaction affects profit or loss.

Where the hedged item is a non-financial asset or liability, such as a forecast foreign currency transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are reclassified to the initial carrying amount of the non-financial asset or liability. Where the hedged item is an equity investment, the amounts recognized in other comprehensive income remain in the separate component of equity until the hedged cash flows affect profit or loss. Where the hedged item is recognized directly in profit or loss, the amounts recognized in other comprehensive income are reclassified to production and manufacturing expenses, except for cash flow hedges of variable interest rate risk which are reclassified to finance costs.

If the hedging instrument expires or is sold, terminated or exercised without replacement or rollover, or if its designation as a hedge is revoked, amounts previously recognized within other comprehensive income remain in equity until the forecast transaction occurs and are reclassified to the income statement or to the initial carrying amount of a non-financial asset or liability as above.

Significant estimate or judgement: application of hedge accounting

The decision as to whether to apply hedge accounting within subsidiaries, and by equity-accounted entities, can have a significant impact on the group's financial statements. Cash flow and fair value hedge accounting is applied to certain finance debt-related instruments in the normal course of business and cash flow hedge accounting is applied to certain highly probable foreign currency transactions as part of the management of currency risk. In addition, the financial statements reflect the application of cash flow hedge accounting to certain of the contracts signed in October 2012 for BP to sell its investment in TNK-BP and obtain an additional shareholding in Rosneft, which were accounted for as derivatives under IFRS. The group applied 'all-in-one' cash flow hedge accounting to the contracts to acquire shares in Rosneft, resulting in a pre-tax loss of $2,061 million being recognized in other comprehensive income in 2013 and a pre-tax gain of $1,410 million in 2012. See Note 15, Note 27, and Note 28 for further details.

Embedded derivatives

Derivatives embedded in other financial instruments or other host contracts are treated as separate derivatives when their risks and characteristics are not closely related to those of the host contract. Contracts are assessed for embedded derivatives when the group becomes a party to them, including at the date of a business combination. Embedded derivatives are measured at fair value at each balance sheet date. Any gains or losses arising from changes in fair value are taken directly to the income statement.

Fair value measurement

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. The group categorizes assets and liabilities measured at fair value into one of three levels depending on the ability to observe inputs employed in their measurement. Level 1 inputs are quoted prices in active markets for identical assets or liabilities. Level 2 inputs are inputs that are observable, either directly or indirectly, other than quoted prices included within level 1 for the asset or liability. Level 3 inputs are unobservable inputs for the asset or liability reflecting significant modifications to observable related market data or BP's assumptions about pricing by market participants.

Significant estimate or judgement: valuation of derivatives

In some cases the fair values of derivatives are estimated using internal models due to the absence of quoted prices or other observable, market-corroborated data. This applies to the group's longer-term derivative contracts and certain options, as well as to the majority of the group's embedded derivatives. These embedded derivatives arise primarily from long-term UK natural gas contracts that use pricing formulae not related to gas prices, for example, oil product and power prices. The majority of these contracts are valued using models with inputs that include price curves for each of the different products that are built up from active market pricing data and extrapolated to the expiry of the contracts using the maximum available external pricing information. Additionally, where limited data exists for certain products, prices are interpolated using historic and long-term pricing relationships. Price volatility is also an input for the models.

Changes in the key assumptions could have a material impact on the fair value gains and losses on derivatives and embedded derivatives recognized in the income statement. For more information see Note 28.

Offsetting of financial assets and liabilities

Financial assets and liabilities are presented gross in the balance sheet unless both of the following criteria are met: the group currently has a legally enforceable right to set off the recognized amounts; and the group intends to either settle on a net basis or realize the asset and settle the liability simultaneously. A right of set off is the group's legal right to settle an amount payable to a creditor by applying against it an amount receivable from the same counterparty. The relevant legal jurisdiction and laws applicable to the relationships between the parties are considered when assessing whether a current legally enforceable right to set off exists.

Provisions, contingencies and reimbursement assets

Provisions are recognized when the group has a present legal or constructive obligation as a result of a past event, it is probable that an outflow of resources embodying economic benefits will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. Where appropriate, the future cash flow estimates are adjusted to reflect risks specific to the liability.

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs. A provision is discounted using either a nominal discount rate of 2.75% (2013 3.25%) or a real discount rate of 0.75% (2013 1%), as appropriate. Provisions are split between amounts expected to be settled within 12 months of the balance sheet date (current) and amounts expected to be settled later (non-current). Contingent liabilities are possible obligations whose existence will only be confirmed by future events not wholly within the control of the group, or present obligations where it is not probable that an outflow of resources will be required or the amount of the obligation cannot be measured with sufficient reliability.

Contingent liabilities are not recognized in the financial statements but are disclosed unless the possibility of an outflow of economic resources is considered remote.

Where the group makes contributions into a separately administered fund for restoration, environmental or other obligations, which it does not control, and the group's right to the assets in the fund is restricted, the obligation to contribute to the fund is recognized as a liability where it is probable that such additional contributions will be made. The group recognizes a reimbursement asset separately, being the lower of the amount of the associated restoration, environmental or other provision and the group's share of the fair value of the net assets of the fund available to contributors.

Significant estimate or judgement: provision relating to the Gulf of Mexico oil spill

Detailed information on the Gulf of Mexico oil spill, including the financial impacts, is provided in Note 2.

The provision recognized is the reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period. There are future expenditures, however, for which it is not possible to measure the obligation reliably. These are not provided for and are disclosed as contingent liabilities. Accounting judgement is required to identify when a provision can be measured reliably, which can be especially challenging when complex litigation activities are ongoing.

In addition, for those provisions which are recognized, there is significant estimation uncertainty about the amounts that will ultimately be paid, especially with regard to amounts payable under the Deepwater Horizon Court Supervised Settlement Program (DHCSSP). A provision is made for these costs when the amount can be measured reliably; this requires an analysis of claims received and processed and consideration of the status of ongoing legal activity.

The provision for penalties under the US Clean Water Act is based on the estimated civil penalty for strict liability. This provision is calculated based on the assumption that BP did not act with gross negligence or engage in wilful misconduct. However, in September 2014 the district court ruled that the discharge of oil was the result of BP's gross negligence and wilful misconduct and it is not now possible to determine a reliable estimate of the liability. The existing provision has been maintained as explained in Note 2 and a contingent liability has been disclosed in relation to the potential for a higher penalty due to this ruling. The amount that will become payable by BP is subject to a very high level of uncertainty since it will depend on the outcome of BP's appeal of the September 2014 gross negligence ruling as well as what is determined by the court in the federal multi-district litigation proceedings in New Orleans (MDL 2179) with respect to the application of statutory penalty factors. See Note 2 for additional information.

Decommissioning

Liabilities for decommissioning costs are recognized when the group has an obligation to plug and abandon a well, dismantle and remove a facility or an item of plant and to restore the site on which it is located, and when a reliable estimate of that liability can be made. Where an obligation exists for a new facility or item of plant, such as oil and natural gas production or transportation facilities, this liability will be recognized on construction or installation. Similarly, where an obligation exists for a well, this liability is recognized when it is drilled. An obligation for decommissioning may also crystallize during the period of operation of a well, facility or item of plant through a change in legislation or through a decision to terminate operations; an obligation may also arise in cases where an asset has been sold but the subsequent owner is no longer able to fulfil its decommissioning obligations, for example due to bankruptcy. The amount recognized is the present value of the estimated future expenditure determined in accordance with local conditions and requirements. The provision for the costs of decommissioning wells, production facilities and pipelines at the end of their economic lives is estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using the real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately 20 years.

An amount equivalent to the decommissioning provision is recognized as part of the corresponding intangible asset (in the case of an exploration or appraisal well) or property, plant and equipment. The decommissioning portion of the property, plant and equipment is subsequently depreciated at the same rate as the rest of the asset.

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

Other than the unwinding of discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset.

Environmental expenditures and liabilities

Environmental expenditures that are required in order for the group to obtain future economic benefits from its assets are capitalized as part of those assets. Expenditures that relate to an existing condition caused by past operations that do not contribute to future earnings are expensed.

Liabilities for environmental costs are recognized when a clean-up is probable and the associated costs can be reliably estimated. Generally, the timing of recognition of these provisions coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The amount recognized is the best estimate of the expenditure required to settle the obligation. Provisions for environmental liabilities have been estimated using existing technology, at current prices and discounted using a real discount rate. The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately five years.

Significant estimate or judgement: provisions

The group holds provisions for the future decommissioning of oil and natural gas production facilities and pipelines at the end of their economic lives. The largest decommissioning obligations facing BP relate to the plugging and abandonment of wells and the removal and disposal of oil and natural gas platforms and pipelines around the world. Most of these decommissioning events are many years in the future and the precise requirements that will have to be met when the removal event occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. BP believes that the impact of any reasonably foreseeable change to these provisions on the group's results of operations, financial position or liquidity will not be material. If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations, judgement must be used to determine whether BP is then responsible for decommissioning, and if so the extent of that responsibility. Consequently, the timing and amounts of future cash flows are subject to significant uncertainty. Any changes in the expected future costs are reflected in both the provision and the asset.

Decommissioning provisions associated with downstream and petrochemicals facilities are generally not recognized, as the potential obligations cannot be measured, given their indeterminate settlement dates. The group performs periodic reviews of its downstream and petrochemicals long-lived assets for any changes in facts and circumstances that might require the recognition of a decommissioning provision.

The provision for environmental liabilities is estimated based on current legal and constructive requirements, technology, price levels and expected plans for remediation. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, prices, discovery and analysis of site conditions and changes in clean-up technology.

Other provisions and liabilities are recognized in the period when it becomes probable that there will be a future outflow of funds resulting from past operations or events and the amount of cash outflow can be reliably estimated. The timing of recognition and quantification of the liability require the application of judgement to existing facts and circumstances, which can be subject to change. Since the cash outflows can take place many years in the future, the carrying amounts of provisions and liabilities are reviewed regularly and adjusted to take account of changing facts and circumstances.

The timing and amount of future expenditures are reviewed annually, together with the interest rate used in discounting the cash flows. The interest rate used to determine the balance sheet obligation at the end of 2014 was a real rate of 0.75% (2013 1.0%), which was based on long-dated US government bonds.

Provisions and contingent liabilities relating to the Gulf of Mexico oil spill are discussed in Note 2. Information about the group's other provisions is provided in Note 21. As further described in Note 21, the group is subject to claims and actions. The facts and circumstances relating to particular cases are evaluated regularly in determining whether it is probable that there will be a future outflow of funds and, once established, whether a provision relating to a specific litigation should be established or revised. Accordingly, significant management judgement relating to provisions and contingent liabilities is required, since the outcome of litigation is difficult to predict.

Employee benefits

Wages, salaries, bonuses, social security contributions, paid annual leave and sick leave are accrued in the period in which the associated services are rendered by employees of the group. Deferred bonus arrangements that have a vesting date more than 12 months after the balance sheet date are valued on an actuarial basis using the projected unit credit method and amortized on a straight-line basis over the service period until the award vests. The accounting policies for share-based payments and for pensions and other post-retirement benefits are described below.

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees is measured by reference to the fair value at the date at which equity instruments are granted and is recognized as an expense over the vesting period, which ends on the date on which the employees become fully entitled to the award. A corresponding credit is recognized within equity. Fair value is determined by using an appropriate, widely used, valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the company (market conditions). Non-vesting conditions, such as the condition that employees contribute to a savings-related plan, are taken into account in the grant-date fair value, and failure to meet a non-vesting condition, where this is within the control of the employee is treated as a cancellation and any remaining unrecognized cost is expensed.

Cash-settled transactions

The cost of cash-settled transactions is recognized as an expense over the vesting period, measured by reference to the fair value of the corresponding liability which is recognized on the balance sheet. The liability is remeasured at fair value at each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions and other post-retirement benefits

The cost of providing benefits under the group's defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period to determine current service cost and to the current and prior periods to determine the present value of the defined benefit obligation. Past service costs, resulting from either a plan amendment or a curtailment (a reduction in future obligations as a result of a material reduction in the plan membership), are recognized immediately when the company becomes committed to a change.

Net interest expense relating to pensions and other post-retirement benefits, which is recognized in the income statement, represents the net change in present value of plan obligations and the value of plan assets resulting from the passage of time, and is determined by applying the discount rate to the present value of the benefit obligation at the start of the year, and to the fair value of plan assets at the start of the year, taking into account expected changes in the obligation or plan assets during the year.

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

Remeasurements of the defined benefit liability and asset, comprising actuarial gains and losses, and the return on plan assets (excluding amounts included in net interest described above) are recognized within other comprehensive income in the period in which they occur and are not subsequently reclassified to profit and loss.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. Defined benefit pension plan surpluses are only recognized to the extent they are recoverable.

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

Significant estimate or judgement: pensions and other post-retirement benefits

Accounting for pensions and other post-retirement benefits involves judgement about uncertain events, including estimated retirement dates, salary levels at retirement, mortality rates, determination of discount rates for measuring plan obligations and net interest expense and assumptions for inflation rates.

These assumptions are based on the environment in each country. The assumptions used may vary from year to year, which would affect future net income and net assets. Any differences between these assumptions and the actual outcome also affect future net income and net assets.

Pension and other post-retirement benefit assumptions are reviewed by management at the end of each year. These assumptions are used to determine the projected benefit obligation at the year end and hence the surpluses and deficits recorded on the group's balance sheet, and pension and other post-retirement benefit expense for the following year.

The assumptions used are provided in Note 22.

The discount rate and inflation rate have a significant effect on the amounts reported. A sensitivity analysis of the impact of changes in these assumptions on the benefit expense and obligation is provided in Note 22.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. Mortality assumptions reflect best practice in the countries in which we provide pensions and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. A sensitivity analysis of the impact of changes in the mortality assumptions on the benefit expense and obligation is provided in Note 22.

Income taxes

Income tax expense represents the sum of current tax and deferred tax. Interest and penalties relating to income tax are also included in the income tax expense.

Income tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity, in which case the related tax is recognized in other comprehensive income or directly in equity.

Current tax is based on the taxable profit for the period. Taxable profit differs from net profit as reported in the income statement because it is determined in accordance with the rules established by the applicable taxation authorities. It therefore excludes items of income or expense that are taxable or deductible in other periods as well as items that are never taxable or deductible. The group's liability for current tax is calculated using tax rates and laws that have been enacted or substantively enacted by the balance sheet date.

Deferred tax is provided, using the liability method, on all temporary differences at the balance sheet date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax liabilities are recognized for all taxable temporary differences except:

- where the deferred tax liability arises on the initial recognition of goodwill; or
- where the deferred tax liability arises on the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss; or
- in respect of taxable temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, where the group is able to control the timing of the reversal of the temporary differences and it is probable that the temporary differences will not reverse in the foreseeable future.

Deferred tax assets are recognized for all deductible temporary differences, carry-forward of unused tax credits and unused tax losses, to the extent that it is probable that taxable profit will be available against which the deductible temporary differences and the carry-forward of unused tax credits and unused tax losses can be utilized except where the deferred tax asset relating to the deductible temporary difference arises from the initial recognition of an asset or liability in a transaction that is not a business combination and, at the time of the transaction, affects neither accounting profit nor taxable profit or loss. In respect of deductible temporary differences associated with investments in subsidiaries and associates and interests in joint arrangements, deferred tax assets are recognized only to the extent that it is probable that the temporary differences will reverse in the foreseeable future and taxable profit will be available against which the temporary differences can be utilized.

The carrying amount of deferred tax assets is reviewed at each balance sheet date and reduced to the extent that it is no longer probable that sufficient taxable profit will be available to allow all or part of the deferred tax asset to be utilized.

Deferred tax assets and liabilities are measured at the tax rates that are expected to apply in the period when the asset is realized or the liability is settled, based on tax rates (and tax laws) that have been enacted or substantively enacted at the balance sheet date. Deferred tax assets and liabilities are not discounted.

Deferred tax assets and liabilities are offset only when there is a legally enforceable right to set off current tax assets against current tax liabilities and when the deferred tax assets and liabilities relate to income taxes levied by the same taxation authority on either the same taxable entity or different taxable entities where there is an intention to settle the current tax assets and liabilities on a net basis or to realize the assets and settle the liabilities simultaneously.

Significant estimate or judgement: income taxes

The computation of the group's income tax expense and liability involves the interpretation of applicable tax laws and regulations in many jurisdictions throughout the world. The resolution of tax positions taken by the group, through negotiations with relevant tax authorities or through litigation, can take several years to complete and in some cases it is difficult to predict the ultimate outcome. Therefore, judgement is required to determine provisions for income taxes.

In addition, the group has carry-forward tax losses and tax credits in certain taxing jurisdictions that are available to offset against future taxable profit. However, deferred tax assets are recognized only to the extent that it is probable that taxable profit will be available against which the unused tax losses or tax credits can be utilized. Management judgement is exercised in assessing whether this is the case.

To the extent that actual outcomes differ from management's estimates, income tax charges or credits, and changes in current and deferred tax assets or liabilities, may arise in future periods. For more information see Note 7.

Judgement is also required when determining whether a particular tax is an income tax or another type of tax (for example a production tax). Accounting for deferred tax is applied to income taxes as described above, but is not applied to other types of taxes; rather such taxes are recognized in the income statement on an appropriate basis.

Customs duties and sales taxes

Customs duties and sales taxes which are passed on to customers are excluded from revenues and expenses. Assets and liabilities are recognized net of the amount of customs duties or sales tax except:

- Where the customs duty or sales taxes incurred on a purchase of goods and services is not recoverable from the taxation authority, in which case the customs duty or sales tax is recognized as part of the cost of acquisition of the asset.
- Receivables and payables are stated with the amount of customs duty or sales tax included.

The net amount of sales tax recoverable from, or payable to, the taxation authority is included within receivables or payables in the balance sheet.

Own equity instruments

The group's holdings in its own equity instruments are shown as deductions from shareholders' equity at cost. For accounting purposes, own equity instruments include both treasury shares and shares purchased from the open market. Some of these own equity instruments are held by Employee Share Ownership Plans (ESOPs), including certain shares transferred out of treasury. Consideration, if any, received for the sale of such shares is also recognized in equity, with any difference between the proceeds from sale and the original cost being taken to the profit and loss account reserve. No gain or loss is recognized in the income statement on the purchase, sale, issue or cancellation of equity shares. Shares repurchased under the share buy-back programme which are immediately cancelled are not shown as treasury shares, but are shown as a deduction from the profit and loss account reserve in the group statement of changes in equity.

Revenue

Revenue arising from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer, which is typically at the point that title passes, and the revenue can be reliably measured.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods provided in the normal course of business, net of discounts, customs duties and sales taxes.

Physical exchanges are reported net, as are sales and purchases made with a common counterparty, as part of an arrangement similar to a physical exchange. Similarly, where the group acts as agent on behalf of a third party to procure or market energy commodities, any associated fee income is recognized but no purchase or sale is recorded. Additionally, where forward sale and purchase contracts for oil, natural gas or power have been determined to be for trading purposes, the associated sales and purchases are reported net within sales and other operating revenues whether or not physical delivery has occurred.

Generally, revenues from the production of oil and natural gas properties in which the group has an interest with joint operation partners are recognized on the basis of the group's working interest in those properties (the entitlement method). Differences between the production sold and the group's share of production are not significant.

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

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

Finance costs

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

Impact of new International Financial Reporting Standards

There are no new or amended standards or interpretations adopted during the year that have a significant impact on the financial statements.

Not yet adopted

The following pronouncements from the IASB will become effective for future financial reporting periods and have not yet been adopted by the group.

The IASB issued IFRS 15 'Revenue from Contracts with Customers', which provides a single model for accounting for revenue arising from contracts with customers and is effective for annual periods beginning on or after 1 January 2017. IFRS 15 will supersede IAS 18 'Revenue'.

The IASB has also issued IFRS 9 'Financial Instruments', which will supersede IAS 39 'Financial Instruments: Recognition and Measurement' and is effective for annual periods beginning on or after 1 January 2018. IFRS 9 covers classification and measurement of financial assets and financial liabilities, impairment methodology and hedge accounting.

BP has not yet decided the date of adoption for the group for IFRS 15 and IFRS 9 and has not yet completed its evaluation of the effect of adoption. The EU has not yet adopted IFRS 15 or IFRS 9.

There are no other standards and interpretations in issue but not yet adopted that the directors anticipate will have a material effect on the reported income or net assets of the group.

2. Significant event – Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill in April 2010, BP continues to incur costs and has also recognized liabilities for certain future costs. Liabilities of uncertain timing or amount, for which no provision has been made, have been disclosed as contingent liabilities.

The cumulative pre-tax income statement charge since the incident amounts to $43.5 billion. For more information on the types of expenditure included in the cumulative income statement charge, see Impact upon the group income statement below. The cumulative income statement charge does not include amounts for obligations that BP considers are not possible, at this time, to measure reliably. For further information, including developments in relation to the interpretation of business economic loss claims under the Plaintiffs' Steering Committee (PSC) settlement and the measurement of the penalty obligation under the Clean Water Act, see Provisions and contingent liabilities below.

The total amounts that will ultimately be paid by BP in relation to all the obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors, as discussed under Provisions and contingent liabilities below, including in relation to any new information or future developments. These could have a material impact on our consolidated financial position, results of operations and cash flows. The risks associated with the incident could also heighten the impact of the other risks to which the group is exposed as further described under Risk factors on page 48 and Legal proceedings on page 228.

The impacts of the Gulf of Mexico oil spill on the income statement, balance sheet and cash flow statement of the group are included within the relevant line items in those statements and are shown in the table below.

			$ million
	2014	2013	2012
Income statement			
Production and manufacturing expenses	**781**	430	4,995
Profit (loss) before interest and taxation	**(781)**	(430)	(4,995)
Finance costs	**38**	39	19
Profit (loss) before taxation	**(819)**	(469)	(5,014)
Less: Taxation	**262**	73	94
Profit (loss) for the period	**(557)**	(396)	(4,920)
Balance sheet			
Current assets			
Trade and other receivables	**1,154**	2,457	
Current liabilities			
Trade and other payables	**(655)**	(1,030)	
Provisions	**(1,702)**	(2,951)	
Net current assets (liabilities)	**(1,203)**	(1,524)	
Non-current assets			
Other receivables	**2,701**	2,442	
Non-current liabilities			
Other payables	**(2,412)**	(2,986)	
Accruals	**(169)**	–	
Provisions	**(6,903)**	(6,395)	
Deferred tax	**1,723**	2,748	
Net non-current assets (liabilities)	**(5,060)**	(4,191)	
Net assets (liabilities)	**(6,263)**	(5,715)	
Cash flow statement			
Profit (loss) before taxation	**(819)**	(469)	(5,014)
Finance costs	**38**	39	19
Net charge for provisions, less payments	**939**	1,129	4,834
(Increase) decrease in other current and non-current assets	**(662)**	(1,481)	(998)
Increase (decrease) in other current and non-current liabilities	**(792)**	(618)	(5,090)
Pre-tax cash flows	**(1,296)**	(1,400)	(6,249)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to an outflow of $9 million (2013 outflow of $73 million and 2012 outflow of $2,382 million).

Trust fund

BP established the Deepwater Horizon Oil Spill Trust (the Trust) in 2010, to be funded in the amount of $20 billion, to satisfy legitimate individual and business claims, state and local government claims resolved by BP, final judgments and settlements, state and local response costs, and natural resource damages and related costs. The Trust is available to fund the qualified settlement funds (QSFs) established under the terms of the settlement agreements (comprising the Economic and Property Damages (EPD) Settlement Agreement and the Medical Benefits Class Action Settlement) with the PSC administered through the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) – see Provisions and contingent liabilities below for further information. Fines and penalties are not covered by the trust fund.

The funding of the Trust was completed in 2012. The obligation to fund the $20-billion trust fund, adjusted to take account of the time value of money, was recognized in full in 2010 and charged to the income statement.

BP's rights and obligations in relation to the $20-billion trust fund are accounted for in accordance with IFRIC 5 'Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds'. An asset has been recognized representing BP's right to receive reimbursement from the trust fund. This is the portion of the estimated future expenditure provided for that will be settled by payments from the trust fund. We use the term 'reimbursement asset' to describe this asset. BP will not actually receive any reimbursements from the trust fund, instead payments will be made directly from the trust fund, and BP will be released from its corresponding obligation. The reimbursement asset is recorded within Trade and other receivables on the balance sheet apportioned between current and non-current elements. The net increase in the provision for items covered by the trust fund of $662 million relates principally to business economic loss claims as well as increases in the provision for claims administration costs. During the year, cumulative charges to be paid by the Trust reached $20 billion. Subsequent additional costs, over and above those provided within the $20 billion, are being expensed to the income statement as incurred.

At 31 December 2014, $3,855 million of the provisions and payables are eligible to be paid from the Trust. The table below shows movements in the reimbursement asset during the period to 31 December 2014.

			$ million
	2014	2013	Cumulative since the incident
At 1 January	**4,899**	6,442	–
Net Increase in provision for items covered by the trust fund	**662**	1,542	20,000
Amounts paid directly by the trust fund	**(1,706)**	(3,085)	(16,145)
At 31 December	**3,855**	4,899	3,855
Of which – current	**1,154**	2,457	1,154
– non-current	**2,701**	2,442	2,701

As at 31 December 2014, the aggregate cash balances in the Trust and the QSFs amounted to $5.1 billion, including $1.1 billion remaining in the seafood compensation fund which has yet to be distributed and $0.4 billion held for natural resource damage early restoration. A further $500-million partial distribution from the seafood compensation fund has been recommended and disbursement of funds commenced in early 2015. The portion of the provision and reimbursement asset that related to the seafood compensation fund were derecognized upon funding of the seafood compensation fund QSF in 2012.

The EPD Settlement Agreement with the PSC provides for a court-supervised settlement programme which commenced operation on 4 June 2012. See Provisions below for further information on the current status of the EPD Settlement Agreement. A separate claims administrator has been appointed to pay medical claims and to implement other aspects of the Medical Benefits Class Action Settlement. For further information on the PSC settlements, see Legal proceedings on page 228.

Other payables

BP reached an agreement with the US government in 2012, which was approved by the court in 2013, to resolve all federal criminal claims arising from the incident. Under the agreement, BP agreed to pay $4 billion over a period of five years. At 31 December 2014, the remaining criminal claims payable, within Other payables, was $2,995 million, of which $595 million falls due in 2015.

BP also reached a settlement with the US Securities and Exchange Commission (SEC) in 2012, resolving the SEC's Gulf of Mexico oil spill-related civil claims. As part of the settlement, BP agreed to a civil penalty of $525 million, with the final instalment paid during 2014.

Provisions and contingent liabilities

Provisions

BP has recorded provisions relating to the Gulf of Mexico oil spill in relation to environmental expenditure (including spill response costs), litigation and claims, and Clean Water Act penalties that can be measured reliably at this time.

Movements in each class of provision during the year and cumulatively since the incident are presented in the tables below.

				$ million
				2014
	Environmental	Litigation and Claims	Clean Water Act	Total
At 1 January	1,679	4,157	3,510	9,346
Increase in provision	190	1,137	–	1,327
Unwinding of discount	1	–	–	1
Change in discount rate	2	–	–	2
Utilization – paid by BP	(83)	(307)	–	(390)
– paid by the trust fund	(648)	(1,033)	–	(1,681)
At 31 December	1,141	3,954	3,510	8,605
Of which – current	528	1,174	–	1,702
– non-current	613	2,780	3,510	6,903

				$ million
				Cumulative since the incident
	Environmental	Litigation and Claims	Clean Water Act	Total
Net increase in provision	14,599	26,595	3,510	44,704
Unwinding of discount	13	6	–	19
Change in discount rate	19	–	–	19
Reclassified to other payables	–	(4,283)	–	(4,283)
Utilization – paid by BP	(11,687)	(4,080)	–	(15,767)
– paid by the trust fund	(1,803)	(14,284)	–	(16,087)
At 31 December 2014	1,141	3,954	3,510	8,605

Environmental

The environmental provision at 31 December 2014 includes the remaining $279 million for BP's commitment to fund the Gulf of Mexico Research Initiative, which is a 10-year research programme to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico. In addition, BP faces claims under the Oil Pollution Act of 1990 (OPA 90) for natural resource damages. These damages include, among other things, the reasonable costs of assessing the injury to natural resources. During 2011, BP entered into a framework agreement with natural resource trustees for the United States and five Gulf-coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the oil spill, to be funded from the $20-billion trust fund. In 2012, work began on the initial set of early restoration projects identified under this framework and during 2014, Phase 3 of the early restoration projects was formally agreed, comprising $627 million of approved project spend (of which $563 million has been paid). At 31 December 2014, the remaining amount provided for natural resource damage assessment costs and early restoration projects was $798 million. Until the size, location and duration of the impact is assessed, it is not possible to estimate reliably either the amounts or timing of the remaining natural resource damages claims other than the assessment and early restoration costs noted above, therefore no additional amounts have been provided for these items and they are disclosed as a contingent liability.

Litigation and claims

The litigation and claims provision includes amounts that can be estimated reliably for the future cost of settling claims by individuals and businesses for damage to real or personal property, lost profits or impairment of earning capacity and loss of subsistence use of natural resources ('Individual and Business Claims'), and claims by state and local government entities for removal costs, damage to real or personal property, loss of government revenue and increased public services costs, under OPA 90 and other legislation ('State and Local Claims'), except as described under Contingent liabilities below. Claims administration costs and legal costs, including legal costs under indemnification agreements, have also been provided for. The timing of payment of litigation and claims provisions classified as non-current is dependent upon ongoing legal activity and is therefore uncertain.

BP has provided for its best estimate of the cost associated with the PSC settlement agreements with the exception of the cost of business economic loss claims, which are provided for where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility. As disclosed in *BP Annual Report and Form 20-F 2013*, as part of its monitoring of payments made by the DHCSSP, BP identified multiple business economic loss claim determinations that appeared to result from an interpretation of the Economic and Property Damages Settlement Agreement (EPD Settlement Agreement) by the claims administrator that BP believes was incorrect.

During 2014, there were various rulings on matters relating to the interpretation of the EPD Settlement Agreement, in particular on the issue of matching revenue and expenses as well as causation requirements of the EPD Settlement Agreement.

In March 2014, the US Court of Appeals for the Fifth Circuit (the Fifth Circuit) affirmed the district court's ruling that the EPD Settlement Agreement contained no causation requirement beyond the revenue and related tests set out in an exhibit to that agreement. In March 2014, BP filed a petition that all the active judges of the Fifth Circuit review the decision; in May 2014 this was denied. The district court dissolved the injunction that had halted the processing and payment of business economic loss claims and instructed the claims administrator to resume the processing and payment of claims. BP sought review by the US Supreme Court (Supreme Court) of the Fifth Circuit's decisions relating to compensation of claims for losses with no apparent connection to the Deepwater Horizon spill. In December 2014, the Supreme Court declined to review BP's petition. As a result, the final deadline for filing claims in the Economic and Property Damages Settlement is 8 June 2015.

Management believes that no reliable estimate can currently be made of any business economic loss claims (i) not yet received; (ii) received, but not yet processed; or (iii) processed, but not yet paid, except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility. The inability to estimate reliably such claims is due to uncertainty regarding both the volume of such claims and the average value per claim.

In respect of uncertainty regarding the volume of claims, in December 2014, the Supreme Court declined to hear BP's appeal of the district court ruling that the EPD Settlement Agreement contained no causation requirement beyond the revenue and related tests set forth in that agreement. This resolution, however, does not reduce uncertainty in the short term regarding the volume of claims, since it is possible that additional claims will be made. In addition, a claims submission deadline of 8 June 2015 has now been set, which may lead to an increase in the rate of claims received until the deadline, compounding management's inability to estimate the total volume of claims that will be made.

In respect of uncertainty regarding the average value per claim, a small proportion of the filed claims have been determined under the revised policy for the matching of revenue and expenses for business economic loss claims (introduced in May 2014) and disputes, disagreements, and uncertainties regarding the proper application of the revised policy to particular claims and categories of claims continue to arise as the claims administrator has begun applying the revised policy. Furthermore, there have been no, or only a small number of, claim determinations made under some of the specialized frameworks that have been put in place for particular industries and so determinations to date may not be representative of the total population of claims. In addition, due to a data secrecy order, detailed data about claims that have not yet been determined is not currently available to BP and so it is not possible to review claim demographics or identify potential populations for each category of claim.

There is therefore very little data to build up a track record of claims determinations under the policies and protocols that are now being applied following resolution of the matching and causation issues. We therefore cannot estimate future trends of the number and proportion of claims that will be determined to be eligible, nor can we estimate the value of such claims. A provision for such business economic loss claims will be established when these uncertainties are resolved and a reliable estimate can be made of the liability.

The current estimate for the total cost of those elements of the PSC settlement that BP considers can be reliably estimated is $9.9 billion. The DHCSSP has issued eligibility notices, most of which are disputed by BP, in respect of business economic loss claims of approximately $400 million which have not been provided for. The majority of these claims are being re-assessed using the new matching policy. Furthermore, a significant number of business economic loss claims have been received but have not yet been processed, and further claims are likely to be received. The total cost of the PSC settlement is likely to be significantly higher than the amount recognized to date of $9.9 billion because the current estimate does not reflect business economic loss claims not yet received, or received but not yet processed, or processed but not yet paid, except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility.

The provision recognized for litigation and claims includes an estimate for State and Local Claims. Although the provision recognized is BP's current reliable best estimate of the amount required to settle these obligations, significant uncertainty exists in relation to the outcome of any litigation proceedings and the amount of claims that will become payable by BP.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable, including claims payable under the DHCSSP and State and Local Claims. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported as described above and in Legal proceedings on page 228 and the outcomes of any further litigation including in relation to potential opt-outs from the PSC settlement or otherwise. There is also uncertainty as to the cost of administering the claims process under the DHCSSP and in relation to future legal costs.

See Legal proceedings on page 228 and Contingent liabilities below for further details.

2. Significant event – Gulf of Mexico oil spill – continued

Clean Water Act penalties

A provision of $3,510 million was recognized in 2010 for estimated civil penalties under Section 311 of the Clean Water Act. At the time the provision for the Clean Water Act penalty was made, the number of barrels of oil spilled was determined by using the mid-point (47,500 barrels per day) of the range of estimates (35,000 to 60,000 barrels per day) from the intra-agency Flow Rate Technical Group created by the National Incident Commander in charge of the spill response. The initial estimate of 3.2 million barrels was calculated using a total flow of 47,500 barrels per day multiplied by the 85 days from 22 April 2010 to 15 July 2010 less an estimate of the amount captured on the surface (approximately 850,000 barrels). This estimated discharge volume was then multiplied by $1,100 per barrel – the maximum amount the statute allows in the absence of gross negligence or wilful misconduct – for the purposes of estimating a potential penalty. This resulted in a provision of $3,510 million for potential penalties under Section 311.

The estimates of cumulative discharge presented by experts testifying in the Phase 2 trial varied significantly. In January 2015, the district court issued its decision in the Phase 2 trial that 3.19 million barrels of oil were discharged into the Gulf of Mexico and therefore subject to a Clean Water Act penalty. This amount is consistent with the number of barrels BP has used to calculate the provision. In addition, the district court found that BP was not grossly negligent in its source control efforts. BP and other parties to the proceedings have filed notices of appeal of the Phase 2 ruling and therefore the findings from the Phase 2 trial remain subject to uncertainty.

In September 2014, the district court issued its decision in the Phase 1 trial that the discharge of oil was the result of the gross negligence and wilful misconduct of BP Exploration & Production Inc. (BPXP) and that BPXP is therefore subject to enhanced civil penalties. The statutory maximum penalty is up to $4,300 per barrel of oil discharged where gross negligence or wilful misconduct is proven. BP does not believe that the evidence at trial supports a finding of gross negligence and wilful misconduct and in December 2014 filed notice of appeal of the Phase 1 ruling.

As a result of the September 2014 district court ruling that the discharge of oil was the result of BP's gross negligence and wilful misconduct, the Clean Water Act penalty obligation is not considered to be reliably measurable and it is therefore no longer possible to determine a best estimate of the Clean Water Act penalty provision. Under IFRS, a provision is reversed when it is no longer probable that an outflow of resources will be required to settle the obligation. With regard to the Clean Water Act penalty obligation, it continues to be probable that there will be an outflow of resources and therefore, in the absence of the ability to identify the best estimate of the liability, the previously recognized provision of $3,510 million has been maintained. Note 1 – Provisions, contingencies and reimbursement assets identifies the significant accounting estimates and judgements made in relation to the Clean Water Act provision.

BP continues to believe that a provision of $3,510 million represents a reliable estimate of the amount of the liability if the appeal is successful. If BP is unsuccessful in its appeal, and the ruling of gross negligence and wilful misconduct is upheld, the maximum penalty that could be imposed is up to $4,300 per barrel. Based upon this penalty rate and the district court's ruling on the number of barrels spilled, which, as noted above is also subject to appeal, the maximum penalty could be up to $13.7 billion.

However, in assessing the amount of the penalty, the court is directed to consider the following statutory penalty factors: 'the seriousness of the violation or violations, the economic benefit to the violator, if any, resulting from the violation, the degree of culpability involved, any other penalty for the same incident, any history of prior violations, the nature, extent, and degree of success of any efforts of the violator to minimize or mitigate the effects of the discharge, the economic impact of the penalty on the violator, and any other matters as justice may require'. The court has wide discretion in deciding how to apply these factors to determine the penalty and what weighting to ascribe to different factors. BP is therefore unable to ascribe probabilities to possible outcomes within the range of potential penalties and cannot determine a reliable estimate for any additional penalty which might apply should the gross negligence finding be upheld. The trial phase to determine the amount of the Clean Water Act penalty commenced on 20 January 2015.

The amount that may become payable by BP is subject to a very high level of uncertainty since it will depend on the outcome of BP's appeals as well as what is determined by the district court with respect to the application of statutory penalty factors as noted above. The court has wide discretion in the application of statutory penalty factors. The timing of any payment is also uncertain.

Given the significant uncertainty, the very wide range of possible outcomes if BP is unsuccessful in this appeal of the September ruling, and the inability to ascribe probabilities to possible outcomes within the range, management is not able to estimate reliably any further liability for the Clean Water Act penalty arising in the event that BP is not successful in its appeal. A contingent liability is therefore disclosed. See Contingent liabilities below for further information.

Provision movements

The total amount recognized as an increase in provisions during the year was $1,327 million. After deducting amounts utilized during the year totalling $2,071 million, including payments from the trust fund of $1,681 million and payments made directly by BP of $390 million (2013 $3,777 million, including payments from the trust fund of $3,051 million and payments made directly by BP of $726 million), and after adjustments for discounting, the remaining provision as at 31 December 2014 was $8,605 million (2013 $9,346 million).

The total amounts that will ultimately be paid by BP for all obligations relating to the incident are subject to significant uncertainty and the ultimate exposure and cost to BP will be dependent on many factors. Furthermore, significant uncertainty exists in relation to the amount of claims that will become payable by BP, the amount of fines that will ultimately be levied on BP, the outcome of litigation and arbitration proceedings, and any costs arising from any longer-term environmental consequences of the oil spill, which will also impact upon the ultimate cost for BP. The amount and timing of any amounts payable could also be impacted by any further settlements which may or may not occur. Although the provision recognized is the current best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, there are future expenditures for which it is not possible to measure the obligation reliably.

Contingent liabilities

BP has provided for its best estimate of amounts expected to be paid that can be measured reliably. It is not possible, at this time, to measure reliably other obligations arising from the incident, nor is it practicable to estimate their magnitude or possible timing of payment. Therefore, no amounts have been provided for these obligations as at 31 December 2014.

2. Significant event – Gulf of Mexico oil spill – continued

Natural resource damage claims

As described above in Provisions, a provision has been made for natural resource damage assessment and early restoration projects under the $1-billion framework agreement. Natural resource damages resulting from the oil spill are currently being assessed. BP and the federal and state trustees are collecting extensive data in order to assess the extent of damage to wildlife, shoreline, near shore and deepwater habitats, and recreational uses, among other things. The study data will inform an assessment of injury to the Gulf Coast natural resources and the development of a restoration plan to address the identified injuries.

Detailed analysis and interpretation continue on the data that have been collected. Any early restoration projects undertaken pursuant to the $1-billion framework agreement could mitigate the total damages resulting from the incident. Accordingly, until the size, location and duration of the impact is assessed, it is not possible to estimate reliably either the amounts or timing of the remaining natural resource damage claims and associated legal costs, therefore no such amounts have been provided as at 31 December 2014.

Business economic loss claims under the PSC settlement

BP identified multiple business economic loss claim determinations under the PSC settlement that appeared to result from an interpretation of the EPD Settlement Agreement by the claims administrator that BP believes was incorrect. The potential cost of business economic loss claims not yet received, processed and paid (except where an eligibility notice had been issued before the end of the month following the balance sheet date and is not subject to appeal by BP within the claims facility) is not provided for and is disclosed as a contingent liability. A significant number of business economic loss claims have been received but have not yet been processed and paid and further claims are likely to be received. See Provisions above for further information.

State and Local claims

As described above in Provisions, a provision has been made for State and Local claims that can be measured reliably. The States of Alabama, Mississippi, Florida, Louisiana and Texas submitted or asserted claims to BP under OPA 90 for alleged losses including economic losses and property damage as a result of the Gulf of Mexico oil spill. The amounts claimed, certain of which include punitive damages or other multipliers, are very substantial. However, BP considers these claims unsubstantiated and the methodologies used to calculate these claims to be seriously flawed, not supported by OPA 90, not supported by documentation, and to substantially overstate the claims. Similar claims have also been submitted by various local government entities and a foreign government under OPA 90. The amounts alleged in the submissions for these State and Local Claims total approximately $35 billion. BP will defend vigorously against these claims if adjudicated at trial; the timing of any outflow of resources in relation to State and Local claims is dependent on the timing of the court process in relation to these claims.

Clean Water Act penalties

A provision has been maintained for BP's obligation under the Clean Water Act, as described above in Provisions. Any obligation in relation to any further liability for the Clean Water Act penalty arising in the event that BP is not successful in its appeal of the Phase 1 ruling is disclosed as a contingent liability. The trial phase to determine the amount of the Clean Water Act penalty commenced in January 2015 and post-trial briefing is scheduled to complete in April 2015. BP does not know when the district court will rule on the Penalty Phase of the trial and so the timing of any payment continues to be uncertain.

Securities-related litigation

Proceedings relating to securities class actions (MDL 2185) pending in federal court in Texas, including a purported class action on behalf of purchasers of American Depositary Shares under US federal securities law, are continuing. A jury trial is scheduled to begin in January 2016 and the timing of any outflow of resources, if any, is dependent on the duration of the court process. No reliable estimate can be made of the amounts that may be payable in relation to these proceedings, if any, so no provision has been recognized at 31 December 2014. In addition, no reliable estimate can be made of the amounts that may be payable in relation to any other securities litigation, if any, so no provision has been recognized at 31 December 2014.

Other litigation

In addition to the State and Local claims and securities class actions described above, BP is named as a defendant in approximately 3,000 other civil lawsuits brought by individuals, corporations and government entities in US federal and state courts, as well as certain non-US jurisdictions, resulting from the Deepwater Horizon accident, the Gulf of Mexico oil spill, and the spill response efforts. Further actions are likely to be brought. Among other claims, these lawsuits assert claims for personal injury or wrongful death in connection with the accident and the spill response, commercial and economic injury, damage to real and personal property, breach of contract and violations of statutes, including, but not limited to, alleged violations of US securities and environmental statutes. In addition, claims have been received, primarily from business claimants, under OPA 90 in relation to the 2010 federal deepwater drilling moratoria. Until further fact and expert disclosures occur, court rulings clarify the issues in dispute, liability and damage trial activity nears or progresses, or other actions such as further possible settlements occur, it is not possible given these uncertainties to arrive at a range of outcomes or a reliable estimate of the liabilities that may accrue to BP in connection with or as a result of these lawsuits, nor it is possible to determine the timing of any payment that may arise. Therefore no amounts have been provided for these items as at 31 December 2014.

It is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties. There are a number of federal and state environmental and other provisions of law, other than the Clean Water Act, under which one or more governmental agencies could seek civil fines and penalties from BP. For example, a complaint filed by the United States sought to reserve the ability to seek penalties and other relief under a number of other laws. Given the unsubstantiated nature of certain claims that may be asserted, it is not possible at this time to determine whether and to what extent any such claims would be successful or what penalties or fines would be assessed. Therefore no amounts have been provided for these items.

Settlement and other agreements

Under the settlement agreements with Anadarko and MOEX, and with Cameron International, the designer and manufacturer of the Deepwater Horizon blowout preventer, BP has agreed to indemnify Anadarko, MOEX and Cameron for certain claims arising from the accident. It is therefore possible that BP may face claims under these indemnities, but it is not currently possible to reliably measure, nor identify the timing of, any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2014. There are also agreements indemnifying certain third-party contractors in relation to litigation costs and certain other claims. A contingent liability is also disclosed in relation to other obligations under these agreements.

The magnitude and timing of all possible obligations in relation to the Gulf of Mexico oil spill continue to be subject to a very high degree of uncertainty as described further in Risk factors on page 48. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

2. Significant event – Gulf of Mexico oil spill – continued

Impact upon the group income statement

The amount of the provision recognized during the year can be reconciled to the charge to the income statement as follows:

$ million

	2014	2013	2012	Cumulative since the incident
Net increase in provision	**1,327**	1,860	6,074	44,705
Change in discount rate relating to provisions	**2**	(5)	–	19
Costs charged directly to the income statement	**114**	136	257	4,358
Trust fund liability – discounted	**–**	–	–	19,580
Change in discounting relating to trust fund liability	**–**	–	–	283
Recognition of reimbursement asset, net	**(662)**	(1,542)	(1,191)	(20,000)
Settlements credited to the income statement	**–**	(19)	(145)	(5,681)
(Profit) loss before interest and taxation	**781**	430	4,995	43,264
Finance costs	**38**	39	19	231
(Profit) loss before taxation	**819**	469	5,014	43,495

The group income statement for 2014 includes a pre-tax charge of $819 million (2013 pre-tax charge of $469 million) in relation to the Gulf of Mexico oil spill. The costs charged in 2014 relate primarily to the ongoing costs of operating the Gulf Coast Restoration Organization (GCRO) and increases in the provisions for natural resource damage assessment, business economic loss claims, claims administration costs, legal and litigation costs. Finance costs of $38 million (2013 $39 million) reflect the unwinding of the discount on payables and provisions. The cumulative amount charged to the income statement to date comprises spill response costs arising in the aftermath of the incident, GCRO operating costs, amounts charged upon initial recognition of the trust obligation, litigation, claims, environmental and legal costs not paid through the Trust and estimated obligations for future costs that can be estimated reliably at this time, net of settlements agreed with the co-owners of the Macondo well and other third parties.

The total amount recognized in the income statement is analysed in the table below.

$ million

	2014	2013	2012	Cumulative since the incident
Trust fund liability – discounted	**–**	–	–	19,580
Change in discounting relating to trust fund liability	**–**	–	–	283
Recognition of reimbursement asset, net	**(662)**	(1,542)	(1,191)	(20,000)
Other	**–**	–	–	8
Total (credit) charge relating to the trust fund	**(662)**	(1,542)	(1,191)	(129)
Environmental – amount provided	**190**	47	801	3,134
– change in discount rate relating to provisions	**2**	(5)	–	19
– costs charged directly to the income statement	**–**	–	–	70
Total (credit) charge relating to environmental	**192**	42	801	3,223
Spill response – amount provided	**–**	(113)	109	11,465
– costs charged directly to the income statement	**–**	–	9	2,839
Total (credit) charge relating to spill response	**–**	(113)	118	14,304
Litigation and claims – amount provided, net of provision derecognized	**1,137**	1,926	5,164	26,596
– costs charged directly to the income statement	**–**	–	–	184
Total charge relating to litigation and claims	**1,137**	1,926	5,164	26,780
Clean Water Act penalties – amount provided	**–**	–	–	3,510
Other costs charged directly to the income statement	**114**	136	248	1,257
Settlements credited to the income statement	**–**	(19)	(145)	(5,681)
(Profit) loss before interest and taxation	**781**	430	4,995	43,264
Finance costs	**38**	39	19	231
(Profit) loss before taxation	**819**	469	5,014	43,495

The total amounts that will ultimately be paid by BP in relation to all obligations relating to the incident are subject to significant uncertainty as described under Provisions and contingent liabilities above.

3. Disposals and impairment

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

			$ million
	2014	2013	2012
Gains on sale of businesses and fixed assets			
Upstream	**405**	371	6,504
Downstream	**474**	214	152
TNK-BP	**–**	12,500	–
Other businesses and corporate	**16**	30	41
	895	13,115	6,697

			$ million
	2014	2013	2012
Losses on sale of businesses and fixed assets			
Upstream	**345**	144	109
Downstream	**401**	78	195
Other businesses and corporate	**3**	8	6
	749	230	310
Impairment losses			
Upstream	**6,737**	1,255	3,046
Downstream	**1,264**	484	2,892
Other businesses and corporate	**317**	218	320
	8,318	1,957	6,258
Impairment reversals			
Upstream	**(102)**	(226)	(289)
Downstream	**–**	–	(1)
Other businesses and corporate	**–**	–	(3)
	(102)	(226)	(293)
Impairment and losses on sale of businesses and fixed assets	**8,965**	1,961	6,275

Disposals

As part of the response to the consequences of the Gulf of Mexico oil spill in 2010, the group announced plans to deliver up to $38 billion of disposal proceeds by the end of 2013. By 31 December 2012, the group had announced disposals of $38 billion, and in addition, announced the sale of our 50% investment in TNK-BP. During 2013, the group announced that it expected to divest a further $10 billion of assets before the end of 2015. BP had agreed around $4.7 billion of such further divestments and received proceeds of $3.6 billion as at 31 December 2014.

			$ million
	2014	2013	2012
Proceeds from disposals of fixed assets	**1,820**	18,115	9,992
Proceeds from disposals of businesses, net of cash disposed	**1,671**	3,884	1,606
	3,491	21,999	11,598
By business			
Upstream	**2,533**	1,288	10,667
Downstream	**864**	3,991	637
TNK-BP	**–**	16,646	–
Other businesses and corporate	**94**	74	294
	3,491	21,999	11,598

At 31 December 2014, deferred consideration relating to disposals amounted to $1,137 million receivable within one year (2013 $23 million and 2012 $24 million) and $333 million receivable after one year (2013 $1,374 million and 2012 $1,433 million). In addition, contingent consideration relating to the disposals of the Devenick field and the Texas City refinery amounted to $454 million at 31 December 2014 (2013 $953 million) – see Notes 16 and 28 for further information.

Upstream

In 2014, gains principally resulted from the sale of certain onshore assets in the US, and the sale of certain interests in the Gulf of Mexico and the North Sea. Losses principally arose from adjustments to prior year disposals in Canada and the North Sea.

In 2013, gains principally resulted from the sale of certain of our interests in the central North Sea, and the Yacheng field in China.

In 2012, gains principally resulted from the sale of certain interests in the Gulf of Mexico and certain onshore assets in the US, the sale of our interests in our Canadian natural gas liquids business, and the sale of a number of interests in the North Sea.

Downstream

In 2014, gains principally resulted from the disposal of our global aviation turbine oils business. Losses principally arose from costs associated with the decision to cease refining operations at Bulwer Island in Australia.

3. Disposals and impairment – continued

In 2013, gains principally resulted from the disposal of our global LPG business and closing adjustments on the sales of the Texas City and Carson refineries with their associated marketing and logistics assets.

In 2012, gains principally resulted from the disposal of our interests in purified terephthalic acid production in Malaysia, and retail churn in the US. Losses principally resulted from costs associated with our US refinery divestments.

TNK-BP

In 2013, BP disposed of its 50% interest in TNK-BP to Rosneft, resulting in a gain on disposal of $12,500 million.

Summarized financial information relating to the sale of businesses is shown in the table below. The principal transaction categorized as a business disposal in 2014 was the sale of certain of our interests on the North Slope of Alaska in our upstream business, which had been classified as held for sale during 2014. The principal transactions categorized as business disposals in 2013 were the sales of the Texas City and Carson refineries with their associated marketing and logistics assets. Information relating to sales of fixed assets is excluded from the table.

			$ million
	2014	2013	2012
Non-current assets	**1,452**	2,124	610
Current assets	**182**	2,371	570
Non-current liabilities	**(395)**	(94)	(263)
Current liabilities	**(65)**	(62)	(232)
Total carrying amount of net assets disposed	**1,174**	4,339	685
Recycling of foreign exchange on disposal	**(7)**	23	(15)
Costs on disposal[a]	**128**	13	39
	1,295	4,375	709
Gains on sale of businesses	**280**	69	675
Total consideration	**1,575**	4,444	1,384
Consideration received (receivable)[b]	**96**	(414)	76
Proceeds from the sale of businesses related to completed transactions	**1,671**	4,030	1,460
Deposits received related to assets classified as held for sale	**–**	–	146
Disposals completed in relation to which deposits had been received in prior year	**–**	(146)	–
Proceeds from the sale of businesses[c]	**1,671**	3,884	1,606

[a] 2013 includes pension and other post-retirement benefit plan curtailment gains of $109 million.

[b] Consideration received from prior year business disposals or to be received from current year disposals. 2013 includes contingent consideration of $475 million relating to the disposal of the Texas City refinery.

[c] Substantially all of the consideration received was in the form of cash and cash equivalents. Proceeds are stated net of cash and cash equivalents disposed of $32 million (2013 $42 million and 2012 $4 million).

Impairments

Impairment losses in each segment are described below. For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles and goodwill within Note 1.

Upstream

The 2014 impairment losses of $6,737 million included $4,876 million in the North Sea business, of which $1,964 million related to the Valhall cash-generating unit (CGU), $660 million related to the Andrew area CGU, and $515 million related to the ETAP CGU. These CGUs have recoverable amounts of $767 million, $1,431 million, and $1,753 million respectively. Impairment losses also included an $859-million impairment of our PSVM CGU in Angola to its recoverable amount of $1,964 million, and a $415-million impairment of the Block KG D6 CGU in India to its recoverable amount of $2,364 million. The recoverable amount of the Block KG D6 CGU is stated after the exploration write-off described in Note 6. All of the impairments relate to producing assets. The impairments in the North Sea and Angola arose as a result of a lower price environment in the near term, technical reserves revisions, and increases in expected decommissioning cost estimates. The impairment of Block KG D6 arose following the introduction of a new formula for Indian gas prices. The recoverable amounts of the Valhall and Block KG D6 CGUs are their fair values less costs of disposal based on the present value of future cash flows, a level-3 valuation technique in the fair value hierarchy. The key assumptions in the tests were oil and natural gas prices, production volumes and the discount rate. The recoverable amounts of the Andrew area CGU, the ETAP CGU and the PSVM CGU are their values in use. See Impairment of property, plant and equipment, intangible assets and goodwill within Note 1 for further information on assumptions used for impairment testing. The discount rate used to determine the value in use of the PSVM CGU included the 2% premium for higher-risk countries as described in Note 1. A premium was not applied in determining the recoverable amount of the other CGUs.

The main elements of the 2013 impairment losses of $1,255 million were a $251-million impairment loss relating to the Browse project in Australia and a $253-million aggregate write-down of a number of assets in the North Sea, caused by increases in expected decommissioning costs. Impairment reversals arose on certain of our interests in Alaska, the Gulf of Mexico, and the North Sea, triggered by reductions in decommissioning provisions due to continued review of the expected decommissioning costs and an increase in the discount rate for provisions.

The main elements of the 2012 impairment losses of $3,046 million were a $1,082-million write-down of our interests in certain shale gas assets in the US, due to reserves revisions, lower values being attributed to recent market transactions and a fall in the gas price; a $999-million impairment loss relating to the decision to suspend the Liberty project in Alaska; a $706-million aggregate write-down of a number of assets, primarily in the Gulf of Mexico and North Sea, caused by increases in the decommissioning provision resulting from continued review of the expected decommissioning costs. Impairment reversals principally arose on certain of our interests in the Gulf of Mexico, triggered by a decision to divest assets.

Downstream

The main elements of the 2014 impairment losses of $1,264 million related to our Bulwer Island refinery and certain midstream assets in our fuels business, and certain manufacturing assets in our petrochemicals business.

The main elements of the 2013 impairment losses of $484 million related to impairments of certain refineries in the US and elsewhere in our global fuels portfolio.

The main elements of the 2012 impairment losses of $2,892 million related to assets held for sale for which sales prices had been agreed. This included $1,552 million relating to the Texas City refinery and associated assets and $1,042 million relating to the Carson refinery and associated assets.

3. Disposals and impairment – continued

Other businesses and corporate

Impairment losses totalling $317 million, $218 million, and $320 million were recognized in 2014, 2013 and 2012 respectively. The amount for 2014 is principally in respect of our biofuels businesses in the UK and US. The amount for 2013 is principally in respect of our US wind business. The amount for 2012 is principally in respect of the decision not to proceed with an investment in a biofuels production facility under development in the US.

4. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. At 31 December 2014, BP had three reportable segments: Upstream, Downstream and Rosneft.

Upstream's activities include oil and natural gas exploration, field development and production; midstream transportation, storage and processing; and the marketing and trading of natural gas, including liquefied natural gas (LNG), together with power and natural gas liquids (NGLs).

Downstream's activities include the refining, manufacturing, marketing, transportation, and supply and trading of crude oil, petroleum, petrochemicals products and related services to wholesale and retail customers.

During 2013, BP completed transactions for the sale of BP's interest in TNK-BP to Rosneft, and for BP's further investment in Rosneft. BP's interest in Rosneft is accounted for using the equity method and is reported as a separate operating segment, reflecting the way in which the investment is managed.

Other businesses and corporate comprises the biofuels and wind businesses, the group's shipping and treasury functions, and corporate activities worldwide.

The Gulf Coast Restoration Organization (GCRO), which manages all aspects of our response to the 2010 Gulf of Mexico incident, reports directly to the group chief executive and is overseen by a board committee, however it is not an operating segment. Its costs are presented as a reconciling item between the sum of the results of the reportable segments and the group results.

The accounting policies of the operating segments are the same as the group's accounting policies described in Note 1. However, IFRS requires that the measure of profit or loss disclosed for each operating segment is the measure that is provided regularly to the chief operating decision maker for the purposes of performance assessment and resource allocation. For BP, this measure of profit or loss is replacement cost profit or loss before interest and tax which reflects the replacement cost of supplies by excluding from profit or loss inventory holding gains and losses[a]. Replacement cost profit or loss for the group is not a recognized measure under IFRS.

Sales between segments are made at prices that approximate market prices, taking into account the volumes involved. Segment revenues and segment results include transactions between business segments. These transactions and any unrealized profits and losses are eliminated on consolidation, unless unrealized losses provide evidence of an impairment of the asset transferred. Sales to external customers by region are based on the location of the group subsidiary which made the sale. The UK region includes the UK-based international activities of Downstream.

All surpluses and deficits recognized on the group balance sheet in respect of pension and other post-retirement benefit plans are allocated to Other businesses and corporate. However, the periodic expense relating to these plans is allocated to the operating segments based upon the business in which the employees work.

Certain financial information is provided separately for the US as this is an individually material country for BP, and for the UK as this is BP's country of domicile.

[a] Inventory holding gains and losses represent the difference between the cost of sales calculated using the replacement cost of inventory and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on its historical cost of purchase or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge to the income statement for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen based on the replacement cost of inventory. For this purpose, the replacement cost of inventory is calculated using data from each operation's production and manufacturing system, either on a monthly basis, or separately for each transaction where the system allows this approach. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

4. Segmental analysis – continued

By business	Upstream	Downstream	Rosneft	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
							$ million
							2014
Segment revenues							
Sales and other operating revenues	65,424	323,486	–	1,989	–	(37,331)	353,568
Less: sales and other operating revenues between segments	(36,643)	173	–	(861)	–	37,331	–
Third party sales and other operating revenues	28,781	323,659	–	1,128	–	–	353,568
Equity-accounted earnings	1,089	265	2,101	(83)	–	–	3,372
Segment results							
Replacement cost profit (loss) before interest and taxation	8,934	3,738	2,100	(2,010)	(781)	641	12,622
Inventory holding gains (losses)[a]	(86)	(6,100)	(24)	–	–	–	(6,210)
Profit (loss) before interest and taxation	8,848	(2,362)	2,076	(2,010)	(781)	641	6,412
Finance costs							(1,148)
Net finance expense relating to pensions and other post-retirement benefits							(314)
Profit before taxation							4,950
Other income statement items							
Depreciation, depletion and amortization[b]							
US	4,129	984	–	97	–	–	5,210
Non-US	8,404	1,336	–	213	–	–	9,953
Fair value (gain) loss on embedded derivatives	(430)	–	–	–	–	–	(430)
Charges for provisions, net of write-back of unused provisions, including change in discount rate	260	713	–	323	1,329	–	2,625
Segment assets							
Equity-accounted investments	7,877	3,244	7,312	723	–	–	19,156
Additions to non-current assets[c]	22,587	3,121	–	784	–	–	26,492
Additions to other investments							160
Element of acquisitions not related to non-current assets							(366)
Additions to decommissioning asset							(2,505)
Capital expenditure and acquisitions	19,772	3,106	–	903	–	–	23,781

[a] See explanation of inventory holding gains and losses on page 119.
[b] It is estimated that the benefit arising from the absence of depreciation for the assets held for sale during the year was $221 million.
[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

$ million

2013

By business	Upstream	Downstream	Rosneft	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
Segment revenues								
Sales and other operating revenues	70,374	351,195	–	–	1,805	–	(44,238)	379,136
Less: sales and other operating revenues between segments	(42,327)	(1,045)	–	–	(866)	–	44,238	–
Third party sales and other operating revenues	28,047	350,150	–	–	939	–	–	379,136
Equity-accounted earnings	1,027	195	2,058	–	(91)	–	–	3,189
Segment results								
Replacement cost profit (loss) before interest and taxation	16,657	2,919	2,153	12,500	(2,319)	(430)	579	32,059
Inventory holding gains (losses)[a]	4	(194)	(100)	–	–	–	–	(290)
Profit (loss) before interest and taxation	16,661	2,725	2,053	12,500	(2,319)	(430)	579	31,769
Finance costs								(1,068)
Net finance expense relating to pensions and other post-retirement benefits								(480)
Profit before taxation								30,221
Other income statement items								
Depreciation, depletion and amortization[b]								
US	3,538	747	–	–	181	–	–	4,466
Non-US	7,514	1,343	–	–	187	–	–	9,044
Fair value (gain) loss on embedded derivatives	(459)	–	–	–	–	–	–	(459)
Charges for provisions, net of write-back of unused provisions, including change in discount rate	161	270	–	–	295	1,855	–	2,581
Segment assets								
Equity-accounted investments	7,780	3,302	13,681	–	1,072	–	–	25,835
Additions to non-current assets[c]	19,499	4,449	11,941	–	1,027	–	–	36,916
Additions to other investments								41
Element of acquisitions not related to non-current assets								39
Additions to decommissioning asset								(384)
Capital expenditure and acquisitions	19,115	4,506	11,941	–	1,050	–	–	36,612

[a] See explanation of inventory holding gains and losses on page 119.
[b] It is estimated that the benefit arising from the absence of depreciation for the assets held for sale at 31 December 2012 until their disposal in 2013 amounted to approximately $201 million.
[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

4. Segmental analysis – continued

$ million

By business	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
							2012
Segment revenues							
Sales and other operating revenues	72,225	346,391	–	1,985	–	(44,836)	375,765
Less: sales and other operating revenues between segments	(42,572)	(1,365)	–	(899)	–	44,836	–
Third party sales and other operating revenues	29,653	345,026	–	1,086	–	–	375,765
Equity-accounted earnings	915	101	2,986	(67)	–	–	3,935
Segment results							
Replacement cost profit (loss) before interest and taxation	22,491	2,864	3,373	(2,794)	(4,995)	(576)	20,363
Inventory holding gains (losses)[a]	(104)	(487)	(3)	–	–	–	(594)
Profit (loss) before interest and taxation	22,387	2,377	3,370	(2,794)	(4,995)	(576)	19,769
Finance costs							(1,072)
Net finance expense relating to pensions and other post-retirement benefits							(566)
Profit before taxation							18,131
Other income statement items							
Depreciation, depletion and amortization[b]							
US	3,437	586	–	213	–	–	4,236
Non-US	6,918	1,343	–	190	–	–	8,451
Fair value (gain) loss on embedded derivatives	(347)	–	–	–	–	–	(347)
Charges for provisions, net of write-back of unused provisions, including change in discount rate	897	141	–	505	6,074	–	7,617
Segment assets							
Equity-accounted investments	7,329	3,212	–	1,071	–	–	11,612
Additions to non-current assets[c]	22,603	5,246	–	1,419	–	–	29,268
Additions to other investments							33
Element of acquisitions not related to non-current assets							(72)
Additions to decommissioning asset							(4,025)
Capital expenditure and acquisitions	18,520	5,249	–	1,435	–	–	25,204

[a] See explanation of inventory holding gains and losses on page 119.
[b] It is estimated that the benefit arising from the absence of depreciation for the assets held for sale amounted to approximately $435 million.
[c] Includes additions to property, plant and equipment; goodwill; intangible assets; investments in joint ventures; and investments in associates.

4. Segmental analysis – continued

By geographical area	US	Non-US	Total
			$ million
			2014
Revenues			
Third party sales and other operating revenues[a]	**122,951**	**230,617**	**353,568**
Other income statement items			
Production and similar taxes	**690**	**2,268**	**2,958**
Results			
Replacement cost profit before interest and taxation	**5,251**	**7,371**	**12,622**
Non-current assets			
Non-current assets[b c]	**69,125**	**114,462**	**183,587**
Capital expenditure and acquisitions	**7,227**	**16,554**	**23,781**

[a] Non-US region includes UK $77,522 million.
[b] Non-US region includes UK $18,430 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	Total
			$ million
			2013
Revenues			
Third party sales and other operating revenues[a]	128,764	250,372	379,136
Other income statement items			
Production and similar taxes	1,112	5,935	7,047
Results			
Replacement cost profit before interest and taxation	3,114	28,945	32,059
Non-current assets			
Non-current assets[b c]	70,228	124,439	194,667
Capital expenditure and acquisitions	9,176	27,436	36,612

[a] Non-US region includes UK $82,381 million.
[b] Non-US region includes UK $18,967 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

By geographical area	US	Non-US	Total
			$ million
			2012
Revenues			
Third party sales and other operating revenues[a]	130,940	244,825	375,765
Other income statement items			
Production and similar taxes	1,472	6,686	8,158
Results			
Replacement cost profit before interest and taxation	180	20,183	20,363
Non-current assets			
Non-current assets[b c]	66,751	107,844	174,595
Capital expenditure and acquisitions	10,541	14,663	25,204

[a] Non-US region includes UK $75,364 million.
[b] Non-US region includes UK $17,545 million.
[c] Includes property, plant and equipment; goodwill; intangible assets; investments in joint ventures; investments in associates; and non-current prepayments.

5. Income statement analysis

			$ million
	2014	2013	2012
Currency exchange losses charged to the income statement[a]	**36**	180	106
Expenditure on research and development	**663**	707	674
Finance costs			
Interest payable	**1,025**	1,082	1,234
Capitalized at 1.94% (2013 2% and 2012 2.25%)[b]	**(185)**	(238)	(390)
Unwinding of discount on provisions and other payables	**308**	224	228
	1,148	1,068	1,072

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
[b] Tax relief on capitalized interest is approximately $43 million (2013 $62 million and 2012 $93 million).

Interest and other income of $1,677 million in 2012 includes $709 million of dividends from TNK-BP.

6. Exploration for and evaluation of oil and natural gas resources

The following financial information represents the amounts included within the group totals relating to activity associated with the exploration for and evaluation of oil and natural gas resources. All such activity is recorded within the Upstream segment.

For information on significant estimates and judgements made in relation to oil and natural gas accounting see Intangible assets within Note 1.

			$ million
	2014	2013	2012
Exploration and evaluation costs			
Exploration expenditure written off[a]	**3,029**	2,710	745
Other exploration costs	**603**	731	730
Exploration expense for the year	**3,632**	3,441	1,475
Impairment losses	**–**	253	–
Impairment reversals	**–**	–	(42)
Intangible assets – exploration and appraisal expenditure	**19,344**	20,865	23,434
Liabilities	**227**	212	287
Net assets	**19,117**	20,653	23,147
Capital expenditure	**2,870**	4,464	5,176
Net cash used in operating activities	**603**	731	730
Net cash used in investing activities	**2,786**	4,275	5,010

[a] 2014 included a $544-million write-off relating to disappointing appraisal results of Utica shale in the US Lower 48 and the subsequent decision not to proceed with its development plans, a $524-million write-off relating to the Bourarhat Sud block licence in the Illizi Basin of Algeria, a $395-million write-off relating to Block KG D6 in India and a $295-million write-off relating to the Moccasin discovery in the deepwater Gulf of Mexico. 2013 included a $845-million write-off relating to the value ascribed to Block BM-CAL-13 offshore Brazil as a result of the Pitanga exploration well not encountering commercial quantities of oil and gas and a $257-million write-off of costs relating to the Risha concession in Jordan as our exploration activities did not establish the technical basis for a development project in the concession. For further information see Upstream – Exploration on page 26.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2014 is shown in the table below.

Carrying amount	Location
$1-2 billion	Angola; India
$2-3 billion	Canada; Egypt; Brazil
$4-5 billion	US – Gulf of Mexico

7. Taxation

Tax on profit

			$ million
	2014	2013	2012
Current tax			
Charge for the year	**4,444**	5,724	6,664
Adjustment in respect of prior years	**48**	61	252
	4,492	5,785	6,916
Deferred tax			
Origination and reversal of temporary differences in the current year	**(3,194)**	529	67
Adjustment in respect of prior years	**(351)**	149	(103)
	(3,545)	678	(36)
Tax charge on profit	**947**	6,463	6,880

In 2014, the total tax credit recognized within other comprehensive income was $1,481 million (2013 $1,374 million charge and 2012 $270 million credit). See Note 30 for further information. The total tax charge recognized directly in equity was $36 million (2013 $33 million credit and 2012 $6 million credit).

For information on significant estimates and judgements made in relation to taxation see Income taxes within Note 1.

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit before taxation. With effect from 1 April 2014 the UK statutory corporation tax rate reduced from 23% to 21% on profits arising from activities outside the North Sea. For 2014, the items presented in the reconciliation are distorted as a result of the tax credits related to the impairment losses recognized in the year, and the effect of the impairment losses on the profit for the year. In order to provide a more meaningful analysis of the effective tax rate for 2014, the table also presents separate reconciliations for the group excluding the effects of the impairment losses, and for the effects of the impairment losses in isolation. For 2013 and 2012, the effective tax rate is not affected significantly by impairment losses. See Note 3 for further information.

7. Taxation – continued

					$ million
	2014 excluding impairments	**2014 impacts of impairments**	**2014**	2013	2012
Profit (loss) before taxation	**13,166**	**(8,216)**	**4,950**	30,221	18,131
Tax charge (credit) on profit or loss	**5,036**	**(4,089)**	**947**	6,463	6,880
Effective tax rate	**38%**	**50%**	**19%**	21%	38%

					% of profit before taxation
UK statutory corporation tax rate	**21**	**21**	**21**	23	24
Increase (decrease) resulting from					
UK supplementary and overseas taxes at higher or lower rates[a]	**17**	**34**	**(11)**	4	12
Tax reported in equity-accounted entities	**(5)**	**–**	**(14)**	(2)	(5)
Adjustments in respect of prior years	**(2)**	**–**	**(6)**	1	1
Movement in deferred tax not recognized	**4**	**(3)**	**17**	2	2
Tax incentives for investment	**(4)**	**–**	**(10)**	(2)	(2)
Gulf of Mexico oil spill non-deductible costs	**–**	**–**	**1**	–	8
Permanent differences relating to disposals[b]	**(1)**	**–**	**(1)**	(8)	–
Foreign exchange	**4**	**–**	**10**	2	(1)
Items not deductible for tax purposes	**4**	**(2)**	**12**	1	2
Other	**–**	**–**	**–**	–	(3)
Effective tax rate	**38**	**50**	**19**	21	38

[a] For 2014 excluding impairments, jurisdictions which contribute significantly to this item are Angola, with an applicable statutory tax rate of 50%, Trinidad, with an applicable statutory tax rate of 55% and the US with an applicable federal tax rate of 35%. For 2014, impairment charges have generated losses on which tax credits arise, mainly in Norway and the UK North Sea, with applicable statutory tax rates of 78% and 62% respectively. For 2013 and 2012, jurisdictions which contribute significantly are Angola, the UK and Trinidad with rates as disclosed above.
[b] For 2013, this relates to the non-taxable gain on disposal of our investment in TNK-BP.

Legislation to reduce the UK supplementary charge tax rate applicable to profits arising in the North Sea is expected to be enacted in 2015. The evaluation of the effect of this change for BP has not yet been completed.

Deferred tax

					$ million
		Income statement			Balance sheet
	2014	2013	2012	**2014**	2013
Deferred tax liability					
Depreciation	**(2,178)**	(474)	(75)	**29,062**	31,551
Pension plan surpluses	**(272)**	(691)	–	**–**	284
Other taxable temporary differences	**(1,278)**	(199)	(2,239)	**2,445**	3,653
	(3,728)	(1,364)	(2,314)	**31,507**	35,488
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**492**	787	(33)	**(2,761)**	(2,026)
Decommissioning, environmental and other provisions	**52**	1,385	1,872	**(11,237)**	(11,301)
Derivative financial instruments	**166**	30	(7)	**(575)**	(579)
Tax credits	**589**	(174)	1,802	**(298)**	(888)
Loss carry forward	**(1,397)**	(343)	(911)	**(3,848)**	(2,585)
Other deductible temporary differences	**281**	357	(445)	**(1,204)**	(1,655)
	183	2,042	2,278	**(19,923)**	(19,034)
Net deferred tax charge (credit) and net deferred tax liability	**(3,545)**	678	(36)	**11,584**	16,454
Of which – deferred tax liabilities				**13,893**	17,439
– deferred tax assets				**2,309**	985

The recognition of deferred tax assets of $1,467 million (2013 $67 million), in entities which have suffered a loss in either the current or preceding period, is supported by forecasts which indicate that sufficient future taxable profits will be available to utilize such assets.

		$ million
Analysis of movements during the year in the net deferred tax liability	**2014**	2013
At 1 January	**16,454**	14,369
Exchange adjustments	**122**	43
Charge (credit) for the year on profit	**(3,545)**	678
Charge (credit) for the year in other comprehensive income	**(1,563)**	1,397
Charge (credit) for the year in equity	**36**	(33)
Acquisitions	**80**	–
At 31 December	**11,584**	16,454

7. Taxation – continued

A summary of temporary differences, unused tax credits and unused tax losses for which deferred tax has not been recognized is shown in the table below.

		$ billion
At 31 December	**2014**	2013
Unused tax losses[a]	**2.1**	1.8
Unused tax credits	**20.1**	18.0
of which – arising in the UK[b]	**18.0**	16.3
– arising in the US[c]	**2.0**	1.7
Deductible temporary differences[d]	**17.9**	11.2
Taxable temporary differences associated with investments in subsidiaries and equity-accounted entities[e]	**1.0**	1.1

[a] Substantially all the tax losses have no fixed expiry date.
[b] The UK unused tax credits arise predominantly in overseas branches of UK entities based in jurisdictions with high tax rates. No deferred tax asset has been recognized on these tax credits as they are unlikely to have value in the future; UK taxes on these overseas branches are largely mitigated by double tax relief on the overseas tax. These tax credits have no fixed expiry date.
[c] The US unused tax credits expire 10 years after generation and will all expire in the period 2015-2023.
[d] Deductible temporary differences of $1.0 billion are expected to expire in the period 2015-2021, the remainder do not have an expiry date.
[e] An amendment has been made to the comparative amount.

			$ billion
Impact of previously unrecognized deferred tax or write-down of deferred tax assets on current year charge	**2014**	2013	2012
Current tax benefit relating to the utilization of previously unrecognized tax credits	**0.2**	0.2	0.4
Deferred tax benefit relating to the recognition of previously unrecognized tax credits	**–**	0.2	0.1
Deferred tax expense arising from the write-down of a previously recognized deferred tax asset	**0.2**	–	–

8. Dividends

The quarterly dividend expected to be paid on 27 March 2015 in respect of the fourth quarter 2014 is 10.00 cents per ordinary share ($0.60 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 16 March 2015. A scrip dividend alternative is available, allowing shareholders to elect to receive their dividend in the form of new ordinary shares and ADS holders in the form of new ADSs.

	Pence per share			Cents per share			$ million		
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**5.7065**	6.0013	5.0958	**9.50**	9.00	8.00	**1,426**	1,621	1,211
June	**5.8071**	5.8342	5.1498	**9.75**	9.00	8.00	**1,572**	1,399	1,448
September	**5.9593**	5.7630	5.0171	**9.75**	9.00	8.00	**1,122**	1,245	1,417
December	**6.3769**	5.8008	5.5890	**10.00**	9.50	9.00	**1,728**	1,174	1,216
	23.8498	23.3993	20.8517	**39.00**	36.50	33.00	**5,850**	5,441	5,294
Dividend announced, payable in March 2015				**10.00**			**1,817**		

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

	2014	2013	2012
Number of shares issued (thousand)	**165,644**	202,124	138,406
Value of shares issued ($ million)	**1,318**	1,470	982

The financial statements for the year ended 31 December 2014 do not reflect the dividend announced on 3 February 2015 and expected to be paid in March 2015; this will be treated as an appropriation of profit in the year ended 31 December 2015.

9. Earnings per ordinary share

			Cents per share
	2014	2013	2012
Basic earnings per share	**20.55**	123.87	57.89
Diluted earnings per share	**20.42**	123.12	57.50

Basic earnings per ordinary share amounts are calculated by dividing the profit for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding excludes certain shares that will be issuable in the future under employee share-based payment plans and treasury shares, which includes shares held by the Employee Share Ownership Plan trusts (ESOPs).

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

			$ million
	2014	2013	2012
Profit attributable to BP shareholders	**3,780**	23,451	11,017
Less: dividend requirements on preference shares	**2**	2	2
Profit for the year attributable to BP ordinary shareholders	**3,778**	23,449	11,015

9. Earnings per ordinary share – continued

			Shares thousand
	2014	2013	2012
Basic weighted average number of ordinary shares	**18,385,458**	18,931,021	19,027,929
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**111,836**	115,152	129,959
	18,497,294	19,046,173	19,157,888

The number of ordinary shares outstanding at 31 December 2014, excluding treasury shares, and including certain shares that will be issuable in the future under employee share-based payment plans was 18,199,882,744. Between 31 December 2014 and 17 February 2015, the latest practicable date before the completion of these financial statements, there was a net decrease of 24,096,712 in the number of ordinary shares outstanding as a result of share issues in relation to employee share-based payment plans. During the same period, no further shares were repurchased following the continuation of share buybacks announced on 29 April 2014.

Employee share-based payment plans

The group operates share and share option plans for directors and certain employees to obtain ordinary shares and ADSs in the company. Information on these plans for directors is shown in the Directors remuneration report on pages 72–88.

The following table shows the number of shares potentially issuable under equity-settled employee share option plans, including the number of options outstanding, the number of options exercisable at the end of each year, and the corresponding weighted-average exercise prices. The dilutive effect of these plans at 31 December included in the diluted earnings per share is also shown.

Share options		**2014**		2013
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**113,206**	**9.62**	286,725	7.71
Exercisable	**86,211**	**10.89**	127,290	10.01
Dilutive effect	**5,570**	**n/a**	23,169	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2014 the quoted market price of one BP ordinary share was $6.35 (2013 $8.10).

In addition, the group operates a number of equity-settled employee share plans under which share units are granted to the group's senior leaders and certain other employees. These plans typically have a three-year performance or restricted period during which the units accrue net notional dividends which are treated as having been reinvested. Leaving employment will normally preclude the conversion of units into shares, but special arrangements apply for participants that leave for qualifying reasons. The number of shares that are expected to vest each year under employee share plans are shown in the table below. The dilutive effect of the employee share plans at 31 December included in the diluted earnings per share is also shown.

Share plans	**2014**	2013
Vesting	**Number of shares[a] thousand**	Number of shares[a] thousand
Within one year	**78,467**	35,442
1 to 2 years	**91,993**	120,056
2 to 3 years	**80,966**	115,387
3 to 4 years	**28,564**	14,231
4 to 5 years	**222**	123
	280,212	285,239
Dilutive effect	**99,917**	95,014

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

There has been a net increase of 31,318,880 in the number of potential ordinary shares in relation with employee share-based payment plans between 31 December 2014 and 17 February 2015.

10. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties[a]	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2014	**3,375**	**3,027**	**187,691**	**48,912**	**3,176**	**13,314**	**9,961**	**269,456**
Exchange adjustments	**(284)**	**(105)**	**–**	**(1,737)**	**(93)**	**(44)**	**(871)**	**(3,134)**
Additions	**315**	**183**	**18,033**	**2,008**	**258**	**1,049**	**521**	**22,367**
Acquisitions	**31**	**22**	**–**	**252**	**3**	**–**	**–**	**308**
Transfers	**–**	**–**	**993**	**–**	**–**	**–**	**–**	**993**
Deletions	**(22)**	**(66)**	**(6,203)**	**(620)**	**(313)**	**(500)**	**(565)**	**(8,289)**
At 31 December 2014	**3,415**	**3,061**	**200,514**	**48,815**	**3,031**	**13,819**	**9,046**	**281,701**
Depreciation								
At 1 January 2014	**550**	**1,141**	**97,063**	**20,378**	**1,970**	**8,833**	**5,831**	**135,766**
Exchange adjustments	**(5)**	**(46)**	**–**	**(989)**	**(56)**	**(27)**	**(550)**	**(1,673)**
Charge for the year	**84**	**156**	**11,728**	**1,833**	**267**	**343**	**448**	**14,859**
Impairment losses	**15**	**–**	**6,304**	**625**	**–**	**179**	**504**	**7,627**
Impairment reversals	**–**	**–**	**(19)**	**–**	**–**	**(83)**	**–**	**(102)**
Deletions	**(5)**	**(54)**	**(3,901)**	**(489)**	**(198)**	**(312)**	**(509)**	**(5,468)**
At 31 December 2014	**639**	**1,197**	**111,175**	**21,358**	**1,983**	**8,933**	**5,724**	**151,009**
Net book amount at 31 December 2014	**2,776**	**1,864**	**89,339**	**27,457**	**1,048**	**4,886**	**3,322**	**130,692**
Cost								
At 1 January 2013	3,279	2,812	171,772	45,200	3,346	13,436	9,629	249,474
Exchange adjustments	(4)	(26)	–	(235)	5	(55)	(36)	(351)
Additions	120	286	14,272	4,386	299	51	625	20,039
Acquisitions	–	–	–	8	–	–	–	8
Transfers	–	–	4,365	–	–	–	–	4,365
Deletions	(20)	(45)	(2,718)	(447)	(474)	(118)	(257)	(4,079)
At 31 December 2013	3,375	3,027	187,691	48,912	3,176	13,314	9,961	269,456
Depreciation								
At 1 January 2013	514	1,023	87,965	18,628	2,119	8,409	5,485	124,143
Exchange adjustments	(6)	(1)	–	(61)	7	(28)	(7)	(96)
Charge for the year	37	129	10,334	1,616	278	347	502	13,243
Impairment losses	10	20	611	525	–	160	35	1,361
Impairment reversals	–	–	(209)	–	–	(17)	–	(226)
Transfers	–	–	365	–	–	–	–	365
Deletions	(5)	(30)	(2,003)	(330)	(434)	(38)	(184)	(3,024)
At 31 December 2013	550	1,141	97,063	20,378	1,970	8,833	5,831	135,766
Net book amount at 31 December 2013	2,825	1,886	90,628	28,534	1,206	4,481	4,130	133,690
Assets held under finance leases at net book amount included above								
At 31 December 2014	**–**	**3**	**135**	**295**	**–**	**244**	**–**	**677**
At 31 December 2013	–	7	187	265	–	4	–	463
Assets under construction included above								
At 31 December 2014								**26,429**
At 31 December 2013								27,900

[a] For information on significant estimates and judgements made in relation to the estimation of oil and natural reserves see Property, plant and equipment within Note 1.

11. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2014 amounted to $15,635 million (2013 $13,705 million).

12. Goodwill and impairment review of goodwill

		$ million
	2014	2013
Cost		
At 1 January	**12,851**	12,804
Exchange adjustments	**(278)**	46
Acquisitions	**73**	44
Deletions	**(164)**	(43)
At 31 December	**12,482**	12,851
Impairment losses		
At 1 January	**670**	614
Impairment losses for the year	**–**	56
Deletions	**(56)**	–
At 31 December	**614**	670
Net book amount at 31 December	**11,868**	12,181
Net book amount at 1 January	**12,181**	12,190

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2014**	2013
Upstream	**7,819**	7,812
Downstream	**3,968**	4,277
Other businesses and corporate	**81**	92
	11,868	12,181

Goodwill acquired through business combinations has been allocated to groups of cash-generating units that are expected to benefit from the synergies of the acquisition. For Upstream, goodwill is allocated to all oil and gas assets in aggregate at the segment level. For Downstream, goodwill has been allocated to Lubricants and Other.

For information on significant estimates and judgements made in relation to impairments see Impairment of property, plant and equipment, intangibles and goodwill within Note 1.

Upstream

		$ million
	2014	2013
Goodwill	**7,819**	7,812
Excess of recoverable amount over carrying amount	**26,077**	6,811

The table above shows the carrying amount of goodwill for the segment and the excess of the recoverable amount over the carrying amount (the headroom).

In 2014, the recoverable amount is calculated using a fair value less costs of disposal approach, whereas a value-in-use approach was used in 2013. The change in valuation technique was made in order to more accurately reflect the recoverable amount, based on our view of assumptions that would be used by a market participant. Both the fair value less costs of disposal and value-in-use calculations are based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field, based on current estimates of reserves (for value in use) and reserves and risked resources (for fair value less costs of disposal). The fair value calculation is based primarily on level 3 inputs as defined by the IFRS 13 'Fair value measurement' hierarchy. As the production profile and related cash flows can be estimated from BP's experience, management believes that the estimated cash flows expected to be generated over the life of each field is the appropriate basis upon which to assess goodwill and individual assets for impairment. The estimated date of cessation of production depends on the interaction of a number of variables, such as the recoverable quantities of hydrocarbons, the production profile of the hydrocarbons, the cost of the development of the infrastructure necessary to recover the hydrocarbons, production costs, the contractual duration of the production concession and the selling price of the hydrocarbons produced. As each producing field has specific reservoir characteristics and economic circumstances, the cash flows of the fields are computed using appropriate individual economic models and key assumptions agreed by BP management. Capital expenditure, operating costs and expected hydrocarbon production profiles are derived from the business segment plan adjusted for assumptions reflecting the current price environment. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis are developed to be consistent with this. The production profiles used are consistent with the reserve and resource volumes approved as part of BP's centrally controlled process for the estimation of proved and probable reserves and total resources. Intangible assets are deemed to have a recoverable amount equal to their carrying amount. Consistent with prior years, the 2014 review for impairment was carried out during the fourth quarter.

The key assumptions used in the fair value less costs of disposal calculation are oil and natural gas prices (see Note 1), production volumes and the discount rate (see Note 1). The sensitivity of the headroom to changes in the key assumptions was estimated. Due to the non-linear relationship of different variables, the calculations were performed using a number of simplifying assumptions, including assuming a change to the variable being tested only, therefore a detailed calculation at any given price may produce a different result.

It is estimated that if the oil price assumption for all future years was approximately 15% below the current assumption for 2020 and beyond, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment. It is estimated that there is no reasonably possible change in the price assumption for natural gas that would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

Estimated production volumes are based on detailed data for each field and take into account development plans agreed by management as part of the long-term planning process. The average production for the purposes of goodwill impairment testing over the next 15 years is 847mmboe per year

12. Goodwill and impairment review of goodwill – continued

(2013 597mmboe per year). It is estimated that if production volume were to be reduced by approximately 5% for the whole period, this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

It is estimated that if the post-tax discount rate was approximately 10% for the entire portfolio this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

Downstream

						$ million
			2014			2013
	Lubricants	**Other**	**Total**	Lubricants	Other	Total
Goodwill	**3,264**	**704**	**3,968**	3,518	759	4,277

Cash flows for each cash-generating unit are derived from the business segment plans, which cover a period of two to five years. To determine the value in use for each of the cash-generating units, cash flows for a period of 10 years are discounted and aggregated with a terminal value.

Lubricants

As permitted by IAS 36, the detailed calculations of the Lubricants unit's recoverable amount performed in the most recent detailed calculation in 2013 were used for the 2014 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2013; there have been no significant changes in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time was remote.

The key assumptions to which the calculation of value in use for the Lubricants unit is most sensitive are operating unit margins, sales volumes, and discount rate. The values assigned to these key assumptions reflect past experience. No reasonably possible change in any of these key assumptions would cause the unit's carrying amount to exceed its recoverable amount. Cash flows beyond the two-year plan period were extrapolated using a nominal 3% growth rate.

13. Intangible assets

						$ million
			2014			2013
	Exploration and appraisal expenditure[a]	**Other intangibles**	**Total**	Exploration and appraisal expenditure[a]	Other intangibles	Total
Cost						
At 1 January	**21,742**	**3,936**	**25,678**	24,511	3,739	28,250
Exchange adjustments	**–**	**(175)**	**(175)**	–	(5)	(5)
Acquisitions	**–**	**455**	**455**	–	–	–
Additions	**2,871**	**394**	**3,265**	4,464	336	4,800
Transfers	**(993)**	**–**	**(993)**	(4,365)	–	(4,365)
Deletions	**(1,897)**	**(342)**	**(2,239)**	(2,868)	(134)	(3,002)
At 31 December	**21,723**	**4,268**	**25,991**	21,742	3,936	25,678
Amortization						
At 1 January	**877**	**2,762**	**3,639**	1,077	2,541	3,618
Exchange adjustments	**–**	**(72)**	**(72)**	–	(2)	(2)
Charge for the year	**3,029**	**304**	**3,333**	2,710	267	2,977
Impairment losses	**–**	**50**	**50**	253	85	338
Transfers	**–**	**–**	**–**	(365)	–	(365)
Deletions	**(1,527)**	**(339)**	**(1,866)**	(2,798)	(129)	(2,927)
At 31 December	**2,379**	**2,705**	**5,084**	877	2,762	3,639
Net book amount at 31 December	**19,344**	**1,563**	**20,907**	20,865	1,174	22,039
Net book amount at 1 January	**20,865**	**1,174**	**22,039**	23,434	1,198	24,632

[a] For further information see Intangible assets within Note 1 and Note 6.

14. Investments in joint ventures

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

			$ million
	2014	2013	2012
Sales and other operating revenues	**12,208**	12,507	12,507
Profit before interest and taxation	**1,210**	1,076	778
Finance costs	**125**	130	113
Profit before taxation	**1,085**	946	665
Taxation	**515**	499	405
Profit for the year	**570**	447	260
Other comprehensive income	**(15)**	38	(52)
Total comprehensive income	**555**	485	208
Non-current assets	**11,586**	11,576	
Current assets	**2,853**	3,095	
Total assets	**14,439**	14,671	
Current liabilities	**2,222**	2,276	
Non-current liabilities	**3,774**	3,499	
Total liabilities	**5,996**	5,775	
Net assets	**8,443**	8,896	
Group investment in joint ventures			
Group share of net assets (as above)	**8,443**	8,896	
Loans made by group companies to joint ventures	**310**	303	
	8,753	9,199	

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

						$ million
Sales to joint ventures		**2014**		2013		2012
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**3,148**	**300**	4,125	342	4,272	379

						$ million
Purchases from joint ventures		**2014**		2013		2012
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**907**	**129**	503	51	1,107	116

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

15. Investments in associates

The following table provides aggregated summarized financial information for the group's associates as it relates to the amounts recognized in the group income statement and on the group balance sheet.

					$ million
	Income statement			Balance sheet	
	Earnings from associates – after interest and tax			Investments in associates	
	2014	2013	2012	**2014**	2013
Rosneft	**2,101**	2,058	–	**7,312**	13,681
TNK-BP	**–**	–	2,986	**–**	–
Other associates	**701**	684	689	**3,091**	2,955
	2,802	2,742	3,675	**10,403**	16,636

The associate that is material to the group at both 31 December 2014 and 2013 is Rosneft. In 2013, BP sold its 50% interest in TNK-BP to Rosneft and increased its investment in Rosneft. The net cash inflow in 2013 relating to the transaction included in Net cash used in investing activities in the cash flow statement was $11.8 billion. From 22 October 2012, the investment in TNK-BP was classified as an asset held for sale and, therefore, equity accounting ceased. Profits of approximately $738 million and $731 million were not recognized in 2013 and 2012 respectively as a result of the discontinuance of equity accounting.

15. Investments in associates – continued

Since 21 March 2013, BP has owned 19.75% of the voting shares of Rosneft. Rosneft shares are listed on the MICEX stock exchange in Moscow and its global depositary receipts are listed on the London Stock Exchange. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2014.

BP classifies its investment in Rosneft as an associate because, in management's judgement, BP has significant influence over Rosneft; see Note 1 – Interests in other entities – Significant estimate or judgement: accounting for interests in other entities. The group's investment in Rosneft is a foreign operation, the functional currency of which is the Russian rouble. The reduction in the group's equity-accounted investment balance for Rosneft at 31 December 2014 compared with 31 December 2013 was principally due to the weakening of the Russian rouble compared to the US dollar, the effects of which have been recognized in other comprehensive income.

The fair value of BP's 19.75% shareholding in Rosneft was $7,346 million at 31 December 2014 (2013 $15,937 million) based on the quoted market share price of $3.51 per share (2013 $7.62 per share).

The following table provides summarized financial information relating to the group's material associates. This information is presented on a 100% basis and reflects adjustments made by BP to the associates' own results in applying the equity method of accounting. BP adjusts Rosneft's results for the accounting required under IFRS relating to BP's purchase of its interest in Rosneft and the amortization of the deferred gain relating to the disposal of BP's interest in TNK-BP. The adjustments relating to Rosneft have increased the reported profit for 2014, as shown in the table below, compared with the equivalent amount in Russian roubles that we expect Rosneft to report in its own financial statements under IFRS. Consistent with other line items in the income statement, the amount reported for Rosneft sales and other operating revenue is calculated by translating the amounts reported in Russian roubles into US dollars using the average exchange rate for the year.

			$ million
			Gross amount
	2014	2013	2012
	Rosneft	Rosneft	TNK-BP[a]
Sales and other operating revenues	**142,856**	122,866	49,350
Profit before interest and taxation	**19,367**	14,106	8,810
Finance costs	**5,230**	1,337	168
Profit before taxation	**14,137**	12,769	8,642
Taxation	**3,428**	2,137	1,958
Non-controlling interests	**71**	213	712
Profit for the year	**10,638**	10,419	5,972
Other comprehensive income	**(13,038)**	(441)	26
Total comprehensive income	**(2,400)**	9,978	5,998
Non-current assets	**101,073**	149,149	
Current assets	**38,278**	48,775	
Total assets	**139,351**	197,924	
Current liabilities	**36,400**	43,175	
Non-current liabilities	**65,266**	83,458	
Total liabilities	**101,666**	126,633	
Net assets	**37,685**	71,291	
Less: non-controlling interests	**663**	2,020	
	37,022	69,271	

[a] BP ceased equity accounting for TNK-BP on 22 October 2012.

The group received dividends of $693 million from Rosneft in 2014, net of withholding tax (2013 dividends of $456 million from Rosneft and 2012 dividends of $709 million from TNK-BP).

15. Investments in associates – continued

Summarized financial information for the group's share of associates is shown below. Income statement and other comprehensive income information shown below includes data relating to associates classified as assets held for sale during the period prior to their classification as assets held for sale.

									$ million
									BP share
			2014			2013			2012
	Rosneft[a]	**Other**	**Total**	Rosneft	Other[b]	Total	TNK-BP	Other	Total
Sales and other operating revenues	**28,214**	**9,724**	**37,938**	24,266	12,998	37,264	24,675	11,965	36,640
Profit before interest and taxation	**3,825**	**938**	**4,763**	2,786	908	3,694	4,405	906	5,311
Finance costs	**1,033**	**7**	**1,040**	264	11	275	84	16	100
Profit before taxation	**2,792**	**931**	**3,723**	2,522	897	3,419	4,321	890	5,211
Taxation	**677**	**230**	**907**	422	213	635	979	201	1,180
Non-controlling interests	**14**	**–**	**14**	42	–	42	356	–	356
Profit for the year	**2,101**	**701**	**2,802**	2,058	684	2,742	2,986	689	3,675
Other comprehensive income	**(2,575)**	**10**	**(2,565)**	(87)	2	(85)	13	(6)	7
Total comprehensive income	**(474)**	**711**	**237**	1,971	686	2,657	2,999	683	3,682
Non-current assets	**19,962**	**2,975**	**22,937**	29,457	3,148	32,605			
Current assets	**7,560**	**2,199**	**9,759**	9,633	2,477	12,110			
Total assets	**27,522**	**5,174**	**32,696**	39,090	5,625	44,715			
Current liabilities	**7,189**	**1,614**	**8,803**	8,527	2,114	10,641			
Non-current liabilities	**12,890**	**921**	**13,811**	16,483	1,053	17,536			
Total liabilities	**20,079**	**2,535**	**22,614**	25,010	3,167	28,177			
Net assets	**7,443**	**2,639**	**10,082**	14,080	2,458	16,538			
Less: non-controlling interests	**131**	**–**	**131**	399	–	399			
	7,312	**2,639**	**9,951**	13,681	2,458	16,139			
Group investment in associates									
Group share of net assets (as above)	**7,312**	**2,639**	**9,951**	13,681	2,458	16,139			
Loans made by group companies to associates	**–**	**452**	**452**	–	497	497			
	7,312	**3,091**	**10,403**	13,681	2,955	16,636			

[a] On 1 October 2014, Rosneft adopted hedge accounting in relation to a portion of highly probable future export revenue denominated in US dollars. Since 1 October 2014, foreign exchange gains and losses arising on the retranslation of borrowings denominated in currencies other than the Russian rouble and designated as hedging instruments have been recognized initially in other comprehensive income, and will be reclassified to the income statement as the hedged revenue is recognized over the next five years.
[b] An amendment has been made to the amount previously disclosed for Sales and other operating revenues.

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		**2014**		2013		2012
Product	**Sales**	**Amount receivable at 31 December**	Sales	Amount receivable at 31 December	Sales	Amount receivable at 31 December
LNG, crude oil and oil products, natural gas	**9,589**	**1,258**	5,170	783	3,771	401

						$ million
Purchases from associates		**2014**		2013		2012
Product	**Purchases**	**Amount payable at 31 December**	Purchases	Amount payable at 31 December	Purchases	Amount payable at 31 December
Crude oil and oil products, natural gas, transportation tariff	**22,703**	**2,307**	21,205	3,470	9,135	932

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

BP has commitments amounting to $6,946 million (2013 $6,077 million) in relation to contracts with its associates for the purchase of crude oil and oil products, transportation and storage.

The majority of the sales to, purchases from, and commitments in relation to contracts with associates relate to crude oil and oil products transactions with Rosneft.

16. Other investments

				$ million
		2014		2013
	Current	**Non-current**	Current	Non-current
Equity investments[a]	**–**	**420**	–	291
Repurchased gas pre-paid bonds	**254**	**153**	276	408
Contingent consideration	**9**	**56**	186	292
Other	**66**	**599**	5	574
	329	**1,228**	467	1,565

[a] The majority of equity investments are unlisted.

BP entered into long-term gas supply contracts which are backed by gas pre-paid bonds. In 2010, BP was unsuccessful in the remarketing of these bonds and repurchased them. The outstanding bonds associated with these long-term gas supply contracts held by BP are recorded within other investments, with the related liability recorded within other payables on the balance sheet. The fair value of the gas pre-paid bonds is the same as the carrying amount, as the bonds are based on floating rate interest with weekly market re-set, and as such are in level 1 of the fair value hierarchy.

At both 31 December 2014 and 2013 the group had contingent consideration receivable, classified as an available-for-sale financial asset, in respect of the disposal of the Devenick field in 2013.

Other non-current investments at 31 December 2014 of $599 million relate to life insurance policies (2013 $574 million). The life insurance policies have been designated as financial assets at fair value through profit and loss and their valuation methodology is in level 3 of the fair value hierarchy. Fair value gains of $41 million were recognized in the income statement (2013 $4 million loss and 2012 $70 million gain).

17. Inventories

		$ million
	2014	2013
Crude oil	**5,614**	10,190
Natural gas	**285**	235
Refined petroleum and petrochemical products	**8,975**	15,427
	14,874	25,852
Supplies	**3,051**	2,735
	17,925	28,587
Trading inventories	**448**	644
	18,373	29,231
Cost of inventories expensed in the income statement	**281,907**	298,351

The inventory valuation at 31 December 2014 is stated net of a provision of $2,879 million (2013 $322 million) to write inventories down to their net realizable value. The net charge to the income statement in the year in respect of inventory net realizable value provisions was $2,625 million (2013 $195 million charge).

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

18. Trade and other receivables

				$ million
		2014		2013
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**19,671**	**166**	28,868	183
Amounts receivable from joint ventures and associates	**1,558**	**–**	1,213	47
Other receivables	**7,863**	**1,293**	6,594	2,725
	29,092	**1,459**	36,675	2,955
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**1,154**	**2,701**	2,457	2,442
Other receivables	**792**	**627**	699	588
	1,946	**3,328**	3,156	3,030
	31,038	**4,787**	39,831	5,985

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 27 for further information.

19. Valuation and qualifying accounts

						$ million
		2014		2013		2012
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**343**	**168**	489	349	332	643
Charged to costs and expenses	**127**	**438**	82	4	240	196
Charged to other accounts[a]	**(24)**	**(2)**	(4)	4	7	18
Deductions	**(115)**	**(87)**	(224)	(189)	(90)	(508)
At 31 December	**331**	**517**	343	168	489	349

[a] Principally exchange adjustments.

Valuation and qualifying accounts comprise impairment provisions for accounts receivable and fixed asset investments, and are deducted in the balance sheet from the assets to which they apply.

For information on significant estimates and judgements made in relation to the recoverability of trade receivables see Impairment of loans and receivables within Note 1.

20. Trade and other payables

				$ million
		2014		2013
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**23,074**	**–**	28,926	–
Amounts payable to joint ventures and associates	**2,436**	**–**	3,576	47
Other payables	**11,832**	**2,985**	11,288	4,235
	37,342	**2,985**	43,790	4,282
Non-financial liabilities				
Other payables	**2,776**	**602**	3,369	474
	40,118	**3,587**	47,159	4,756

Trade and other payables are predominantly interest free. See Note 27 for further information.

21. Provisions

						$ million
	Decommissioning	**Environmental[a]**	**Litigation and claims**	**Clean Water Act penalties**	**Other**	**Total**
At 1 January 2014	**17,205**	**3,454**	**4,911**	**3,510**	**2,880**	**31,960**
Exchange adjustments	**(489)**	**(18)**	**(12)**	**–**	**(122)**	**(641)**
Acquisitions	**8**	**–**	**–**	**–**	**13**	**21**
New or increased provisions	**2,216**	**561**	**1,290**	**–**	**1,101**	**5,168**
Write-back of unused provisions	**(60)**	**(92)**	**(27)**	**–**	**(252)**	**(431)**
Unwinding of discount	**202**	**19**	**12**	**–**	**24**	**257**
Change in discount rate	**778**	**21**	**14**	**–**	**9**	**822**
Utilization	**(682)**	**(1,098)**	**(1,449)**	**–**	**(565)**	**(3,794)**
Deletions	**(458)**	**–**	**–**	**–**	**(6)**	**(464)**
At 31 December 2014	**18,720**	**2,847**	**4,739**	**3,510**	**3,082**	**32,898**
Of which – current	**836**	**927**	**1,420**	**–**	**635**	**3,818**
– non-current	**17,884**	**1,920**	**3,319**	**3,510**	**2,447**	**29,080**
Of which – Gulf of Mexico oil spill[b]	**–**	**1,141**	**3,954**	**3,510**	**–**	**8,605**

[a] Spill response provisions are now included within environmental provisions as they are no longer individually significant.
[b] Further information on the financial impacts of the Gulf of Mexico oil spill is provided in Note 2.

The decommissioning provision comprises the future cost of decommissioning oil and natural gas wells, facilities and related pipelines. The environmental provision includes provisions for costs related to the control, abatement, clean-up or elimination of environmental pollution relating to soil, groundwater, surface water and sediment contamination. The litigation and claims category includes provisions for matters related to, for example, commercial disputes, product liability, and allegations of exposures of third parties to toxic substances. Included within the other category at 31 December 2014 are provisions for deferred employee compensation of $553 million (2013 $602 million).

For information on significant estimates and judgements made in relation to provisions, including those for the Gulf of Mexico oil spill, see Provisions, contingencies and reimbursement assets within Note 1.

22. Pensions and other post-retirement benefits

Most group companies have pension plans, the forms and benefits of which vary with conditions and practices in the countries concerned. Pension benefits may be provided through defined contribution plans (money purchase schemes) or defined benefit plans (final salary and other types of schemes with committed pension benefit payments). For defined contribution plans, retirement benefits are determined by the value of funds arising from contributions paid in respect of each employee. For defined benefit plans, retirement benefits are based on such factors as the employees' pensionable salary and length of service. Defined benefit plans may be funded or unfunded. The assets of funded plans are generally held in separately administered trusts.

22. Pensions and other post-retirement benefits – continued

For information on significant estimates and judgements made in relation to accounting for these plans see Pensions and other post-retirement benefits within Note 1.

The primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, including an independent director and an independent chairman nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan. The UK plan is closed to new joiners but remains open to ongoing accrual for current members. New joiners in the UK are eligible for membership of a defined contribution plan.

In the US, a range of retirement arrangements is provided. Historically this has included a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new joiners, but with effect from 2015 all employees who are members of the final salary pension plan accrue benefits only under a cash balance arrangement. Retired US employees typically take their pension benefit in the form of a lump sum payment. The plan's assets are overseen by a fiduciary investment committee composed of seven BP employees appointed by the president of BP Corporation North America Inc. (the appointing officer). The investment committee is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as the investment policies of the plan. US employees are also eligible to participate in a defined contribution (401k) plan in which employee contributions are matched with company contributions. In the US, group companies also provide post-retirement healthcare and life insurance benefits to retired employees and their dependants; the entitlement to these benefits is usually based on the employee remaining in service until retirement age and completion of a minimum period of service.

In the Eurozone, there are defined benefit pension plans in Germany, France, the Netherlands and other countries. In Germany and France, the majority of the pensions are unfunded, in line with market practice. In Germany, the group's largest Eurozone plan, employees receive a pension and also have a choice to supplement their core pension through salary sacrifice. For employees who joined since 2002 the core pension benefit is a career average plan with retirement benefits based on such factors as employees' pensionable salary and length of service. The returns on the notional contributions made by both the company and employees are set out in German tax law. Retired German employees take their pension benefit typically in the form of an annuity. The German plan is governed by a legal agreement between BP and the works council.

The level of contributions to funded defined benefit plans is the amount needed to provide adequate funds to meet pension obligations as they fall due. During 2014 the aggregate level of contributions was $1,252 million (2013 $1,272 million and 2012 $1,275 million). The aggregate level of contributions in 2015 is expected to be approximately $1,250 million, and includes contributions in all countries that we expect to be required to make contributions by law or under contractual agreements, as well as an allowance for discretionary funding.

For the primary UK plan there is a funding agreement between the group and the trustee. On an annual basis the latest funding position is reviewed and a schedule of contributions covering the next five years is agreed. The funding agreement can be terminated unilaterally by either party with two years' notice. The minimum funding requirement therefore represents seven years of future contributions, which amounted to $4,720 million at 31 December 2014. This amount is included in the group's committed cash flows relating to pensions and other post-retirement benefit plans as set out in the table of contractual obligations on page 212. There are no such minimum funding requirements after this seven-year period, and the obligation is taken into account in the determination of the amount of any pension plan surplus recognized on the balance sheet.

Contributions in the US are determined by legislation and are supplemented by discretionary contributions. All of the contributions made into the US plan in 2014 were discretionary and no statutory funding requirement is expected in the next 12 months.

There was no minimum funding requirement for the US plan, and no significant minimum funding requirements in other countries at 31 December 2014.

The obligation and cost of providing pensions and other post-retirement benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2014. The group's principal plans are subject to a formal actuarial valuation every three years in the UK, with valuations being required more frequently in many other countries. The most recent formal actuarial valuation of the UK pension plans was as at 31 December 2011 and a valuation as at 31 December 2014 is currently under way. A valuation of the US plan is carried out annually.

The material financial assumptions used to estimate the benefit obligations of the various plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate the accrued benefit obligation at 31 December and pension expense for the following year.

									%
Financial assumptions used to determine benefit obligation			UK			US			Eurozone
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Discount rate for plan liabilities	**3.6**	4.6	4.4	**3.7**	4.3	3.3	**2.0**	3.6	3.5
Rate of increase in salaries	**4.5**	5.1	4.9	**4.0**	3.9	4.2	**3.4**	3.4	3.4
Rate of increase for pensions in payment	**3.0**	3.3	3.1	**–**	–	–	**1.8**	1.8	1.8
Rate of increase in deferred pensions	**3.0**	3.3	3.1	**–**	–	–	**0.7**	0.7	0.7
Inflation for plan liabilities	**3.0**	3.3	3.1	**1.6**	2.1	2.4	**2.0**	2.0	2.0

Financial assumptions used to determine benefit expense			UK			US			Eurozone
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Discount rate for plan service cost	**4.8**	4.4	4.8	**4.6**	3.3	4.3	**3.9**	3.5	4.8
Discount rate for plan other finance expense	**4.6**	4.4	4.8	**4.3**	3.3	4.3	**3.6**	3.5	4.8
Inflation for plan service cost	**3.4**	3.1	3.2	**2.1**	2.4	1.9	**2.0**	2.0	2.0

The discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and the Eurozone we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. The Eurozone inflation rate assumption is based on the central bank inflation target. In other countries we use one of these approaches, or advice from the local actuary depending on the information available. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions where there is such an increase.

22. Pensions and other post-retirement benefits – continued

The assumptions for the rate of increase in salaries are based on the inflation assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of up to 1.0% depending on country.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the countries in which we provide pensions, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future. BP's most substantial pension liabilities are in the UK, the US and the Eurozone where our mortality assumptions are as follows:

									Years
Mortality assumptions			UK			US			Eurozone
	2014	2013	2012	**2014**	2013	2012	**2014**	2013	2012
Life expectancy at age 60 for a male currently aged 60	**28.3**	27.8	27.7	**25.6**	24.9	24.9	**24.7**	24.4	24.3
Life expectancy at age 60 for a male currently aged 40	**30.9**	30.7	30.6	**27.4**	26.4	26.3	**27.3**	26.9	26.9
Life expectancy at age 60 for a female currently aged 60	**29.4**	29.5	29.4	**29.1**	26.5	26.4	**28.7**	28.5	28.5
Life expectancy at age 60 for a female currently aged 40	**31.8**	32.2	32.1	**30.9**	27.3	27.3	**31.1**	30.7	30.6

Pension plan assets are generally held in trusts. The primary objective of the trusts is to accumulate pools of assets sufficient to meet the obligations of the various plans. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term of such assets with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

The current asset allocation policy for the major plans is as follows:

	UK	US
Asset category	%	%
Total equity (including private equity)	**70**	**60**
Bonds/cash	**23**	**40**
Property/real estate	**7**	**–**

The group's main pension plans do not invest directly in either securities or property/real estate of the company or of any subsidiary. Some of the group's pension plans use derivative financial instruments as part of their asset mix to manage the level of risk.

For the primary UK pension plan there is an agreement with the trustee to reduce the proportion of plan assets held as equities and increase the proportion held as bonds over time, with a view to better matching of the asset portfolio with the pension liabilities. There is a similar agreement in place in the US.

BP's principal plans in the UK and US do not currently follow a liability driven investment approach, a form of investing designed to match the movement in pension plan assets with the movement in projected benefit obligations over time.

22. Pensions and other post-retirement benefits – continued

The fair values of the various categories of assets held by the defined benefit plans at 31 December are presented in the table below, including the effects of derivative financial instruments. Movements in the fair value of plan assets during the year are shown in detail in the table on page 139.

					$ million
	UK[a]	US[b]	Eurozone	Other	Total
Fair value of pension plan assets					
At 31 December 2014					
Listed equities – developed markets	**16,190**	**3,026**	**415**	**420**	**20,051**
– emerging markets	**2,719**	**293**	**45**	**47**	**3,104**
Private equity	**2,983**	**1,571**	**2**	**26**	**4,582**
Government issued nominal bonds	**642**	**1,535**	**753**	**604**	**3,534**
Index-linked bonds	**892**	**–**	**9**	**–**	**901**
Corporate bonds	**4,687**	**1,726**	**541**	**340**	**7,294**
Property	**2,403**	**7**	**51**	**69**	**2,530**
Cash	**1,145**	**134**	**85**	**191**	**1,555**
Other	**112**	**63**	**72**	**38**	**285**
	31,773	**8,355**	**1,973**	**1,735**	**43,836**
At 31 December 2013					
Listed equities – developed markets	17,341	3,260	414	499	21,514
– emerging markets	2,290	308	32	52	2,682
Private equity	2,907	1,432	2	4	4,345
Government issued nominal bonds	549	1,259	717	541	3,066
Index-linked bonds	787	–	12	57	856
Corporate bonds	4,427	1,323	597	385	6,732
Property	2,200	6	57	77	2,340
Cash	855	135	120	158	1,268
Other	160	55	64	49	328
	31,516	7,778	2,015	1,822	43,131
At 31 December 2012					
Listed equities – developed markets	15,659	3,622	307	537	20,125
– emerging markets	1,074	341	37	52	1,504
Private equity	2,879	1,468	3	4	4,354
Government issued nominal bonds	544	904	532	510	2,490
Index-linked bonds	491	–	9	69	569
Corporate bonds	3,850	1,255	398	368	5,871
Property	1,783	5	54	85	1,927
Cash	1,000	87	170	151	1,408
Other	66	105	200	47	418
	27,346	7,787	1,710	1,823	38,666

[a] Bonds held by the UK pension plans are all denominated in sterling. Property held by the UK pension plans is in the United Kingdom.
[b] Bonds held by the US pension plans are denominated in US dollars.

22. Pensions and other post-retirement benefits – continued

					$ million
					2014
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	494	356	72	87	1,009
Past service cost[b]	–	(33)	20	1	(12)
Settlement[c]	–	(66)	–	–	(66)
Operating charge relating to defined benefit plans	494	257	92	88	931
Payments to defined contribution plans	30	214	11	54	309
Total operating charge	524	471	103	142	1,240
Interest income on plan assets[a]	(1,425)	(317)	(70)	(80)	(1,892)
Interest on plan liabilities	1,378	458	255	115	2,206
Other finance expense	(47)	141	185	35	314
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	1,269	768	119	31	2,187
Change in financial assumptions underlying the present value of the plan liabilities	(3,188)	(1,004)	(1,845)	(350)	(6,387)
Change in demographic assumptions underlying the present value of the plan liabilities	42	(264)	(20)	(9)	(251)
Experience gains and losses arising on the plan liabilities	(41)	13	(86)	(25)	(139)
Remeasurements recognized in other comprehensive income	(1,918)	(487)	(1,832)	(353)	(4,590)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	30,552	11,002	7,536	2,443	51,533
Exchange adjustments	(1,993)	–	(1,040)	(256)	(3,289)
Operating charge relating to defined benefit plans	494	257	92	88	931
Interest cost	1,378	458	255	115	2,206
Contributions by plan participants[d]	39	–	4	7	50
Benefit payments (funded plans)[e]	(1,231)	(865)	(83)	(119)	(2,298)
Benefit payments (unfunded plans)[e]	(10)	(238)	(370)	(24)	(642)
Acquisitions	–	6	–	–	6
Disposals	–	–	(18)	–	(18)
Remeasurements	3,187	1,255	1,951	384	6,777
Benefit obligation at 31 December[a f]	32,416	11,875	8,327	2,638	55,256
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	31,516	7,778	2,015	1,822	43,131
Exchange adjustments	(1,958)	–	(257)	(161)	(2,376)
Interest income on plan assets[a g]	1,425	317	70	80	1,892
Contributions by plan participants[d]	39	–	4	7	50
Contributions by employers (funded plans)	713	354	110	75	1,252
Benefit payments (funded plans)[e]	(1,231)	(865)	(83)	(119)	(2,298)
Acquisitions	–	3	–	–	3
Disposals	–	–	(5)	–	(5)
Remeasurements[g]	1,269	768	119	31	2,187
Fair value of plan assets at 31 December	31,773	8,355	1,973	1,735	43,836
Surplus (deficit) at 31 December	(643)	(3,520)	(6,354)	(903)	(11,420)
Represented by					
Asset recognized	15	–	3	13	31
Liability recognized	(658)	(3,520)	(6,357)	(916)	(11,451)
	(643)	(3,520)	(6,354)	(903)	(11,420)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	(310)	(19)	(663)	(384)	(1,376)
Unfunded	(333)	(3,501)	(5,691)	(519)	(10,044)
	(643)	(3,520)	(6,354)	(903)	(11,420)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(32,083)	(8,374)	(2,636)	(2,119)	(45,212)
Unfunded	(333)	(3,501)	(5,691)	(519)	(10,044)
	(32,416)	(11,875)	(8,327)	(2,638)	(55,256)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.
[b] Past service costs in the US include a credit of $21 million as the result of a curtailment in the pension arrangement of a number of employees following a business reorganization and a credit of $12 million reflecting a plan amendment to a medical plan. A charge of $21 million for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes mostly in the Eurozone.
[c] Settlements represent a gain of $66 million arising from an offer to a group of plan members in the US to settle annuity liabilities with lump sum payments.
[d] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.
[e] The benefit payments amount shown above comprises $2,621 million benefits and $257 million settlements, plus $62 million of plan expenses incurred in the administration of the benefit.
[f] The benefit obligation for the US is made up of $9,033 million for pension liabilities and $2,842 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $5,220 million for pension liabilities in Germany which is largely unfunded.
[g] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

22. Pensions and other post-retirement benefits – continued

					$ million
					2013
	UK	US	Eurozone	Other	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	497	407	81	96	1,081
Past service cost[b]	(22)	(49)	26	1	(44)
Settlement	–	–	–	(1)	(1)
Operating charge relating to defined benefit plans	475	358	107	96	1,036
Payments to defined contribution plans	24	223	9	44	300
Total operating charge	499	581	116	140	1,336
Interest income on plan assets[a]	(1,139)	(240)	(63)	(67)	(1,509)
Interest on plan liabilities	1,223	406	254	106	1,989
Other finance expense	84	166	191	39	480
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	2,671	730	15	99	3,515
Change in financial assumptions underlying the present value of the plan liabilities	68	1,160	62	213	1,503
Change in demographic assumptions underlying the present value of the plan liabilities	–	14	–	(65)	(51)
Experience gains and losses arising on the plan liabilities	43	(249)	2	1	(203)
Remeasurements recognized in other comprehensive income	2,782	1,655	79	248	4,764
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,323	12,874	7,364	2,720	52,281
Exchange adjustments	706	–	323	(192)	837
Operating charge relating to defined benefit plans	475	358	107	96	1,036
Interest cost	1,223	406	254	106	1,989
Contributions by plan participants[c]	37	–	4	9	50
Benefit payments (funded plans)[d]	(1,087)	(1,365)	(87)	(105)	(2,644)
Benefit payments (unfunded plans)[d]	(5)	(285)	(365)	(29)	(684)
Disposals	(9)	(61)	–	(13)	(83)
Remeasurements[e]	(111)	(925)	(64)	(149)	(1,249)
Benefit obligation at 31 December[a f]	30,552	11,002	7,536	2,443	51,533
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	27,346	7,787	1,710	1,823	38,666
Exchange adjustments	822	–	92	(129)	785
Interest income on plan assets[a]	1,139	240	63	67	1,509
Contributions by plan participants[c]	37	–	4	9	50
Contributions by employers (funded plans)	597	386	218	71	1,272
Benefit payments (funded plans)[d]	(1,087)	(1,365)	(87)	(105)	(2,644)
Disposals	(9)	–	–	(13)	(22)
Remeasurements[e]	2,671	730	15	99	3,515
Fair value of plan assets at 31 December	31,516	7,778	2,015	1,822	43,131
Surplus (deficit) at 31 December	964	(3,224)	(5,521)	(621)	(8,402)
Represented by					
Asset recognized	1,291	6	20	59	1,376
Liability recognized	(327)	(3,230)	(5,541)	(680)	(9,778)
	964	(3,224)	(5,521)	(621)	(8,402)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,285	(5)	(180)	(140)	960
Unfunded	(321)	(3,219)	(5,341)	(481)	(9,362)
	964	(3,224)	(5,521)	(621)	(8,402)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(30,231)	(7,783)	(2,195)	(1,962)	(42,171)
Unfunded	(321)	(3,219)	(5,341)	(481)	(9,362)
	(30,552)	(11,002)	(7,536)	(2,443)	(51,533)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

[b] Past service costs include a credit of $73 million as the result of a curtailment in the pension arrangement of a number of employees in the UK and US following divestment transactions. A charge of $29 million for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.

[c] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.

[d] The benefit payments amount shown above comprises $3,269 million benefits plus $59 million of plan expenses incurred in the administration of the benefit.

[e] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

[f] The benefit obligation for the US is made up of $8,364 million for pension liabilities and $2,638 million for other post-retirement benefit liabilities (which are unfunded and are primarily retiree medical liabilities). The benefit obligation for the Eurozone includes $4,874 million for pension liabilities in Germany which is largely unfunded.

22. Pensions and other post-retirement benefits – continued

	UK	US	Eurozone	Other	$ million 2012 Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	477	379	55	96	1,007
Past service cost	(1)	20	84	(2)	101
Settlement	–	–	4	(3)	1
Operating charge relating to defined benefit plans	476	399	143	91	1,109
Payments to defined contribution plans	14	223	6	38	281
Total operating charge	490	622	149	129	1,390
Interest income on plan assets[a]	(1,146)	(304)	(71)	(83)	(1,604)
Interest on plan liabilities	1,250	516	282	122	2,170
Other finance expense	104	212	211	39	566
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets	1,523	718	107	66	2,414
Change in financial assumptions underlying the present value of the plan liabilities	(1,476)	(1,240)	(1,037)	(26)	(3,779)
Change in demographic assumptions underlying the present value of the plan liabilities	–	52	(12)	(25)	15
Experience gains and losses arising on the plan liabilities	(118)	20	(101)	(23)	(222)
Remeasurements recognized in other comprehensive income	(71)	(450)	(1,043)	(8)	(1,572)

[a] The costs of managing plan investments are offset against the investment return, the costs of administering pension plan benefits are generally included in current service cost and the costs of administering other post-retirement benefit plans are included in the benefit obligation.

At 31 December 2014, reimbursement balances due from or to other companies in respect of pensions amounted to $426 million reimbursement assets (2013 $399 million) and $16 million reimbursement liabilities (2013 $15 million). These balances are not included as part of the pension surpluses and deficits, but are reflected within other receivables and other payables in the group balance sheet.

Sensitivity analysis

The discount rate, inflation, salary growth and the mortality assumptions all have a significant effect on the amounts reported. A one-percentage point change, in isolation, in certain assumptions as at 31 December 2014 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2015 comprise the total of current service cost and net finance income or expense.

	$ million One percentage point Increase	Decrease
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2015	**(499)**	**487**
Effect on pension and other post-retirement benefit obligation at 31 December 2014	**(8,174)**	**10,632**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2015	**543**	**(406)**
Effect on pension and other post-retirement benefit obligation at 31 December 2014	**8,264**	**(6,531)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2015	**157**	**(139)**
Effect on pension and other post-retirement benefit obligation at 31 December 2014	**1,103**	**(1,080)**

[a] The amounts presented reflect that the discount rate is used to determine the asset interest income as well as the interest cost on the obligation.

One additional year of longevity in the mortality assumptions would increase the 2015 pension and other post-retirement benefit expense by $74 million and the pension and other post-retirement benefit obligation at 31 December 2014 by $1,582 million.

Estimated future benefit payments and the weighted average duration of defined benefit obligations

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2024 and the weighted average duration of the defined benefit obligations at 31 December 2014 are as follows:

Estimated future benefit payments	UK	US	Eurozone	Other	$ million Total
2015	**1,192**	**899**	**439**	**136**	**2,666**
2016	**1,248**	**917**	**421**	**134**	**2,720**
2017	**1,256**	**923**	**412**	**139**	**2,730**
2018	**1,329**	**921**	**400**	**146**	**2,796**
2019	**1,377**	**916**	**389**	**151**	**2,833**
2020-2024	**7,156**	**4,343**	**1,848**	**791**	**14,138**
					years
Weighted average duration	**19.0**	**9.8**	**14.5**	**14.2**	

Financial statements

23. Cash and cash equivalents

		$ million
	2014	2013
Cash at bank and in hand	**5,112**	6,907
Term bank deposits	**18,392**	12,246
Cash equivalents	**6,259**	3,367
	29,763	22,520

Cash and cash equivalents comprise cash in hand; current balances with banks and similar institutions; term deposits of three months or less with banks and similar institutions; money market funds and commercial paper. The carrying amounts of cash at bank and in hand and term bank deposits approximate their fair values. Substantially all of the other cash equivalents are categorized within level 1 of the fair value hierarchy.

Cash and cash equivalents at 31 December 2014 includes $2,264 million (2013 $1,626 million) that is restricted. The restricted cash balances include amounts required to cover initial margin on trading exchanges and certain cash balances which are subject to exchange controls.

The group holds $3 billion (2013 $2 billion) of cash outside the UK and it is not expected that any significant tax will arise on repatriation.

24. Finance debt

						$ million
			2014			2013
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**6,831**	**45,240**	**52,071**	7,340	40,317	47,657
Net obligations under finance leases	**46**	**737**	**783**	41	494	535
	6,877	**45,977**	**52,854**	7,381	40,811	48,192

The main elements of current borrowings are the current portion of long-term borrowings that is due to be repaid in the next 12 months of $6,343 million (2013 $6,230 million) and issued commercial paper of $444 million (2013 $1,050 million). Finance debt does not include accrued interest, which is reported within other payables.

At 31 December 2014, $137 million (2013 $141 million) of finance debt was secured by the pledging of assets. The remainder of finance debt was unsecured.

The following table shows the weighted average interest rates achieved through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures.

			Fixed rate debt		**Floating rate debt**	**Total**
	Weighted average interest rate %	**Weighted average time for which rate is fixed Years**	**Amount $ million**	**Weighted average interest rate %**	**Amount $ million**	**Amount $ million**
						2014
US dollar	**3**	**3**	**14,285**	**1**	**36,275**	**50,560**
Other currencies	**6**	**19**	**871**	**1**	**1,423**	**2,294**
			15,156		**37,698**	**52,854**
						2013
US dollar	3	4	16,405	1	29,740	46,145
Other currencies	4	11	611	2	1,436	2,047
			17,016		31,176	48,192

The floating rate debt denominated in other currencies represents euro debt not swapped to US dollars, which is naturally hedged with respect to foreign currency risk by holding equivalent euro cash and cash equivalent amounts.

Fair values

The estimated fair value of finance debt is shown in the table below together with the carrying amount as reflected in the balance sheet.

Long-term borrowings in the table below include the portion of debt that matures in the 12 months from 31 December 2014, whereas in the balance sheet the amount is reported within current finance debt.

The carrying amount of the group's short-term borrowings, comprising mainly commercial paper, approximates their fair value. The fair values of the group's long-term borrowings are principally determined using quoted prices in active markets (and so fall within level 1 of the fair value hierarchy). Where quoted prices are not available, quoted prices for similar instruments in active markets are used. The fair value of the group's finance lease obligations is estimated using discounted cash flow analyses based on the group's current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
		2014		2013
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**487**	**487**	1,110	1,110
Long-term borrowings	**51,995**	**51,584**	47,398	46,547
Net obligations under finance leases	**1,343**	**783**	654	535
Total finance debt	**53,825**	**52,854**	49,162	48,192

25. Capital disclosures and analysis of changes in net debt

The group defines capital as total equity. We maintain our financial framework to support the pursuit of value growth for shareholders, while ensuring a secure financial base. We continue to target a gearing range of 10-20% and to maintain a significant liquidity buffer while uncertainties remain.

The group monitors capital on the basis of the net debt ratio, that is, the ratio of net debt to net debt plus equity. Net debt is calculated as gross finance debt, as shown in the balance sheet, plus the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is applied, less cash and cash equivalents. Net debt and net debt ratio are non-GAAP measures. BP believes these measures provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. All components of equity are included in the denominator of the calculation. At 31 December 2014, the net debt ratio was 16.7% (2013 16.2%).

		$ million
At 31 December	**2014**	2013
Gross debt	**52,854**	48,192
Less: fair value asset of hedges related to finance debt	**445**	477
	52,409	47,715
Less: cash and cash equivalents	**29,763**	22,520
Net debt	**22,646**	25,195
Equity	**112,642**	130,407
Net debt ratio	**16.7%**	16.2%

An analysis of changes in net debt is provided below.

						$ million
		2014				2013
Movement in net debt	**Finance debt[a]**	**Cash and cash equivalents**	**Net debt**	Finance debt[a]	Cash and cash equivalents	Net debt
At 1 January	**(47,715)**	**22,520**	**(25,195)**	(47,100)	19,635	(27,465)
Exchange adjustments	**1,160**	**(671)**	**489**	(219)	40	(179)
Net cash flow	**(5,419)**	**7,914**	**2,495**	(836)	2,845	2,009
Movement in finance debt relating to investing activities	**–**	**–**	**–**	632	–	632
Other movements	**(435)**	**–**	**(435)**	(192)	–	(192)
At 31 December	**(52,409)**	**29,763**	**(22,646)**	(47,715)	22,520	(25,195)

[a] Including the fair value of associated derivative financial instruments.

26. Operating leases

The minimum lease payments charged to the income statement in the year were $6,324 million (2013 $5,961 million and 2012 $5,257 million).

The future minimum lease payments at 31 December 2014, before deducting related rental income from operating sub-leases of $234 million (2013 $223 million), are shown in the table below. This does not include future contingent rentals. Where the lease rentals are dependent on a variable factor, the future minimum lease payments are based on the factor as at inception of the lease.

		$ million
Future minimum lease payments	**2014**	2013
Payable within		
1 year	**5,401**	5,188
2 to 5 years	**9,916**	10,408
Thereafter	**3,468**	3,590
	18,785	19,186

In the case of an operating lease entered into by BP as the operator of a joint operation, the amounts included in the totals disclosed represent the net operating lease expense and net future minimum lease payments. These net amounts are after deducting amounts reimbursed, or to be reimbursed, by joint operators, whether the joint operators have co-signed the lease or not. Where BP is not the operator of a joint operation, BP's share of the lease expense and future minimum lease payments is included in the amounts shown, whether BP has co-signed the lease or not.

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

The group has entered into a number of structured operating leases for ships and in most cases the lease rental payments vary with market interest rates. The variable portion of the lease payments above or below the amount based on the market interest rate prevailing at inception of the lease is treated as contingent rental expense. The group also routinely enters into bareboat charters, time-charters and voyage-charters for ships on standard industry terms.

The most significant items of plant and machinery hired under operating leases are drilling rigs used in the Upstream segment. At 31 December 2014, the future minimum lease payments relating to drilling rigs amounted to $8,180 million (2013 $8,776 million).

Commercial vehicles hired under operating leases are primarily railcars. Retail service station sites and office accommodation are the main items in the land and buildings category.

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

27. Financial instruments and financial risk factors

The accounting classification of each category of financial instruments, and their carrying amounts, are set out below.

$ million

At 31 December 2014	Note	Loans and receivables	Available-for-sale financial assets	Held-to-maturity investments	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
Financial assets								
Other investments – equity shares	**16**	**–**	**420**	**–**	**–**	**–**	**–**	**420**
– other	**16**	**–**	**538**	**–**	**599**	**–**	**–**	**1,137**
Loans		**992**	**–**	**–**	**–**	**–**	**–**	**992**
Trade and other receivables	**18**	**30,551**	**–**	**–**	**–**	**–**	**–**	**30,551**
Derivative financial instruments	**28**	**–**	**–**	**–**	**8,511**	**1,096**	**–**	**9,607**
Cash and cash equivalents	**23**	**23,504**	**2,989**	**3,270**	**–**	**–**	**–**	**29,763**
Financial liabilities								
Trade and other payables	**20**	**–**	**–**	**–**	**–**	**–**	**(40,327)**	**(40,327)**
Derivative financial instruments	**28**	**–**	**–**	**–**	**(6,100)**	**(788)**	**–**	**(6,888)**
Accruals		**–**	**–**	**–**	**–**	**–**	**(7,963)**	**(7,963)**
Finance debt	**24**	**–**	**–**	**–**	**–**	**–**	**(52,854)**	**(52,854)**
		55,047	**3,947**	**3,270**	**3,010**	**308**	**(101,144)**	**(35,562)**

At 31 December 2013	Note	Loans and receivables	Available-for-sale financial assets	Held-to-maturity investments	At fair value through profit or loss	Derivative hedging instruments	Financial liabilities measured at amortized cost	Total carrying amount
Financial assets								
Other investments – equity shares	16	–	291	–	–	–	–	291
– other	16	–	1,167	–	574	–	–	1,741
Loans		979	–	–	–	–	–	979
Trade and other receivables	18	39,630	–	–	–	–	–	39,630
Derivative financial instruments	28	–	–	–	5,189	995	–	6,184
Cash and cash equivalents	23	19,153	2,267	1,100	–	–	–	22,520
Financial liabilities								
Trade and other payables	20	–	–	–	–	–	(48,072)	(48,072)
Derivative financial instruments	28	–	–	–	(4,159)	(388)	–	(4,547)
Accruals		–	–	–	–	–	(9,507)	(9,507)
Finance debt	24	–	–	–	–	–	(48,192)	(48,192)
		59,762	3,725	1,100	1,604	607	(105,771)	(38,973)

The fair value of finance debt is shown in Note 24. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

Financial risk factors

The group is exposed to a number of different financial risks arising from natural business exposures as well as its use of financial instruments including market risks relating to commodity prices, foreign currency exchange rates and interest rates; credit risk; and liquidity risk.

The group financial risk committee (GFRC) advises the group chief financial officer (CFO) who oversees the management of these risks. The GFRC is chaired by the CFO and consists of a group of senior managers including the group treasurer and the heads of the group finance, tax and the integrated supply and trading functions. The purpose of the committee is to advise on financial risks and the appropriate financial risk governance framework for the group. The committee provides assurance to the CFO and the group chief executive (GCE), and via the GCE to the board, that the group's financial risk-taking activity is governed by appropriate policies and procedures and that financial risks are identified, measured and managed in accordance with group policies and group risk appetite.

The group's trading activities in the oil, natural gas and power markets are managed within the integrated supply and trading function, while the activities in the financial markets are managed by the treasury function, working under the compliance and control structure of the integrated supply and trading function. All derivative activity is carried out by specialist teams that have the appropriate skills, experience and supervision. These teams are subject to close financial and management control.

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk, credit risk and operational risk associated with trading activity. A policy and risk committee monitors and validates limits and risk exposures, reviews incidents and validates risk-related policies, methodologies and procedures. A commitments committee approves value-at-risk delegations, the trading of new products, instruments and strategies and material commitments.

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

(a) Market risk

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

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

27. Financial instruments and financial risk factors – continued

(i) Commodity price risk

The group's integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes and pipeline positions available in the related commodity markets. Oil and natural gas swaps, options and futures are used to mitigate price risk. Power trading is undertaken using a combination of over-the-counter forward contracts and other derivative contracts, including options and futures. This activity is on both a standalone basis and in conjunction with gas derivatives in relation to gas-generated power margin. In addition, NGLs are traded around certain US inventory locations using over-the-counter forward contracts in conjunction with over-the-counter swaps, options and physical inventories.

The group measures market risk exposure arising from its trading positions in liquid periods using value-at-risk techniques. These techniques make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period. The value-at-risk measure is supplemented by stress testing. Trading activity occurring in liquid periods is subject to value-at-risk limits for each trading activity and for this trading activity in total. The board has delegated a limit of $100 million value at risk in support of this trading activity. Alternative measures are used to monitor exposures which are outside liquid periods and which cannot be actively risk-managed.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $214 million at 31 December 2014 (2013 liability of $652 million). For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or adverse change in each key assumption is less than $100 million in each case.

(ii) Foreign currency exchange risk

Where the group enters into foreign currency exchange contracts for entrepreneurial trading purposes the activity is controlled using trading value-at-risk techniques as explained above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have a significant effect on the group's reported results. The effects of most exchange rate fluctuations are absorbed in business operating results through changing cost competitiveness, lags in market adjustment to movements in rates and translation differences accounted for on specific transactions. For this reason, the total effect of exchange rate fluctuations is not identifiable separately in the group's reported results. The main underlying economic currency of the group's cash flows is the US dollar. This is because BP's major product, oil, is priced internationally in US dollars. BP's foreign currency exchange management policy is to limit economic and material transactional exposures arising from currency movements against the US dollar. The group co-ordinates the handling of foreign currency exchange risks centrally, by netting off naturally-occurring opposite exposures wherever possible, and then managing any material residual foreign currency exchange risks.

The group manages these exposures by constantly reviewing the foreign currency economic value at risk and aims to manage such risk to keep the 12-month foreign currency value at risk below $400 million. At no point over the past three years did the value at risk exceed the maximum risk limit. The most significant exposures relate to capital expenditure commitments and other UK and European operational requirements, for which a hedging programme is in place and hedge accounting is claimed as outlined in Note 28.

For highly probable forecast capital expenditures the group locks in the US dollar cost of non-US dollar supplies by using currency forwards and futures. The main exposures are sterling, euro, Norwegian krone, Australian dollar and Korean won. At 31 December 2014 the most significant open contracts in place were for $321 million sterling (2013 $723 million sterling).

For other UK, European and Australian operational requirements the group uses cylinders (purchased call and sold put options) to manage the estimated exposures on a 12-month rolling basis. At 31 December 2014, the open positions relating to cylinders consisted of receive sterling, pay US dollar cylinders for $2,787 million (2013 $2,770 million); receive euro, pay US dollar cylinders for $867 million (2013 $962 million); receive Australian dollar, pay US dollar cylinders for $418 million (2013 $401 million).

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2014, the total foreign currency net borrowings not swapped into US dollars amounted to $871 million (2013 $665 million).

(iii) Interest rate risk

Where the group enters into money market contracts for entrepreneurial trading purposes the activity is controlled using value-at-risk techniques as described above.

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt. While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a floating rate exposure, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps at 31 December 2014 was 71% of total finance debt outstanding (2013 65%). The weighted average interest rate on finance debt at 31 December 2014 was 2% (2013 2%) and the weighted average maturity of fixed rate debt was four years (2013 four years).

The group's earnings are sensitive to changes in interest rates on the floating rate element of the group's finance debt. If the interest rates applicable to floating rate instruments were to have increased by one percentage point on 1 January 2015, it is estimated that the group's finance costs for 2015 would increase by approximately $377 million (2013 $312 million increase).

(b) Credit risk

Credit risk is the risk that a customer or counterparty to a financial instrument will fail to perform or fail to pay amounts due causing financial loss to the group and arises from cash and cash equivalents, derivative financial instruments and deposits with financial institutions and principally from credit exposures to customers relating to outstanding receivables. Credit exposure also exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2014 were $83 million (2013 $199 million) in respect of liabilities of joint ventures and associates and $244 million (2013 $305 million) in respect of liabilities of other third parties.

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

27. Financial instruments and financial risk factors – continued

The maximum credit exposure associated with financial assets is equal to the carrying amount. The group does not aim to remove credit risk entirely but expects to experience a certain level of credit losses. As at 31 December 2014, the group had in place credit enhancements designed to mitigate approximately $10.8 billion of credit risk (2013 $13 billion). Reports are regularly prepared and presented to the GFRC that cover the group's overall credit exposure and expected loss trends, exposure by segment, and overall quality of the portfolio.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2014 it is estimated that over 70% (2013 over 80%) of the unmitigated credit exposure is to counterparties of investment grade credit quality.

For cash and cash equivalents, the treasury function dynamically manages bank deposit limits to ensure cash is well-diversified and to reduce concentration risks. At 31 December 2014, 89% of the cash and cash equivalents balance was deposited with financial institutions rated at least A- by Standard & Poor's Rating Services and Fitch Ratings, and A3 by Moody's Investors Service. Of the total cash and cash equivalents at year end, $8,184 million was held in collateralised tri-partite repurchase agreements. The collateral is held by third-party custodians and would only be released to BP in the event of repayment default by the borrower.

Trade and other receivables classified as financial assets are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 75-85% (2013 approximately 70-80%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality.

		$ million
Trade and other receivables at 31 December	**2014**	2013
Neither impaired nor past due	**28,519**	37,201
Impaired (net of provision)	**37**	27
Not impaired and past due in the following periods		
within 30 days	**841**	1,054
31 to 60 days	**249**	249
61 to 90 days	**178**	216
over 90 days	**727**	883
	30,551	39,630

Movements in the impairment provision for trade receivables are shown in Note 19.

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

The following table shows the gross amounts of recognized financial assets and liabilities (i.e. before offsetting) and the amounts offset in the balance sheet.

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

						$ million
				Related amounts not set off in the balance sheet		
At 31 December 2014	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	**11,515**	**(2,383)**	**9,132**	**(1,164)**	**(458)**	**7,510**
Derivative liabilities	**(8,971)**	**2,383**	**(6,588)**	**1,164**	**–**	**(5,424)**
Trade receivables	**10,502**	**(6,080)**	**4,422**	**(485)**	**(145)**	**3,792**
Trade payables	**(9,062)**	**6,080**	**(2,982)**	**485**	**–**	**(2,497)**
At 31 December 2013						
Derivative assets	7,271	(1,563)	5,708	(344)	(231)	5,133
Derivative liabilities	(5,457)	1,563	(3,894)	344	–	(3,550)
Trade receivables	11,034	(7,744)	3,290	(1,287)	(264)	1,739
Trade payables	(10,619)	7,744	(2,875)	1,287	–	(1,588)

(c) Liquidity risk

Liquidity risk is the risk that suitable sources of funding for the group's business activities may not be available. The group's liquidity is managed centrally with operating units forecasting their cash and currency requirements to the central treasury function. Unless restricted by local regulations, subsidiaries pool their cash surpluses to treasury, which will then arrange to fund other subsidiaries' requirements, or invest any net surplus in the market or arrange for necessary external borrowings, while managing the group's overall net currency positions.

Standard & Poor's Rating Services changed BP's long-term credit rating to A (negative outlook) from A (positive outlook) and Moody's Investors Service rating changed to A2 (negative outlook) from A2 (stable outlook) during 2014.

During 2014, $11.8 billion of long-term taxable bonds were issued with terms ranging from 5 to 12 years. Commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, amounting to $29.8 billion at 31 December 2014 (2013 $22.5 billion), primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice. At 31 December 2014, the group had substantial amounts of undrawn borrowing facilities available, consisting of $7,375 million of standby facilities, of which $6,975 million is available to draw and repay until the first half of 2018, and $400 million is available to draw and repay until April 2016. These facilities were renegotiated during 2013 with 26 international banks, and borrowings under them would be at pre-agreed rates.

The group also has committed letter of credit (LC) facilities totalling $7,150 million with a number of banks, allowing LCs to be issued for a maximum two-year duration. There were also uncommitted secured LC facilities in place at 31 December 2014 for $2,410 million, which are secured against inventories or receivables when utilized. The facilities only terminate by either party giving a stipulated termination notice to the other.

27. Financial instruments and financial risk factors – continued

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

								$ million
				2014				2013
	Trade and other payables	**Accruals**	**Finance debt**	**Interest relating to finance debt**	Trade and other payables	Accruals	Finance debt	Interest relating to finance debt
Within one year	**37,342**	**7,102**	**6,877**	**892**	43,790	8,960	7,381	885
1 to 2 years	**708**	**493**	**6,311**	**776**	1,007	207	6,630	752
2 to 3 years	**757**	**119**	**5,652**	**672**	822	66	6,720	621
3 to 4 years	**1,446**	**76**	**5,226**	**578**	761	73	5,828	498
4 to 5 years	**23**	**41**	**6,056**	**479**	1,405	37	5,279	388
5 to 10 years	**24**	**95**	**19,504**	**1,111**	207	113	15,933	809
Over 10 years	**27**	**37**	**3,228**	**521**	80	51	421	119
	40,327	**7,963**	**52,854**	**5,029**	48,072	9,507	48,192	4,072

The group manages liquidity risk associated with derivative contracts, other than derivative hedging instruments, based on the expected maturities of both derivative assets and liabilities as indicated in Note 28. Management does not currently anticipate any cash flows that could be of a significantly different amount, or could occur earlier than the expected maturity analysis provided.

The table below shows cash outflows for derivative hedging instruments based upon contractual payment dates. The amounts reflect the maturity profile of the fair value liability where the instruments will be settled net, and the gross settlement amount where the pay leg of a derivative will be settled separately from the receive leg, as in the case of cross-currency swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement-day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts (inflows) for the receive leg of derivatives that are settled separately from the pay leg, which amount to $14,615 million at 31 December 2014 (2013 $12,222 million) to be received on the same day as the related cash outflows.

		$ million
	2014	2013
Within one year	**293**	1,095
1 to 2 years	**2,959**	293
2 to 3 years	**2,690**	2,959
3 to 4 years	**1,505**	2,577
4 to 5 years	**1,700**	1,505
5 to 10 years	**5,764**	3,835
Over 10 years	**1,325**	–
	16,236	12,264

28. Derivative financial instruments

In the normal course of business the group enters into derivative financial instruments (derivatives) to manage its normal business exposures in relation to commodity prices, foreign currency exchange rates and interest rates, including management of the balance between floating rate and fixed rate debt, consistent with risk management policies and objectives. An outline of the group's financial risks and the objectives and policies pursued in relation to those risks is set out in Note 27. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

For information on significant estimates and judgements made in relation to the application of hedge accounting and the valuation of derivatives see Derivative financial instruments within Note 1.

The fair values of derivative financial instruments at 31 December are set out below.

Exchange traded derivatives are valued using closing prices provided by the exchange as at the balance sheet date. These derivatives are categorized within level 1 of the fair value hierarchy. Over-the-counter (OTC) financial swaps and physical commodity sale and purchase contracts are generally valued using readily available information in the public markets and quotations provided by brokers and price index developers. These quotes are corroborated with market data and are categorized within level 2 of the fair value hierarchy.

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

28. Derivative financial instruments – continued

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

				$ million
		2014		2013
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**122**	**(902)**	192	(111)
Oil price derivatives	**3,133**	**(1,976)**	810	(806)
Natural gas price derivatives	**3,859**	**(2,518)**	2,840	(2,029)
Power price derivatives	**922**	**(404)**	871	(560)
Other derivatives	**389**	**–**	475	–
	8,425	**(5,800)**	5,188	(3,506)
Embedded derivatives				
Commodity price contracts	**86**	**(300)**	1	(653)
	86	**(300)**	1	(653)
Cash flow hedges				
Currency forwards, futures and cylinders	**1**	**(161)**	129	(30)
Cross-currency interest rate swaps	**–**	**(97)**	–	(69)
	1	**(258)**	129	(99)
Fair value hedges				
Currency forwards, futures and swaps	**78**	**(518)**	340	(154)
Interest rate swaps	**1,017**	**(12)**	526	(135)
	1,095	**(530)**	866	(289)
	9,607	**(6,888)**	6,184	(4,547)
Of which – current	**5,165**	**(3,689)**	2,675	(2,322)
– non-current	**4,442**	**(3,199)**	3,509	(2,225)

Derivatives held for trading

The group maintains active trading positions in a variety of derivatives. The contracts may be entered into for risk management purposes, to satisfy supply requirements or for entrepreneurial trading. Certain contracts are classified as held for trading, regardless of their original business objective, and are recognized at fair value with changes in fair value recognized in the income statement. Trading activities are undertaken by using a range of contract types in combination to create incremental gains by arbitraging prices between markets, locations and time periods. The net of these exposures is monitored using market value-at-risk techniques as described in Note 27.

The following tables show further information on the fair value of derivatives and other financial instruments held for trading purposes.

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

							$ million
							2014
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Currency derivatives	**120**	**–**	**2**	**–**	**–**	**–**	**122**
Oil price derivatives	**2,434**	**416**	**185**	**63**	**31**	**4**	**3,133**
Natural gas price derivatives	**1,991**	**644**	**261**	**202**	**160**	**601**	**3,859**
Power price derivatives	**488**	**203**	**87**	**50**	**39**	**55**	**922**
Other derivatives	**70**	**97**	**161**	**61**	**–**	**–**	**389**
	5,103	**1,360**	**696**	**376**	**230**	**660**	**8,425**

							$ million
							2013
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	143	–	21	–	–	28	192
Oil price derivatives	694	78	23	13	2	–	810
Natural gas price derivatives	1,034	526	334	192	154	600	2,840
Power price derivatives	528	202	81	22	8	30	871
Other derivatives	102	–	93	147	66	67	475
	2,501	806	552	374	230	725	5,188

At both 31 December 2014 and 2013 the group had contingent consideration receivable in respect of a business disposal. The sale agreement contained an embedded derivative – the whole agreement has, consequently, been designated at fair value through profit or loss and shown within other derivatives held for trading, and falls within level 3 of the fair value hierarchy. The valuation depends on refinery throughput and future margins.

28. Derivative financial instruments – continued

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

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2014
Currency derivatives	**(69)**	**(180)**	**(1)**	**(1)**	**(192)**	**(459)**	**(902)**
Oil price derivatives	**(1,714)**	**(186)**	**(61)**	**(8)**	**(6)**	**(1)**	**(1,976)**
Natural gas price derivatives	**(1,310)**	**(292)**	**(144)**	**(117)**	**(99)**	**(556)**	**(2,518)**
Power price derivatives	**(217)**	**(127)**	**(39)**	**(10)**	**(4)**	**(7)**	**(404)**
	(3,310)	**(785)**	**(245)**	**(136)**	**(301)**	**(1,023)**	**(5,800)**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2013
Currency derivatives	(111)	–	–	–	–	–	(111)
Oil price derivatives	(620)	(100)	(42)	(31)	(13)	–	(806)
Natural gas price derivatives	(778)	(319)	(157)	(110)	(102)	(563)	(2,029)
Power price derivatives	(400)	(99)	(48)	(13)	–	–	(560)
	(1,909)	(518)	(247)	(154)	(115)	(563)	(3,506)

The following table shows the fair value of derivative assets and derivative liabilities held for trading, analysed by maturity period and by methodology of fair value estimation. This information is presented on a gross basis, that is, before netting by counterparty.

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2014
Fair value of derivative assets							
Level 1	**170**	**–**	**–**	**–**	**–**	**–**	**170**
Level 2	**6,388**	**1,353**	**354**	**130**	**71**	**20**	**8,316**
Level 3	**483**	**374**	**409**	**255**	**159**	**642**	**2,322**
	7,041	**1,727**	**763**	**385**	**230**	**662**	**10,808**
Less: netting by counterparty	**(1,938)**	**(367)**	**(67)**	**(9)**	**–**	**(2)**	**(2,383)**
	5,103	**1,360**	**696**	**376**	**230**	**660**	**8,425**
Fair value of derivative liabilities							
Level 1	**(37)**	**–**	**–**	**–**	**–**	**–**	**(37)**
Level 2	**(4,905)**	**(1,017)**	**(197)**	**(45)**	**(202)**	**(488)**	**(6,854)**
Level 3	**(306)**	**(135)**	**(115)**	**(100)**	**(99)**	**(537)**	**(1,292)**
	(5,248)	**(1,152)**	**(312)**	**(145)**	**(301)**	**(1,025)**	**(8,183)**
Less: netting by counterparty	**1,938**	**367**	**67**	**9**	**–**	**2**	**2,383**
	(3,310)	**(785)**	**(245)**	**(136)**	**(301)**	**(1,023)**	**(5,800)**
Net fair value	**1,793**	**575**	**451**	**240**	**(71)**	**(363)**	**2,625**

	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
							$ million
							2013
Fair value of derivative assets							
Level 1	100	–	–	–	–	–	100
Level 2	3,118	981	399	83	20	30	4,631
Level 3	389	183	252	291	210	695	2,020
	3,607	1,164	651	374	230	725	6,751
Less: netting by counterparty	(1,106)	(358)	(99)	–	–	–	(1,563)
	2,501	806	552	374	230	725	5,188
Fair value of derivative liabilities							
Level 1	(87)	–	–	–	–	–	(87)
Level 2	(2,790)	(733)	(215)	(36)	(15)	(31)	(3,820)
Level 3	(138)	(143)	(131)	(118)	(100)	(532)	(1,162)
	(3,015)	(876)	(346)	(154)	(115)	(563)	(5,069)
Less: netting by counterparty	1,106	358	99	–	–	–	1,563
	(1,909)	(518)	(247)	(154)	(115)	(563)	(3,506)
Net fair value	592	288	305	220	115	162	1,682

28. Derivative financial instruments – continued

Level 3 derivatives

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

$ million

	Oil price	**Natural gas price**	**Power price**	**Other**	**Total**
Net fair value of contracts at 1 January 2014	**(18)**	**313**	**86**	**475**	**856**
Gains recognized in the income statement	**350**	**152**	**141**	**94**	**737**
Settlements	**(86)**	**(56)**	**(13)**	**(180)**	**(335)**
Transfers out of level 3	**–**	**(228)**	**–**	**–**	**(228)**
Net fair value of contracts at 31 December 2014	**246**	**181**	**214**	**389**	**1,030**

$ million

	Oil price	Natural gas price	Power price	Other	Total
Net fair value of contracts at 1 January 2013	105	304	(43)	71	437
Gains (losses) recognized in the income statement	(47)	62	81	–	96
Purchases	110	1	–	–	111
New contracts	–	–	–	475	475
Settlements	(143)	(52)	10	(71)	(256)
Transfers out of level 3	(43)	(1)	36	–	(8)
Exchange adjustments	–	(1)	2	–	1
Net fair value of contracts at 31 December 2013	(18)	313	86	475	856

The amount recognized in the income statement for the year relating to level 3 held for trading derivatives still held at 31 December 2014 was a $456 million gain (2013 $110 million gain related to derivatives still held at 31 December 2013).

The most significant gross assets and liabilities categorized in level 3 of the fair value hierarchy are US natural gas contracts. At 31 December 2014, the gross US natural gas price instruments dependent on inputs at level 3 of the fair value hierarchy were an asset of $586 million and liability of $526 million (net fair value of $60 million), with $126 million, net, valued using level 2 inputs. US natural gas price derivatives are valued using observable market data for maturities up to 60 months in basis locations that trade at a premium or discount to the NYMEX Henry Hub price, and using internally developed price curves based on economic forecasts for periods beyond that time. The significant unobservable inputs for fair value measurements categorized within level 3 of the fair value hierarchy for the year ended 31 December 2014 are presented below.

	Unobservable inputs	**Range $/mmBtu**	**Weighted average $/mmBtu**
Natural gas price contracts	Long-dated market price	3.44-6.39	4.64

If the natural gas prices after 2019 were 10% higher (lower), this would result in a decrease (increase) in derivative assets of $85 million, and decrease (increase) in derivative liabilities of $64 million, and a net decrease (increase) in profit before tax of $21 million.

Derivative gains and losses

Gains and losses relating to derivative contracts are included within sales and other operating revenues and within purchases in the income statement depending upon the nature of the activity and type of contract involved. The contract types treated in this way include futures, options, swaps and certain forward sales and forward purchases contracts, and relate to both currency and commodity trading activities. Gains or losses arise on contracts entered into for risk management purposes, optimization activity and entrepreneurial trading. They also arise on certain contracts that are for normal procurement or sales activity for the group but that are required to be fair valued under accounting standards. Also included within sales and other operating revenues are gains and losses on inventory held for trading purposes. The total amount relating to all these items (excluding gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases) was a net gain of $6,154 million (2013 $587 million net gain and 2012 $411 million net loss). This number does not include gains and losses on realized physical derivative contracts that have been reflected gross in the income statement within sales and purchases or the change in value of transportation and storage contracts which are not recognized under IFRS, but does include the associated financially settled contracts. The net amount for actual gains and losses relating to derivative contracts and all related items therefore differs significantly from the amount disclosed above.

Embedded derivatives

The group is a party to certain natural gas contracts containing embedded derivatives. Prior to the development of an active gas trading market, UK gas contracts were priced using a basket of available price indices, primarily relating to oil products, power and inflation. After the development of an active UK gas market, certain contracts were entered into or renegotiated using pricing formulae not directly related to gas prices, for example, oil product and power prices. In these circumstances, pricing formulae have been determined to be derivatives, embedded within the overall contractual arrangements that are not clearly and closely related to the underlying commodity. The resulting fair value relating to these contracts is recognized on the balance sheet with gains or losses recognized in the income statement.

Key information on the natural gas contracts is given below.

At 31 December	**2014**	2013
Remaining contract terms	**5 months to 3 years and 9 months**	1 year and 5 months to 4 years and 9 months
Contractual/notional amount	**70 million therms**	153 million therms

28. Derivative financial instruments – continued

The commodity price embedded derivatives relate to natural gas contracts and are categorized in levels 2 and 3 of the fair value hierarchy. The contracts in level 2 are valued using inputs that include price curves for each of the different products that are built up from active market pricing data. Where necessary, the price curves are extrapolated to the expiry of the contracts (the last of which is in 2018) using all available external pricing information; additionally, where limited data exists for certain products, prices are interpolated using historical and long-term pricing relationships. These valuations are categorized in level 3. Transfers from level 3 to level 2 occur when the valuation no longer depends significantly on extrapolated or interpolated data. Valuations use observable market data for maturities up to 36 months, and internally developed price curves based on economic forecasts for periods beyond that time.

The fair value gain on commodity price embedded derivatives was $430 million (2013 gain of $459 million, 2012 gain of $347 million).

The following table shows the changes during the year in the net fair value of embedded derivatives, within level 3 of the fair value hierarchy.

		$ million
	2014	2013
	Commodity price	Commodity price
Net fair value of contracts at 1 January	**(379)**	(1,112)
Settlements	**24**	316
Gains recognized in the income statement	**219**	142
Transfers out of level 3	**–**	258
Exchange adjustments	**10**	17
Net fair value of contracts at 31 December	**(126)**	(379)

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2014 was a $220 million gain (2013 $67 million gain related to derivatives still held at 31 December 2013).

Cash flow hedges

At 31 December 2014, the group held currency forwards and futures contracts and cylinders that were being used to hedge the foreign currency risk of highly probable forecast transactions. Note 27 outlines the group's approach to foreign currency exchange risk management. For cash flow hedges the group only claims hedge accounting for the intrinsic value on the currency with any fair value attributable to time value taken immediately to the income statement. The amounts remaining in equity at 31 December 2014 in relation to these cash flow hedges consist of deferred losses of $160 million maturing in 2015, deferred losses of $10 million maturing in 2016 and deferred gains of $3 million maturing in 2017 and beyond.

At 31 December 2012, BP had entered into three agreements to sell its 50% interest in TNK-BP and acquire 18.5% of Rosneft. During the period from signing until completion on 21 March 2013, these agreements represented derivative financial instruments that were required to be measured at fair value. BP designated two of the agreements, for the acquisition of a 5.66% shareholding in Rosneft from Rosneftegaz, and for the acquisition of a 9.80% shareholding from Rosneft, as hedging instruments in a cash flow hedge, and so changes in the fair values of these agreements were recognized in other comprehensive income. The third agreement, under which BP sold its 50% interest in TNK-BP in exchange for cash and a 3.04% shareholding in Rosneft, was also a derivative financial instrument, but its fair value could not be reliably measured. An asset of $1,410 million related to these agreements was recognized on the balance sheet at 31 December 2012, of which $1,339 million related to the fair value of the cash flow hedge derivatives. The derivatives measured at fair value at 31 December 2012 were categorized in level 3 of the fair value hierarchy using inputs that included the quoted Rosneft share price. During 2013, a charge of $2,061 million was recognized in other comprehensive income in relation to these agreements and $4 million was recognized in the income statement. The resulting cumulative charge of $651 million recognized in other comprehensive income would only be recognized in the income statement if the investment in Rosneft were either sold or impaired. The cash flow hedge derivatives were valued using the quoted Rosneft share price at the time the deal completed, of $7.60 per share.

Fair value hedges

At 31 December 2014, the group held interest rate and cross-currency interest rate swap contracts as fair value hedges of the interest rate risk on fixed rate debt issued by the group. The loss on the hedging derivative instruments recognized in the income statement in 2014 was $14 million (2013 $1,240 million loss and 2012 $536 million gain) offset by a gain on the fair value of the finance debt of $8 million (2013 $1,228 million gain and 2012 $537 million loss).

The interest rate and cross-currency interest rate swaps mature within one to twelve years, and have the same maturity terms as the debt that they are hedging. They are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar, Norwegian Krone and Hong Kong dollar denominated fixed rate borrowings into floating rate debt. Note 27 outlines the group's approach to interest rate and foreign currency exchange risk management.

29. Called-up share capital

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

	2014		2013		2012	
Issued	**Shares thousand**	**$ million**	Shares thousand	$ million	Shares thousand	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9	5,473	9
		21		21		21
Ordinary shares of 25 cents each						
At 1 January	**20,426,632**	**5,108**	20,959,159	5,240	20,813,410	5,203
Issue of new shares for the scrip dividend programme	**165,644**	**41**	202,124	51	138,406	35
Issue of new shares for employee share-based payment plans[b]	**25,598**	**6**	18,203	5	7,343	2
Repurchase of ordinary share capital[c]	**(611,913)**	**(153)**	(752,854)	(188)	–	–
At 31 December	**20,005,961**	**5,002**	20,426,632	5,108	20,959,159	5,240
		5,023		5,129		5,261

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.
[b] Consideration received relating to the issue of new shares for employee share-based payment plans amounted to $207 million (2013 $116 million and 2012 $47 million).
[c] Purchased for a total consideration of $4,796 million, including transaction costs of $26 million (2013 $5,493 million, including transaction costs of $30 million). All shares purchased were for cancellation. The repurchased shares represented 3% of ordinary share capital.

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

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

In 2014, the company completed the $8-billion share repurchase programme announced on 22 March 2013 and further continuation of share buybacks was announced on 29 April 2014. During the year, the company repurchased 612 million ordinary shares at a cost of $4,770 million (2013 753 million ordinary shares at a cost of $5,463 million). The number of shares in issue is reduced when shares are repurchased, but is not reduced in respect of the year-end commitment to repurchase shares subsequent to the end of the year, for which an amount of $nil has been accrued at 31 December 2014 (2013 $1,430 million).

Treasury shares[a]

	2014		2013		2012	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,787,939**	**447**	1,823,408	455	1,837,508	459
Shares re-issued for employee share-based payment plans	**(16,836)**	**(4)**	(35,469)	(8)	(14,100)	(4)
At 31 December	**1,771,103**	**443**	1,787,939	447	1,823,408	455

[a] Excluding shares held by ESOPs, see Note 30 for more information.

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 8.8% (2013 8.7% and 2012 8.8%) of the called-up ordinary share capital of the company.

During 2014, the movement in treasury shares represented less than 0.1% (2013 less than 0.2% and 2012 less than 0.1%) of the ordinary share capital of the company.

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30. Capital and reserves

	Share capital	**Share premium account**	**Capital redemption reserve**	**Merger reserve**	**Total share capital and capital reserves**
At 1 January 2014	**5,129**	**10,061**	**1,260**	**27,206**	**43,656**
Profit for the year	**–**	**–**	**–**	**–**	**–**
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)[a]	**–**	**–**	**–**	**–**	**–**
Cash flow hedges (including recycling)	**–**	**–**	**–**	**–**	**–**
Share of items relating to equity-accounted entities, net of tax[a]	**–**	**–**	**–**	**–**	**–**
Other	**–**	**–**	**–**	**–**	**–**
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	**–**	**–**	**–**	**–**	**–**
Share of items relating to equity-accounted entities, net of tax	**–**	**–**	**–**	**–**	**–**
Total comprehensive income	**–**	**–**	**–**	**–**	**–**
Dividends	**41**	**(41)**	**–**	**–**	**–**
Repurchases of ordinary share capital	**(153)**	**–**	**153**	**–**	**–**
Share-based payments, net of tax[b]	**6**	**240**	**–**	**–**	**246**
Share of equity-accounted entities' changes in equity, net of tax	**–**	**–**	**–**	**–**	**–**
Transactions involving non-controlling interests	**–**	**–**	**–**	**–**	**–**
At 31 December 2014	**5,023**	**10,260**	**1,413**	**27,206**	**43,902**

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2013	5,261	9,974	1,072	27,206	43,513
Profit for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Other	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	51	(51)	–	–	–
Repurchases of ordinary share capital	(188)	–	188	–	–
Share-based payments, net of tax[b]	5	138	–	–	143
Share of equity-accounted entities' changes in equity, net of tax	–	–	–	–	–
Transactions involving non-controlling interests	–	–	–	–	–
At 31 December 2013	5,129	10,061	1,260	27,206	43,656

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2012	5,224	9,952	1,072	27,206	43,454
Profit for the year	–	–	–	–	–
Items that may be reclassified subsequently to profit or loss					
Currency translation differences (including recycling)	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Other	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	–	–	–	–	–
Share of items relating to equity-accounted entities, net of tax	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	35	(35)	–	–	–
Share-based payments, net of tax[b]	2	57	–	–	59
Transactions involving non-controlling interests	–	–	–	–	–
At 31 December 2012	5,261	9,974	1,072	27,206	43,513

[a] Principally affected by a weakening of the Russian rouble compared to the US dollar.
[b] Includes new share issues and movements in treasury shares where these relate to employee share-based payment plans.

$ million

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(20,971)	3,525	–	(695)	(695)	103,787	129,302	1,105	130,407
–	–	–	–	–	3,780	3,780	223	4,003
–	(6,934)	1	–	1	–	(6,933)	(32)	(6,965)
–	–	–	(203)	(203)	–	(203)	–	(203)
–	–	–	–	–	(2,584)	(2,584)	–	(2,584)
–	–	–	–	–	289	289	–	289
–	–	–	–	–	(3,256)	(3,256)	–	(3,256)
–	–	–	–	–	4	4	–	4
–	(6,934)	1	(203)	(202)	(1,767)	(8,903)	191	(8,712)
–	–	–	–	–	(5,850)	(5,850)	(255)	(6,105)
–	–	–	–	–	(3,366)	(3,366)	–	(3,366)
252	–	–	–	–	(313)	185	–	185
–	–	–	–	–	73	73	–	73
–	–	–	–	–	–	–	160	160
(20,719)	(3,409)	1	(898)	(897)	92,564	111,441	1,201	112,642

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(21,054)	5,128	685	1,090	1,775	89,184	118,546	1,206	119,752
–	–	–	–	–	23,451	23,451	307	23,758
–	(1,603)	–	–	–	–	(1,603)	(15)	(1,618)
–	–	(685)	–	(685)	–	(685)	–	(685)
–	–	–	(1,785)	(1,785)	–	(1,785)	–	(1,785)
–	–	–	–	–	(24)	(24)	–	(24)
–	–	–	–	–	(25)	(25)	–	(25)
–	–	–	–	–	3,243	3,243	–	3,243
–	–	–	–	–	2	2	–	2
–	(1,603)	(685)	(1,785)	(2,470)	26,647	22,574	292	22,866
–	–	–	–	–	(5,441)	(5,441)	(469)	(5,910)
–	–	–	–	–	(6,923)	(6,923)	–	(6,923)
83	–	–	–	–	247	473	–	473
–	–	–	–	–	73	73	–	73
–	–	–	–	–	–	–	76	76
(20,971)	3,525	–	(695)	(695)	103,787	129,302	1,105	130,407

Treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(21,323)	4,509	389	(122)	267	84,661	111,568	1,017	112,585
–	–	–	–	–	11,017	11,017	234	11,251
–	619	–	(5)	(5)	–	614	2	616
–	–	296	–	296	–	296	–	296
–	–	–	1,217	1,217	–	1,217	–	1,217
–	–	–	–	–	(39)	(39)	–	(39)
–	–	–	–	–	23	23	–	23
–	–	–	–	–	(1,134)	(1,134)	2	(1,132)
–	–	–	–	–	(6)	(6)	–	(6)
–	619	296	1,212	1,508	9,861	11,988	238	12,226
–	–	–	–	–	(5,294)	(5,294)	(82)	(5,376)
269	–	–	–	–	(44)	284	–	284
–	–	–	–	–	–	–	33	33
(21,054)	5,128	685	1,090	1,775	89,184	118,546	1,206	119,752

30. Capital and reserves – continued

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

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

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

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

Treasury shares
Treasury shares represent BP shares repurchased and available for specific and limited purposes.

For accounting purposes shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans are treated in the same manner as treasury shares and are therefore included in the financial statements as treasury shares. The ESOPs are funded by the group and have waived their rights to dividends in respect of such shares held for future awards. Until such time as the shares held by the ESOPs vest unconditionally to employees, the amount paid for those shares is shown as a reduction in shareholders' equity. Assets and liabilities of the ESOPs are recognized as assets and liabilities of the group.

At 31 December 2014, the ESOPs held 34,169,554 shares (2013 32,748,354 shares and 2012 22,428,179 shares) for potential future awards, which had a market value of $219 million (2013 $253 million and 2012 $154 million). At 31 December 2014, a further 6,024,978 ordinary share equivalents (2013 12,856,914 ordinary share equivalents) were held by the group in the form of ADSs to meet the requirements of employee share-based payment plans in the US.

Foreign currency translation reserve
The foreign currency translation reserve records exchange differences arising from the translation of the financial statements of foreign operations. Upon disposal of foreign operations, the related accumulated exchange differences are recycled to the income statement.

Available-for-sale investments
This reserve records the changes in fair value of available-for-sale investments except for impairment losses, foreign exchange gains or losses, or changes arising from revised estimates of future cash flows. On disposal or impairment of the investments, the cumulative changes in fair value are recycled to the income statement.

Cash flow hedges
This reserve records the portion of the gain or loss on a hedging instrument in a cash flow hedge that is determined to be an effective hedge. For further information see Note 1 – Derivative financial instruments and hedging activities.

Profit and loss account
The balance held on this reserve is the accumulated retained profits of the group.

30. Capital and reserves – continued

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

			$ million
			2014
	Pre-tax	**Tax**	**Net of tax**
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	**(6,787)**	**(178)**	**(6,965)**
Cash flow hedges (including recycling)	**(239)**	**36**	**(203)**
Share of items relating to equity-accounted entities, net of tax	**(2,584)**	**–**	**(2,584)**
Other	**–**	**289**	**289**
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	**(4,590)**	**1,334**	**(3,256)**
Share of items relating to equity-accounted entities, net of tax	**4**	**–**	**4**
Other comprehensive income	**(14,196)**	**1,481**	**(12,715)**

			$ million
			2013
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	(1,586)	(32)	(1,618)
Available-for-sale investments (including recycling)	(695)	10	(685)
Cash flow hedges (including recycling)	(1,979)	194	(1,785)
Share of items relating to equity-accounted entities, net of tax	(24)	–	(24)
Other	–	(25)	(25)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	4,764	(1,521)	3,243
Share of items relating to equity-accounted entities, net of tax	2	–	2
Other comprehensive income	482	(1,374)	(892)

			$ million
			2012
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	470	146	616
Available-for-sale investments (including recycling)	305	(9)	296
Cash flow hedges (including recycling)	1,547	(330)	1,217
Share of items relating to equity-accounted entities, net of tax	(39)	–	(39)
Other	–	23	23
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	(1,572)	440	(1,132)
Share of items relating to equity-accounted entities, net of tax	(6)	–	(6)
Other comprehensive income	705	270	975

31. Contingent liabilities

Contingent liabilities related to the Gulf of Mexico oil spill

Details of contingent liabilities related to the Gulf of Mexico oil spill are set out in Note 2.

Contingent liabilities not related to the Gulf of Mexico oil spill

There were contingent liabilities at 31 December 2014 in respect of guarantees and indemnities entered into as part of the ordinary course of the group's business. No material losses are likely to arise from such contingent liabilities. Further information is included in Note 27.

Lawsuits arising out of the Exxon Valdez oil spill in Prince William Sound, Alaska, in March 1989 were filed against Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP's combination with Atlantic Richfield Company (Atlantic Richfield). Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that Exxon has incurred. BP will defend any such claims vigorously. It is not possible to estimate any financial effect.

In the normal course of the group's business, legal proceedings are pending or may be brought against BP group entities arising out of current and past operations, including matters related to commercial disputes, product liability, antitrust, commodities trading, premises-liability claims, consumer protection, general environmental claims and allegations of exposures of third parties to toxic substances, such as lead pigment in paint, asbestos and other chemicals. BP believes that the impact of these legal proceedings on the group's results of operations, liquidity or financial position will not be material.

With respect to lead pigment in paint in particular, Atlantic Richfield, a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property. Although it is not possible to predict the outcome of the legal proceedings, Atlantic Richfield believes it has valid defences that render the incurrence of a liability remote; however, the amounts claimed and the costs of implementing the remedies sought in the various cases could be substantial. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. Atlantic Richfield intends to defend such actions vigorously.

31. Contingent liabilities – continued

The group files tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group's tax returns. Tax returns contain matters that could be subject to differing interpretations of applicable tax laws and regulations and the resolution of tax positions through negotiations with relevant tax authorities, or through litigation, can take several years to complete. While it is difficult to predict the ultimate outcome in some cases, the group does not anticipate that there will be any material impact upon the group's results of operations, financial position or liquidity.

The group is subject to numerous national and local environmental laws and regulations concerning its products, operations and other activities. These laws and regulations may require the group to take future action to remediate the effects on the environment of prior disposal or release of chemicals or petroleum substances by the group or other parties. Such contingencies may exist for various sites including refineries, chemical plants, oil fields, service stations, terminals and waste disposal sites. In addition, the group may have obligations relating to prior asset sales or closed facilities. The ultimate requirement for remediation and its cost are inherently difficult to estimate. However, the estimated cost of known environmental obligations has been provided in these accounts in accordance with the group's accounting policies. While the amounts of future costs that are not provided for could be significant and could be material to the group's results of operations in the period in which they are recognized, it is not possible to estimate the amounts involved. BP does not expect these costs to have a material effect on the group's financial position or liquidity.

If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations it is possible that, in certain circumstances, BP could be partially or wholly responsible for decommissioning. Furthermore, as described in Provisions, contingencies and reimbursement assets within Note 1, decommissioning provisions associated with downstream and petrochemical facilities are not generally recognized as the potential obligations cannot be measured given their indeterminate settlement dates.

The group generally restricts its purchase of insurance to situations where this is required for legal or contractual reasons. This is because external insurance is not considered an economic means of financing losses for the group. Losses will therefore be borne as they arise rather than being spread over time through insurance premiums with attendant transaction costs. The position is reviewed periodically.

32. Remuneration of senior management and non-executive directors

Remuneration of directors

			$ million
	2014	2013	2012
Total for all directors			
Emoluments	**14**	16	12
Amounts awarded under incentive schemes	**14**	2	3
Total	**28**	18	15

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year. There was no compensation for loss of office in 2014 (2013 $nil and 2012 $nil).

Pension contributions

During 2014 two executive directors participated in a non-contributory pension scheme established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2014.

Further information

Full details of individual directors' remuneration are given in the Directors' remuneration report on page 72.

Remuneration of senior management and non-executive directors

			$ million
	2014	2013	2012
Total for senior management and non-executive directors			
Short-term employee benefits	**34**	36	29
Pensions and other post-retirement benefits	**3**	3	3
Share-based payments	**34**	43	37
Total	**71**	82	69

Senior management, comprises members of the executive team, see pages 56-57 for further information.

Short-term employee benefits

These amounts comprise fees and benefits paid to the non-executive chairman and non-executive directors, as well as salary, benefits and cash bonuses for senior management. Deferred annual bonus awards, to be settled in shares, are included in share-based payments. Short-term employee benefits includes compensation for loss of office of $1.5 million (2013 $3 million and 2012 $nil).

Pensions and other post-retirement benefits

The amounts represent the estimated cost to the group of providing defined benefit pensions and other post-retirement benefits to senior management in respect of the current year of service measured in accordance with IAS 19 'Employee Benefits'.

Share-based payments

This is the cost to the group of senior management's participation in share-based payment plans, as measured by the fair value of options and shares granted, accounted for in accordance with IFRS 2 'Share-based Payments'.

33. Employee costs and numbers

Employee costs	2014	2013	2012
			$ million
Wages and salaries[a]	**10,710**	10,161	9,910
Social security costs	**983**	958	908
Share-based payments[b]	**689**	719	674
Pension and other post-retirement benefit costs	**1,554**	1,816	1,956
	13,936	13,654	13,448

			2014			2013			2012
Average number of employees[c]	**US**	**Non-US**	**Total**	US	Non-US	Total	US	Non-US	Total
Upstream	**9,100**	**15,600**	**24,700**	9,400	15,100	24,500	9,300	14,100	23,400
Downstream[d]	**8,200**	**39,900**	**48,100**	9,300	39,800	49,100	12,000	39,900	51,900
Other businesses and corporate[e f]	**1,800**	**10,100**	**11,900**	2,000	9,000	11,000	2,000	8,700	10,700
	19,100	**65,600**	**84,700**	20,700	63,900	84,600	23,300	62,700	86,000

[a] Includes termination payments of $527 million (2013 $212 million and 2012 $77 million).
[b] The group provides certain employees with shares and share options as part of their remuneration packages. The majority of these share-based payment arrangements are equity-settled.
[c] Reported to the nearest 100.
[d] Includes 14,200 (2013 14,100 and 2012 14,700) service station staff.
[e] Includes 5,100 (2013 4,300 and 2012 3,600) agricultural, operational and seasonal workers in Brazil.
f Includes employees of the Gulf Coast Restoration Organization.

34. Auditor's remuneration

Fees – Ernst & Young	2014	2013	2012
			$ million
The audit of the company annual accounts[a]	**27**	26	26
The audit of accounts of any subsidiaries of the company	**13**	13	13
Total audit	**40**	39	39
Audit-related assurance services[b]	**7**	8	7
Total audit and audit-related assurance services	**47**	47	46
Taxation compliance services	**1**	1	2
Taxation advisory services	**1**	1	2
Services relating to corporate finance transactions	**1**	2	2
Other assurance services	**2**	1	1
Total non-audit or non-audit-related assurance services	**5**	5	7
Services relating to BP pension plans[c]	**1**	1	1
	53	53	54

[a] Fees in respect of the audit of the accounts of BP p.l.c. including the group's consolidated financial statements.
[b] Includes interim reviews and reporting on internal financial controls and non-statutory audit services.
[c] The pension plan services include tax compliance services of $398,000 (2013 $240,000 and 2012 $50,000).

2014 includes $2 million of additional fees for 2013, and 2013 includes $3 million of additional fees for 2012. Auditors' remuneration is included in the income statement within distribution and administration expenses.

The tax services relate to income tax and indirect tax compliance, employee tax services and tax advisory services.

The audit committee has established pre-approval policies and procedures for the engagement of Ernst & Young to render audit and certain assurance and tax services. The audit fees payable to Ernst & Young are reviewed by the audit committee in the context of other global companies for cost-effectiveness. Ernst & Young performed further assurance and tax services that were not prohibited by regulatory or other professional requirements and were pre-approved by the committee. Ernst & Young is engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young compared with that of other potential service providers. These services are for a fixed term.

Under SEC regulations, the remuneration of the auditor of $53 million (2013 $53 million and 2012 $54 million) is required to be presented as follows: audit $40 million (2013 $39 million and 2012 $39 million); other audit-related services $7 million (2013 $8 million and 2012 $7 million); tax $2 million (2013 $2 million and 2012 $4 million); and all other fees $4 million (2013 $4 million and 2012 $4 million).

35. Subsidiaries, joint arrangements and associates

The more important subsidiaries and associates of the group at 31 December 2014 and the group percentage of ordinary share capital (to nearest whole number) are set out below. There are no individually significant joint arrangements. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. A complete list of investments in subsidiaries, joint arrangements and associates will be attached to the parent company's annual return made to the Registrar of Companies.

Subsidiaries	%	Country of incorporation	Principal activities
International			
*BP Corporate Holdings	100	England & Wales	Investment holding
BP Exploration Operating Company	100	England & Wales	Exploration and production
*BP Global Investments	100	England & Wales	Investment holding
*BP International	100	England & Wales	Integrated oil operations
BP Oil International	100	England & Wales	Integrated oil operations
*Burmah Castrol	100	Scotland	Lubricants
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Australia			
BP Australia Capital Markets	100	Australia	Finance
BP Finance Australia	100	Australia	Finance
Azerbaijan			
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Brazil			
BP Energy do Brazil	100	Brazil	Exploration and production
Germany			
BP Europa SE	100	Germany	Refining and marketing
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Norway			
BP Norge	100	Norway	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	
BP America	100	US	
BP America Production Company	100	US	
BP Company North America	100	US	Exploration and production, refining and marketing pipelines and petrochemicals
BP Corporation North America	100	US	
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

Associates	%	Country of incorporation	Principal activities
Russia			
Rosneft	20	Russia	Integrated oil operations

36. Condensed consolidating information on certain US subsidiaries

BP p.l.c. fully and unconditionally guarantees the payment obligations of its 100%-owned subsidiary BP Exploration (Alaska) Inc. under the BP Prudhoe Bay Royalty Trust. The following financial information for BP p.l.c., BP Exploration (Alaska) Inc. and all other subsidiaries on a condensed consolidating basis is intended to provide investors with meaningful and comparable financial information about BP p.l.c. and its subsidiary issuers of registered securities and is provided pursuant to Rule 3-10 of Regulation S-X in lieu of the separate financial statements of each subsidiary issuer of public debt securities. Investments include the investments in subsidiaries recorded under the equity method for the purposes of the condensed consolidating financial information. Equity-accounted income of subsidiaries is the group's share of profit related to such investments. The eliminations and reclassifications column includes the necessary amounts to eliminate the intercompany balances and transactions between BP p.l.c., BP Exploration (Alaska) Inc. and other subsidiaries. The financial information presented in the following tables for BP Exploration (Alaska) Inc. for all years includes equity income arising from subsidiaries of BP Exploration (Alaska) Inc. some of which operate outside of Alaska and excludes the BP group's midstream operations in Alaska that are reported through different legal entities and that are included within the 'other subsidiaries' column in these tables. BP p.l.c. also fully and unconditionally guarantees securities issued by BP Capital Markets p.l.c. and BP Capital Markets America Inc. These companies are 100%- owned finance subsidiaries of BP p.l.c.

Income statement

					$ million
For the year ended 31 December					**2014**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	6,227	–	353,529	(6,188)	353,568
Earnings from joint ventures – after interest and tax	–	–	570	–	570
Earnings from associates – after interest and tax	–	–	2,802	–	2,802
Equity-accounted income of subsidiaries – after interest and tax	–	4,531	–	(4,531)	–
Interest and other income	2	193	910	(262)	843
Gains on sale of businesses and fixed assets	19	–	876	–	895
Total revenues and other income	6,248	4,724	358,687	(10,981)	358,678
Purchases	2,375	–	285,720	(6,188)	281,907
Production and manufacturing expenses	1,779	–	25,596	–	27,375
Production and similar taxes	554	–	2,404	–	2,958
Depreciation, depletion and amortization	545	–	14,618	–	15,163
Impairment and losses on sale of businesses and fixed assets	153	–	8,812	–	8,965
Exploration expense	–	–	3,632	–	3,632
Distribution and administration expenses	48	929	11,794	(75)	12,696
Fair value gain on embedded derivatives	–	–	(430)	–	(430)
Profit before interest and taxation	794	3,795	6,541	(4,718)	6,412
Finance costs	57	23	1,255	(187)	1,148
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(50)	364	–	314
Profit before taxation	737	3,822	4,922	(4,531)	4,950
Taxation	279	42	626	–	947
Profit for the year	458	3,780	4,296	(4,531)	4,003
Attributable to					
BP shareholders	458	3,780	4,073	(4,531)	3,780
Non-controlling interests	–	–	223	–	223
	458	3,780	4,296	(4,531)	4,003

Statement of comprehensive income

					$ million
For the year ended 31 December					**2014**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Profit for the year	458	3,780	4,296	(4,531)	4,003
Other comprehensive income	–	(1,840)	(10,875)	–	(12,715)
Equity-accounted other comprehensive income of subsidiaries	–	(10,843)	–	10,843	–
Total comprehensive income	458	(8,903)	(6,579)	6,312	(8,712)
Attributable to					
BP shareholders	458	(8,903)	(6,770)	6,312	(8,903)
Non-controlling interests	–	–	191	–	191
	458	(8,903)	(6,579)	6,312	(8,712)

36. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2013
Sales and other operating revenues	5,397	–	379,136	(5,397)	379,136
Earnings from joint ventures – after interest and tax	–	–	447	–	447
Earnings from associates – after interest and tax	–	–	2,742	–	2,742
Equity-accounted income of subsidiaries – after interest and tax	–	24,693	–	(24,693)	–
Interest and other income	7	118	841	(189)	777
Gains on sale of businesses and fixed assets	–	–	13,115	–	13,115
Total revenues and other income	5,404	24,811	396,281	(30,279)	396,217
Purchases	861	–	302,887	(5,397)	298,351
Production and manufacturing expenses	1,473	–	26,054	–	27,527
Production and similar taxes	1,010	–	6,037	–	7,047
Depreciation, depletion and amortization	616	–	12,894	–	13,510
Impairment and losses on sale of businesses and fixed assets	(68)	–	2,029	–	1,961
Exploration expense	–	–	3,441	–	3,441
Distribution and administration expenses	108	1,234	11,728	–	13,070
Fair value gain on embedded derivatives	–	–	(459)	–	(459)
Profit before interest and taxation	1,404	23,577	31,670	(24,882)	31,769
Finance costs	42	43	1,172	(189)	1,068
Net finance (income) expense relating to pensions and other post-retirement benefits	–	81	399	–	480
Profit before taxation	1,362	23,453	30,099	(24,693)	30,221
Taxation	522	2	5,939	–	6,463
Profit for the year	840	23,451	24,160	(24,693)	23,758
Attributable to					
BP shareholders	840	23,451	23,853	(24,693)	23,451
Non-controlling interests	–	–	307	–	307
	840	23,451	24,160	(24,693)	23,758

Statement of comprehensive income continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million 2013
Profit for the year	840	23,451	24,160	(24,693)	23,758
Other comprehensive income	–	2,819	(3,711)	–	(892)
Equity-accounted other comprehensive income of subsidiaries	–	(3,696)	–	3,696	–
Total comprehensive income	840	22,574	20,449	(20,997)	22,866
Attributable to					
BP shareholders	840	22,574	20,157	(20,997)	22,574
Non-controlling interests	–	–	292	–	292
	840	22,574	20,449	(20,997)	22,866

36. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2012
Sales and other operating revenues	5,501	–	375,765	(5,501)	375,765
Earnings from joint ventures – after interest and tax	–	–	260	–	260
Earnings from associates – after interest and tax	–	–	3,675	–	3,675
Equity-accounted income of subsidiaries – after interest and tax	(59)	12,649	–	(12,590)	–
Interest and other income	12	187	1,764	(286)	1,677
Gains on sale of businesses and fixed assets	3,580	–	6,697	(3,580)	6,697
Total revenues and other income	9,034	12,836	388,161	(21,957)	388,074
Purchases	777	–	297,498	(5,501)	292,774
Production and manufacturing expenses	1,475	–	32,451	–	33,926
Production and similar taxes	1,374	–	6,784	–	8,158
Depreciation, depletion and amortization	457	–	12,230	–	12,687
Impairment and losses on sale of businesses and fixed assets	957	–	5,318	–	6,275
Exploration expense	–	–	1,475	–	1,475
Distribution and administration expenses	35	1,766	11,641	(85)	13,357
Fair value gain on embedded derivatives	–	–	(347)	–	(347)
Profit before interest and taxation	3,959	11,070	21,111	(16,371)	19,769
Finance costs	48	43	1,182	(201)	1,072
Net finance expense relating to pensions and other post-retirement benefits	–	103	463	–	566
Profit before taxation	3,911	10,924	19,466	(16,170)	18,131
Taxation	203	(93)	6,770	–	6,880
Profit for the year	3,708	11,017	12,696	(16,170)	11,251
Attributable to					
BP shareholders	3,708	11,017	12,462	(16,170)	11,017
Non-controlling interests	–	–	234	–	234
	3,708	11,017	12,696	(16,170)	11,251

Statement of comprehensive income continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2012
Profit for the year	3,708	11,017	12,696	(16,170)	11,251
Other comprehensive income	–	(232)	1,207	–	975
Equity-accounted other comprehensive income of subsidiaries	–	1,203	–	(1,203)	–
Total comprehensive income	3,708	11,988	13,903	(17,373)	12,226
Attributable to					
BP shareholders	3,708	11,988	13,665	(17,373)	11,988
Non-controlling interests	–	–	238	–	238
	3,708	11,988	13,903	(17,373)	12,226

36. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet

At 31 December	Issuer	Guarantor			$ million 2014
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	7,787	–	122,905	–	130,692
Goodwill	–	–	11,868	–	11,868
Intangible assets	473	–	20,434	–	20,907
Investments in joint ventures	–	–	8,753	–	8,753
Investments in associates	–	2	10,401	–	10,403
Other investments	–	–	1,228	–	1,228
Subsidiaries – equity-accounted basis	–	138,863	–	(138,863)	–
Fixed assets	8,260	138,865	175,589	(138,863)	183,851
Loans	7	–	5,238	(4,586)	659
Trade and other receivables	–	–	4,787	–	4,787
Derivative financial instruments	–	–	4,442	–	4,442
Prepayments	10	–	954	–	964
Deferred tax assets	–	–	2,309	–	2,309
Defined benefit pension plan surpluses	–	15	16	–	31
	8,277	138,880	193,335	(143,449)	197,043
Current assets					
Loans	–	–	333	–	333
Inventories	338	–	18,035	–	18,373
Trade and other receivables	10,323	7,159	33,463	(19,907)	31,038
Derivative financial instruments	–	–	5,165	–	5,165
Prepayments	31	–	1,393	–	1,424
Current tax receivable	–	–	837	–	837
Other investments	–	–	329	–	329
Cash and cash equivalents	–	31	29,732	–	29,763
	10,692	7,190	89,287	(19,907)	87,262
Total assets	18,969	146,070	282,622	(163,356)	284,305
Current liabilities					
Trade and other payables	905	2,476	56,644	(19,907)	40,118
Derivative financial instruments	–	–	3,689	–	3,689
Accruals	134	391	6,577	–	7,102
Finance debt	–	–	6,877	–	6,877
Current tax payable	328	–	1,683	–	2,011
Provisions	1	–	3,817	–	3,818
	1,368	2,867	79,287	(19,907)	63,615
Non-current liabilities					
Other payables	16	4,563	3,594	(4,586)	3,587
Derivative financial instruments	–	–	3,199	–	3,199
Accruals	–	90	771	–	861
Finance debt	–	–	45,977	–	45,977
Deferred tax liabilities	1,232	–	12,661	–	13,893
Provisions	1,975	–	27,105	–	29,080
Defined benefit pension plan and other post-retirement benefit plan deficits	–	599	10,852	–	11,451
	3,223	5,252	104,159	(4,586)	108,048
Total liabilities	4,591	8,119	183,446	(24,493)	171,663
Net assets	14,378	137,951	99,176	(138,863)	112,642
Equity					
BP shareholders' equity	14,378	137,951	97,975	(138,863)	111,441
Non-controlling interests	–	–	1,201	–	1,201
	14,378	137,951	99,176	(138,863)	112,642

Balance sheet continued

					$ million
At 31 December					2013
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	8,546	–	125,144	–	133,690
Goodwill	–	–	12,181	–	12,181
Intangible assets	417	–	21,622	–	22,039
Investments in joint ventures	–	–	9,199	–	9,199
Investments in associates	–	2	16,634	–	16,636
Other investments	–	–	1,565	–	1,565
Subsidiaries – equity-accounted basis	–	142,143	–	(142,143)	–
Fixed assets	8,963	142,145	186,345	(142,143)	195,310
Loans	–	–	5,356	(4,593)	763
Trade and other receivables	–	–	5,985	–	5,985
Derivative financial instruments	–	–	3,509	–	3,509
Prepayments	22	–	900	–	922
Deferred tax assets	–	–	985	–	985
Defined benefit pension plan surpluses	–	1,020	356	–	1,376
	8,985	143,165	203,436	(146,736)	208,850
Current assets					
Loans	–	–	216	–	216
Inventories	152	–	29,079	–	29,231
Trade and other receivables	9,593	21,550	42,363	(33,675)	39,831
Derivative financial instruments	–	–	2,675	–	2,675
Prepayments	18	–	1,370	–	1,388
Current tax receivable	–	–	512	–	512
Other investments	–	–	467	–	467
Cash and cash equivalents	–	6	22,514	–	22,520
	9,763	21,556	99,196	(33,675)	96,840
Assets classified as held for sale	–	–	–	–	–
	9,763	21,556	99,196	(33,675)	96,840
Total assets	18,748	164,721	302,632	(180,411)	305,690
Current liabilities					
Trade and other payables	889	2,727	77,218	(33,675)	47,159
Derivative financial instruments	–	–	2,322	–	2,322
Accruals	171	1,540	7,249	–	8,960
Finance debt	–	–	7,381	–	7,381
Current tax payable	166	–	1,779	–	1,945
Provisions	1	–	5,044	–	5,045
	1,227	4,267	100,993	(33,675)	72,812
Liabilities directly associated with assets classified as held for sale	–	–	–	–	–
	1,227	4,267	100,993	(33,675)	72,812
Non-current liabilities					
Other payables	9	4,584	4,756	(4,593)	4,756
Derivative financial instruments	–	–	2,225	–	2,225
Accruals	–	58	489	–	547
Finance debt	–	–	40,811	–	40,811
Deferred tax liabilities	1,659	–	15,780	–	17,439
Provisions	1,942	–	24,973	–	26,915
Defined benefit pension plan and other post-retirement benefit plan deficits	–	–	9,778	–	9,778
	3,610	4,642	98,812	(4,593)	102,471
Total liabilities	4,837	8,909	199,805	(38,268)	175,283
Net assets	13,911	155,812	102,827	(142,143)	130,407
Equity					
BP shareholders' equity	13,911	155,812	101,722	(142,143)	129,302
Non-controlling interests	–	–	1,105	–	1,105
	13,911	155,812	102,827	(142,143)	130,407

36. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2014
Net cash provided by operating activities	**92**	**15,550**	**19,241**	**(2,129)**	**32,754**
Net cash used in investing activities	**(92)**	**(5,085)**	**(14,397)**	**–**	**(19,574)**
Net cash used in financing activities	**–**	**(10,440)**	**3,045**	**2,129**	**(5,266)**
Currency translation differences relating to cash and cash equivalents	**–**	**–**	**(671)**	**–**	**(671)**
Increase in cash and cash equivalents	**–**	**25**	**7,218**	**–**	**7,243**
Cash and cash equivalents at beginning of year	**–**	**6**	**22,514**	**–**	**22,520**
Cash and cash equivalents at end of year	**–**	**31**	**29,732**	**–**	**29,763**

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2013
Net cash provided by operating activities	746	11,488	25,094	(16,228)	21,100
Net cash used in investing activities	(746)	(690)	(6,419)	–	(7,855)
Net cash used in financing activities	–	(10,801)	(15,827)	16,228	(10,400)
Currency translation differences relating to cash and cash equivalents	–	–	40	–	40
Increase (decrease) in cash and cash equivalents	–	(3)	2,888	–	2,885
Cash and cash equivalents at beginning of year	–	9	19,626	–	19,635
Cash and cash equivalents at end of year	–	6	22,514	–	22,520

For the year ended 31 December	Issuer: BP Exploration (Alaska) Inc.	Guarantor: BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2012
Net cash provided by operating activities	681	12,381	20,932	(13,515)	20,479
Net cash used in investing activities	(680)	(7,060)	(5,335)	–	(13,075)
Net cash used in financing activities	–	(5,312)	(10,213)	13,515	(2,010)
Currency translation differences relating to cash and cash equivalents	–	–	64	–	64
Increase in cash and cash equivalents	1	9	5,448	–	5,458
Cash and cash equivalents at beginning of year	(1)	–	14,178	–	14,177
Cash and cash equivalents at end of year	–	9	19,626	–	19,635

Supplementary information on oil and natural gas (unaudited)[a]

The regional analysis presented below is on a continent basis, with separate disclosure for countries that contain 15% or more of the total proved reserves (for subsidiaries plus equity-accounted entities), in accordance with SEC and FASB requirements.

Oil and gas reserves – certain definitions

Unless the context indicates otherwise, the following terms have the meanings shown below:

Proved oil and gas reserves

Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
  (A) The area identified by drilling and limited by fluid contacts, if any; and
  (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
  (A) Successful testing by a pilot project in an area of the reservoir with properties no more favourable than in the reservoir as a whole, the operation of an installed programme in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or programme was based; and
  (B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Undeveloped oil and gas reserves

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Developed oil and gas reserves

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

For details on BP's proved reserves and production compliance and governance processes, see pages 219–224.

[a] 2013 equity-accounted entities information includes BP's share of TNK-BP from 1 January to 20 March, and Rosneft for the period 21 March to 31 December.

Oil and natural gas exploration and production activities

$ million

2014	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	31,496	10,578	76,476	3,205	9,796	39,020	–	24,177	5,061	199,809
Unproved properties	395	165	6,294	2,454	2,984	5,769	–	2,773	888	21,722
	31,891	10,743	82,770	5,659	12,780	44,789	–	26,950	5,949	221,531
Accumulated depreciation	21,068	6,610	39,383	190	5,482	25,105	–	13,501	2,215	113,554
Net capitalized costs	10,823	4,133	43,387	5,469	7,298	19,684	–	13,449	3,734	107,977
Costs incurred for the year ended 31 December[b]										
Acquisition of properties										
Proved	42	–	6	–	–	–	–	557	–	605
Unproved	–	–	346	–	75	57	–	–	–	478
	42	–	352	–	75	57		557	–	1,083
Exploration and appraisal costs[c]	279	16	888	109	325	899	–	194	201	2,911
Development	2,067	293	4,792	706	983	2,881	–	3,205	169	15,096
Total costs	2,388	309	6,032	815	1,383	3,837	–	3,956	370	19,090
Results of operations for the year ended 31 December										
Sales and other operating revenues[d]										
Third parties	529	77	1,218	4	2,802	2,536	–	1,135	1,891	10,192
Sales between businesses	1,069	1,662	14,894	15	450	6,289	–	6,951	631	31,961
	1,598	1,739	16,112	19	3,252	8,825	–	8,086	2,522	42,153
Exploration expenditure	94	47	1,294	63	502	860	–	712	60	3,632
Production costs	979	436	3,492	34	783	1,542	–	1,289	232	8,787
Production taxes	(234)	–	690	–	175	–	–	2,234	93	2,958
Other costs (income)[e]	(1,515)	77	3,260	55	284	120	57	(69)	306	2,575
Depreciation, depletion and amortization	506	676	3,805	4	678	3,343	–	2,461	255	11,728
Impairments and (gains) losses on sale of businesses and fixed assets	2,537	2,278	(28)	–	11	1,128	–	391	–	6,317
	2,367	3,514	12,513	156	2,433	6,993	57	7,018	946	35,997
Profit (loss) before taxation[f]	(769)	(1,775)	3,599	(137)	819	1,832	(57)	1,068	1,576	6,156
Allocable taxes	(1,383)	(1,108)	1,269	15	865	1,216	3	67	599	1,543
Results of operations	614	(667)	2,330	(152)	(46)	616	(60)	1,001	977	4,613
Upstream and Rosneft segments replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	(769)	(1,775)	3,599	(137)	819	1,832	(57)	1,068	1,576	6,156
Midstream activities – subsidiaries[g]	163	99	703	130	175	(170)	(26)	(63)	653	1,664
Equity-accounted entities[h]	–	62	23	–	480	(33)	2,125	557	–	3,214
Total replacement cost profit before interest and tax	(606)	(1,614)	4,325	(7)	1,474	1,629	2,042	1,562	2,229	11,034

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[d] Presented net of transportation costs, purchases and sales taxes.
[e] Includes property taxes, other government take and the fair value gain on embedded derivatives of $430 million. The UK region includes a $1,016 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.
[f] Excludes the unwinding of the discount on provisions and payables amounting to $207 million which is included in finance costs in the group income statement.
[g] Midstream and other activities excludes inventory holding gains and losses.
[h] The profits of equity-accounted entities are included after interest and tax.

Oil and natural gas exploration and production activities – continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
$ million 2014	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)[b]										
Capitalized costs at 31 December[c]										
Gross capitalized costs										
Proved properties	–	–	–	–	8,719	–	12,971	3,073	–	24,763
Unproved properties	–	–	–	–	5	–	376	25	–	406
	–	–	–	–	8,724	–	13,347	3,098	–	25,169
Accumulated depreciation	–	–	–	–	3,652	–	2,031	2,986	–	8,669
Net capitalized costs	–	–	–	–	5,072	–	11,316	112	–	16,500
Costs incurred for the year ended 31 December[d]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	(46)	–	–	(46)
Unproved	–	–	–	–	–	–	87	–	–	87
	–	–	–	–	–	–	41	–	–	41
Exploration and appraisal costs[d]	–	–	–	–	5	–	128	4	–	137
Development	–	–	–	–	1,026	–	1,913	669	–	3,608
Total costs	–	–	–	–	1,031	–	2,082	673	–	3,786
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	2,472	–	–	1,257	–	3,729
Sales between businesses	–	–	–	–	–	–	10,972	19	–	10,991
	–	–	–	–	2,472	–	10,972	1,276	–	14,720
Exploration expenditure	–	–	–	–	4	–	62	1	–	67
Production costs	–	–	–	–	567	–	1,318	152	–	2,037
Production taxes	–	–	–	–	721	–	5,214	692	–	6,627
Other costs (income)	–	–	–	–	4	–	302	–	–	306
Depreciation, depletion and amortization	–	–	–	–	370	–	1,509	371	–	2,250
Impairments and losses on sale of businesses and fixed assets	–	–	–	–	25	–	–	–	–	25
	–	–	–	–	1,691	–	8,405	1,216	–	11,312
Profit (loss) before taxation	–	–	–	–	781	–	2,567	60	–	3,408
Allocable taxes	–	–	–	–	402	–	637	29	–	1,068
Results of operations	–	–	–	–	379	–	1,930	31	–	2,340
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	379	–	1,930	31	–	2,340
Midstream and other activities after tax[f]	–	62	23	–	101	(33)	195	526	–	874
Total replacement cost profit after interest and tax	–	62	23	–	480	(33)	2,125	557	–	3,214

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.
[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[c] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[e] Presented net of transportation costs and sales taxes.
[f] Includes interest, non-controlling interests and excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities – continued

$ million

2013

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	29,314	10,040	75,313	2,501	8,809	35,720	–	20,726	4,681	187,104
Unproved properties	316	195	6,816	2,408	3,366	5,079	–	2,756	805	21,741
	29,630	10,235	82,129	4,909	12,175	40,799	–	23,482	5,486	208,845
Accumulated depreciation	18,707	3,650	38,236	193	5,063	20,082	–	10,069	1,962	97,962
Net capitalized costs	10,923	6,585	43,893	4,716	7,112	20,717	–	13,413	3,524	110,883
Costs incurred for the year ended 31 December[b]										
Acquisition of properties										
Proved	–	–	1	–	7	–	–	–	–	8
Unproved	–	–	158	–	284	30	–	7	–	479
	–	–	159	–	291	30	–	7	–	487
Exploration and appraisal costs[c]	178	14	1,291	194	951	883	–	1,090	210	4,811
Development	1,942	455	4,877	569	683	2,755	–	2,082	189	13,552
Total costs	2,120	469	6,327	763	1,925	3,668	–	3,179	399	18,850
Results of operations for the year ended 31 December										
Sales and other operating revenues[d]										
Third parties	1,129	183	934	5	2,413	3,195	–	1,005	1,784	10,648
Sales between businesses	1,661	1,280	14,047	12	1,154	6,518	–	11,432	941	37,045
	2,790	1,463	14,981	17	3,567	9,713	–	12,437	2,725	47,693
Exploration expenditure	280	17	437	28	1,477	387	–	768	47	3,441
Production costs	1,102	430	3,691	42	892	1,623	–	1,091	187	9,058
Production taxes	(35)	–	1,112	–	184	–	–	5,660	126	7,047
Other costs (income)[e]	(1,731)	86	3,241	55	322	89	65	84	351	2,562
Depreciation, depletion and amortization	504	490	3,268	–	559	3,132	–	2,174	207	10,334
Impairments and (gains) losses on sale of businesses and fixed assets	118	15	(80)	–	129	29	–	(16)	230	425
	238	1,038	11,669	125	3,563	5,260	65	9,761	1,148	32,867
Profit (loss) before taxation[f]	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,577	14,826
Allocable taxes	554	475	1,204	(26)	642	1,925	(2)	682	641	6,095
Results of operations	1,998	(50)	2,108	(82)	(638)	2,528	(63)	1,994	936	8,731
Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,577	14,826
Midstream activities – subsidiaries[g]	244	(40)	296	(14)	153	(154)	(4)	(29)	347	799
TNK-BP gain on sale	–	–	–	–	–	–	12,500	–	–	12,500
Equity-accounted entities[h]	–	28	17	–	405	24	2,158	553	–	3,185
Total replacement cost profit before interest and tax	2,796	413	3,625	(122)	562	4,323	14,589	3,200	1,924	31,310

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[d] Presented net of transportation costs, purchases and sales taxes.
[e] Includes property taxes, other government take and the fair value gain on embedded derivatives of $459 million. The UK region includes a $1,055 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.
[f] Excludes the unwinding of the discount on provisions and payables amounting to $141 million which is included in finance costs in the group income statement.
[g] Midstream and other activities excludes inventory holding gains and losses.
[h] The profits of equity-accounted entities are included after interest and tax.

Oil and natural gas exploration and production activities – continued

	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia[a]	Asia Rest of Asia	Australasia	$ million 2013 Total
Equity-accounted entities (BP share)[b]										
Capitalized costs at 31 December[c]										
Gross capitalized costs										
Proved properties	–	–	–	–	7,648	–	18,942	4,239	–	30,829
Unproved properties	–	–	–	–	29	–	638	21	–	688
	–	–	–	–	7,677	–	19,580	4,260	–	31,517
Accumulated depreciation	–	–	–	–	3,282	–	1,077	4,061	–	8,420
Net capitalized costs	–	–	–	–	4,395	–	18,503	199	–	23,097
Costs incurred for the year ended 31 December[d]										
Acquisition of properties										
Proved	–	–	–	–	–	–	1,816	–	–	1,816
Unproved	–	–	–	–	–	–	657	–	–	657
	–	–	–	–	–	–	2,473	–	–	2,473
Exploration and appraisal costs[e]	–	–	–	–	8	–	133	12	–	153
Development	–	–	–	–	714	–	1,860	538	–	3,112
Total costs	–	–	–	–	722	–	4,466	550	–	5,738
Results of operations for the year ended 31 December										
Sales and other operating revenues[f]										
Third parties	–	–	–	–	2,294	–	435	4,770	–	7,499
Sales between businesses	–	–	–	–	–	–	9,679	14	–	9,693
	–	–	–	–	2,294	–	10,114	4,784	–	17,192
Exploration expenditure	–	–	–	–	–	–	126	1	–	127
Production costs	–	–	–	–	586	–	1,177	404	–	2,167
Production taxes	–	–	–	–	630	–	4,511	3,645	–	8,786
Other costs (income)	–	–	–	–	6	–	94	(1)	–	99
Depreciation, depletion and amortization	–	–	–	–	317	–	1,232	544	–	2,093
Impairments and losses on sale of businesses and fixed assets	–	–	–	–	–	–	37	–	–	37
	–	–	–	–	1,539	–	7,177	4,593	–	13,309
Profit (loss) before taxation	–	–	–	–	755	–	2,937	191	–	3,883
Allocable taxes	–	–	–	–	460	–	367	40	–	867
Results of operations	–	–	–	–	295	–	2,570	151	–	3,016
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	295	–	2,570	151	–	3,016
Midstream and other activities after tax[g]	–	28	17	–	110	24	(412)	402	–	169
Total replacement cost profit after interest and tax	–	28	17	–	405	24	2,158	553	–	3,185

[a] Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.
[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP and Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[c] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[d] The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.
[e] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[f] Presented net of transportation costs and sales taxes.
[g] Includes interest, non-controlling interests and excludes inventory holding gains and losses.

										$ million
										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b c]										
Gross capitalized costs										
Proved properties	28,370	9,421	70,133	1,928	8,153	32,755	–	16,757	3,676	171,193
Unproved properties	400	199	7,084	2,244	3,590	4,524	–	4,920	1,540	24,501
	28,770	9,620	77,217	4,172	11,743	37,279	–	21,677	5,216	195,694
Accumulated depreciation	19,002	3,161	35,459	197	4,444	16,901	–	8,360	1,517	89,041
Net capitalized costs	9,768	6,459	41,758	3,975	7,299	20,378	–	13,317	3,699	106,653
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[d e]										
Proved	–	–	256	–	51	–	–	–	–	307
Unproved	–	–	1,111	–	27	239	–	(68)	–	1,309
	–	–	1,367	–	78	239	–	(68)	–	1,616
Exploration and appraisal costs[f]	173	47	1,069	230	758	1,024	–	814	241	4,356
Development	1,907	784	3,866	611	581	2,992	–	1,591	221	12,553
Total costs	2,080	831	6,302	841	1,417	4,255	–	2,337	462	18,525
Results of operations for the year ended 31 December										
Sales and other operating revenues[g]										
Third parties	1,595	76	453	10	2,026	3,424	–	1,299	1,749	10,632
Sales between businesses	2,975	783	15,713	10	984	5,633	–	11,345	915	38,358
	4,570	859	16,166	20	3,010	9,057	–	12,644	2,664	48,990
Exploration expenditure	105	29	649	4	120	310	–	126	132	1,475
Production costs	1,310	348	3,854	71	812	1,323	–	1,076	191	8,985
Production taxes	92	–	1,472	–	162	–	–	6,291	141	8,158
Other costs (income)[h]	(1,474)	78	3,505	63	109	221	(330)	84	264	2,520
Depreciation, depletion and amortization	1,102	145	3,187	10	606	2,281	–	2,116	211	9,658
Impairments and (gains) losses on sale of businesses and fixed assets	373	83	(3,576)	98	6	24	–	(2)	(5)	(2,999)
	1,508	683	9,091	246	1,815	4,159	(330)	9,691	934	27,797
Profit (loss) before taxation[i]	3,062	176	7,075	(226)	1,195	4,898	330	2,953	1,730	21,193
Allocable taxes	1,121	(313)	2,762	(67)	804	2,371	(13)	663	755	8,083
Results of operations	1,941	489	4,313	(159)	391	2,527	343	2,290	975	13,110
Upstream and TNK-BP segments replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	3,062	176	7,075	(226)	1,195	4,898	330	2,953	1,730	21,193
Midstream activities – subsidiaries[j]	(250)	(114)	(173)	774	163	(46)	11	32	370	767
Equity-accounted entities[k]	–	35	16	–	160	48	3,005	640	–	3,904
Total replacement cost profit before interest and tax	2,812	97	6,918	548	1,518	4,900	3,346	3,625	2,100	25,864

[a] These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill or assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Excludes balances associated with assets held for sale.
[d] Includes costs capitalized as a result of asset exchanges.
[e] Excludes goodwill associated with business combinations.
[f] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[g] Presented net of transportation costs, purchases and sales taxes.
[h] Includes property taxes, other government take and the fair value gain on embedded derivatives of $347 million. The UK region includes a $1,161 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme. The Russia region, for which equity accounting ceased on 22 October 2012, includes a net non-operating gain of $351 million, including dividend income of $709 million partly offset by a settlement charge of $325 million.
[i] Excludes the unwinding of the discount on provisions and payables amounting to $173 million which is included in finance costs in the group income statement.
[j] Midstream and other activities exclude inventory holding gains and losses.
[k] The profits of equity-accounted entities are included after interest and tax and the results exclude balances associated with assets held for sale.

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2012
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		Total
Equity-accounted entities (BP share)[b]										
Capitalized costs at 31 December[c]										
Gross capitalized costs										
Proved properties	–	–	–	–	6,958	–	–	4,036	–	10,994
Unproved properties	–	–	–	–	21	–	–	16	–	37
	–	–	–	–	6,979	–	–	4,052	–	11,031
Accumulated depreciation	–	–	–	–	2,965	–	–	3,648	–	6,613
Net capitalized costs	–	–	–	–	4,014	–	–	404	–	4,418
Costs incurred for the year ended 31 December[c]										
Acquisition of properties[d]										
Proved	–	–	–	–	–	–	4	–	–	4
Unproved	–	–	–	–	439	–	15	–	–	454
	–	–	–	–	439	–	19	–	–	458
Exploration and appraisal costs[e]	–	–	–	–	31	–	195	7	–	233
Development	–	–	–	–	599	–	1,560	556	–	2,715
Total costs	–	–	–	–	1,069	–	1,774	563	–	3,406
Results of operations for the year ended 31 December										
Sales and other operating revenues[f]										
Third parties	–	–	–	–	2,267	–	6,472	4,245	–	12,984
Sales between businesses	–	–	–	–	–	–	3,639	21	–	3,660
	–	–	–	–	2,267	–	10,111	4,266	–	16,644
Exploration expenditure	–	–	–	–	31	–	93	1	–	125
Production costs	–	–	–	–	555	–	1,605	295	–	2,455
Production taxes	–	–	–	–	959	–	4,400	3,245	–	8,604
Other costs (income)	–	–	–	–	(11)	–	(24)	(2)	–	(37)
Depreciation, depletion and amortization	–	–	–	–	328	–	786	538	–	1,652
Impairments and losses on sale of businesses and fixed assets	–	–	–	–	–	–	(27)	–	–	(27)
	–	–	–	–	1,862	–	6,833	4,077	–	12,772
Profit (loss) before taxation	–	–	–	–	405	–	3,278	189	–	3,872
Allocable taxes	–	–	–	–	294	–	536	54	–	884
Results of operations	–	–	–	–	111	–	2,742	135	–	2,988
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	111	–	2,742	135	–	2,988
Midstream and other activities after tax[g]	–	35	16	–	49	48	263	505	–	916
Total replacement cost profit after interest and tax	–	35	16	–	160	48	3,005	640	–	3,904

[a] The Russia region includes BP's equity-accounted share of TNK-BP's earnings. For 2012, equity-accounted earnings are included until 21 October 2012 only, after which our investment was classified as an asset held for sale and therefore equity accounting ceased. The amounts shown exclude BP's share of costs incurred and results of operations for the period 22 October to 31 December 2012.
[b] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.
[c] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year. Capitalised costs exclude balances associated with assets held for sale.
[d] Includes costs capitalized as a result of asset exchanges.
[e] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[f] Presented net of transportation costs and sales taxes.
[g] Includes interest, non-controlling interests and the net results of equity-accounted entities and excludes inventory holding gains and losses.

Movements in estimated net proved reserves

million barrels

Crude oil[a b]										2014
	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	160	147	1,007	–	15	316	–	320	49	2,013
Undeveloped	374	53	752	–	17	180	–	202	19	1,597
	534	200	1,760	–	31	495	–	522	69	3,610
Changes attributable to										
Revisions of previous estimates	(41)	(68)	87	–	9	20	–	96	(2)	101
Improved recovery	2	–	16	–	1	3	–	–	–	23
Purchases of reserves-in-place	5	–	–	–	–	–	–	12	–	17
Discoveries and extensions	5	–	–	–	1	–	–	8	–	13
Production[d]	(17)	(15)	(123)	–	(5)	(81)	–	(57)	(7)	(305)
Sales of reserves-in-place	–	–	(45)	–	(5)	–	–	–	–	(50)
	(46)	(82)	(66)	–	1	(58)	–	59	(9)	(201)
At 31 December[e]										
Developed	159	95	1,030	–	10	317	–	384	40	2,035
Undeveloped	329	22	664	–	22	120	–	197	19	1,375
	488	117	1,694	–	32	437	–	581	59	3,409
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	316	2	2,970	120	–	3,407
Undeveloped	–	–	–	1	314	2	1,858	7	–	2,182
	–	–	–	1	630	4	4,828	127	–	5,590
Changes attributable to										
Revisions of previous estimates	–	–	–	–	4	(2)	213	9	–	224
Improved recovery	–	–	–	–	12	–	–	–	–	12
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	10	–	187	–	–	197
Production	–	–	–	–	(26)	–	(297)	(36)	–	(359)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(2)	103	(27)	–	74
At 31 December[g]										
Developed	–	–	–	–	316	2	2,997	89	–	3,405
Undeveloped	–	–	–	–	314	–	1,933	11	–	2,258
	–	–	–	1	630	2	4,930	101	–	5,663
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	160	147	1,007	–	331	317	2,970	440	49	5,421
Undeveloped	374	53	752	1	331	182	1,858	209	19	3,779
	534	200	1,760	1	661	499	4,828	649	69	9,200
At 31 December										
Developed	159	95	1,030	–	326	319	2,997	473	40	5,440
Undeveloped	329	22	664	–	336	120	1,933	208	19	3,632
	488	117	1,694	1	662	439	4,930	682	59	9,072

[a] Crude oil includes condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Includes 10 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 38 million barrels of crude oil in respect of the 0.15% non-controlling interest in Rosneft.
[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,961 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 30 million barrels in Venezuela and 4,930 million barrels in Russia.

Movements in estimated net proved reserves – continued

Natural gas liquids[a b]										million barrels 2014
	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	9	16	290	–	14	4	–	–	8	342
Undeveloped	6	2	155	–	28	15	–	–	3	209
	15	18	444	–	43	20	–	–	10	551
Changes attributable to										
Revisions of previous estimates	(6)	(2)	15	–	–	(6)	–	–	–	1
Improved recovery	–	–	13	–	–	–	–	–	–	13
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	1
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[c]	(1)	(2)	(27)	–	(4)	(2)	–	–	(1)	(36)
Sales of reserves-in-place	–	–	(18)	–	–	–	–	–	–	(18)
	(6)	(4)	(17)	–	(4)	(8)	–	–	(1)	(40)
At 31 December[d]										
Developed	6	13	323	–	11	5	–	–	6	364
Undeveloped	3	1	104	–	28	7	–	–	3	146
	9	14	427	–	39	12	–	–	10	510
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	–	8	94	–	–	103
Undeveloped	–	–	–	–	–	8	21	–	–	29
	–	–	–	–	–	16	115	–	–	131
Changes attributable to										
Revisions of previous estimates	–	–	–	–	–	–	(69)	–	–	(69)
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	–	–	–	–
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(1)	(69)	–	–	(69)
At 31 December[f]										
Developed	–	–	–	–	–	15	30	–	–	46
Undeveloped	–	–	–	–	–	–	16	–	–	16
	–	–	–	–	–	15	46	–	–	62
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	9	16	290	–	14	13	94	–	8	444
Undeveloped	6	2	155	–	28	23	21	–	3	238
	15	18	444	–	43	36	115	–	10	682
At 31 December										
Developed	6	13	323	–	11	20	30	–	6	410
Undeveloped	3	1	104	–	28	7	16	–	3	163
	9	14	427	–	39	27	46	–	10	572

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.
[d] Includes 12 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 47 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 46 million barrels in Russia.

Movements in estimated net proved reserves – continued

Bitumen[a b]	million barrels 2014 Rest of North America	Total
Subsidiaries		
At 1 January		
Developed	–	–
Undeveloped	188	188
	188	188
Changes attributable to		
Revisions of previous estimates	(16)	(16)
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	–	–
Production	–	–
Sales of reserves-in-place	–	–
	(16)	(16)
At 31 December		
Developed	9	9
Undeveloped	163	163
	172	172

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

Movements in estimated net proved reserves – continued

Total liquids[a b]										million barrels 2014
	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	169	163	1,297	–	29	320	–	320	57	2,354
Undeveloped	380	55	907	188	46	195	–	202	22	1,994
	549	217	2,204	188	74	515	–	523	78	4,348
Changes attributable to										
Revisions of previous estimates	(47)	(70)	101	(16)	9	14	–	96	(2)	86
Improved recovery	2	–	28	–	1	3	–	–	–	36
Purchases of reserves-in-place	5	–	–	–	–	–	–	12	–	18
Discoveries and extensions	5	–	–	–	1	–	–	8	–	14
Production[d]	(17)	(17)	(150)	–	(9)	(83)	–	(57)	(8)	(341)
Sales of reserves-in-place	–	–	(63)	–	(5)	–	–	–	–	(68)
	(52)	(86)	(83)	(16)	(3)	(66)	–	59	(10)	(257)
At 31 December[e]										
Developed	166	108	1,352	9	21	322	–	384	46	2,407
Undeveloped	332	23	769	163	50	127	–	197	22	1,684
	497	131	2,121	172	71	449	–	581	68	4,092
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	316	10	3,063	120	–	3,510
Undeveloped	–	–	–	1	314	10	1,879	7	–	2,210
	–	–	–	1	630	20	4,943	127	–	5,721
Changes attributable to										
Revisions of previous estimates	–	–	–	–	4	(3)	144	9	–	155
Improved recovery	–	–	–	–	12	–	–	–	–	12
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	10	–	187	–	–	197
Production	–	–	–	–	(26)	–	(297)	(36)	–	(359)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(3)	34	(27)	–	4
At 31 December[g h]										
Developed	–	–	–	–	316	17	3,028	89	–	3,451
Undeveloped	–	–	–	–	314	–	1,949	11	–	2,274
	–	–	–	1	630	17	4,976	101	–	5,725
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	169	163	1,297	–	345	331	3,063	440	57	5,865
Undeveloped	380	55	907	188	359	205	1,879	209	22	4,204
	549	217	2,204	189	704	535	4,943	650	78	10,069
At 31 December										
Developed	166	108	1,352	9	337	339	3,028	473	46	5,858
Undeveloped	332	23	769	164	364	127	1,949	208	22	3,958
	497	131	2,121	173	701	466	4,976	682	68	9,817

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.
[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 38 million barrels in respect of the non-controlling interest in Rosneft.
[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 5,007 million barrels, comprising 1 million barrels in Canada, 30 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,976 million barrels in Russia.

billion cubic feet

Natural gas[a b]	Europe UK	Europe Rest of Europe	North America US	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2014 Total
Subsidiaries										
At 1 January										
Developed	643	364	7,122	10	3,109	961	–	1,519	3,932	17,660
Undeveloped	314	39	2,825	–	6,116	1,807	–	3,671	1,755	16,527
	957	403	9,947	10	9,225	2,768	–	5,190	5,687	34,187
Changes attributable to										
Revisions of previous estimates	(260)	(46)	(29)	11	(258)	(84)	–	(34)	(351)	(1,050)
Improved recovery	7	–	582	–	220	28	–	–	–	838
Purchases of reserves-in-place	1	–	5	–	–	–	–	322	–	328
Discoveries and extensions	94	–	2	–	271	4	–	267	–	637
Production[c]	(30)	(40)	(625)	(4)	(792)	(218)	–	(165)	(302)	(2,177)
Sales of reserves-in-place	–	–	(266)	–	–	–	–	–	–	(266)
	(189)	(85)	(332)	7	(559)	(271)	–	389	(652)	(1,691)
At 31 December[d]										
Developed	382	300	7,168	17	2,352	901	–	1,688	3,316	16,124
Undeveloped	386	19	2,447	–	6,313	1,597	–	3,892	1,719	16,372
	768	318	9,615	17	8,666	2,497	–	5,580	5,035	32,496
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	1,364	230	4,171	72	–	5,837
Undeveloped	–	–	–	1	747	135	5,054	14	–	5,951
	–	–	–	1	2,111	365	9,225	86	–	11,788
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(87)	38	767	1	–	720
Improved recovery	–	–	–	–	23	–	–	–	–	23
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	69	–	183	–	–	252
Production[c]	–	–	–	–	(172)	(3)	(390)	(18)	–	(583)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	(166)	35	560	(17)	–	412
At 31 December[f g]										
Developed	–	–	–	1	1,228	400	4,674	60	–	6,363
Undeveloped	–	–	–	1	717	–	5,111	9	–	5,837
	–	–	–	1	1,945	400	9,785	69	–	12,200
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	643	364	7,122	10	4,473	1,191	4,171	1,591	3,932	23,497
Undeveloped	314	39	2,825	1	6,863	1,942	5,054	3,685	1,755	22,478
	957	403	9,947	11	11,336	3,133	9,225	5,276	5,687	45,975
At 31 December										
Developed	382	300	7,168	18	3,581	1,301	4,674	1,748	3,316	22,487
Undeveloped	386	19	2,447	1	7,030	1,597	5,111	3,901	1,719	22,209
	768	318	9,615	18	10,610	2,897	9,785	5,648	5,035	44,695

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Includes 181 billion cubic feet of natural gas consumed in operations, 151 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.
[d] Includes 2,519 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 91 billion cubic feet of natural gas in respect of the 0.18% non-controlling interest in Rosneft.
[g] Total proved gas reserves held as part of our equity interest in Rosneft is 9,827 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 26 billion cubic feet in Vietnam and 9,785 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	280	225	2,525	2	564	486	–	582	735	5,399
Undeveloped	434	62	1,394	188	1,100	507	–	835	324	4,844
	714	287	3,919	190	1,664	993	–	1,417	1,059	10,243
Changes attributable to										
Revisions of previous estimates	(91)	(78)	96	(14)	(36)	(1)	–	90	(62)	(96)
Improved recovery	3	–	129	–	39	8	–	–	–	180
Purchases of reserves-in-place	6	–	1	–	–	–	–	68	–	74
Discoveries and extensions	21	–	1	–	47	1	–	54	–	123
Production[e f]	(23)	(24)	(258)	(1)	(146)	(121)	–	(86)	(60)	(717)
Sales of reserves-in-place	–	–	(109)	–	(5)	–	–	–	–	(114)
	(84)	(101)	(140)	(14)	(99)	(113)	–	126	(122)	(548)
At 31 December[g]										
Developed	232	160	2,588	12	426	477	–	675	618	5,187
Undeveloped	398	26	1,191	163	1,139	403	–	868	319	4,507
	630	186	3,779	175	1,565	880	–	1,543	937	9,694
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	–	–	–	–	552	50	3,782	133	–	4,517
Undeveloped	–	–	–	1	442	33	2,751	9	–	3,236
	–	–	–	1	994	83	6,533	142	–	7,753
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(11)	4	276	9	–	278
Improved recovery	–	–	–	–	16	–	–	–	–	16
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	22	–	219	–	–	241
Production[f]	–	–	–	–	(56)	(1)	(365)	(39)	–	(460)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	(29)	3	130	(29)	–	75
At 31 December[i j]										
Developed	–	–	–	–	528	86	3,834	100	–	4,548
Undeveloped	–	–	–	1	438	–	2,830	13	–	3,280
	–	–	–	1	965	86	6,663	112	–	7,828
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996
At 31 December										
Developed	232	160	2,588	12	954	563	3,834	775	618	9,735
Undeveloped	398	26	1,191	164	1,576	403	2,830	881	319	7,788
	630	186	3,779	176	2,530	966	6,663	1,656	937	17,523

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[e] Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.
[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 26 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.
[g] Includes 456 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[i] Includes 54 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.
[j] Total proved reserves held as part of our equity interest in Rosneft is 6,702 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 33 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,663 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil[a b]	Europe UK	Europe Rest of Europe	North America US[c]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	million barrels 2013 Total
Subsidiaries										
At 1 January										
Developed	228	153	1,127	–	16	306	–	268	45	2,143
Undeveloped	426	73	818	–	20	236	–	137	34	1,743
	654	226	1,945	–	36	542	–	405	79	3,886
Changes attributable to										
Revisions of previous estimates	(79)	(15)	(111)	–	1	30	–	65	(5)	(114)
Improved recovery	11	–	33	–	1	2	–	65	–	112
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	2	–	–	–	–	39	3	44
Production	(21)	(11)	(108)	–	(7)	(79)	–	(52)	(8)	(285)
Sales of reserves-in-place	(31)	–	(1)	–	–	–	–	–	–	(32)
	(120)	(26)	(185)	–	(5)	(47)	–	117	(10)	(276)
At 31 December[d]										
Developed	160	147	1,007	–	15	316	–	320	49	2,013
Undeveloped	374	53	752	–	17	180	–	202	19	1,597
	534	200	1,760	–	31	495	–	522	69	3,610
Equity-accounted entities (BP share)[e f]										
At 1 January										
Developed	–	–	–	–	336	3	2,433	198	–	2,970
Undeveloped	–	–	–	–	347	2	1,943	13	–	2,305
	–	–	–	–	683	5	4,376	211	–	5,275
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(14)	(1)	295	1	–	281
Improved recovery	–	–	–	–	27	–	–	–	–	27
Purchases of reserves-in-place	–	–	–	–	34	–	4,550	–	–	4,584
Discoveries and extensions	–	–	–	–	12	–	228	–	–	240
Production	–	–	–	–	(27)	–	(301)	(85)	–	(412)
Sales of reserves-in-place	–	–	–	–	(85)	–	(4,321)	–	–	(4,406)
	–	–	–	1	(53)	(1)	451	(84)	–	314
At 31 December[g]										
Developed	–	–	–	–	316	2	2,970	120	–	3,407
Undeveloped	–	–	–	1	314	2	1,858	7	–	2,182
	–	–	–	1	630	4	4,828	127	–	5,590
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	228	153	1,127	–	352	309	2,433	466	45	5,113
Undeveloped	426	73	818	–	367	239	1,943	150	34	4,048
	654	226	1,945	–	719	547	4,376	616	79	9,162
At 31 December										
Developed	160	147	1,007	–	331	317	2,970	440	49	5,421
Undeveloped	374	53	752	1	331	182	1,858	209	19	3,779
	534	200	1,760	1	661	499	4,828	649	69	9,200

[a] Crude oil includes condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Includes 8 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.
[g] Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,860 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 32 million barrels in Venezuela and 4,827 million barrels in Russia.

Movements in estimated net proved reserves – continued

million barrels

Natural gas liquids[a] [b]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	14	17	316	–	6	6	–	–	7	366
Undeveloped	5	6	171	–	12	19	–	–	11	225
	19	23	487	–	18	25	–	–	18	591
Changes attributable to										
Revisions of previous estimates	1	(4)	(30)	–	29	(4)	–	–	(7)	(15)
Improved recovery	1	–	19	–	–	–	–	–	–	20
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	2	–	–	–	–	–	–	2
Production[c]	(1)	(1)	(24)	–	(4)	(1)	–	–	(1)	(33)
Sales of reserves-in-place	(5)	–	(10)	–	–	–	–	–	–	(15)
	(4)	(5)	(43)	–	25	(5)	–	–	(8)	(40)
At 31 December[d]										
Developed	9	16	290	–	14	4	–	–	8	342
Undeveloped	6	2	155	–	28	15	–	–	3	209
	15	18	444	–	43	20	–	–	10	551
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	3	9	59	–	–	71
Undeveloped	–	–	–	–	4	9	19	–	–	32
	–	–	–	–	7	18	78	–	–	103
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(7)	(2)	89	–	–	81
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	29	–	–	29
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	(2)	–	–	(3)
Sales of reserves-in-place	–	–	–	–	–	–	(78)	–	–	(78)
	–	–	–	–	(7)	(2)	38	–	–	29
At 31 December[f]										
Developed	–	–	–	–	–	8	94	–	–	103
Undeveloped	–	–	–	–	–	8	21	–	–	29
	–	–	–	–	–	16	115	–	–	131
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	14	17	316	–	9	15	59	–	7	437
Undeveloped	5	6	171	–	16	27	19	–	11	257
	19	23	487	–	25	43	78	–	18	693
At 31 December										
Developed	9	16	290	–	14	13	94	–	8	444
Undeveloped	6	2	155	–	28	23	21	–	3	238
	15	18	444	–	43	36	115	–	10	682

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.
[d] Includes 13 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Total proved NGL reserves held as part of our equity interest in Rosneft is 115 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 115 million barrels in Russia.

Movements in estimated net proved reserves – continued

Bitumen[a b]	million barrels 2013 Rest of North America	Total
Subsidiaries		
At 1 January		
Developed	–	–
Undeveloped	195	195
	195	195
Changes attributable to		
Revisions of previous estimates	(7)	(7)
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	–	–
Production	–	–
Sales of reserves-in-place	–	–
	(7)	(7)
At 31 December		
Developed	–	–
Undeveloped	188	188
	188	188

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]	Europe UK	Europe Rest of Europe	North America US[c]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2013 Total
Subsidiaries										
At 1 January										
Developed	242	170	1,444	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	195	32	255	–	137	45	2,164
	673	249	2,433	195	54	567	–	405	96	4,673
Changes attributable to										
Revisions of previous estimates	(78)	(19)	(141)	(7)	30	26	–	65	(12)	(136)
Improved recovery	12	–	52	–	1	2	–	65	–	132
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	3	–	–	–	–	39	3	45
Production[d]	(22)	(13)	(132)	–	(11)	(80)	–	(52)	(9)	(319)
Sales of reserves-in-place	(36)	–	(12)	–	–	–	–	–	–	(48)
	(124)	(31)	(229)	(7)	20	(52)	–	117	(18)	(324)
At 31 December[e]										
Developed	169	163	1,297	–	29	320	–	320	57	2,354
Undeveloped	380	55	907	188	46	195	–	202	22	1,994
	549	217	2,204	188	74	515	–	523	78	4,348
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	691	23	4,453	211	–	5,378
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(21)	(3)	384	1	–	362
Improved recovery	–	–	–	–	27	–	–	–	–	27
Purchases of reserves-in-place	–	–	–	–	34	–	4,579	–	–	4,613
Discoveries and extensions	–	–	–	–	11	–	228	–	–	239
Production	–	–	–	–	(27)	–	(302)	(85)	–	(414)
Sales of reserves-in-place	–	–	–	–	(85)	–	(4,399)	–	–	(4,485)
	–	–	–	1	(61)	(3)	490	(84)	–	343
At 31 December[g h]										
Developed	–	–	–	–	316	10	3,063	120	–	3,510
Undeveloped	–	–	–	1	314	10	1,879	7	–	2,210
	–	–	–	1	630	20	4,943	127	–	5,721
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	242	170	1,444	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	195	384	266	1,962	150	45	4,501
	673	249	2,433	195	745	590	4,453	616	96	10,051
At 31 December										
Developed	169	163	1,297	–	345	331	3,063	440	57	5,865
Undeveloped	380	55	907	188	359	205	1,879	209	22	4,204
	549	217	2,204	189	704	535	4,943	650	78	10,069

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.
[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 23 million barrels in respect of the non-controlling interest in Rosneft.
[h] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,975 million barrels, comprising 1 million barrels in Canada, 32 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,943 million barrels in Russia.

Movements in estimated net proved reserves – continued

billion cubic feet

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		2013
Subsidiaries										
At 1 January										
Developed	1,038	340	8,245	4	3,588	1,139	–	926	3,282	18,562
Undeveloped	666	141	2,986	–	6,250	1,923	–	413	2,323	14,702
	1,704	481	11,231	4	9,838	3,062	–	1,339	5,605	33,264
Changes attributable to										
Revisions of previous estimates	(62)	(47)	(1,166)	10	62	(138)	–	2,148	(140)	667
Improved recovery	49	–	630	–	144	28	–	94	–	945
Purchases of reserves-in-place	9	–	–	–	–	–	–	–	–	9
Discoveries and extensions	–	–	39	–	–	55	–	1,875	511	2,480
Production[c]	(66)	(31)	(635)	(4)	(819)	(239)	–	(199)	(289)	(2,282)
Sales of reserves-in-place	(677)	–	(152)	–	–	–	–	(67)	–	(896)
	(747)	(78)	(1,284)	6	(613)	(294)	–	3,851	82	923
At 31 December[d]										
Developed	643	364	7,122	10	3,109	961	–	1,519	3,932	17,660
Undeveloped	314	39	2,825	–	6,116	1,807	–	3,671	1,755	16,527
	957	403	9,947	10	9,225	2,768	–	5,190	5,687	34,187
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	1,276	175	2,617	128	–	4,196
Undeveloped	–	–	–	–	904	164	1,759	18	–	2,845
	–	–	–	–	2,180	339	4,376	146	–	7,041
Changes attributable to										
Revisions of previous estimates	–	–	–	1	3	29	685	1	–	719
Improved recovery	–	–	–	–	64	–	–	3	–	67
Purchases of reserves-in-place	–	–	–	–	14	–	8,871	33	–	8,918
Discoveries and extensions	–	–	–	–	51	–	254	–	–	305
Production[c]	–	–	–	–	(163)	(3)	(292)	(23)	–	(481)
Sales of reserves-in-place	–	–	–	–	(38)	–	(4,669)	(74)	–	(4,781)
	–	–	–	1	(69)	26	4,849	(60)	–	4,747
At 31 December[f g]										
Developed	–	–	–	–	1,364	230	4,171	72	–	5,837
Undeveloped	–	–	–	1	747	135	5,054	14	–	5,951
	–	–	–	1	2,111	365	9,225	86	–	11,788
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	1,038	340	8,245	4	4,864	1,314	2,617	1,054	3,282	22,758
Undeveloped	666	141	2,986	–	7,154	2,087	1,759	431	2,323	17,547
	1,704	481	11,231	4	12,018	3,401	4,376	1,485	5,605	40,305
At 31 December										
Developed	643	364	7,122	10	4,473	1,191	4,171	1,591	3,932	23,497
Undeveloped	314	39	2,825	1	6,863	1,942	5,054	3,685	1,755	22,478
	957	403	9,947	11	11,336	3,133	9,225	5,276	5,687	45,975

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Includes 180 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities.
[d] Includes 2,685 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.
[g] Total proved gas reserves held as part of our equity interest in Rosneft is 9,271 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 31 billion cubic feet in Vietnam and 9,225 billion cubic feet in Russia.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]									million barrels of oil equivalent[c] 2013
	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	421	229	2,865	1	640	508	–	427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587	–	209	445	4,699
	967	332	4,369	196	1,750	1,095	–	636	1,063	10,408
Changes attributable to										
Revisions of previous estimates	(89)	(27)	(342)	(5)	41	3	–	435	(36)	(20)
Improved recovery	20	–	161	–	25	7	–	81	–	294
Purchases of reserves-in-place	2	–	–	–	–	–	–	–	–	2
Discoveries and extensions	–	–	10	–	–	9	–	363	91	473
Production[e f]	(34)	(18)	(241)	(1)	(152)	(121)	–	(86)	(59)	(712)
Sales of reserves-in-place	(152)	–	(38)	–	–	–	–	(12)	–	(202)
	(253)	(45)	(450)	(6)	(86)	(102)	–	781	(4)	(165)
At 31 December[g]										
Developed	280	225	2,525	2	564	486	–	582	735	5,399
Undeveloped	434	62	1,394	188	1,100	507	–	835	324	4,844
	714	287	3,919	190	1,664	993	–	1,417	1,059	10,243
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed	–	–	–	–	559	43	2,943	220	–	3,765
Undeveloped	–	–	–	–	508	39	2,265	15	–	2,827
	–	–	–	–	1,067	82	5,208	235	–	6,592
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(20)	2	502	1	–	486
Improved recovery	–	–	–	–	38	–	–	1	–	39
Purchases of reserves-in-place	–	–	–	–	36	–	6,108	6	–	6,150
Discoveries and extensions	–	–	–	–	20	–	272	–	–	292
Production[f]	–	–	–	–	(55)	(1)	(353)	(88)	–	(497)
Sales of reserves-in-place	–	–	–	–	(92)	–	(5,204)	(13)	–	(5,309)
	–	–	–	1	(73)	1	1,325	(93)	–	1,161
At 31 December[i j]										
Developed	–	–	–	–	552	50	3,782	133	–	4,517
Undeveloped	–	–	–	1	442	33	2,751	9	–	3,236
	–	–	–	1	994	83	6,533	142	–	7,753
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	421	229	2,865	1	1,199	551	2,943	647	618	9,474
Undeveloped	546	103	1,504	195	1,618	626	2,265	224	445	7,526
	967	332	4,369	196	2,817	1,177	5,208	871	1,063	17,000
At 31 December										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[e] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels of oil equivalent per day.
[f] Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 26 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.
[g] Includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[i] Includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.
[j] Total proved reserves held as part of our equity interest in Rosneft is 6,574 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 34 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,533 million barrels of oil equivalent in Russia.

Movements in estimated net proved reserves – continued

Crude oil[a b]										million barrels 2012
	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	276	66	1,337	–	23	304	–	176	50	2,233
Undeveloped	436	208	1,021	–	30	294	–	279	36	2,304
	712	274	2,357	–	53	598	–	455	86	4,537
Changes attributable to										
Revisions of previous estimates	(30)	(23)	(288)	–	(11)	(1)	–	(2)	–	(354)
Improved recovery	3	–	77	–	–	13	–	2	–	95
Purchases of reserves-in-place	4	–	4	–	–	–	–	–	–	8
Discoveries and extensions	–	1	10	–	–	2	–	–	–	12
Production	(30)	(8)	(115)	–	(6)	(70)	–	(51)	(8)	(287)
Sales of reserves-in-place	(6)	(18)	(101)	–	–	–	–	–	–	(124)
	(59)	(48)	(412)	–	(17)	(56)	–	(51)	(8)	(650)
At 31 December[d e]										
Developed	228	153	1,127	–	16	306	–	268	45	2,143
Undeveloped	426	73	818	–	20	236	–	137	34	1,743
	654	226	1,945	–	36	542	–	405	79	3,886
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	345	–	2,596	256	–	3,197
Undeveloped	–	–	–	–	344	3	1,613	58	–	2,018
	–	–	–	–	689	3	4,209	314	–	5,215
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(2)	3	377	(23)	–	355
Improved recovery	–	–	–	–	24	–	47	–	–	71
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	67	–	–	67
Production	–	–	–	–	(29)	–	(309)	(80)	–	(418)
Sales of reserves-in-place	–	–	–	–	–	–	(15)	–	–	(15)
	–	–	–	–	(7)	3	167	(103)	–	60
At 31 December[g h i]										
Developed	–	–	–	–	336	3	2,433	198	–	2,970
Undeveloped	–	–	–	–	347	2	1,943	13	–	2,305
	–	–	–	–	683	5	4,376	211	–	5,275
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	276	66	1,337	–	368	304	2,596	432	50	5,430
Undeveloped	436	208	1,021	–	375	297	1,613	337	36	4,322
	712	274	2,357	–	743	601	4,209	769	86	9,752
At 31 December										
Developed	228	153	1,127	–	352	309	2,433	466	45	5,113
Undeveloped	426	73	818	–	367	239	1,943	150	34	4,048
	654	226	1,945	–	719	547	4,376	616	79	9,162

[a] Crude oil includes condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Includes 9 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Includes assets held for sale of 39 million barrels.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 328 million barrels of crude oil in respect of the 7.35% non-controlling interest in TNK-BP.
[h] Total proved crude oil reserves held as part of our equity interest in TNK-BP is 4,463 million barrels, comprising 87 million barrels in Venezuela and 4,376 million barrels in Russia.
[i] Includes assets held for sale of 4,463 million barrels.

Movements in estimated net proved reserves – continued

million barrels

Natural gas liquids[a b]	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	12	3	348	–	4	7	–	1	9	383
Undeveloped	9	22	152	–	18	21	–	–	11	233
	21	25	501	–	22	28	–	1	20	616
Changes attributable to										
Revisions of previous estimates	–	(2)	8	–	–	–	–	–	–	5
Improved recovery	–	–	63	–	–	–	–	–	–	63
Purchases of reserves-in-place	–	–	17	–	–	–	–	–	–	17
Discoveries and extensions	–	–	13	–	–	–	–	–	–	14
Production[c]	(1)	–	(27)	–	(4)	(3)	–	–	(1)	(37)
Sales of reserves-in-place	–	–	(87)	–	–	–	–	–	–	(88)
	(1)	(2)	(14)	–	(4)	(3)	–	–	(1)	(26)
At 31 December[d]										
Developed	14	17	316	–	6	6	–	–	7	366
Undeveloped	5	6	171	–	12	19	–	–	11	225
	19	23	487	–	18	25	–	–	18	591
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed	–	–	–	–	4	–	–	–	–	4
Undeveloped	–	–	–	–	4	11	–	–	–	15
	–	–	–	–	8	11	–	–	–	19
Changes attributable to										
Revisions of previous estimates	–	–	–	–	–	6	85	–	–	91
Improved recovery	–	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	(7)	–	–	(7)
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	6	78	–	–	84
At 31 December[f g]										
Developed	–	–	–	–	3	9	59	–	–	71
Undeveloped	–	–	–	–	4	9	19	–	–	32
	–	–	–	–	7	18	78	–	–	103
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	12	3	348	–	8	7	–	1	9	387
Undeveloped	9	22	152	–	21	32	–	–	11	248
	21	25	501	–	29	39	–	1	20	635
At 31 December										
Developed	14	17	316	–	9	15	59	–	7	437
Undeveloped	5	6	171	–	16	27	19	–	11	257
	19	23	487	–	25	43	78	–	18	693

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels per day.
[d] Includes 5 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[f] Total proved NGL reserves held as part of our equity interest in TNK-BP is 78 million barrels, all in Russia.
[g] Includes assets held for sale of 78 million barrels.

Movements in estimated net proved reserves – continued

Bitumen[a b]	million barrels 2012 Rest of North America	Total
Subsidiaries		
At 1 January		
Developed	–	–
Undeveloped	178	178
	178	178
Changes attributable to		
Revisions of previous estimates	17	17
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	–	–
Production	–	–
Sales of reserves-in-place	–	–
	17	17
At 31 December		
Developed	–	–
Undeveloped	195	195
	195	195

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

Movements in estimated net proved reserves – continued

million barrels

Total liquids[a b]	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	287	69	1,686	–	27	311	–	177	59	2,617
Undeveloped	445	230	1,173	178	48	314	–	279	47	2,714
	733	299	2,859	178	75	625	–	456	106	5,331
Changes attributable to										
Revisions of previous estimates	(29)	(25)	(280)	18	(11)	(1)	–	(2)	–	(331)
Improved recovery	3	–	140	–	–	13	–	2	–	158
Purchases of reserves-in-place	4	–	21	–	–	–	–	–	–	24
Discoveries and extensions	–	1	23	–	–	2	–	–	–	26
Production[d]	(31)	(8)	(141)	–	(10)	(72)	–	(51)	(9)	(324)
Sales of reserves-in-place	(6)	(18)	(188)	–	–	–	–	–	–	(212)
	(59)	(51)	(425)	18	(21)	(59)	–	(51)	(10)	(658)
At 31 December[e f]										
Developed	242	170	1,444	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	195	32	255	–	137	45	2,164
	673	249	2,433	195	54	567	–	405	96	4,673
Equity-accounted entities (BP share)[g]										
At 1 January										
Developed	–	–	–	–	349	–	2,595	256	–	3,201
Undeveloped	–	–	–	–	348	14	1,614	58	–	2,034
	–	–	–	–	697	14	4,209	314	–	5,234
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(2)	9	462	(24)	–	445
Improved recovery	–	–	–	–	24	–	47	–	–	71
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	67	–	–	67
Production	–	–	–	–	(29)	–	(316)	(80)	–	(425)
Sales of reserves-in-place	–	–	–	–	–	–	(15)	–	–	(15)
	–	–	–	–	(7)	9	244	(103)	–	144
At 31 December[h i j]										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	691	23	4,453	211	–	5,378
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	287	69	1,686	–	376	311	2,595	433	59	5,817
Undeveloped	445	230	1,173	178	396	328	1,614	337	47	4,748
	733	299	2,859	178	772	640	4,209	770	106	10,565
At 31 December										
Developed	242	170	1,444	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	195	384	266	1,962	150	45	4,501
	673	249	2,433	195	745	590	4,453	616	96	10,051

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[d] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels of oil equivalent per day.
[e] Also includes 14 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[f] Includes assets held for sale of 4,540 million barrels.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[h] Includes 328 million barrels in respect of the non-controlling interest in TNK-BP.
[i] Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,540 million barrels, comprising 87 million barrels in Venezuela and 4,454 million barrels in Russia.
[j] Includes assets held for sale of 39 million barrels.

Movements in estimated net proved reserves – continued

billion cubic feet

Natural gas[a b]										2012
	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	1,411	43	9,721	28	2,869	1,224	–	1,034	3,570	19,900
Undeveloped	909	450	3,831	–	6,529	2,033	–	364	2,365	16,481
	2,320	493	13,552	28	9,398	3,257	–	1,398	5,935	36,381
Changes attributable to										
Revisions of previous estimates	(18)	(13)	(1,853)	(19)	(116)	(14)	–	38	(41)	(2,036)
Improved recovery	95	–	885	–	756	69	–	156	–	1,961
Purchases of reserves-in-place	17	(1)	232	–	–	–	–	–	–	248
Discoveries and extensions	–	7	225	–	598	1	–	–	–	831
Production[c]	(164)	(5)	(661)	(5)	(775)	(251)	–	(253)	(289)	(2,403)
Sales of reserves-in-place	(546)	–	(1,149)	–	(23)	–	–	–	–	(1,718)
	(616)	(12)	(2,321)	(24)	440	(195)	–	(59)	(330)	(3,117)
At 31 December[d e]										
Developed	1,038	340	8,245	4	3,588	1,139	–	926	3,282	18,562
Undeveloped	666	141	2,986	–	6,250	1,923	–	413	2,323	14,702
	1,704	481	11,231	4	9,838	3,062	–	1,339	5,605	33,264
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed	–	–	–	–	1,144	–	2,119	104	–	3,367
Undeveloped	–	–	–	–	1,006	195	659	51	–	1,911
	–	–	–	–	2,150	195	2,778	155	–	5,278
Changes attributable to										
Revisions of previous estimates	–	–	–	–	86	144	569	25	–	824
Improved recovery	–	–	–	–	110	–	–	1	–	111
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	3	–	1,310	–	–	1,313
Production[c]	–	–	–	–	(169)	–	(280)	(35)	–	(484)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	30	144	1,598	(9)	–	1,763
At 31 December[g h i]										
Developed	–	–	–	–	1,276	175	2,617	128	–	4,196
Undeveloped	–	–	–	–	904	164	1,759	18	–	2,845
	–	–	–	–	2,180	339	4,376	146	–	7,041
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	1,411	43	9,721	28	4,013	1,224	2,119	1,138	3,570	23,267
Undeveloped	909	450	3,831	–	7,535	2,228	659	415	2,365	18,392
	2,320	493	13,552	28	11,548	3,452	2,778	1,553	5,935	41,659
At 31 December										
Developed	1,038	340	8,245	4	4,864	1,314	2,617	1,054	3,282	22,758
Undeveloped	666	141	2,986	–	7,154	2,087	1,759	431	2,323	17,547
	1,704	481	11,231	4	12,018	3,401	4,376	1,485	5,605	40,305

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] Includes 190 billion cubic feet of natural gas consumed in operations, 145 billion cubic feet in subsidiaries, 45 billion cubic feet in equity-accounted entities and excludes 9 billion cubic feet of produced non-hydrocarbon components that meet regulatory requirements for sales.
[d] Includes 2,890 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[e] Includes assets held for sale of 590 billion cubic feet.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 270 billion cubic feet of natural gas in respect of the 6.17% non-controlling interest in TNK-BP.
[h] Total proved gas reserves held as part of our equity interest in TNK-BP is 4,492 billion cubic feet, comprising 38 billion cubic feet in Venezuela, 78 billion cubic feet in Vietnam and 4,376 billion cubic feet in Russia.
[i] Includes assets held for sale of 4,492 billion cubic feet.

Movements in estimated net proved reserves – continued

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
million barrels of oil equivalent[c]										**2012**
Subsidiaries										
At 1 January										
Developed	531	76	3,362	5	522	522	–	355	675	6,048
Undeveloped	602	308	1,833	178	1,173	665	–	342	455	5,556
	1,133	384	5,195	183	1,695	1,187	–	697	1,130	11,604
Changes attributable to										
Revisions of previous estimates	(33)	(27)	(600)	14	(31)	(3)	–	5	(8)	(683)
Improved recovery	19	–	293	–	130	25	–	29	–	496
Purchases of reserves-in-place	7	–	61	–	–	–	–	–	–	68
Discoveries and extensions	–	2	62	–	103	2	–	–	–	169
Production[e f]	(59)	(9)	(256)	(1)	(143)	(116)	–	(95)	(59)	(738)
Sales of reserves-in-place	(100)	(18)	(386)	–	(4)	–	–	–	–	(508)
	(166)	(52)	(826)	13	55	(92)	–	(61)	(67)	(1,196)
At 31 December[g h]										
Developed	421	229	2,865	1	640	508	–	427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587	–	209	445	4,699
	967	332	4,369	196	1,750	1,095	–	636	1,063	10,408
Equity-accounted entities (BP share)[i]										
At 1 January										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	–	522	48	1,727	66	–	2,363
	–	–	–	–	1,068	48	4,688	340	–	6,144
Changes attributable to										
Revisions of previous estimates	–	–	–	–	13	34	560	(19)	–	588
Improved recovery	–	–	–	–	43	–	47	–	–	90
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	1	–	292	–	–	293
Production[e f]	–	–	–	–	(58)	–	(364)	(86)	–	(508)
Sales of reserves-in-place	–	–	–	–	–	–	(15)	–	–	(15)
	–	–	–	–	(1)	34	520	(105)	–	448
At 31 December[j k l]										
Developed	–	–	–	–	559	43	2,943	220	–	3,765
Undeveloped	–	–	–	–	508	39	2,265	15	–	2,827
	–	–	–	–	1,067	82	5,208	235	–	6,592
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	531	76	3,362	5	1,068	522	2,961	629	675	9,829
Undeveloped	602	308	1,833	178	1,695	713	1,727	408	455	7,919
	1,133	384	5,195	183	2,763	1,235	4,688	1,037	1,130	17,748
At 31 December										
Developed	421	229	2,865	1	1,199	551	2,943	647	618	9,474
Undeveloped	546	103	1,504	195	1,618	626	2,265	224	445	7,526
	967	332	4,369	196	2,817	1,177	5,208	871	1,063	17,000

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.
[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.
[e] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels of oil equivalent per day.
[f] Includes 33 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 8 million barrels of oil equivalent in equity-accounted entities and excludes 2 million barrels of oil equivalent of produced non-hydrocarbon components that meet regulatory requirements for sales.
[g] Includes 591 million barrels of NGLs. Also includes 512 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[h] Includes assets held for sale of 140 million barrels of oil equivalent.
[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[j] Includes 103 million barrels of NGLs. Also includes 374 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.
[k] Total proved reserves held as part of our equity interest in TNK-BP is 5,315 million barrels of oil equivalent, comprising 93 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 5,208 million barrels of oil equivalent in Russia.
[l] Includes assets held for sale of 5,315 million barrels of oil equivalent.

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

The following tables set out the standardized measure of discounted future net cash flows, and changes therein, relating to crude oil and natural gas production from the group's estimated proved reserves. This information is prepared in compliance with FASB Oil and Gas Disclosures requirements.

Future net cash flows have been prepared on the basis of certain assumptions which may or may not be realized. These include the timing of future production, the estimation of crude oil and natural gas reserves and the application of average crude oil and natural gas prices and exchange rates from the previous 12 months. Furthermore, both proved reserves estimates and production forecasts are subject to revision as further technical information becomes available and economic conditions change. BP cautions against relying on the information presented because of the highly arbitrary nature of the assumptions on which it is based and its lack of comparability with the historical cost information presented in the financial statements.

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	54,400	14,900	216,600	11,000	35,300	55,800	–	90,300	54,800	533,100
Future production cost[b]	21,400	8,100	90,500	4,800	11,300	15,600	–	41,500	17,600	210,800
Future development cost[b]	7,300	1,400	24,500	1,600	8,000	9,600	–	23,000	5,700	81,100
Future taxation[c]	16,400	3,000	32,900	700	8,400	10,100	–	5,100	9,400	86,000
Future net cash flows	9,300	2,400	68,700	3,900	7,600	20,500	–	20,700	22,100	155,200
10% annual discount[d]	4,700	700	33,100	2,500	3,100	7,800	–	11,000	11,800	74,700
Standardized measure of discounted future net cash flows[e]	4,600	1,700	35,600	1,400	4,500	12,700	–	9,700	10,300	80,500
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	47,300	–	349,200	10,200	–	406,700
Future production cost[b]	–	–	–	–	22,300	–	200,000	7,800	–	230,100
Future development cost[b]	–	–	–	–	5,700	–	17,400	2,100	–	25,200
Future taxation[c]	–	–	–	–	6,700	–	24,200	100	–	31,000
Future net cash flows	–	–	–	–	12,600	–	107,600	200	–	120,400
10% annual discount[d]	–	–	–	–	8,000	–	65,500	–	–	73,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	4,600	–	42,100	200	–	46,900
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	4,600	1,700	35,600	1,400	9,100	12,700	42,100	9,900	10,300	127,400

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

$ million

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(30,500)	(6,900)	(37,400)
Development costs for the current year as estimated in previous year	15,700	3,600	19,300
Extensions, discoveries and improved recovery, less related costs	1,900	1,500	3,400
Net changes in prices and production cost	(17,000)	10,500	(6,500)
Revisions of previous reserves estimates	1,200	2,000	3,200
Net change in taxation	17,300	(4,900)	12,400
Future development costs	(4,500)	(400)	(4,900)
Net change in purchase and sales of reserves-in-place	(700)	–	(700)
Addition of 10% annual discount	8,800	3,800	12,600
Total change in the standardized measure during the year[i]	(7,800)	9,200	1,400

[a] The marker prices used were Brent $101.27/bbl, Henry Hub $4.31/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,400 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Non-controlling interests in Rosneft amounted to $100 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within 'Net changes in prices and production cost'.

										$ million
										2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	66,200	26,300	234,500	9,400	40,000	67,500	–	89,000	57,600	590,500
Future production cost[b]	21,900	11,200	99,000	4,600	11,600	17,800	–	35,000	20,000	221,100
Future development cost[b]	6,500	2,000	27,700	2,000	7,600	10,900	–	23,700	6,900	87,300
Future taxation[c]	23,900	8,000	37,000	400	11,100	14,300	–	6,200	8,100	109,000
Future net cash flows	13,900	5,100	70,800	2,400	9,700	24,500	–	24,100	22,600	173,100
10% annual discount[d]	6,800	2,200	34,300	1,900	4,200	9,300	–	13,300	12,800	84,800
Standardized measure of discounted future net cash flows[e]	7,100	2,900	36,500	500	5,500	15,200	–	10,800	9,800	88,300
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	45,800	–	255,600	14,300	–	315,700
Future production cost[b]	–	–	–	–	22,500	–	139,000	11,800	–	173,300
Future development cost[b]	–	–	–	–	6,000	–	19,700	2,100	–	27,800
Future taxation[c]	–	–	–	–	5,900	–	15,200	100	–	21,200
Future net cash flows	–	–	–	–	11,400	–	81,700	300	–	93,400
10% annual discount[d]	–	–	–	–	6,900	–	48,700	100	–	55,700
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	4,500	–	33,000	200	–	37,700
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	7,100	2,900	36,500	500	10,000	15,200	33,000	11,000	9,800	126,000

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(30,600)	(7,900)	(38,500)
Development costs for the current year as estimated in previous year	14,000	3,200	17,200
Extensions, discoveries and improved recovery, less related costs	1,900	2,000	3,900
Net changes in prices and production cost	(1,800)	(100)	(1,900)
Revisions of previous reserves estimates	(3,100)	(400)	(3,500)
Net change in taxation	12,900	3,400	16,300
Future development costs	(4,100)	(2,100)	(6,200)
Net change in purchase and sales of reserves-in-place	(3,500)	9,000	5,500
Addition of 10% annual discount	9,300	2,800	12,100
Total change in the standardized measure during the year[i]	(5,000)	9,900	4,900

[a] The marker prices used were Brent $108.02/bbl, Henry Hub $3.66/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,700 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Non-controlling interests in Rosneft amounted to $200 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Total change in the standardized measure during the year includes the effect of exchange rate movements.

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

										$ million
										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	88,000	30,800	261,100	9,500	30,400	75,800	–	54,200	54,300	604,100
Future production cost[b]	24,600	10,400	117,000	4,600	10,700	17,200	–	14,000	19,000	217,500
Future development cost[b]	7,400	2,400	29,600	2,400	7,700	13,000	–	10,900	3,700	77,100
Future taxation[c]	35,200	11,700	40,700	400	6,300	17,500	–	6,900	8,400	127,100
Future net cash flows	20,800	6,300	73,800	2,100	5,700	28,100	–	22,400	23,200	182,400
10% annual discount[d]	10,900	2,400	40,100	2,000	2,700	10,900	–	8,300	11,800	89,100
Standardized measure of discounted future net cash flows[e]	9,900	3,900	33,700	100	3,000	17,200	–	14,100	11,400	93,300
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	49,400	–	203,600	24,400	–	277,400
Future production cost[b]	–	–	–	–	24,800	–	133,400	21,000	–	179,200
Future development cost[b]	–	–	–	–	5,500	–	16,600	1,900	–	24,000
Future taxation[c]	–	–	–	–	6,600	–	10,100	200	–	16,900
Future net cash flows	–	–	–	–	12,500	–	43,500	1,300	–	57,300
10% annual discount[d]	–	–	–	–	7,600	–	21,600	300	–	29,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	4,900	–	21,900	1,000	–	27,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[i]	9,900	3,900	33,700	100	7,900	17,200	21,900	15,100	11,400	121,100

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

			$ million
	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
Sales and transfers of oil and gas produced, net of production costs	(34,600)	(8,300)	(42,900)
Development costs for the current year as estimated in previous year	14,400	3,100	17,500
Extensions, discoveries and improved recovery, less related costs	8,000	1,200	9,200
Net changes in prices and production cost	(15,300)	2,900	(12,400)
Revisions of previous reserves estimates	(16,000)	(1,000)	(17,000)
Net change in taxation	23,200	300	23,500
Future development costs	(7,700)	(500)	(8,200)
Net change in purchase and sales of reserves-in-place	(6,800)	(100)	(6,900)
Addition of 10% annual discount	11,600	2,800	14,400
Total change in the standardized measure during the year[j]	(23,200)	400	(22,800)

[a] The marker prices used were Brent $111.13/bbl, Henry Hub $2.75/mmBtu.
[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.
[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.
[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.
[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $900 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Non-controlling interests in TNK-BP amounted to $1,600 million in Russia.
[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.
[i] Includes future net cash flows for assets held for sale at 31 December 2012.
[j] Total change in the standardized measure during the year includes the effect of exchange rate movements.

Operational and statistical information

The following tables present operational and statistical information related to production, drilling, productive wells and acreage. Figures include amounts attributable to assets held for sale.

Crude oil and natural gas production

The following table shows crude oil, natural gas liquids and natural gas production for the years ended 31 December 2014, 2013 and 2012.

Production for the year[a] [b]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[c]	Rest of Asia		
Subsidiaries										
Crude oil[d]										thousand barrels per day
2014	**46**	**41**	**347**	**–**	**13**	**222**	**–**	**156**	**19**	**844**
2013	58	31	305	–	17	217	–	141	21	789
2012	81	22	327	–	16	191	–	137	22	795
Natural gas liquids										thousand barrels per day
2014	**2**	**5**	**63**	**–**	**12**	**5**	**–**	**–**	**3**	**91**
2013	3	4	58	–	12	3	–	1	4	86
2012	5	1	64	1	13	7	–	2	4	96
Natural gas[e]										million cubic feet per day
2014	**71**	**102**	**1,519**	**10**	**2,147**	**513**	**–**	**408**	**814**	**5,585**
2013	157	80	1,539	11	2,221	561	–	490	784	5,845
2012	414	8	1,651	13	2,097	590	–	633	787	6,193
Equity-accounted entities (BP share)										
Crude oil[d]										thousand barrels per day
2014	**–**	**–**	**–**	**–**	**65**	**–**	**816**	**98**	**–**	**979**
2013	–	–	–	–	62	–	826	232	–	1,120
2012	–	–	–	–	64	–	857	217	–	1,137
Natural gas liquids										thousand barrels per day
2014	**–**	**–**	**–**	**–**	**3**	**4**	**5**	**–**	**–**	**12**
2013	–	–	–	–	3	5	11	–	–	19
2012	–	–	–	–	3	5	20	–	–	27
Natural gas[e]										million cubic feet per day
2014	**–**	**–**	**–**	**–**	**402**	**–**	**1,084**	**28**	**–**	**1,515**
2013	–	–	–	–	384	–	801	30	–	1,216
2012	–	–	–	–	390	–	785	26	–	1,200

[a] Production excludes royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.
[b] Because of rounding, some totals may not exactly agree with the sum of their component parts.
[c] Amounts reported for Russia include BP's share of Rosneft (2014, 2013), and TNK-BP (2012) worldwide activities, including insignificant amounts outside Russia.
[d] Crude oil includes condensate.
[e] Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

The following tables show the number of gross and net productive oil and natural gas wells and total gross and net developed and undeveloped oil and natural gas acreage in which the group and its equity-accounted entities had interests as at 31 December 2014. A 'gross' well or acre is one in which a whole or fractional working interest is owned, while the number of 'net' wells or acres is the sum of the whole or fractional working interests in gross wells or acres. Productive wells are producing wells and wells capable of production. Developed acreage is the acreage within the boundary of a field, on which development wells have been drilled, which could produce the reserves; while undeveloped acres are those on which wells have not been drilled or completed to a point that would permit the production of commercial quantities, whether or not such acres contain proved reserves.

		Europe		North America		South America	Africa	Asia		Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Number of productive wells at 31 December 2014											
Oil wells[b]	– gross	**116**	**65**	**2,407**	**119**	**4,752**	**634**	**44,548**	**936**	**12**	**53,589**
	– net	**71**	**26**	**823**	**31**	**2,620**	**446**	**8,798**	**302**	**2**	**13,119**
Gas wells[c]	– gross	**67**	**6**	**22,676**	**363**	**728**	**139**	**383**	**833**	**61**	**25,256**
	– net	**28**	**1**	**9,339**	**180**	**262**	**53**	**76**	**314**	**13**	**10,266**
Oil and natural gas acreage at 31 December 2014											Thousands of acres
Developed	– gross	**131**	**39**	**6,355**	**232**	**1,365**	**637**	**4,581**	**837**	**194**	**14,371**
	– net	**73**	**16**	**3,285**	**110**	**407**	**223**	**865**	**259**	**36**	**5,274**
Undeveloped[d]	– gross	**1,208**	**1,754**	**7,378**	**9,702**	**28,183**	**33,833**	**378,899**	**6,988**	**20,050**	**487,995**
	– net	**755**	**648**	**5,365**	**5,564**	**11,593**	**21,799**	**74,009**	**2,302**	**10,755**	**132,790**

[a] Based on information received from Rosneft as at 31 December 2014.
[b] Includes approximately 11,271 gross (2,237 net) multiple completion wells (more than one formation producing into the same well bore).
[c] Includes approximately 3,239 gross (1,482 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.
[d] Undeveloped acreage includes leases and concessions.

Net oil and gas wells completed or abandoned

The following table shows the number of net productive and dry exploratory and development oil and natural gas wells completed or abandoned in the years indicated by the group and its equity-accounted entities. Productive wells include wells in which hydrocarbons were encountered and the drilling or completion of which, in the case of exploratory wells, has been suspended pending further drilling or evaluation. A dry well is one found to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2014										
Exploratory										
Productive	**2.9**	**–**	**5.3**	**–**	**3.7**	**0.7**	**5.3**	**0.6**	**–**	**18.5**
Dry	**0.5**	**–**	**7.9**	**–**	**1.4**	**1.6**	**–**	**1.4**	**0.2**	**13.0**
Development										
Productive	**3.1**	**1.8**	**294.1**	**1.5**	**100.5**	**13.8**	**76.2**	**46.3**	**–**	**537.3**
Dry	**–**	**0.8**	**–**	**0.1**	**3.9**	**1.0**	**–**	**0.4**	**0.4**	**6.6**
2013										
Exploratory										
Productive	1.0	–	12.7	–	4.5	1.5	4.0	3.5	–	27.2
Dry	–	–	1.1	–	1.4	0.6	–	0.9	0.5	4.5
Development										
Productive	1.0	1.2	285.7	–	94.6	12.6	395.0	58.0	0.2	848.3
Dry	–	0.2	0.4	–	2.7	0.2	–	0.7	0.4	4.6
2012										
Exploratory										
Productive	–	0.3	17.1	–	5.8	2.3	14.7	–	–	40.2
Dry	0.2	–	0.6	–	1.0	0.5	5.0	–	–	7.3
Development										
Productive	1.6	–	317.8	–	78.9	17.7	552.5	43.1	–	1,011.6
Dry	–	–	–	–	–	1.0	–	9.5	–	10.5

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as of 31 December 2014. Suspended development wells and long-term suspended exploratory wells are also included in the table.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2014										
Exploratory										
Gross	**–**	**–**	**7.0**	**–**	**3.0**	**6.0**	**–**	**–**	**1.0**	**17.0**
Net	**–**	**–**	**5.6**	**–**	**0.6**	**4.0**	**–**	**–**	**0.2**	**10.4**
Development										
Gross	**2.0**	**1.0**	**339.0**	**1.0**	**47.0**	**25.0**	**–**	**66.0**	**15.0**	**496.0**
Net	**1.1**	**0.4**	**119.6**	**0.1**	**17.7**	**6.6**	**–**	**22.5**	**1.4**	**169.4**

Parent company financial statements of BP p.l.c.

Company balance sheet

At 31 December	Note	2014	2013
			$ million
Fixed assets			
Investments			
Subsidiary undertakings	3	**139,239**	134,125
Associated undertakings	3	**2**	2
Total fixed assets		**139,241**	134,127
Current assets			
Debtors – amounts falling due within one year	4	**7,159**	21,550
Deferred taxation	2	**–**	41
Cash at bank and in hand		**31**	6
		7,190	21,597
Creditors – amounts falling due within one year	5	**2,867**	4,267
Net current assets		**4,323**	17,330
Total assets less current liabilities		**143,564**	151,457
Creditors – amounts falling due after more than one year	5	**4,653**	4,642
Net assets excluding pension plan (deficit) surplus		**138,911**	146,815
Defined benefit pension plan (deficit) surplus	6	**(584)**	979
Net assets		**138,327**	147,794
Represented by			
Capital and reserves			
Called-up share capital	7	**5,023**	5,129
Share premium account	8	**10,260**	10,061
Capital redemption reserve	8	**1,413**	1,260
Merger reserve	8	**26,509**	26,509
Treasury shares	8	**(20,719)**	(20,971)
Profit and loss account	8	**115,841**	125,806
		138,327	147,794

The financial statements on pages 197–206 were approved and signed by the group chief executive on 3 March 2015 having been duly authorized to do so by the board of directors:

R W Dudley Group Chief Executive

Financial statements

The parent company financial statements of BP p.l.c. on pages 197-206 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company cash flow statement

For the year ended 31 December

	Note	2014	2013
			$ million
Net cash inflow (outflow) from operating activities	9	**13,253**	(4,813)
Servicing of finance and returns on investments			
Interest received		**192**	116
Interest paid		**(23)**	(43)
Dividends received		**2,129**	16,228
Net cash inflow from servicing of finance and returns on investments		**2,298**	16,301
Tax paid		**(1)**	(2)
Capital expenditure and financial investment			
Payments for fixed assets – investments		**(5,085)**	(690)
Net cash outflow for capital expenditure and financial investment		**(5,085)**	(690)
Equity dividends paid		**(5,850)**	(5,441)
Net cash inflow before financing		**4,615**	5,355
Financing			
Other share-based payment movements		**207**	135
Repurchases of ordinary share capital		**(4,797)**	(5,493)
Net cash outflow from financing		**(4,590)**	(5,358)
Increase (decrease) in cash	9	**25**	(3)

Company statement of total recognized gains and losses

For the year ended 31 December

	Note	2014	2013
			$ million
Profit for the year		**2,100**	15,691
Currency translation differences		**31**	47
Actuarial (loss) gain relating to pensions	6	**(2,634)**	2,108
Tax on actuarial (loss) gain relating to pensions	2	**41**	(41)
Total recognized gains and losses relating to the year		**(462)**	17,805

The parent company financial statements of BP p.l.c. on pages 197-206 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Notes on the financial statements

1. Accounting policies

Accounting standards

These accounts are prepared on a going concern basis and in accordance with the Companies Act 2006 and applicable UK accounting standards.

Accounting convention

The financial statements are prepared under the historical cost convention.

Foreign currency transactions

Functional currency is the currency of the primary economic environment in which an entity operates and is normally the currency in which the entity primarily generates and expends cash. Transactions in foreign currencies are initially recorded in the functional currency by applying the rate of exchange ruling at the date of the transaction. Monetary assets and liabilities denominated in foreign currencies are retranslated into the functional currency at the rate of exchange ruling at the balance sheet date. Any resulting exchange differences are included in profit for the year. Exchange adjustments arising when the opening net assets and the profits for the year retained by non-US dollar functional currency branches are translated into US dollars are taken to a separate component of equity and reported in the statement of total recognized gains and losses.

Investments

Investments in subsidiaries and associated undertakings are recorded at cost. The company assesses investments for impairment whenever events or changes in circumstances indicate that the carrying value of an investment may not be recoverable. If any such indication of impairment exists, the company makes an estimate of its recoverable amount. Where the carrying amount of an investment exceeds its recoverable amount, the investment is considered impaired and is written down to its recoverable amount.

Share-based payments

Equity-settled transactions

The cost of equity-settled transactions with employees of the company and other members of the group is measured by reference to the fair value at the date at which equity instruments are granted and is recognized as an expense over the vesting period, which ends on the date on which the employees become fully entitled to the award. A corresponding credit is recognized within equity. Fair value is determined by using an appropriate, widely used, valuation model. In valuing equity-settled transactions, no account is taken of any vesting conditions, other than conditions linked to the price of the shares of the company (market conditions). Non-vesting conditions, such as the condition that employees contribute to a savings-related plan, are taken into account in the grant-date fair value, and failure to meet a non-vesting condition, where this is within the control of the employee, is treated as a cancellation.

Cash-settled transactions

The cost of cash-settled transactions 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 each balance sheet date until settlement, with changes in fair value recognized in the income statement.

Pensions

The cost of providing benefits under the defined benefit plans is determined separately for each plan using the projected unit credit method, which attributes entitlement to benefits to the current period (to determine current service cost) and to the current and prior periods (to determine the present value of the defined benefit obligation). Past service costs and settlement costs are recognized immediately when the company becomes committed to a change in pension plan design, or when a curtailment or settlement event occurs.

The interest element of the defined benefit cost represents the change in present value of scheme obligations resulting from the passage of time, and is determined by applying the discount rate to the opening present value of the benefit obligation, taking into account material changes in the obligation during the year. The expected return on plan assets is based on an assessment made at the beginning of the year of long-term market returns on plan assets, adjusted for the effect on the fair value of plan assets of contributions received and benefits paid during the year. The difference between the expected return on plan assets and the interest cost is recognized in the income statement as other finance income or expense.

Actuarial gains and losses are recognized in full within the statement of total recognized gains and losses in the period in which they occur.

The defined benefit pension plan surplus or deficit in the balance sheet comprises the total for each plan of the present value of the defined benefit obligation (using a discount rate based on high quality corporate bonds), less the fair value of plan assets out of which the obligations are to be settled directly. Fair value is based on market price information and, in the case of quoted securities, is the published bid price. The surplus or deficit, net of taxation thereon, is presented separately above the total for net assets on the face of the balance sheet. Deferred benefit pension plan surpluses are only recognized to the extent they are recoverable.

The BP Pension Fund is operated in a way that does not allow the individual participating employing companies in the pension fund to identify their share of the underlying assets and liabilities of the fund, and hence the company recognizes the full defined benefit pension plan surplus or deficit in its balance sheet.

Deferred taxation

Deferred tax is recognized in respect of all timing differences that have originated but not reversed at the balance sheet date where transactions or events have occurred at that date that will result in an obligation to pay more, or a right to pay less, tax in the future.

Deferred tax assets are recognized only to the extent that it is considered more likely than not that there will be suitable taxable profits from which the underlying timing differences can be deducted.

Deferred tax is measured on an undiscounted basis at the tax rates that are expected to apply in the periods in which timing differences reverse, based on tax rates and laws enacted or substantively enacted at the balance sheet date.

Use of estimates

The preparation of accounts in conformity with generally accepted accounting practice requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the accounts and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from these estimates.

The parent company financial statements of BP p.l.c. on pages 197-206 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

2. Taxation

Tax charge included in the statement of total recognized gains and losses	2014	2013
		$ million
Deferred tax		
Origination and reversal of timing differences in the current year	**–**	–
This comprises:		
Actuarial gain relating to pensions and other post-retirement benefits	**(41)**	41
Other taxable timing differences	**41**	(41)

Deferred tax	2014	2013
Deferred tax liability		
Pensions	**–**	41
Deferred tax asset		
Other taxable timing differences	**–**	41
Net deferred tax liability (asset)	**–**	–
Analysis of movements during the year		
At 1 January	**–**	–
Charge (credit) for the year on ordinary activities	**41**	(41)
(Credit) charge for the year in the statement of total recognized gains and losses	**(41)**	41
At 31 December	**–**	–

At 31 December 2014, deferred tax assets of $95 million on other timing differences and $25 million on pensions (2013 $72 million on other timing differences) were not recognized as it is not considered more likely than not that suitable taxable profits will be available in the company from which the future reversal of the underlying timing differences can be deducted. It is anticipated that the reversal of these timing differences will benefit other group companies in the future.

3. Fixed assets – investments

	Subsidiary undertakings	Associated undertakings		$ million
	Shares	Shares	Loans	Total
Cost				
At 1 January 2014	**134,199**	**2**	**2**	**134,203**
Additions	**5,114**	**–**	**–**	**5,114**
Disposals	**–**	**–**	**(2)**	**(2)**
At 31 December 2014	**139,313**	**2**	**–**	**139,315**
Amounts provided				
At 1 January 2014	**74**	**–**	**2**	**76**
Disposals	**–**	**–**	**(2)**	**(2)**
At 31 December 2014	**74**	**–**	**–**	**74**
Cost				
At 1 January 2013	133,494	2	2	133,498
Additions	705	–	–	705
At 31 December 2013	134,199	2	2	134,203
Amounts provided				
At 1 January 2013	74	–	2	76
At 31 December 2013	74	–	2	76
Net book amount				
At 31 December 2014	**139,239**	**2**	**–**	**139,241**
At 31 December 2013	134,125	2	–	134,127

The more important subsidiary undertakings of the company at 31 December 2014 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. A complete list of investments in subsidiary undertakings, joint ventures and associated undertakings will be attached to the company's annual return made to the Registrar of Companies.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings	100	England & Wales	Investment holding
BP Global Investments	100	England & Wales	Investment holding
BP International	100	England & Wales	Integrated oil operations
BP Shipping	100	England & Wales	Shipping
Burmah Castrol	100	Scotland	Lubricants
Canada			
BP Holdings Canada	100	England & Wales	Investment holding
US			
BP Holdings North America	100	England & Wales	Investment holding

The carrying value of BP International in the accounts of the company at 31 December 2014 was $67.63 billion (2013 $62.63 billion).

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4. Debtors

	$ million	
	2014	2013
	Within 1 year	Within 1 year
Group undertakings	**7,159**	21,550
	7,159	21,550

The carrying amounts of debtors approximate their fair value.

5. Creditors

				$ million
		2014		2013
	Within 1 year	**After 1 year**	Within 1 year	After 1 year
Group undertakings	**2,476**	**4,563**	2,526	4,584
Accruals and deferred income	**391**	**90**	1,540	58
Other creditors	**–**	**–**	201	–
	2,867	**4,653**	4,267	4,642

The carrying amounts of creditors approximate their fair value.

Amounts falling due after one year include $4,236 million (2013 $4,236 million), payable to a group undertaking. This amount is subject to interest payable quarterly at LIBOR plus 55 basis points.

The maturity profile of the financial liabilities included in the balance sheet at 31 December is shown in the table below. These amounts are included within Creditors – amounts falling due after more than one year, and are denominated in US dollars.

		$ million
	2014	2013
Due within		
1 to 2 years	**404**	372
2 to 5 years	**13**	22
More than 5 years	**4,236**	4,248
	4,653	4,642

6. Pensions

The primary pension arrangement in the UK is a funded final salary pension plan under which retired employees draw the majority of their benefit as an annuity. This pension plan is governed by a corporate trustee whose board is composed of four member-nominated directors, four company-nominated directors, including an independent director and an independent chairman nominated by the company. The trustee board is required by law to act in the best interests of the plan participants and is responsible for setting certain policies, such as investment policies of the plan. The UK plan is closed to new joiners but remains open to ongoing accrual for current members. New joiners in the UK are eligible for membership of a defined contribution plan.

For the primary UK plan there is a funding agreement between the company and the trustee. On an annual basis the latest funding position is reviewed and a schedule of contributions covering the next five years is agreed. The funding agreement can be terminated unilaterally by either party with two years' notice. The minimum funding requirement therefore represents seven years of future contributions, which amounted to $4,720 million at 31 December 2014. There are no such minimum funding requirements after this seven-year period, and the obligation is taken into account in the determination of the amount of any pension plan surplus recognized on the balance sheet.

The obligation and cost of providing the pension benefits is assessed annually using the projected unit credit method. The date of the most recent actuarial review was 31 December 2014. The principal plans are subject to a formal actuarial valuation every three years in the UK. The most recent formal actuarial valuation of the main UK pension plan was as at 31 December 2011, and a valuation as at 31 December 2014 is currently under way.

The material financial assumptions used for estimating the benefit obligations of the plans are set out below. The assumptions are reviewed by management at the end of each year, and are used to evaluate accrued pension benefits at 31 December and pension expense for the following year.

Financial assumptions used to determine benefit obligation			%
	2014	2013	2012
Discount rate for pension plan liabilities	**3.6**	4.6	4.4
Rate of increase in salaries	**4.5**	5.1	4.9
Rate of increase for pensions in payment	**3.0**	3.3	3.1
Rate of increase in deferred pensions	**3.0**	3.3	3.1
Inflation for pension plan liabilities	**3.0**	3.3	3.1

Financial assumptions used to determine benefit expense			%
	2014	2013	2012
Discount rate for pension plan service costs	**4.8**	4.4	4.8
Discount rate for pension plan other finance expense	**4.6**	4.4	4.8
Expected long-term rate of return	**6.9**	6.9	6.9
Inflation for pension plan service costs	**3.4**	3.1	3.2

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6. Pensions – continued

Our discount rate assumption is based on third-party AA corporate bond indices and we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumption is based on the difference between the yields on index-linked and fixed-interest long-term government bonds. The inflation assumptions are used to determine the rate of increase for pensions in payment and the rate of increase in deferred pensions.

Our assumption for the rate of increase in salaries is based on our inflation assumption plus an allowance for expected long-term real salary growth. This includes allowance for promotion-related salary growth of 0.7%.

In addition to the financial assumptions, we regularly review the demographic and mortality assumptions. The mortality assumptions reflect best practice in the UK, and have been chosen with regard to the latest available published tables adjusted where appropriate to reflect the experience of the group and an extrapolation of past longevity improvements into the future.

Mortality assumptions			%
	2014	2013	2012
Life expectancy at age 60 for a male currently aged 60	**28.3**	27.8	27.7
Life expectancy at age 60 for a male currently aged 40	**30.9**	30.7	30.6
Life expectancy at age 60 for a female currently aged 60	**29.4**	29.5	29.4
Life expectancy at age 60 for a female currently aged 40	**31.8**	32.2	32.1

The assets of the principal plan are held in a trust. The primary objective of the trust is to accumulate pools of assets sufficient to meet the obligations of the plan. The assets of the trusts are invested in a manner consistent with fiduciary obligations and principles that reflect current practices in portfolio management.

A significant proportion of the assets are held in equities, owing to a higher expected level of return over the long term of such assets with an acceptable level of risk. In order to provide reasonable assurance that no single security or type of security has an unwarranted impact on the total portfolio, the investment portfolios are highly diversified.

The fair values of the various categories of asset held by the defined benefit plans at 31 December are set out below.

		2014		2013		2012
	Expected long-term rate of return %	**Market value $ million**	Expected long-term rate of return %	Market value $ million	Expected long-term rate of return %	Market value $ million
Listed equity – developed	**8.0**	**16,190**	8.0	17,341	8.0	15,659
– emerging	**8.0**	**2,719**	8.0	2,290	8.0	1,074
Private equity	**8.0**	**2,983**	8.0	2,907	8.0	2,879
Government issued nominal bonds[a]	**3.3**	**642**	3.8	549	2.8	544
Index-linked bonds[a]	**3.3**	**892**	3.6	787	2.6	491
Corporate bonds[a]	**3.3**	**4,687**	4.6	4,427	4.2	3,850
Property[b]	**6.5**	**2,403**	6.5	2,200	6.5	1,783
Cash	**0.9**	**1,145**	0.8	855	0.9	1,000
Other	**0.9**	**112**	0.8	160	0.9	66
	6.7	**31,773**	6.9	31,516	6.9	27,346
Present value of plan liabilities		**32,357**		30,496		29,259
(Deficit) surplus in the plans		**(584)**		1,020		(1,913)

[a] Bonds held are denominated in sterling.
[b] Property held is all located in the United Kingdom.

The main pension plan does not invest directly in either securities or property/real estate of the company or of any subsidiary. Some of the pension plans use derivative financial instruments as part of their asset mix to manage the level of risk.

For the primary UK pension plan there is an agreement with the trustee to reduce the proportion of plan assets held as equities and increase the proportion held as bonds over time, with a view to better matching of the asset portfolio with the pension liabilities.

The company's principal plan in the UK does not currently follow a liability driven investment approach, a form of investing designed to match the movement in pension plan assets with the movement in projected benefit obligations over time.

	2014	2013
Analysis of the amount charged to operating profit		
Current service cost[a]	**494**	497
Settlement, curtailment and special termination benefits	**–**	(22)
Payments to defined contribution plans	**30**	24
Total operating charge	**524**	499
Analysis of the amount credited to other finance income		
Expected return on pension plan assets	**2,147**	1,803
Interest on pension plan liabilities	**(1,375)**	(1,221)
Other finance income	**772**	582
Analysis of the amount recognized in the statement of total recognized gains and losses		
Actual return less expected return on pension plan assets	**547**	2,007
Change in assumptions underlying the present value of the plan liabilities	**(3,139)**	60
Experience gains and losses arising on the plan liabilities	**(42)**	41
Actuarial (loss) gain recognized in statement of total recognized gains and losses	**(2,634)**	2,108

a The costs of managing the fund's investments are offset against the investment return. The costs of administering our pensions plan benefits are included in current service cost.

The parent company financial statements of BP p.l.c. on pages 197-206 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

6. Pensions – continued

	2014	2013
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**30,496**	29,259
Exchange adjustment	**(1,989)**	705
Current service cost[a]	**494**	497
Interest cost	**1,375**	1,221
Curtailments	**–**	(24)
Disposals	**–**	(9)
Past Service Cost	**–**	2
Contributions by plan participants[d]	**39**	37
Benefit payments (funded plans)[b]	**(1,231)**	(1,087)
Benefit payments (unfunded plans)[b]	**(8)**	(4)
Actuarial loss (gain) on obligation	**3,181**	(101)
Benefit obligation at 31 December	**32,357**	30,496
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**31,516**	27,346
Exchange adjustment	**(1,958)**	822
Expected return on plan assets[a c]	**2,147**	1,803
Contributions by plan participants[d]	**39**	37
Contributions by employers (funded plans)	**713**	597
Disposals	**–**	(9)
Benefit payments (funded plans)[b]	**(1,231)**	(1,087)
Actuarial gain on plan assets[c]	**547**	2,007
Fair value of plan assets at 31 December[e]	**31,773**	31,516
(Deficit) surplus at 31 December	**(584)**	1,020

[a] The costs of managing the fund's investments are offset against the investment return, the costs of administering our pensions plan benefits are included in current service cost.
[b] The benefit payments amount shown above comprises $1,218 million benefits plus $21 million of plan expenses incurred in the administration of the benefit.
[c] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain on plan assets as disclosed above.
[d] The contributions by plan participants for the UK are mostly comprised of contributions made under salary sacrifice arrangements.
[e] Reflects $31,600 million of assets held in the BP Pension Fund (2013 $31,362 million) and $134 million held in the BP Global Pension Trust (2013 $114 million), with $39 million representing the company's share of Merchant Navy Officers Pension Fund (2013 $40 million).

	2014	2013
Reconciliation of plan (deficit) surplus to balance sheet		
(Deficit) surplus at 31 December	**(584)**	1,020
Deferred tax	**–**	(41)
	(584)	979
Represented by		
Plans in surplus	**15**	1,238
Plans in deficit	**(599)**	(259)
	(584)	979

The aggregate level of employer contributions into the BP Pension Fund in 2015 is expected to be $519 million.

	2014	2013	2012	2011	2010
History of (deficit) surplus and of experience gains and losses					
Benefit obligation at 31 December	**32,357**	30,496	29,259	25,675	20,742
Fair value of plan assets at 31 December	**31,773**	31,516	27,346	23,587	22,612
(Deficit) surplus	**(584)**	1,020	(1,913)	(2,088)	1,870
Experience gains and losses on plan liabilities					
Amount ($ million)	**(42)**	41	(116)	(84)	12
Percentage of benefit obligation	**0%**	0%	0%	0%	0%
Actual return less expected return on pension plan assets					
Amount ($ million)	**547**	2,007	989	(1,976)	1,479
Percentage of plan assets	**2%**	6%	4%	(8)%	7%
Actuarial (loss) gain recognized in statement of total recognized gains and losses					
Amount ($ million)	**(2,634)**	2,108	(573)	(4,770)	457
Percentage of benefit obligation	**(8)%**	7%	(2)%	(19)%	2%
Cumulative amount recognized in statement of total recognized gains and losses	**(7,104)**	(4,470)	(6,578)	(6,005)	(1,235)

The parent company financial statements of BP p.l.c. on pages 197-206 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

7. Called-up share capital

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

	2014		2013	
Issued	Shares (thousand)	$ million	Shares (thousand)	$ million
8% cumulative first preference shares of £1 each[a]	**7,233**	**12**	7,233	12
9% cumulative second preference shares of £1 each[a]	**5,473**	**9**	5,473	9
		21		21
Ordinary shares of 25 cents each				
At 1 January	**20,426,632**	**5,108**	20,959,159	5,240
Issue of new shares for the scrip dividend programme	**165,644**	**41**	202,124	51
Issue of new shares for employee share-based payment plans[b]	**25,598**	**6**	18,203	5
Repurchase of ordinary share capital[c]	**(611,913)**	**(153)**	(752,854)	(188)
31 December	**20,005,961**	**5,002**	20,426,632	5,108
		5,023		5,129

[a] The nominal amount of 8% cumulative first preference shares and 9% cumulative second preference shares that can be in issue at any time shall not exceed £10,000,000 for each class of preference shares.

[b] Consideration received relating to the issue of new shares for employee share plans amounted to $207 million (2013 $116 million and 2012 $47 million).

[c] Purchased for a total consideration of $4,796 million, including transaction costs of $26 million (2013 $5,493 million, including transaction costs of $30 million). All shares purchased were for cancellation. The repurchased shares represented 3% of ordinary share capital.

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

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

In 2014, the company completed the $8-billion share repurchase programme announced on 22 March 2013 and further continuation of share buybacks was announced on 29 April 2014. During the year, the company repurchased 612 million ordinary shares at a cost of $4,770 million (2013 753 million ordinary shares at a cost of $5,463 million). The number of shares in issue is reduced when shares are repurchased, but is not reduced in respect of the year-end commitment to repurchase shares subsequent to the end of the year, for which an amount of $nil has been accrued at 31 December 2014 (2013 $1,430 million).

8. Capital and reserves

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Treasury shares	Profit and loss account	Total
At 1 January 2014	**5,129**	**10,061**	**1,260**	**26,509**	**(20,971)**	**125,806**	**147,794**
Currency translation differences	**–**	**–**	**–**	**–**	**–**	**31**	**31**
Actuarial loss on pensions (net of tax)	**–**	**–**	**–**	**–**	**–**	**(2,593)**	**(2,593)**
Share-based payments	**6**	**240**	**–**	**–**	**252**	**(287)**	**211**
Repurchases of ordinary share capital	**(153)**	**–**	**153**	**–**	**–**	**(3,366)**	**(3,366)**
Profit for the year	**–**	**–**	**–**	**–**	**–**	**2,100**	**2,100**
Dividends	**41**	**(41)**	**–**	**–**	**–**	**(5,850)**	**(5,850)**
At 31 December 2014	**5,023**	**10,260**	**1,413**	**26,509**	**(20,719)**	**115,841**	**138,327**

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Treasury shares	Profit and loss account	Total
At 1 January 2013	5,261	9,974	1,072	26,509	(21,054)	120,161	141,923
Currency translation differences	–	–	–	–	–	47	47
Actuarial gain on pensions (net of tax)	–	–	–	–	–	2,067	2,067
Share-based payments	5	138	–	–	83	204	430
Repurchases of ordinary share capital	(188)	–	188	–	–	(6,923)	(6,923)
Profit for the year	–	–	–	–	–	15,691	15,691
Dividends	51	(51)	–	–	–	(5,441)	(5,441)
At 31 December 2013	5,129	10,061	1,260	26,509	(20,971)	125,806	147,794

As a consolidated income statement is presented for the group, a separate income statement for the parent company is not required to be published.

The profit and loss account reserve includes $24,107 million (2013 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The accounts for the year ended 31 December 2014 do not reflect the dividend announced on 3 February 2015 and payable in March 2015; this will be treated as an appropriation of profit in the year ended 31 December 2015.

The parent company financial statements of BP p.l.c. on pages 197-206 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

9. Cash flow

Notes on cash flow statement

	2014	2013
		$ million
Reconciliation of net cash flow to movement of funds		
Increase (decrease) in cash	**25**	(3)
Movement of funds	**25**	(3)
Net cash at 1 January	**6**	9
Net cash at 31 December	**31**	6

Notes on cash flow statement		
Reconciliation of operating profit to net cash inflow (outflow) from operating activities	**2014**	2013
Operating profit	**1,393**	15,112
Net operating charge for pensions and other post-retirement benefits, less contributions	**(227)**	(127)
Dividends, interest and other income	**(2,321)**	(16,414)
Share-based payments	**376**	297
(Increase) decrease in debtors	**14,391**	(4,054)
Increase (decrease) in creditors	**(359)**	373
Net cash inflow (outflow) from operating activities	**13,253**	(4,813)

$ million

Analysis of movements of funds	At 1 January 2014	Cash flow	At 31 December 2014
Cash at bank	**6**	**25**	**31**

10. Contingent liabilities

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2014 were $51,463 million (2013 $47,042 million), the majority of which relate to finance debt of subsidiaries. The company has also issued uncapped indemnities and guarantees, including a guarantee of subsidiaries' liabilities under the PSC agreement relating to the Gulf of Mexico oil spill (see Note 2 to the consolidated financial statements), and in relation to potential losses arising from environmental incidents involving ships leased and operated by a subsidiary.

11. Share-based payments

Effect of share-based payment transactions on the company's result and financial position

	2014	2013
		$ million
Total expense recognized for equity-settled share-based payment transactions	**770**	709
Total (credit) expense recognized for cash-settled share-based payment transactions	**(81)**	10
Total expense recognized for share-based payment transactions	**689**	719
Closing balance of liability for cash-settled share-based payment transactions	**108**	17
Total intrinsic value for vested cash-settled share-based payments	**54**	2

Additional information on the company's share-based payment plans is provided in Note 9 to the consolidated financial statements.

12. Auditor's remuneration

Note 34 to the consolidated financial statements provides details of the remuneration of the company's auditor on a group basis.

13. Directors' remuneration

Remuneration of directors	2014	2013
		$ million
Total for all directors		
Emoluments	**14**	16
Amounts awarded under incentive schemes	**14**	2
Total	**28**	18

Emoluments
These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year. There was no compensation for loss of office in 2014 (2013 $nil).

The parent company financial statements of BP p.l.c. on pages 197-206 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

13. Directors' remuneration – continued

Pension contributions

During 2014, two executive directors participated in a non-contributory pension scheme established for UK staff by a separate trust fund to which contributions are made by BP based on actuarial advice. One US executive director participated in the US BP Retirement Accumulation Plan during 2014.

Further information

Full details of individual directors' remuneration are given in the directors' remuneration report on pages 72-88.

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