Financial statements

116 Statement of directors' responsibilities

117 Consolidated financial statements of the BP group

- Independent auditor's reports **117**
- Group income statement **122**
- Group statement of comprehensive income **123**
- Group statement of changes in equity **123**
- Group balance sheet **124**
- Group cash flow statement **125**

126 Notes on financial statements

1. Significant accounting policies, judgements, estimates and assumptions **126**
2. Significant event – Gulf of Mexico oil spill **139**
3. Business combinations **145**
4. Non-current assets held for sale **145**
5. Disposals and impairment **145**
6. Disposal of TNK-BP and investment in Rosneft **148**
7. Segmental analysis **149**
8. Income statement analysis **154**
9. Operating leases **154**
10. Exploration for and evaluation of oil and natural gas resources **155**
11. Taxation **156**
12. Dividends **158**
13. Earnings per ordinary share **158**
14. Property, plant and equipment **160**
15. Goodwill and impairment review of goodwill **161**
16. Intangible assets **163**
17. Investments in joint ventures **163**
18. Investments in associates **164**
19. Financial instruments and financial risk factors **166**
20. Other investments **170**
21. Inventories **170**
22. Trade and other receivables **171**
23. Cash and cash equivalents **171**
24. Valuation and qualifying accounts **171**
25. Trade and other payables **171**
26. Derivative financial instruments **172**
27. Finance debt **176**
28. Capital disclosures and analysis of changes in net debt **177**
29. Provisions **178**
30. Pensions and other post-retirement benefits **178**
31. Called-up share capital **185**
32. Capital and reserves **186**
33. Employee costs and numbers **189**
34. Remuneration of directors and senior management **190**
35. Contingent liabilities **191**
36. Capital commitments **191**
37. Auditor's remuneration **192**
38. Subsidiaries, joint arrangements and associates **193**
39. Condensed consolidated information on certain US subsidiaries **194**

200 Supplementary information on oil and natural gas (unaudited)

- Oil and natural gas exploration and production activities **201**
- Movements in estimated net proved reserves **207**
- Standardized measure of discounted future net cash flows and changes therein relating to proved oil and gas reserves **219**
- Operational and statistical information **222**

224 Parent company financial statements of BP p.l.c.

- Independent auditor's report to the members of BP p.l.c. **224**
- Company balance sheet **225**
- Company cash flow statement **226**
- Company statement of total recognized gains and losses **226**
- Notes on financial statements **227**

1. Accounting policies **227**
2. Taxation **228**
3. Fixed assets – investments **228**
4. Debtors **229**
5. Creditors **229**
6. Pensions **230**
7. Called-up share capital **232**
8. Capital and reserves **233**
9. Cash flow **233**
10. Contingent liabilities **234**
11. Share-based payments **234**
12. Auditor's remuneration **234**
13. Directors' remuneration **234**

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 56 to 58 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 38 to 40 and elsewhere in this report, including Safety on pages 41 to 44. 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

In accordance with the principles of the UK Corporate Governance Code, the board has established arrangements to evaluate whether the information presented in the Annual Report is fair, balanced and understandable: these are described on page 69.

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
6 March 2014

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 the financial statements

In our opinion the consolidated financial statements:

- give a true and fair view of the state of the group's affairs as at 31 December 2013 and of its profit for the year then ended;
- have been properly prepared in accordance with IFRS as adopted by the European Union; and
- have been prepared in accordance with the requirements of the Companies Act 2006 and 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 we have considered the adequacy of the disclosures made in Note 2 to the financial statements concerning the provisions, future expenditures for which reliable estimates cannot be made and other contingencies related to the Gulf of Mexico oil spill significant event. The total amounts that will ultimately be paid by BP in relation to 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 (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), 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. 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

The consolidated financial statements of BP p.l.c for the year ended 31 December 2013 comprise the group income statement, the group statement of comprehensive income, the group statement of changes in equity, the group balance sheet, the group cash flow statement and the related notes 1 to 38. The financial reporting framework that has been applied in their preparation is applicable law and International Financial Reporting Standards (IFRS) as adopted by the European Union.

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 116, the directors are responsible for the preparation of the consolidated 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 consolidated 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 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 and Accounts 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 significant uncertainties over provisions and contingencies related to the Gulf of Mexico oil spill;
- the impact of the estimation of the quantity of oil and gas reserves on impairment testing, depreciation, depletion and amortization and decommissioning provisions;
- unauthorized trading activity;
- BP's ability to exercise significant influence over Rosneft and the consequent accounting for the interest in Rosneft using the equity method; and
- the fair value accounting on the acquisition of the equity interest in Rosneft.

Our application of materiality

We apply the concept of materiality in planning and performing our audit, and in evaluating the effect of misstatements on our audit and on the financial statements. For the purposes of determining whether 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.

When establishing our overall audit strategy, we determined the magnitude of uncorrected and undetected misstatements that we judged would be material for the financial statements as a whole. We determined materiality for the group to be $1 billion (2012 $1 billion). Our evaluation of materiality requires professional judgement and necessarily takes into account qualitative as well as quantitative (i.e. profit before taxation in the group income statement) considerations implicit in the definition. This materiality provided a basis for identifying and assessing the risk of material misstatement and determining the nature, timing and extent of further audit procedures.

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

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

On the basis of our risk assessments, together with our assessment of the group's overall control environment, our judgement was that overall performance materiality (that is our tolerance for misstatement in an individual account or balance) for the group should be 75% (2012 75%) of the materiality we have determined for the group, namely $750 million (2012 $750 million). Our objective in adopting this approach was to ensure that total uncorrected and undetected audit differences do not exceed our materiality level of $1 billion for the financial statements as a whole.

We agreed with the audit committee that we would report to the committee all audit differences in excess of $50 million (2012 $50 million), as well as differences below that threshold that, in our view, warranted reporting on qualitative grounds.

An overview of the scope of our audit

We adopted a risk-based approach in determining our audit strategy. This approach focuses audit effort towards higher risk areas, such as management judgements and estimates and on locations that are considered significant based upon size, complexity and risk.

Our group audit scope focused on key locations. They were selected to provide an appropriate basis for undertaking audit work to address the risks of material misstatement identified above. Together with the group functions, which are also subject to audit, these locations represent the principal business units of the group and account for 75% (2012 72%) of the group's total assets and 84% (2012 72%) of the group's profit before tax. All locations within the scope were subject to audit procedures and the extent of audit work was based on our assessment of the risks of material misstatement and of the materiality of the group's business operations at those locations. For the remaining locations, we performed other procedures to ensure there were no significant risks of material misstatement in the group financial statements.

One of the key locations in scope for the group audit is Rosneft, a material associate that represents approximately 4% of the group's total assets and 7% of the group's profit before tax. Rosneft is not controlled by the group. We were provided with sufficient access to Rosneft's auditors in order to ensure appropriate audit procedures had been completed by them on the financial statements of Rosneft from which the BP equity accounting entries are determined.

The group audit team continued to follow a programme of planned visits that were designed to ensure that the Senior Statutory Auditor or his designates visit each of the locations where the group audit scope was focused at least once every two years and the most significant of them at least once a year. The Senior Statutory Auditor visited Houston four times during the audit primarily to consider the uncertainties over provisions and contingencies related to the Gulf of Mexico oil spill and he visited Moscow three times primarily to consider the matters related to the equity interest in Rosneft.

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

- we focused on the significant uncertainties over provisions and contingencies related to the Gulf of Mexico oil spill; specifically the areas of highest uncertainty where assumptions or new events could result in a material change to the provisions recorded or contingent liabilities disclosed. We engaged actuaries to work with the audit team and challenge the expert input provided to BP by external actuaries. We considered the legal opinions that determined management's positions, in particular relating to whether BP will be found grossly negligent and the implications for the fines and penalties payable under the Clean Water Act.
- we performed testing of controls over BP's internal certification process for technical and commercial experts who are responsible for the estimation of oil and gas reserves. We assessed whether the changes in proved reserves have been made in compliance with relevant regulations. We ensured that the updated reserves estimates were included appropriately in consideration of impairment, depreciation, depletion and amortization and decommissioning provisions.
- we performed testing relating to controls over unauthorized trading activity and obtained confirmations directly from third parties for a sample of trades. 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 challenged management's judgement that BP exercises significant influence over Rosneft, including obtaining evidence of BP's participation in decision-making through representation on the Rosneft board and committees of the board.
- we challenged management's assumptions used in the determination of the fair value of the assets and liabilities of the Rosneft business. We engaged valuations specialists to work with the audit team to consider the valuation methodology and specifically the assumptions used around future oil and gas prices, exchange rates and discount rates. We performed procedures to ensure the veracity of the valuation model and that the base data used in the model agreed to the underlying books and records.

Opinion on other matter prescribed by the Companies Act 2006

In our opinion the information given in the Strategic Report and the Directors' Report for the financial year for which the consolidated financial statements are prepared is consistent with the consolidated financial statements.

Matters on which we are required to report by exception

We have nothing to report in respect of the matters set out below.

Under the International Standards on Auditing (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.

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. – continued

Under the Companies Act 2006 we are required to report to you if, in our opinion:

- 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 statement of directors' responsibilities, set out on page 116, 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.

Other matter

We have reported separately on the parent company financial statements of BP p.l.c. for the year ended 31 December 2013 and on the information in the Directors' remuneration report that is described as having been audited.

Ernst & Young LLP
John C. Flaherty (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
6 March 2014

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kindom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

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

Consolidated financial statements of the BP group

Report of Independent Registered Public Accounting Firm 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 2013, 31 December 2012 and 1 January 2012, 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 2013. 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 2013, 31 December 2012 and 1 January 2012 and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2013, 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 we have considered the adequacy of the disclosures made in Note 2 to the financial statements concerning the provisions, future expenditures for which reliable estimates cannot be made and other contingencies related to the Gulf of Mexico oil spill significant event. The total amounts that will ultimately be paid by BP in relation to 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 (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), 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. Our opinion is not qualified in respect of these matters.

As discussed in Note 1 to the consolidated financial statements, the group has changed its accounting policies for employee benefits and interests in joint arrangements, including related disclosures, as a result of adopting new and revised International Financial Reporting Standards.

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 2013, 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 6 March 2014 expressed an unqualified opinion.

/s/ Ernst & Young LLP
London, England
6 March 2014

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kindom 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 2013, 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 111. 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 2013, 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 2013 and 2012, 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 2013, and our report dated 6 March 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
London, England
6 March 2014

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 6 March 2014, 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 2013 in the following Registration Statements:

Registration Statement on Form F-3 (File No. 333-179953) of BP Capital Markets p.l.c. and BP p.l.c.; and
Registration Statements on Form S-8 (File Nos. 333-149778, 333-79399, 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 and 333-186462) of BP p.l.c.

/s/ Ernst & Young LLP
London, England
6 March 2014

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kindom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

Group income statement

For the year ended 31 December

	Note	2013	2012[a]	2011[a]
				$ million
Sales and other operating revenues	7	**379,136**	375,765	375,713
Earnings from joint ventures – after interest and tax	17	**447**	260	767
Earnings from associates – after interest and tax	18	**2,742**	3,675	4,916
Interest and other income	8	**777**	1,677	688
Gains on sale of businesses and fixed assets	5	**13,115**	6,697	4,132
Total revenues and other income		**396,217**	388,074	386,216
Purchases	21	**298,351**	292,774	285,133
Production and manufacturing expenses[b]		**27,527**	33,926	24,163
Production and similar taxes	7	**7,047**	8,158	8,280
Depreciation, depletion and amortization	7	**13,510**	12,687	11,357
Impairment and losses on sale of businesses and fixed assets	5	**1,961**	6,275	2,058
Exploration expense	10	**3,441**	1,475	1,520
Distribution and administration expenses		**13,070**	13,357	13,958
Fair value gain on embedded derivatives	26	**(459)**	(347)	(68)
Profit before interest and taxation		**31,769**	19,769	39,815
Finance costs[b]	8	**1,068**	1,072	1,187
Net finance expense relating to pensions and other post-retirement benefits	30	**480**	566	400
Profit before taxation		**30,221**	18,131	38,228
Taxation[b]	11	**6,463**	6,880	12,619
Profit for the year		**23,758**	11,251	25,609
Attributable to				
BP shareholders	32	**23,451**	11,017	25,212
Non-controlling interests	32	**307**	234	397
		23,758	11,251	25,609
Earnings per share – cents				
Profit for the year attributable to BP shareholders				
Basic	13	**123.87**	57.89	133.35
Diluted	13	**123.12**	57.50	131.74

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 'Joint Arrangements' and the amended IAS 19 'Employee Benefits'.
[b] 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

For the year ended 31 December

$ million

	Note	2013	2012[a]	2011[a]
Profit for the year		**23,758**	11,251	25,609
Other comprehensive income				
Items that may be reclassified subsequently to profit or loss				
Currency translation differences		**(1,608)**	485	(543)
Exchange gains (losses) on translation of foreign operations reclassified to gain or loss on sale of businesses and fixed assets		**22**	(15)	19
Available-for-sale investments marked to market		**(172)**	306	(71)
Available-for-sale investments reclassified to the income statement		**(523)**	(1)	(3)
Cash flow hedges marked to market	26	**(2,000)**	1,466	44
Cash flow hedges reclassified to the income statement	26	**4**	62	(195)
Cash flow hedges reclassified to the balance sheet	26	**17**	19	(13)
Share of items relating to equity-accounted entities, net of tax		**(24)**	(39)	(39)
Income tax relating to items that may be reclassified	11,32	**147**	(170)	23
		(4,137)	2,113	(778)
Items that will not be reclassified to profit or loss				
Remeasurements of the net pension and other post-retirement benefit liability or asset	30	**4,764**	(1,572)	(5,301)
Share of items relating to equity-accounted entities, net of tax		**2**	(6)	–
Income tax relating to items that will not be reclassified	11,32	**(1,521)**	440	1,467
		3,245	(1,138)	(3,834)
Other comprehensive income		**(892)**	975	(4,612)
Total comprehensive income		**22,866**	12,226	20,997
Attributable to				
BP shareholders	32	**22,574**	11,988	20,613
Non-controlling interests	32	**292**	238	384
		22,866	12,226	20,997

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 'Joint Arrangements', the amended IAS 19 'Employee Benefits' and the amended IAS 1 'Presentation of Financial Statements'.

Group statement of changes in equity[a b]

$ million

	Share capital and capital reserves	Own shares and treasury shares	Foreign currency translation reserve	Fair value reserve	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
At 1 January 2013	**43,513**	**(21,054)**	**5,128**	**1,775**	**1,608**	**87,576**	**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**	**–**	**–**	**97**	**150**	**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)**	**1,705**	**102,082**	**129,302**	**1,105**	**130,407**
At 1 January 2012	43,454	(21,323)	4,509	267	1,582	83,079	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	–	–	26	(70)	284	–	284
Transactions involving non-controlling interests	–	–	–	–	–	–	–	33	33
At 31 December 2012	43,513	(21,054)	5,128	1,775	1,608	87,576	118,546	1,206	119,752
At 1 January 2011	43,448	(21,211)	5,036	469	1,586	65,754	95,082	904	95,986
Profit for the year	–	–	–	–	–	25,212	25,212	397	25,609
Other comprehensive income	–	–	(527)	(202)	–	(3,870)	(4,599)	(13)	(4,612)
Total comprehensive income	–	–	(527)	(202)	–	21,342	20,613	384	20,997
Dividends	–	–	–	–	–	(4,072)	(4,072)	(245)	(4,317)
Share-based payments, net of tax	6	(112)	–	–	(4)	102	(8)	–	(8)
Transactions involving non-controlling interests	–	–	–	–	–	(47)	(47)	(26)	(73)
At 31 December 2011	43,454	(21,323)	4,509	267	1,582	83,079	111,568	1,017	112,585

[a] See Note 32 for further information.
[b] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 'Joint Arrangements' and the amended IAS 19 'Employee Benefits'.

Group balance sheet

	Note	31 December 2013	31 December 2012[a]	1 January 2012[a]
				$ million
Non-current assets				
Property, plant and equipment	14	**133,690**	125,331	123,431
Goodwill	15	**12,181**	12,190	12,429
Intangible assets	16	**22,039**	24,632	21,653
Investments in joint ventures	17	**9,199**	8,614	8,303
Investments in associates	18	**16,636**	2,998	13,291
Other investments	20	**1,565**	2,704	2,635
Fixed assets		**195,310**	176,469	181,742
Loans		**763**	642	824
Trade and other receivables	22	**5,985**	5,961	5,738
Derivative financial instruments	26	**3,509**	4,294	5,038
Prepayments		**922**	830	739
Deferred tax assets	11	**985**	874	611
Defined benefit pension plan surpluses	30	**1,376**	12	17
		208,850	189,082	194,709
Current assets				
Loans		**216**	247	244
Inventories	21	**29,231**	28,203	26,073
Trade and other receivables	22	**39,831**	37,611	43,589
Derivative financial instruments	26	**2,675**	4,507	3,857
Prepayments		**1,388**	1,091	1,315
Current tax receivable		**512**	456	235
Other investments	20	**467**	319	288
Cash and cash equivalents	23	**22,520**	19,635	14,177
		96,840	92,069	89,778
Assets classified as held for sale	4	**–**	19,315	8,420
		96,840	111,384	98,198
Total assets		**305,690**	300,466	292,907
Current liabilities				
Trade and other payables	25	**47,159**	46,673	52,000
Derivative financial instruments	26	**2,322**	2,658	3,220
Accruals		**8,960**	6,875	6,016
Finance debt	27	**7,381**	10,033	9,039
Current tax payable		**1,945**	2,503	1,943
Provisions	29	**5,045**	7,587	11,238
		72,812	76,329	83,456
Liabilities directly associated with assets classified as held for sale	4	**–**	846	538
		72,812	77,175	83,994
Non-current liabilities				
Other payables	25	**4,756**	2,292	3,214
Derivative financial instruments	26	**2,225**	2,723	3,773
Accruals		**547**	491	400
Finance debt	27	**40,811**	38,767	35,169
Deferred tax liabilities	11	**17,439**	15,243	15,220
Provisions	29	**26,915**	30,396	26,462
Defined benefit pension plan and other post-retirement benefit plan deficits	30	**9,778**	13,627	12,090
		102,471	103,539	96,328
Total liabilities		**175,283**	180,714	180,322
Net assets		**130,407**	119,752	112,585
Equity				
BP shareholders' equity	32	**129,302**	118,546	111,568
Non-controlling interests	32	**1,105**	1,206	1,017
Total equity	32	**130,407**	119,752	112,585

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 'Joint Arrangements' and the amended IAS 19 'Employee Benefits'.

C-H Svanberg Chairman
R W Dudley Group Chief Executive
6 March 2014

Group cash flow statement

For the year ended 31 December — $ million

	Note	2013	2012[a]	2011[a]
Operating activities				
Profit before taxation[b]		**30,221**	18,131	38,228
Adjustments to reconcile profit before taxation to net cash provided by operating activities				
Exploration expenditure written off	10	**2,710**	745	1,024
Depreciation, depletion and amortization	7	**13,510**	12,687	11,357
Impairment and (gain) loss on sale of businesses and fixed assets	5	**(11,154)**	(422)	(2,074)
Earnings from joint ventures and associates		**(3,189)**	(3,935)	(5,683)
Dividends received from joint ventures and associates		**1,391**	1,763	5,040
Interest receivable		**(314)**	(379)	(284)
Interest received		**173**	175	210
Finance costs	8	**1,068**	1,072	1,187
Interest paid		**(1,084)**	(1,166)	(1,125)
Net finance expense relating to pensions and other post-retirement benefits	30	**480**	566	400
Share-based payments		**297**	156	(88)
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	30	**(920)**	(858)	(1,003)
Net charge for provisions, less payments		**1,061**	5,338	2,988
(Increase) decrease in inventories		**(1,193)**	(1,720)	(4,079)
(Increase) decrease in other current and non-current assets		**(2,718)**	2,933	(9,860)
Increase (decrease) in other current and non-current liabilities		**(2,932)**	(8,125)	(5,957)
Income taxes paid		**(6,307)**	(6,482)	(8,063)
Net cash provided by operating activities		**21,100**	20,479	22,218
Investing activities				
Capital expenditure		**(24,520)**	(23,222)	(17,978)
Acquisitions, net of cash acquired	3	**(67)**	(116)	(10,909)
Investment in joint ventures		**(451)**	(1,526)	(855)
Investment in associates		**(4,994)**	(54)	(55)
Proceeds from disposals of fixed assets	5	**18,115**	9,992	3,504
Proceeds from disposals of businesses, net of cash disposed[c]	5	**3,884**	1,606	(663)
Proceeds from loan repayments		**178**	245	203
Net cash used in investing activities		**(7,855)**	(13,075)	(26,753)
Financing activities				
Net issue (repurchase) of shares		**(5,358)**	122	74
Proceeds from long-term financing		**8,814**	11,087	11,600
Repayments of long-term financing		**(5,959)**	(7,177)	(9,102)
Net increase (decrease) in short-term debt		**(2,019)**	(666)	2,222
Net increase (decrease) in non-controlling interests		**32**	–	–
Dividends paid				
BP shareholders	12	**(5,441)**	(5,294)	(4,072)
Non-controlling interests		**(469)**	(82)	(245)
Net cash provided by (used in) financing activities		**(10,400)**	(2,010)	477
Currency translation differences relating to cash and cash equivalents		**40**	64	(493)
Increase (decrease) in cash and cash equivalents		**2,885**	5,458	(4,551)
Cash and cash equivalents at beginning of year		**19,635**	14,177	18,728
Cash and cash equivalents at end of year		**22,520**	19,635	14,177

[a] See Note 1 for information on the restatement of comparative amounts as a result of the adoption of IFRS 11 'Joint Arrangements' and the amended IAS 19 'Employee Benefits'.
[b] 2012 included $709 million of dividends received from TNK-BP. See Note 6 for further information.
[c] 2011 included the repayment of a deposit received in advance of $3,530 million following the termination of an agreement in respect of the expected sale of our interest in Pan American Energy LLC.

Notes on financial statements

Changes to the 2013 financial statements

BP aims for the highest standard of financial reporting and supports the initiatives of the UK Financial Reporting Council and the US Securities and Exchange Commission to improve understandability and transparency by cutting immaterial 'clutter' from financial statements. We continually review the structure and content of our financial reports. For the 2013 financial statements, to increase their understandability and navigability, we have changed the grouping of certain notes, and have also sought to remove immaterial disclosures. In applying materiality to the financial statement disclosures, we consider both the amount and the nature of each item. The main changes compared with the financial statements included in the *BP Annual Report and Form 20-F 2012* are as follows:

- Note 1 Significant accounting policies, judgements, estimates and assumptions – this note includes the critical accounting estimates and judgements in boxed text following the relevant accounting policy. Last year this information was shown under Critical accounting policies in the Additional disclosures section of the Directors' Report.
- Note 2 Significant event – Gulf of Mexico oil spill now contains all of our financial statement note disclosures in respect of the 2010 oil spill. Last year we also included information in the Provisions and Contingent liabilities notes to the financial statements.
- Note 7 Segmental analysis now includes analysis of depreciation, depletion and amortization and production and similar taxes, previously provided in separate notes.
- Note 8 Income statement analysis now combines a number of notes previously provided separately, simplifying the presentation while retaining materially the same content.
- Note 15 Goodwill and impairment review of goodwill now contains the disclosures related to impairment testing of goodwill, which were provided in a separate note last year.
- Note 19 Financial instruments and financial risk factors and Note 26 Derivative financial instruments have been rationalized to focus only on the material matters.
- Note 38 Subsidiaries, joint arrangements and associates now lists only the most significant entities.
- A separate share-based payment note is no longer presented. The share-based payment expense for the year is included in Note 33 Employee costs and numbers and information on the dilutive impact of employee share plans is included in Note 13 Earnings per ordinary share.

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 2013 were approved and signed by the group chief executive and chairman on 6 March 2014 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 critical 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 2013. The standards and interpretations adopted in the year, and the corresponding impact on the financial statements, are described further on page 137.

The accounting policies that follow have been consistently applied to all years presented. Where retrospective restatements were required as a result of the implementation of new accounting standards or changes to existing accounting standards, these have been applied to all comparative years presented.

Subsequent to releasing our unaudited fourth quarter and full year 2013 results announcement dated 4 February 2014, a minor amendment has been made to the split of the Upstream replacement cost profit before interest and tax between US and non-US. The amount reported for US for the year has been reduced by $0.2 billion to $3.1 billion and the amount reported for non-US has been increased by $0.2 billion to $28.9 billion. Similarly, amendments have also been made to the geographical analysis for revenues and capital expenditure and acquisitions. There was no impact on the group's profit or loss, net assets or cash flows for the year.

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

Critical 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 critical 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 in relation to acquisitions of 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. Control of an investee exists when the investor is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. To have power over an investee, the investor must have existing rights that give it the current ability to direct the relevant activities of the investee. 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. Intercompany balances and transactions, including unrealized profits arising from intragroup 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 the group.

Interests in other entities

Business combinations and goodwill

A business combination is a transaction or other event in which an acquirer obtains control of one or more businesses. A business is an integrated set of activities and assets that is capable of being conducted and managed for the purpose of providing a return in the form of dividends or lower costs or other economic benefits directly to investors or other owners or participants. A business consists of inputs and processes applied to those inputs that have the ability to create outputs.

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. Non-controlling interests are stated either at fair value or at the proportionate share of the recognized amounts of the acquiree's identifiable net assets. 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 is reviewed for impairment annually or more frequently if events or changes in circumstances indicate the recoverable amount of the cash-generating unit to which the goodwill relates should be assessed. Where the recoverable amount of the cash-generating unit is less than the carrying amount, an impairment loss is recognized. An impairment loss recognized for goodwill is not reversed in a subsequent period.

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

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, and any impairment of the investment is included within the group's share of earnings from joint ventures and associates.

Interests in joint arrangements

A joint arrangement is an arrangement of which two or more parties have joint control. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. The results, assets and liabilities of a joint venture 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, which are joint arrangements whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. 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

An associate is an entity over which the group has significant influence, through the power to participate in the financial and operating policy decisions of the investee, but which is not a subsidiary or a joint arrangement. The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting as described below.

Significant estimate or judgement

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.

At 31 December 2013, and since the transaction described in Note 6 concluded on 21 March 2013, BP 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 2013. 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, he is a member of the Rosneft board's Strategic Planning Committee and he participated in Rosneft's steering committee to integrate TNK-BP. 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 in an equity-accounted entity (joint venture or associate) is carried on the balance sheet at cost plus post-acquisition changes in the group's share of net assets of the equity-accounted 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 to sell and value in use. Where 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 on the date from 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.

On 22 October 2012, BP announced that it had signed heads of terms for a proposed transaction to sell its 50% share in TNK-BP to Rosneft. Following this agreement, BP's investment in TNK-BP met the criteria to be classified as held for sale. On 21 March 2013, the disposal of BP's investment in TNK-BP completed and BP increased its investment in Rosneft. See Note 6 for further information. BP's investment in Rosneft is reported as a separate operating segment since that date, reflecting the way in which the investment is managed.

A separate organization within the group deals with the ongoing response to the Gulf of Mexico oil spill. This organization reports directly to the group chief executive and its costs are excluded from the results of the operating segments. Under IFRS 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 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 supplies by excluding from profit inventory holding gains and losses. Replacement cost profit for the group is not a recognized measure under IFRS. For further information see Note 7.

Foreign currency translation

The 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.

In individual subsidiaries, joint ventures and associates, 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 the income statement. 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. 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 intragroup 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 deferred cumulative amount of exchange gains and losses recognized in equity relating to that particular non-US dollar operation is 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 once classified as held for sale. The group ceases to use the equity method of accounting from the date on which an interest in a joint venture or associate becomes held for sale. If a non-current asset or disposal group has been classified as held for sale, but subsequently ceases to meet the criteria to be classified as held for sale, the group ceases to classify the asset or disposal group as held for sale. Non-current assets and disposal groups that cease to be classified as held for sale are measured at the lower of the carrying amount before the asset or disposal group was classified as held for sale (adjusted for any depreciation, amortization or revaluation that would have been recognized had the asset or disposal group not been classified as held for sale) and its recoverable amount at the date of the subsequent decision not to sell. Except for any interests in equity-accounted entities that cease to be classified as held for sale, any adjustment to the carrying amount is recognized in profit or loss in the period in which the asset ceases to be classified as held for sale. When an interest in an equity-accounted entity ceases to be classified as held for sale, it is accounted for using the equity method as from the date of its classification as held for sale and the financial statements for the periods since classification as held for sale are amended accordingly.

Intangible assets

Intangible assets, other than goodwill, include expenditure on the exploration for and evaluation of oil and natural gas resources, computer software, patents, licences and trademarks and are stated at the amount initially recognized, less accumulated amortization and accumulated impairment losses. For information on accounting for expenditures on the exploration for and evaluation of oil and natural gas resources, see the accounting policy for oil and natural gas exploration, appraisal and development expenditure below.

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 trademarks, expected useful life is the shorter of the duration of the legal agreement and economic useful life, and can range from three to 15 years. Computer software costs generally have a useful life of three to five years.

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

The carrying value of intangible assets is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

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

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. 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 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.

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, borrowing 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. Exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. The gain or loss on derecognition of the asset given up is recognized in profit or loss.

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

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

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.

The carrying amount of property, plant and equipment is reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable.

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

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 200, which is unaudited. Details on BP's proved reserves and production compliance and governance processes are provided on page 245.

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 2013 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 200. 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 7 respectively.

Impairment of intangible assets and property, plant and equipment

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. 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 to sell 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. 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 to sell is identified as 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.

Significant estimate or judgement

Determination as to whether, and how much, an asset 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. Prices for oil and natural gas used for future cash flow calculations are based on market prices for the first five years and the group's long-term price assumptions thereafter. As at 31 December 2013, the group's long-term price assumptions were $90 per barrel for Brent and $6.50/mmBtu for Henry Hub (2012 $90 per barrel and $6.50/mmBtu). These long-term price assumptions are subject to periodic review and revision. The estimated future level of production is based on assumptions about future commodity prices, production and development costs, field decline rates, current fiscal regimes and other factors.

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, although other rates may be used if appropriate to the specific circumstances. In 2013 the rates ranged from 12% to 14% nominal (2012 12% to 14% nominal). The discount rates applied in assessments of impairment are reassessed each year. In cases where fair value less costs to sell is used to determine the recoverable amount of an asset, where recent market transactions for the asset are not available for reference, accounting judgements are made about the assumptions market participants would use when pricing the asset. Fair value less costs to sell may be determined based on similar recent market transaction data or using discounted cash flow techniques. Where discounted cash flow analyses are used to calculate fair value less costs to sell, the discount rate used is the group's post-tax weighted average cost of capital.

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 $12.2 billion on its balance sheet (2012 $12.2 billion), principally relating to the Atlantic Richfield, Burmah Castrol, Devon Energy and Reliance transactions. In testing goodwill for impairment, the group uses a similar approach to that described above for asset impairment. 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 significant 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 5 and details on the carrying amounts of assets are shown in Note 14, Note 15 and Note 16.

Inventories

Inventories, other than inventory 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.

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.

Leases

Finance leases, which transfer to the group substantially all the risks and benefits incidental to ownership of the leased item, 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. For both finance and operating leases, contingent rents are recognized in the income statement in the period in which they are incurred.

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 non-derivative financial assets with fixed or determinable payments that are not quoted in an active market. Such assets are carried at amortized cost using the effective interest method if the time value of money is significant. Gains and losses are recognized in 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

Such 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 non-derivative financial assets with fixed or determinable payments and fixed maturity that management has the positive intention and ability to hold to maturity. They are measured at amortized cost using the effective interest method, less any impairment.

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

Available-for-sale financial assets

Available-for-sale financial assets are those non-derivative financial assets that are not classified as loans and receivables, financial assets at fair value through profit or loss, or held-to-maturity 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, 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 financial assets

The group assesses at each balance sheet date whether a financial asset or group of financial assets is impaired.

Loans and receivables

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

Judgements are required in assessing the recoverability of overdue trade receivables, such as those in Egypt (see Note 19 for further details), 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 19 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

Such 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. Such 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 relating to unquoted equity instruments are carried at cost where it is not possible to reliably measure their fair value subsequent to initial recognition. 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. Contracts to buy or sell equity investments, including investments in associates, are also 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 either attributable to 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.

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

The group applies fair value hedge accounting for hedging fixed interest rate risk on borrowings. The gain or loss relating to the effective portion of the interest rate swap is recognized in the income statement within finance costs, offsetting the amortization of the interest on the underlying borrowings.

If the criteria for hedge accounting are no longer met, or if the group revokes the designation, the adjustment to the carrying amount of a hedged item for which the effective interest method is used is amortized to profit or loss over the period to maturity.

Cash flow hedges

For cash flow hedges, the effective portion of the gain or loss on the 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 transferred to the income statement when the hedged transaction affects profit or loss. The gain or loss relating to the effective portion of interest rate swaps hedging variable rate borrowings is recognized in the income statement within finance costs.

Where the hedged item is the cost of a non-financial asset or liability, such as a forecast transaction for the purchase of property, plant and equipment, the amounts recognized within other comprehensive income are transferred to the initial carrying amount of the non-financial asset or liability. Where the hedged item is an equity investment, such as an investment in an associate, the amounts recognized in other comprehensive income remain in the separate component of equity until the investment is sold or impaired.

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 transferred to the income statement or to the initial carrying amount of a non-financial asset or liability as above.

Significant estimate or judgement

The decision as to whether to apply hedge accounting or not can have a significant impact on the group's financial statements. Cash flow and fair value hedge accounting is applied to certain of the group's finance debt-related derivatives in the normal course of business. 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. We 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 for the year (2012 pre-tax gain of $1,410 million). See Note 26 for further information.

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

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, and to the forward contracts entered into in 2012 to purchase shares in Rosneft, as well as to the majority of the group's natural gas embedded contracts. The group's embedded derivatives arise primarily from long-term UK gas contracts that use pricing formulae not related to gas prices, for example, oil product and power prices. 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 26.

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. If both of the criteria are met, the amounts are set off and presented net.

Provisions, contingencies and reimbursement assets

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

If the effect of the time value of money is material, provisions are determined by discounting the expected future cash flows at a pre-tax risk-free rate that reflects current market assessments of the time value of money. Where discounting is used, the increase in the provision due to the passage of time is recognized within finance costs. Provisions are 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

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

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

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

The provision recognized is the best reliable estimate of expenditures required to settle certain present obligations at the end of the reporting period, however there are future expenditures 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 estimates as to the volume of oil spilled, as well as the assumption that BP did not act with gross negligence or engage in wilful misconduct, each of which will eventually be determined by the court on the basis of the trial proceedings.

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.

A corresponding intangible asset (in the case of an exploration or appraisal well) or item of property, plant and equipment of an amount equivalent to the provision is also recognized. The item of property, plant and equipment is subsequently depreciated as part of the asset.

Other than the unwinding of discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset. Such changes include foreign exchange gains and losses arising on the retranslation of the liability into the functional currency of the reporting entity, when it is known that the liability will be settled in a foreign currency.

Environmental expenditures and liabilities

Environmental expenditures that relate to future revenues are capitalized. 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. Where the liability will not be settled for a number of years, the amount recognized is the present value of the estimated future expenditure.

Significant estimate or judgement

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 actually occurs are uncertain. Decommissioning technologies and costs are constantly changing, as well as political, environmental, safety and public expectations. 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 such 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 actual 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 2013 was a real rate of 1.0% (2012 0.5%), which was based on long-dated government bonds.

Provisions and contingent liabilities in relation to the Gulf of Mexico oil spill are discussed in Note 2. Information about the group's other provisions is provided in Note 29. As further described in Note 35, 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.

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

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 period end 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. Fair value is determined by using an appropriate 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 expensed.

Cash-settled transactions

The cost of cash-settled transactions is measured at fair value at each balance sheet date and recognized as an expense over the vesting period, with a corresponding liability for the cumulative expense recognized on the balance sheet.

Pensions and other post-retirement benefits

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, 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 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. Net interest expense relating to pensions and other post-retirement benefits is recognized in the income statement.

Remeasurements of the net defined benefit liability or 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.

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.

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

Significant estimate or judgement

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, assumptions for inflation rates, US healthcare cost trend rates and rates of utilization of healthcare services by US retirees.

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. In 2013, we adopted the revised version of IAS 19 'Employee Benefits' (see below for further information), and we now apply the same rate of return on plan assets as we use to discount our pension liabilities. The impact of this change on key financial statement line items is shown at the end of this note.

The pension and other post-retirement benefit assumptions at 31 December 2013, 2012 and 2011 are provided in Note 30.

The discount rate, inflation rate and the US healthcare cost trend 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 30.

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 30.

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, joint ventures and associates, 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, joint ventures and associates, 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

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 35.

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 tax 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, including ordinary shares held by Employee Share Ownership Plans (ESOPs), are classified as 'treasury shares', or 'own shares' for the ESOPs, and are shown as deductions from shareholders' equity at cost. Consideration 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 or own shares, but are shown as a deduction from the profit and loss 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.

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

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.

Research

Research costs are expensed as incurred.

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

Adopted for 2013

BP adopted several new and amended standards issued by the IASB with effect from 1 January 2013. Of these the following two standards have a significant effect on the group's consolidated financial statements:

IFRS 11 'Joint Arrangements'

In May 2011, the IASB issued IFRS 11 'Joint Arrangements', one of a suite of standards relating to interests in other entities and related disclosures. IFRS 11 establishes a principle that applies to the accounting for all joint arrangements, whereby parties to the arrangement account for their underlying contractual rights and obligations relating to the joint arrangement. IFRS 11 identifies two types of joint arrangements. A 'joint venture' is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement. A 'joint operation' is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Investments in joint ventures are accounted for using the equity method. Investments in joint operations are accounted for by recognizing the group's assets, liabilities, revenue and expenses relating to the joint operation.

The main impact of IFRS 11 is that certain of the group's former jointly controlled entities, which were equity accounted, now fall under the definition of a joint operation under IFRS 11. Whilst the effect of the new requirements on the group's reported income and net assets is not material, the change does impact certain of the component lines of the group's financial statements, as shown in the table below. We have derecognized approximately $7 billion of investments and we now recognize the group's assets, liabilities, revenue and expenses relating to these arrangements. BP's share of oil and natural gas reserves associated with former jointly controlled entities that were previously equity-accounted, and are now classified as joint operations, have been reclassified from 'equity-accounted entities' to 'subsidiaries' in the Supplementary information on oil and natural gas.

Amendments to IAS 19 'Employee Benefits'

In June 2011, the IASB issued an amended version of IAS 19 'Employee Benefits', which brings in various changes relating to the recognition and measurement of post-retirement defined benefit expense and termination benefits, and to the disclosures for all employee benefits. The main impact for BP is that the expense for defined benefit pension and other post-retirement benefit plans now includes a net interest income or expense, which is calculated by taking the discount rate used for measuring the obligation and applying that to the net defined benefit asset or liability. This means that the expected return on assets credited to profit or loss (previously calculated based on the expected long-term return on pension assets) is now based on a lower corporate bond rate, the same rate that is used to discount the pension liability. The impact was to decrease profit before tax by $1,001 million for the year ended 31 December 2013 (2012 $763 million, 2011 $659 million) with other comprehensive income being increased by the same amount. There was no impact on the balance sheet at 31 December or on cash flows.

Adjustments made to certain selected financial statement line items

The following table sets out the adjustments made to certain selected financial statement line items of the previously reported comparative amounts as a result of the adoption of the amended IAS 19 'Employee Benefits' and the new standard IFRS 11 'Joint Arrangements'.

								$ million (except per share amounts)
				2012				2011
Selected lines only	As reported	IFRS 11	IAS 19	As restated	As reported	IFRS 11	IAS 19	As restated[a]
Income statement								
Earnings from joint ventures – after interest and tax	744	(484)	–	260	1,304	(537)	–	767
Net finance income (expense) relating to pensions and other post-retirement benefits	201	(4)	(763)	(566)	263	(4)	(659)	(400)
Profit for the year	11,816	22	(587)	11,251	26,097	2	(490)	25,609
Earnings per share – cents								
Profit for the year attributable to BP shareholders								
Basic	60.86	0.12	(3.09)	57.89	135.93	0.01	(2.59)	133.35
Diluted	60.45	0.11	(3.06)	57.50	134.29	0.01	(2.56)	131.74
Balance sheet								
Property, plant and equipment	120,448	4,883	–	125,331	119,214	4,217	–	123,431
Intangible assets	24,041	591	–	24,632	21,102	551	–	21,653
Investments in joint ventures	15,724	(7,110)	–	8,614	15,518	(7,215)	–	8,303
Net assets	119,620	132	–	119,752	112,482	103	–	112,585
Cash flow statement								
Profit (loss) before taxation	18,809	85	(763)	18,131	38,834	53	(659)	38,228
Net cash provided by operating activities	20,397	82	–	20,479	22,154	64	–	22,218
Net cash used in investing activities	(12,962)	(113)	–	(13,075)	(26,633)	(120)	–	(26,753)
Increase (decrease) in cash and cash equivalents	5,481	(23)	–	5,458	(4,489)	(62)	–	(4,551)

[a] Balance sheet amounts presented are as at 1 January 2012.

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

Detailed restated financial information for 2012 and 2011 is shown in *BP Financial and Operating Information 2008-2012* available on *bp.com/investors*.

Other standards

A number of other new or amended standards have been adopted by the group with effect from 1 January 2013 but do not have a significant impact on the financial statements. These include:

IFRS 10 'Consolidated Financial Statements' introduces a single consolidation model that identifies control as the basis for consolidation. The new model applies to all types of entities, including structured entities. Under the new model, an investor controls an investee when it is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee. There was no effect on the group's reported income or net assets as a result of the adoption of IFRS 10.

IFRS 12 'Disclosures of Interests in Other Entities' combines all the disclosure requirements for an entity's interests in subsidiaries, joint arrangements, associates and structured entities into one comprehensive disclosure standard. There was no effect on the group's reported income or net assets as a result of the adoption of IFRS 12. The disclosures required by the standard are included in this report.

In May 2011, the IASB issued a new standard, IFRS 13 'Fair Value Measurement'. The new standard defines fair value, sets out a framework for measuring fair value and contains the required disclosures about fair value measurements. IFRS 13 does not require fair value measurements in addition to those already required or permitted by other standards, rather it prescribes how fair value should be measured if another standard requires it. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date i.e. it is an exit price. There was no significant impact on the group's reported income or net assets as a result of the adoption of IFRS 13. The disclosures required by the new standard are included in this report.

In December 2011, the IASB issued an amendment to IFRS 7 'Disclosures – Offsetting Financial Assets and Financial Liabilities'. This amendment introduces new disclosure requirements about the effects of offsetting financial assets and financial liabilities and related arrangements on an entity's balance sheet. The new disclosures are included in this report.

In June 2011, the IASB issued amendments to IAS 1 'Presentation of Financial Statements' on the presentation of other comprehensive income (OCI). The amendments require that those items of OCI that might be reclassified to profit or loss at a future date be presented separately from those items that will never be reclassified to profit or loss. The adoption of the amended standard has a presentational impact on the group's statement of comprehensive income, with no effect on the reported income, total comprehensive income, or net assets of the group. The presentation required by the amended standard is included in this report.

In May 2013, the IASB issued an amendment to IAS 36 'Impairment of Assets' in relation to the disclosure of recoverable amounts for non-financial assets. The amendment addressed certain unintended consequences arising from consequential amendments made to IAS 36 when IFRS 13 was issued. Although the mandatory effective date for application of the amendment is for annual periods beginning on or after 1 January 2014, the group has early-adopted it in these financial statements.

In addition, a number of other standards and interpretations were adopted in the year which had no significant impact on the group's reported income and net assets.

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.

As part of the IASB's project to replace IAS 39 'Financial Instruments: Recognition and Measurement', in November 2009 the IASB issued the first phase of IFRS 9 'Financial Instruments', dealing with the classification and measurement of financial assets. In October 2010, the IASB updated IFRS 9 by incorporating the requirements for the accounting for financial liabilities and in November 2013 the IASB published revised guidance for hedge accounting. The remaining phase of IFRS 9, dealing with impairment, and further changes to the classification and measurement requirements, are still to be completed. In November 2013, the IASB also removed the effective date from IFRS 9 and will decide on an effective date when the entire IFRS 9 project is closer to completion. BP has not yet decided the date of adoption for the group and has not yet completed its evaluation of the effect of adoption. The EU has not yet adopted IFRS 9.

In December 2011, the IASB issued an amendment to IAS 32 'Offsetting Financial Assets and Financial Liabilities'. This amendment clarifies the presentation requirements in relation to offsetting financial assets and financial liabilities on an entity's balance sheet. The amendment to IAS 32 is effective for annual periods beginning on or after 1 January 2014. BP's evaluation of the effect of adoption of the amendment to IAS 32 is substantially complete, and is not expected to result in any significant changes to the offsetting of financial assets and liabilities on the group's balance sheet.

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 $42.7 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, 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 51 and Legal proceedings on page 257.

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
		2013		2012		2011
	Total	**Of which: amount related to the trust fund**	Total	Of which: amount related to the trust fund	Total	Of which: amount related to the trust fund
Income statement						
Production and manufacturing expenses	**430**	**(1,542)**	4,995	(1,191)	(3,800)	(3,995)
Profit (loss) before interest and taxation	**(430)**	**1,542**	(4,995)	1,191	3,800	3,995
Finance costs	**39**	**–**	19	12	58	52
Profit (loss) before taxation	**(469)**	**1,542**	(5,014)	1,179	3,742	3,943
Less: Taxation	**73**	**–**	94	–	(1,387)	–
Profit (loss) for the period	**(396)**	**1,542**	(4,920)	1,179	2,355	3,943
Balance sheet						
Current assets						
Trade and other receivables	**2,457**	**2,457**	4,239	4,178		
Current liabilities						
Trade and other payables	**(1,030)**	**(1)**	(522)	(22)		
Provisions	**(2,951)**	**–**	(5,449)	–		
Net current assets (liabilities)	**(1,524)**	**2,456**	(1,732)	4,156		
Non-current assets						
Other receivables	**2,442**	**2,442**	2,264	2,264		
Non-current liabilities						
Other payables	**(2,986)**	**–**	(175)	–		
Provisions	**(6,395)**	**–**	(9,751)	–		
Deferred tax	**2,748**	**–**	4,002	–		
Net non-current assets (liabilities)	**(4,191)**	**2,442**	(3,660)	2,264		
Net assets (liabilities)	**(5,715)**	**4,898**	(5,392)	6,420		
Cash flow statement						
Profit (loss) before taxation	**(469)**	**1,542**	(5,014)	1,179	3,742	3,943
Finance costs	**39**	**–**	19	12	58	52
Net charge for provisions, less payments	**1,129**	**–**	4,834	–	2,699	–
(Increase) decrease in other current and non-current assets	**(1,481)**	**(1,542)**	(998)	(1,191)	(4,292)	(4,038)
Increase (decrease) in other current and non-current liabilities	**(618)**	**–**	(5,090)	(4,860)	(11,113)	(10,097)
Pre-tax cash flows	**(1,400)**	**–**	(6,249)	(4,860)	(8,906)	(10,140)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to an outflow of $73 million (2012 outflow of $2,382 million and 2011 outflow of $6,813 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), and the separate BP claims programme – 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 the fourth quarter of 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 other receivables on the balance sheet apportioned between current and non-current elements. The table below shows movements in the

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

reimbursement asset during the period to 31 December 2013. The net increase in the provision of $1,542 million for the full year relates principally to business economic loss claims processed by the DHCSSP subsequent to finalization of the *BP Annual Report and Form 20-F 2012* that have been paid as well as increases in the provision for claims administration costs. The amount of the reimbursement asset at 31 December 2013 is equal to the amount of provisions and payables recognized at that date that will be covered by the trust fund – see below.

			$ million
	2013	2012	Cumulative since the incident
At 1 January	**6,442**	9,875	–
Increase in provision for items covered by the trust fund	**1,921**	1,985	20,511
Derecognition of provision for items that cannot be reliably estimated	**(379)**	(794)	(1,173)
Amounts paid directly by the trust fund	**(3,085)**	(4,624)	(14,439)
At 31 December	**4,899**	6,442	4,899
Of which – current	**2,457**	4,178	2,457
– non-current	**2,442**	2,264	2,442

Any increases in estimated future expenditure that will be covered by the trust fund (up to an aggregate of $20 billion) have no net income statement effect as a reimbursement asset is also recognized, as described above. As at 31 December 2013, the cumulative charges, and the associated reimbursement asset recognized, amounted to $19,338 million. Thus, a further $662 million could be charged in subsequent periods for items covered by the trust fund with no net impact on the income statement. Additional liabilities in excess of this amount regarding claims under the Oil Pollution Act of 1990 (OPA 90), claims that are currently administered by the DHCSSP, or otherwise, including the various claims described in Legal proceedings on page 257, would be expensed to the income statement. Information on those items that currently cannot be estimated reliably is provided under Provisions and contingent liabilities below.

Under the terms of the EPD Settlement Agreement with the PSC, several QSFs were established in 2012. These QSFs each relate to specific elements of the agreement, have been and will continue to be funded through payments from the Trust, and are available to make payments to claimants in accordance with those elements of the agreement.

As at 31 December 2013, the aggregate cash balances in the Trust and the QSFs amounted to $6.7 billion, including $1.2 billion remaining in the seafood compensation fund which has yet to be distributed and $0.9 billion held for natural resource damage early restoration. Should the cash balances in the trust fund not be sufficient, payments in respect of legitimate claims and other costs will be made directly by BP.

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. In addition, a separate BP claims programme began processing claims from claimants not in the Economic and Property Damages class as determined by the EPD Settlement Agreement or who have requested to opt out of that settlement. Payments made to claimants through the BP claims programme are paid directly from the Trust. 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 257.

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 will pay $4 billion over a period of five years. At 31 December 2013, the remaining payable was $3,525 million, of which $565 million falls due in 2014.

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. At 31 December 2013 the remaining payable, due in 2014, was $175 million plus accrued interest.

The amounts described above were reclassified from provisions to other payables upon court approval of the agreement with the US government and settlement with the SEC.

Provisions and contingent liabilities

Provisions

BP has recorded provisions relating to the Gulf of Mexico oil spill in relation to environmental expenditure, 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
					2013
	Environmental	Spill response	Litigation and claims	Clean Water Act	Total
At 1 January	1,862	345	9,483	3,510	15,200
Increase (decrease) in provision – items not covered by the trust fund	(24)	(66)	408	–	318
– items covered by the trust fund	24	–	1,897	–	1,921
Derecognition of provision for items that cannot be reliably estimated[a]	–	–	(379)	–	(379)
Reclassification of amounts between categories of provision	47	(47)	–	–	–
Unwinding of discount	1	–	–	–	1
Change in discount rate	(5)	–	–	–	(5)
Reclassified to other payables – items covered by the trust fund	–	–	(84)	–	(84)
– items not covered by the trust fund	–	–	(3,849)	–	(3,849)
Utilization – paid by BP	(60)	(143)	(523)	–	(726)
– paid by the trust fund	(255)	–	(2,796)	–	(3,051)
At 31 December	1,590	89	4,157	3,510	9,346
Of which – current	389	84	2,478	–	2,951
– non-current	1,201	5	1,679	3,510	6,395
Of which – payable from the trust fund	1,253	–	3,595	–	4,848

[a] Relates to items covered by the trust fund.

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

					$ million
					Cumulative since the incident
	Environmental	Spill response	Litigation and claims	Clean Water Act	Total
Increase in provision – items not covered by the trust fund	544	11,456	8,529	3,510	24,039
– items covered by the trust fund	2,353	56	18,102	–	20,511
Derecognition of provision for items that cannot be reliably estimated[a]	–	–	(1,173)	–	(1,173)
Reclassification of amounts between categories of provision	47	(47)	–	–	–
Unwinding of discount	12	–	6	–	18
Change in discount rate	17	–	–	–	17
Reclassified to other payables – items covered by the trust fund	–	–	(84)	–	(84)
– items not covered by the trust fund	–	–	(4,199)	–	(4,199)
Utilization – paid by BP	(237)	(11,367)	(3,773)	–	(15,377)
– paid by the trust fund	(1,146)	(9)	(13,251)	–	(14,406)
At 31 December 2013	1,590	89	4,157	3,510	9,346

[a] Relates to items covered by the trust fund.

Environmental

The environmental provision includes $320 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 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. At 31 December 2013 the amount provided for natural resource damage assessment costs and early restoration projects was $1,224 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.

Spill response

The spill response provision relates primarily to ongoing shoreline operational activity.

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 ('State and Local Claims'), under OPA 90 and other legislation, except as described under Contingent liabilities below. Claims administration costs and legal costs have also been provided for. The timing of payment of litigation and claims provisions classified as non-current is dependent on on-going 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. 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 EPD Settlement Agreement by the claims administrator that BP believes was incorrect.

Between March 2013 and March 2014, there were various rulings from both the federal District Court in New Orleans (the District Court) and a panel of the US Court of Appeals for the Fifth Circuit (the business economic loss panel) 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.

As reported in *BP Annual Report and Form 20-F 2012*, the estimated cost of the PSC settlement for Individual and Business Claims was $7.7 billion at 31 December 2012. This estimate increased during the year to $9.6 billion to reflect all claims processed by the DHCSSP for which eligibility notices had been issued and increases in claims administration costs. As a result of the District Court's preliminary injunction issued on 18 October 2013 that, amongst other things, required the claims administrator to temporarily suspend payments of business economic loss claims other than those claims supported by sufficiently matched accrual-basis accounting or any other business economic loss claim for which the claims administrator determines that the matching of revenue and expenses is not an issue, the provision for $0.4 billion of claims for which eligibility notices had been issued but had not yet been paid was derecognized as BP considered and continues to consider that no reliable estimate can be made for these claims. At 31 December 2013, the total costs of the PSC settlement that BP considers can be reliably estimated is therefore $9.2 billion.

On 5 December 2013, the District Court amended its earlier preliminary injunction and temporarily suspended the issuance of final determination notices and payments of business economic loss claims, until the business economic loss issues have been resolved. On 24 December 2013, the District Court ruled on the issues in relation to the matching of revenue and expenses and causation that were remanded to it by the business economic loss panel. Regarding matching, the District Court reversed its earlier decision and ruled that the claims administrator, in administering business economic loss claims, must match revenue with the variable expenses incurred by claimants in conducting their business, even where the revenues and expenses were recorded at different times. The District Court assigned to the claims administrator the development of more detailed matching requirements. On 12 February 2014, the claims administrator issued a draft policy addressing the matching of revenue and expenses for business economic loss claims. The parties have made written submissions on the draft policy and the claims administrator will issue a final policy to which BP and the PSC have the right to object and seek review by the District Court. Regarding causation, the District Court ruled that the EPD Settlement Agreement contained no causation requirement beyond the revenue and related tests set out in an exhibit to that agreement. BP appealed the District Court's ruling on causation to the business economic loss panel and moved for a permanent injunction that would prevent the claims administrator from making awards to claimants whose alleged injuries are not traceable to the spill. On 3 March 2014, the business economic loss panel affirmed the District Court's ruling on causation and denied BP's motion for a permanent injunction. BP is considering its appeal options, including a potential petition that all the active judges of the Fifth Circuit review the 3 March decision. Under the terms of the business economic loss panel's ruling, the injunction temporarily suspending issuance of final determination notices and payments of business economic loss claims will be lifted when the matter is transferred back to the District Court; the timing of this would be affected by the status of any such petition by BP.

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

In addition to the proceedings in relation to the interpretation of the EPD Settlement Agreement, following the District Court's final order and judgment approving the EPD Settlement in January 2013, groups of purported members of the Economic and Property Damages Settlement Class (the Appellants) appealed from the District Court's approval of that settlement to a different panel of the Fifth Circuit. On 10 January 2014, that other panel of the Fifth Circuit affirmed the District Court's approval of the EPD Settlement but left to the business economic loss panel of the Fifth Circuit the question of how to interpret the EPD Settlement Agreement, including the meaning of the causation requirements of that agreement (see above). BP and several Appellants have filed petitions requesting that all the active judges of the Fifth Circuit review the decision to uphold approval of the EPD Settlement.

See Legal proceedings on page 257 for further details on the settlements with the PSC and related matters.

Until the uncertainties described below are resolved, management is unable to estimate reliably the value and volume of future business economic loss claims and whether and to what extent received or processed but unpaid business economic loss claims will be paid. Firstly, the inherent uncertainty as to the interpretation of the EPD Settlement Agreement in respect of matching and causation issues will continue until the more detailed matching requirements are finalized by the claims administrator and are implemented by the DHCSSP; the issue of causation and the requirements for class membership under the EPD Settlement Agreement are resolved on appeal; and the impact of any new policies and procedures in response to these issues on the value and volume of business economic loss claims becomes clear. Furthermore, the Fifth Circuit has yet to decide whether to grant the petitions seeking review of its decision affirming approval of the EPD Settlement and, if granted, whether to alter its decision in that appeal. Secondly, uncertainty arises from the lack of sufficient claims data under the DHCSSP from which to extrapolate any reliable trends – the number of business economic loss claims received and the average amounts paid in respect of such claims prior to the District Court's injunction were higher than previously assumed by BP. This inability to extrapolate any reliable trends may or may not continue once the uncertainties concerning the interpretation of the EPD Settlement Agreement described above have been resolved. Thirdly, there is uncertainty as to the ultimate deadline for filing business economic loss claims, which is dependent on the date on which all relevant appeals are concluded. Management believes, therefore, that no reliable estimate can currently be made of any business economic loss claims not yet received, processed and paid by the DHCSSP. A provision for business economic loss claims will be established when a reliable estimate can be made of the liability.

The total cost of the PSC settlement is likely to be significantly higher than the amount recognized to date of $9.2 billion because the current estimate does not reflect business economic loss claims not yet received, processed and paid. The DHCSSP has issued eligibility notices, disputed by BP, in respect of business economic loss claims of $1,019 million which have not yet been paid. 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 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. See Legal proceedings on page 257 and Contingent liabilities below for further details.

Clean Water Act penalties

A charge for potential Clean Water Act Section 311 penalties was first included in BP's second-quarter 2010 interim financial statements. At the time that charge was taken, the latest estimate from the intra-agency Flow Rate Technical Group created by the National Incident Commander in charge of the spill response was between 35,000 and 60,000 barrels per day. The mid-point of that range, 47,500 barrels per day, was used for the purposes of calculating the charge. For the purposes of calculating the amount of the oil flow that was discharged into the Gulf of Mexico, the amount of oil that had been or was projected to be captured in vessels on the surface was subtracted from the total estimated flow up until when the well was capped on 15 July 2010. The result of this calculation was an estimate that approximately 3.2 million barrels of oil had been discharged into the Gulf. This 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.

BP intends to argue for a penalty lower than $1,100 per barrel. The actual penalty a court may impose could be lower than $1,100 per barrel if it were determined that such a lower penalty was appropriate based on the factors a court is directed to consider in assessing a penalty. In particular, in determining the amount of a civil penalty, Section 311 directs a court to consider a number of enumerated factors, including "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". Civil penalties above $1,100 per barrel up to a statutory maximum of $4,300 per barrel of oil discharged would only be imposed if alleged gross negligence or wilful misconduct were proven. The $1,100 per-barrel rate has been utilized for the purposes of calculating the provision after considering and weighing all possible outcomes and in light of: (i) the company's conclusion that it did not act with gross negligence or engage in wilful misconduct; and (ii) the uncertainty as to whether a court would assess a penalty below the $1,100 statutory maximum.

On 2 August 2010, the United States Department of Energy and the Flow Rate Technical Group had issued an estimate that 4.9 million barrels of oil had flowed from the Macondo well, and 4.05 million barrels had been discharged into the Gulf (the difference being the amount of oil captured by vessels on the surface as part of BP's well containment efforts).

It was and remains BP's view, based on the analysis of available data by its experts, that the 2 August 2010 Government estimate is not reliable. BP believes that the 2 August 2010 discharge estimate is overstated by at least 20%. If the flow rate were 20% lower than the 2 August 2010 estimate, then the amount of oil that flowed from the Macondo well would be approximately 3.9 million barrels and the amount discharged into the Gulf would be approximately 3.1 million barrels (using a current estimate of barrels captured by vessels on the surface of 810,000 in line with the stipulation entered with the US government – see Legal proceedings), which is not materially different from the amount we used for our original estimate at the end of the second quarter 2010.

For the purposes of calculating a provision for fines and penalties under Section 311 of the Clean Water Act, BP has continued to use an estimate of 3.2 million barrels of oil discharged to the Gulf of Mexico and a penalty of $1,100 per barrel, as its current best estimate, as defined in paragraphs 36-40 of IAS 37 'Provisions, Contingent Liabilities and Contingent Assets', of the amounts which may be used in calculating the penalty under Section 311 of the Clean Water Act and as a result, the provision at the end of the year was $3,510 million.

The amount and timing of the amount to be paid ultimately is subject to significant uncertainty since it will depend on what is determined by the court in the federal multi-district litigation proceedings in New Orleans (MDL 2179) as to negligence, gross negligence or wilful misconduct, the volume of oil spilled and the application of statutory penalty factors. The trial court could issue its decision on the first two phases of the trial (which considered the issues of negligence or gross negligence in phase one, and source control efforts and the volume of oil spilled in phase two) at any time and has not yet scheduled a hearing on the subsequent phase regarding the application of statutory penalty factors. The court has wide discretion in its determination as to whether a defendant's conduct involved negligence or gross negligence as well as in its determinations on the volume of oil spilled and the application of statutory penalty factors.

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

See Legal proceedings on page 257 for further details on all litigation and claims activity.

Provision movements

The total amount recognized as an increase in provisions during the year was $2,239 million, including $1,921 million for items covered by the trust fund and $318 million for other items (2012 $6,868 million, including $1,985 million for items covered by the trust fund and $4,883 million for other items). In addition, $379 million (2012 $794 million) was derecognized relating to items that will be covered by the trust fund but which can no longer be reliably estimated. After deducting amounts utilized during the year totalling $3,777 million, including payments from the trust fund of $3,051 million and payments made directly by BP of $726 million (2012 $5,864 million, including payments from the trust fund of $4,624 million and payments made directly by BP of $1,240 million), and after reclassifications and adjustments for discounting, the remaining provision as at 31 December 2013 was $9,346 million (2012 $15,200 million).

The total amounts that will ultimately be paid by BP in relation to 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 (including any determination of BP's culpability based on any findings of negligence, gross negligence or wilful misconduct), 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 from the trust fund that can be measured reliably. This includes certain amounts expected to be paid pursuant to the Oil Pollution Act of 1990 (OPA 90). It is not possible, at this time, to measure reliably other obligations arising from the incident that are under the terms of the trust fund, namely any obligation in relation to natural resource damages claims or associated legal costs (except for the estimated costs of the assessment phase and costs relating to early restoration agreements under the $1-billion framework agreement referred to above), claims asserted in civil litigation including any further litigation through excluded parties from the PSC settlement including as set out in Legal proceedings, the cost of business economic loss claims under the PSC settlement not yet received, processed and paid by the DHCSSP, any further obligation that may arise from state and local government submissions under OPA 90 and any obligation in relation to other potential private or governmental litigation, 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 2013.

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 damages claims, therefore no such amounts have been provided as at 31 December 2013.

As described under Provisions above, BP has 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. Uncertainty as to the interpretation of the EPD Settlement Agreement will continue until the effects of the implementation of new policies and procedures are known, the issue of causation and the requirements for class membership under the EPD Settlement Agreement are resolved on appeal and the courts have ruled on the appeals in relation to the final order and judgment approving the EPD Settlement. Therefore the potential cost of business economic loss claims not yet received, processed and paid 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.

As described above in Provisions, a provision has been made for State and Local claims that can be measured reliably. In January 2013, the States of Alabama, Mississippi and Florida submitted or asserted claims to BP under OPA 90 for alleged losses including economic losses and property damage as a result of the Gulf of Mexico oil spill. BP is evaluating these claims. The States of Louisiana and Texas have also asserted similar claims. The amounts claimed, certain of which include punitive damages or other multipliers, are very substantial. However BP considers these claims unsubstantiated and the methodologies used to calculate these claims to be seriously flawed, not supported by OPA 90, not supported by documentation, and to substantially overstate the claims. Similar claims have also been submitted by various local government entities and a foreign government under OPA 90, and more claims are expected to be submitted. 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.

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 Depository Shares under US federal securities law, are continuing. A jury trial is scheduled to begin in October 2014. 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 2013.

In addition to the State and Local claims and securities class actions described above, BP is named as a defendant in approximately 2,950 other civil lawsuits brought by individuals, corporations and government entities in US federal and state courts, as well as certain foreign 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. 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. Therefore no amounts have been provided for these items as at 31 December 2013. See Legal proceedings on page 257 for further information.

For those items not covered by the trust fund it is not possible to measure reliably any obligation in relation to other litigation or potential fines and penalties except, subject to certain assumptions detailed above, for those relating to the Clean Water Act. 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.

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

Under the settlement agreements with Anadarko and MOEX, and with Cameron International, the designer and manufacturer of the Deepwater Horizon blowout preventer, with M-I L.L.C. (M-I), the mud contractor, and with Weatherford, the designer and manufacturer of the float collar used on the Macondo well, BP has agreed to indemnify Anadarko, MOEX, Cameron, M-I and Weatherford 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 any obligation in relation to such claims and therefore no amount has been provided as at 31 December 2013.

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 51. Any such possible obligations are therefore contingent liabilities and, at present, it is not practicable to estimate their magnitude or possible timing of payment. Furthermore, other material unanticipated obligations may arise in future in relation to the incident.

Impact upon the group income statement

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

				$ million
	2013	2012	2011	Cumulative since the incident
Net increase in provision	**2,239**	6,868	5,183	44,551
Derecognition of provision for items that cannot be reliably estimated	**(379)**	(794)	–	(1,173)
Change in discount rate relating to provisions	**(5)**	–	17	17
Costs charged directly to the income statement	**136**	257	512	4,244
Trust fund liability – discounted	**–**	–	–	19,580
Change in discounting relating to trust fund liability	**–**	–	43	283
Recognition of reimbursement asset, net	**(1,542)**	(1,191)	(4,038)	(19,338)
Settlements credited to the income statement	**(19)**	(145)	(5,517)	(5,681)
(Profit) loss before interest and taxation	**430**	4,995	(3,800)	42,483
Finance costs	**39**	19	58	193
(Profit) loss before taxation	**469**	5,014	(3,742)	42,676

The group income statement for 2013 includes a pre-tax charge of $469 million (2012 pre-tax charge of $5,014 million) in relation to the Gulf of Mexico oil spill. The costs charged in 2013 relate primarily to the ongoing costs of operating the Gulf Coast Restoration Organization (GCRO) and increases in legal costs. Finance costs of $39 million (2012 $19 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, estimated obligations for future costs that can be estimated reliably at this time and rights and obligations relating to the trust fund, 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
	2013	2012	2011	Cumulative since the incident
Trust fund liability – discounted	**–**	–	–	19,580
Change in discounting relating to trust fund liability	**–**	–	43	283
Recognition of reimbursement asset	**(1,542)**	(1,191)	(4,038)	(19,338)
Other	**–**	–	–	8
Total (credit) charge relating to the trust fund	**(1,542)**	(1,191)	(3,995)	533
Environmental – amount provided	**47**	801	1,167	2,944
– change in discount rate relating to provisions	**(5)**	–	17	17
– costs charged directly to the income statement	**–**	–	–	70
Total (credit) charge relating to environmental	**42**	801	1,184	3,031
Spill response – amount provided	**(113)**	109	586	11,465
– costs charged directly to the income statement	**–**	9	85	2,839
Total (credit) charge relating to spill response	**(113)**	118	671	14,304
Litigation and claims – amount provided, net of provision derecognized	**1,926**	5,164	3,430	25,459
– costs charged directly to the income statement	**–**	–	–	184
Total charge relating to litigation and claims	**1,926**	5,164	3,430	25,643
Clean Water Act penalties – amount provided	**–**	–	–	3,510
Other costs charged directly to the income statement	**136**	248	427	1,143
Settlements credited to the income statement	**(19)**	(145)	(5,517)	(5,681)
(Profit) loss before interest and taxation	**430**	4,995	(3,800)	42,483
Finance costs	**39**	19	58	193
(Profit) loss before taxation	**469**	5,014	(3,742)	42,676

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. Business combinations

BP undertook a number of minor business combinations in 2013 and 2012 for a total consideration of $67 million and $116 million in cash respectively.

In 2011, BP undertook a number of business combinations with total consideration paid in cash amounting to $11.3 billion, offset by cash acquired of $0.4 billion. The fair value of contingent consideration payable amounted to $0.1 billion. BP acquired from Reliance Industries Limited (Reliance) a 30% interest in 21 oil and gas production-sharing agreements (PSAs) operated by Reliance in India for $7,026 million. In addition, we completed the final part of the transaction with Devon Energy (Devon) for the acquisition of Devon's equity stake in a number of assets in Brazil for consideration of $3.6 billion and BP's Alternative Energy business acquired Companhia Nacional de Açúcar e Álcool (CNAA) in Brazil for consideration of $0.7 billion. There were a number of other individually insignificant business combinations.

4. Non-current assets held for sale

There were no assets or associated liabilities classified as held for sale as at 31 December 2013. The disposal of the assets and associated liabilities classified as held for sale at 31 December 2012 completed during 2013.

Impairment losses amounting to $186 million (2012 $2,594 million) were recognized relating to certain assets that were classified as held for sale at 31 December 2012, of which $137 million related to the Carson refinery and associated assets. See Note 5 for further information.

Non-current assets classified as held for sale are not depreciated. 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 (2012 $435 million). In addition, profits of approximately $738 million (2012 $731 million) were not recognized as a result of the discontinuance of equity accounting for our interest in TNK-BP.

Non-current assets held for sale at 31 December 2012

At 31 December 2012 assets classified as held for sale included property, plant and equipment of $3,663 million, investments in associates of $12,322 million and inventories of $2,377 million.

Within the Upstream segment, BP's interests in the BP-operated Maclure, Harding and Devenick fields and non-operated interests in the Brae complex of fields and the Braemar field in the central North Sea were classified as held for sale. In the Downstream segment, the Texas City refinery and related assets, and the southern part of the US West Coast fuels value chain, including the Carson refinery, were classified as held for sale at 31 December 2012. BP's investment in TNK-BP was classified as an asset held for sale at 31 December 2012. All of the assets classified as held for sale at 31 December 2012 were sold during 2013. See Notes 5 and 6 for further information.

5. Disposals and impairment

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

			$ million
	2013	2012	2011
Gains on sale of businesses and fixed assets			
Upstream	**371**	6,504	3,477
Downstream	**214**	152	319
TNK-BP	**12,500**	–	–
Other businesses and corporate	**30**	41	336
	13,115	6,697	4,132

			$ million
	2013	2012	2011
Losses on sale of businesses and fixed assets			
Upstream	**144**	109	49
Downstream	**78**	195	52
Other businesses and corporate	**8**	6	3
	230	310	104
Impairment losses			
Upstream	**1,255**	3,046	1,443
Downstream	**484**	2,892	599
Other businesses and corporate	**218**	320	58
	1,957	6,258	2,100
Impairment reversals			
Upstream	**(226)**	(289)	(146)
Downstream	**–**	(1)	–
Other businesses and corporate	**–**	(3)	–
	(226)	(293)	(146)
Impairment and losses on sale of businesses and fixed assets	**1,961**	6,275	2,058

5. Disposals and impairment – continued

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. This target was reached during 2012; as at 31 December 2012, BP had announced disposals of $38 billion, and in addition, the sale of our 50% investment in TNK-BP. During 2013 the group announced that it expects to divest a further $10 billion of assets before the end of 2015.

			$ million
	2013	2012	2011
Proceeds from disposals of fixed assets	**18,115**	9,992	3,504
Proceeds from disposals of businesses, net of cash disposed	**3,884**	1,606	(663)
	21,999	11,598	2,841
By segment			
Upstream	**1,288**	10,667	1,080
Downstream	**3,991**	637	830
TNK-BP	**16,646**	–	–
Other businesses and corporate	**74**	294	931
	21,999	11,598	2,841

Proceeds from disposals for 2012 included a deposit of $632 million received in respect of the disposal in 2013 of interests in a number of central North Sea oil and gas fields. Disposal proceeds for 2011 included the repayment of a deposit of $3,530 million received in 2010 in advance of the expected sale of our interest in Pan American Energy LLC, which did not complete.

At 31 December 2013, deferred consideration relating to disposals amounted to $23 million receivable within one year (2012 $24 million and 2011 $117 million) and $1,374 million receivable after one year (2012 $1,433 million and 2011 $1,524 million). In addition, contingent consideration relating to the disposals of the Devenick field and the Texas City refinery amounted to $953 million at 31 December 2013 – see Notes 20 and 26 for further information.

Upstream

In 2013, the major disposal transaction in the segment was the sale of our interests in the BP-operated Maclure, Harding and Devenick fields and non-operated interests in the Brae complex of fields and the Braemar field in the central North Sea to TAQA. In addition, we sold our interests in the Yacheng field in China to Kuwait Foreign Petroleum Exploration Company, as well as other interests in the North Sea and the US.

In 2012, the major disposal transactions were the sale of our interests in the Marlin, Horn Mountain, Holstein, Ram Powell and Diana Hoover fields in the Gulf of Mexico to Plains Exploration and Production Company, the sale of our interests in the Hugoton and Jayhawk gas production and processing assets in Kansas, and our interest in the Jonah and Pinedale upstream operations in Wyoming, to LINN Energy, LLC, and the sale of our interests in our Canadian natural gas liquids (NGL) business to Plains Midstream Canada ULC. In addition, we sold a number of interests in the North Sea, including the disposal of our Southern Gas Assets to Perenco UK Ltd.

In 2011, the major disposal transactions were the sale of our interests in Colombia to Ecopetrol and Talisman, the sale of our upstream and midstream assets in Vietnam and our investments in equity-accounted entities in Venezuela to TNK-BP, and the sale of our assets in Pakistan to United Energy Group. In addition, we completed the disposal of half of the 3.29% interest in the Azeri-Chirag-Gunashli development in Azerbaijan to SOCAR and a number of interests in the Gulf of Mexico to Marubeni Group.

Downstream

In 2013, gains 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. Losses principally resulted from the disposal of a number of assets, principally in our global fuels portfolio.

In 2012, gains on disposal resulted from the disposal of our interests in purified terephthalic acid production in Malaysia to Reliance Global Holdings Pte. Ltd., retail churn in the US and a number of other assets in the segment. Losses resulted from the ongoing costs associated with our US refinery divestments and the disposal of a number of assets in the segment portfolio.

In 2011, gains on disposal resulted from our disposal of the fuels marketing business in Namibia, Malawi, Zambia and Tanzania to Puma Energy, certain non-strategic pipelines and terminals in the US and other assets in the segment. Losses resulted from the disposal of a number of assets in the segment portfolio.

TNK-BP

In 2013, BP disposed of its 50% interest in TNK-BP. See Note 6 for further information.

Other businesses and corporate

In 2011, we disposed of our aluminium business in the US which resulted in a gain.

5. Disposals and impairment – continued

Summarized financial information relating to the sale of businesses is shown in the table below. 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
	2013	2012	2011
Non-current assets	**2,124**	610	2,085
Current assets	**2,371**	570	1,008
Non-current liabilities	**(94)**	(263)	(212)
Current liabilities	**(62)**	(232)	(611)
Total carrying amount of net assets disposed	**4,339**	685	2,270
Recycling of foreign exchange on disposal	**23**	(15)	8
Costs on disposal[a]	**13**	39	17
	4,375	709	2,295
Profit on sale of businesses[b]	**69**	675	2,232
Total consideration	**4,444**	1,384	4,527
Consideration received (receivable)[c]	**(414)**	76	116
Proceeds from the sale of businesses related to completed transactions	**4,030**	1,460	4,643
Deposits received (repaid) related to assets classified as held for sale[d]	**–**	146	(3,530)
Disposals completed in relation to which deposits had been received in prior year	**(146)**	–	(1,776)
Proceeds from the sale of businesses[e]	**3,884**	1,606	(663)

[a] 2013 includes pension and other post-retirement benefit plan curtailment gains of $109 million.
[b] In 2011 a $278-million gain was not recognized in the income statement as it represented an unrealized gain on the sale of business assets in Vietnam to our former associate TNK-BP.
[c] 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.
[d] 2011 relates to the repayment of a deposit received in advance of $3,530 million following the termination of the sale agreement in respect of the expected sale of our interest in Pan American Energy LLC.
[e] 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 $42 million (2012 $4 million and 2011 $14 million).

Impairment

Upstream

During 2013, the Upstream segment recognized impairment losses of $1,255 million. The main elements were impairment losses of $251 million and $159 million relating to the Browse project in Australia and the Mad Dog Phase 2 project in the Gulf of Mexico respectively, resulting from the selection of alternative development scenarios for both projects; write-downs of a number of assets in the North Sea, caused by increases in expected decommissioning costs, amounting to $253 million in aggregate; a $134-million write-down of pipelines in the North Sea due to cost increases; a $122-million write-down to fair value less costs to sell based on expected proceeds resulting from a decision to divest our interest in the Polvo field in Brazil; and other impairment losses amounting to $335 million in total that were not individually significant. These impairment losses were partly offset by reversals of impairment of certain of our interests in Alaska, the Gulf of Mexico, and the North Sea amounting to $226 million in total, triggered by reductions in expected decommissioning costs, partly as a result of an increase in the discount rate for provisions.

During 2012, the Upstream segment recognized impairment losses of $3,046 million. The main elements were a $1,082-million write-down of our interests in the Fayetteville and Woodford 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; a $144-million write-down of certain gas storage assets in Europe due to changes to the European gas market; and other impairment losses amounting to $116 million in total that were not individually significant. These impairment losses were partly offset by reversals of impairment of certain of our interests in the Gulf of Mexico amounting to $222 million, triggered by a decision to divest assets; and other reversals of impairment amounting to $67 million in total that were not individually significant.

During 2011, the Upstream segment recognized impairment losses of $1,443 million. The main elements were a $555-million impairment loss relating to a number of our interests in the Gulf of Mexico, caused by an increase in the decommissioning provision as a result of further assessments of the regulations relating to idle infrastructure and a decrease in our assumption of the discount rate for provisions; the $393-million write-down of our interest in the Fayetteville shale gas asset in the US, triggered by a decrease in value by reference to a sale transaction by a partner of its interest in the same asset; and the $153-million write-down of our interest in the proposed Denali gas pipeline in Alaska, resulting from a decision not to proceed with the project. There were several other impairment losses amounting to $342 million in total that were not individually significant. These impairment losses were partly offset by reversals of impairment of certain of our interests in the Gulf of Mexico and Egypt amounting to $146 million in total, triggered by an increase in our assumption of long-term oil prices.

Downstream

During 2013, the Downstream segment recognized impairment losses of $484 million which mainly relates to impairments of certain refineries in the US and elsewhere in our global fuels portfolio.

During 2012, the Downstream segment recognized impairment losses of $2,892 million largely related to assets held for sale for which sales prices had been agreed, see Note 4 for further information. This impairment loss 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.

During 2011, the Downstream segment recognized impairment losses of $599 million, of which $398 million related to assets classified as held for sale. Other impairment losses, related to retail churn in Europe and other minor asset disposals, amounted to $201 million in total.

Other businesses and corporate

Impairment losses totalling $218 million, $320 million and $58 million were recognized in 2013, 2012 and 2011 respectively related to various assets in the Alternative Energy business. The amount for 2013 is principally in respect of our US wind business. The amount for 2012 includes $258 million in respect of the decision not to proceed with an investment in a biofuels production facility under development in the US.

6. Disposal of TNK-BP and investment in Rosneft

Disposal of TNK-BP

BP announced on 22 November 2012 that it, Rosneft and Rosneftegaz – the Russian state-owned parent company of Rosneft – had signed definitive and binding sale and purchase agreements (SPAs) for the sale of BP's 50% interest in TNK-BP to Rosneft, and for BP's further investment in Rosneft. The transaction would consist of three tranches:

- BP to sell its 50% shareholding in TNK-BP to Rosneft for cash consideration of $25.4 billion (which included a dividend of $0.7 billion received from TNK-BP in December 2012) and Rosneft shares representing a 3.04% stake in Rosneft.
- BP would use $4.8 billion of the cash consideration to acquire a further 5.66% stake in Rosneft from the Russian government at a price of $8 per share (representing a premium of 12% to the Rosneft share price on the bid date of 18 October 2012).
- BP would use $8.3 billion of the cash consideration to acquire a further 9.8% stake in Rosneft from a Rosneft subsidiary at a price of $8 per share.

The net result of the overall transaction was that BP would receive $12.3 billion in cash (including $0.7 billion of TNK-BP dividends received by BP in December 2012) and acquire an 18.5% shareholding in Rosneft. Combined with BP's existing 1.25% shareholding, this would result in BP owning 19.75% of Rosneft.

On completion, the transactions between BP, Rosneft and the Rosneft subsidiary were instead settled on a net basis, so that BP received the 9.80% stake in Rosneft directly rather than receiving and immediately paying $8.3 billion in cash; however, the net result was the same.

BP accounts for its investment in Rosneft as an associate, and so equity accounts for its share of Rosneft's earnings, production and reserves. See Note 18 for more information on BP's investment in Rosneft.

The gain on disposal of BP's investment in TNK-BP, recognized in the TNK-BP segment in 2013, was $12.5 billion as shown in the table below.

	$ million
Agreed cash disposal proceeds	25,425
Amount settled net in Rosneft shares (9.80% stake)	(8,309)
TNK-BP dividend received by BP in December 2012	(709)
Interest on cash proceeds	239
Disposal proceeds received in cash	16,646
Shares in Rosneft received (9.80% and 3.04% stake)	10,755
Consideration received	27,401
Less: carrying value of investment in TNK-BP	(12,393)
	15,008
Deferral of gain	(2,959)
Gain on existing 1.25% investment in Rosneft	523
Other	(72)
Gain on disposal of investment in TNK-BP	12,500

Disposal proceeds of $4.9 billion were used to purchase the 5.66% stake in Rosneft from Rosneftegaz ($4.8 billion described above plus $0.1 billion of interest). The net cash inflow relating to the transaction included in net cash flow from investing activities in the cash flow statement was $11.8 billion.

Part of the gain arising on the disposal, amounting to $3.0 billion, was deferred due to BP selling its investment in TNK-BP to Rosneft, which in turn is now accounted for by BP as an associate. The deferred gain will be released to BP's income statement over time as the TNK-BP assets are depreciated or amortized.

Investment in Rosneft

BP's investment in Rosneft is included in the group balance sheet within investments in associates, as described in Note 1. The investment is measured at cost less the deferred gain described above, plus post-acquisition changes in BP's share of Rosneft's net assets. The amount recognized as BP's initial investment in Rosneft was determined as shown in the table below.

	$ million
Shares in Rosneft received	10,755
Shares purchased from Rosneftegaz	4,871
Value of agreements to purchase Rosneft shares accounted for as derivatives (see Note 26)	(726)
Deferred gain	(2,959)
Amount included in capital expenditure	11,941
Value of existing 1.25% investment in Rosneft	1,006
Investment in Rosneft on completion	12,947

The exercise to determine BP's share of the fair value of Rosneft's identifiable net assets and the consequent impact recognized via equity accounting in BP's income statement has been completed and the results are reflected in these financial statements.

7. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. At 31 December 2013, 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 Alternative Energy business, the group's shipping and treasury functions, and corporate activities worldwide. The Alternative Energy business is an operating segment which is reported within Other businesses and corporate as it does not meet the materiality thresholds for separate segment reporting.

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.

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 seller. 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 other 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 average cost to BP of supplies acquired during the period 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 historic 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 if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a monthly basis by dividing the total cost of inventory acquired in the period by the number of barrels acquired. 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.

7. Segmental analysis – continued

								$ million
								2013
By segment	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
Interest income	76	93	–	–	113	–	–	282
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								
US	3,538	747	–	–	181	–	–	4,466
Non-US	7,514	1,343	–	–	187	–	–	9,044
Impairment losses	1,255	484	–	–	218	–	–	1,957
Impairment reversals	(226)	–	–	–	–	–	–	(226)
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	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 149.

							$ million
							2012
By segment	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
Segment revenues							
Sales and other operating revenues	72,225	346,391	–	1,985	–	(44,836)	375,765
Less: sales and other operating revenues between segments	(42,572)	(1,365)	–	(899)	–	44,836	–
Third party sales and other operating revenues	29,653	345,026	–	1,086	–	–	375,765
Equity-accounted earnings	915	101	2,986	(67)	–	–	3,935
Interest income	107	108	–	104	–	–	319
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							
US	3,437	586	–	213	–	–	4,236
Non-US	6,918	1,343	–	190	–	–	8,451
Impairment losses	3,046	2,892	–	320	–	–	6,258
Impairment reversals	(289)	(1)	–	(3)	–	–	(293)
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	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 149.

Financial statements

7. Segmental analysis – continued

By segment	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
							$ million
							2011
Segment revenues							
Sales and other operating revenues	75,754	344,033	–	2,957	–	(47,031)	375,713
Less: sales and other operating revenues between segments	(44,766)	(1,396)	–	(869)	–	47,031	–
Third party sales and other operating revenues	30,988	342,637	–	2,088	–	–	375,713
Equity-accounted earnings	1,150	381	4,185	(33)	–	–	5,683
Interest income	(10)	108	–	146	–	–	244
Segment results							
Replacement cost profit (loss) before interest and taxation	26,358	5,470	4,134	(2,468)	3,800	(113)	37,181
Inventory holding gains (losses)[a]	81	2,487	51	15	–	–	2,634
Profit (loss) before interest and taxation	26,439	7,957	4,185	(2,453)	3,800	(113)	39,815
Finance costs							(1,187)
Net finance expense relating to pensions and other post-retirement benefits							(400)
Profit before taxation							38,228
Other income statement items							
Depreciation, depletion and amortization							
US	3,201	860	–	151	–	–	4,212
Non-US	5,540	1,431	–	174	–	–	7,145
Impairment losses	1,443	599	–	58	–	–	2,100
Impairment reversals	(146)	–	–	–	–	–	(146)
Fair value (gain) loss on embedded derivatives	(191)	–	–	123	–	–	(68)
Charges for provisions, net of write-back of unused provisions, including change in discount rate	213	373	–	942	5,200	–	6,728
Segment assets							
Equity-accounted investments	7,301	3,256	10,013	1,024	–	–	21,594
Additions to non-current assets	34,813	4,281	–	1,864	–	–	40,958
Additions to other investments							27
Element of acquisitions not related to non-current assets							(1,089)
Additions to decommissioning asset							(7,937)
Capital expenditure and acquisitions	25,821	4,285	–	1,853	–	–	31,959

[a] See explanation of inventory holding gains and losses on page 149.

7. Segmental analysis – continued

By geographical area	US	Non-US	Total
			$ million
			2013
	US	**Non-US**	**Total**
Revenues			
Third party sales and other operating revenues[a]	**128,764**	**250,372**	**379,136**
Other income statement items			
Production and similar taxes	**1,112**	**5,935**	**7,047**
Results			
Replacement cost profit before interest and taxation	**3,114**	**28,945**	**32,059**
Non-current assets			
Other non-current assets[b c]	**70,228**	**124,439**	**194,667**
Other investments			**1,565**
Loans			**763**
Trade and other receivables			**5,985**
Derivative financial instruments			**3,509**
Deferred tax assets			**985**
Defined benefit pension plan surpluses			**1,376**
Total non-current assets			**208,850**
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] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

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			
Other non-current assets[b c]	66,751	107,844	174,595
Other investments			2,704
Loans			642
Trade and other receivables			5,961
Derivative financial instruments			4,294
Deferred tax assets			874
Defined benefit pension plan surpluses			12
Total non-current assets			189,082
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] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

7. Segmental analysis – continued

By geographical area	US	Non-US	Total
			$ million
			2011
Revenues			
Third party sales and other operating revenues[a]	131,488	244,225	375,713
Other income statement items			
Production and similar taxes	1,854	6,426	8,280
Results			
Replacement cost profit before interest and taxation	10,202	26,979	37,181
Non-current assets			
Other non-current assets[b c]	66,523	113,323	179,846
Other investments			2,635
Loans			824
Trade and other receivables			5,738
Derivative financial instruments			5,038
Deferred tax assets			611
Defined benefit pension plan surpluses			17
Total non-current assets			194,709
Capital expenditure and acquisitions	8,931	23,028	31,959

[a] Non-US region includes UK $75,816 million.
[b] Non-US region includes UK $18,363 million.
[c] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

8. Income statement analysis

			$ million
	2013	2012	2011
Interest and other income			
Interest income	**282**	319	244
Other income[a]	**495**	1,358	444
	777	1,677	688
Currency exchange losses (gains) charged (credited) to the income statement[b]	**180**	106	(69)
Expenditure on research and development	**707**	674	636
Finance costs			
Interest payable	**1,082**	1,234	1,151
Capitalized at 2% (2012 2.25% and 2011 2.63%)[c]	**(238)**	(390)	(349)
Unwinding of discount on provisions[d]	**147**	140	244
Unwinding of discount on other payables[d]	**77**	88	141
	1,068	1,072	1,187

[a] 2012 includes $709 million of dividends received from TNK-BP. See Note 6 for further information.
[b] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.
[c] Tax relief on capitalized interest is approximately $62 million (2012 $93 million and 2011 $107 million).
[d] Unwinding of discount on provisions relating to the Gulf of Mexico oil spill was $1 million (2012 $7 million and 2011 $6 million) and unwinding of discount on other payables relating to the Gulf of Mexico oil spill was $38 million (2012 $12 million and 2011 $52 million). See Note 2 for further information on the financial impacts of the Gulf of Mexico oil spill.

9. Operating leases

In the case of an operating lease entered into by BP as the operator of a joint operation, the amounts shown in the tables below 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.

The table below shows the expense for the year in respect of operating leases.

			$ million
	2013	2012	2011
Minimum lease payments	**5,961**	5,257	4,868
Contingent rentals	**(50)**	(79)	(97)
Sub-lease rentals	**(88)**	(228)	(153)
	5,823	4,950	4,618

9. Operating leases – continued

The future minimum lease payments at 31 December 2013, before deducting related rental income from operating sub-leases of $223 million (2012 $271 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	**2013**	2012
Payable within		
1 year	**5,188**	4,533
2 to 5 years	**10,408**	9,735
Thereafter	**3,590**	4,195
	19,186	18,463

The group enters into operating leases of ships, plant and machinery, commercial vehicles and land and buildings. Typical durations of the leases are as follows:

	Years
Ships	up to 15
Plant and machinery	up to 10
Commercial vehicles	up to 15
Land and buildings	up to 40

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 2013, the future minimum lease payments relating to drilling rigs amounted to $8,776 million (2012 $8,527 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.

10. 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.

			$ million
	2013	2012	2011
Exploration and evaluation costs			
Exploration expenditure written off[a]	**2,710**	745	1,024
Other exploration costs	**731**	730	496
Exploration expense for the year	**3,441**	1,475	1,520
Impairment losses	**253**	–	7
Impairment reversals	**–**	(42)	–
Intangible assets – exploration and appraisal expenditure	**20,865**	23,434	20,433
Liabilities	**212**	287	306
Net assets	**20,653**	23,147	20,127
Capital expenditure	**4,464**	5,176	8,926
Net cash used in operating activities	**731**	730	496
Net cash used in investing activities	**4,275**	5,010	8,571

[a] 2013 included an $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 or 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 28.

The carrying amount, by location, of exploration and appraisal expenditure capitalized as intangible assets at 31 December 2013 is shown in the table below.

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

11. Taxation

Tax on profit

			$ million
	2013	2012	2011
Current tax			
Charge for the year	**5,724**	6,664	7,500
Adjustment in respect of prior years	**61**	252	111
	5,785	6,916	7,611
Deferred tax			
Origination and reversal of temporary differences in the current year	**529**	67	5,523
Adjustment in respect of prior years	**149**	(103)	(515)
	678	(36)	5,008
Tax charge on profit	**6,463**	6,880	12,619

In 2013, the total tax charge recognized within other comprehensive income was $1,374 million (2012 $270 million credit and 2011 $1,490 million credit), and the total tax credit recognized directly in equity was $33 million (2012 $6 million credit and 2011 $7 million credit). See Note 32 for further information.

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 2013 the UK statutory corporation tax rate reduced from 24% to 23% on profits arising from activities outside the North Sea.

			$ million
	2013	2012	2011
Profit before taxation	**30,221**	18,131	38,228
Tax charge on profit	**6,463**	6,880	12,619
Effective tax rate	**21%**	38%	33%

			% of profit before taxation
UK statutory corporation tax rate	**23**	24	26
Increase (decrease) resulting from			
UK supplementary and overseas taxes at higher or lower rates[a]	**4**	12	14
Tax reported in equity-accounted entities	**(2)**	(5)	(3)
Adjustments in respect of prior years	**1**	1	(1)
Movement in deferred tax not recognized	**2**	2	–
Tax incentives for investment	**(2)**	(2)	(1)
Gulf of Mexico oil spill non-deductible costs	**–**	8	–
Permanent differences relating to disposals[b]	**(8)**	–	(2)
Foreign exchange	**2**	(1)	1
Other	**1**	(1)	(1)
Effective tax rate	**21**	38	33

[a] Jurisdictions which contribute significantly to this item are Angola, with an applicable statutory tax rate of 50%, the UK, currently with an applicable statutory tax rate of 62% for North Sea activities, and Trinidad and Tobago, with an applicable statutory tax rate of 55%.

[b] For 2013, this relates to the non-taxable gain on disposal of our investment in TNK-BP; for 2011, this mainly relates to the sale of our Upstream interests in Columbia.

11. Taxation – continued

Deferred tax

					$ million
		Income statement			Balance sheet
	2013	2012	2011	**2013**	2012
Deferred tax liability					
Depreciation	**(474)**	(75)	4,774	**31,551**	32,065
Pension plan surpluses	**(691)**	–	–	**284**	–
Other taxable temporary differences	**(199)**	(2,239)	141	**3,653**	3,671
	(1,364)	(2,314)	4,915	**35,488**	35,736
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**787**	(33)	224	**(2,026)**	(3,421)
Decommissioning, environmental and other provisions	**1,385**	1,872	(1,443)	**(11,301)**	(12,705)
Derivative financial instruments	**30**	(7)	24	**(579)**	(281)
Tax credits	**(174)**	1,802	(401)	**(888)**	(714)
Loss carry forward	**(343)**	(911)	(223)	**(2,585)**	(2,214)
Other deductible temporary differences	**357**	(445)	1,912	**(1,655)**	(2,032)
	2,042	2,278	93	**(19,034)**	(21,367)
Net deferred tax charge (credit) and net deferred tax liability	**678**	(36)	5,008	**16,454**	14,369
Of which – deferred tax liabilities				**17,439**	15,243
– deferred tax assets				**985**	874

		$ million
Analysis of movements during the year in the net deferred tax liability	**2013**	2012
At 1 January	**14,369**	14,609
Exchange adjustments	**43**	(27)
Charge (credit) for the year on profit	**678**	(36)
Charge (credit) for the year in other comprehensive income	**1,397**	(272)
Charge (credit) for the year in equity	**(33)**	4
Acquisitions	**–**	11
Reclassified as assets/liabilities held for sale	**–**	48
Deletions	**–**	32
At 31 December	**16,454**	14,369

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	**2013**	2012
Unused tax losses[a]	**1.8**	0.9
Unused tax credits	**18.0**	18.3
of which – arising in the UK[b]	**16.3**	16.0
– arising in the US[c]	**1.7**	2.3
Other deductible temporary differences[d]	**11.2**	7.0
Other taxable temporary differences associated with investments in subsidiaries and equity-accounted entities	**0.5**	0.5

[a] Substantially all the tax losses have no fixed expiry date.
[b] The UK 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 tax credits expire 10 years after generation and will all expire in the period 2015-2021.
[d] Other deductible temporary differences of $0.7 billion are expected to expire in the period 2014-2020, the remainder do not have an expiry date.

			$ billion
Benefit of previously unrecognized deferred tax on current year tax charge	**2013**	2012	2011
Current tax benefit relating to the utilization of previously unrecognized tax losses	**–**	–	0.1
Current tax benefit relating to the utilization of previously unrecognized tax credits	**0.2**	0.4	0.1
Deferred tax benefit relating to the recognition of previously unrecognized tax credits	**0.2**	0.1	–

12. Dividends

The quarterly dividend expected to be paid on 28 March 2014 in respect of the fourth quarter 2013 is 9.5 cents per ordinary share ($0.57 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 17 March 2014. 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		
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**6.0013**	5.0958	4.3372	**9.0**	8.0	7.0	**1,621**	1,211	808
June	**5.8342**	5.1498	4.2809	**9.0**	8.0	7.0	**1,399**	1,448	794
September	**5.7630**	5.0171	4.3160	**9.0**	8.0	7.0	**1,245**	1,417	1,224
December	**5.8008**	5.5890	4.4694	**9.5**	9.0	7.0	**1,174**	1,216	1,244
	23.3993	20.8517	17.4035	**36.5**	33.0	28.0	**5,441**	5,294	4,072
Dividend announced, payable in March 2014				**9.5**			**1,733**		

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

	2013	2012	2011
Number of shares issued (thousand)	**202,124**	138,406	165,601
Value of shares issued ($ million)	**1,470**	982	1,219

The financial statements for the year ended 31 December 2013 do not reflect the dividend announced on 4 February 2014 and expected to be paid in March 2014; this will be treated as an appropriation of profit in the year ended 31 December 2014.

13. Earnings per ordinary share

			Cents per share
	2013	2012	2011
Basic earnings per share	**123.87**	57.89	133.35
Diluted earnings per share	**123.12**	57.50	131.74

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 treasury shares and the shares held by the Employee Share Ownership Plan trusts (ESOPs) and includes certain shares that will be issuable in the future under employee share-based payment plans.

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
	2013	2012	2011
Profit attributable to BP shareholders	**23,451**	11,017	25,212
Less: dividend requirements on preference shares	**2**	2	2
Profit for the year attributable to BP ordinary shareholders	**23,449**	11,015	25,210

			Shares thousand
	2013	2012	2011
Basic weighted average number of ordinary shares	**18,931,021**	19,027,929	18,904,812
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**115,152**	129,959	231,388
	19,046,173	19,157,888	19,136,200

The number of ordinary shares outstanding at 31 December 2013, excluding treasury shares and the shares held by the ESOPs, and including certain shares that will be issuable in the future under employee share-based payment plans was 18,611,489,958. Between 31 December 2013 and 18 February 2014, the latest practicable date before the completion of these financial statements, there was a net decrease of 171,061,543 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, the group repurchased 195 million of its own ordinary shares as part of the share repurchase programme announced on 22 March 2013.

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 page 81.

13. Earnings per ordinary share – continued

The following table shows the number of shares potentially issuable under 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 the employee share option plans at 31 December included in the diluted earnings per share is also shown.

Share options	2013		2012	
	Number of options[a b] thousand	**Weighted average exercise price $**	Number of options[a b] thousand	Weighted average exercise price $
Outstanding	**286,725**	**7.71**	324,096	7.62
Exercisable	**127,290**	**10.01**	159,419	9.33
Dilutive effect	**23,169**	**n/a**	16,435	n/a

[a] Numbers of options shown are ordinary share equivalents (one ADS is equivalent to six ordinary shares).
[b] At 31 December 2013, the quoted market price of one BP ordinary share was $8.10 (2012 $6.94).

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.

Shares	2013	2012
Vesting	**Number of shares[a] thousand**	Number of shares[a] thousand
Within one year	**35,442**	29,138
1 to 2 years	**120,056**	67,593
2 to 3 years	**115,387**	120,621
3 to 4 years	**14,231**	25,066
4 to 5 years	**123**	233
	285,239	242,651
Dilutive effect	**95,014**	95,683

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

There has been a net decrease of 32,378,757 in the number of potential ordinary shares in relation to employee share-based payment plans between 31 December 2013 and 18 February 2014.

14. Property, plant and equipment

$ million

	Land and land improvements	Buildings	Oil and gas properties	Plant, machinery and equipment	Fixtures, fittings and office equipment	Transportation	Oil depots, storage tanks and service stations	Total
Cost								
At 1 January 2013	**3,279**	**2,812**	**171,772**	**45,200**	**3,346**	**13,436**	**9,059**	**248,904**
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**	**9,391**	**268,886**
Depreciation								
At 1 January 2013	**514**	**1,023**	**87,965**	**18,628**	**2,119**	**8,409**	**4,915**	**123,573**
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**	**5,261**	**135,196**
Net book amount at 31 December 2013	**2,825**	**1,886**	**90,628**	**28,534**	**1,206**	**4,481**	**4,130**	**133,690**
Cost								
At 1 January 2012	3,169	2,942	176,988	41,319	3,140	12,753	8,611	248,922
Exchange adjustments	86	14	–	320	28	8	272	728
Additions	120	387	16,303	4,481	314	902	533	23,040
Acquisitions	–	–	44	2	–	15	–	61
Transfers	–	–	1,306	–	–	–	–	1,306
Reclassified as assets held for sale	–	–	(19,410)	(143)	–	(172)	(2)	(19,727)
Deletions	(96)	(531)	(3,459)	(779)	(136)	(70)	(355)	(5,426)
At 31 December 2012	3,279	2,812	171,772	45,200	3,346	13,436	9,059	248,904
Depreciation								
At 1 January 2012	511	1,411	91,994	16,915	1,940	8,149	4,571	125,491
Exchange adjustments	8	13	–	228	25	6	151	431
Charge for the year	33	123	9,659	1,442	289	320	504	12,370
Impairment losses	8	–	2,765	493	–	70	7	3,343
Impairment reversals	–	–	(221)	–	–	–	(1)	(222)
Reclassified as assets held for sale	–	–	(13,774)	(36)	–	(126)	(2)	(13,938)
Deletions	(46)	(524)	(2,458)	(414)	(135)	(10)	(315)	(3,902)
At 31 December 2012	514	1,023	87,965	18,628	2,119	8,409	4,915	123,573
Net book amount at 31 December 2012	2,765	1,789	83,807	26,572	1,227	5,027	4,144	125,331
Net book amount at 1 January 2012	2,658	1,531	84,994	24,404	1,200	4,604	4,040	123,431
Assets held under finance leases at net book amount included above								
At 31 December 2013	**–**	**7**	**187**	**265**	**–**	**4**	**–**	**463**
At 31 December 2012	–	9	157	254	–	9	–	429
Assets under construction included above								
At 31 December 2013								**27,900**
At 31 December 2012								29,203

15. Goodwill and impairment review of goodwill

		$ million
	2013	2012
Cost		
At 1 January	**12,804**	14,041
Exchange adjustments	**46**	160
Acquisitions	**44**	25
Reclassified as assets held for sale	**–**	(1,327)
Deletions	**(43)**	(95)
At 31 December	**12,851**	12,804
Impairment losses		
At 1 January	**614**	1,612
Impairment losses for the year	**56**	–
Reclassified as assets held for sale	**–**	(977)
Deletions	**–**	(21)
At 31 December	**670**	614
Net book amount at 31 December	**12,181**	12,190
Net book amount at 1 January	**12,190**	12,429

Impairment review of goodwill

		$ million
Goodwill at 31 December	**2013**	2012
Upstream	**7,812**	7,862
Downstream	**4,277**	4,168
Other businesses and corporate	**92**	160
	12,181	12,190

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 the Rhine fuels value chain (FVC), Lubricants and Other.

In assessing whether goodwill has been impaired, the carrying amount of the cash-generating unit (CGU) or groups of CGUs (including goodwill) is compared with the recoverable amount of the CGU or groups of CGUs. The recoverable amount is the higher of fair value less costs to sell and value in use. In the absence of readily available information about the fair value of a cash-generating unit, the recoverable amount is deemed to be the value in use for the purposes of performing an impairment test of goodwill, unless this would lead to an impairment loss. If goodwill would be impaired using value in use as the recoverable amount, a fair value less costs to sell assessment would be performed as this may lead to a higher recoverable amount.

The group calculates the value in use using a discounted cash flow model. The 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. The rate to be applied to each country is reassessed each year. Discount rates of 12% and 14% have been used for goodwill impairment calculations performed in 2013 (2012 12% and 14%).

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 environmental assumptions, such as oil prices, natural gas prices, refining margins, refined product margins and cost inflation rates, are set by senior management. These environmental assumptions take account of existing prices, global supply-demand equilibrium for oil and natural gas, other macroeconomic factors and historical trends and variability.

Upstream

		$ million
	2013	2012
Goodwill	**7,812**	7,862
Excess of recoverable amount over carrying amount	**6,811**	25,871

The table above shows the carrying amount of the goodwill for the segment and the excess of the recoverable amount, based upon a value in use calculation, over the carrying amount (the headroom).

The value in use is based on the cash flows expected to be generated by the projected oil or natural gas production profiles up to the expected dates of cessation of production of each producing field, based on current estimates of reserves. As the production profile and related cash flows can be estimated from BP's past experience, management believes that the cash flows generated over the estimated life of field is the appropriate basis upon which to assess goodwill and individual assets for impairment. The 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, the 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's management. Capital expenditure, operating costs and expected hydrocarbon production profiles up to 2023 are derived from the business segment plan. Estimated production volumes and cash flows up to the date of cessation of production on a field-by-field basis are developed to be consistent with this. The production profiles used are consistent with the reserve volumes approved as part of BP's centrally controlled process for the estimation of proved and probable reserves and total resources.

15. Goodwill and impairment review of goodwill – continued

Intangible assets are deemed to have a recoverable amount equal to their carrying amount. Consistent with prior years, the 2013 review for impairment was carried out during the fourth quarter.

The Brent oil price and Henry Hub natural gas price assumptions used in the impairment review of goodwill are shown in the table below.

						2013
	2014	**2015**	**2016**	**2017**	**2018**	**2019 and thereafter**
Brent oil price ($/bbl)	**108**	**102**	**97**	**93**	**90**	**90**
Henry Hub natural gas price ($/mmBtu)	**3.86**	**4.02**	**4.10**	**4.17**	**4.27**	**6.50**

						2012
	2013	2014	2015	2016	2017	2018 and thereafter
Brent oil price ($/bbl)	105	100	96	93	91	90
Henry Hub natural gas price ($/mmBtu)	3.96	4.25	4.42	4.61	4.82	6.50

Key assumptions for oil and gas prices for the first five years were derived from forward price curves in the fourth quarter. Prices in 2019 and beyond were determined using long-term views of global supply and demand, building upon past experience of the industry and using information from external sources. These prices were adjusted to arrive at appropriate consistent price assumptions for different qualities of oil and gas, or where appropriate, contracted oil and gas prices were applied.

The key assumptions required for the value-in-use estimation are the oil and natural gas prices, production volumes and the discount rate. 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 equal to the current assumption for 2019 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 if the price assumption for natural gas was around 24% lower than the current assumption for 2019 and beyond the headroom would be reduced to zero.

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 597mmboe per year (2012 576mmboe per year). It is estimated that if this production volume were to be reduced by around 2% 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 discount rate was approximately 14% 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
				2013				2012
	Rhine FVC	**Lubricants**	**Other**	**Total**	Rhine FVC	Lubricants	Other	Total
Goodwill	**643**	**3,518**	**116**	**4,277**	627	3,441	100	4,168
Excess of recoverable amount over carrying amount	**2,759**	**n/a**	**n/a**	**n/a**	2,411	n/a	n/a	n/a

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.

Rhine FVC

The key assumptions to which the calculation of value in use for the Rhine FVC is most sensitive are refinery gross margins, throughput volumes and discount rate. Gross margin assumptions used in the Rhine FVC plan are consistent with those used to develop the regional Refining Marker Margin (RMM). The average values assigned to the regional RMM and refinery throughput volume over the plan period are $12.35 per barrel and 250mmbbl per year (2012 $12.30 per barrel and 246mmbbl per year). These values reflect past experience and are consistent with external sources. Cash flows beyond the five-year plan period are extrapolated using a nominal 4% growth rate (2012 4%).

No reasonably possible change in the discount rate would cause the Rhine FVC unit's carrying amount to exceed its recoverable amount. It is estimated that if the refinery margin assumption was $1.9 per barrel lower than the current assumption, the recoverable amount would equal the carrying amount. It is also estimated that if the refinery throughput volume assumption was 32mmbbl per year lower than the current assumption, the recoverable amount would equal the carrying amount.

Lubricants

In certain circumstances IAS 36 allows the use of the most recent detailed calculations of the recoverable amount performed in an earlier period as the basis for the current year's goodwill impairment test. The most recent detailed calculation of the Lubricants unit's recoverable amount was performed in 2009 and this was used as the basis for the tests in 2010-2012 as the criteria of IAS 36 were met in each of those years. IAS 36 does not specify for how many years such an approach is appropriate and management determined that a re-performance of the test was appropriate in 2013 given the passage of time since 2009. There was no significant change in the outcome of this test compared to that in 2009.

The key assumptions to which the calculation of the value in use for the Lubricants unit is most sensitive are operating margins, sales volumes, and discount rate. Operating margin and sales volumes assumptions used in the detailed impairment review of goodwill calculation are consistent with the assumptions used in the Lubricant unit's business plan and values assigned to these key assumptions reflect past experience. No reasonably possible change in any of these key assumptions would cause the unit's carrying amount to exceed its recoverable amount. Cash flows beyond the plan period are extrapolated using a 3% growth rate (2009 3%).

16. Intangible assets

						$ million
			2013			2012
	Exploration and appraisal expenditure	**Other intangibles**	**Total**	Exploration and appraisal expenditure	Other intangibles	Total
Cost						
At 1 January	**24,511**	**3,739**	**28,250**	21,216	3,500	24,716
Exchange adjustments	**–**	**(5)**	**(5)**	–	50	50
Acquisitions	**–**	**–**	**–**	(68)	80	12
Additions	**4,464**	**336**	**4,800**	5,244	343	5,587
Transfers	**(4,365)**	**–**	**(4,365)**	(1,306)	–	(1,306)
Reclassified as assets held for sale	**–**	**–**	**–**	(67)	(26)	(93)
Deletions	**(2,868)**	**(134)**	**(3,002)**	(508)	(208)	(716)
At 31 December	**21,742**	**3,936**	**25,678**	24,511	3,739	28,250
Amortization						
At 1 January	**1,077**	**2,541**	**3,618**	783	2,280	3,063
Exchange adjustments	**–**	**(2)**	**(2)**	–	25	25
Charge for the year	**2,710**	**267**	**2,977**	745	317	1,062
Impairment losses	**253**	**85**	**338**	–	126	126
Impairment reversals	**–**	**–**	**–**	(42)	–	(42)
Transfers	**(365)**	**–**	**(365)**	–	–	–
Reclassified as assets held for sale	**–**	**–**	**–**	–	(21)	(21)
Deletions	**(2,798)**	**(129)**	**(2,927)**	(409)	(186)	(595)
At 31 December	**877**	**2,762**	**3,639**	1,077	2,541	3,618
Net book amount at 31 December	**20,865**	**1,174**	**22,039**	23,434	1,198	24,632
Net book amount at 1 January	**23,434**	**1,198**	**24,632**	20,433	1,220	21,653

17. Investments in joint ventures

The significant joint ventures of the BP group at 31 December 2013 are shown in Note 38. Summarized financial information for the group's share of joint ventures is shown below. Balance sheet information shown below excludes data relating to joint ventures classified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to joint ventures reclassified as assets held for sale during the period up until the date of reclassification. The group does not have any individually material joint ventures.

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

			$ million
	2013	2012	2011
Sales and other operating revenues	**12,507**	12,507	11,993
Profit before interest and taxation	**1,076**	778	1,315
Finance costs	**130**	113	115
Profit before taxation	**946**	665	1,200
Taxation	**499**	405	433
Profit for the year	**447**	260	767
Other comprehensive income	**38**	(52)	–
Total comprehensive income	**485**	208	767
Non-current assets	**11,576**	11,147	
Current assets	**3,095**	2,931	
Total assets	**14,671**	14,078	
Current liabilities	**2,276**	2,350	
Non-current liabilities	**3,499**	3,379	
Total liabilities	**5,775**	5,729	
	8,896	8,349	
Group investment in joint ventures			
Group share of net assets (as above)	**8,896**	8,349	
Loans made by group companies to joint ventures	**303**	265	
	9,199	8,614	

17. Investments in joint ventures – continued

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

Sales to joint ventures						$ million
		2013		2012		2011
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, employee services	**4,125**	**342**	4,272	379	3,196	423

Purchases from joint ventures						$ million
		2013		2012		2011
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	**503**	**51**	1,107	116	1,165	62

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.

BP has commitments amounting to $21 million (2012 $53 million) in relation to contracts with joint ventures for the purchase of LNG, crude oil and oil products, refinery operating costs and storage and handling services. See Note 36 for further information on capital commitments relating to BP's investments in joint ventures.

18. Investments in associates

The following table provides aggregated 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
	Earnings from associates – after interest and tax			Investments in associates		
	2013	2012	2011	**2013**	2012	2011
Rosneft	**2,058**	–	–	**13,681**	–	–
TNK-BP	**–**	2,986	4,185	**–**	–	10,013
Other associates	**684**	689	731	**2,955**	2,998	3,278
	2,742	3,675	4,916	**16,636**	2,998	13,291

The associate that is material to the group at 31 December 2013 is Rosneft (2012 TNK-BP). In 2013, BP concluded transactions to sell its 50% interest in TNK-BP to Rosneft and to increase BP's investment in Rosneft. BP and Rosneft announced heads of terms for this transaction on 22 October 2012, after which our investment in TNK-BP was classified as an asset held for sale and therefore equity accounting ceased. See below and Note 6 for further information. Other significant associates of the BP group at 31 December 2013 are shown in Note 38.

At 31 December 2013, and since the transaction described in Note 6 concluded on 21 March 2013, BP owned 19.75% of the voting shares of OJSC Oil Company Rosneft (Rosneft), a Russian oil and gas company. Rosneft shares are listed on the MICEX stock exchange in Moscow and its global depository receipts are listed on the London Stock Exchange. The Russian federal government, through its investment company OJSC Rosneftegaz, owned 69.5% of the voting shares of Rosneft at 31 December 2013.

BP uses the equity method of accounting for its investment in Rosneft because in management's judgement BP has significant influence over Rosneft, see Note 1 – Interests in other entities – significant estimate or judgement for further information.

18. Investments in associates – continued

The following table provides summarized financial information at 100% share relating to each of the group's material associates.

			$ million
			Gross amount
	2013	2012	2011
	Rosneft	TNK-BP[a]	TNK-BP
Sales and other operating revenues	**122,866**	49,350	60,200
Profit before interest and taxation	**14,106**	8,810	11,984
Finance costs	**1,337**	168	264
Profit before taxation	**12,769**	8,642	11,720
Taxation	**2,137**	1,958	2,666
Non-controlling interests	**213**	712	684
Profit for the year	**10,419**	5,972	8,370
Other comprehensive income	**(441)**	26	(77)
Total comprehensive income	**9,978**	5,998	8,293
Non-current assets	**149,149**		
Current assets	**48,775**		
Total assets	**197,924**		
Current liabilities	**43,175**		
Non-current liabilities	**83,458**		
Total liabilities	**126,633**		
Non-controlling interests	**2,020**		
	69,271		

[a] BP ceased equity accounting for TNK-BP on 22 October 2012. See Note 6 for further information.

The group received dividends of $456 million from Rosneft in 2013, net of withholding tax (2012 dividends of $709 million from TNK-BP and 2011 dividends of $3,747 million from TNK-BP).

Summarized financial information for the group's share of associates is shown below. Balance sheet information shown below does not include data relating to associates classified as assets held for sale as at the end of the period. 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
			2013			2012			2011
	Rosneft[a]	**Other**	**Total**	TNK-BP[b]	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	**24,266**	**7,967**	**32,233**	24,675	11,965	36,640	30,100	12,145	42,245
Profit before interest and taxation	**2,786**	**908**	**3,694**	4,405	906	5,311	5,992	958	6,950
Finance costs	**264**	**11**	**275**	84	16	100	132	13	145
Profit before taxation	**2,522**	**897**	**3,419**	4,321	890	5,211	5,860	945	6,805
Taxation	**422**	**213**	**635**	979	201	1,180	1,333	214	1,547
Non-controlling interests	**42**	**–**	**42**	356	–	356	342	–	342
Profit for the year	**2,058**	**684**	**2,742**	2,986	689	3,675	4,185	731	4,916
Other comprehensive income	**(87)**	**2**	**(85)**	13	(6)	7	(39)	–	(39)
Total comprehensive income	**1,971**	**686**	**2,657**	2,999	683	3,682	4,146	731	4,877
Non-current assets	**29,457**	**3,148**	**32,605**	–	3,270	3,270			
Current assets	**9,633**	**2,477**	**12,110**	–	2,399	2,399			
Total assets	**39,090**	**5,625**	**44,715**	–	5,669	5,669			
Current liabilities	**8,527**	**2,114**	**10,641**	–	2,126	2,126			
Non-current liabilities	**16,483**	**1,053**	**17,536**	–	1,290	1,290			
Total liabilities	**25,010**	**3,167**	**28,177**	–	3,416	3,416			
Non-controlling interests	**399**	**–**	**399**	–	–	–			
	13,681	**2,458**	**16,139**	–	2,253	2,253			
Group investment in associates									
Group share of net assets (as above)	**13,681**	**2,458**	**16,139**	–	2,253	2,253			
Loans made by group companies to associates	**–**	**497**	**497**	–	745	745			
	13,681	**2,955**	**16,636**	–	2,998	2,998			

[a] The fair value of BP's 19.75% stake in Rosneft was $15,937 million at 31 December 2013 based on the quoted market share price of $7.62 per share.
[b] BP ceased equity accounting for TNK-BP on 22 October 2012. See Note 6 for further information.

Financial statements

18. Investments in associates – continued

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		**2013**		2012		2011
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, employee services	**5,170**	**783**	3,771	401	3,855	393

						$ million
Purchases from associates		**2013**		2012		2011
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	**21,205**	**3,470**	9,135	932	8,159	815

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

The majority of the purchases from associates are crude oil and oil products purchased from Rosneft. BP has commitments amounting to $6,077 million (2012 $595 million) in relation to contracts with its associates for the purchase of crude oil and oil products, transportation and storage. See Note 36 for further information on capital commitments relating to BP's investments in associates.

19. 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 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	**20**	**–**	**291**	**–**	**–**	**–**	**–**	**291**
– other	**20**	**–**	**1,167**	**–**	**574**	**–**	**–**	**1,741**
Loans		**979**	**–**	**–**	**–**	**–**	**–**	**979**
Trade and other receivables	**22**	**39,630**	**–**	**–**	**–**	**–**	**–**	**39,630**
Derivative financial instruments	**26**	**–**	**–**	**–**	**5,189**	**995**	**–**	**6,184**
Cash and cash equivalents	**23**	**19,153**	**2,267**	**1,100**	**–**	**–**	**–**	**22,520**
Financial liabilities								
Trade and other payables	**25**	**–**	**–**	**–**	**–**	**–**	**(48,072)**	**(48,072)**
Derivative financial instruments	**26**	**–**	**–**	**–**	**(4,159)**	**(388)**	**–**	**(4,547)**
Accruals		**–**	**–**	**–**	**–**	**–**	**(9,507)**	**(9,507)**
Finance debt	**27**	**–**	**–**	**–**	**–**	**–**	**(48,192)**	**(48,192)**
		59,762	**3,725**	**1,100**	**1,604**	**607**	**(105,771)**	**(38,973)**
At 31 December 2012								
Financial assets								
Other investments – equity shares	20	–	1,433	–	–	–	–	1,433
– other	20	–	1,005	–	585	–	–	1,590
Loans		889	–	–	–	–	–	889
Trade and other receivables	22	35,962	–	–	–	–	–	35,962
Derivative financial instruments	26	–	–	–	5,342	3,459	–	8,801
Cash and cash equivalents	23	15,128	4,507	–	–	–	–	19,635
Financial liabilities								
Trade and other payables	25	–	–	–	–	–	(44,405)	(44,405)
Derivative financial instruments	26	–	–	–	(5,093)	(288)	–	(5,381)
Accruals		–	–	–	–	–	(7,366)	(7,366)
Finance debt	27	–	–	–	–	–	(48,168)	(48,168)
		51,979	6,945	–	834	3,171	(99,939)	(37,010)

The fair value of finance debt is shown in Note 27. 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, interest rates and equity prices; credit risk; and liquidity risk.

19. Financial instruments and financial risk factors – continued

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 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, interest rate risk and equity price risk, each of which is discussed below.

(i) Commodity price risk

The group's integrated supply and trading function uses conventional financial and commodity instruments and physical cargoes 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 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. Value-at-risk limits are in place for each trading activity and for the group's trading activity in total. The board has delegated a limit of $100 million value at risk in support of this trading activity.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $652 million at 31 December 2013 (2012 liability of $1,112 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 26.

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 2013 the most significant open contracts in place were for $723 million sterling (2012 $853 million sterling).

For other UK, European and Australian operational requirements the group uses cylinders (purchased call and sold put options) and currency forwards to manage the estimated exposures on a 12-month rolling basis. At 31 December 2013, the open positions relating to cylinders consisted of receive sterling, pay US dollar cylinders for $2,770 million (2012 $2,886 million); receive euro, pay US dollar cylinders for $962 million (2012 $1,636 million); receive Australian dollar, pay US dollar cylinders for $401 million (2012 $522 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 2013, the total foreign currency net borrowings not swapped into US dollars amounted to $665 million (2012 $364 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.

19. Financial instruments and financial risk factors – continued

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 2013 was 65% of total finance debt outstanding (2012 65%). The weighted average interest rate on finance debt at 31 December 2013 was 2% (2012 2%) and the weighted average maturity of fixed rate debt was four years (2012 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 2014, it is estimated that the group's finance costs for 2014 would increase by approximately $312 million (2012 $311 million increase in 2013).

(iv) Equity price risk

The group holds equity investments, typically for strategic purposes, that are classified as non-current available-for-sale financial assets and are measured initially at fair value with changes in fair value recognized in other comprehensive income.

At 31 December 2013 the group had no significant exposure to the price of quoted equity instruments. At 31 December 2012, an increase or decrease of 10% in quoted equity prices would have resulted in an immediate credit or charge to other comprehensive income of $1,502 million. At 31 December 2012, 82% of the carrying amount of non-current available-for-sale equity financial assets represented the group's 1.25% stake in Rosneft, thus the group's exposure was concentrated on changes in the share price of this equity in particular. The sensitivity analysis at 31 December 2012 includes the impact of a change in the share price on the valuation of the contracts to acquire Rosneft shares accounted for as cash flow hedge derivatives.

(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 2013 were $199 million (2012 $237 million) in respect of liabilities of joint ventures and associates and $305 million (2012 $717 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 of the group is typically responsible for its own credit risk management and reporting consistent with group policy, the treasury function holds group-wide credit risk authority and oversight responsibility for exposure to banks and financial institutions.

The maximum credit exposure associated with financial assets is equal to the carrying amount. The group does not aim to remove credit risk entirely but expects to experience a certain level of credit losses. As at 31 December 2013, the group had in place credit enhancements designed to mitigate approximately $13 billion of credit risk (2012 $12 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 2013 it is estimated that over 80% (2012 over 70%, excluding the contracts with Rosneft accounted for as derivatives) 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 2013, 92% of the cash and cash equivalents balance was deposited with financial institutions rated at least A- by Standard & Poor's and Fitch, and A3 by Moody's. Of the total cash and cash equivalents held at year end, collateral of $5,450 million was held by third-party custodians in tri-partite repurchase agreements, which would only be released to BP in the event of repayment default by the borrower.

Trade and other receivables of the group are analysed in the table below. By comparing the BP credit ratings to the equivalent external credit ratings, it is estimated that approximately 70-80% (2012 approximately 70-80%) of the unmitigated trade receivables portfolio exposure is of investment grade credit quality. Current assets, including trade and other receivables, in Egypt amount to $2.3 billion (see page 241), of which over one third relates to trade receivables which are not impaired but are past the original due date. Management is working with the counterparties to continue to collect these amounts.

		$ million
Trade and other receivables at 31 December	**2013**	2012
Neither impaired nor past due	**37,201**	33,053
Impaired (net of provision)	**27**	80
Not impaired and past due in the following periods		
within 30 days	**1,054**	1,337
31 to 60 days	**249**	286
61 to 90 days	**216**	225
over 90 days	**883**	981
	39,630	35,962

Movements in the impairment provision for trade receivables are shown in Note 24.

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. Financial assets and liabilities are only offset when 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 need to be considered when assessing whether a current legally enforceable right to set off exists.

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

$ million

At 31 December 2013	Gross amounts of recognized financial assets (liabilities)	Amounts set off	Net amounts presented on the balance sheet	Related amounts not set off in the balance sheet: Master netting arrangements	Cash collateral (received) pledged	Net amount
Derivative assets	**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)**
At 31 December 2012						
Derivative assets	9,291	(1,870)	7,421	(754)	(175)	6,492
Derivative liabilities	(6,117)	1,870	(4,247)	754	–	(3,493)
Trade receivables	8,829	(6,368)	2,461	(578)	(176)	1,707
Trade payables	(9,330)	6,368	(2,962)	578	–	(2,384)

(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.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise up to $30 billion of debt for maturities of one month or longer. At 31 December 2013, the amount drawn down against the DIP was $13,854 million (2012 $14,043 million). Since 5 February 2013, the group has had a US shelf registration with a limit of $30 billion. This was converted from an unlimited shelf registration following the approval in December 2012 of the settlement with the US Securities and Exchange Commission in respect of Gulf of Mexico oil spill related claims. Amounts drawn down since conversion total $6.9 billion. In addition, the group has an Australian Note Issuance Programme of A$5 billion, and as at 31 December 2013 the amount drawn down was A$800 million (2012 A$500 million).

The group's long-term credit ratings are A (positive outlook) from Standard & Poor's, and A2 (stable outlook) from Moody's Investor Services, both remaining unchanged during 2013.

During 2013, $8.6 billion of long-term taxable bonds were issued with terms ranging from 18 months to 10 years. Commercial paper is issued at competitive rates to meet short-term borrowing requirements as and when needed.

As a further liquidity measure, the group continues to maintain suitable levels of cash and cash equivalents, amounting to $22.5 billion at 31 December 2013, primarily invested with highly rated banks or money market funds and readily accessible at immediate and short notice (2012 $19.6 billion). At 31 December 2013, 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 $7,475 million with a number of banks, allowing LCs to be issued for a maximum one-year duration. There were also uncommitted secured LC facilities in place at 31 December 2013 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.

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

	2013				2012			
	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	**43,790**	**8,960**	**7,381**	**885**	42,512	6,875	9,401[a]	893
1 to 2 years	**1,007**	**207**	**6,630**	**752**	903	136	5,906	755
2 to 3 years	**822**	**66**	**6,720**	**621**	434	80	5,902	634
3 to 4 years	**761**	**73**	**5,828**	**498**	373	52	6,024	510
4 to 5 years	**1,405**	**37**	**5,279**	**388**	71	83	5,797	388
5 to 10 years	**207**	**113**	**15,933**	**809**	79	84	14,790	885
Over 10 years	**80**	**51**	**421**	**119**	33	56	348	50
	48,072	**9,507**	**48,192**	**4,072**	44,405	7,366	48,168	4,115

[a] In addition, current finance debt on the group balance sheet at 31 December 2012 included $632 million in respect of cash deposits received for disposals which completed in 2013.

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 26. 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

Financial statements

19. Financial instruments and financial risk factors – continued

settlement amounts (inflows) for the receive leg of derivatives that are settled separately from the pay leg, which amount to $12,222 million at 31 December 2013 (2012 $8,620 million) to be received on the same day as the related cash outflows.

		$ million
	2013	2012
Within one year	**1,095**	1,356
1 to 2 years	**293**	1,107
2 to 3 years	**2,959**	295
3 to 4 years	**2,577**	1,261
4 to 5 years	**1,505**	2,577
5 to 10 years	**3,835**	1,903
	12,264	8,499

20. Other investments

				$ million
		2013		2012
	Current	**Non-current**	Current	Non-current
Equity investments – listed	**–**	**3**	–	1,182
– unlisted	**–**	**288**	–	251
Repurchased gas pre-paid bonds	**276**	**408**	303	686
Contingent consideration	**186**	**292**	–	–
Other	**5**	**574**	16	585
	467	**1,565**	319	2,704

At 31 December 2012 the group's 1.25% stake in Rosneft was the most significant listed investment, with a fair value of $1,179 million.

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

Other non-current investments at 31 December 2013 include $574 million relating to life insurance policies (2012 $585 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 losses of $4 million were recognized in the income statement (2012 $70 million gain and 2011 $21 million gain).

21. Inventories

		$ million
	2013	2012
Crude oil	**10,190**	9,123
Natural gas	**235**	187
Refined petroleum and petrochemical products	**15,427**	15,465
	25,852	24,775
Supplies	**2,735**	2,428
	28,587	27,203
Trading inventories	**644**	1,000
	29,231	28,203
Cost of inventories expensed in the income statement	**298,351**	292,774

The inventory valuation at 31 December 2013 is stated net of a provision of $322 million (2012 $124 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 $195 million (2012 $28 million credit).

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.

Inventories with a carrying amount of $227 million (2012 $64 million) have been pledged as security for certain of the group's liabilities at 31 December 2013.

22. Trade and other receivables

				$ million
		2013		2012
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**28,868**	**183**	26,485	151
Amounts receivable from joint ventures and associates	**1,213**	**47**	871	102
Other receivables	**6,594**	**2,725**	5,683	2,670
	36,675	**2,955**	33,039	2,923
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**2,457**	**2,442**	4,178	2,264
Other receivables	**699**	**588**	394	774
	3,156	**3,030**	4,572	3,038
	39,831	**5,985**	37,611	5,961

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 19 for further information.

Receivables with a carrying amount of $236 million (2012 $12 million) have been pledged as security for certain of the group's liabilities at 31 December 2013.

23. Cash and cash equivalents

		$ million
	2013	2012
Cash at bank and in hand	**6,907**	5,885
Term bank deposits	**12,246**	9,243
Cash equivalents	**3,367**	4,507
	22,520	19,635

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 2013 includes $1,626 million (2012 $1,544 million) that is restricted. Included in restricted cash at 31 December 2012 was $709 million relating to the dividend received from TNK-BP in December 2012 which remained restricted until completion of the sale of BP's interest in TNK-BP to Rosneft, which occurred in the first quarter of 2013. See Note 6 for further information. The remaining restricted cash balances relate largely to amounts required to cover initial margin on trading exchanges.

24. Valuation and qualifying accounts

						$ million
		2013		2012		2011
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**489**	**349**	332	643	428	540
Charged to costs and expenses	**82**	**4**	240	196	115	111
Charged to other accounts[a]	**(4)**	**4**	7	18	(16)	(3)
Deductions	**(224)**	**(189)**	(90)	(508)	(195)	(5)
At 31 December	**343**	**168**	489	349	332	643

[a] Principally currency transactions.

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.

25. Trade and other payables

				$ million
		2013		2012
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**28,926**	**–**	29,920	–
Amounts payable to joint ventures and associates	**3,576**	**47**	1,105	102
Other payables	**11,288**	**4,235**	11,487	1,791
	43,790	**4,282**	42,512	1,893
Non-financial liabilities				
Other payables	**3,369**	**474**	4,161	399
	47,159	**4,756**	46,673	2,292

Trade and other payables are predominantly non-interest bearing. See Note 19 for further information.

26. 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 19. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts.

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

				$ million
		2013		2012
	Fair value asset	**Fair value liability**	Fair value asset	Fair value liability
Derivatives held for trading				
Currency derivatives	**192**	**(111)**	175	(189)
Oil price derivatives	**810**	**(806)**	841	(707)
Natural gas price derivatives	**2,840**	**(2,029)**	3,536	(2,496)
Power price derivatives	**871**	**(560)**	719	(589)
Other derivatives	**475**	**–**	71	–
	5,188	**(3,506)**	5,342	(3,981)
Embedded derivatives				
Commodity price contracts	**1**	**(653)**	–	(1,112)
	1	**(653)**	–	(1,112)
Cash flow hedges				
Equity price derivatives	**–**	**–**	1,339	–
Currency forwards, futures and cylinders	**129**	**(30)**	51	(41)
Cross-currency interest rate swaps	**–**	**(69)**	1	–
	129	**(99)**	1,391	(41)
Fair value hedges				
Currency forwards, futures and swaps	**340**	**(154)**	875	(247)
Interest rate swaps	**526**	**(135)**	1,193	–
	866	**(289)**	2,068	(247)
	6,184	**(4,547)**	8,801	(5,381)
Of which – current	**2,675**	**(2,322)**	4,507	(2,658)
– non-current	**3,509**	**(2,225)**	4,294	(2,723)

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.

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.

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 19.

26. Derivative financial instruments – continued

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
							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**

							$ million
							2012
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	169	6	–	–	–	–	175
Oil price derivatives	656	109	38	21	12	5	841
Natural gas price derivatives	1,532	711	418	259	144	472	3,536
Power price derivatives	327	188	114	62	19	9	719
Other derivatives	71	–	–	–	–	–	71
	2,755	1,014	570	342	175	486	5,342

At 31 December 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. At 31 December 2012, other derivatives related to the anticipated transaction with Rosneft – see Cash flow hedges below for further information.

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

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

							$ million
							2012
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(189)	–	–	–	–	–	(189)
Oil price derivatives	(580)	(77)	(27)	(12)	(8)	(3)	(707)
Natural gas price derivatives	(1,199)	(440)	(241)	(135)	(78)	(403)	(2,496)
Power price derivatives	(341)	(133)	(59)	(21)	(10)	(25)	(589)
	(2,309)	(650)	(327)	(168)	(96)	(431)	(3,981)

26. Derivative financial instruments – continued

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

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

							$ million
							2012
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Fair value of derivative assets							
Level 1	187	6	–	–	–	–	193
Level 2	3,766	1,088	520	216	46	10	5,646
Level 3	302	184	137	136	136	478	1,373
	4,255	1,278	657	352	182	488	7,212
Less: netting by counterparty	(1,500)	(264)	(87)	(10)	(7)	(2)	(1,870)
	2,755	1,014	570	342	175	486	5,342
Fair value of derivative liabilities							
Level 1	(189)	–	–	–	–	–	(189)
Level 2	(3,476)	(810)	(315)	(78)	(19)	(28)	(4,726)
Level 3	(144)	(104)	(99)	(100)	(84)	(405)	(936)
	(3,809)	(914)	(414)	(178)	(103)	(433)	(5,851)
Less: netting by counterparty	1,500	264	87	10	7	2	1,870
	(2,309)	(650)	(327)	(168)	(96)	(431)	(3,981)
Net fair value	446	364	243	174	79	55	1,361

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 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**

					$ million
	Oil price	Natural gas price	Power price	Other	Total
Net fair value of contracts at 1 January 2012	162	408	13	–	583
Gains (losses) recognized in the income statement	30	4	(4)	–	30
New contracts	–	–	–	71	71
Settlements	(87)	(56)	–	–	(143)
Transfers into level 3	–	(19)	–	–	(19)
Transfers out of level 3	–	(33)	(51)	–	(84)
Exchange adjustments	–	–	(1)	–	(1)
Net fair value of contracts at 31 December 2012	105	304	(43)	71	437

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. At 31 December 2013, the US natural gas derivatives in level 3 of the fair value hierarchy had a net fair value of $351 million. Of this amount, $71 million (asset of $598 million and liability of $527 million) depends on level 3 inputs, with the remainder valued using level 2 inputs. The significant unobservable inputs for fair value measurements categorized within level 3 of the fair value hierarchy for the year ended 31 December 2013 are presented below.

	Unobservable inputs	Range $/mmBtu	Weighted average $/mmBtu
Natural gas price contracts	Long-dated market price	3.15-6.71	4.63

If the natural gas prices after 2018 were 10% higher (lower), this would result in a decrease (increase) in derivative assets of $82 million, and decrease (increase) in derivative liabilities of $78 million, and a net decrease (increase) in profit before tax of $4 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 gain of $587 million (2012 $411 million net loss and 2011 $216 million net gain[a]).

[a] The comparative amounts for 2012 and 2011 have been amended and now reflect only the margin on derivative contracts that have been reflected net within the income statement.

Embedded derivatives

The group is a party to contracts containing embedded derivatives, the majority of which relate to certain natural gas contracts. 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	**2013**	2012
Remaining contract terms	**1 year and 5 months to 4 years and 9 months**	2 years and 5 months to 5 years and 9 months
Contractual/notional amount	**153 million therms**	117 million therms

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 historic 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 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
	2013	2012
	Commodity price	Commodity price
Net fair value of contracts at 1 January	**(1,112)**	(1,417)
Settlements	**316**	375
Gains (losses) recognized in the income statement	**142**	(6)
Transfers out of level 3	**258**	–
Exchange adjustments	**17**	(64)
Net fair value of contracts at 31 December	**(379)**	(1,112)

Financial statements

26. Derivative financial instruments – continued

The fair value gain (loss) on embedded derivatives is shown below.

			$ million
	2013	2012	2011
Commodity price embedded derivatives	**459**	347	190
Other embedded derivatives	**–**	–	(122)
Fair value gain (loss)	**459**	347	68

Cash flow hedges

At 31 December 2013, 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 19 outlines the management of risk aspects for currency risk. 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 pre-tax amount reclassified from equity and recognized in the income statement in production and manufacturing expenses was a loss of $4 million (2012 $62 million loss and 2011 $195 million gain). The amount reclassified from equity and recognized in the carrying amount of non-financial assets was a loss of $17 million (2012 $19 million loss and 2011 $13 million gain). The amounts remaining in equity at 31 December 2013 in relation to these cash flow hedges consist of deferred gains of $85 million maturing in 2014, deferred losses of $23 million maturing in 2015 and deferred gains of $10 million maturing in 2016 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, as described in Note 6. 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 2013, 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 effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The loss on the hedging derivative instruments recognized in the income statement in 2013 was $1,240 million (2012 $536 million gain and 2011 $328 million gain) offset by a gain on the fair value of the finance debt of $1,228 million (2012 $537 million loss and 2011 $327 million loss).

The interest rate and cross-currency interest rate swaps mature within one to 10 years, with an average maturity of four to five years (2012 four to five years) and are used to convert sterling, euro, Swiss franc, Australian dollar, Canadian dollar and Hong Kong dollar denominated borrowings primarily into US dollar floating rate debt. Note 19 outlines the group's approach to interest rate and currency risk management.

27. Finance debt

						$ million
			2013			2012
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**7,340**	**40,317**	**47,657**	9,372	38,412	47,784
Net obligations under finance leases	**41**	**494**	**535**	29	355	384
	7,381	**40,811**	**48,192**	9,401	38,767	48,168
Disposal deposits	**–**	**–**	**–**	632	–	632
	7,381	**40,811**	**48,192**	10,033	38,767	48,800

The main elements of current borrowings are the current portion of long-term borrowings that are due to be repaid in the next 12 months of $6,230 million (2012 $6,240 million) and issued commercial paper of $1,050 million (2012 $3,028 million). Finance debt does not include accrued interest, which is reported within other payables.

Deposits for disposal transactions of $632 million were included in current finance debt at 31 December 2012. This unsecured debt was extinguished on completion of the transactions in 2013. There were no deposits for disposal transactions included within finance debt at 31 December 2013.

At 31 December 2013, $141 million (2012 $142 million) of finance debt was secured by the pledging of assets. The remainder of finance debt was unsecured.

27. Finance debt – continued

The following table shows, by major currency, the group's finance debt at 31 December and the weighted average interest rates achieved at those dates through a combination of borrowings and derivative financial instruments entered into to manage interest rate and currency exposures. The disposal deposits noted above are excluded from this analysis.

	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
						2013
US dollar	**3**	**4**	**16,405**	**1**	**29,740**	**46,145**
Euro	**5**	**30**	**157**	**2**	**1,396**	**1,553**
Other currencies	**4**	**7**	**454**	**2**	**40**	**494**
			17,016		**31,176**	**48,192**
						2012
US dollar	3	4	16,744	1	26,208	42,952
Euro	5	2	20	1	4,854	4,874
Other currencies	4	11	255	3	87	342
			17,019		31,149	48,168

The euro debt not swapped to US dollar is naturally hedged with respect to the 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 2013, whereas in the balance sheet the amount is reported within current finance debt. The disposal deposits noted above are excluded from this analysis.

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) or, where quoted prices are not available, quoted prices for similar instruments in active markets. 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
		2013		2012
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**1,110**	**1,110**	3,131	3,131
Long-term borrowings	**47,398**	**46,547**	45,969	44,653
Net obligations under finance leases	**654**	**535**	520	384
Total finance debt	**49,162**	**48,192**	49,620	48,168

28. Capital disclosures and analysis of changes in net debt

The group defines capital as total equity. The group's approach to managing capital is set out in its financial framework which BP continues to refine to support the pursuit of value growth for shareholders, whilst maintaining a secure financial base. We intend to maintain a net debt ratio within the 10-20% gearing range, and continue to hold 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 2013, the net debt ratio was 16.2% (2012 18.7%).

During 2013, the company repurchased 753 million shares for a total amount of $5.5 billion, including fees and stamp duty, as part of its share buyback programme announced on 22 March 2013. During 2012, the company did not repurchase any of its own shares, other than as needed to satisfy the requirements of certain employee share-based payment plans.

		$ million
At 31 December	**2013**	2012
Gross debt	**48,192**	48,800
Fair value (asset) liability of hedges related to finance debt	**(477)**	(1,700)
	47,715	47,100
Less: cash and cash equivalents	**22,520**	19,635
Net debt	**25,195**	27,465
Equity	**130,407**	119,752
Net debt ratio	**16.2%**	18.7%

28. Capital disclosures and analysis of changes in net debt – continued

An analysis of changes in net debt is provided below.

						$ million
		2013				2012
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	**(47,100)**	**19,635**	**(27,465)**	(43,075)	14,177	(28,898)
Exchange adjustments	**(219)**	**40**	**(179)**	(75)	64	(11)
Net cash flow	**(836)**	**2,845**	**2,009**	(3,244)	5,394	2,150
Movement in finance debt relating to investing activities[b]	**632**	**–**	**632**	(602)	–	(602)
Other movements	**(192)**	**–**	**(192)**	(104)	–	(104)
At 31 December	**(47,715)**	**22,520**	**(25,195)**	(47,100)	19,635	(27,465)

[a] Including the fair value of associated derivative financial instruments.
[b] See Note 27 for further information.

29. Provisions

							$ million
	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
At 1 January 2013	**17,374**	**3,631**	**345**	**10,251**	**3,510**	**2,872**	**37,983**
Exchange adjustments	**(37)**	**(7)**	**–**	**5**	**–**	**14**	**(25)**
New or increased provisions	**2,092**	**472**	**(66)**	**2,466**	**–**	**464**	**5,428**
Derecognition of provisions for items that cannot be reliably estimated	**–**	**–**	**–**	**(379)**	**–**	**–**	**(379)**
Write-back of unused provisions	**(2)**	**(52)**	**–**	**(38)**	**–**	**(210)**	**(302)**
Transfer between categories of provision	**–**	**47**	**(47)**	**–**	**–**	**–**	**–**
Unwinding of discount	**110**	**11**	**–**	**10**	**–**	**16**	**147**
Change in discount rate	**(1,602)**	**(41)**	**–**	**(20)**	**–**	**(13)**	**(1,676)**
Utilization	**(500)**	**(695)**	**(143)**	**(3,451)**	**–**	**(230)**	**(5,019)**
Reclassified to other payables	**–**	**–**	**–**	**(3,933)**	**–**	**–**	**(3,933)**
Deletions	**(230)**	**(1)**	**–**	**–**	**–**	**(33)**	**(264)**
At 31 December 2013	**17,205**	**3,365**	**89**	**4,911**	**3,510**	**2,880**	**31,960**
Of which – current	**866**	**769**	**84**	**2,725**	**–**	**601**	**5,045**
– non-current	**16,339**	**2,596**	**5**	**2,186**	**3,510**	**2,279**	**26,915**
Of which – Gulf of Mexico oil spill	**–**	**1,590**	**89**	**4,157**	**3,510**	**–**	**9,346**

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

The group makes full provision for the future cost of decommissioning oil and natural gas wells, facilities and related pipelines on a discounted basis upon installation. The provision for the costs of decommissioning these wells, production facilities and pipelines at the end of their economic lives has been estimated using existing technology, at current prices or future assumptions, depending on the expected timing of the activity, and discounted using a real discount rate of 1% (2012 0.5%). The amount provided in the year for new or increased decommissioning provisions was $2,092 million (2012 $3,766 million). The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately 20 years. While the provision is based on the best estimate of future costs and the economic lives of the facilities and pipelines, there is uncertainty regarding both the amount and timing of these costs.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be estimated reliably. Generally, this coincides with commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites. The provision for environmental liabilities has been estimated using existing technology, at current prices and discounted using a real discount rate of 1% (2012 0.5%). The weighted average period over which these costs are generally expected to be incurred is estimated to be approximately five years. The extent and cost of future remediation programmes are inherently difficult to estimate; they depend on the scale of any possible contamination, the timing and extent of corrective actions, and also the group's share of the liability.

The litigation 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 2013 are provisions for deferred employee compensation of $602 million (2012 $618 million). These provisions are discounted using either a nominal discount rate of 3.25% (2012 2.5%) or a real discount rate of 1% (2012 0.5%), as appropriate.

30. 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 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.

In particular, 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 trustee board composed of four member-nominated and four company-nominated representatives, an independent chairman, an independent director and a chief executive officer appointed by the chairman. 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.

30. Pensions and other post-retirement benefits – continued

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. This includes a funded final salary pension plan for certain heritage employees and a cash balance arrangement for new joiners. 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 company employees appointed by the appointing officer, who is the president of BP Corporation North America Inc. 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.

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 2013, contributions of $597 million (2012 $884 million and 2011 $429 million) and $386 million (2012 $153 million and 2011 $777 million) were made to the UK plans and US plans respectively. In addition, contributions of $289 million (2012 $238 million and 2011 $223 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2014 is expected to be approximately $1,250 million, and includes contributions in all countries that we expect to be required to make by law or under contractual agreements as well as an allowance for discretionary funding.

For the primary UK plan there is an agreement between the group and the trustee under which contributions are determined annually based on the funding level of the plan. Under this agreement a proportion of any deficit and the service cost is funded in the following year. Contributions in the US are determined by legislation and are supplemented by discretionary contributions.

Certain group companies, principally in the US, 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.

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 2013. 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.

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 accrued pension and other post-retirement benefits at 31 December and pension expense for the following year.

									%
Financial assumptions used to determine benefit obligation			UK			US			Other
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Discount rate for pension plan liabilities	**4.6**	4.4	4.8	**4.3**	3.2	4.3	**3.9**	3.6	4.7
Discount rate for other post-retirement benefit plan liabilities	**n/a**	n/a	n/a	**4.5**	3.7	4.5	**n/a**	n/a	n/a
Rate of increase in salaries	**5.1**	4.9	5.1	**3.9**	4.2	3.7	**3.7**	3.7	3.7
Rate of increase for pensions in payment	**3.3**	3.1	3.2	**–**	–	–	**1.7**	1.7	1.7
Rate of increase in deferred pensions	**3.3**	3.1	3.2	**–**	–	–	**1.3**	1.2	1.2
Inflation for pension plan liabilities	**3.3**	3.1	3.2	**2.1**	2.4	1.9	**2.2**	2.2	2.2

Financial assumptions used to determine benefit expense			UK			US			Other
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Discount rate for pension plan service cost	**4.4**	4.8	5.5	**3.2**	4.3	4.7	**3.6**	4.7	5.3
Discount rate for pension plan other finance expense	**4.4**	4.8	5.5	**3.2**	4.3	4.7	**3.6**	4.7	5.3
Discount rate for other post-retirement benefit plan service cost	**n/a**	n/a	n/a	**3.7**	4.5	5.3	**n/a**	n/a	n/a
Inflation for pension plan service cost	**3.1**	3.2	3.5	**2.4**	1.9	2.3	**2.2**	2.2	2.3

Our discount rate assumptions are based on third-party AA corporate bond indices and for our largest plans in the UK, US and Germany we use yields that reflect the maturity profile of the expected benefit payments. The inflation rate assumptions for our UK and US plans are based on the difference between the yields on index-linked and fixed-interest long-term government bonds. In other countries we use either this approach, or the central bank inflation target, or advice from the local actuary depending on the information that is available to us. 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.

Our assumptions for the rate of increase in salaries are based on our inflation assumption plus an allowance for expected long-term real salary growth. These include allowance for promotion-related salary growth, of between 0.3% and 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 Germany where our mortality assumptions are as follows:

									Years
Mortality assumptions			UK			US			Germany[a]
	2013	2012	2011	**2013**	2012	2011	**2013**	2012	2011
Life expectancy at age 60 for a male currently aged 60	**27.8**	27.7	27.6	**24.9**	24.9	24.8	**23.3**	23.1	23.0
Life expectancy at age 60 for a male currently aged 40	**30.7**	30.6	30.5	**26.4**	26.3	26.3	**26.1**	26.0	25.8
Life expectancy at age 60 for a female currently aged 60	**29.5**	29.4	29.3	**26.5**	26.4	26.4	**27.8**	27.7	27.5
Life expectancy at age 60 for a female currently aged 40	**32.2**	32.1	32.0	**27.3**	27.3	27.3	**30.5**	30.3	30.2

[a] Minor amendments have been made to comparative amounts.

30. Pensions and other post-retirement benefits – continued

Our assumption for future US healthcare cost trend rate for the first year after the reporting date reflects the rate of actual cost increases seen in recent years. The ultimate trend rate reflects our long-term expectations of the level at which cost inflation will stabilize based on past healthcare cost inflation seen over a longer period of time. The assumed future US healthcare cost trend rate assumptions are as follows:

			%
	2013	2012	2011
First year's US healthcare cost trend rate	**7.3**	7.3	7.6
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2021**	2020	2020

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 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 long-term asset allocation policy for the major plans is as follows:

			%
Asset category	UK	US	Other
Total equity	**70**	**60**	**17-65**
Bonds/cash	**23**	**40**	**25-78**
Property/real estate	**7**	**–**	**0-10**

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 at certain market trigger points, over time, with a view to better matching the pension liabilities. During 2013 the first trigger point was reached. There is a similar agreement in place in the US where trigger points were reached in 2011 and 2013.

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

30. 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 182.

$ million

	UK pension plans[a]	US pension plans[b]	US other post-retirement benefit plans	Other plans	Total
Fair value of pension plan assets					
At 31 December 2013					
Listed equities – developed markets	**17,341**	**3,260**	**–**	**913**	**21,514**
– emerging markets	**2,290**	**308**	**–**	**84**	**2,682**
Private equity	**2,907**	**1,432**	**–**	**6**	**4,345**
Government issued nominal bonds	**549**	**1,259**	**–**	**1,258**	**3,066**
Index-linked bonds	**787**	**–**	**–**	**69**	**856**
Corporate bonds	**4,427**	**1,323**	**–**	**982**	**6,732**
Property	**2,200**	**6**	**–**	**134**	**2,340**
Cash	**855**	**135**	**–**	**278**	**1,268**
Other	**160**	**55**	**–**	**113**	**328**
	31,516	**7,778**	**–**	**3,837**	**43,131**
At 31 December 2012					
Listed equities – developed markets	15,659	3,622	–	844	20,125
– emerging markets	1,074	341	–	89	1,504
Private equity	2,879	1,468	–	7	4,354
Government issued nominal bonds	544	904	–	1,042	2,490
Index-linked bonds	491	–	–	78	569
Corporate bonds	3,850	1,255	–	766	5,871
Property	1,783	5	–	139	1,927
Cash	1,000	86	1	321	1,408
Other	66	105	–	247	418
	27,346	7,786	1	3,533	38,666
At 31 December 2011					
Listed equities – developed markets	13,622	3,328	–	754	17,704
– emerging markets	890	299	–	69	1,258
Private equity	2,690	1,407	–	8	4,105
Government issued nominal bonds	513	733	–	993	2,239
Index-linked bonds	390	–	–	123	513
Corporate bonds	3,238	1,289	–	724	5,251
Property	1,710	4	–	117	1,831
Cash	470	88	4	326	888
Other	64	56	–	172	292
	23,587	7,204	4	3,286	34,081

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

30. Pensions and other post-retirement benefits – continued

$ million

2013	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	497	358	49	177	1,081
Past service cost[b]	(22)	(49)	–	27	(44)
Settlement	–	–	–	(1)	(1)
Operating charge relating to defined benefit plans	475	309	49	203	1,036
Payments to defined contribution plans	24	223	–	53	300
Total operating charge	499	532	49	256	1,336
Interest income on plan assets	(1,139)	(240)	–	(130)	(1,509)
Interest on plan liabilities	1,221	305	101	362	1,989
Other finance expense	82	65	101	232	480
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets[a]	2,671	730	–	114	3,515
Change in financial assumptions underlying the present value of the plan liabilities	60	1,054	106	283	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	41	(205)	(44)	5	(203)
Remeasurements recognized in other comprehensive income	2,772	1,593	62	337	4,764
Movements in benefit obligation during the year					
Benefit obligation at 1 January	29,259	10,029	2,845	10,148	52,281
Exchange adjustments	705	–	–	132	837
Operating charge relating to defined benefit plans	475	309	49	203	1,036
Interest cost	1,221	305	101	362	1,989
Contributions by plan participants[c]	37	–	–	13	50
Benefit payments (funded plans)[d]	(1,087)	(1,364)	(1)	(192)	(2,644)
Benefit payments (unfunded plans)[d]	(4)	(52)	(233)	(395)	(684)
Disposals	(9)	–	(61)	(13)	(83)
Remeasurements	(101)	(863)	(62)	(223)	(1,249)
Benefit obligation at 31 December[a e]	30,496	8,364	2,638	10,035	51,533
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	27,346	7,786	1	3,533	38,666
Exchange adjustments	822	–	–	(37)	785
Interest income on plan assets[a]	1,139	240	–	130	1,509
Contributions by plan participants[c]	37	–	–	13	50
Contributions by employers (funded plans)	597	386	–	289	1,272
Benefit payments (funded plans)[d]	(1,087)	(1,364)	(1)	(192)	(2,644)
Disposals	(9)	–	–	(13)	(22)
Remeasurements[f]	2,671	730	–	114	3,515
Fair value of plan assets at 31 December	31,516	7,778	–	3,837	43,131
Surplus (deficit) at 31 December	1,020	(586)	(2,638)	(6,198)	(8,402)
Represented by					
Asset recognized	1,291	6	–	79	1,376
Liability recognized	(271)	(592)	(2,638)	(6,277)	(9,778)
	1,020	(586)	(2,638)	(6,198)	(8,402)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	1,285	(5)	–	(320)	960
Unfunded	(265)	(581)	(2,638)	(5,878)	(9,362)
	1,020	(586)	(2,638)	(6,198)	(8,402)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(30,231)	(7,783)	–	(4,157)	(42,171)
Unfunded	(265)	(581)	(2,638)	(5,878)	(9,362)
	(30,496)	(8,364)	(2,638)	(10,035)	(51,533)

[a] The costs of managing the plan's investments are treated as being part of the return on plan assets, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our 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 arrangements 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 benefit obligation for other plans includes $4,874 million for the German plan, which is largely unfunded.
[f] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurment of plan assets as disclosed above.

30. Pensions and other post-retirement benefits – continued

	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
					$ million
					2012
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	477	328	51	151	1,007
Past service cost[b]	(1)	20	–	82	101
Settlement	–	–	–	1	1
Operating charge relating to defined benefit plans	476	348	51	234	1,109
Payments to defined contribution plans	14	223	–	44	281
Total operating charge	490	571	51	278	1,390
Interest income on plan assets	(1,146)	(304)	–	(154)	(1,604)
Interest on plan liabilities	1,249	382	134	405	2,170
Other finance expense	103	78	134	251	566
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets[a]	1,523	718	–	173	2,414
Change in financial assumptions underlying the present value of the plan liabilities	(1,446)	(1,427)	187	(1,093)	(3,779)
Change in demographic assumptions underlying the present value of the plan liabilities	–	–	52	(37)	15
Experience gains and losses arising on the plan liabilities	(116)	68	(48)	(126)	(222)
Remeasurements recognized in other comprehensive income	(39)	(641)	191	(1,083)	(1,572)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	25,675	8,617	3,061	8,801	46,154
Exchange adjustments	1,313	–	–	254	1,567
Operating charge relating to defined benefit plans	476	348	51	234	1,109
Interest cost	1,249	382	134	405	2,170
Contributions by plan participants[c]	39	–	–	14	53
Benefit payments (funded plans)[d]	(1,038)	(593)	(3)	(230)	(1,864)
Benefit payments (unfunded plans)[d]	(7)	(84)	(207)	(394)	(692)
Disposals	(10)	–	–	(192)	(202)
Remeasurements	1,562	1,359	(191)	1,256	3,986
Benefit obligation at 31 December[a e]	29,259	10,029	2,845	10,148	52,281
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	23,587	7,204	4	3,286	34,081
Exchange adjustments	1,215	–	–	88	1,303
Interest income on plan assets[a]	1,146	304	–	154	1,604
Contributions by plan participants[c]	39	–	–	14	53
Contributions by employers (funded plans)	884	153	–	238	1,275
Benefit payments (funded plans)[d]	(1,038)	(593)	(3)	(230)	(1,864)
Disposals	(10)	–	–	(190)	(200)
Remeasurements[f]	1,523	718	–	173	2,414
Fair value of plan assets at 31 December	27,346	7,786	1	3,533	38,666
Deficit at 31 December	(1,913)	(2,243)	(2,844)	(6,615)	(13,615)
Represented by					
Asset recognized	–	–	–	12	12
Liability recognized	(1,913)	(2,243)	(2,844)	(6,627)	(13,627)
	(1,913)	(2,243)	(2,844)	(6,615)	(13,615)
The surplus (deficit) may be analysed between funded and unfunded plans as follows					
Funded	(1,688)	(1,599)	(43)	(539)	(3,869)
Unfunded	(225)	(644)	(2,801)	(6,076)	(9,746)
	(1,913)	(2,243)	(2,844)	(6,615)	(13,615)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(29,034)	(9,385)	(44)	(4,072)	(42,535)
Unfunded	(225)	(644)	(2,801)	(6,076)	(9,746)
	(29,259)	(10,029)	(2,845)	(10,148)	(52,281)

[a] The costs of managing the plan's investments are treated as being part of the return on plan assets, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.
[b] Past service costs are charges for special termination benefits representing 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 $2,501 million benefits plus $55 million of plan expenses incurred in the administration of the benefit.
[e] The benefit obligation for other plans includes $4,783 million for the German plan, which is largely unfunded.
[f] The actual return on plan assets is made up of the sum of the interest income on plan assets and the remeasurement of plan assets as disclosed above.

30. Pensions and other post-retirement benefits – continued

$ million

2011	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
Analysis of the amount charged to profit before interest and taxation					
Current service cost[a]	383	280	53	135	851
Past service cost	3	184	–	43	230
Settlement	–	–	–	4	4
Operating charge relating to defined benefit plans	386	464	53	182	1,085
Payments to defined contribution plans	5	199	–	41	245
Total operating charge	391	663	53	223	1,330
Analysis of the amount credited (charged) to other finance expense					
Interest income on plan assets	(1,361)	(304)	–	(178)	(1,843)
Interest on plan liabilities	1,263	369	163	448	2,243
Other finance (income) expense	(98)	65	163	270	400
Analysis of the amount recognized in other comprehensive income					
Actual asset return less interest income on plan assets[a]	(1,552)	224	(1)	(54)	(1,383)
Change in financial assumptions underlying the present value of the plan liabilities	(2,251)	(468)	(63)	(636)	(3,418)
Change in demographic assumptions underlying the present value of the plan liabilities	(429)	(44)	102	(6)	(377)
Experience gains and losses arising on the plan liabilities	(84)	(102)	89	(26)	(123)
Remeasurements recognized in other comprehensive income	(4,316)	(390)	127	(722)	(5,301)

[a] The costs of managing the plan's investments are treated as being part of the return on plan assets, the costs of administering our pension plan benefits are generally included in current service cost and the costs of administering our other post-retirement benefit plans are included in the benefit obligation.

At 31 December 2013, reimbursement balances due from or to other companies in respect of pensions amounted to $399 million reimbursement assets (2012 $381 million) and $15 million reimbursement liabilities (2012 $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, US healthcare cost trend rate 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 2013 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2014 comprise the total of current service cost and net finance income or expense.

$ million

	One percentage point Increase	One percentage point Decrease
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2014	**(474)**	**481**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**(6,918)**	**9,059**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2014	**521**	**(397)**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**7,120**	**(5,658)**
Salary growth		
Effect on pension and other post-retirement benefit expense in 2014	**142**	**(123)**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**1,300**	**(1,158)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2014	**16**	**(13)**
Effect on US other post-retirement obligation at 31 December 2013	**278**	**(233)**

[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 have the effects shown in the table below. The effect shown for the expense in 2014 comprises the total of current service cost and net finance income or expense.

$ million

	UK pension plans	US pension plans	US other post-retirement benefit plans	German pension plans
One additional year's longevity				
Effect on pension and other post-retirement benefit expense in 2014	**52**	**5**	**3**	**9**
Effect on pension and other post-retirement benefit obligation at 31 December 2013	**927**	**95**	**46**	**213**

30. Pensions and other post-retirement benefits – continued

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 2023 and the weighted average duration of the defined benefit obligations at the end of the reporting period are as follows:

					$ million
Estimated future benefit payments	UK pension plans	US pension plans	US other post-retirement benefit plans	Other plans	Total
2014	**1,153**	**690**	**174**	**596**	**2,613**
2015	**1,201**	**715**	**177**	**585**	**2,678**
2016	**1,265**	**726**	**178**	**582**	**2,751**
2017	**1,281**	**733**	**178**	**570**	**2,762**
2018	**1,361**	**735**	**178**	**560**	**2,834**
2019-2023	**7,282**	**3,533**	**874**	**2,651**	**14,340**
					years
Weighted average duration	**17.6**	**8.3**	**10.5**	**13.2**	

31. Called-up share capital

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

	2013		2012		2011	
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	**20,959,159**	**5,240**	20,813,410	5,203	20,647,160	5,162
Issue of new shares for the scrip dividend programme	**202,124**	**51**	138,406	35	165,601	41
Issue of new shares for employee share-based payment plans[b]	**18,203**	**5**	7,343	2	649	–
Repurchase of ordinary share capital[c]	**(752,854)**	**(188)**	–	–	–	–
At 31 December	**20,426,632**	**5,108**	20,959,159	5,240	20,813,410	5,203
		5,129		5,261		5,224

[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] The nominal value of new shares issued for the employee share plans in 2011 amounted to $162,000. Consideration received relating to the issue of new shares for employee share plans amounted to $116 million (2012 $47 million and 2011 $4 million).
[c] Purchased for a total consideration of $5,493 million, including transaction costs of $30 million. All shares purchased were for cancellation. The repurchased shares represented 3.6% 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.

During 2013 the company repurchased 753 million ordinary shares at a cost of $5,463 million as part of the share repurchase programme announced on 22 March 2013. 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 $1,430 million has been accrued at 31 December 2013 (2012 nil).

Treasury shares

	2013		2012		2011	
	Shares thousand	**Nominal value $ million**	Shares thousand	Nominal value $ million	Shares thousand	Nominal value $ million
At 1 January	**1,823,408**	**455**	1,837,508	459	1,850,699	462
Shares re-issued for employee share-based payment plans	**(35,469)**	**(8)**	(14,100)	(4)	(13,191)	(3)
At 31 December	**1,787,939**	**447**	1,823,408	455	1,837,508	459

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 8.7% (2012 8.8% and 2011 9.0%) of the called-up ordinary share capital of the company.

During 2013, the movement in treasury shares represented less than 0.2% (2012 less than 0.1% and 2011 less than 0.1%) of the ordinary share capital of the company.

32. Capital and reserves

	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[a]	**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[a]	2	57	–	–	59
Transactions involving non-controlling interests	–	–	–	–	–
At 31 December 2012	5,261	9,974	1,072	27,206	43,513

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2011	5,183	9,987	1,072	27,206	43,448
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	–	–	–	–	–
Items that will not be reclassified to profit or loss					
Remeasurements of the net pension and other post-retirement benefit liability or asset	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	41	(41)	–	–	–
Share-based payments, net of tax[a]	–	6	–	–	6
Transactions involving non-controlling interests	–	–	–	–	–
At 31 December 2011	5,224	9,952	1,072	27,206	43,454

[a] Includes new share issues and movements in own shares and treasury shares where these relate to employee share-based payment plans.

$ million

Own shares	Treasury shares	Total own shares and treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(280)	**(20,774)**	**(21,054)**	**5,128**	**685**	**1,090**	**1,775**	**1,608**	**87,576**	**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)
(321)	404	83	–	–	–	–	97	150	473	–	473
–	–	–	–	–	–	–	–	73	73	–	73
–	–	–	–	–	–	–	–	–	–	76	76
(601)	**(20,370)**	**(20,971)**	**3,525**	**–**	**(695)**	**(695)**	**1,705**	**102,082**	**129,302**	**1,105**	**130,407**

Own shares	Treasury shares	Total own shares and treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(388)	(20,935)	(21,323)	4,509	389	(122)	267	1,582	83,079	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)
108	161	269	–	–	–	–	26	(70)	284	–	284
–	–	–	–	–	–	–	–	–	–	33	33
(280)	(20,774)	(21,054)	5,128	685	1,090	1,775	1,608	87,576	118,546	1,206	119,752

Own shares	Treasury shares	Total own shares and treasury shares	Foreign currency translation reserve	Available-for-sale investments	Cash flow hedges	Total fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Non-controlling interests	Total equity
(126)	(21,085)	(21,211)	5,036	463	6	469	1,586	65,754	95,082	904	95,986
–	–	–	–	–	–	–	–	25,212	25,212	397	25,609
–	–	–	(527)	–	(1)	(1)	–	–	(528)	(10)	(538)
–	–	–	–	(74)	–	(74)	–	–	(74)	–	(74)
–	–	–	–	–	(127)	(127)	–	–	(127)	–	(127)
–	–	–	–	–	–	–	–	(39)	(39)	–	(39)
–	–	–	–	–	–	–	–	(3,831)	(3,831)	(3)	(3,834)
–	–	–	(527)	(74)	(128)	(202)	–	21,342	20,613	384	20,997
–	–	–	–	–	–	–	–	(4,072)	(4,072)	(245)	(4,317)
(262)	150	(112)	–	–	–	–	(4)	102	(8)	–	(8)
–	–	–	–	–	–	–	–	(47)	(47)	(26)	(73)
(388)	(20,935)	(21,323)	4,509	389	(122)	267	1,582	83,079	111,568	1,017	112,585

32. Capital and reserves – continued

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

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

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

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

Own shares
Own shares represent BP shares held in Employee Share Ownership Plans (ESOPs) to meet the future requirements of the employee share-based payment plans. The ESOPs have waived their rights to dividends on shares held for future awards and are funded by the group. Until such time as the company's own 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 2013, the ESOPs held 32,748,354 shares (2012 22,428,179 shares and 2011 27,784,503 shares) for potential future awards, which had a market value of $253 million (2012 $154 million and 2011 $197 million). At 31 December 2013, a further 12,856,914 ordinary share equivalents (2012 18,673,926 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.

Treasury shares
Treasury shares represent BP shares repurchased and available for re-issue.

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.

Share-based payment reserve
This reserve represents cumulative amounts charged to profit in respect of employee share-based payment plans where the scheme has not yet been settled by means of an award of shares to an individual.

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

32. Capital and reserves – continued

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

			$ million
			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

			$ million
			2011
	Pre-tax	Tax	Net of tax
Items that may be reclassified subsequently to profit or loss			
Currency translation differences (including recycling)	(524)	(14)	(538)
Available-for-sale investments (including recycling)	(74)	–	(74)
Cash flow hedges (including recycling)	(164)	37	(127)
Share of items relating to equity-accounted entities, net of tax	(39)	–	(39)
Items that will not be reclassified to profit or loss			
Remeasurements of the net pension and other post-retirement benefit liability or asset	(5,301)	1,467	(3,834)
Other comprehensive income	(6,102)	1,490	(4,612)

33. Employee costs and numbers

			$ million
Employee costs	**2013**	2012	2011
Wages and salaries[a b]	**10,161**	9,910	9,333
Social security costs	**958**	908	854
Share-based payments[c]	**719**	674	584
Pension and other post-retirement benefit costs	**1,816**	1,956	1,730
	13,654	13,448	12,501

Number of employees at 31 December[d]	**2013**	2012	2011
Upstream	**24,700**	24,200	22,400
Downstream[e]	**48,000**	51,800	51,500
Other businesses and corporate[f]	**11,100**	10,300	10,100
Gulf Coast Restoration Organization	**100**	100	100
	83,900	86,400	84,100
By geographical area			
US	**19,600**	23,400	22,900
Non-US[e]	**64,300**	63,000	61,200
	83,900	86,400	84,100

Financial statements

33. Employee costs and numbers – continued

Average number of employees[d]	US 2013	Non-US 2013	Total 2013	US 2012	Non-US 2012	Total 2012	US 2011	Non-US 2011	Total 2011
Upstream	**9,400**	**15,100**	**24,500**	9,300	14,100	23,400	8,500	13,400	21,900
Downstream	**9,300**	**39,800**	**49,100**	12,000	39,900	51,900	12,300	39,700	52,000
Other businesses and corporate	**1,900**	**9,000**	**10,900**	1,900	8,700	10,600	1,700	6,500	8,200
Gulf Coast Restoration Organization	**100**	**–**	**100**	100	–	100	100	–	100
	20,700	**63,900**	**84,600**	23,300	62,700	86,000	22,600	59,600	82,200

[a] Includes termination payments of $212 million (2012 $77 million and 2011 $126 million).
[b] Wages and salaries for 2012 and 2011 have been amended.
[c] 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.
[d] Reported to the nearest 100.
[e] Includes 14,100 (2012 14,700 and 2011 14,600) service station staff.
[f] Includes 4,300 (2012 3,600 and 2011 4,000) agricultural, operational and seasonal workers in Brazil.

34. Remuneration of directors and senior management

Remuneration of directors

$ million	2013	2012	2011
Total for all directors			
Emoluments	**16**	12	10
Gains made on exercise of share options	**–**	–	–
Amounts awarded under incentive schemes	**2**	3	1
Total	**18**	15	11

Emoluments
These amounts comprise fees and benefits 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 2013 (2012 nil and 2011 nil).

Pension contributions
During 2013 two executive directors participated in a non-contributory pension scheme established for UK employees. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2013.

Office facilities for former chairmen and deputy chairmen
It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information
Full details of individual directors' remuneration are given in the Directors' remuneration report on page 81.

Remuneration of directors and senior management

Total for all senior management ($ million)	2013	2012[a]	2011[a]
Total for all senior management			
Short-term employee benefits	**36**	29	34
Pensions and other post-retirement benefits	**3**	3	3
Share-based payments	**43**	37	28
Total	**82**	69	65

[a] Prior year comparatives have been amended to include the portion of bonuses that were deferred and will be settled in shares in the future.

Senior management, in addition to executive and non-executive directors, includes other senior managers who are members of the executive management team.

Short-term employee benefits
In addition to fees and benefits paid to the non-executive chairman and non-executive directors, these amounts comprise, for executive directors and senior managers, salary and benefits earned during the year, plus cash bonuses awarded for the year. 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 $3 million (2012 nil and 2011 $9 million).

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'. The main plans in which senior management have participated are the EDIP, DAB, ACBD, SVP and RSP.

35. 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 2013 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 19.

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.

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.

The group also has obligations to decommission oil and natural gas production facilities and related pipelines. Provision is made for the estimated costs of these activities, however there is uncertainty regarding both the amount and timing of these costs, given the long-term nature of these obligations. BP believes that the impact of any reasonably foreseeable changes to these provisions on the group's results of operations, financial position or liquidity will not be material. If oil and natural gas production facilities and pipelines are sold to third parties and the subsequent owner is unable to meet their decommissioning obligations, judgement must be used to determine whether BP is then responsible for decommissioning, and if so the extent of that responsibility.

The 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.

36. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2013 amounted to $13,705 million (2012 $14,894 million). BP's share of capital commitments of joint ventures amounted to $317 million (2012 $293 million).

37. Auditor's remuneration

Fees – EY	2013	2012	2011
			$ million
The audit of the company annual accounts[a]	**26**	26	26
The audit of accounts of any subsidiaries of the company	**13**	13	15
Total audit	**39**	39	41
Audit-related assurance services[b]	**8**	7	6
Total audit and audit-related assurance services	**47**	46	47
Taxation compliance services	**1**	2	1
Taxation advisory services	**1**	2	1
Services relating to corporate finance transactions	**2**	2	4
Other assurance services	**1**	1	1
Total non-audit or non-audit-related assurance services	**5**	7	7
Services relating to BP pension plans[c]	**1**	1	1
	53	54	55

[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 $240,000 (2012 $50,000 and 2011 $108,000).

2013 includes $3 million of additional fees for 2012, and 2012 includes $2 million of additional fees for 2011. 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 (2012 $54 million and 2011 $55 million) is required to be presented as follows: audit $39 million (2012 $39 million and 2011 $41 million); other audit-related services $8 million (2012 $7 million and 2011 $6 million); tax $2 million (2012 $4 million and 2011 $2 million); and all other fees $4 million (2012 $4 million and 2011 $6 million).

38. Subsidiaries, joint arrangements and associates

The more important subsidiaries, joint arrangements and associates of the group at 31 December 2013 and the group percentage of ordinary share capital or joint arrangement interest (to nearest whole number) are set out below. Those held directly by the parent company are marked with an asterisk (*), the percentage owned being that of the group unless otherwise indicated. The group has interests in a number of joint arrangements, but none of these is individually material to the group. 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
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
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

39. 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					**2013**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Sales and other operating revenues	**5,397**	**–**	**379,136**	**(5,397)**	**379,136**
Earnings from joint ventures – after interest and tax	**–**	**–**	**447**	**–**	**447**
Earnings from associates – after interest and tax	**–**	**–**	**2,742**	**–**	**2,742**
Equity-accounted income of subsidiaries – after interest and tax	**–**	**24,693**	**–**	**(24,693)**	**–**
Interest and other income	**7**	**118**	**841**	**(189)**	**777**
Gains on sale of businesses and fixed assets	**–**	**–**	**13,115**	**–**	**13,115**
Total revenues and other income	**5,404**	**24,811**	**396,281**	**(30,279)**	**396,217**
Purchases	**861**	**–**	**302,887**	**(5,397)**	**298,351**
Production and manufacturing expenses	**1,473**	**–**	**26,054**	**–**	**27,527**
Production and similar taxes	**1,010**	**–**	**6,037**	**–**	**7,047**
Depreciation, depletion and amortization	**616**	**–**	**12,894**	**–**	**13,510**
Impairment and losses on sale of businesses and fixed assets	**(68)**	**–**	**2,029**	**–**	**1,961**
Exploration expense	**–**	**–**	**3,441**	**–**	**3,441**
Distribution and administration expenses	**108**	**1,234**	**11,728**	**–**	**13,070**
Fair value gain on embedded derivatives	**–**	**–**	**(459)**	**–**	**(459)**
Profit before interest and taxation	**1,404**	**23,577**	**31,670**	**(24,882)**	**31,769**
Finance costs	**42**	**43**	**1,172**	**(189)**	**1,068**
Net finance (income) expense relating to pensions and other post-retirement benefits	**–**	**81**	**399**	**–**	**480**
Profit before taxation	**1,362**	**23,453**	**30,099**	**(24,693)**	**30,221**
Taxation	**522**	**2**	**5,939**	**–**	**6,463**
Profit for the year	**840**	**23,451**	**24,160**	**(24,693)**	**23,758**
Attributable to					
BP shareholders	**840**	**23,451**	**23,853**	**(24,693)**	**23,451**
Non-controlling interests	**–**	**–**	**307**	**–**	**307**
	840	**23,451**	**24,160**	**(24,693)**	**23,758**

Statement of comprehensive income

					$ million
For the year ended 31 December					**2013**
	Issuer	**Guarantor**			
	BP Exploration (Alaska) Inc.	**BP p.l.c.**	**Other subsidiaries**	**Eliminations and reclassifications**	**BP group**
Profit for the year	**840**	**23,451**	**24,160**	**(24,693)**	**23,758**
Other comprehensive income	**–**	**2,819**	**(3,711)**	**–**	**(892)**
Total comprehensive income	**840**	**26,270**	**20,449**	**(24,693)**	**22,866**
Attributable to					
BP shareholders	**840**	**26,270**	**20,157**	**(24,693)**	**22,574**
Non-controlling interests	**–**	**–**	**292**	**–**	**292**
	840	**26,270**	**20,449**	**(24,693)**	**22,866**

39. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

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

Statement of comprehensive income continued

					$ million
For the year ended 31 December					2012
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit for the year	3,708	11,017	12,696	(16,170)	11,251
Other comprehensive income	–	(232)	1,207	–	975
Total comprehensive income	3,708	10,785	13,903	(16,170)	12,226
Attributable to					
BP shareholders	3,708	10,785	13,665	(16,170)	11,988
Non-controlling interests	–	–	238	–	238
	3,708	10,785	13,903	(16,170)	12,226

39. Condensed consolidating information on certain US subsidiaries – continued

Income statement continued

For the year ended 31 December	Issuer	Guarantor			$ million 2011
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	6,159	–	375,713	(6,159)	375,713
Earnings from joint ventures – after interest and tax	–	–	767	–	767
Earnings from associates – after interest and tax	–	–	4,916	–	4,916
Equity-accounted income of subsidiaries – after interest and tax	313	26,019	–	(26,332)	–
Interest and other income	10	242	756	(320)	688
Gains on sale of businesses and fixed assets	–	1	4,131	–	4,132
Total revenues and other income	6,482	26,262	386,283	(32,811)	386,216
Purchases	978	–	290,314	(6,159)	285,133
Production and manufacturing expenses	1,280	–	22,883	–	24,163
Production and similar taxes	1,684	–	6,596	–	8,280
Depreciation, depletion and amortization	335	–	11,022	–	11,357
Impairment and losses on sale of businesses and fixed assets	–	–	2,058	–	2,058
Exploration expense	4	–	1,516	–	1,520
Distribution and administration expenses	27	1,048	12,992	(109)	13,958
Fair value gain on embedded derivatives	–	–	(68)	–	(68)
Profit before interest and taxation	2,174	25,214	38,970	(26,543)	39,815
Finance costs	32	47	1,319	(211)	1,187
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(94)	494	–	400
Profit before taxation	2,142	25,261	37,157	(26,332)	38,228
Taxation	729	49	11,841	–	12,619
Profit for the year	1,413	25,212	25,316	(26,332)	25,609
Attributable to					
BP shareholders	1,413	25,212	24,919	(26,332)	25,212
Non-controlling interests	–	–	397	–	397
	1,413	25,212	25,316	(26,332)	25,609

Statement of comprehensive income continued

For the year ended 31 December	Issuer	Guarantor			$ million 2011
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit for the year	1,413	25,212	25,316	(26,332)	25,609
Other comprehensive income	–	(3,674)	(938)	–	(4,612)
Total comprehensive income	1,413	21,538	24,378	(26,332)	20,997
Attributable to					
BP shareholders	1,413	21,538	23,994	(26,332)	20,613
Non-controlling interests	–	–	384	–	384
	1,413	21,538	24,378	(26,332)	20,997

Balance sheet

At 31 December	Issuer	Guarantor			$ million 2013
	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

39. Condensed consolidating information on certain US subsidiaries – continued

Balance sheet continued

At 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
					$ million
					2012
Non-current assets					
Property, plant and equipment	8,343	–	116,988	–	125,331
Goodwill	–	–	12,190	–	12,190
Intangible assets	379	–	24,253	–	24,632
Investments in joint ventures	–	–	8,614	–	8,614
Investments in associates	–	2	2,996	–	2,998
Other investments	–	–	2,704	–	2,704
Subsidiaries – equity-accounted basis	–	136,553	–	(136,553)	–
Fixed assets	8,722	136,555	167,745	(136,553)	176,469
Loans	–	–	4,924	(4,282)	642
Trade and other receivables	–	–	5,961	–	5,961
Derivative financial instruments	–	–	4,294	–	4,294
Prepayments	34	–	796	–	830
Deferred tax assets	–	–	874	–	874
Defined benefit pension plan surpluses	–	–	12	–	12
	8,756	136,555	184,606	(140,835)	189,082
Current assets					
Loans	–	–	247	–	247
Inventories	174	–	28,029	–	28,203
Trade and other receivables	11,835	17,496	43,008	(34,728)	37,611
Derivative financial instruments	–	–	4,507	–	4,507
Prepayments	15	–	1,076	–	1,091
Current tax receivable	–	–	456	–	456
Other investments	–	–	319	–	319
Cash and cash equivalents	–	9	19,626	–	19,635
	12,024	17,505	97,268	(34,728)	92,069
Assets classified as held for sale	–	–	19,315	–	19,315
	12,024	17,505	116,583	(34,728)	111,384
Total assets	20,780	154,060	301,189	(175,563)	300,466
Current liabilities					
Trade and other payables	3,914	2,577	74,910	(34,728)	46,673
Derivative financial instruments	–	–	2,658	–	2,658
Accruals	140	27	6,708	–	6,875
Finance debt	–	–	10,033	–	10,033
Current tax payable	145	–	2,358	–	2,503
Provisions	1	–	7,586	–	7,587
	4,200	2,604	104,253	(34,728)	76,329
Liabilities directly associated with assets classified as held for sale	–	–	846	–	846
	4,200	2,604	105,099	(34,728)	77,175
Non-current liabilities					
Other payables	8	4,449	2,117	(4,282)	2,292
Derivative financial instruments	–	–	2,723	–	2,723
Accruals	–	38	453	–	491
Finance debt	–	–	38,767	–	38,767
Deferred tax liabilities	1,654	–	13,589	–	15,243
Provisions	1,887	–	28,509	–	30,396
Defined benefit pension plan and other post-retirement benefit plan deficits	–	1,913	11,714	–	13,627
	3,549	6,400	97,872	(4,282)	103,539
Total liabilities	7,749	9,004	202,971	(39,010)	180,714
Net assets	13,031	145,056	98,218	(136,553)	119,752
Equity					
BP shareholders' equity	13,031	145,056	97,012	(136,553)	118,546
Non-controlling interests	–	–	1,206	–	1,206
	13,031	145,056	98,218	(136,553)	119,752

39. Condensed consolidating information on certain US subsidiaries – continued

Cash flow statement

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

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

For the year ended 31 December	Issuer	Guarantor			$ million 2011
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Net cash provided by operating activities	661	8,321	25,178	(11,942)	22,218
Net cash used in investing activities	(661)	(3,710)	(22,382)	–	(26,753)
Net cash (used in) provided by financing activities	–	(4,615)	(6,850)	11,942	477
Currency translation differences relating to cash and cash equivalents	–	–	(493)	–	(493)
Decrease in cash and cash equivalents	–	(4)	(4,547)	–	(4,551)
Cash and cash equivalents at beginning of year	(1)	4	18,725	–	18,728
Cash and cash equivalents at end of year	(1)	–	14,178	–	14,177

Supplementary information on oil and natural gas (unaudited)

2013 reserves and production information for equity-accounted entities includes BP's share of TNK-BP from 1 January to 20 March, and Rosneft for the period 21 March to 31 December. For the period 22 October 2012 to 31 December 2012, and throughout all of 2013, financial information for equity-accounted entities does not include any information for TNK-BP, as equity accounting ceased on 22 October 2012. Comparative information for 2012 and 2011 has been restated to reflect the adoption of IFRS 11 'Joint Arrangements'. For further information see Financial statements – Note 1.

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 page 245.

										$ 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.

$ million

2013	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)[b]										
Capitalized costs at 31 December[c]										
Gross capitalized costs										
Proved properties	–	–	–	–	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 interest and the net results of equity-accounted entities, and excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities – continued

	Europe		North America		South America	Africa	Asia		Australasia	$ million 2012 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[b j]										
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[c k]										
Proved	–	–	256	–	51	–	–	–	–	307
Unproved	–	–	1,111	–	27	239	–	(68)	–	1,309
	–	–	1,367	–	78	239	–	(68)	–	1,616
Exploration and appraisal costs[d]	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[e]										
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)[f]	(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[g]	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 segment and TNK-BP segment 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[h]	(250)	(114)	(173)	774	163	(46)	11	32	370	767
Equity-accounted entities[i]	–	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] Includes costs capitalized as a result of asset exchanges.
[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.
[e] Presented net of transportation costs, purchases and sales taxes.
[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $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.
[g] 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.
[h] Midstream and other activities exclude inventory holding gains and losses.
[i] The profits of equity-accounted entities are included after interest and tax and the results exclude balances associated with assets held for sale.
[j] Excludes balances associated with assets held for sale.
[k] Excludes goodwill associated with business combinations.

Oil and natural gas exploration and production activities – continued

$ million

	UK	Rest of Europe	US	Rest of North America	South America	Africa	Russia[a]	Rest of Asia	Australasia	Total
	Europe		North America		South America	Africa	Asia		Australasia	2012 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. Capitalized 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 interest and the net results of equity-accounted entities, and excludes inventory holding gains and losses.

										$ million
										2011
	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 j]										
Gross capitalized costs										
Proved properties	37,491	8,994	73,626	1,296	7,471	29,358	–	14,833	3,370	176,439
Unproved properties	368	180	6,198	2,017	2,986	3,689	–	4,495	1,279	21,212
	37,859	9,174	79,824	3,313	10,457	33,047	–	19,328	4,649	197,651
Accumulated depreciation	26,953	3,715	36,009	139	3,839	14,595	–	6,235	1,294	92,779
Net capitalized costs	10,906	5,459	43,815	3,174	6,618	18,452	–	13,093	3,355	104,872
Costs incurred for the year ended 31 December[b j]										
Acquisition of properties[c k]										
Proved	–	–	1,178	8	237	–	–	1,733	–	3,156
Unproved	–	1	418	–	2,592	679	–	3,008	–	6,698
	–	1	1,596	8	2,829	679	–	4,741	–	9,854
Exploration and appraisal costs[d]	211	1	566	132	271	490	6	511	225	2,413
Development	1,361	889	3,016	227	405	2,933	–	1,340	251	10,422
Total costs	1,572	891	5,178	367	3,505	4,102	6	6,592	476	22,689
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,997	–	751	25	2,263	3,353	–	1,450	1,611	11,450
Sales between businesses	3,495	1,273	19,089	20	1,409	4,858	–	10,811	967	41,922
	5,492	1,273	19,840	45	3,672	8,211	–	12,261	2,578	53,372
Exploration expenditure	37	1	1,065	9	35	163	6	134	70	1,520
Production costs	1,372	230	3,402	66	503	1,146	4	787	194	7,704
Production taxes	72	–	1,854	–	278	–	–	5,956	147	8,307
Other costs (income)[f]	(1,357)	101	4,688	62	935	215	72	118	257	5,091
Depreciation, depletion and amortization	874	199	2,980	6	523	1,668	–	1,692	172	8,114
Impairments and (gains) losses on sale of businesses and fixed assets	26	(64)	(492)	15	(1,085)	18	(1)	(537)	–	(2,120)
	1,024	467	13,497	158	1,189	3,210	81	8,150	840	28,616
Profit (loss) before taxation[g]	4,468	806	6,343	(113)	2,483	5,001	(81)	4,111	1,738	24,756
Allocable taxes	2,483	384	2,152	(159)	1,205	2,184	(21)	1,001	677	9,906
Results of operations	1,985	422	4,191	46	1,278	2,817	(60)	3,110	1,061	14,850
Upstream segment and TNK-BP segment replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	4,468	806	6,343	(113)	2,483	5,001	(81)	4,111	1,738	24,756
Midstream activities – subsidiaries[h]	(118)	29	(157)	299	78	(4)	(1)	42	284	452
Equity-accounted entities[i]	–	12	10	–	525	69	4,095	573	–	5,284
Total replacement cost profit before interest and tax	4,350	847	6,196	186	3,086	5,066	4,013	4,726	2,022	30,492

[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. 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] Includes costs capitalized as a result of asset exchanges.

[d] Includes exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred.

[e] Presented net of transportation costs, purchases and sales taxes.

[f] Includes property taxes, other government take and the fair value gain on embedded derivatives of $191 million. The UK region includes a $1,442 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme. The South America region includes a charge of $700 million associated with the termination of the agreement to sell our 60% interest in Pan American Energy LLC to Bridas Corporation.

[g] Excludes the unwinding of the discount on provisions and payables amounting to $267 million which is included in finance costs in the group income statement.

[h] Midstream activities exclude inventory holding gains and losses.

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

[j] Excludes balances associated with assets held for sale.

[k] Excludes goodwill associated with business combinations.

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
										$ million
										2011
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	–	6,562	–	16,214	3,571	–	26,347
Unproved properties	–	–	–	–	19	–	652	9	–	680
	–	–	–	–	6,581	–	16,866	3,580	–	27,027
Accumulated depreciation	–	–	–	–	2,644	–	6,978	3,017	–	12,639
Net capitalized costs	–	–	–	–	3,937	–	9,888	563	–	14,388
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	46	–	46
Unproved	–	–	–	–	6	–	37	–	–	43
	–	–	–	–	6	–	37	46	–	89
Exploration and appraisal costs[d]	–	–	–	–	2	–	167	9	–	178
Development	–	–	–	–	587	–	1,862	435	–	2,884
Total costs	–	–	–	–	595	–	2,066	490	–	3,151
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	2,381	–	7,380	3,828	–	13,589
Sales between businesses	–	–	–	–	–	–	5,149	23	–	5,172
	–	–	–	–	2,381	–	12,529	3,851	–	18,761
Exploration expenditure	–	–	–	–	10	–	72	1	–	83
Production costs	–	–	–	–	459	–	1,846	212	–	2,517
Production taxes	–	–	–	–	1,098	–	5,000	3,125	–	9,223
Other costs (income)	–	–	–	–	(239)	–	2	(1)	–	(238)
Depreciation, depletion and amortization	–	–	–	–	329	–	988	431	–	1,748
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	1,657	–	7,908	3,768	–	13,333
Profit (loss) before taxation	–	–	–	–	724	–	4,621	83	–	5,428
Allocable taxes	–	–	–	–	294	–	806	19	–	1,119
Results of operations	–	–	–	–	430	–	3,815	64	–	4,309
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	–	430	–	3,815	64	–	4,309
Midstream and other activities after tax[f]	–	12	10	–	95	69	280	509	–	975
Total replacement cost profit after interest and tax	–	12	10	–	525	69	4,095	573	–	5,284

[a] 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.
[b] Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.
[c] Includes costs capitalized as a result of asset exchanges.
[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 interest 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]										2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[b]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2013										
Developed	242	170	1,443	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	–	32	255	–	137	45	1,968
	673	249	2,432	–	54	567	–	405	97	4,477
Changes attributable to										
Revisions of previous estimates	(78)	(19)	(141)	–	30	26	–	65	(12)	(129)
Improved recovery	12	–	52	–	1	2	–	65	–	132
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	4	–	–	–	–	39	3	46
Production[c]	(22)	(12)	(132)	–	(11)	(80)	–	(52)	(9)	(318)
Sales of reserves-in-place	(36)	–	(11)	–	–	–	–	–	–	(47)
	(124)	(31)	(228)	–	20	(52)	–	117	(18)	(316)
At 31 December 2013[d]										
Developed	169	163	1,297	–	29	320	–	320	57	2,355
Undeveloped	380	55	907	–	45	195	–	202	22	1,806
	549	218	2,204	–	74	515	–	522	79	4,161
Equity-accounted entities (BP share)[e]										
At 1 January 2013										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	690	23	4,454	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	–	–	–	–	12	–	228	–	–	240
Production	–	–	–	–	(27)	–	(303)	(85)	–	(415)
Sales of reserves-in-place	–	–	–	–	(85)	–	(4,399)	–	–	(4,484)
	–	–	–	1	(60)	(3)	489	(84)	–	343
At 31 December 2013[f g]										
Developed	–	–	–	–	316	10	3,064	120	–	3,510
Undeveloped	–	–	–	1	314	10	1,879	7	–	2,211
	–	–	–	1	630	20	4,943	127	–	5,721
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2013										
Developed	242	170	1,443	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	–	383	266	1,962	150	45	4,305
	673	249	2,432	–	744	590	4,454	616	97	9,855
At 31 December 2013										
Developed	169	163	1,297	–	345	330	3,064	440	57	5,865
Undeveloped	380	55	907	1	359	205	1,879	209	22	4,017
	549	218	2,204	1	704	535	4,943	649	79	9,882

[a] Crude oil includes NGLs and 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] 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.
[c] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.
[d] Includes 551 million barrels of NGLs. Also includes 21 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 131 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.
[g] Total proved liquid reserves held as part of our equity interest in Rosneft is 4,975 million barrels, comprising less than 1 mmboe in Vietnam and Canada, 32 million barrels in Venezuela and 4,943 million barrels in Russia.

Movements in estimated net proved reserves – continued

billion cubic feet

Natural gas[a]	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 2013										
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[b]	(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 2013[c]										
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)[d]										
At 1 January 2013										
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[b]	–	–	–	–	(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 2013[e f]										
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 2013										
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 2013										
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] 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.
[c] Includes 2,685 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[d] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[e] Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.
[f] 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

Bitumen[a]	million barrels 2013 Rest of North America	Total
Subsidiaries		
At 1 January 2013		
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 2013		
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.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2013										
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[d e]	(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 2013[f]										
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)[g]										
At 1 January 2013										
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[e]	–	–	–	–	(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 2013[h i]										
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 2013										
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 2013										
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] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[c] 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.
[d] Excludes NGLs from processing plants in which an interest is held of 5,500 barrels of oil equivalent per day.
[e] 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.
[f] Includes 551 million barrels of NGLs. Also includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[h] Includes 131 million barrels of NGLs. Also includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.
[i] 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]										million barrels 2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[b]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2012										
Developed	288	69	1,685	–	27	311	–	177	59	2,616
Undeveloped	445	230	1,173	–	48	315	–	279	47	2,537
	733	299	2,858	–	75	626	–	456	106	5,153
Changes attributable to										
Revisions of previous estimates	(30)	(25)	(280)	–	(11)	(1)	–	(2)	–	(349)
Improved recovery	3	–	140	–	–	13	–	2	–	158
Purchases of reserves-in-place	4	–	21	–	–	–	–	–	–	25
Discoveries and extensions	–	1	23	–	–	2	–	–	–	26
Production[c]	(31)	(8)	(142)	–	(10)	(73)	–	(51)	(9)	(324)
Sales of reserves-in-place	(6)	(18)	(188)	–	–	–	–	–	–	(212)
	(60)	(50)	(426)	–	(21)	(59)	–	(51)	(9)	(676)
At 31 December 2012[d h]										
Developed	242	170	1,443	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	–	32	255	–	137	45	1,968
	673	249	2,432	–	54	567	–	405	97	4,477
Equity-accounted entities (BP share)[e]										
At 1 January 2012										
Developed	–	–	–	–	349	–	2,596	256	–	3,201
Undeveloped	–	–	–	–	348	14	1,613	58	–	2,033
	–	–	–	–	697	14	4,209	314	–	5,234
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(2)	9	462	(23)	–	446
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	245	(103)	–	144
At 31 December 2012[f g i]										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	690	23	4,454	211	–	5,378
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2012										
Developed	288	69	1,685	–	376	311	2,596	433	59	5,817
Undeveloped	445	230	1,173	–	396	329	1,613	337	47	4,570
	733	299	2,858	–	772	640	4,209	770	106	10,387
At 31 December 2012										
Developed	242	170	1,443	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	–	383	266	1,962	150	45	4,305
	673	249	2,432	–	744	590	4,454	616	97	9,855

[a] Crude oil includes NGLs and 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] 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.
[c] Excludes NGLs from processing plants in which an interest is held of 13,500 barrels per day.
[d] Includes 591 million barrels of NGLs. Also includes 14 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 103 million barrels of NGLs. Also includes 328 million barrels of crude oil in respect of the 7.35% non-controlling interest in TNK-BP.
[g] 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.
[h] Includes assets held for sale of 39 million barrels.
[i] Includes assets held for sale of 4,540 million barrels.

Movements in estimated net proved reserves – continued

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	Total
billion cubic feet, 2012	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2012										
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[b]	(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 2012[c g]										
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)[d]										
At 1 January 2012										
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[b]	–	–	–	–	(169)	–	(280)	(35)	–	(484)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	30	144	1,598	(9)	–	1,763
At 31 December 2012[e f h]										
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 2012										
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 2012										
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] 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.
[c] Includes 2,890 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[d] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[e] Includes 270 billion cubic feet of natural gas in respect of the 6.17% non-controlling interest in TNK-BP.
[f] 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.
[g] Includes assets held for sale of 590 billion cubic feet.
[h] Includes assets held for sale of 4,492 billion cubic feet.

Movements in estimated net proved reserves – continued

Bitumen[a]	million barrels	
	2012	
	Rest of North America	Total
Subsidiaries		
At 1 January 2012		
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 2012		
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.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]										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 2012										
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[d,e]	(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 2012[f,j]										
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)[g]										
At 1 January 2012										
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[d,e]	–	–	–	–	(58)	–	(364)	(86)	–	(508)
Sales of reserves-in-place	–	–	–	–	–	–	(15)	–	–	(15)
	–	–	–	–	(1)	34	520	(105)	–	448
At 31 December 2012[h,i,k]										
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 2012										
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 2012										
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] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[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] 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.
[f] 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.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[h] Includes 103 million barrels of NGLs. Also includes 374 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.
[i] 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.
[j] Includes assets held for sale of 140 million barrels of oil equivalent.
[k] Includes assets held for sale of 5,315 million barrels of oil equivalent.

Movements in estimated net proved reserves – continued

million barrels

Crude oil[a]	Europe UK	Europe Rest of Europe	North America US[b]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2011 Total
Subsidiaries										
At 1 January 2011										
Developed	364	77	1,729	–	44	371	–	269	48	2,902
Undeveloped	431	221	1,190	–	58	374	–	325	58	2,657
	795	298	2,919	–	102	745	–	594	106	5,559
Changes attributable to										
Revisions of previous estimates	(1)	5	27	–	6	(68)	–	(131)	3	(159)
Improved recovery	14	8	97	–	1	10	–	70	6	206
Purchases of reserves-in-place	–	–	10	–	7	–	–	4	–	21
Discoveries and extensions	–	–	1	–	1	19	–	–	–	21
Production[c]	(41)	(12)	(162)	–	(13)	(68)	–	(50)	(9)	(355)
Sales of reserves-in-place	(34)	–	(34)	–	(29)	(12)	–	(31)	–	(140)
	(62)	1	(61)	–	(27)	(119)	–	(138)	–	(406)
At 31 December 2011[d]										
Developed	288	69	1,685	–	27	311	–	177	59	2,616
Undeveloped	445	230	1,173	–	48	315	–	279	47	2,537
	733	299	2,858	–	75	626	–	456	106	5,153
Equity-accounted entities (BP share)[e]										
At 1 January 2011										
Developed	–	–	–	–	408	–	2,388	370	–	3,166
Undeveloped	–	–	–	–	407	12	1,362	24	–	1,805
	–	–	–	–	815	12	3,750	394	–	4,971
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(12)	2	677	(5)	–	662
Improved recovery	–	–	–	–	70	–	73	–	–	143
Purchases of reserves-in-place	–	–	–	–	98	–	–	1	–	99
Discoveries and extensions	–	–	–	–	–	–	25	–	–	25
Production	–	–	–	–	(30)	–	(316)	(76)	–	(422)
Sales of reserves-in-place	–	–	–	–	(244)	–	–	–	–	(244)
	–	–	–	–	(118)	2	459	(80)	–	263
At 31 December 2011[f g]										
Developed	–	–	–	–	349	–	2,596	256	–	3,201
Undeveloped	–	–	–	–	348	14	1,613	58	–	2,033
	–	–	–	–	697	14	4,209	314	–	5,234
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	364	77	1,729	–	452	371	2,388	639	48	6,068
Undeveloped	431	221	1,190	–	465	386	1,362	349	58	4,462
	795	298	2,919	–	917	757	3,750	988	106	10,530
At 31 December 2011										
Developed	288	69	1,685	–	376	311	2,596	433	59	5,817
Undeveloped	445	230	1,173	–	396	329	1,613	337	47	4,570
	733	299	2,858	–	772	640	4,209	770	106	10,387

[a] Crude oil includes NGLs and 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] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 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.
[c] Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels per day.
[d] Includes 616 million barrels of NGLs. Also includes 20 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 19 million barrels of NGLs. Also includes 310 million barrels of crude oil in respect of the 7.37% non-controlling interest in TNK-BP.
[g] Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,305 million barrels, comprising 95 million barrels in Venezuela, one million barrels in Vietnam and 4,209 million barrels in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved liquid reserves of 221 million barrels.

Financial statements

Movements in estimated net proved reserves – continued

Natural gas[a]										billion cubic feet 2011
	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 2011										
Developed	1,416	40	9,495	58	3,575	1,329	–	1,290	3,563	20,766
Undeveloped	829	430	4,248	–	6,575	2,351	–	268	2,342	17,043
	2,245	470	13,743	58	10,150	3,680	–	1,558	5,905	37,809
Changes attributable to										
Revisions of previous estimates	169	30	–	(9)	202	(206)	–	69	299	554
Improved recovery	56	1	597	–	84	15	–	28	22	803
Purchases of reserves-in-place	8	–	93	7	–	–	–	310	–	418
Discoveries and extensions	–	–	219	–	47	–	–	–	–	266
Production[b]	(146)	(8)	(737)	(5)	(811)	(232)	–	(244)	(291)	(2,474)
Sales of reserves-in-place	(12)	–	(363)	(23)	(274)	–	–	(323)	–	(995)
	75	23	(191)	(30)	(752)	(423)	–	(160)	30	(1,428)
At 31 December 2011[c]										
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
Equity-accounted entities (BP share)[d]										
At 1 January 2011										
Developed	–	–	–	–	1,075	–	1,900	71	–	3,046
Undeveloped	–	–	–	–	1,192	175	459	19	–	1,845
	–	–	–	–	2,267	175	2,359	90	–	4,891
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(75)	20	683	(3)	–	625
Improved recovery	–	–	–	–	190	–	–	12	–	202
Purchases of reserves-in-place	–	–	–	–	31	–	–	76	–	107
Discoveries and extensions	–	–	–	–	–	–	–	–	–	–
Production[b]	–	–	–	–	(167)	–	(264)	(20)	–	(451)
Sales of reserves-in-place	–	–	–	–	(96)	–	–	–	–	(96)
	–	–	–	–	(117)	20	419	65	–	387
At 31 December 2011[e f]										
Developed	–	–	–	–	1,144	–	2,119	104	–	3,367
Undeveloped	–	–	–	–	1,006	195	659	51	–	1,911
	–	–	–	–	2,150	195	2,778	155	–	5,278
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	1,416	40	9,495	58	4,650	1,329	1,900	1,361	3,563	23,812
Undeveloped	829	430	4,248	–	7,767	2,526	459	287	2,342	18,888
	2,245	470	13,743	58	12,417	3,855	2,359	1,648	5,905	42,700
At 31 December 2011										
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

[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] Includes 196 billion cubic feet of natural gas consumed in operations,155 billion cubic feet in subsidiaries, 41 billion cubic feet in equity-accounted entities and excludes 14 billion cubic feet of produced non-hydrocarbon components which meet regulatory requirements for sales.
[c] Includes 2,759 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[d] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[e] Includes 174 billion cubic feet of natural gas in respect of the 6.27% non-controlling interest in TNK-BP.
[f] Total proved gas reserves held as part of our equity interest in TNK-BP is 2,881 billion cubic feet, comprising 30 billion cubic feet in Venezuela, 73 billion cubic feet in Vietnam and 2,778 billion cubic feet in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved gas reserves of 185 billion cubic feet.

Movements in estimated net proved reserves – continued

Bitumen[a]	million barrels 2011 Rest of North America	Total
Subsidiaries		
At 1 January 2011		
Developed	–	–
Undeveloped	179	179
	179	179
Changes attributable to		
Revisions of previous estimates	(1)	(1)
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	–	–
Production	–	–
Sales of reserves-in-place	–	–
	(1)	(1)
At 31 December 2011		
Developed	–	–
Undeveloped	178	178
	178	178

[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.

Movements in estimated net proved reserves – continued

million barrels of oil equivalent[b]

Total hydrocarbons[a]	Europe		North America		South America	Africa	Asia		Australasia	2011 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2011										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	179	1,192	779	–	371	462	5,775
	1,182	379	5,289	189	1,852	1,379	–	862	1,124	12,256
Changes attributable to										
Revisions of previous estimates	28	10	27	(3)	41	(103)	–	(119)	55	(64)
Improved recovery	24	8	200	–	15	12	–	75	10	344
Purchases of reserves-in-place	1	–	26	2	7	–	–	58	–	94
Discoveries and extensions	–	–	39	–	9	19	–	–	–	67
Production[d e]	(66)	(13)	(289)	(1)	(153)	(108)	–	(92)	(59)	(781)
Sales of reserves-in-place	(36)	–	(97)	(4)	(76)	(12)	–	(87)	–	(312)
	(49)	5	(94)	(6)	(157)	(192)	–	(165)	6	(652)
At 31 December 2011[f]										
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
Equity-accounted entities (BP share)[g]										
At 1 January 2011										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	–	613	43	1,441	27	–	2,124
	–	–	–	–	1,206	43	4,157	409	–	5,815
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(25)	5	795	(5)	–	770
Improved recovery	–	–	–	–	103	–	73	2	–	178
Purchases of reserves-in-place	–	–	–	–	103	–	–	14	–	117
Discoveries and extensions	–	–	–	–	–	–	25	–	–	25
Production[d e]	–	–	–	–	(59)	–	(362)	(80)	–	(501)
Sales of reserves-in-place	–	–	–	–	(260)	–	–	–	–	(260)
	–	–	–	–	(138)	5	531	(69)	–	329
At 31 December 2011[h i]										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	–	522	48	1,727	66	–	2,363
	–	–	–	–	1,068	48	4,688	340	–	6,144
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071
At 31 December 2011										
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

[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] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.
[c] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 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 28 thousand barrels of oil equivalent a day.
[e] Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 27 million barrels of oil equivalent in subsidiaries, seven million barrels of oil equivalent in equity-accounted entities and excludes two million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.
[f] Includes 616 million barrels of NGLs. Also includes 496 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[h] Includes 19 million barrels of NGLs. Also includes 340 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.
[i] Total proved reserves held as part of our equity interest in TNK-BP is 4,802 million barrels of oil equivalent, comprising 100 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 4,688 million barrels of oil equivalent in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved reserves of 253 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	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2013										
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 interest 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 interest 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 reserve – 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 2012										
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 interest 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 interest 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.

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

$ million

	Europe		North America		South America	Africa	Asia		Australasia	Total
2011	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December 2011										
Subsidiaries										
Future cash inflows[a]	97,900	36,400	332,900	9,200	39,100	82,100	–	59,200	53,900	710,700
Future production cost[b]	30,500	10,900	140,700	3,200	10,500	16,800	–	16,000	15,600	244,200
Future development cost[b]	8,500	2,700	32,300	1,900	7,600	13,200	–	9,600	3,200	79,000
Future taxation[c]	37,100	15,200	57,000	900	11,400	19,800	–	8,100	9,000	158,500
Future net cash flows	21,800	7,600	102,900	3,200	9,600	32,300	–	25,500	26,100	229,000
10% annual discount[d]	11,200	3,100	55,500	2,800	4,100	12,500	–	9,800	13,500	112,500
Standardized measure of discounted future net cash flows[e]	10,600	4,500	47,400	400	5,500	19,800	–	15,700	12,600	116,500
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	–	46,700	–	188,900	34,200	–	269,800
Future production cost[b]	–	–	–	–	21,500	–	123,800	30,100	–	175,400
Future development cost[b]	–	–	–	–	5,000	–	15,600	2,400	–	23,000
Future taxation[c]	–	–	–	–	5,900	–	9,600	200	–	15,700
Future net cash flows	–	–	–	–	14,300	–	39,900	1,500	–	55,700
10% annual discount[d]	–	–	–	–	8,700	–	19,000	600	–	28,300
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	5,600	–	20,900	900	–	27,400
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	10,600	4,500	47,400	400	11,100	19,800	20,900	16,600	12,600	143,900

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	(30,900)	(5,700)	(36,600)
Development costs for the current year as estimated in previous year	13,200	2,500	15,700
Extensions, discoveries and improved recovery, less related costs	6,600	2,800	9,400
Net changes in prices and production cost	75,100	15,700	90,800
Revisions of previous reserves estimates	(21,900)	2,000	(19,900)
Net change in taxation	(18,200)	(1,400)	(19,600)
Future development costs	(11,000)	(2,500)	(13,500)
Net change in purchase and sales of reserves-in-place	(6,500)	(2,700)	(9,200)
Addition of 10% annual discount	10,000	1,500	11,500
Total change in the standardized measure during the year[i]	16,400	12,200	28,600

[a] The marker prices used were Brent $110.96/bbl, Henry Hub $4.12/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 interest in BP Trinidad and Tobago LLC amounted to $1,600 million.
[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.
[g] Non-controlling interest 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] 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 and natural gas production for the years ended 31 December 2013, 2012 and 2011.

Production for the year[a]

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
Crude oil[b]										thousand barrels per day
2013	**61**	**34**	**363**	**–**	**30**	**225**	**–**	**141**	**25**	**879**
2012	86	23	390	1	28	202	–	139	27	896
2011	113	32	453	2	39	190	–	138	25	992
Natural gas[c]										million cubic feet per day
2013	**157**	**80**	**1,539**	**11**	**2,221**	**561**	**–**	**494**	**780**	**5,845**
2012	414	8	1,651	13	2,097	590	–	633	787	6,193
2011	355	13	1,843	14	2,197	558	–	618	795	6,393
Equity-accounted entities(BP share)										
Crude oil[b]										thousand barrels per day
2013	**–**	**–**	**–**	**–**	**73**	**–**	**829**	**232**	**–**	**1,134**
2012	–	–	–	–	80	–	863	217	–	1,160
2011	–	–	–	–	90	–	865	210	–	1,165
Natural gas[c]										million cubic feet per day
2013	**–**	**–**	**–**	**–**	**386**	**8**	**780**	**41**	**–**	**1,216**
2012	–	–	–	–	394	–	734	72	–	1,200
2011	–	–	–	–	392	–	699	34	–	1,125

[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] Crude oil includes natural gas liquids and condensate.
[c] Natural gas production excludes gas consumed in operations.

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

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 2013. 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	Rest of Asia		
Number of productive wells at 31 December 2013											
Oil wells[a]	– gross	**115**	**63**	**2,456**	**55**	**4,681**	**608**	**41,541**	**2,166**	**13**	**51,698**
	– net	**71**	**25**	**975**	**28**	**2,583**	**441**	**7,779**	**439**	**2**	**12,343**
Gas wells[b]	– gross	**68**	**6**	**21,445**	**364**	**688**	**135**	**72**	**761**	**74**	**23,613**
	– net	**29**	**1**	**9,367**	**179**	**239**	**52**	**14**	**280**	**14**	**10,175**
Oil and natural gas acreage at 31 December 2013											Thousands of acres
Developed	– gross	**128**	**39**	**6,340**	**223**	**1,634**	**621**	**4,380**	**1,982**	**162**	**15,509**
	– net	**71**	**16**	**3,334**	**109**	**453**	**221**	**831**	**355**	**35**	**5,425**
Undeveloped[c]	– gross	**1,118**	**1,196**	**6,669**	**9,710**	**29,100**	**26,538**	**257,896**	**20,141**	**16,021**	**368,389**
	– net	**672**	**403**	**4,585**	**7,638**	**12,943**	**17,142**	**50,285**	**7,258**	**11,254**	**112,180**

[a] Includes approximately 7,639 gross (1,491 net) multiple completion wells (more than one formation producing into the same well bore).
[b] Includes approximately 2,859 gross (1,350 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.
[c] 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[e]	Rest of Asia		
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
2011										
Exploratory										
Productive	0.4	–	34.1	–	4.4	2.1	16.7	1.0	0.2	58.9
Dry	–	–	2.1	–	0.2	–	7.2	0.3	0.3	10.1
Development										
Productive	1.7	–	199.4	–	101.3	16.0	582.0	45.1	–	945.5
Dry	–	–	0.2	–	3.0	2.7	–	0.4	–	6.3

[e] Information for 2011 and 2012 includes BP's share of TNK-BP which was sold to Rosneft on 21 March 2013.

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 2013. 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 2013										
Exploratory										
Gross	**2.0**	**–**	**32.0**	**3.0**	**6.0**	**10.0**	**–**	**4.0**	**–**	**57.0**
Net	**0.8**	**–**	**9.2**	**1.5**	**2.2**	**5.2**	**–**	**0.8**	**–**	**19.7**
Development										
Gross	**6.0**	**3.0**	**780.0**	**55.0**	**33.0**	**20.0**	**100.0**	**58.0**	**10.0**	**1,065.0**
Net	**4.0**	**1.1**	**169.1**	**27.5**	**16.6**	**6.1**	**19.8**	**20.7**	**1.4**	**266.3**

Parent company financial statements of BP p.l.c.

Independent auditor's report to the members of BP p.l.c.

We have audited the parent company financial statements of BP p.l.c. for the year ended 31 December 2013 which comprise the company balance sheet, the company cash flow statement, the company statement of total recognized gains and losses and the related notes 1 to 13. The financial reporting framework that has been applied in their preparation 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 116, the directors are responsible for the preparation of the parent company 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 parent company 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 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 and Accounts 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.

Opinion on financial statements

In our opinion the parent company financial statements:
- give a true and fair view of the state of the company's affairs as at 31 December 2013;
- have been properly prepared in accordance with United Kingdom Generally Accepted Accounting Practice; and
- have been prepared in accordance with the requirements of the Companies Act 2006.

Opinion on other matters 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 parent company financial statements.

Matters on which we are required to report by exception

We have nothing to report in respect of the following matters where the Companies Act 2006 requires us 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.

Other matter

We have reported separately on the group financial statements of BP p.l.c. for the year ended 31 December 2013. That report includes an emphasis of matter on the significant uncertainty over provisions and contingencies related to the Gulf of Mexico oil spill.

Ernst & Young LLP
John C. Flaherty (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
6 March 2014

1. The maintenance and integrity of the BP p.l.c. website are the responsibility of the directors; the work carried out by the auditors does not involve consideration of these matters and, accordingly, the auditors accept no responsibility for any changes that may have occurred to the financial statements since they were initially presented on the website.
2. Legislation in the United Kindom governing the preparation and dissemination of financial statements may differ from legislation in other jurisdictions.

The parent company financial statements of BP p.l.c. on pages 224-234 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Company balance sheet

At 31 December

	Note	2013	2012
			$ million
Fixed assets			
Investments			
Subsidiary undertakings	3	**134,125**	133,420
Associated undertakings	3	**2**	2
Total fixed assets		**134,127**	133,422
Current assets			
Debtors – amounts falling due within one year	4	**21,550**	17,496
Deferred taxation	2	**41**	–
Cash at bank and in hand		**6**	9
		21,597	17,505
Creditors – amounts falling due within one year	5	**4,267**	2,604
Net current assets		**17,330**	14,901
Total assets less current liabilities		**151,457**	148,323
Creditors – amounts falling due after more than one year	5	**4,642**	4,487
Net assets excluding pension plan surplus (deficit)		**146,815**	143,836
Defined benefit pension plan surplus (deficit)	6	**979**	(1,913)
Net assets		**147,794**	141,923
Represented by			
Capital and reserves			
Called-up share capital	7	**5,129**	5,261
Share premium account	8	**10,061**	9,974
Capital redemption reserve	8	**1,260**	1,072
Merger reserve	8	**26,509**	26,509
Own shares	8	**(601)**	(280)
Treasury shares	8	**(20,370)**	(20,774)
Share-based payment reserve	8	**1,661**	1,604
Profit and loss account	8	**124,145**	118,557
		147,794	141,923

The financial statements on pages 225-234 were approved and signed by the group chief executive on 6 March 2014 having been duly authorized to do so by the board of directors:

R W Dudley Group Chief Executive

The parent company financial statements of BP p.l.c. on pages 224-234 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	2013	2012
			$ million
Net cash outflow from operating activities	9	**(4,813)**	(1,272)
Servicing of finance and returns on investments			
Interest received		**116**	183
Interest paid		**(43)**	(43)
Dividends received		**16,228**	13,515
Net cash inflow from servicing of finance and returns on investments		**16,301**	13,655
Tax paid		**(2)**	(2)
Capital expenditure and financial investment			
Payments for fixed assets – investments		**(690)**	(7,060)
Net cash outflow for capital expenditure and financial investment		**(690)**	(7,060)
Equity dividends paid		**(5,441)**	(5,294)
Net cash inflow before financing		**5,355**	27
Financing			
Other share-based payment movements		**135**	(18)
Repurchases of ordinary share capital		**(5,493)**	–
Net cash outflow from financing		**(5,358)**	(18)
(Decrease) increase in cash	9	**(3)**	9

Company statement of total recognized gains and losses

For the year ended 31 December

	Note	2013	2012
			$ million
Profit for the year		**15,691**	12,322
Currency translation differences		**47**	(98)
Actuarial gain (loss) relating to pensions	6	**2,108**	(573)
Tax on actuarial gain (loss) relating to pensions	2	**(41)**	–
Total recognized gains and losses relating to the year		**17,805**	11,651

The parent company financial statements of BP p.l.c. on pages 224-234 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. Fair value is determined by using an appropriate 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 is measured at fair value and recognized as an expense over the vesting period, with a corresponding liability for the cumulative expense recognized on the balance sheet.

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.

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 224-234 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

2. Taxation

		$ million
Tax charge included in the statement of total recognized gains and losses	**2013**	2012
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**	–
Other taxable timing differences	**(41)**	–
Deferred tax		
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	**–**	–
Credit for the year on ordinary activities	**(41)**	–
Charge for the year in the statement of total recognized gains and losses	**41**	–
At 31 December	**–**	–

At 31 December 2013, deferred tax assets of $72 million on other timing differences (2012 $82 million on other timing differences and $97 million on pensions) 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

				$ million
	Subsidiary undertakings	**Associated undertakings**		
	Shares	**Shares**	**Loans**	**Total**
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**
Cost				
At 1 January 2012	126,434	2	2	126,438
Additions	7,060	–	–	7,060
At 31 December 2012	133,494	2	2	133,498
Amounts provided				
At 1 January 2012	74	–	2	76
At 31 December 2012	74	–	2	76
Net book amount				
At 31 December 2013	**134,125**	**2**	**–**	**134,127**
At 31 December 2012	133,420	2	–	133,422

The more important subsidiary undertakings of the company at 31 December 2013 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.

The parent company financial statements of BP p.l.c. on pages 224-234 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

3. Fixed assets – investments – continued

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
South Africa			
BP Southern Africa	75	South Africa	Refining and marketing
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 2013 was $62.63 billion (2012 $62.63 billion).

4. Debtors

		$ million
	2013	2012
	Within 1 year	Within 1 year
Group undertakings	**21,550**	17,496
	21,550	17,496

The carrying amounts of debtors approximate their fair value.

5. Creditors

				$ million
		2013		2012
	Within 1 year	**After 1 year**	Within 1 year	After 1year
Group undertakings	**2,526**	**4,584**	2,376	4,274
Accruals and deferred income	**1,540**	**58**	27	38
Other creditors	**201**	**–**	201	175
	4,267	**4,642**	2,604	4,487

The carrying amounts of creditors approximate their fair value.

Amounts falling due after one year include $4,236 million payable to a group undertaking. This amount is subject to interest payable quarterly at LIBOR plus 55 basis points.

Other creditors includes an amount of $175 million payable in respect of the settlement with the US Securities and Exchange Commission described in Note 2 of the consolidated financial statements.

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
	2013	2012
Due within		
1 to 2 years	**372**	230
2 to 5 years	**22**	17
More than 5 years	**4,248**	4,240
	4,642	4,487

The parent company financial statements of BP p.l.c. on pages 224-234 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

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. 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.

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 2013. 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.

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 and other post-retirement benefits at 31 December and pension expense for the following year.

Financial assumptions used to determine benefit obligation			%
	2013	2012	2011
Expected long-term rate of return	**6.9**	6.9	7.0
Discount rate for pension plan liabilities	**4.6**	4.4	4.8
Rate of increase in salaries	**5.1**	4.9	5.1
Rate of increase for pensions in payment	**3.3**	3.1	3.2
Rate of increase in deferred pensions	**3.3**	3.1	3.2
Inflation for pension plan liabilities	**3.3**	3.1	3.2

Financial assumptions used to determine benefit expense			%
	2013	2012	2011
Discount rate for pension plan service costs	**4.4**	4.8	5.5
Discount rate for pension plan other finance expense	**4.4**	4.8	5.5
Inflation for pension plan service costs	**3.1**	3.2	3.5

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			
	2013	2012	2011
Life expectancy at age 60 for a male currently aged 60	**27.8**	27.7	27.6
Life expectancy at age 60 for a male currently aged 40	**30.7**	30.6	30.5
Life expectancy at age 60 for a female currently aged 60	**29.5**	29.4	29.3
Life expectancy at age 60 for a female currently aged 40	**32.2**	32.1	32.0

The fair values of the various categories of asset held by the pension plan at 31 December are set out below.

						$ million
		2013		2012		2011
	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**	**17,341**	8.0	15,659	8.0	13,622
– emerging	**8.0**	**2,290**	8.0	1,074	8.0	890
Private equity	**8.0**	**2,907**	8.0	2,879	8.0	2,690
Government issued nominal bonds[a]	**3.8**	**549**	2.8	544	3.0	513
Index-linked bonds[a]	**3.6**	**787**	2.6	491	2.8	390
Corporate bonds[a]	**4.6**	**4,427**	4.2	3,850	4.9	3,238
Property[b]	**6.5**	**2,200**	6.5	1,783	6.5	1,710
Cash	**0.8**	**855**	0.9	1,000	1.7	470
Other	**0.8**	**160**	0.9	66	1.7	64
	6.9	**31,516**	6.9	27,346	7.0	23,587
Present value of plan liabilities		**30,496**		29,259		25,675
Surplus (deficit) in the plan		**1,020**		(1,913)		(2,088)

[a] Bonds held are typically denominated in sterling.
[b] Property held is all located in the United Kingdom.

The parent company financial statements of BP p.l.c. on pages 224-234 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

6. Pensions – continued

		$ million
	2013	2012
Analysis of the amount charged to operating profit		
Current service cost[a]	497	477
Settlement, curtailment and special termination benefits	(22)	(1)
Payments to defined contribution plans	24	14
Total operating charge[c]	499	490
Analysis of the amount credited (charged) to other finance income		
Expected return on pension plan assets	1,803	1,680
Interest on pension plan liabilities	(1,221)	(1,249)
Other finance income	582	431
Analysis of the amount recognized in the statement of total recognized gains and losses		
Actual return less expected return on pension plan assets	2,007	989
Change in assumptions underlying the present value of the plan liabilities	60	(1,446)
Experience gains and losses arising on the plan liabilities	41	(116)
Actuarial gain (loss) recognized in statement of total recognized gains and losses	2,108	(573)

		$ million
	2013	2012
Movements in benefit obligation during the year		
Benefit obligation at 1 January	29,259	25,675
Exchange adjustment	705	1,313
Current service cost[a]	497	477
Interest cost	1,221	1,249
Curtailments	(24)	(8)
Disposals	(9)	(10)
Special termination benefits[b]	2	7
Contributions by plan participants[e]	37	39
Benefit payments (funded plans)[c]	(1,087)	(1,038)
Benefit payments (unfunded plans)[c]	(4)	(7)
Actuarial (gain) loss on obligation	(101)	1,562
Benefit obligation at 31 December	30,496	29,259
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	27,346	23,587
Exchange adjustment	822	1,215
Expected return on plan assets[a d]	1,803	1,680
Contributions by plan participants[e]	37	39
Contributions by employers (funded plans)	597	884
Disposals	(9)	(10)
Benefit payments (funded plans)[c]	(1,087)	(1,038)
Actuarial gain on plan assets[d]	2,007	989
Fair value of plan assets at 31 December[f]	31,516	27,346
Surplus (deficit) at 31 December	1,020	(1,913)

[a] The costs of managing the fund's investments are treated as being part of the investment return, the costs of administering our pensions plan benefits are included in current service cost.
[b] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[c] The benefit payments amount shown above comprises $1,073 million benefits plus $18 million of plan expenses incurred in the administration of the benefit.
[d] 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.
[e] The contributions by plan participants are mostly comprised of contributions made under salary sacrifice arrangements.
[f] Reflects $31,362 million of assets held in the BP Pension Fund (2012 $27,219 million) and $114 million held in the BP Global Pension Trust (2012 $94 million), with $40 million representing the company's share of Merchant Navy Officers Pension Fund (2012 $32 million).

The parent company financial statements of BP p.l.c. on pages 224-234 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

6. Pensions – continued

Reconciliation of plan surplus (deficit) to balance sheet	2013	2012
		$ million
Surplus (deficit) at 31 December	**1,020**	(1,913)
Deferred tax	**(41)**	–
	979	(1,913)
Represented by		
Asset recognized on balance sheet	**1,238**	–
Liability recognized on balance sheet	**(259)**	(1,913)
	979	(1,913)

The aggregate level of employer contributions into the BP Pension Fund in 2014 is expected to be $485 million.

History of surplus (deficit) and of experience gains and losses	2013	2012	2011	2010	2009
					$ million
Benefit obligation at 31 December	**30,496**	29,259	25,675	20,742	19,882
Fair value of plan assets at 31 December	**31,516**	27,346	23,587	22,612	20,953
Surplus (deficit)	**1,020**	(1,913)	(2,088)	1,870	1,071
Experience gains and losses on plan liabilities					
Amount ($ million)	**41**	(116)	(84)	12	(146)
Percentage of benefit obligation	**0%**	0%	0%	0%	(1%)
Actual return less expected return on pension plan assets					
Amount ($ million)	**2,007**	989	(1,976)	1,479	1,634
Percentage of plan assets	**6%**	4%	(8%)	7%	8%
Actuarial gain (loss) recognized in statement of total recognized gains and losses					
Amount ($ million)	**2,108**	(573)	(4,770)	457	(585)
Percentage of benefit obligation	**7%**	2%	(19%)	2%	(3%)
Cumulative amount recognized in statement of total recognized gains and losses	**(4,470)**	(6,578)	(6,005)	(1,235)	(1,692)

7. Called-up share capital

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

	2013		2012	
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	**20,959,159**	**5,240**	20,813,410	5,203
Issue of new shares for the scrip dividend programme	**202,124**	**51**	138,406	35
Issue of new shares for employee share-based payment plans[b]	**18,203**	**5**	7,343	2
Repurchase of ordinary share capital[c]	**(752,854)**	**(188)**	–	–
31 December	**20,426,632**	**5,108**	20,959,159	5,240
		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 plans amounted to $116 million (2012 $47 million).
[c] Purchased for a total consideration of $5,493 million, including transaction costs of $30 million. All shares purchased were for cancellation. The repurchased shares represented 3.6% 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.

During 2013 the company repurchased 753 million ordinary shares at a cost of $5,463 million as part of the share repurchase programme announced on 22 March 2013. 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 $1,430 million has been accrued at 31 December 2013 (2012 nil).

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8. Capital and reserves

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Own shares	Treasury shares	Share-based payment reserve	Profit and loss account	Total
At 1 January 2013	**5,261**	**9,974**	**1,072**	**26,509**	**(280)**	**(20,774)**	**1,604**	**118,557**	**141,923**
Currency translation differences	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**47**	**47**
Actuarial gain on pensions (net of tax)	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**2,067**	**2,067**
Share-based payments	**5**	**138**	**–**	**–**	**(321)**	**404**	**57**	**147**	**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**	**(601)**	**(20,370)**	**1,661**	**124,145**	**147,794**

$ million

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Own shares	Treasury shares	Share-based payment reserve	Profit and loss account	Total
At 1 January 2012	5,224	9,952	1,072	26,509	(388)	(20,935)	1,574	112,285	135,293
Currency translation differences	–	–	–	–	–	–	–	(98)	(98)
Actuarial loss on pensions (net of tax)	–	–	–	–	–	–	–	(573)	(573)
Share-based payments	2	57	–	–	108	161	30	(85)	273
Profit for the year	–	–	–	–	–	–	–	12,322	12,322
Dividends	35	(35)	–	–	–	–	–	(5,294)	(5,294)
At 31 December 2012	5,261	9,974	1,072	26,509	(280)	(20,774)	1,604	118,557	141,923

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 (2012 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The accounts for the year ended 31 December 2013 do not reflect the dividend announced on 4 February 2014 and payable in March 2014; this will be treated as an appropriation of profit in the year ended 31 December 2014.

9. Cash flow

Notes on cash flow statement

$ million

	2013	2012
Reconciliation of net cash flow to movement of funds		
(Decrease) increase in cash	**(3)**	9
Movement of funds	**(3)**	9
Net cash at 1 January	**9**	–
Net cash at 31 December	**6**	9

Notes on cash flow statement (a) Reconciliation of operating profit to net cash outflow from operating activities	2013	2012
Operating profit	**15,112**	11,936
Net operating charge for pensions and other post-retirement benefits, less contributions	**(127)**	(414)
Dividends, interest and other income	**(16,414)**	(13,758)
Share-based payments	**297**	350
(Increase) decrease in debtors	**(4,054)**	240
Increase in creditors	**373**	374
Net cash outflow from operating activities	**(4,813)**	(1,272)

$ million

(b) Analysis of movements of funds	At 1 January 2013	Cash flow	At 31 December 2013
Cash at bank	**9**	**(3)**	**6**

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10. Contingent liabilities

The company has issued guarantees under which the maximum aggregate liabilities at 31 December 2013 were $47,042 million (2012 $45,400 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

		$ million
	2013	2012
Total expense recognized for equity-settled share-based payment transactions	**709**	669
Total expense recognized for cash-settled share-based payment transactions	**10**	5
Total expense recognized for share-based payment transactions	**719**	674
Closing balance of liability for cash-settled share-based payment transactions	**17**	12
Total intrinsic value for vested cash-settled share-based payments	**2**	–

Additional information on the company's share-based payment plans is provided in Note 13 to the consolidated financial statements.

12. Auditor's remuneration

Note 37 to the consolidated financial statements provides details of the remuneration of the company's auditor on a group basis.

13. Directors' remuneration

		$ million
Remuneration of directors	**2013**	2012
Total for all directors		
Emoluments	**16**	12
Gains made on the exercise of share options	**–**	–
Amounts awarded under incentive schemes	**2**	3

Emoluments
These amounts comprise fees and benefits 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 2013 (2012 nil).

Pension contributions
During 2013, two executive directors participated in a non-contributory pension scheme established for UK employees. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2013.

Office facilities for former chairmen and deputy chairmen
It is customary for the company to make available to former chairmen and deputy chairmen, who were previously employed executives, the use of office and basic secretarial facilities following their retirement. The cost involved in doing so is not significant.

Further information
Full details of individual directors' remuneration are given in the Directors' remuneration report on page 81.

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