Financial statements

Statement of directors' responsibilities

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

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

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

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

The directors draw attention to Notes 2, 36 and 43 on the consolidated financial statements which describe 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 90-93 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 59-62 and elsewhere in this report, including Safety on pages 46-50. 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 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.

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.

We have audited the consolidated financial statements of BP p.l.c. for the year ended 31 December 2012 which 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 1-45. 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 178, 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 to identify material inconsistencies with the audited financial statements. 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 consolidated financial statements:

- give a true and fair view of the state of the group's affairs as at 31 December 2012 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.

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.

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 Notes 2, 36 and 43 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.

Opinion on other matter prescribed by the Companies Act 2006

In our opinion the information given in 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 following:

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 directors' statement, set out on page 178, in relation to going concern;
- 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; and
- certain elements of the report to shareholders by the Board on directors' remuneration.

Other matter

We have reported separately on the parent company financial statements of BP p.l.c. for the year ended 31 December 2012 and on the information in the Directors' Remuneration Report that is described as having been audited.

Ernst & Young LLP
Allister Wilson (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
6 March 2013

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 Kingdom 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 at 31 December 2012 and 2011, 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 2012. 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 2012 and 2011, and the group results of its operations and its cash flows for each of the three years in the period ended 31 December 2012, 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 Notes 2, 36 and 43 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.

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 at 31 December 2012, 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 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP
London, United Kingdom
6 March 2013

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

Consolidated financial statements of the BP group

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

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

We have audited BP p.l.c.'s internal control over financial reporting as at 31 December 2012, 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 149. 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 at 31 December 2012, 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 at 31 December 2012 and 2011, 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 2012, and our report dated 6 March 2013 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP
London, United Kingdom
6 March 2013

Consent of independent registered public accounting firm

We consent to the incorporation by reference of our reports dated 6 March 2013, 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 2012 in the following Registration Statements:

Registration Statements on Form F-3 (File No. 333-179953, File No. 333-157906) 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
Ernst & Young LLP
London, United Kingdom
6 March 2013

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 Kingdom 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	2012	2011	2010
				$ million
Sales and other operating revenues	6	**375,580**	375,517	297,107
Earnings from jointly controlled entities – after interest and tax	24	**744**	1,304	1,175
Earnings from associates – after interest and tax	25	**3,675**	4,916	3,582
Interest and other income	7	**1,590**	596	681
Gains on sale of businesses and fixed assets	5	**6,696**	4,130	6,383
Total revenues and other income		**388,285**	386,463	308,928
Purchases	28	**293,242**	285,618	216,211
Production and manufacturing expenses[a]		**33,911**	24,145	64,615
Production and similar taxes	8	**8,158**	8,280	5,244
Depreciation, depletion and amortization	9	**12,481**	11,135	11,164
Impairment and losses on sale of businesses and fixed assets	5	**6,275**	2,058	1,689
Exploration expense	15	**1,475**	1,520	843
Distribution and administration expenses	11	**13,357**	13,958	12,555
Fair value (gain) loss on embedded derivatives	33	**(347)**	(68)	309
Profit (loss) before interest and taxation		**19,733**	39,817	(3,702)
Finance costs[a]	17	**1,125**	1,246	1,170
Net finance expense (income) relating to pensions and other post-retirement benefits	37	**(201)**	(263)	(47)
Profit (loss) before taxation		**18,809**	38,834	(4,825)
Taxation[a]	18	**6,993**	12,737	(1,501)
Profit (loss) for the year		**11,816**	26,097	(3,324)
Attributable to				
BP shareholders	39	**11,582**	25,700	(3,719)
Minority interest	39	**234**	397	395
		11,816	26,097	(3,324)
Earnings per share – cents				
Profit (loss) for the year attributable to BP shareholders				
Basic	20	**60.86**	135.93	(19.81)
Diluted	20	**60.45**	134.29	(19.81)

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

Group statement of comprehensive income

For the year ended 31 December	Note	2012	2011	2010
				$ million
Profit (loss) for the year		**11,816**	26,097	(3,324)
Currency translation differences		**531**	(531)	259
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets		**(15)**	19	(20)
Actuarial loss relating to pensions and other post-retirement benefits	37	**(2,335)**	(5,960)	(320)
Available-for-sale investments marked to market		**306**	(71)	(191)
Available-for-sale investments – recycled to the income statement		**(1)**	(3)	(150)
Cash flow hedges marked to market	33	**1,466**	44	(65)
Cash flow hedges – recycled to the income statement	33	**62**	(195)	(25)
Cash flow hedges – recycled to the balance sheet	33	**19**	(13)	53
Share of equity-accounted entities' other comprehensive income, net of tax		**(98)**	(57)	–
Taxation	18, 39	**446**	1,659	(137)
Other comprehensive income		**381**	(5,108)	(596)
Total comprehensive income		**12,197**	20,989	(3,920)
Attributable to				
BP shareholders	39	**11,959**	20,605	(4,318)
Minority interest	39	**238**	384	398
		12,197	20,989	(3,920)

Group statement of changes in equity[a]

$ million

	Share capital and capital reserves	Own shares and treasury shares	Foreign currency translation reserve	Fair value reserves	Share-based payment reserve	Profit and loss account	BP shareholders' equity	Minority interest	Total equity
At 1 January 2012	**43,454**	**(21,323)**	**4,422**	**267**	**1,582**	**83,063**	**111,465**	**1,017**	**112,482**
Profit for the year	**–**	**–**	**–**	**–**	**–**	**11,582**	**11,582**	**234**	**11,816**
Other comprehensive income	**–**	**–**	**665**	**1,508**	**–**	**(1,796)**	**377**	**4**	**381**
Total comprehensive income	**–**	**–**	**665**	**1,508**	**–**	**9,786**	**11,959**	**238**	**12,197**
Dividends	**–**	**–**	**–**	**–**	**–**	**(5,294)**	**(5,294)**	**(82)**	**(5,376)**
Share-based payments (net of tax)	**59**	**269**	**–**	**–**	**26**	**(70)**	**284**	**–**	**284**
Transactions involving minority interests	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**33**	**33**
At 31 December 2012	**43,513**	**(21,054)**	**5,087**	**1,775**	**1,608**	**87,485**	**118,414**	**1,206**	**119,620**
At 1 January 2011	43,448	(21,211)	4,937	469	1,586	65,758	94,987	904	95,891
Profit for the year	–	–	–	–	–	25,700	25,700	397	26,097
Other comprehensive income	–	–	(515)	(202)	–	(4,378)	(5,095)	(13)	(5,108)
Total comprehensive income	–	–	(515)	(202)	–	21,322	20,605	384	20,989
Dividends	–	–	–	–	–	(4,072)	(4,072)	(245)	(4,317)
Share-based payments (net of tax)	6	(112)	–	–	(4)	102	(8)	–	(8)
Transactions involving minority interests	–	–	–	–	–	(47)	(47)	(26)	(73)
At 31 December 2011	43,454	(21,323)	4,422	267	1,582	83,063	111,465	1,017	112,482
At 1 January 2010	43,304	(21,517)	4,811	776	1,584	72,655	101,613	500	102,113
Profit (loss) for the year	–	–	–	–	–	(3,719)	(3,719)	395	(3,324)
Other comprehensive income	–	–	126	(307)	–	(418)	(599)	3	(596)
Total comprehensive income	–	–	126	(307)	–	(4,137)	(4,318)	398	(3,920)
Dividends	–	–	–	–	–	(2,627)	(2,627)	(315)	(2,942)
Share-based payments (net of tax)	144	306	–	–	2	(113)	339	–	339
Transactions involving minority interests	–	–	–	–	–	(20)	(20)	321	301
At 31 December 2010	43,448	(21,211)	4,937	469	1,586	65,758	94,987	904	95,891

[a] See Note 39 for further information.

Group balance sheet

At 31 December

	Note	2012	2011
			$ million
Non-current assets			
Property, plant and equipment	21	**120,448**	119,214
Goodwill	22	**11,861**	12,100
Intangible assets	23	**24,041**	21,102
Investments in jointly controlled entities	24	**15,724**	15,518
Investments in associates	25	**2,998**	13,291
Other investments	27	**2,702**	2,633
Fixed assets		**177,774**	183,858
Loans		**695**	884
Trade and other receivables	29	**4,754**	4,337
Derivative financial instruments	33	**4,294**	5,038
Prepayments		**809**	739
Deferred tax assets	18	**874**	611
Defined benefit pension plan surpluses	37	**12**	17
		189,212	195,484
Current assets			
Loans		**247**	244
Inventories	28	**27,867**	25,661
Trade and other receivables	29	**37,664**	43,526
Derivative financial instruments	33	**4,507**	3,857
Prepayments		**1,058**	1,286
Current tax receivable		**456**	235
Other investments	27	**319**	288
Cash and cash equivalents	30	**19,548**	14,067
		91,666	89,164
Assets classified as held for sale	4	**19,315**	8,420
		110,981	97,584
Total assets		**300,193**	293,068
Current liabilities			
Trade and other payables	32	**47,154**	52,405
Derivative financial instruments	33	**2,658**	3,220
Accruals		**6,810**	5,932
Finance debt	34	**10,030**	9,044
Current tax payable		**2,501**	1,941
Provisions	36	**7,587**	11,238
		76,740	83,780
Liabilities directly associated with assets classified as held for sale	4	**846**	538
		77,586	84,318
Non-current liabilities			
Other payables	32	**2,102**	3,437
Derivative financial instruments	33	**2,723**	3,773
Accruals		**448**	389
Finance debt	34	**38,767**	35,169
Deferred tax liabilities	18	**15,064**	15,078
Provisions	36	**30,334**	26,404
Defined benefit pension plan and other post-retirement benefit plan deficits	37	**13,549**	12,018
		102,987	96,268
Total liabilities		**180,573**	180,586
Net assets		**119,620**	112,482
Equity			
BP shareholders' equity	39	**118,414**	111,465
Minority interest	39	**1,206**	1,017
Total equity	39	**119,620**	112,482

R W Dudley Group Chief Executive
6 March 2013

Group cash flow statement

For the year ended 31 December				$ million
	Note	**2012**	2011	2010
Operating activities				
Profit (loss) before taxation[a]		**18,809**	38,834	(4,825)
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities				
Exploration expenditure written off	15	**745**	1,024	375
Depreciation, depletion and amortization	9	**12,481**	11,135	11,164
Impairment and (gain) loss on sale of businesses and fixed assets	5	**(421)**	(2,072)	(4,694)
Earnings from jointly controlled entities and associates		**(4,419)**	(6,220)	(4,757)
Dividends received from jointly controlled entities and associates		**2,210**	5,381	3,277
Interest receivable		**(295)**	(198)	(277)
Interest received		**181**	216	205
Finance costs	17	**1,125**	1,246	1,170
Interest paid		**(1,154)**	(1,110)	(912)
Net finance expense (income) relating to pensions and other post-retirement benefits	37	**(201)**	(263)	(47)
Share-based payments		**156**	(88)	197
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans		**(857)**	(1,004)	(959)
Net charge for provisions, less payments		**5,340**	2,976	19,217
(Increase) decrease in inventories		**(1,797)**	(3,988)	(3,895)
(Increase) decrease in other current and non-current assets		**2,968**	(9,913)	(15,620)
Increase (decrease) in other current and non-current liabilities		**(8,022)**	(5,767)	20,607
Income taxes paid		**(6,452)**	(8,035)	(6,610)
Net cash provided by operating activities		**20,397**	22,154	13,616
Investing activities				
Capital expenditure		**(23,078)**	(17,845)	(18,421)
Acquisitions, net of cash acquired		**(116)**	(10,909)	(2,468)
Investment in jointly controlled entities		**(1,530)**	(857)	(461)
Investment in associates		**(54)**	(55)	(65)
Proceeds from disposals of fixed assets	5	**9,991**	3,500	7,492
Proceeds from disposals of businesses, net of cash disposed[b]	5	**1,455**	(768)	9,462
Proceeds from loan repayments		**370**	301	501
Net cash used in investing activities		**(12,962)**	(26,633)	(3,960)
Financing activities				
Net issue of shares		**122**	74	169
Proceeds from long-term financing		**11,087**	11,600	11,934
Repayments of long-term financing		**(7,177)**	(9,102)	(4,702)
Net increase (decrease) in short-term debt		**(674)**	2,227	(3,619)
Dividends paid				
BP shareholders		**(5,294)**	(4,072)	(2,627)
Minority interest		**(82)**	(245)	(315)
Net cash provided by (used in) financing activities		**(2,018)**	482	840
Currency translation differences relating to cash and cash equivalents		**64**	(492)	(279)
Increase (decrease) in cash and cash equivalents		**5,481**	(4,489)	10,217
Cash and cash equivalents at beginning of year		**14,067**	18,556	8,339
Cash and cash equivalents at end of year		**19,548**	14,067	18,556

[a] 2012 includes $709 million of dividends received from TNK-BP. See Note 4 for further information.

[b] 2010 included a deposit received in advance of $3,530 million in respect of the expected sale of our interest in Pan American Energy LLC; 2011 included the repayment of the same amount following the termination of the sale agreement.

Notes on financial statements

1. Significant accounting policies

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 2012 were approved and signed by the group chief executive on 6 March 2013 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 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 2012. The standards and interpretations adopted in the year are described further on page 192.

The accounting policies that follow have been consistently applied to all years presented.

Subsequent to releasing our unaudited fourth quarter and full year 2012 results announcement dated 5 February 2013, an adjustment of $0.8 billion has been made to provisions relating to the Gulf of Mexico oil spill as at 31 December 2012, with a corresponding adjustment to the reimbursement asset. There was no impact on profit or loss for the year. For further information see Note 36. In addition, an adjustment has been made to correct a $4.7 billion understatement of revenue and purchases for the year ended 31 December 2012. There was no impact on profit or loss 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.

For further information regarding the key judgements and estimates made by management in applying the group's accounting policies, refer to Critical accounting policies on pages 171-174, which forms part of these financial statements.

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 comprises the power to govern the financial and operating policies of the investee so as to obtain benefit from its activities and is achieved through direct and indirect ownership of voting rights; currently exercisable or convertible potential voting rights; or by way of contractual agreement. 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. Minority interests represent the equity in subsidiaries that is not attributable, directly or indirectly, to the group.

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. With effect from 1 January 2012, the former Exploration and Production segment was separated to form two new operating segments, Upstream and TNK-BP, reflecting the way in which our investment in TNK-BP is managed. In addition, we began reporting the Refining and Marketing segment as Downstream.

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. See Note 4 for further information.

During 2010 a separate organization was created within the group to deal with the ongoing response to the Gulf of Mexico oil spill. This organization reports directly to the group chief executive officer and its costs are excluded from the results of the operating segments. Under IFRS its costs are therefore 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 generally accepted accounting practice (GAAP). For further information see Note 6.

Interests in joint ventures

A joint venture is a contractual arrangement whereby two or more parties (venturers) undertake an economic activity that is subject to joint control. Joint control exists only when the strategic financial and operating decisions relating to the activity require the unanimous consent of the venturers. A jointly controlled entity is a joint venture that involves the establishment of a company, partnership or other entity to engage in economic activity that the group jointly controls with its fellow venturers.

The results, assets and liabilities of a jointly controlled entity are incorporated in these financial statements using the equity method of accounting. Under the equity method, the investment in a jointly controlled entity is carried in the balance sheet at cost, plus post-acquisition changes in the group's share of net assets of the jointly controlled entity, less distributions received and less any impairment in value of the investment. Loans advanced to jointly controlled 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 jointly controlled entity.

Financial statements of jointly controlled entities are prepared for the same reporting year as the group. Where necessary, 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 jointly controlled entities are eliminated to the extent of the group's interest in the jointly controlled entities. Unrealized losses are also eliminated unless the transaction provides evidence of an impairment of the asset transferred.

The group assesses investments in jointly controlled 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 or significant influence over the joint venture or associate respectively, or when the interest becomes classified as an asset held for sale.

Certain of the group's activities, particularly in the Upstream segment, are conducted through joint ventures where the venturers have a direct ownership interest in, and jointly control, the assets of the venture. BP recognizes, on a line-by-line basis in the consolidated financial statements, its share of the assets, liabilities and expenses of these jointly controlled assets 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 venture.

1. Significant accounting policies continued

Interests in associates

An associate is an entity over which the group is in a position to exercise significant influence through participation in the financial and operating policy decisions of the investee, but which is not a subsidiary or a jointly controlled entity. The results, assets and liabilities of an associate are incorporated in these financial statements using the equity method of accounting as described above for jointly controlled entities.

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, jointly controlled entities 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, jointly controlled entities 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, jointly controlled entities 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, jointly controlled entities 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, jointly controlled entity 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.

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 minority interest in the acquiree. Minority 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 minority 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 that the carrying value may be impaired. Impairment is determined by assessing the recoverable amount of the cash-generating unit to which the goodwill relates. 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 jointly controlled entities 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 investments in jointly controlled entities and associates, and any impairment of the investment is included within the group's share of earnings from jointly controlled entities and associates.

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 jointly controlled entity or an interest in an 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 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.

1. Significant accounting policies continued

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.

All such carried costs are subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are written off. 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.

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 qualifying assets, 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.

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 amortization of common facilities costs takes into account expenditures incurred to date, together with the future capital expenditure expected to be incurred in relation to 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.

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 volumes 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.

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

1. Significant accounting policies continued

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.

Financial assets

Financial assets are classified as loans and receivables; available-for-sale financial assets; financial assets at fair value through profit or loss; or as derivatives designated as hedging instruments in an effective hedge, 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.

Available-for-sale financial assets

Available-for-sale financial assets are those non-derivative financial assets that are not classified as loans and receivables or financial assets at fair value through profit or loss. After initial recognition, available-for-sale financial assets are measured at fair value, with gains or losses recognized within other comprehensive income. Accumulated changes in fair value are recorded as a separate component of equity until the investment is derecognized or impaired.

The fair value of quoted investments is determined by reference to bid prices at the close of business on the balance sheet date. Where there is no active market, fair value is determined using valuation techniques. Where fair value cannot be reliably measured, assets are carried at cost.

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.

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.

Available-for-sale financial assets

If an available-for-sale financial asset is impaired, the cumulative loss previously recognized in equity is transferred to the income statement. Any subsequent recovery in the fair value of the asset is recognized within other comprehensive income.

If there is objective evidence that an impairment loss on an unquoted equity instrument that is carried at 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 current market rate of return for a similar financial asset.

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.

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.

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.

1. Significant accounting policies continued

Derivative financial instruments and hedging activities

The group uses derivative financial instruments to manage certain exposures to fluctuations in foreign currency exchange rates, interest rates and commodity prices as well as for trading purposes. 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.

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 item. Such hedges are expected at inception to be highly effective in achieving offsetting changes in fair value or cash flows. Hedges meeting the criteria for hedge accounting are accounted for as follows:

Fair value hedges

The change in fair value of a hedging derivative is recognized in profit or loss. The change in the fair value of the hedged item attributable to the risk being hedged is recorded as part of the carrying value of the hedged item and is also recognized in profit or loss.

The group applies fair value hedge accounting 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. If a forecast transaction is no longer expected to occur, amounts previously recognized in equity are reclassified to the income statement.

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.

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 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.

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. 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.

1. Significant accounting policies continued

Other than the unwinding of discount on the provision, any change in the present value of the estimated expenditure is reflected as an adjustment to the provision and the corresponding asset. 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 current or future revenues are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations that do not contribute to current or 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.

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 relevant 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 is treated as a cancellation, where this is within the control of the employee.

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management's best estimate of the achievement or otherwise of non-market conditions and the number of equity instruments that will ultimately vest or, in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

When the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

When an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation and any cost not yet recognized in the income statement for the award is expensed immediately.

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 are recognized immediately when the company becomes committed to a change in pension plan design. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the plan membership or a reduction in future entitlement) occurs, the obligation and related plan assets are remeasured using current actuarial assumptions and the resultant gain or loss is recognized in the income statement during the period in which the settlement or curtailment occurs.

The interest element of the defined benefit cost represents the change in present value of plan 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 forecasts 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 other comprehensive income in the year 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.

Corporate taxes

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

1. Significant accounting policies continued

- 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, jointly controlled entities 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, jointly controlled entities 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.

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.

Revenue

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

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

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

Generally, revenues from the production of oil and natural gas properties in which the group has an interest with joint venture 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.

Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities as well as the disclosure of contingent assets and liabilities at the balance sheet date and the reported amounts of revenues and expenses during the reporting period. Actual outcomes could differ from those estimates.

Impact of new International Financial Reporting Standards

Adopted for 2012

There are no new or amended standards or interpretations adopted with effect from 1 January 2012 that have a significant impact on the financial statements.

Not yet adopted

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

Interests in other entities and related disclosures

In May 2011, the IASB issued three new standards relating to interests in other entities and related disclosures. The new standards are IFRS 10 'Consolidated Financial Statements', IFRS 11 'Joint Arrangements' and IFRS 12 'Disclosure of Interests in Other Entities'. In addition, the IASB issued amendments to IAS 27 'Consolidated and Separate Financial Statements' (renamed IAS 27 'Separate Financial Statements') and IAS 28 'Investments in Associates' (renamed IAS 28 'Investments in Associates and Joint Ventures').

IFRS 10 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.

1. Significant accounting policies continued

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 will be accounted for using the equity method. Investments in joint operations will be accounted for by recognizing the group's assets, liabilities, revenue and expenses relating to the joint operation.

IFRS 12 combines all the disclosure requirements for an entity's interests in subsidiaries, joint arrangements, associates and structured entities into one comprehensive disclosure standard.

These new and amended standards are effective for annual periods beginning on or after 1 January 2013 and BP will adopt them from this date. The evaluation of the effect of adoption of these standards is largely complete. The main impact of this suite of new standards is that certain of the group's existing jointly controlled entities, which are currently equity accounted, will fall under the definition of a joint operation under IFRS 11 and thus we will recognize the group's assets, liabilities, revenue and expenses relating to these arrangements. Whilst the effect on the group's reported income and net assets as a result of the new requirements is not expected to be material, the change is expected to materially impact certain of the component lines of the balance sheet and income statement. On the balance sheet, we expect a reduction in investments in jointly controlled entities of approximately $7 billion, which will be replaced with the recognition (on the relevant line items, principally intangible assets and property, plant and equipment) of our share of the assets and liabilities relating to these arrangements. In the income statement, we expect a reduction in earnings from jointly controlled entities of approximately $0.5 billion, which will be replaced with the recognition (on the relevant line items) of our share of the revenue and expenses relating to these arrangements.

This new suite of standards was adopted by the EU in December 2012.

Other new standards not yet adopted

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 will be that the expense for defined benefit pension and other post-retirement benefit plans will include a net interest income or expense, which will be calculated by applying 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 (currently calculated based on the expected long-term return on pension assets) will now be based on a lower corporate bond rate, the same rate that is used to discount the pension liability. The amended IAS 19 is effective for annual periods beginning on or after 1 January 2013 and BP will adopt this amended standard from that date. The evaluation of the effect of adoption of the amended standard is largely complete. Under the amended IAS 19, net finance expense (income) relating to pensions and other post-retirement benefits and profit before tax would have been approximately $0.8 billion and $0.7 billion lower for 2012 and 2011 respectively, with corresponding pre-tax increases in other comprehensive income. There is no impact on cash flows or on the balance sheet at 31 December 2012.

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. IFRS 13 is effective for annual periods beginning on or after 1 January 2013 and BP will adopt it from this date. For BP, no significant impact is expected as a result of the adoption of IFRS 13.

In December 2011, the IASB issued amendments to IFRS 7 'Disclosures – Offsetting Financial Assets and Financial Liabilities' and amendments to IAS 32 'Offsetting Financial Assets and Financial Liabilities'. These amendments introduce new presentation and disclosure requirements about the effects of offsetting financial assets and financial liabilities and related arrangements on an entity's financial position. The amendments to IFRS 7 are effective for annual periods beginning on or after 1 January 2013, with the amendments to IAS 32 effective for annual periods beginning on or after 1 January 2014. BP will adopt these amendments with effect from 1 January 2013 and 1 January 2014 respectively. As a result of the amendments to IFRS 7, the notes to BP's 2013 financial statements will disclose additional information on gross and net financial instruments balances. The evaluation of the effect of adoption of the amendments to IAS 32 is not expected to result in any significant changes to the offsetting of financial assets and liabilities.

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. These amendments to IAS 1 are effective for annual periods beginning on or after 1 July 2012. BP will adopt the amendments with effect from 1 January 2013. The adoption of the amended standard will have a presentational impact on the group's statement of comprehensive income, with no effect on the reported income or net assets of 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. The remaining phases of IFRS 9 (covering impairment and hedge accounting) are still to be completed. In December 2011, the IASB decided that IFRS 9 will be effective for annual periods beginning on or after 1 January 2015, rather than 1 January 2013 as originally indicated. BP has not yet decided the date of adoption for the group and has not yet completed its evaluation of the effect of adoption.

With the exception of IFRS 9, the EU has now adopted all of the above-mentioned other new standards that have been issued but not yet adopted by the group.

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, as described on pages 59-62, BP continues to incur costs and has also recognized liabilities for future costs. Liabilities of uncertain timing or amount and contingent liabilities have been accounted for and/or disclosed in accordance with IAS 37 'Provisions, Contingent Liabilities and Contingent Assets'. These are discussed in further detail in Note 36 for provisions and Note 43 for contingent liabilities. BP's rights and obligations in relation to the $20-billion trust fund which was established in 2010 are accounted for in accordance with IFRIC 5 'Rights to Interests Arising from Decommissioning, Restoration and Environmental Rehabilitation Funds'. Key aspects of the accounting for the oil spill are summarized below.

The financial impacts of the Gulf of Mexico oil spill on the income statement, balance sheet and cash flow statement of the group are shown in the table below. Amounts related to the trust fund are separately identified.

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 see Note 43.

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 in Note 43, 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 in Risk factors on pages 38-44.

						$ million
		2012		2011		2010
	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	**4,995**	**(1,191)**	(3,800)	(3,995)	40,858	7,261
Profit (loss) before interest and taxation	**(4,995)**	**1,191**	3,800	3,995	(40,858)	(7,261)
Finance costs	**19**	**12**	58	52	77	73
Profit (loss) before taxation	**(5,014)**	**1,179**	3,742	3,943	(40,935)	(7,334)
Less: taxation	**94**	**–**	(1,387)	–	12,894	–
Profit (loss) for the period	**(4,920)**	**1,179**	2,355	3,943	(28,041)	(7,334)
Balance sheet						
Current assets						
Trade and other receivables	**4,239**	**4,178**	8,487	8,233	5,943	5,943
Current liabilities						
Trade and other payables	**(522)**	**(22)**	(5,425)	(4,872)	(6,587)	(5,002)
Provisions	**(5,449)**	**–**	(9,437)	–	(7,938)	–
Net current liabilities	**(1,732)**	**4,156**	(6,375)	3,361	(8,582)	941
Non-current assets						
Other receivables	**2,264**	**2,264**	1,642	1,642	3,601	3,601
Non-current liabilities						
Other payables	**(175)**	**–**	–	–	(9,899)	(9,899)
Provisions	**(9,751)**	**–**	(5,896)	–	(8,397)	–
Deferred tax	**4,002**	**–**	7,775	–	11,255	–
Net non-current liabilities	**(3,660)**	**2,264**	3,521	1,642	(3,440)	(6,298)
Net assets	**(5,392)**	**6,420**	(2,854)	5,003	(12,022)	(5,357)
Cash flow statement						
Profit (loss) before taxation	**(5,014)**	**1,179**	3,742	3,943	(40,935)	(7,334)
Finance costs	**19**	**12**	58	52	77	73
Net charge for provisions, less payments	**4,834**	**–**	2,699	–	19,354	–
(Increase) decrease in other current and non-current assets	**(998)**	**(1,191)**	(4,292)	(4,038)	(12,567)	(12,567)
Increase (decrease) in other current and non-current liabilities	**(5,090)**	**(4,860)**	(11,113)	(10,097)	16,413	14,828
Pre-tax cash flows	**(6,249)**	**(4,860)**	(8,906)	(10,140)	(17,658)	(5,000)

The impact on net cash provided by operating activities, on a post-tax basis, amounted to $2,382 million (2011 $6,813 million and 2010 $16,019 million).

Trust fund

In 2010, BP established the Deepwater Horizon Oil Spill Trust (the Trust) to be funded in the amount of $20 billion (the trust fund) over the period to the fourth quarter of 2013, which is available to satisfy legitimate individual and business claims that were previously administered by the Gulf Coast Claims Facility (GCCF), 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 satisfy claims that were previously processed through the transitional court-supervised claims facility, to fund the qualified settlement funds (QSFs) established under the terms of the settlement agreements with the Plaintiffs' Steering Committee (PSC) administered through the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), and the separate BP claims programme – see below for further information. Fines, penalties and claims administration costs are not covered by the trust fund. The establishment of the trust fund does not represent a cap or floor on BP's liabilities and BP does not admit to a liability of this amount.

In 2010, BP contributed $5 billion to the fund, and further regular contributions totalling $5 billion were made in 2011. During 2011, BP also contributed the cash settlements received from MOEX, Weatherford and Anadarko, amounting in total to $5.1 billion. A further cash settlement from Cameron was received in January 2012 and was also contributed to the trust fund. As a result of these accelerated contributions and BP's regular contributions, the $20-billion commitment was paid in full during 2012. The income statement charge for 2010 included $20 billion in relation to the trust fund, adjusted to take account of the time value of money.

2. Significant event – Gulf of Mexico oil spill continued

Under the terms of the Trust agreement, BP has no right to access the funds once they have been contributed to the trust fund and BP has no decision-making role in connection with the payment by the trust fund of individual and business claims resolved by the GCCF and the new court-supervised claims processes referred to below. BP will receive funds from the trust fund only upon its expiration, if there are any funds remaining at that point. Any amount remaining in the trust fund when the trustees determine that all claims have been settled would be returned to BP. However, it is not possible to reliably estimate the number or total amount of the claims that will be settled from the trust fund, and therefore it is not possible to reliably measure the fair value of BP's residual interest in it. The carrying amount of BP's residual interest is, consequently, nil. BP has the authority under the Trust agreement to present certain resolved claims, including natural resource damages claims and state and local response claims, to the Trust for payment, by providing the trustees with all the required documents establishing that such claims are valid under the Trust agreement. However, any such payments can only be made on the authority of the trustees and any funds distributed are paid directly to the claimants, not to BP. BP will not settle any such items directly or receive reimbursement from the trust fund for such items.

BP's obligation to make contributions to the trust fund was recognized in full in 2010, amounting to $20 billion on an undiscounted basis. On initial recognition the discounted amount recognized was $19,580 million. The funding of the Trust has now been completed.

The table below shows movements in the funding obligation during the period to 31 December 2012. The remaining liability of $22 million at 31 December 2012 represents amounts reimbursable to the Trust for administrative costs incurred.

			$ million
	2012	2011	2010
At 1 January	**4,872**	14,901	–
Trust fund liability initially recognized – discounted	**–**	–	19,580
Unwinding of discount	**12**	52	73
Change in discounting	**–**	43	240
Contributions	**(4,860)**	(10,140)	(5,000)
Other	**(2)**	16	8
At 31 December	**22**	4,872	14,901

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 to claimants from the trust fund, and BP will be released from its corresponding obligation.

The provision was increased during the year for items that will be covered by the trust fund by $1,985 million (2011 $4,038 million) and payments of $4,624 million (2011 $3,707 million) were made during the year from the trust fund. This includes payments from the trust fund to the seafood compensation fund and payments from QSFs other than the seafood compensation fund to claimants. In addition, a provision of $794 million was derecognized relating to items that will be covered by the trust fund but which can no longer be reliably estimated. The remaining reimbursement asset as at 31 December 2012 was $6,442 million and is recorded within other receivables on the balance sheet. The amount of the reimbursement asset is equal to the amount of provisions as at 31 December 2012 that will be covered by the trust fund – see Note 36 in the table under Provisions relating to the Gulf of Mexico oil spill.

Movements in the reimbursement asset are presented in the table below.

			$ million
	2012	2011	2010
At 1 January	**9,875**	9,544	–
Increase in provision for items covered by the trust fund	**1,985**	4,038	12,567
Derecognition of provision for items that cannot be reliably estimated	**(794)**	–	–
Amounts paid directly by the trust fund	**(4,624)**	(3,707)	(3,023)
At 31 December	**6,442**	9,875	9,544
Of which – current	**4,178**	8,233	5,943
– non-current	**2,264**	1,642	3,601

The amount charged or credited in the income statement, before finance costs, related to the trust fund comprises:

			$ million
	2012	2011	2010
Trust fund liability – discounted	**–**	–	19,580
Change in discounting relating to trust fund liability	**–**	43	240
Recognition of reimbursement asset, net	**(1,191)**	(4,038)	(12,567)
Other	**–**	–	8
Total (credit) charge relating to the trust fund	**(1,191)**	(3,995)	7,261

As noted above, the obligation to fund the $20-billion trust fund was recognized in full in 2010, on a discounted basis. In addition, a reimbursement asset was recognized, reflecting the portion of provisions recognized that will be covered by the trust fund. Any new provisions, or increases in provisions that are covered by the trust fund (up to the amount of $20 billion) have no net income statement effect as a reimbursement asset is also recognized, as described above. During 2012, a further net charge of $1,191 million (2011 $4,038 million) was recognized for new, increased and derecognized provisions for items covered by the trust fund with a corresponding increase in the reimbursement asset, resulting in no net income statement effect. The cumulative net charges for provisions, and the associated reimbursement asset, recognized from 2010 to 2012 amounted to $17,796 million. Thus, a further $2,204 million could be provided in subsequent periods for items covered by the trust fund with no net impact on the income statement. Such future increases in amounts provided could arise from adjustments to existing provisions, or from the initial recognition of provisions for items that currently cannot be estimated reliably, namely natural resource damages claims under Oil Pollution Act of 1990 (OPA 90) (other than the estimated costs of the assessment phase and the costs of early restoration agreements referred to below), the cost of business economic loss claims under the PSC settlement not yet received or processed by the DHCSSP, or any other potential litigation (including through excluded parties from the PSC settlement and any obligation in relation to other potential private or governmental litigation). Further information on those items that currently cannot be reliably estimated is provided under Provisions and contingencies below and in Note 43.

2. Significant event – Gulf of Mexico oil spill continued

The $20-billion trust fund may not be sufficient to satisfy all claims under OPA 90 or otherwise that will ultimately be paid.

The Trust agreement does not require BP to make further contributions to the trust fund in excess of the agreed $20 billion should this be insufficient to cover all claims administered by the GCCF and the new court-supervised claims processes, or to settle other items that are covered by the trust fund, as described above. Should the $20-billion trust fund not be sufficient, BP would commence settling legitimate claims and other costs by making payments directly to claimants or directly to the QSFs, as appropriate. In this case, increases in estimated future expenditure above $20 billion would be recognized as provisions with a corresponding charge in the income statement. The provisions would be utilized and derecognized at the point that BP made the payments. Under the terms of the Economic and Property Damages Settlement Agreement, several QSFs were established during 2012. These QSFs each relate to specific elements of the agreement, have and will 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 2012, the cash balances in the Trust and the QSFs amounted to $10,471 million, including $1,847 million remaining in the seafood compensation fund yet to be distributed. Under the terms of the Economic and Property Damage Settlement, the QSFs are subject to certain minimum balances that shall be maintained in the respective funds.

The Economic and Property Damages Settlement with the PSC provides for a transition from the GCCF to the DHCSSP. A transitional claims facility for economic and property damages claims commenced operation in March 2012. The transitional claims facility ceased processing new claims in June 2012. The DHCSSP began processing new claims from claimants under the Economic and Property Damages Settlement. In addition, a separate BP claims programme began processing claims from claimants not in the Economic and Property Damages Settlement Class as determined by the Economic and Property Damages Settlement Agreement or who have requested to opt out of that settlement. Moreover, upon the effective date of the Medical Benefits Class Action Settlement (that is, after any appeals of the final approval of that settlement are exhausted), a separate court-supervised settlement programme will begin paying medical claims and implementing other aspects of the medical benefits settlement, such as the Periodic Medical Consultation Program. In addition, some payments to projects under the Gulf Region Health Outreach Program portion of the Medical Benefits Class Action Settlement have already been made.

BP pledged certain Gulf of Mexico assets, through an overriding royalty interest, as collateral for the obligation to fund the Trust pursuant to an agreement entered into in September 2010. As noted above, in November 2012 BP met its $20-billion funding obligation to the Trust. Upon completion of the funding obligation, the overriding royalty interest provided as collateral terminated pursuant to its terms.

Provisions and contingencies

At 31 December 2012, BP has recorded certain provisions and disclosed certain contingent liabilities as a consequence of the Gulf of Mexico oil spill. These are described below under Oil Pollution Act of 1990 and Other items.

Oil Pollution Act of 1990 (OPA 90)

The claims against BP under OPA 90 fall into three categories: (i) claims by individuals and businesses for removal costs, 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"); (ii) claims by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs ("State and Local Claims"); and (iii) claims by the United States, a State trustee, an Indian tribe trustee, or a foreign trustee for natural resource damages ("Natural Resource Damages claims"). In addition, BP faces civil litigation in which claims for liability under OPA 90 along with other causes of actions, including personal injury claims, are asserted by individuals, businesses and government entities.

Provisions have been recorded for Individual and Business Claims and State and Local Claims, except as noted below. A provision has also been recorded for claims administration costs, natural resource damage assessment costs and costs relating to early natural resource damages restoration agreements. BP considers that it is not possible to measure reliably any obligation in relation to natural resource damage claims (other than the estimated costs of the assessment phase and the costs relating to early restoration agreements), the cost of business economic loss claims under the PSC settlement not yet received or processed by the DHCSSP, or any other potential litigation (including through excluded parties from the PSC settlement and any obligation in relation to other potential private or governmental litigation), fines, or penalties, other than as described above. These items are therefore disclosed as contingent liabilities – see Note 43 for further information.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process established pursuant to the PSC settlement. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the Economic and Property Damages Settlement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. See Note 36 for further information.

The $20-billion trust fund described above is available to satisfy the OPA 90 claims and litigation referred to above. BP's rights and obligations in relation to the trust fund have been recognized and $20 billion, adjusted to take account of the time value of money, was charged to the income statement in 2010.

Other items

Provisions at 31 December 2012 also include amounts in relation to completing the oil spill response, BP's commitment to a 10-year research programme in the Gulf of Mexico, the discounted cost of the agreement with the US government to settle all federal criminal charges, estimated penalties for liability under Clean Water Act Section 311 and estimated legal fees. These are not covered by the trust fund.

The provision does not reflect any amounts in relation to fines and penalties except for those relating to the Clean Water Act, as it is not possible to estimate reliably either the amount or timing of such additional items. BP also considers that it is not possible to measure reliably any obligation in relation to litigation other than as included within the settlement with the PSC as set forth in Note 36 and the settlement with the US government for federal criminal charges. These items are therefore disclosed as contingent liabilities. Further information on provisions is provided below and in Note 36. Further information on contingent liabilities is provided in Note 43.

Provision movements

A provision has been recognized for estimated future expenditure relating to the incident, for items that can be measured reliably at this time, in accordance with BP's accounting policy for provisions, as set out in Note 1.

2. Significant event – Gulf of Mexico oil spill continued

The total amount recognized as an increase in provisions during the year was $6,868 million, including $1,985 million for items covered by the trust fund and $4,883 million for other items (2011 $5,183 million, including $4,038 million for items covered by the trust fund and $1,145 million for other items). In addition, $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 $5,864 million, including payments from the trust fund of $4,624 million and payments made directly by BP of $1,240 million (2011 $6,208 million, including payments from the trust fund of $3,707 million and payments made directly by BP of $2,501 million), and after reclassifications and adjustments for discounting, the remaining provision as at 31 December 2012 was $15,200 million (2011 $15,333 million).

Movements in the provision are presented in the table below.

			$ million
	2012	2011	2010
At 1 January	**15,333**	16,335	–
Increase in provision – items not covered by the trust fund	**4,883**	1,145	17,694
– items covered by the trust fund	**1,985**	4,038	12,567
Derecognition of provision for items that cannot be reliably estimated[a]	**(794)**	–	–
Unwinding of discount	**7**	6	4
Reclassified to other payables	**(350)**	–	–
Change in discount rate	**–**	17	5
Utilization – paid by BP	**(1,240)**	(2,501)	(10,912)
– paid by the trust fund	**(4,624)**	(3,707)	(3,023)
At 31 December	**15,200**	15,333	16,335
Of which – current	**5,449**	9,437	7,938
– non-current	**9,751**	5,896	8,397

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

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. See Note 43 for further information.

Impact upon the group income statement

The group income statement for 2012 includes a pre-tax charge of $5,014 million (2011 pre-tax credit of $3,742 million) in relation to the Gulf of Mexico oil spill. The amount charged to date comprises costs incurred up to 31 December 2012, settlements agreed with the co-owners of the Macondo well and other third parties, estimated obligations for future costs that can be estimated reliably at this time and rights and obligations relating to the trust fund. Finance costs of $19 million (2011 $58 million) reflect the unwinding of the discount on the trust fund liability and provisions. The amount of the provision recognized during the year can be reconciled to the income statement amount as follows:

			$ million
	2012	2011	2010
Net increase in provision	**6,868**	5,183	30,261
Derecognition of provision for items that cannot be reliably estimated	**(794)**	–	–
Change in discount rate relating to provisions	**–**	17	5
Costs charged directly to the income statement	**257**	512	3,339
Trust fund liability – discounted	**–**	–	19,580
Change in discounting relating to trust fund liability	**–**	43	240
Recognition of reimbursement asset, net	**(1,191)**	(4,038)	(12,567)
Settlements credited to the income statement	**(145)**	(5,517)	–
(Profit) loss before interest and taxation	**4,995**	(3,800)	40,858

Costs charged directly to the income statement relate to expenditure prior to the establishment of a provision at the end of the second quarter 2010 and ongoing operating costs of the GCRO. The accounting associated with the recognition of the trust fund liability and the expenditure which will be settled from the trust fund is described above.

2. Significant event – Gulf of Mexico oil spill continued

The total amount in the income statement is analysed in the table below. Costs charged directly to the income statement in 2010 in relation to spill response, environmental and litigation and claims are those that arose prior to recording a provision at the end of the second quarter of that year.

			$ million
	2012	2011	2010
Trust fund liability – discounted	**–**	–	19,580
Change in discounting relating to trust fund liability	**–**	43	240
Recognition of reimbursement asset, net	**(1,191)**	(4,038)	(12,567)
Other	**–**	–	8
Total (credit) charge relating to the trust fund	**(1,191)**	(3,995)	7,261
Spill response – amount provided	**109**	586	10,883
Spill response – costs charged directly to the income statement	**9**	85	2,745
Total charge relating to spill response	**118**	671	13,628
Environmental – amount provided	**801**	1,167	929
Environmental – change in discount rate relating to provisions	**–**	17	5
Environmental – costs charged directly to the income statement	**–**	–	70
Total charge relating to environmental	**801**	1,184	1,004
Litigation and claims – amount provided, net of derecognition of provision	**5,164**	3,430	14,939
Litigation and claims – costs charged directly to the income statement	**–**	–	184
Total charge relating to litigation and claims	**5,164**	3,430	15,123
Clean Water Act penalties – amount provided	**–**	–	3,510
Other costs charged directly to the income statement	**248**	427	332
Settlements credited to the income statement	**(145)**	(5,517)	–
(Profit) loss before interest and taxation	**4,995**	(3,800)	40,858
Finance costs	**19**	58	77
(Profit) loss before taxation	**5,014**	(3,742)	40,935

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 above under Provisions and contingencies.

3. Business combinations

Business combinations in 2012

BP undertook a number of minor business combinations in 2012 for a total consideration of $116 million in cash. The most significant of these was the acquisition of Shell and Cosan Indústria e Commércio's interests in significant aviation fuels assets at seven Brazilian airports in the Downstream segment. Fair value adjustments were made to the acquired assets and liabilities.

Certain measurement period adjustments were recognized in 2012 relating to the Reliance transaction, a business combination undertaken in 2011 – see below for further details.

Business combinations in 2011

BP undertook a number of business combinations in 2011. Total consideration paid in cash amounted to $11.3 billion, offset by cash acquired of $0.4 billion. The fair value of contingent consideration payable amounted to $0.1 billion.

On 30 August 2011, 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. This included the producing KG D6 block. In addition, on 17 November 2011, the companies formed a 50:50 joint venture for the sourcing and marketing of gas in India. This transaction provided BP with access to an emerging market with growth in energy demand; it builds BP's business in natural gas and it represents an important partnership with a leading national energy business.

The transaction was accounted for as a business combination using the acquisition method. During 2012, measurement period adjustments amounted to an overall decrease of $115 million in the net fair value of the identifiable assets and liabilities acquired, an increase of $46 million in the goodwill arising on acquisition and an adjustment to reduce the contingent consideration to nil.

Goodwill of $2,569 million arose on acquisition, attributed to market access and other benefits arising from the business combination.

3. Business combinations continued

The provisional fair values of the identifiable assets and liabilities acquired, as reported at 31 December 2011, are shown in the table below, together with the subsequent measurement period adjustments recognized during 2012.

			$ million
	Final amounts recognized 2012	**Measurement period adjustments 2012**	Provisional amounts recognized 2011
Assets			
Property, plant and equipment	**1,860**	**–**	1,860
Intangible assets	**2,901**	**(69)**	2,970
Inventories	**55**	**–**	55
Prepayments	**5**	**–**	5
Liabilities			
Trade and other payables	**(167)**	**(22)**	(145)
Provisions	**(266)**	**(24)**	(242)
	4,388	**(115)**	4,503
Goodwill arising on acquisition	**2,569**	**46**	2,523
Total consideration	**6,957**	**(69)**	7,026

The consideration for the transaction included $6,957 million in cash, paid in 2011. In addition, contingent consideration of up to $1,800 million, dependent upon exploration success in certain of the interests resulting in the development of commercial discoveries, was agreed.

Transaction costs of $13 million were paid in 2011 and charged within production and manufacturing expenses in the group income statement.

In addition to the Reliance transaction described above, BP undertook a number of other business combinations in 2011. These included the completion of the final part of the transaction with Devon Energy (Devon), the acquisition of Devon's equity stake in a number of assets in Brazil for consideration of $3.6 billion (see below). Additionally, BP's Alternative Energy business acquired Companhia Nacional de Açúcar e Álcool (CNAA) in Brazil for consideration of $0.7 billion and increased its share in the Brazilian biofuels company, Tropical BioEnergia S.A., to 100% by acquiring the remaining 50% for consideration of $71 million. There were a number of other individually insignificant business combinations.

Business combinations in 2010

BP undertook a number of business combinations in 2010 for a total consideration of $3.6 billion, of which $3 billion comprised cash consideration. The most significant acquisition was a transaction in the Upstream segment with Devon, undertaken in a number of stages during 2010 and 2011. This transaction strengthened BP's position in the Gulf of Mexico, enhanced interests in Azerbaijan and facilitated the development of Canadian assets.

On 27 April 2010, BP acquired 100% of Devon's Gulf of Mexico deepwater properties for $1.8 billion. This included a number of exploration properties, Devon's interest in the major Paleogene discovery Kaskida (giving BP a 100% interest in the project), four producing assets and one non-producing asset. As part of the transaction, BP sold to Devon a 50% stake in its Kirby oil sands interests in Alberta, Canada for $500 million and Devon committed to fund an additional $150 million of capital costs on BP's behalf by issuing a promissory note to BP. In addition, the companies formed a 50:50 joint venture, operated by Devon, to pursue the development of the interest. On 16 August 2010, the group acquired Devon's 3.29% (after pre-emption exercised by some of the partners) interest in the BP-operated Azeri-Chirag-Gunashli (ACG) development in the Azerbaijan sector of the Caspian Sea for $1.1 billion, increasing BP's interest to 37.43%.

The business combination was accounted for using the acquisition method. Goodwill of $332 million was recognized on the 2010 part of the Devon transaction. As part of the Devon transaction, the gain on the disposal of the group's 50% interest in the Kirby oil sands in Alberta, Canada amounted to $633 million.

The final part of the Devon transaction, the acquisition of 100% of Devon's equity stake in a number of entities holding all Devon's assets in Brazil for consideration of $3.6 billion, completed in May 2011. Goodwill of $966 million was recognized in 2011 for this part of the transaction.

In addition to the Devon transaction, BP undertook a number of other minor business combinations in 2010, the most significant of which was the acquisition by BP's Alternative Energy business of Verenium Corporation's lignocellulosic biofuels business, for consideration of $98 million.

4. Non-current assets held for sale

As a result of the group's disposal programme, various assets, and associated liabilities, have been presented as held for sale in the group balance sheet at 31 December 2012. The carrying amount of the assets held for sale is $19,315 million, with associated liabilities of $846 million.

The majority of the transactions noted below are subject to post-closing adjustments, which may include adjustments for working capital and adjustments for profits attributable to the purchaser between the agreed effective date and the closing date of the transaction. Such post-closing adjustments may result in the final amounts received by BP from the purchasers differing from the disposal proceeds noted below. Non-current assets held for sale at 31 December 2012 included the following items:

Upstream

On 28 November 2012, BP announced that it had agreed to sell its interests in a number of central North Sea oil and gas fields to TAQA for $1,058 million plus future payments which, dependent on oil price and production, are currently expected to exceed $250 million after tax. The assets included in the sale are 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. The sale is subject to third-party and regulatory approvals and is expected to complete in the second quarter of 2013.

Downstream

On 13 August 2012, BP announced that it had reached agreement to sell its Carson refinery in California and related assets in the region, including marketing and logistics assets, to Tesoro Corporation for $2.5 billion. The assets, and associated liabilities, of the refinery and related assets are classified as held for sale in the group balance sheet at 31 December 2012. Completion is subject to regulatory and other approvals, and the transaction is expected to close by the middle of 2013.

4. Non-current assets held for sale continued

On 1 February 2013, BP announced that it had completed the sale of its Texas City refinery and a portion of its retail and logistics network in the south-eastern US to Marathon Petroleum Corporation for $0.6 billion in relation to the fixed assets, $1.1 billion related to working capital, principally inventory, and a six-year earn-out arrangement, of up to $0.7 billion, based on future margins and refinery throughput. The consideration is subject to post-closing adjustments and will be fair-valued for accounting purposes. The assets, and associated liabilities, of the refinery and related retail and logistics network are classified as held for sale in the group balance sheet at 31 December 2012.

TNK-BP

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. From this date, BP's investment in TNK-BP met the criteria to be classified as an asset held for sale. Consequently, BP ceased equity accounting for its share of TNK-BP's earnings from the date of the announcement. The TNK-BP segment result includes a dividend of $709 million paid by TNK-BP subsequent to the reclassification. BP continues to report its share of TNK-BP's production and reserves until the transaction closes.

On 22 November 2012, BP announced that it, Rosneft and Rosneftegaz – the Russian state-owned parent company of Rosneft – had signed definitive and binding sale and purchase agreements for the sale of BP's 50% interest in TNK-BP to Rosneft and for BP's investment in Rosneft. On completion, the overall effect of the transaction will be that BP will receive $11.6 billion in cash ($12.3 billion previously announced less the $0.7 billion dividend received by BP), subject to closing adjustments, and acquire an 18.5% stake in Rosneft for its stake in TNK-BP. Combined with BP's existing 1.25% shareholding, this will result in BP owning 19.75% of Rosneft. Completion of the transaction is subject to certain customary closing conditions, including governmental, regulatory and anti-trust approvals. Completion is expected to occur in the first half of 2013.

Impairment losses amounting to $2,594 million (2011 $398 million) have been recognized in relation to certain assets classified as held for sale as at 31 December 2012. 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 noted above amounted to approximately $435 million (2011 $166 million). In addition, BP's share of profits of approximately $731 million were not recognized in 2012 as a result of the discontinuance of equity accounting.

Deposits of $632 million ($30 million at 31 December 2011) received in advance of completion of certain of these transactions have been classified as finance debt on the group balance sheet at 31 December 2012.

The major classes of assets and liabilities reclassified as held for sale as at 31 December are as follows:

		$ million
	2012	2011
Assets		
Property, plant and equipment	**3,663**	4,772
Goodwill	**89**	8
Intangible assets	**103**	20
Investments in jointly controlled entities	**108**	122
Investments in associates	**12,322**	38
Loans	**96**	–
Inventories	**2,377**	3,167
Cash	**–**	–
Other current assets	**557**	293
Assets classified as held for sale	**19,315**	8,420
Liabilities		
Trade and other payables	**158**	300
Provisions	**688**	98
Deferred tax liabilities	**–**	140
Liabilities directly associated with assets classified as held for sale	**846**	538

There were accumulated foreign exchange losses of $26 million recognized within other comprehensive income relating to the assets held for sale at 31 December 2012 (2011 nil).

2011

At 31 December 2011, within the Upstream segment, the Canadian natural gas liquids (NGL) business was classified as an asset held for sale and the sale completed in the first half of 2012. The investment in the Phu My 3 plant facility was classified as held for sale in the group balance sheet at 31 December 2011, for which a disposal deposit of $30 million had been received. This disposal did not complete during the year, the deposit was repaid and the assets are no longer classified as held for sale.

Within 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 assets held for sale at 31 December 2011.

5. Disposals and impairment

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

			$ million
	2012	2011	2010
Gains on sale of businesses and fixed assets			
Upstream	**6,504**	3,477	5,267
Downstream	**151**	317	999
Other businesses and corporate	**41**	336	117
	6,696	4,130	6,383

			$ million
	2012	2011	2010
Losses on sale of businesses and fixed assets			
Upstream	**109**	49	196
Downstream	**195**	52	119
Other businesses and corporate	**6**	3	6
	310	104	321
Impairment losses			
Upstream	**3,046**	1,443	1,259
Downstream	**2,892**	599	144
Other businesses and corporate	**320**	58	113
	6,258	2,100	1,516
Impairment reversals			
Upstream	**(289)**	(146)	–
Downstream	**(1)**	–	(141)
Other businesses and corporate	**(3)**	–	(7)
	(293)	(146)	(148)
Impairment and losses on sale of businesses and fixed assets	**6,275**	2,058	1,689

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. At 31 December 2012, BP had announced disposals of $38 billion, excluding the sale of our 50% investment in TNK-BP.

See Note 4 for further information relating to assets held for sale at 31 December 2012.

			$ million
	2012	2011	2010
Proceeds from disposals of fixed assets	**9,991**	3,500	7,492
Proceeds from disposals of businesses, net of cash disposed	**1,455**	(768)	9,462
	11,446	2,732	16,954
By business			
Upstream	**10,667**	1,080	14,392
Downstream	**485**	721	1,840
Other businesses and corporate	**294**	931	722
	11,446	2,732	16,954

Proceeds from disposals for 2012 include a deposit of $632 million received from a counterparty in respect of the disposal of interests in a number of central North Sea oil and gas fields. During 2012, a $30 million disposal deposit held at 31 December 2011 was returned as the sale did not complete. Proceeds from disposals for 2010 included deposits of $6,197 million received from counterparties in respect of disposal transactions in the Upstream segment not completed at 31 December 2010. This included a deposit of $3,530 million received in advance of the expected sale of our interest in Pan American Energy LLC. The repayment of the same amount following the termination of the sale agreement is included in proceeds from disposals for 2011. For further information on disposal transactions not yet completed see Note 4.

Deferred consideration relating to disposals of businesses and fixed assets at 31 December 2012 amounted to $24 million receivable within one year (2011 $117 million and 2010 $562 million) and $90 million receivable after one year (2011 $111 million and 2010 $271 million).

Upstream

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. All these transactions resulted in gains on disposal.

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. All these transactions resulted in gains on disposal.

In 2010, the major transactions were the sale of Permian Basin assets in the US, upstream gas assets in Canada and exploration concessions in Egypt to Apache Corporation. In addition, we sold 50% of our interests in Kirby oil sands in Canada to Devon Energy as part of a business combination described in Note 3. All these transactions resulted in gains on disposal.

5. Disposals and impairment continued

Downstream

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.

In 2010, gains resulted from our disposals of the French retail fuels and convenience business to Delek Europe, the fuels marketing business in Botswana to Puma Energy, certain non-strategic pipelines and terminals in the US, our interests in ethylene and polyethylene production in Malaysia to Petronas and our interest in a futures exchange. Losses resulted from the disposal of a number of assets in the segment portfolio.

Other businesses and corporate

In 2012, a gain arose on the additional cash consideration falling due on the contribution of assets in 2011 to the jointly controlled entity Flat Ridge 2 Wind Holdings LLC on meeting project milestones, whilst maintaining our 50% equity interests. In addition, disposal proceeds included a return of capital of $190 million in the jointly controlled entities Flat Ridge 2 Wind Holdings LLC and Mehoopany Wind Holdings LLC following the drawdown of project debt which did not change our percentage interest in either entity.

In 2011, we disposed of our aluminium business in the US which resulted in a gain. We also contributed assets in exchange for cash and 50% equity interests in the jointly controlled entities Mehoopany Wind Holdings LLC and Flat Ridge 2 Wind Holdings LLC.

In 2010, we disposed of our 35% interest in K-Power, a gas-fired power asset in South Korea, and contributed assets in exchange for a 50% equity interest in a jointly controlled entity, Cedar Creek II Holdings LLC and cash. In addition, there was a return of capital in the jointly controlled entities Fowler II Holdings LLC and Cedar Creek II Holdings LLC which did not change our percentage interest in either entity.

Summarized financial information relating to the sale of businesses is shown in the table below. Information relating to sales of fixed assets which are not related to businesses is excluded from the table.

			$ million
	2012	2011	2010
Non-current assets	**610**	2,085	2,319
Current assets	**570**	1,008	310
Non-current liabilities	**(263)**	(212)	(303)
Current liabilities	**(232)**	(611)	(124)
Total carrying amount of net assets disposed	**685**	2,270	2,202
Recycling of foreign exchange on disposal	**(15)**	8	(52)
Costs on disposal	**39**	17	18
	709	2,295	2,168
Profit (loss) on sale of businesses[a]	**675**	2,232	1,968
Total consideration	**1,384**	4,527	4,136
Consideration received (receivable)[b]	**(75)**	11	20
Proceeds from the sale of businesses related to completed transactions	**1,309**	4,538	4,156
Deposits received (repaid) related to assets classified as held for sale[c]	**146**	(3,530)	5,306
Disposals completed in relation to which deposits had been received in prior year	**–**	(1,776)	–
Proceeds from the sale of businesses[d]	**1,455**	(768)	9,462

[a] 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 associate TNK-BP.
[b] Consideration received from prior year business disposals or not yet received from current year disposals.
[c] 2010 included a deposit received in advance of $3,530 million in respect of the expected sale of our interest in Pan American Energy LLC; 2011 includes the repayment of the same amount following the termination of the sale agreement.
[d] Net of cash and cash equivalents disposed of $4 million (2011 $14 million and 2010 $55 million).

Impairment

In assessing whether a write-down is required in the carrying value of a potentially impaired intangible asset, item of property, plant and equipment or an equity-accounted investment, the asset's carrying value is compared with its recoverable amount. The recoverable amount is the higher of the asset's fair value less costs to sell and value in use. Unless indicated otherwise, the recoverable amount used in assessing the impairment losses described below is value in use. The group estimates value in use using a discounted cash flow model. The future cash flows are adjusted for risks specific to the asset and are discounted using a pre-tax discount rate. This 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 2012, the rates used ranged from 12-14% (2011 12-14%). The rate applied in each country is reassessed each year. In certain circumstances an impairment assessment may be carried out using fair value less costs to sell as the recoverable amount when, for example, a recent market transaction for a similar asset has taken place.

Upstream

During 2012, the Upstream segment recognized impairment losses of $3,046 million. The main elements were a $1,082-million write-down to fair value less costs to sell based on recent market transactions of our interests in the Fayetteville and Woodford shale gas assets in the US, due to reserves revisions; 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.

5. Disposals and impairment continued

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.

During 2010, the Upstream segment recognized impairment losses of $1,259 million. The main elements were the $501-million write-down of assets in the Gulf of Mexico, triggered by an increase in the decommissioning provision as a result of new regulations in the US relating to idle infrastructure; impairments of oil and gas properties in the Gulf of Mexico and onshore North America of $310 million and $80 million respectively, as a result of decisions to dispose of assets at a price lower than the assets' carrying values; a $341-million write-down of accumulated costs in Sakhalin, Russia, triggered by a change in the outlook on the future recoverability of the investment; and several other individually insignificant impairment losses amounting to $27 million in total.

Downstream

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. Impairment losses of $398 million related to assets classified as held for sale. Other impairment losses were also recognized relating to retail churn in Europe and other minor asset disposals amounting to $201 million in total.

During 2010, the Downstream segment recognized impairment losses amounting to $144 million relating to retail churn in Europe and other minor asset disposals. These losses were largely offset by the reversal of a previously recognized impairment loss of $141 million relating to the investment in our jointly controlled entity China American Petrochemical Company resulting from a change in market conditions.

Other businesses and corporate

During 2012, 2011 and 2010, Other businesses and corporate recognized impairment losses totalling $318 million, $58 million and $113 million respectively related to various assets in the Alternative Energy 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. Segmental analysis

The group's organizational structure reflects the various activities in which BP is engaged. In 2012, BP had three reportable segments: Upstream, Downstream and TNK-BP. BP's activities in low-carbon energy are managed through our Alternative Energy business, which is reported in Other businesses and corporate.

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). The segment is organized into three functional divisions – Exploration, Developments and Production – integrated through a Strategy and Integration organization.

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.

From 1 January 2012, the group's investment in TNK-BP is reported as a separate operating segment, rather than within the Upstream segment, reflecting the way in which the investment is managed. 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 and the transaction is expected to complete in the first half of 2013. See Note 4 for further information.

Other businesses and corporate comprises the Alternative Energy business, Shipping, Treasury (which in the segmental analysis includes all of the group's cash, cash equivalents and associated interest income), and corporate activities worldwide. It also included the group's aluminium business until its disposal during 2011. The Alternative Energy business is an operating segment that has been aggregated with the other activities within Other businesses and corporate as it does not meet the materiality thresholds for separate segment reporting.

In 2010, following the Gulf of Mexico incident, we established the Gulf Coast Restoration Organization (GCRO) and equipped it with dedicated resources and capabilities to manage all aspects of our response to the incident. This organization 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.

[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.

6. Segmental analysis continued

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.

							$ million
							2012
By business	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	71,940	346,491	–	1,985	–	(44,836)	375,580
Less: sales and other operating revenues between businesses	(42,572)	(1,365)	–	(899)	–	44,836	–
Third party sales and other operating revenues	29,368	345,126	–	1,086	–	–	375,580
Equity-accounted earnings	1,054	446	2,986	(67)	–	–	4,419
Interest income	112	27	–	104	–	–	243
Segment results							
Replacement cost profit (loss) before interest and taxation	22,474	2,846	3,373	(2,795)	(4,995)	(576)	20,327
Inventory holding losses[a]	(104)	(487)	(3)	–	–	–	(594)
Profit (loss) before interest and taxation	22,370	2,359	3,370	(2,795)	(4,995)	(576)	19,733
Finance costs							(1,125)
Net finance income relating to pensions and other post-retirement benefits							201
Profit before taxation							18,809
Other income statement items							
Depreciation, depletion and amortization	10,309	1,769	–	403	–	–	12,481
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 and derecognition of provisions, including change in discount rate	898	142	–	505	6,074	–	7,619
Segment assets							
Equity-accounted investments	11,084	6,567	–	1,071	–	–	18,722
Additions to non-current assets	21,935	5,045	–	1,419	–	–	28,399
Additions to other investments							33
Element of acquisitions not related to non-current assets							(72)
Additions to decommissioning asset							(4,018)
Capital expenditure and acquisitions	17,859	5,048	–	1,435	–	–	24,342

[a] See explanation of inventory holding gains and losses on page 203.

6. Segmental analysis continued

By business	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	75,475	344,116	–	2,957	–	(47,031)	375,517
Less: sales and other operating revenues between businesses	(44,766)	(1,396)	–	(869)	–	47,031	–
Third party sales and other operating revenues	30,709	342,720	–	2,088	–	–	375,517
Equity-accounted earnings	1,281	787	4,185	(33)	–	–	6,220
Interest income	(4)	25	–	146	–	–	167
Segment results							
Replacement cost profit (loss) before interest and taxation	26,366	5,474	4,134	(2,478)	3,800	(113)	37,183
Inventory holding gains[a]	81	2,487	51	15	–	–	2,634
Profit (loss) before interest and taxation	26,447	7,961	4,185	(2,463)	3,800	(113)	39,817
Finance costs							(1,246)
Net finance income relating to pensions and other post-retirement benefits							263
Profit before taxation							38,834
Other income statement items							
Depreciation, depletion and amortization	8,693	2,117	–	325	–	–	11,135
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	371	–	942	5,200	–	6,726
Segment assets							
Equity-accounted investments	11,041	6,731	10,013	1,024	–	–	28,809
Additions to non-current assets	34,527	4,128	–	1,864	–	–	40,519
Additions to other investments							25
Element of acquisitions not related to non-current assets							(1,089)
Additions to decommissioning asset							(7,937)
Capital expenditure and acquisitions	25,535	4,130	–	1,853	–	–	31,518

[a] See explanation of inventory holding gains and losses on page 203.

6. Segmental analysis continued

$ million

By business	Upstream	Downstream	TNK-BP	Other businesses and corporate	Gulf of Mexico oil spill response	Consolidation adjustment and eliminations	Total group
							2010
Segment revenues							
Sales and other operating revenues	66,266	266,751	–	3,328	–	(39,238)	297,107
Less: sales and other operating revenues between businesses	(37,049)	(1,358)	–	(831)	–	39,238	–
Third party sales and other operating revenues	29,217	265,393	–	2,497	–	–	297,107
Equity-accounted earnings	1,362	755	2,617	23	–	–	4,757
Interest income	83	46	–	109	–	–	238
Segment results							
Replacement cost profit (loss) before interest and taxation	28,269	5,555	2,617	(1,516)	(40,858)	447	(5,486)
Inventory holding gains[a]	84	1,684	–	16	–	–	1,784
Profit (loss) before interest and taxation	28,353	7,239	2,617	(1,500)	(40,858)	447	(3,702)
Finance costs							(1,170)
Net finance income relating to pensions and other post-retirement benefits							47
Loss before taxation							(4,825)
Other income statement items							
Depreciation, depletion and amortization	8,616	2,258	–	290	–	–	11,164
Impairment losses	1,259	144	–	113	–	–	1,516
Impairment reversals	–	(141)	–	(7)	–	–	(148)
Fair value loss on embedded derivatives	309	–	–	–	–	–	309
Charges for provisions, net of write-back of unused provisions, including change in discount rate	303	275	–	206	30,266	–	31,050
Segment assets							
Equity-accounted investments	10,384	7,043	9,995	840	–	–	28,262
Additions to non-current assets	20,113	4,030	–	1,226	–	–	25,369
Additions to other investments							20
Element of acquisitions not related to non-current assets							(401)
Additions to decommissioning asset							(1,972)
Capital expenditure and acquisitions	17,753	4,029	–	1,234	–	–	23,016

[a] See explanation of inventory holding gains and losses on page 203.

6. Segmental analysis continued

By geographical area	US	Non-US	Total
			$ million
			2012
Revenues			
Third party sales and other operating revenues[a]	**130,940**	**244,640**	**375,580**
Results			
Replacement cost profit before interest and taxation	**180**	**20,147**	**20,327**
Non-current assets			
Other non-current assets[b c]	**68,295**	**107,586**	**175,881**
Other investments			**2,702**
Loans			**695**
Trade and other receivables			**4,754**
Derivative financial instruments			**4,294**
Deferred tax assets			**874**
Defined benefit pension plan surpluses			**12**
Total non-current assets			**189,212**
Capital expenditure and acquisitions	**10,410**	**13,932**	**24,342**

[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.

By geographical area	US	Non-US	Total
			$ million
			2011
Revenues			
Third party sales and other operating revenues[a]	131,488	244,029	375,517
Results			
Replacement cost profit before interest and taxation	10,202	26,981	37,183
Non-current assets			
Other non-current assets[b c]	68,191	113,773	181,964
Other investments			2,633
Loans			884
Trade and other receivables			4,337
Derivative financial instruments			5,038
Deferred tax assets			611
Defined benefit pension plan surpluses			17
Total non-current assets			195,484
Capital expenditure and acquisitions	8,830	22,688	31,518

[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.

By geographical area	US	Non-US	Total
			$ million
			2010
Revenues			
Third party sales and other operating revenues[a]	101,768	195,339	297,107
Results			
Replacement cost profit (loss) before interest and taxation	(30,087)	24,601	(5,486)
Non-current assets			
Other non-current assets[b c]	67,000	95,255	162,255
Other investments			1,689
Loans			894
Trade and other receivables			6,298
Derivative financial instruments			4,210
Deferred tax assets			528
Defined benefit pension plan surpluses			2,176
Total non-current assets			178,050
Capital expenditure and acquisitions	10,370	12,646	23,016

[a] Non-US region includes UK $62,794 million.
[b] Non-US region includes UK $16,650 million.
[c] Excluding financial instruments, deferred tax assets and defined benefit pension plan surpluses.

7. Interest and other income

	2012	2011	2010
			$ million
Interest income			
Interest income from available-for-sale financial assets[a]	**14**	21	23
Interest income from loans and receivables[a]	**62**	101	88
Interest from loans to equity-accounted entities	**36**	32	36
Other interest	**131**	13	91
	243	167	238
Other income			
Dividend income from available-for-sale financial assets[a]	**51**	29	37
Other income[ab]	**1,296**	400	406
	1,347	429	443
	1,590	596	681

[a] Total interest and other income related to financial instruments amounted to $197 million (2011 $172 million and 2010 $206 million).
[b] 2012 includes $709 million of dividends received from TNK-BP. See Note 4 for further information.

8. Production and similar taxes

	2012	2011	2010
			$ million
US	**1,472**	1,854	1,093
Non-US	**6,686**	6,426	4,151
	8,158	8,280	5,244

9. Depreciation, depletion and amortization

By business	2012	2011	2010
			$ million
Upstream			
US	**3,437**	3,201	3,751
Non-US	**6,872**	5,492	4,865
	10,309	8,693	8,616
Downstream			
US	**562**	840	955
Non-US[a]	**1,207**	1,277	1,303
	1,769	2,117	2,258
Other businesses and corporate			
US	**213**	151	140
Non-US	**190**	174	150
	403	325	290
By geographical area			
US	**4,212**	4,192	4,846
Non-US	**8,269**	6,943	6,318
	12,481	11,135	11,164

[a] Non-US area includes the UK-based international activities of Downstream.

10. Impairment review of goodwill

Goodwill at 31 December	2012	2011
		$ million
Upstream	**7,533**	7,931
Downstream	**4,168**	4,014
Other businesses and corporate	**160**	155
	11,861	12,100

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 held 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 any information about the fair value of a cash-generating unit, the recoverable amount is deemed to be the value in use.

10. Impairment review of goodwill continued

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 2012 (2011 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
	2012	2011
Goodwill	**7,533**	7,931
Excess of recoverable amount over carrying amount	**26,614**	49,247

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. 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 and operating costs for the first four years and expected hydrocarbon production profiles up to 2020 are derived from the business segment plan. Estimated production quantities 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 resource volumes approved as part of BP's centrally-controlled process for the estimation of proved reserves and total resources. Consistent with prior years, the 2012 review for impairment was carried out during the fourth quarter.

The table above shows the carrying amount of the goodwill for the segment and the excess of the recoverable amount over the carrying amount (the headroom). Consistent with prior periods, midstream and intangible oil and gas assets were excluded from the headroom calculation.

The Brent oil price assumption used in the impairment review of goodwill is shown in the table below.

						2012
	2013	**2014**	**2015**	**2016**	**2017**	**2018 and thereafter**
Brent oil price ($/bbl)	**105**	**100**	**96**	**93**	**91**	**90**

						2011
	2012	2013	2014	2015	2016	2017 and thereafter
Brent oil price ($/bbl)	106	101	97	94	92	90

Key assumptions for oil and gas prices for the first five years were derived from forward price curves in the fourth quarter. Prices in 2018 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. A change in any one variable will impact multiple other inputs to the calculation such that the relationship between any variables will not be linear. In order to simplify the sensitivity calculations they were performed assuming a change to the variable being tested only. A detailed calculation on any given change in assumptions may therefore produce a different result.

It was estimated that if the oil price assumption for all future years was around 12% lower than the current assumption for 2018 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 was estimated that no reasonably possible change in the long-term price of natural gas would cause the headroom to be reduced to zero.

Estimated production volumes are based on detailed data for the fields and take into account development plans for the fields 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 563mmboe per year. In 2012, it was estimated that if this production were to be reduced by around 7% for the whole of this period then this would cause the recoverable amount to be equal to the carrying amount of goodwill and related non-current assets of the segment.

Management believes that currently there is no reasonably possible change in discount rate that would cause the carrying amount to exceed the recoverable amount.

10. Impairment review of goodwill continued

Downstream

								$ million
				2012				2011
	Rhine FVC	**Lubricants**	**Other**	**Total**	Rhine FVC	Lubricants	Other	Total
Goodwill	**627**	**3,441**	**100**	**4,168**	618	3,284	112	4,014
Excess of recoverable amount over carrying amount	**2,178**	**n/a**	**n/a**	**n/a**	2,264	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 $12.30 per barrel and 246mmbbl per year (2011 $11.35 per barrel and 257mmbbl 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 (2011 cash flows beyond the five-year plan period were extrapolated using a nominal 4% growth rate).

	2012
Sensitivity analysis	
Sensitivity of value in use to a change in refinery margins of $1 per barrel ($ billion)	**1.5**
Adverse change in refinery margins to reduce recoverable amount to carrying amount ($ per barrel)	**1.4**
Sensitivity of value in use to a 5% change in production volume ($ billion)	**0.9**
Adverse change in throughput volume to reduce recoverable amount to carrying amount (million barrels per year)	**30**
Sensitivity of value in use to a change in the discount rate of 1% ($ billion)	**0.6**
Discount rate to reduce recoverable amount to carrying amount	**16%**

Lubricants

As permitted by IAS 36, the detailed calculations of the Lubricants unit's recoverable amount performed in the most recent detailed calculation in 2009 were used for the 2012 impairment test as the criteria in that standard were considered satisfied: the headroom was substantial in 2009; there have been no significant changes in the assets and liabilities; and the likelihood that the recoverable amount would be less than the carrying amount at the time was remote.

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

11. Distribution and administration expenses

			$ million
	2012	2011	2010
Distribution	**11,561**	12,416	11,393
Administration	**1,796**	1,542	1,162
	13,357	13,958	12,555

12. Currency exchange gains and losses

			$ million
	2012	2011	2010
Currency exchange losses (gains) charged (credited) to the income statement[a]	**113**	(70)	218

[a] Excludes exchange gains and losses arising on financial instruments measured at fair value through profit or loss.

13. Research and development

			$ million
	2012	2011	2010
Expenditure on research and development	**674**	636	780

14. Operating leases

In the case of an operating lease entered into by BP as the operator of a jointly controlled asset, 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 venture partners, whether the joint venture partners have co-signed the lease or not. Where BP is not the operator of a jointly controlled asset, 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
	2012	2011	2010
Minimum lease payments	**5,255**	4,866	5,371
Contingent rentals	**(79)**	(97)	(60)
Sub-lease rentals	**(228)**	(153)	(121)
	4,948	4,616	5,190

The future minimum lease payments at 31 December 2012, before deducting related rental income from operating sub-leases of $271 million (2011 $566 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	**2012**	2011
Payable within		
1 year	**4,531**	4,182
2 to 5 years	**9,733**	8,346
Thereafter	**4,195**	3,544
	18,459	16,072

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 spot-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 2012, the future minimum lease payments relating to drilling rigs amounted to $8,527 million (2011 $6,292 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.

15. 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
	2012	2011	2010
Exploration and evaluation costs			
Exploration expenditure written off	**745**	1,024	375
Other exploration costs	**730**	496	468
Exploration expense for the year	**1,475**	1,520	843
Intangible assets – exploration and appraisal expenditure	**22,849**	19,887	13,126
Liabilities	**287**	306	157
Net assets	**22,562**	19,581	12,969
Capital expenditure	**5,137**	8,911	6,422
Net cash used in operating activities	**729**	496	468
Net cash used in investing activities	**4,971**	8,556	6,428

16. Auditor's remuneration

Fees – Ernst & Young	2012	2011	2010
			$ million
The audit of the company annual accounts[a]	**24**	24	25
The audit of accounts of any subsidiaries of the company	**9**	11	12
Total audit	**33**	35	37
Audit-related assurance services[b]	**13**	12	14
Total audit and audit-related assurance services	**46**	47	51
Taxation compliance services	**2**	1	1
Taxation advisory services	**2**	1	1
Services relating to corporate finance transactions	**2**	4	–
Other assurance services	**1**	1	1
Total non-audit or non-audit-related assurance services	**7**	7	3
Services relating to BP pension plans[c]	**1**	1	1
	54	55	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 $50,000 (2011 $108,000 and 2010 $300,000).

2012 includes $2 million of additional fees for 2011, and 2011 includes $1 million of additional fees for 2010. Auditor's 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 $54 million (2011 $55 million and 2010 $55 million) is required to be presented as follows: audit $33 million (2011 $35 million and 2010 $37 million); other audit-related services $13 million (2011 $12 million and 2010 $14 million); tax $4 million (2011 $2 million and 2010 $2 million); and all other fees $4 million (2011 $6 million and 2010 $2 million).

17. Finance costs

	2012	2011	2010
			$ million
Interest payable	**1,220**	1,135	955
Capitalized at 2.25% (2011 2.63% and 2010 2.75%)[a]	**(378)**	(347)	(254)
Unwinding of discount on provisions[b]	**140**	243	234
Unwinding of discount on other payables[b]	**143**	215	235
	1,125	1,246	1,170

[a] Tax relief on capitalized interest is $93 million (2011 $107 million and 2010 $71 million).
[b] Unwinding of discount on provisions relating to the Gulf of Mexico oil spill was $7 million (2011 $6 million and 2010 $4 million) and unwinding of discount on other payables relating to the Gulf of Mexico oil spill was $12 million (2011 $52 million and 2010 $73 million). See Note 2 for further information on the financial impacts of the Gulf of Mexico oil spill.

18. Taxation

Tax on profit

	2012	2011	2010
			$ million
Current tax			
Charge for the year	**6,632**	7,477	6,766
Adjustment in respect of prior years	**252**	111	(74)
	6,884	7,588	6,692
Deferred tax			
Origination and reversal of temporary differences in the current year	**212**	5,664	(8,157)
Adjustment in respect of prior years	**(103)**	(515)	(36)
	109	5,149	(8,193)
Tax charge (credit) on profit (loss)	**6,993**	12,737	(1,501)

Tax included in other comprehensive income[a]

	2012	2011	2010
			$ million
Current tax	**2**	(10)	(107)
Deferred tax	**(448)**	(1,649)	244
	(446)	(1,659)	137

[a] See Note 39 for further information.

18. Taxation continued

Tax included directly in equity

			$ million
	2012	2011	2010
Current tax	**(10)**	–	(37)
Deferred tax	**4**	(7)	64
	(6)	(7)	27

Reconciliation of the effective tax rate

The following table provides a reconciliation of the UK statutory corporation tax rate to the effective tax rate of the group on profit or loss before taxation. With effect from 1 April 2012 the UK statutory corporation tax rate reduced from 26% to 24% on profits arising from activities outside the North Sea.

For 2010, the items presented in the reconciliation are distorted as a result of the overall tax credit for the year and the loss before taxation. In order to provide a more meaningful analysis of the effective tax rate for 2010, the table also presents separate reconciliations for the group excluding the impacts of the Gulf of Mexico oil spill, and for the impacts of the Gulf of Mexico oil spill in isolation.

					$ million
	2012	2011	2010 excluding impacts of Gulf of Mexico oil spill	2010 impacts of Gulf of Mexico oil spill	2010
Profit (loss) before taxation	**18,809**	38,834	36,110	(40,935)	(4,825)
Tax charge (credit) on profit (loss)	**6,993**	12,737	11,393	(12,894)	(1,501)
Effective tax rate	**37%**	33%	32%	31%	31%

					% of profit or loss before taxation
UK statutory corporation tax rate	**24**	26	28	28	28
Increase (decrease) resulting from					
UK supplementary and overseas taxes at higher or lower rates[a]	**11**	14	9	7	(4)
Tax reported in equity-accounted entities	**(5)**	(3)	(3)	–	23
Adjustments in respect of prior years	**1**	(1)	–	–	2
Movements in losses not recognized	**–**	–	–	–	1
Tax incentives for investment	**(2)**	(1)	(1)	–	9
Gulf of Mexico oil spill non-deductible costs	**8**	–	–	(4)	(30)
Permanent differences relating to disposals	**–**	(2)	(1)	–	5
Other	**–**	–	–	–	(3)
Effective tax rate	**37**	33	32	31	31

[a] For 2012, the jurisdictions which contributed significantly to this item were Angola, with an applicable statutory tax rate of 50%, the UK, with an applicable statutory tax rate of 62% for North Sea activities, and Trinidad & Tobago, with an applicable statutory tax rate of 55%.

Deferred tax

					$ million
	Income statement			Balance sheet	
	2012	2011[a]	2010[a]	**2012**	2011[a]
Deferred tax liability					
Depreciation	**(121)**	4,738	1,304	**31,839**	32,119
Pension plan surpluses	**–**	–	38	**–**	–
Other taxable temporary differences	**(2,240)**	149	1,178	**3,681**	5,704
	(2,361)	4,887	2,520	**35,520**	37,823
Deferred tax asset					
Pension plan and other post-retirement benefit plan deficits	**160**	388	179	**(3,389)**	(2,872)
Decommissioning, environmental and other provisions	**1,872**	(1,443)	(8,210)	**(12,705)**	(14,743)
Derivative financial instruments	**(7)**	24	(56)	**(281)**	(274)
Tax credits	**1,802**	(401)	(1,088)	**(714)**	(2,549)
Loss carry forward	**(912)**	(218)	24	**(2,209)**	(1,295)
Other deductible temporary differences	**(445)**	1,912	(1,562)	**(2,032)**	(1,623)
	2,470	262	(10,713)	**(21,330)**	(23,356)
Net deferred tax charge (credit) and net deferred tax liability	**109**	5,149	(8,193)	**14,190**	14,467
Of which – deferred tax liabilities				**15,064**	15,078
– deferred tax assets				**874**	611

[a] Certain comparative amounts shown in the analysis of deferred tax by category of temporary difference have been reclassified. There is no change to the tax amounts reported in the income statement, balance sheet or cash flow statement.

18. Taxation continued

Analysis of movements during the year in the net deferred tax liability	2012	2011
		$ million
At 1 January	**14,467**	10,380
Exchange adjustments	**(33)**	55
Charge for the year on profit	**109**	5,149
Credit for the year in other comprehensive income	**(448)**	(1,649)
Charge (credit) for the year in equity	**4**	(7)
Acquisitions	**11**	692
Reclassified as assets/liabilities held for sale	**48**	(140)
Deletions	**32**	(13)
At 31 December	**14,190**	14,467

Deferred tax assets are recognized 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.

At 31 December 2012, the group had approximately $6.8 billion (2011 $4.6 billion) of carry-forward tax losses that would be available to offset against future taxable profit. A deferred tax asset has been recognized in respect of $6.0 billion of these losses (2011 $3.8 billion). No deferred tax asset has been recognized in respect of $0.8 billion of losses (2011 $0.8 billion). In 2012 no current tax benefit arose relating to losses utilized on which a deferred tax asset had not previously been recognized (2011 $0.1 billion). Substantially all the tax losses have no fixed expiry date.

At 31 December 2012, the group had approximately $19.0 billion of unused tax credits, predominantly in the UK and US (2011 $18.2 billion). At 31 December 2012, a deferred tax asset of $0.7 billion has been recognized in respect of unused tax credits (2011 $2.5 billion). No deferred tax asset has been recognized in respect of $18.3 billion of tax credits (2011 $15.7 billion). In 2012 a current tax benefit of $0.4 billion arose relating to tax credits utilized on which a deferred tax asset had not previously been recognized (2011 $0.1 billion). Also in 2012, a deferred tax benefit of $0.1 billion arose relating to the recognition of previously unrecognized tax credits (2011 nil). The UK tax credits, arising in overseas branches of UK entities, with no associated deferred tax asset, amount to $16.0 billion (2011 $13.0 billion) and have no fixed expiry date. These credits arise in branches predominantly based in high tax rate jurisdictions so are unlikely to have value in the future as UK taxes on these overseas branches are largely mitigated by the double tax relief on the overseas tax. The US tax credits with no associated deferred tax asset, amounting to $2.3 billion (2011 $2.7 billion), expire 10 years after generation and will all expire in the period 2014-2021.

The group had other unrecognized deferred tax assets at 31 December 2012 of $1.8 billion (2011 $1.1 billion), of which $1.3 billion arose in the UK (2011 $0.9 billion), which have not been recognized due to uncertainty over future recovery.

The group recognized significant costs in 2010 in relation to the Gulf of Mexico oil spill and in 2011 recognized certain recoveries relating to the incident as well as further costs. In 2012, the group has recognized further costs, including costs relating to the settlement of all criminal and securities claims with the US government which are not tax deductible. Tax has been calculated on the expenditures that are expected to qualify for tax relief, and on the recoveries, at the US statutory tax rate. A deferred tax asset has been recognized in respect of provisions for future expenditure that are expected to qualify for tax relief, included under the heading decommissioning, environmental and other provisions in the table above.

The other major components of temporary differences at the end of 2012 relate to tax depreciation, provisions, US inventory holding gains (classified as other taxable temporary differences) and pension and other post-retirement benefit plan deficits.

During 2012, our method of accounting, for tax purposes, for oil and gas inventory in the US has changed from the last-in first-out (“LIFO”) basis to the first-in first-out (“FIFO”) basis. This has accelerated the taxation of inventory holding gains and reduced the taxable temporary difference in respect of this item.

At 31 December 2012, the group had $0.5 billion (2011 $0.1 billion) of taxable temporary differences associated with investments in subsidiaries and equity-accounted entities for which deferred tax liabilities have not been recognized on the basis that the group is able to control the timing of the reversal of the temporary differences and it is not probable that the temporary differences will reverse in the foreseeable future.

In 2012, legislation to restrict relief for UK decommissioning expenditure in the North Sea from 62% to 50% was enacted and increased the deferred tax charge in the income statement by $289 million, of which $256 million relates to the revaluation of the deferred tax balance at 1 January 2012. In 2011, the enactment of a 12% increase in the UK supplementary charge on oil and gas production activities in the North Sea raised the overall corporation tax rate applicable to North Sea activities to 62%. This rate change increased the deferred tax charge in the 2011 income statement by $713 million, of which $683 million related to the revaluation of the deferred tax balance at 1 January 2011.

Also in 2012, the enactment of a further 2% reduction in the rate of UK corporation tax to 23% with effect from 1 April 2013 on profits arising from activities outside the North Sea reduced the deferred tax charge in the income statement by $165 million. In 2011, the enactment of a 2% reduction in the rate of UK corporation tax to 25% with effect from 1 April 2011 similarly reduced the deferred tax charge in the income statement by $120 million.

19. Dividends

The quarterly dividend expected to be paid on 28 March 2013 in respect of the fourth quarter 2012 is 9 cents per ordinary share ($0.54 per American Depositary Share (ADS)). The corresponding amount in sterling will be announced on 18 March 2013. 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		
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Dividends announced and paid in cash									
Preference shares							**2**	2	2
Ordinary shares									
March	**5.096**	4.3372	8.679	**8**	7	14	**1,211**	808	2,625
June	**5.150**	4.2809	–	**8**	7	–	**1,448**	794	–
September	**5.017**	4.3160	–	**8**	7	–	**1,417**	1,224	–
December	**5.589**	4.4694	–	**9**	7	–	**1,216**	1,244	–
	20.852	17.4035	8.679	**33**	28	14	**5,294**	4,072	2,627
Dividend announced, payable in March 2013				**9**			**1,724**		

19. Dividends continued

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

	2012	2011	2010
Number of shares issued (thousand)	**138,406**	165,601	–
Value of shares issued ($ million)	**982**	1,219	–

The financial statements for the year ended 31 December 2012 do not reflect the dividend announced on 5 February 2013 and expected to be paid in March 2013; this will be treated as an appropriation of profit in the year ended 31 December 2013.

20. Earnings per ordinary share

			Cents per share
	2012	2011	2010
Basic earnings per share	**60.86**	135.93	(19.81)
Diluted earnings per share	**60.45**	134.29	(19.81)

Basic earnings per ordinary share amounts are calculated by dividing the profit or loss for the year attributable to ordinary shareholders by the weighted average number of ordinary shares outstanding during the year. The average number of shares outstanding excludes treasury shares and the shares held by the Employee Share Ownership Plans (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 number of shares that are potentially issuable in connection with employee share-based payment plans using the treasury stock method. If the inclusion of potentially issuable shares would decrease the loss per share, the potentially issuable shares are excluded from the diluted earnings per share calculation.

			$ million
	2012	2011	2010
Profit (loss) attributable to BP shareholders	**11,582**	25,700	(3,719)
Less: dividend requirements on preference shares	**2**	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	**11,580**	25,698	(3,721)

			Shares thousand
	2012	2011	2010
Basic weighted average number of ordinary shares	**19,027,929**	18,904,812	18,785,912
Potential dilutive effect of ordinary shares issuable under employee share-based payment plans	**129,959**	231,388	211,895
	19,157,888	19,136,200	18,997,807

The number of ordinary shares outstanding at 31 December 2012, 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 19,119,756,993. Between 31 December 2012 and 19 February 2013, the latest practicable date before the completion of these financial statements, there was a net increase of 46,285,758 in the number of ordinary shares outstanding as a result of share issues in relation to employee share-based payment plans. The number of potential ordinary shares issuable in relation to employee share-based payment plans was 112,118,647 at 31 December 2012. There has been a net decrease of 42,238,872 in the number of potential ordinary shares between 31 December 2012 and 19 February 2013.

21. 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 2012	**3,099**	**2,846**	**175,874**	**35,709**	**3,095**	**12,753**	**8,611**	**241,987**
Exchange adjustments	**73**	**12**	**–**	**229**	**29**	**8**	**272**	**623**
Additions	**120**	**387**	**15,709**	**4,248**	**312**	**902**	**533**	**22,211**
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)**	**(532)**	**(3,460)**	**(758)**	**(135)**	**(70)**	**(355)**	**(5,406)**
At 31 December 2012	**3,196**	**2,713**	**170,063**	**39,287**	**3,301**	**13,436**	**9,059**	**241,055**
Depreciation								
At 1 January 2012	**510**	**1,372**	**91,994**	**14,266**	**1,911**	**8,149**	**4,571**	**122,773**
Exchange adjustments	**8**	**12**	**–**	**165**	**24**	**6**	**151**	**366**
Charge for the year	**33**	**122**	**9,658**	**1,242**	**286**	**320**	**504**	**12,165**
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)**	**(2,457)**	**(394)**	**(134)**	**(10)**	**(315)**	**(3,880)**
At 31 December 2012	**513**	**982**	**87,965**	**15,736**	**2,087**	**8,409**	**4,915**	**120,607**
Net book amount at 31 December 2012	**2,683**	**1,731**	**82,098**	**23,551**	**1,214**	**5,027**	**4,144**	**120,448**
Cost								
At 1 January 2011	3,560	2,835	160,184	42,827	2,965	12,216	9,652	234,239
Exchange adjustments	(73)	(73)	–	(294)	(35)	(12)	(225)	(712)
Additions	39	46	18,515	3,782	370	655	512	23,919
Acquisitions	62	134	2,100	567	4	–	–	2,867
Transfers	–	–	1,013	–	–	–	–	1,013
Reclassified as assets held for sale	(325)	–	(832)	(9,931)	–	–	–	(11,088)
Deletions	(164)	(96)	(5,106)	(1,242)	(209)	(106)	(1,328)	(8,251)
At 31 December 2011	3,099	2,846	175,874	35,709	3,095	12,753	8,611	241,987
Depreciation								
At 1 January 2011	572	1,384	88,047	19,183	1,876	7,940	5,074	124,076
Exchange adjustments	(10)	(36)	–	(108)	(34)	(6)	(113)	(307)
Charge for the year	36	111	8,116	1,411	278	252	567	10,771
Impairment losses	133	4	1,239	245	–	42	46	1,709
Impairment reversals	–	–	(146)	–	–	–	–	(146)
Reclassified as assets held for sale	(115)	–	(680)	(5,761)	–	–	–	(6,556)
Deletions	(106)	(91)	(4,582)	(704)	(209)	(79)	(1,003)	(6,774)
At 31 December 2011	510	1,372	91,994	14,266	1,911	8,149	4,571	122,773
Net book amount at 31 December 2011	2,589	1,474	83,880	21,443	1,184	4,604	4,040	119,214
Net book amount at 1 January 2011	2,988	1,451	72,137	23,644	1,089	4,276	4,578	110,163

Assets held under finance leases at net book amount included above								
At 31 December 2012	**–**	**9**	**157**	**254**	**–**	**9**	**–**	**429**
At 31 December 2011	–	10	213	326	–	7	18	574

Assets under construction included above	
At 31 December 2012	**27,308**
At 31 December 2011	26,443

22. Goodwill

		$ million
	2012	2011
Cost		
At 1 January	**13,703**	10,177
Exchange adjustments	**160**	(26)
Acquisitions	**25**	3,602
Reclassified as assets held for sale	**(1,327)**	(50)
Deletions	**(95)**	–
At 31 December	**12,466**	13,703
Impairment losses		
At 1 January	**(1,603)**	(1,579)
Impairment losses for the year	**–**	(66)
Reclassified as assets held for sale	**977**	42
Deletions	**21**	–
At 31 December	**(605)**	(1,603)
Net book amount at 31 December	**11,861**	12,100
Net book amount at 1 January	**12,100**	8,598

23. Intangible assets

						$ million
			2012			2011
	Exploration and appraisal expenditure	**Other intangibles**	**Total**	Exploration and appraisal expenditure	Other intangibles	Total
Cost						
At 1 January	**20,670**	**3,474**	**24,144**	13,476	3,403	16,879
Exchange adjustments	**–**	**49**	**49**	–	(21)	(21)
Acquisitions	**(68)**	**80**	**12**	5,563	176	5,739
Additions	**5,205**	**341**	**5,546**	3,348	352	3,700
Transfers	**(1,306)**	**–**	**(1,306)**	(1,013)	–	(1,013)
Reclassified as assets held for sale	**(67)**	**(26)**	**(93)**	–	(66)	(66)
Deletions	**(508)**	**(208)**	**(716)**	(704)	(370)	(1,074)
At 31 December	**23,926**	**3,710**	**27,636**	20,670	3,474	24,144
Amortization						
At 1 January	**783**	**2,259**	**3,042**	350	2,231	2,581
Exchange adjustments	**–**	**24**	**24**	–	(11)	(11)
Charge for the year	**745**	**316**	**1,061**	1,024	364	1,388
Impairment losses	**–**	**126**	**126**	7	79	86
Impairment reversals	**(42)**	**–**	**(42)**	–	–	–
Reclassified as assets held for sale	**–**	**(21)**	**(21)**	–	(46)	(46)
Deletions	**(409)**	**(186)**	**(595)**	(598)	(358)	(956)
At 31 December	**1,077**	**2,518**	**3,595**	783	2,259	3,042
Net book amount at 31 December	**22,849**	**1,192**	**24,041**	19,887	1,215	21,102
Net book amount at 1 January	**19,887**	**1,215**	**21,102**	13,126	1,172	14,298

24. Investments in jointly controlled entities

The significant jointly controlled entities of the BP group at 31 December 2012 are shown in Note 45. Summarized financial information for the group's share of jointly controlled entities is shown below. Balance sheet information shown below excludes data relating to jointly controlled entities reclassified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to jointly controlled entities reclassified as assets held for sale during the period up until their date of reclassification as held for sale.

			$ million
	2012	2011	2010
Sales and other operating revenues	**16,237**	15,720	11,679
Profit before interest and taxation	**1,331**	1,918	1,730
Finance costs	**129**	134	122
Profit before taxation	**1,202**	1,784	1,608
Taxation	**458**	480	433
Profit for the year	**744**	1,304	1,175
Non-current assets	**17,945**	16,495	
Current assets	**4,374**	4,613	
Total assets	**22,319**	21,108	
Current liabilities	**3,014**	2,553	
Non-current liabilities	**4,410**	3,980	
Total liabilities	**7,424**	6,533	
	14,895	14,575	
Group investment in jointly controlled entities			
Group share of net assets (as above)	**14,895**	14,575	
Loans made by group companies to jointly controlled entities	**829**	943	
	15,724	15,518	

Transactions between the group and its jointly controlled entities are summarized below.

						$ million
Sales to jointly controlled entities		**2012**		2011		2010
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	**6,423**	**1,713**	5,095	1,616	3,804	1,352

						$ million
Purchases from jointly controlled entities		**2012**		2011		2010
Product	**Purchases**	**Amount payable at 31 December[a]**	Purchases	Amount payable at 31 December[a]	Purchases	Amount payable at 31 December[a]
LNG, crude oil and oil products, natural gas, refinery operating costs, plant processing fees	**7,641**	**516**	7,798	369	8,063	683

[a] In addition to the amounts shown above, there are amounts payable to jointly controlled entities of $1,222 million (2011 $2,256 million and 2010 $2,583 million) relating to BP's contribution on the establishment of the Sunrise Oil Sands joint venture.

The terms of the outstanding balances receivable from jointly controlled entities are typically 30 to 45 days, except for a receivable from Ruhr Oel of $757 million (2011 $605 million), part of which is a reimbursement balance relating to pensions that will be received over several years. 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 above balances.

BP has commitments amounting to $4,391 million (2011 $4,155 million) in relation to contracts with jointly controlled entities for the purchase of LNG, crude oil and oil products, refinery operating costs and storage and handling services. See Note 44 for further information on capital commitments relating to BP's investments in jointly controlled entities.

25. Investments in associates

The significant associates of the BP group at 31 December 2012 are shown in Note 45. Summarized financial information for the group's share of associates is set out below. Balance sheet information shown below excludes data relating to associates reclassified as assets held for sale as at the end of the period. Income statement information shown below includes data relating to associates reclassified as assets held for sale for the period up until their date of reclassification as held for sale.

									$ million
			2012			2011			2010
	TNK-BP	**Other**	**Total**	TNK-BP	Other	Total	TNK-BP	Other	Total
Sales and other operating revenues	**24,675**	**11,965**	**36,640**	30,100	12,145	42,245	22,323	10,031	32,354
Profit before interest and taxation	**4,405**	**906**	**5,311**	5,992	958	6,950	3,866	1,215	5,081
Finance costs	**84**	**16**	**100**	132	13	145	128	22	150
Profit before taxation	**4,321**	**890**	**5,211**	5,860	945	6,805	3,738	1,193	4,931
Taxation	**979**	**201**	**1,180**	1,333	214	1,547	913	228	1,141
Minority interest	**356**	**–**	**356**	342	–	342	208	–	208
Profit for the year	**2,986**	**689**	**3,675**	4,185	731	4,916	2,617	965	3,582
Non-current assets			**3,270**	16,172	3,865	20,037			
Current assets			**2,399**	4,210	2,273	6,483			
Total assets			**5,669**	20,382	6,138	26,520			
Current liabilities			**2,126**	3,086	2,149	5,235			
Non-current liabilities			**1,290**	6,416	1,744	8,160			
Total liabilities			**3,416**	9,502	3,893	13,395			
Minority interest			**–**	867	–	867			
			2,253	10,013	2,245	12,258			
Group investment in associates									
Group share of net assets (as above)			**2,253**	10,013	2,245	12,258			
Loans made by group companies to associates			**745**	–	1,033	1,033			
			2,998	10,013	3,278	13,291			

Transactions between the group and its associates are summarized below.

						$ million
Sales to associates		**2012**		2011		2010
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	**3,771**	**401**	3,855	393	3,561	330

						$ million
Purchases from associates		**2012**		2011		2010
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	**9,135**	**915**	8,159	815	4,889	633

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.

The amounts receivable and payable at 31 December 2012, as shown in the table above, exclude $159 million (2011 $220 million) due from and due to an intermediate associate which provides funding for our associate The Baku-Tbilisi-Ceyhan Pipeline Company. These balances are expected to be settled in cash throughout the period to 2015.

Dividends receivable at 31 December 2012 of $34 million (2011 $38 million) are also excluded from the table above.

BP has commitments amounting to $595 million (2011 $1,477 million) in relation to contracts with its associates for the purchase of crude oil and oil products, transportation and storage. See Note 44 for further information on capital commitments relating to BP's investments in associates.

On 18 October 2010, BP announced that it had reached agreement to sell assets in Vietnam, together with its upstream businesses and associated interests in Venezuela, to TNK-BP. As at 31 December 2010, a deposit of $1 billion had been received from TNK-BP in advance of completion of this transaction and was reported within finance debt on the group balance sheet. This deposit was not reflected in the amount payable in the table above. These sales completed during 2011.

25. Investments in associates continued

On 22 November 2012, BP, Rosneft and Rosneftegaz (the state-owned parent company of Rosneft) signed definitive and binding agreements for the sale of BP's 50% interest in TNK-BP to Rosneft and for BP's investment in Rosneft. BP and Rosneft announced heads of terms for this transaction on 22 October 2012, after which our investment was classified as an asset held for sale and therefore equity accounting ceased. See Note 4 for further information. Summarized financial information for the group's share of TNK-BP for the full year 2012 and at 31 December 2012 is set out below.

	$ million
	2012
Sales and other operating revenues	**30,226**
Profit before interest and taxation	**5,441**
Profit for the year	**3,726**
Non-current assets	**18,243**
Current assets	**5,459**
Total assets	**23,702**
Current liabilities	**3,778**
Non-current liabilities	**6,465**
Total liabilities	**10,243**
Minority interest	**1,071**
	12,388

26. 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							**2012**
	Note	**Loans and receivables**	**Available-for-sale financial assets**	**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	**27**	**–**	**1,431**	**–**	**–**	**–**	**1,431**
– other	**27**	**–**	**1,005**	**585**	**–**	**–**	**1,590**
Loans		**942**	**–**	**–**	**–**	**–**	**942**
Trade and other receivables	**29**	**34,814**	**–**	**–**	**–**	**–**	**34,814**
Derivative financial instruments	**33**	**–**	**–**	**5,342**	**3,459**	**–**	**8,801**
Cash and cash equivalents	**30**	**15,043**	**4,505**	**–**	**–**	**–**	**19,548**
Financial liabilities							
Trade and other payables	**32**	**–**	**–**	**–**	**–**	**(44,706)**	**(44,706)**
Derivative financial instruments	**33**	**–**	**–**	**(5,093)**	**(288)**	**–**	**(5,381)**
Accruals		**–**	**–**	**–**	**–**	**(7,258)**	**(7,258)**
Finance debt	**34**	**–**	**–**	**–**	**–**	**(48,165)**	**(48,165)**
		50,799	**6,941**	**834**	**3,171**	**(100,129)**	**(38,384)**

							$ million
At 31 December							2011
	Note	Loans and receivables	Available-for-sale financial assets	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	27	–	1,128	–	–	–	1,128
– other	27	–	1,277	516	–	–	1,793
Loans		1,128	–	–	–	–	1,128
Trade and other receivables	29	36,879	–	–	–	–	36,879
Derivative financial instruments	33	–	–	7,188	1,707	–	8,895
Cash and cash equivalents	30	9,750	4,317	–	–	–	14,067
Financial liabilities							
Trade and other payables	32	–	–	–	–	(50,651)	(50,651)
Derivative financial instruments	33	–	–	(6,436)	(557)	–	(6,993)
Accruals		–	–	–	–	(6,321)	(6,321)
Finance debt	34	–	–	–	–	(44,183)	(44,183)
		47,757	6,722	1,268	1,150	(101,155)	(44,258)

The fair value of finance debt is shown in Note 34. For all other financial instruments, the carrying amount is either the fair value, or approximates the fair value.

26. Financial instruments and financial risk factors continued

Financial risk factors

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

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

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

The integrated supply and trading function maintains formal governance processes that provide oversight of market risk 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 group measures market risk exposure arising from its trading positions using value-at-risk techniques. These techniques are based on Monte Carlo simulation and make a statistical assessment of the market risk arising from possible future changes in market prices over a one-day holding period. The calculation of the range of potential changes in fair value takes into account a snapshot of the end-of-day exposures and the history of one-day price movements, together with the correlation of these price movements. The value-at-risk measure is supplemented by stress testing.

The value-at-risk table does not incorporate any of the group's natural business exposures or any derivatives entered into to risk manage those exposures. Market risk exposure in respect of embedded derivatives is also not included in the value-at-risk table.

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. The high and low values at risk indicated in the table below for each type of activity are independent of each other. Through the portfolio effect the high value at risk for the group as a whole is lower than the sum of the highs for the constituent parts. The potential movement in fair values is expressed to a 95% confidence interval. This means that, in statistical terms, one would expect to see a decrease in fair values greater than the trading value at risk on one occasion per month if the portfolio were left unchanged.

								$ million
Value at risk for 1 day at 95% confidence interval				2012				2011
	High	**Low**	**Average**	**Year end**	High	Low	Average	Year end
Group trading	**51**	**19**	**34**	**25**	83	28	42	28
Oil price trading	**50**	**18**	**31**	**23**	84	23	39	27
Gas and power trading	**30**	**4**	**12**	**8**	20	6	11	7

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. Trading value-at-risk information in relation to these activities is shown in the table above.

As described above, the group also carries out risk management of certain natural business exposures using over-the-counter swaps and exchange futures contracts. Together with certain physical supply contracts that are classified as derivatives, these contracts fall outside the value-at risk framework. For these derivative contracts the sensitivity of the net fair value to an immediate 10% increase or decrease in all reference prices would have been $16 million at 31 December 2012 (2011 $23 million). This figure does not include any corresponding economic benefit or disbenefit that would arise from the natural business exposure which would be expected to offset the gain or loss on the over-the-counter swaps and exchange futures contracts mentioned above.

In addition, the group has embedded derivatives relating to certain natural gas contracts. The net fair value of these contracts was a liability of $1,112 million at 31 December 2012 (2011 liability of $1,417 million). Key information on the natural gas contracts is given below.

At 31 December	2012	2011
Remaining contract terms	**2 years and 5 months to 5 years and 9 months**	3 years and 5 months to 6 years and 9 months
Contractual/notional amount	**117 million therms**	952 million therms

26. Financial instruments and financial risk factors continued

For these embedded derivatives the sensitivity of the net fair value to an immediate 10% favourable or adverse change in the key assumptions is as follows.

								$ million
At 31 December				**2012**				2011
	Gas price	**Oil price**	**Power price**	**Discount rate**	Gas price	Oil price	Power price	Discount rate
Favourable 10% change	**16**	**90**	**10**	**2**	100	74	4	5
Unfavourable 10% change	**(33)**	**(95)**	**(10)**	**(2)**	(109)	(77)	(4)	(5)

The sensitivities for risk management activity and embedded derivatives are hypothetical and should not be considered to be predictive of future performance. In addition, for the purposes of this analysis, in the above table, the effect of a variation in a particular assumption on the fair value of the embedded derivatives is calculated independently of any change in another assumption. In reality, changes in one factor may contribute to changes in another, which may magnify or counteract the sensitivities. Furthermore, the estimated fair values as disclosed should not be considered indicative of future earnings on these contracts.

(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. This activity is included within oil price trading in the value-at-risk table above.

Since BP has global operations, fluctuations in foreign currency exchange rates can have significant effects 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 minimize 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 dealing with 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 $200 million. At 31 December 2012, the foreign currency value at risk was $71 million (2011 $100 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 33.

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 and at 31 December 2012 open contracts were in place for $853 million sterling, $104 million euro, $172 million Norwegian krone, $112 million Australian dollar and $153 million Korean won capital expenditures maturing within seven years, with over 68% of the deals maturing within two years (2011 $1,242 million sterling, $158 million euro, $118 million Norwegian krone, $210 million Australian dollar and $230 million Korean won capital expenditures maturing within five years, with over 69% of the deals maturing within two years).

For other UK, European and Australian operational requirements the group uses cylinders and currency forwards to hedge the estimated exposures on a 12-month rolling basis. At 31 December 2012, the open positions relating to cylinders consisted of receive sterling, pay US dollar, purchased call and sold put options (cylinders) for $2,886 million (2011 $2,683 million); receive euro, pay US dollar cylinders for $1,636 million (2011 $1,304 million); receive Australian dollar, pay US dollar cylinders for $522 million (2011 $312 million).

In addition, most of the group's borrowings are in US dollars or are hedged with respect to the US dollar. At 31 December 2012, the total foreign currency net borrowings not swapped into US dollars amounted to $361 million (2011 $371 million). Of this total, $142 million was denominated in currencies other than the functional currency of the individual operating unit being entirely Canadian dollars (2011 $129 million, being entirely Canadian dollars). It is estimated that a 10% change in the corresponding exchange rates would result in an exchange gain or loss in the income statement of $14 million (2011 $13 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. This activity is included within oil price trading in the value-at-risk table above.

BP is also exposed to interest rate risk from the possibility that changes in interest rates will affect future cash flows or the fair values of its financial instruments, principally finance debt. While the group issues debt in a variety of currencies based on market opportunities, it uses derivatives to swap the debt to a floating rate exposure, mainly to US dollar floating, but in certain defined circumstances maintains a US dollar fixed rate exposure for a proportion of debt. The proportion of floating rate debt net of interest rate swaps and excluding disposal deposits at 31 December 2012 was 65% of total finance debt outstanding (2011 65%). The weighted average interest rate on finance debt at 31 December 2012 is 2% (2011 2%) and the weighted average maturity of fixed rate debt is four years (2011 five years).

The group's earnings are sensitive to changes in interest rates on the floating rate element of the group's finance debt. If the interest rates applicable to floating rate instruments were to have increased by 1% on 1 January 2013, it is estimated that the group's finance costs for 2013 would increase by approximately $311 million (2011 $289 million increase in 2012). This assumes that the amount and mix of fixed and floating rate debt, including finance leases, remains unchanged from that in place at 31 December 2012 and that the change in interest rates is effective from the beginning of the year. Where the interest rate applicable to an instrument is reset during a quarter it is assumed that this occurs at the beginning of the quarter and remains unchanged for the rest of the year. In reality, the fixed/floating rate mix will fluctuate over the year and interest rates will change continually. Furthermore, the effect on earnings shown by this analysis does not consider the effect of any other changes in general economic activity that may accompany such an increase in interest rates.

26. Financial instruments and financial risk factors continued

(iv) Equity price risk

The group holds equity investments, typically made 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. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired. No impairment losses have been recognized in the years presented relating to listed non-current available-for-sale investments. For further information see Note 27. In addition, at 31 December 2012, the group was a party to certain equity price derivatives described in further detail below.

At 31 December 2012, it is estimated that an increase of 10% in quoted equity prices would result in an immediate credit to other comprehensive income of $1,502 million (2011 $87 million credit to other comprehensive income), while a decrease of 10% in quoted equity prices would result in an immediate charge to other comprehensive income of $1,502 million (2011 $87 million charge to other comprehensive income). At 31 December 2012, 82% (2011 77%) 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 is concentrated on changes in the share price of this equity in particular. As described in Note 33, the agreements for the purchase of 5.66% and 9.80% shareholdings in Rosneft are derivative financial instruments, whose fair value is impacted by the Rosneft share price, and are accounted for as cash flow hedges, with changes in fair value recognized in other comprehensive income to the extent the hedge is effective. See Note 4 for further information.

(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.

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 global credit environment remained challenging in 2012, suffering not only from continuing economic and political uncertainties but also from key event risks, causing the group to further heighten awareness, discussion and co-ordination of the material credit risks arising from its activities.

Before trading with a new counterparty can start, its creditworthiness is assessed and a credit rating is allocated that indicates the probability of default, along with a credit exposure limit. The assessment process takes into account all available qualitative and quantitative information about the counterparty and the group, if any, to which the counterparty belongs. The counterparty's business activities, financial resources and business risk management processes are taken into account in the assessment, to the extent that this information is publicly available or otherwise disclosed to BP by the counterparty, together with external credit ratings. Creditworthiness continues to be evaluated after transactions have been initiated and a watchlist of higher-risk counterparties is maintained.

The group does not aim to remove credit risk but expects to experience a certain level of credit losses. The group attempts to mitigate credit risk by entering into contracts that permit netting and allow for termination of the contract on the occurrence of certain events of default. Depending on the creditworthiness of the counterparty, the group may require collateral or other credit enhancements such as cash deposits, letters of credit, trade credit insurance, liens, third-party guarantees and other forms of credit mitigation. Trade receivables and payables, and derivative assets and liabilities, are presented on a net basis where unconditional netting arrangements are in place with counterparties and where there is an intent to settle amounts due on a net basis. The maximum credit exposure associated with financial assets is equal to the carrying amount. Collateral received and recognized in the balance sheet at the year end was $334 million (2011 $273 million) and collateral held off balance sheet was $148 million (2011 $6 million). As at 31 December 2012, the group had in place other credit enhancements designed to mitigate approximately $11.5 billion of credit risk (2011 $8.6 billion). Credit exposure exists in relation to guarantees issued by group companies under which amounts outstanding at 31 December 2012 were $237 million (2011 $415 million) in respect of liabilities of jointly controlled entities and associates and $713 million (2011 $1,430 million) in respect of liabilities of other third parties.

Notwithstanding the processes described above, significant unexpected credit losses can occasionally occur. Exposure to unexpected losses increases with concentrations of credit risk that exist when a number of counterparties are involved in similar activities or operate in the same industry sector or geographical area, which may result in their ability to meet contractual obligations being impacted by changes in economic, political or other conditions. The group's principal customers, suppliers and financial institutions with which it conducts business are located throughout the world. In addition, these risks are managed by maintaining a group watchlist and aggregating multi-segment exposures to ensure that a material credit risk is not missed.

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. The reports also include details of the largest counterparties by exposure level and expected loss, and details of counterparties on the group watchlist.

For the contracts comprising derivative financial instruments in an asset position at 31 December 2012, excluding the contracts with Rosneft accounted for as derivatives, it is estimated that over 72% (2011 over 76%) 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 2012, over 98% of the cash and cash equivalents balance was deposited with financial institutions rated at least A- by Standard & Poor's and A3 by Moody's. Direct cash and cash equivalent exposures to Greek, Italian, Irish, Portuguese and Spanish financial institutions totalled less than 0.6% of total cash and cash equivalents.

26. Financial instruments and financial risk factors continued

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% (2011 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 $3.0 billion (see page 69), 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	**2012**	2011
Neither impaired nor past due	**31,916**	34,563
Impaired (net of valuation allowance)	**80**	33
Not impaired and past due in the following periods		
within 30 days	**1,334**	1,263
31 to 60 days	**285**	250
61 to 90 days	**224**	132
over 90 days	**975**	638
	34,814	36,879

The movement in the impairment provision for trade receivables is set out below.

		$ million
	2012	2011
At 1 January	**332**	428
Exchange adjustments	**7**	(16)
Charge for the year	**240**	115
Utilization	**(65)**	(124)
Write back	**(25)**	(71)
At 31 December	**489**	332

(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.

In managing its liquidity risk, the group has access to a wide range of funding at competitive rates through capital markets and banks. The group's treasury function centrally co-ordinates relationships with banks, borrowing requirements, foreign exchange requirements and cash management. The group believes it has access to sufficient funding through its own current cash holdings and future cash generation including disposal proceeds, the commercial paper markets and by using undrawn committed borrowing facilities to meet foreseeable liquidity requirements.

The group has in place a European Debt Issuance Programme (DIP) under which the group may raise up to $20 billion of debt for maturities of one month or longer. At 31 December 2012, the amount drawn down against the DIP was $14,043 million (2011 $11,582 million). The group also had in place an unlimited US Shelf Registration throughout 2012 and until 5 February 2013, under which it could raise debt with maturities of one month or longer. From 5 February 2013 the Well-known Seasoned Issuer (WKSI) shelf was converted to a non-WKSI shelf with a limit of $30 billion, with no draw down since the conversion. In addition, the group has an Australian Note Issue Programme of A$5 billion, and as at 31 December 2012 the amount drawn down was A$500 million (2011 nil).

The group had a long-term debt rating of A2 (stable outlook) assigned by Moody's consistently throughout the year, and a rating of A (positive outlook) assigned by Standard & Poor's since July 2012, strengthened from A (stable outlook) in force at the start of the year.

During 2012, $10.9 billion of long-term taxable bonds were issued with tenors of three to 10 years. Flexible 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 $19.5 billion at 31 December 2012, invested with highly rated banks or money market funds and readily accessible at immediate and short notice (2011 $14.1 billion). At 31 December 2012, the group had substantial amounts of undrawn borrowing facilities available, consisting of $6,825 million of standby facilities available to draw and repay until mid-March 2014. These facilities were renegotiated during 2011 with 23 international banks, and borrowings under them would be at pre-agreed rates.

The group also has committed letter of credit (LC) facilities totalling $6,925 million with a number of banks for a one-year duration, allowing LCs to be issued to a maximum one-year duration. There were also uncommitted secured LC evergreen facilities in place at 31 December 2012 for $2,160 million, secured against inventories or receivables when utilized.

The amounts shown for finance debt in the table below include future minimum lease payments with respect to finance leases.

26. Financial instruments and financial risk factors continued

Current finance debt on the group balance sheet at 31 December 2012 includes $632 million (2011 $30 million) in respect of cash deposits received for disposals expected to complete in 2013, which will be considered extinguished on completion of the transactions. This amount is excluded from the table below.

The table also shows the timing of cash outflows relating to trade and other payables and accruals.

								$ million
				2012				2011
	Trade and other payables	**Accruals**	**Finance debt**	**Interest relating to finance debt**	Trade and other payables[a]	Accruals	Finance debt	Interest relating to finance debt
Within one year	**43,001**	**6,810**	**9,398**	**893**	47,678	5,933	9,013	1,011
1 to 2 years	**893**	**134**	**5,906**	**755**	1,605	137	7,094	772
2 to 3 years	**385**	**79**	**5,902**	**634**	569	55	6,703	608
3 to 4 years	**318**	**52**	**6,024**	**510**	449	26	5,019	468
4 to 5 years	**52**	**48**	**5,797**	**388**	259	49	4,278	356
5 to 10 years	**24**	**84**	**14,790**	**885**	31	82	11,574	806
Over 10 years	**33**	**51**	**348**	**50**	72	39	502	71
	44,706	**7,258**	**48,165**	**4,115**	50,663	6,321	44,183	4,092

[a] Trade and other payables at 31 December 2011 included the Gulf of Mexico oil spill trust fund liability amounting to $4,884 million which was payable within one year.

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 33. 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 interest rate swaps hedging non-US dollar finance debt. The swaps are with high investment-grade counterparties and therefore the settlement day risk exposure is considered to be negligible. Not shown in the table are the gross settlement amounts for the receive leg of derivatives that are settled separately from the pay leg, which amount to $8,620 million at 31 December 2012 (2011 $9,099 million) to be received on the same day as the related cash outflows. Also not shown are the expected cash outflows under the Rosneft share purchase agreements described in Note 33, nor the related expected cash inflows for the sale of our 50% interest in TNK-BP.

		$ million
	2012	2011
Within one year	**1,356**	1,738
1 to 2 years	**1,107**	1,372
2 to 3 years	**295**	1,115
3 to 4 years	**1,261**	298
4 to 5 years	**2,577**	1,262
5 to 10 years	**1,903**	3,459
	8,499	9,244

The group has issued third-party guarantees, as described above under credit risk. These amounts represent the maximum exposure of the group, substantially all of which could be called within one year.

27. Other investments

				$ million
		2012		2011
	Current	**Non-current**	Current	Non-current
Equity investments – listed	**–**	**1,182**	–	876
– unlisted	**–**	**249**	–	252
Repurchased gas pre-paid bonds	**303**	**686**	288	989
Other	**16**	**585**	–	516
	319	**2,702**	288	2,633

Equity investments have no fixed maturity date or coupon rate, and are classified as available-for-sale financial assets. As such they are recorded at fair value with the gain or loss arising as a result of changes in fair value recorded in other comprehensive income. Accumulated fair value changes are recycled to the income statement on disposal, or when the investment is impaired.

The fair value of listed investments has been determined by reference to quoted market bid prices and as such are in level 1 of the fair value hierarchy. Unlisted investments are stated at cost less accumulated impairment losses.

The most significant listed investment is the group's 1.25% stake in Rosneft which had a fair value of $1,179 million at 31 December 2012 (2011 $873 million). The fair value gain arising on revaluation of this investment during 2012 has been recorded within other comprehensive income.

In 2012, impairment losses of $6 million were recognized relating to unlisted investments (2011 $12 million and 2010 nil); there were no impairment losses relating to listed investments in 2012, 2011 or 2010.

27. Other investments continued

Other non-current investments at 31 December 2012 include $585 million relating to life insurance policies. In the 2011 Annual Report and Form 20-F the corresponding amount of $516 million was included in non-current prepayments. This amount has been reclassified to other non-current investments in the balance sheet comparative figures shown in this Annual Report and Form 20-F. The life insurance policies have been designated as financial assets at fair value through profit or loss and their valuation methodology is in level 3 of the fair value hierarchy. Fair value gains of $70 million were recognized in the income statement (2011 $21 million and 2010 $58 million).

BP has 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.

28. Inventories

		$ million
	2012	2011
Crude oil	**9,123**	7,702
Natural gas	**187**	178
Refined petroleum and petrochemical products	**15,149**	14,909
	24,459	22,789
Supplies	**2,408**	2,057
	26,867	24,846
Trading inventories	**1,000**	815
	27,867	25,661
Cost of inventories expensed in the income statement	**293,242**	285,618

The inventory valuation at 31 December 2012 is stated net of a provision of $124 million (2011 $152 million) to write inventories down to their net realizable value. The net movement in the year in respect of inventory net realizable value provisions was a credit of $28 million (2011 $111 million debit). Inventories with a carrying amount of $64 million (2011 nil) had been pledged as security for certain of the group's liabilities at 31 December 2012.

29. Trade and other receivables

				$ million
		2012		2011
	Current	**Non-current**	Current	Non-current
Financial assets				
Trade receivables	**25,977**	**151**	27,929	508
Amounts receivable from jointly controlled entities	**952**	**761**	1,004	612
Amounts receivable from associates	**492**	**102**	492	159
Other receivables	**5,677**	**702**	5,429	746
	33,098	**1,716**	34,854	2,025
Non-financial assets				
Gulf of Mexico oil spill trust fund reimbursement asset[a]	**4,178**	**2,264**	8,233	1,642
Other receivables	**388**	**774**	439	670
	4,566	**3,038**	8,672	2,312
	37,664	**4,754**	43,526	4,337

[a] See Note 2 for further information.

Trade and other receivables are predominantly non-interest bearing. See Note 26 for further information.

30. Cash and cash equivalents

		$ million
	2012	2011
Cash at bank and in hand	**5,800**	4,872
Term bank deposits	**9,243**	4,878
Cash equivalents	**4,505**	4,317
	19,548	14,067

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; and 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. 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 2012 includes $1,544 million (2011 $901 million) that is restricted. This relates principally to amounts required to cover initial margin on trading exchanges and $709 million relating to the dividend received from TNK-BP in December 2012 which meets the criteria to be treated as restricted cash until completion of the anticipated sale of BP's interest in TNK-BP to Rosneft. See Note 4 and Note 26 for further information.

31. Valuation and qualifying accounts

						$ million
		2012		2011		2010
	Accounts receivable	**Fixed asset investments**	Accounts receivable	Fixed asset investments	Accounts receivable	Fixed asset investments
At 1 January	**332**	**643**	428	540	430	349
Charged to costs and expenses	**240**	**196**	115	111	150	376
Charged to other accounts[a]	**7**	**18**	(16)	(3)	(9)	(3)
Deductions	**(90)**	**(508)**	(195)	(5)	(143)	(182)
At 31 December	**489**	**349**	332	643	428	540

[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.

32. Trade and other payables

				$ million
		2012		2011
	Current	**Non-current**	Current	Non-current
Financial liabilities				
Trade payables	**29,703**	**–**	29,830	–
Amounts payable to jointly controlled entities	**1,580**	**158**	1,578	1,047
Amounts payable to associates	**972**	**102**	876	159
Gulf of Mexico oil spill trust fund liability[a]	**22**	**–**	4,872	–
Other payables	**10,723**	**1,446**	10,510	1,779
	43,000	**1,706**	47,666	2,985
Non-financial liabilities				
Other payables	**4,154**	**396**	4,739	452
	47,154	**2,102**	52,405	3,437

[a] See Note 2 for further information.

Trade and other payables are predominantly non-interest bearing. See Note 26 for further information.

33. Derivative financial instruments

An outline of the group's financial risks and the objectives and policies pursued in relation to those risks is set out in Note 26.

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. Additionally, the group has a well-established entrepreneurial trading operation that is undertaken in conjunction with these activities using a similar range of contracts. At 31 December 2012, the group was also party to certain equity price derivatives arising in connection with the anticipated completion of the transaction with Rosneft – see below for further information.

IAS 39 prescribes strict criteria for hedge accounting, and requires that any derivative that does not meet these criteria should be classified as held for trading and fair valued, with gains and losses recognized in the income statement.

The carrying amounts of derivative financial instruments at 31 December are set out below.

				$ million
		2012		2011
	Asset	**Liability**	Asset	Liability
Derivatives held for trading				
Currency derivatives	**175**	**(189)**	217	(217)
Oil price derivatives	**841**	**(707)**	823	(536)
Natural gas price derivatives	**3,536**	**(2,496)**	5,305	(3,603)
Power price derivatives	**719**	**(589)**	843	(663)
Equity price derivatives	**71**	**–**	–	–
	5,342	**(3,981)**	7,188	(5,019)
Embedded derivatives				
Commodity price contracts	**–**	**(1,112)**	–	(1,417)
	–	**(1,112)**	–	(1,417)
Cash flow hedges				
Equity price derivatives	**1,339**	**–**	–	–
Currency forwards, futures and cylinders	**51**	**(41)**	25	(159)
Cross-currency interest rate swaps	**1**	**–**	–	–
	1,391	**(41)**	25	(159)
Fair value hedges				
Currency forwards, futures and swaps	**875**	**(247)**	842	(398)
Interest rate swaps	**1,193**	**–**	840	–
	2,068	**(247)**	1,682	(398)
	8,801	**(5,381)**	8,895	(6,993)
Of which – current	**4,507**	**(2,658)**	3,857	(3,220)
– non-current	**4,294**	**(2,723)**	5,038	(3,773)

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 26.

33. Derivative financial instruments continued

The following tables show further information on the derivatives and other financial instruments held for trading purposes. Derivative assets held for trading have the following carrying amounts and maturities.

							$ 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**
Equity price derivatives	**71**	**–**	**–**	**–**	**–**	**–**	**71**
	2,755	**1,014**	**570**	**342**	**175**	**486**	**5,342**

							$ million
							2011
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	194	18	5	–	–	–	217
Oil price derivatives	573	135	77	25	10	3	823
Natural gas price derivatives	2,493	1,160	597	346	207	502	5,305
Power price derivatives	498	160	101	54	30	–	843
	3,758	1,473	780	425	247	505	7,188

Derivative liabilities held for trading have the following carrying amounts and maturities.

							$ 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)**

							$ million
							2011
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Currency derivatives	(168)	(49)	–	–	–	–	(217)
Oil price derivatives	(483)	(37)	(7)	(4)	(3)	(2)	(536)
Natural gas price derivatives	(1,696)	(876)	(347)	(197)	(102)	(385)	(3,603)
Power price derivatives	(328)	(176)	(89)	(46)	(24)	–	(663)
	(2,675)	(1,138)	(443)	(247)	(129)	(387)	(5,019)

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 this initial valuation are recognized immediately through the income statement.

The following table shows the changes in the day-one profits and losses deferred on the balance sheet.

					$ million
			2012		2011
	Oil price	**Power price**	**Natural gas price**	Power price	Natural gas price
Fair value of contracts not recognized through the income statement at 1 January	**–**	**9**	**114**	–	69
Fair value of new contracts at inception not recognized in the income statement	**(1)**	**(4)**	**28**	9	51
Fair value recognized in the income statement	**1**	**(9)**	**(19)**	–	(6)
Fair value of contracts not recognized through the income statement at 31 December	**–**	**(4)**	**123**	9	114

33. 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.

IFRS 7 'Financial Instruments: Disclosures' sets out a fair value hierarchy which consists of three levels that describe the methodology of estimation as follows:

Level 1 – using quoted prices in active markets for identical assets or liabilities.

Level 2 – using inputs for the asset or liability, other than quoted prices, that are observable either directly (i.e. as prices) or indirectly (i.e. derived from prices).

Level 3 – using inputs for the asset or liability that are not based on observable market data such as prices based on internal models or other valuation methods.

This information is presented on a gross basis, that is, before netting by counterparty.

							$ 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**

							$ million
							2011[a]
	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	229	18	5	–	–	–	252
Level 2	6,526	1,724	639	268	80	8	9,245
Level 3	338	305	262	221	170	500	1,796
	7,093	2,047	906	489	250	508	11,293
Less: netting by counterparty	(3,335)	(574)	(126)	(64)	(3)	(3)	(4,105)
	3,758	1,473	780	425	247	505	7,188
Fair value of derivative liabilities							
Level 1	(168)	(49)	–	–	–	–	(217)
Level 2	(5,652)	(1,499)	(412)	(163)	(20)	(7)	(7,753)
Level 3	(190)	(164)	(157)	(148)	(112)	(383)	(1,154)
	(6,010)	(1,712)	(569)	(311)	(132)	(390)	(9,124)
Less: netting by counterparty	3,335	574	126	64	3	3	4,105
	(2,675)	(1,138)	(443)	(247)	(129)	(387)	(5,019)
Net fair value	1,083	335	337	178	118	118	2,169

[a] The presentation of certain comparative data for 2011 before netting has been amended.

33. Derivative financial instruments continued

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**	**Equity price**	**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**

				$ million
	Oil price	Natural gas price	Power price	Total
Net fair value of contracts at 1 January 2011	164	667	(1)	830
Gains (losses) recognized in the income statement	69	129	11	209
Settlements	(71)	(110)	3	(178)
Transfers out of level 3	–	(278)	–	(278)
Net fair value of contracts at 31 December 2011	162	408	13	583

Transfers out of level 3 of the fair value hierarchy in 2012 relate primarily to the delivery dates for a number of natural gas and power forward contracts moving into a time period where market observable prices are available, and therefore being reclassified to level 2 of the fair value hierarchy.

The amount recognized in the income statement for the year relating to level 3 held for trading derivatives still held at 31 December 2012 was a $10 million gain (2011 $204 million gain relating to derivatives still held at 31 December 2011).

Gains and losses relating to derivative contracts are included either within sales and other operating revenues or 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 was a net loss of $726 million (2011 $934 million net loss and 2010 $1,738 million net gain).

Embedded derivatives

The group has 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.

All the commodity price embedded derivatives relate to natural gas contracts, are categorized in level 3 of the fair value hierarchy and 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, these 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.

33. Derivative financial instruments continued

Embedded derivative liabilities relate mainly to commodity price contracts and have the following fair values and maturities.

							$ million
							2012
	Less than 1 year	**1-2 years**	**2-3 years**	**3-4 years**	**4-5 years**	**Over 5 years**	**Total**
Net fair value	**(322)**	**(299)**	**(252)**	**(151)**	**(57)**	**(31)**	**(1,112)**

							$ million
							2011
	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Over 5 years	Total
Net fair value	(347)	(319)	(306)	(236)	(134)	(75)	(1,417)

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
	2012	2011
	Commodity price	Commodity price
Net fair value of contracts at 1 January	**(1,417)**	(1,607)
Settlements	**375**	301
Losses recognized in the income statement	**(6)**	(106)
Exchange adjustments	**(64)**	(5)
Net fair value of contracts at 31 December	**(1,112)**	(1,417)

The amount recognized in the income statement for the year relating to level 3 embedded derivatives still held at 31 December 2012 was a loss of $6 million (2011 $106 million loss relating to embedded derivatives still held at 31 December 2011).

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

			$ million
	2012	2011	2010
Commodity price embedded derivatives	**347**	190	(309)
Other embedded derivatives	**–**	(122)	–
Fair value gain (loss)	**347**	68	(309)

Cash flow hedges

At 31 December 2012, 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, categorized in level 2 of the fair value hierarchy. Note 26 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. There were no highly probable transactions for which hedge accounting has been claimed that have not occurred and no significant element of hedge ineffectiveness requiring recognition in the income statement. For cash flow hedges the pre-tax amount removed from equity during the period and included in the income statement is a loss of $62 million (2011 $195 million gain and 2010 $25 million gain). The entire loss of $62 million is included in production and manufacturing expenses (2011 $195 million gain in production and manufacturing expenses; 2010 $25 million gain in production and manufacturing expenses). The amount removed from equity during the period and included in the carrying amount of non-financial assets was a loss of $19 million (2011 $13 million gain and 2010 $53 million loss). The amounts retained in equity at 31 December 2012 in relation to these cash flow hedges consist of deferred losses of $18 million maturing in 2013 and deferred gains of $9 million maturing in 2015 and beyond.

The anticipated transaction whereby BP expects to sell its 50% interest in TNK-BP and acquire 18.5% of Rosneft, as described in Note 4, comprises three agreements which, during the period from signing until completion, represent derivative financial instruments that are required to be measured at fair value. BP has 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 are recognized in other comprehensive income. The third agreement, under which BP expects to sell its 50% interest in TNK-BP in exchange for cash and a 3.04% shareholding in Rosneft, is also a derivative financial instrument, but its fair value cannot 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 relates to the fair value of the cash flow hedge derivatives. The derivatives measured at fair value at 31 December 2012 are categorized in level 3 of the fair value hierarchy using inputs that include the quoted Rosneft share price. A credit of $1,410 million recognized in other comprehensive income would be recycled to the income statement only if the investment in Rosneft is sold or impaired.

Fair value hedges

At 31 December 2012, 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, categorized in level 2 of the fair value hierarchy. The effectiveness of each hedge relationship is quantitatively assessed and demonstrated to continue to be highly effective. The gain on the hedging derivative instruments taken to the income statement in 2012 was $536 million (2011 $328 million and 2010 $563 million) offset by a loss on the fair value of the finance debt of $537 million (2011 $327 million and 2010 $554 million).

The interest rate and cross-currency interest rate swaps mature within one to 10 years, with an average maturity of four to five years (2011 four to five years) and are used to convert sterling, euro, Swiss franc, Australian dollar, Japanese yen and Hong Kong dollar denominated borrowings into US dollar floating rate debt. Note 26 outlines the group's approach to interest rate and currency risk management.

34. Finance debt

						$ million
			2012			2011
	Current	**Non-current**	**Total**	Current	Non-current	Total
Borrowings	**9,369**	**38,412**	**47,781**	8,675	34,816	43,491
Net obligations under finance leases	**29**	**355**	**384**	339	353	692
	9,398	**38,767**	**48,165**	9,014	35,169	44,183
Disposal deposits	**632**	**–**	**632**	30	–	30
	10,030	**38,767**	**48,797**	9,044	35,169	44,213

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 $6,240 million (2011 $4,875 million) and issued commercial paper of $3,028 million (2011 $3,635 million). Finance debt does not include accrued interest, which is reported within other payables.

Deposits for disposal transactions expected to complete in 2013 of $632 million are also included in current finance debt (2011 $30 million for transactions expected to complete in 2012). This unsecured debt will be considered extinguished on completion of the transactions.

At 31 December 2012, $142 million (2011 $131 million) of finance debt was secured by the pledging of assets. At 31 December 2011, in connection with $2,344 million of finance debt, BP had entered into crude oil sale contracts in respect of oil produced from certain fields in offshore Angola and Azerbaijan to provide security to lending banks. These loans were repaid during the fourth quarter of 2012 and the sales contracts were terminated.

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**
						2012
US dollar	**3**	**4**	**16,744**	**1**	**26,208**	**42,952**
Euro	**5**	**2**	**20**	**1**	**4,851**	**4,871**
Other currencies	**4**	**11**	**255**	**3**	**87**	**342**
			17,019		**31,146**	**48,165**
						2011
US dollar	4	5	15,016	1	27,285	42,301
Euro	5	3	25	3	1,575	1,600
Other currencies	4	12	240	3	42	282
			15,281		28,902	44,183

The euro debt not swapped to US dollar is naturally hedged for the foreign currency risk by holding equivalent euro cash and cash equivalent amounts.

Finance leases

The group uses finance leases to acquire property, plant and equipment. These leases have terms of renewal but no purchase options and escalation clauses. Renewals are at the option of the lessee. The terms and conditions of these finance leases do not impose significant financial restrictions on the group. Future minimum lease payments under finance leases are set out below.

		$ million
	2012	2011
Future minimum lease payments payable within		
1 year	**59**	454
2 to 5 years	**211**	200
Thereafter	**334**	380
	604	1,034
Less: finance charges	**220**	342
Net obligations	**384**	692
Of which – payable within 1 year	**29**	339
– payable within 2 to 5 years	**109**	99
– payable thereafter	**246**	254

34. Finance debt continued

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 year from 31 December 2012, 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 value of the group's long-term borrowings and finance lease obligations is estimated using quoted prices or, where these are not available, discounted cash flow analyses based on the group's current incremental borrowing rates for similar types and maturities of borrowing.

				$ million
		2012		2011
	Fair value	**Carrying amount**	Fair value	Carrying amount
Short-term borrowings	**3,128**	**3,128**	3,800	3,800
Long-term borrowings	**45,969**	**44,653**	40,606	39,691
Net obligations under finance leases	**520**	**384**	776	692
Total finance debt	**49,617**	**48,165**	45,182	44,183

35. 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. BP intends 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, less 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 2012, the net debt ratio was 18.7% (2011 20.5%).

During 2012 and 2011, 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	**2012**	2011
Gross debt	**48,797**	44,213
Less: fair value asset of hedges related to finance debt	**1,700**	1,133
	47,097	43,080
Less: cash and cash equivalents	**19,548**	14,067
Net debt	**27,549**	29,013
Equity	**119,620**	112,482
Net debt ratio	**18.7%**	20.5%

An analysis of changes in net debt is provided below.

						$ million
			2012			2011
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	**(43,080)**	**14,067**	**(29,013)**	(44,420)	18,556	(25,864)
Exchange adjustments	**(75)**	**64**	**(11)**	30	(492)	(462)
Net cash flow	**(3,236)**	**5,417**	**2,181**	(4,725)	(3,997)	(8,722)
Movement in finance debt relating to investing activities[b]	**(602)**	**–**	**(602)**	6,167	–	6,167
Other movements	**(104)**	**–**	**(104)**	(132)	–	(132)
At 31 December	**(47,097)**	**19,548**	**(27,549)**	(43,080)	14,067	(29,013)

[a] Including the fair value of associated derivative financial instruments.
[b] See Note 34 for further information.

36. Provisions

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
							$ million
At 1 January 2012	**17,240**	**3,264**	**336**	**10,976**	**3,510**	**2,316**	**37,642**
Exchange adjustments	**261**	**3**	**–**	**–**	**–**	**19**	**283**
Acquisitions	**–**	**–**	**–**	**–**	**–**	**24**	**24**
New or increased provisions	**3,756**	**1,350**	**109**	**6,080**	**–**	**1,260**	**12,555**
Derecognition of provision for items that cannot be reliably estimated	**–**	**–**	**–**	**(794)**	**–**	**–**	**(794)**
Write-back of unused provisions	**–**	**(65)**	**–**	**(50)**	**–**	**(271)**	**(386)**
Unwinding of discount	**107**	**9**	**–**	**18**	**–**	**6**	**140**
Utilization	**(651)**	**(841)**	**(100)**	**(5,979)**	**–**	**(411)**	**(7,982)**
Reclassified as liabilities directly associated with assets held for sale	**(3,048)**	**(91)**	**–**	**–**	**–**	**(11)**	**(3,150)**
Deletions	**(350)**	**(1)**	**–**	**–**	**–**	**(60)**	**(411)**
At 31 December 2012	**17,315**	**3,628**	**345**	**10,251**	**3,510**	**2,872**	**37,921**
Of which – current	**721**	**1,235**	**277**	**4,506**	**–**	**848**	**7,587**
– non-current	**16,594**	**2,393**	**68**	**5,745**	**3,510**	**2,024**	**30,334**

	Decommissioning	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Other	Total
							$ million
At 1 January 2011	10,544	2,465	1,043	11,967	3,510	2,378	31,907
Exchange adjustments	(27)	(4)	–	(13)	–	(12)	(56)
Acquisitions	163	–	–	9	–	118	290
New or increased provisions	4,596	1,677	586	3,821	–	1,145	11,825
Write-back of unused provisions	(1)	(140)	–	(92)	–	(416)	(649)
Unwinding of discount	195	27	–	15	–	6	243
Change in discount rate	3,211	90	–	45	–	10	3,356
Utilization	(342)	(840)	(1,293)	(4,715)	–	(876)	(8,066)
Reclassified as liabilities directly associated with assets held for sale	(51)	–	–	–	–	–	(51)
Deletions	(1,048)	(11)	–	(61)	–	(37)	(1,157)
At 31 December 2011	17,240	3,264	336	10,976	3,510	2,316	37,642
Of which – current	596	1,375	282	8,518	–	467	11,238
– non-current	16,644	1,889	54	2,458	3,510	1,849	26,404

Provisions not related to the Gulf of Mexico oil spill

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 0.5% (2011 0.5%). 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 0.5% (2011 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 2012 are provisions for deferred employee compensation of $618 million (2011 $666 million). These provisions are discounted using either a nominal discount rate of 2.5% (2011 2.5%) or a real discount rate of 0.5% (2011 0.5%), as appropriate.

36. Provisions continued

Provisions relating to the Gulf of Mexico oil spill

The Gulf of Mexico oil spill is described on pages 59-62 and in Note 2. Provisions relating to the Gulf of Mexico oil spill, included in the table above, are separately presented below:

					$ million
	Environmental	**Spill response**	**Litigation and claims**	**Clean Water Act penalties**	**Total**
At 1 January 2012	**1,517**	**336**	**9,970**	**3,510**	**15,333**
New or increased provisions – items not covered by the trust funds	**48**	**62**	**4,773**	**–**	**4,883**
– items covered by the trust funds	**753**	**47**	**1,185**	**–**	**1,985**
Derecognition of provision for items that cannot be reliably estimated	**–**	**–**	**(794)**	**–**	**(794)**
Unwinding of discount	**1**	**–**	**6**	**–**	**7**
Utilization – paid by BP	**(76)**	**(100)**	**(1,064)**	**–**	**(1,240)**
– paid by the trust funds	**(381)**	**–**	**(4,243)**	**–**	**(4,624)**
– reclassified to other payables	**–**	**–**	**(350)**	**–**	**(350)**
At 31 December 2012	**1,862**	**345**	**9,483**	**3,510**	**15,200**
Of which – current	**845**	**277**	**4,327**	**–**	**5,449**
– non-current	**1,017**	**68**	**5,156**	**3,510**	**9,751**
Of which – payable from the trust funds	**1,438**	**47**	**4,957**	**–**	**6,442**

					$ million
	Environmental	Spill response	Litigation and claims	Clean Water Act penalties	Total
At 1 January 2011	809	1,043	10,973	3,510	16,335
New or increased provisions – items not covered by the trust funds	34	586	525	–	1,145
– items covered by the trust funds	1,133	–	2,905	–	4,038
Unwinding of discount	6	–	–	–	6
Change in discount rate	17	–	–	–	17
Utilization – paid by BP	(33)	(1,293)	(1,175)	–	(2,501)
– paid by the trust funds	(449)	–	(3,258)	–	(3,707)
At 31 December 2011	1,517	336	9,970	3,510	15,333
Of which – current	961	282	8,194	–	9,437
– non-current	556	54	1,776	3,510	5,896
Of which – payable from the trust funds	1,066	–	8,809	–	9,875

As described in Note 2, BP has recorded provisions at 31 December 2012 relating to the Gulf of Mexico oil spill including amounts in relation to environmental expenditure, spill response costs, litigation and claims, and Clean Water Act penalties, each of which is described below. The total amounts that will ultimately be paid by BP are subject to significant uncertainty as described in Note 2 and below.

Environmental

The amounts committed by BP for a 10-year research programme to study the impact of the incident on the marine and shoreline environment of the Gulf of Mexico have been provided for. BP's commitment is to provide $500 million of funding, and the remaining commitment, on a discounted basis, of $376 million was included in provisions at 31 December 2012. This amount is expected to be spent over the remaining life of the programme.

As a responsible party under the Oil Pollution Act of 1990 (OPA 90), BP faces claims by the United States, as well as by State, tribal, and foreign trustees, if any, for natural resource damages ("Natural Resource Damages claims"). These damages include, among other things, the reasonable costs of assessing the injury to natural resources. BP has been incurring natural resource damage assessment costs and a provision has been made for the estimated costs of the assessment phase. Since May 2010, more than 200 initial and amended work plans have been developed to study resources and habitat. The study data will inform an assessment of injury to the Gulf Coast natural resources and the development of a restoration plan to mitigate the identified injuries. Detailed analysis and interpretation continue on the data that have been collected. The expected assessment spend is based upon past experience as well as identified projects. 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. The total amount provided for natural resource damage assessment costs and early restoration projects was $1,486 million at 31 December 2012. 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. See Note 43 for further information.

Spill response

Further amounts were provided relating to the spill response during 2012, totalling $0.1 billion (2011 $0.6 billion). By the end of 2012, the US Coast Guard's Federal On-Scene Coordinator (FOSC) had deemed removal actions complete on 4,029 miles of shoreline out of 4,376 miles that were in the area of response. Approximately 108 shoreline miles were pending further monitoring or inspection and a determination that removal actions are complete. The remaining 239 miles are in the patrolling and maintenance phase which will continue until the FOSC determines that operational removal activity is complete.

Litigation and claims

BP faces various claims, principally under OPA 90 but also including under general maritime law, by individuals and businesses for removal costs, 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 by state and local government entities for removal costs, physical damage to real or personal property, loss of government revenue and increased public services costs ("State and Local Claims"). BP also faces other litigation related to the Incident brought under US state law

36. Provisions continued

and the laws of certain non-US jurisdictions, as well as claims by private parties under US federal securities laws and other state and federal statutes. See Legal proceedings on pages 162-171 for further information.

The litigation and claims provision includes amounts that can be estimated reliably for the future cost of settling Individual and Business Claims, and State and Local Claims under OPA 90, including certain amounts as set forth below related to the settlements with the PSC, the cost of the agreement with the US government to resolve all federal criminal claims, and claims administration costs and legal fees. During 2012, a provision was recognized in the amount of $525 million in respect of the cost of the agreement with the US Securities and Exchange Commission (SEC) to resolve all of the US government's federal securities claims against the company (the SEC settlement). The remaining obligation for the SEC settlement at 31 December 2012 has been reclassified to other payables (as discussed below).

BP announced on 3 March 2012 that a proposed settlement had been reached with the Plaintiffs' Steering Committee (PSC), subject to final written agreement and court approvals, to resolve the substantial majority of legitimate economic loss and property damage claims and exposure-based medical claims (Individual and Business claims) stemming from the Deepwater Horizon accident and oil spill. The PSC acts on behalf of the individual and business plaintiffs in the multi-district litigation proceedings pending in New Orleans (MDL 2179). The proposed settlement was an adjusting event after the 2011 reporting period and BP's estimate at that time of the cost of the settlement of $7.8 billion was therefore reflected in the 2011 financial statements. On 18 April 2012, BP announced that it had reached definitive and fully documented settlement agreements with the PSC consistent with the terms of that settlement. In November 2012, the court held a fairness hearing with respect to the Economic and Property Damages Settlement Agreement and Medical Benefits Settlement Agreement and subsequently granted final approval to the Economic and Property Damages Settlement on 21 December 2012 and to the medical benefits settlement on 11 January 2013. See Legal proceedings on pages 162-171 for further information.

Under the terms of the PSC settlement agreement, several qualified settlement funds (QSFs) were established during the year. These QSFs, which are funded through the Trust, each relate to specific elements of the agreement and are available to make payments to claimants in accordance with those elements of the agreement.

The total amount allocated to the seafood industry under the PSC settlement is fixed at $2.3 billion and thus amounts contributed from the Trust to the seafood compensation fund extinguish BP's liability, so the provision and related reimbursement asset are derecognized, irrespective of whether amounts have been paid out of the fund to claimants. Utilization of the provision in 2012 included $2,230 million contributed to the seafood compensation fund. Additionally, a further $67 million was paid to seafood industry claimants through the transition claims process. At 31 December 2012, $1,847 million remained in the seafood compensation fund for which the related provision and reimbursement asset had been derecognized.

As at 31 December 2011, the provision for items covered by the settlement with the PSC for Individual and Business claims was $7.8 billion. During 2012, BP increased its estimate of the cost of claims administration by $280 million and also increased the provision by a further $400 million as described below.

Business economic loss claims received by the Deepwater Horizon Court Supervised Settlement Program (DHCSSP) to date are being paid at a significantly higher average amount than previously assumed by BP in formulating the original estimate of the cost. Further, BP's initial estimate of aggregate liability under the settlement agreements was premised on BP's interpretation of certain protocols established in the Economic and Property Damages Settlement Agreement. As part of its monitoring of payments made by the DHCSSP, BP identified multiple claim determinations that appeared to result from an interpretation of the settlement agreement by the claims administrator that BP believes was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP assumed in making the initial estimate. Pursuant to the mechanisms in the settlement agreement, the claims administrator sought clarification from the court on this matter and on 30 January 2013, the court initially upheld the claims administrator's interpretation of the agreement.

In its unaudited fourth quarter and full year 2012 results announcement dated 5 February 2013 (the 'preliminary announcement'), BP stated that if the initial trend of higher average payments than assumed by BP in its original estimate of the cost continued, then it was likely that BP's provision for these claims would be increased significantly. Management's initial assessment of the ruling regarding the interpretation of the settlement agreement led to an increase in the estimated cost of the settlement with the PSC of $400 million, bringing the total estimated cost to $8.5 billion. This estimate was based upon management's initial assessment of the ruling's impact on claims already submitted to and processed by the DHCSSP. At that time, BP was seeking reversal of the court's decision in relation to this matter, and management concluded that it was not possible to estimate reliably the impact of the interpretation on any future claims not yet received or processed by the DHCSSP.

On 6 February 2013, the court reconsidered and vacated its ruling of 30 January 2013 and stayed the processing of certain types of business economic loss claims. The court lifted the stay on 28 February 2013. On 5 March 2013, the court affirmed the claims administrator's interpretation of the agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options including rights of appeal, to challenge this ruling. Other business economic loss claims continue to be paid at a higher average amount than previously assumed by BP in determining its initial estimate of the total cost. Management has continued to analyse the claims in the period since 5 February 2013 to gain a better understanding of whether or not the number and average value of claims received and processed to date are predictive of future claims (and so would allow management to estimate the total cost reliably). Management has concluded, based upon this analysis, that it is not possible to determine whether the claims experience to date is, or is not, an appropriate basis for estimating the total cost. Therefore, given the inherent uncertainty that exists as BP pursues all available legal options to challenge the recent ruling, and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP.

Therefore, the provision for business economic loss claims at 31 December 2012 included in these financial statements now includes only the estimated cost of claims already received and processed by the DHCSSP. As a consequence, an amount of $0.8 billion previously provided for future claims not yet received or processed by the DHCSSP, has been derecognized, with a corresponding reduction in the reimbursement asset and therefore no net impact on the income statement, as no reliable estimate can be made for this liability. It is therefore disclosed as a contingent liability in Note 43. A provision will be re-established when a reliable estimate can be made of the liability as explained more fully below.

BP's current estimate of the total cost of those elements of the PSC settlement that can be estimated reliably, which excludes any future business economic loss claims not yet received or processed by the DHCSSP, is $7.7 billion.

If BP is successful in its challenge to the court's ruling, the total estimated cost of the settlement agreement will, nevertheless, be significantly higher than the current estimate of $7.7 billion because business economic loss claims not yet received or processed are not reflected in the current estimate and the average payments per claim determined so far are higher than anticipated. If BP is not successful in its challenge to the court's ruling, a further significant increase to the total estimated cost of the settlement will be required but BP will continue to challenge the current interpretation and implementation of the settlement agreement by the claims administrator using all legal avenues available, including rights of appeal. However, there can be no certainty as to how the dispute will ultimately be resolved or determined. To the extent that there are insufficient funds available in the Trust fund, payments under the PSC settlement will be made by BP directly and charged to the income statement.

Significant uncertainties exist in relation to the amount of claims that are to be paid and will become payable through the claims process. There is significant uncertainty in relation to the amounts that ultimately will be paid in relation to current claims, and the number, type and amounts payable for claims not yet reported. In addition, there is further uncertainty in relation to interpretations of the claims administrator regarding the protocols under the settlement agreement and judicial interpretation of these protocols, and the outcomes of any further litigation including in relation to potential opt-outs from the settlement or otherwise. The PSC settlement is uncapped except for economic loss claims related to the Gulf seafood industry.

While BP has determined its current best estimate of the cost of those aspects of the settlement with the PSC that can be measured reliably, it is possible that the actual cost of those items could be significantly higher than this estimate due to the uncertainties noted above. In addition, the provision will be re-established for remaining business economic loss claims as more information becomes available, the interpretation of the protocols is clarified and the claims process matures, enabling BP to estimate reliably the cost of these claims. BP will continue to analyse claims data and re-evaluate the assumptions underlying the provision.

The provision recognized for litigation and claims includes an estimate for State and Local government 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. In January 2013, the States of Alabama, Mississippi and Florida formally presented their claims to BP under OPA 90 for alleged losses including economic and property damage as a result of the Gulf of Mexico oil spill (see Note 43 for further information).

BP reached an agreement in November 2012 with the US government, subject to court approval, to resolve all criminal claims arising from the incident under which BP will pay $4 billion in instalments over a period of five years. A provision of $3.85 billion has been recognized, representing the discounted cost of the agreement. This settlement was approved by the court in January 2013 and is not covered by the Trust. In addition, BP reached a settlement with the US Securities and Exchange Commission (SEC), which was approved by the court in December 2012, resolving all of the US government's securities claims against the company, under which BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years. On 10 December 2012, a federal judge issued a final judgment regarding the SEC's claims and the terms of the settlement. During 2012, a provision was recognized in the amount of $525 million in respect of the cost of the SEC settlement. The remaining obligation of $350 million for the SEC settlement at 31 December 2012, which is not covered by the trust fund, has been reclassified to other payables.

BP also faces other litigation for which no reliable estimate of the cost can currently be made. Therefore no amounts have been provided for these items. See Note 43 for further information.

Clean Water Act penalties

A provision has been made for the estimated penalties for strict liability under Section 311 of the Clean Water Act. Such penalties are subject to a statutory maximum calculated as the product of a per-barrel maximum penalty rate and the number of barrels of oil spilled. Uncertainties currently exist in relation to both the penalty rate that will ultimately be imposed and the volume of oil spilled.

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 through 15 July 2010 less an estimate of the amount captured on the surface (approximately 850,000 barrels).

This estimated discharge volume was then multiplied by $1,100 per barrel – the maximum amount the statute allows in the absence of gross negligence or wilful misconduct – for the purposes of estimating a potential penalty. This resulted in a provision of $3,510 million for potential penalties under Section 311.

The 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. BP intends to argue for a penalty lower than $1,100 per barrel based on several of these factors. However, 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 on pages 162-171), 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 will depend upon what is determined by the court in the federal multi-district litigation proceedings in New Orleans (MDL 2179) to be the volume of oil spilled and the penalty rate that is imposed or upon any settlement, if one were to be reached. It is not currently practicable to estimate the timing of expending these costs and the provision has been included within non-current liabilities on the balance sheet. Save in relation to the amounts described in this note, and in Note 2, no other amounts have been provided as at 31 December 2012 in relation to other potential fines and penalties because it is not possible to measure the obligation reliably. Fines and penalties are not covered by the trust fund.

36. Provisions continued

Items not provided for and uncertainties

BP considers that it is not possible, at this time, to measure reliably any obligation in relation to Natural Resource Damages claims under OPA 90 (other than the estimated costs of the assessment phase and the costs of early restoration agreements referred to above). It is also not possible to measure reliably any obligation in relation to business economic loss claims under the PSC settlement not yet received or processed by the DHCSSP, or any other potential litigation (including through excluded parties from the PSC settlement and any obligation in relation to other potential private or governmental litigation), fines, or penalties, other than as described above. These items are therefore disclosed as contingent liabilities – see Note 43 for further information.

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 described further in Note 43.

37. 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 externally 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. With effect from 1 April 2010, BP closed its UK plan to new joiners other than some of those joining the North Sea business. The plan remains open to ongoing accrual for those employees who had joined BP on or before 31 March 2010. The majority of new joiners in the UK have the option to join 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 hires. Retired US employees typically take their pension benefit in the form of a lump sum payment. 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 2012, contributions of $884 million (2011 $429 million and 2010 $411 million) and $153 million (2011 $777 million and 2010 $694 million) were made to the UK plans and US plans respectively. In addition, contributions of $238 million (2011 $223 million and 2010 $188 million) were made to other funded defined benefit plans. The aggregate level of contributions in 2013 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.

Certain group companies, principally in the US, provide post-retirement healthcare and life insurance benefits to their retired employees and 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 plans are funded to a limited extent.

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 2012. 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 for estimating 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. The same assumptions are used to determine pension and other post-retirement benefit expense for the following year, that is, the assumptions at 31 December 2012 are used to determine the pension liabilities at that date and the pension expense for 2013.

			%						
Financial assumptions			UK			US			Other
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Discount rate for pension plan liabilities	**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 plans	**n/a**	n/a	n/a	**3.7**	4.5	5.3	**n/a**	n/a	n/a
Rate of increase in salaries	**4.9**	5.1	5.4	**4.2**	3.7	4.1	**3.7**	3.7	3.8
Rate of increase for pensions in payment	**3.1**	3.2	3.5	**–**	–	–	**1.7**	1.7	1.8
Rate of increase in deferred pensions	**3.1**	3.2	3.5	**–**	–	–	**1.2**	1.2	1.3
Inflation	**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.

37. Pensions and other post-retirement benefits continued

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
	2012	2011	2010	**2012**	2011	2010	**2012**	2011	2010
Life expectancy at age 60 for a male currently aged 60	**27.7**	27.6	26.1	**24.9**	24.8	24.7	**23.6**	23.5	23.3
Life expectancy at age 60 for a male currently aged 40	**30.6**	30.5	29.1	**26.3**	26.3	26.2	**26.5**	26.3	26.2
Life expectancy at age 60 for a female currently aged 60	**29.4**	29.3	28.7	**26.4**	26.4	26.3	**28.2**	28.0	27.9
Life expectancy at age 60 for a female currently aged 40	**32.1**	32.0	31.6	**27.3**	27.3	27.2	**30.8**	30.7	30.6

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:

			%
	2012	2011	2010
First year's US healthcare cost trend rate	**7.3**	7.6	7.8
Ultimate US healthcare cost trend rate	**5.0**	5.0	5.0
Year in which ultimate trend rate is reached	**2020**	2020	2018

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

			%
Asset category	**UK**	**US**	**Other**
Total equity	**73**	**70**	**17-62**
Bonds/cash	**20**	**30**	**25-75**
Property/real estate	**7**	**–**	**0-10**

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

Return on asset assumptions reflect the group's expectations built up by asset class and by plan. The group's expectation is derived from a combination of historical returns over the long term and the forecasts of market professionals. Our assumption for return on equities is based on a long-term view, and the size of the resulting equity risk premium over government bond yields is reviewed each year for reasonableness. Our assumption for return on bonds reflects the portfolio mix of government fixed-interest, index-linked and corporate bonds.

Return on asset assumptions at 31 December each year have been used to date in the determination of the pension expense for the following year. However, with effect from 1 January 2013, the group will adopt an amended version of IAS 19 'Employee Benefits', under which the amount credited to the income statement reflecting the return on pension assets will be calculated by applying the discount rate used to measure the obligation, and will therefore be based on a lower corporate bond rate (see Note 1 under Impact of new International Financial Reporting Standards for further information). Under the amended IAS 19, net finance income relating to pensions and other post-retirement benefits, and profit before taxation, would have been approximately $0.8 billion and $0.7 billion lower for 2012 and 2011 respectively, with corresponding pre-tax increases in other comprehensive income. The impact on the group's 2013 profit before taxation is expected to be approximately $1.0 billion. This change has no impact on the balance sheet and no impact on past or expected future cash flows.

The expected long-term rates of return at 31 December 2012 are therefore not presented in the table below. Instead, the table presents the interest rate assumptions at 31 December 2012, which are equal to the discount rate assumptions for plan liabilities as noted above and which will be used in the determination of the pension expense for 2013. For 2011 and 2010, the expected long-term rates of return and market values of the various categories of assets held by the defined benefit plans at 31 December are presented. The market values include the effects of derivative financial instruments. The amounts classified as equities include investments in companies listed on stock exchanges as well as unlisted investments. Movements in the value of plan assets during the year are shown in detail in the table on page 242.

37. Pensions and other post-retirement benefits continued

	2012		2011		2010	
	Interest rate	**Market value**	Expected long-term rate of return	Market value	Expected long-term rate of return	Market value
	%	**$ million**	%	$ million	%	$ million
UK pension plans						
Equities[a]		**19,612**	8.0	17,202	8.0	18,546
Bonds		**4,885**	4.4	4,141	5.0	3,866
Property/real estate		**1,783**	6.5	1,710	6.5	1,462
Cash		**1,066**	1.7	534	1.4	406
	4.4	**27,346**	7.0	23,587	7.2	24,280
US pension plans						
Equities[a]		**5,431**	9.0	5,034	9.1	5,058
Bonds		**2,159**	4.0	2,022	4.5	1,419
Property/real estate		**5**	8.0	4	8.0	7
Cash		**191**	0.2	144	0.3	165
	3.2	**7,786**	7.4	7,204	8.0	6,649
US other post-retirement benefit plans						
Cash		**1**	0.2	4	0.3	8
	3.7	**1**	0.2	4	0.3	8
Other plans						
Equities		**940**	7.9	831	8.0	1,182
Bonds		**2,114**	3.3	1,951	4.2	1,874
Property/real estate		**139**	6.2	117	6.3	83
Cash		**340**	2.2	387	2.7	155
	3.6	**3,533**	4.7	3,286	5.4	3,294

[a] The amounts classified as equities include investments in companies listed on stock exchanges as well as private equity investments which are substantially all unlisted. The market value of private equity investments at 31 December 2012 was $4,354 million (2011 $4,099 million and 2010 $3,348 million). The equity return assumption shown above for 2011 and 2010 is the weighted average of the assumed returns for listed and private equity assets in each fund.

The discount rate, inflation, US healthcare cost trend rate and the mortality assumptions all have a significant effect on the amounts reported.

A one-percentage point change in the following assumptions as at 31 December 2012 for the group's plans would have had the effects shown in the table below. The effects shown for the expense in 2013 include current service cost and net finance income or expense.

	$ million	
	One percentage point	
	Increase	**Decrease**
Discount rate[a]		
Effect on pension and other post-retirement benefit expense in 2013	**(480)**	**528**
Effect on pension and other post-retirement benefit obligation at 31 December 2012	**(7,364)**	**9,626**
Inflation rate		
Effect on pension and other post-retirement benefit expense in 2013	**553**	**(410)**
Effect on pension and other post-retirement benefit obligation at 31 December 2012	**6,986**	**(5,580)**
US healthcare cost trend rate		
Effect on US other post-retirement benefit expense in 2013	**27**	**(21)**
Effect on US other post-retirement obligation at 31 December 2012	**321**	**(265)**

[a] The amounts presented reflect that from 2013, the discount rate will be used to determine the return on pension assets as well as the interest cost on the obligation, as noted above.

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 2013 includes current service cost and interest on plan liabilities.

				$ 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 2013	**39**	**5**	**3**	**8**
Effect on pension and other post-retirement benefit obligation at 31 December 2012	**647**	**118**	**67**	**197**

37. Pensions and other post-retirement benefits continued

					$ million
					2012
	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]	477	328	51	150	1,006
Past service cost	–	20	–	12	32
Settlement, curtailment and special termination benefits	(1)	–	–	71	70
Payments to defined contribution plans	14	223	–	44	281
Total operating charge[b]	490	571	51	277	1,389
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,680	524	–	163	2,367
Interest on plan liabilities	(1,249)	(382)	(134)	(401)	(2,166)
Other finance income (expense)	431	142	(134)	(238)	201
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	989	498	–	164	1,651
Change in assumptions underlying the present value of the plan liabilities	(1,446)	(1,427)	239	(1,130)	(3,764)
Experience gains and losses arising on the plan liabilities	(116)	68	(48)	(126)	(222)
Actuarial (loss) gain recognized in other comprehensive income	(573)	(861)	191	(1,092)	(2,335)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	25,675	8,617	3,061	8,729	46,082
Exchange adjustments	1,313	–	–	251	1,564
Current service cost[a]	477	328	51	150	1,006
Past service cost	–	20	–	12	32
Interest cost	1,249	382	134	401	2,166
Curtailment	(8)	–	–	(15)	(23)
Settlement	–	–	–	1	1
Special termination benefits[c]	7	–	–	85	92
Contributions by plan participants[d]	39	–	–	14	53
Benefit payments (funded plans)[e]	(1,038)	(593)	(3)	(230)	(1,864)
Benefit payments (unfunded plans)[e]	(7)	(84)	(207)	(392)	(690)
Disposals	(10)	–	–	(192)	(202)
Actuarial loss (gain) on obligation	1,562	1,359	(191)	1,256	3,986
Benefit obligation at 31 December[a f]	29,259	10,029	2,845	10,070	52,203
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
Expected return on plan assets[a g]	1,680	524	–	163	2,367
Contributions by plan participants[d]	39	–	–	14	53
Contributions by employers (funded plans)	884	153	–	238	1,275
Benefit payments (funded plans)[e]	(1,038)	(593)	(3)	(230)	(1,864)
Disposals	(10)	–	–	(190)	(200)
Actuarial gain on plan assets[g]	989	498	–	164	1,651
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)	(6,537)	(13,537)
Represented by					
Asset recognized	–	–	–	12	12
Liability recognized	(1,913)	(2,243)	(2,844)	(6,549)	(13,549)
	(1,913)	(2,243)	(2,844)	(6,537)	(13,537)
The 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)	(5,998)	(9,668)
	(1,913)	(2,243)	(2,844)	(6,537)	(13,537)
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)	(5,998)	(9,668)
	(29,259)	(10,029)	(2,845)	(10,070)	(52,203)

[a] The costs of managing the plan's investments are treated as being part of the investment return, 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] Included within production and manufacturing expenses and distribution and administration expenses.
[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[d] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.
[e] The benefit payments amount shown above comprises $2,499 million benefits plus $55 million of plan expenses incurred in the administration of the benefit.
[f] The benefit obligation for other plans includes $4,705 million for the German plan, which is largely unfunded.
[g] 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.

37. 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	133	849
Past service cost	–	184	–	7	191
Settlement, curtailment and special termination benefits	3	–	–	40	43
Payments to defined contribution plans	5	199	–	41	245
Total operating charge[b]	391	663	53	221	1,328
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,799	518	–	185	2,502
Interest on plan liabilities	(1,263)	(369)	(163)	(444)	(2,239)
Other finance income (expense)	536	149	(163)	(259)	263
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	(1,990)	10	(1)	(61)	(2,042)
Change in assumptions underlying the present value of the plan liabilities	(2,680)	(512)	39	(642)	(3,795)
Experience gains and losses arising on the plan liabilities	(84)	(102)	89	(26)	(123)
Actuarial (loss) gain recognized in other comprehensive income	(4,754)	(604)	127	(729)	(5,960)
Movements in benefit obligation during the year					
Benefit obligation at 1 January	22,363	7,988	3,157	8,404	41,912
Exchange adjustments	(137)	–	–	(326)	(463)
Current service cost[a]	383	280	53	133	849
Past service cost	–	184	–	7	191
Interest cost	1,263	369	163	444	2,239
Curtailment	–	–	–	(1)	(1)
Settlement	–	–	–	4	4
Special termination benefits[c]	3	–	–	37	40
Contributions by plan participants[d]	33	–	–	10	43
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Benefit payments (unfunded plans)[e]	(4)	(68)	(181)	(405)	(658)
Disposals	–	–	–	(20)	(20)
Actuarial loss (gain) on obligation	2,764	614	(128)	668	3,918
Benefit obligation at 31 December[a f]	25,675	8,617	3,061	8,729	46,082
Movements in fair value of plan assets during the year					
Fair value of plan assets at 1 January	24,280	6,649	8	3,294	34,231
Exchange adjustments	29	–	–	(123)	(94)
Expected return on plan assets[a g]	1,799	518	–	185	2,502
Contributions by plan participants[d]	33	–	–	10	43
Contributions by employers (funded plans)	429	777	–	223	1,429
Benefit payments (funded plans)[e]	(993)	(750)	(3)	(226)	(1,972)
Disposals	–	–	–	(16)	(16)
Actuarial gain (loss) on plan assets[g]	(1,990)	10	(1)	(61)	(2,042)
Fair value of plan assets at 31 December	23,587	7,204	4	3,286	34,081
Deficit at 31 December	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
Represented by					
Asset recognized	–	–	–	17	17
Liability recognized	(2,088)	(1,413)	(3,057)	(5,460)	(12,018)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The deficit may be analysed between funded and unfunded plans as follows					
Funded	(1,852)	(784)	(41)	(492)	(3,169)
Unfunded	(236)	(629)	(3,016)	(4,951)	(8,832)
	(2,088)	(1,413)	(3,057)	(5,443)	(12,001)
The defined benefit obligation may be analysed between funded and unfunded plans as follows					
Funded	(25,439)	(7,988)	(45)	(3,778)	(37,250)
Unfunded	(236)	(629)	(3,016)	(4,951)	(8,832)
	(25,675)	(8,617)	(3,061)	(8,729)	(46,082)

[a] The costs of managing the plan's investments are treated as being part of the investment return, 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] Included within production and manufacturing expenses and distribution and administration expenses.
[c] The charge for special termination benefits represents the increased liability arising as a result of early retirements occurring as part of restructuring programmes.
[d] Most of the contributions made by plan participants into UK pension plans were made under salary sacrifice.
[e] The benefit payments amount shown above comprises $2,576 million benefits plus $54 million of plan expenses incurred in the administration of the benefit.
[f] The benefit obligation for other plans includes $3,909 million for the German plan, which is largely unfunded.
[g] 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.

37. Pensions and other post-retirement benefits continued

					$ million
					2010
	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]	393	241	48	120	802
Past service cost	–	–	–	3	3
Settlement, curtailment and special termination benefits	24	–	–	161	185
Payments to defined contribution plans	1	187	–	35	223
Total operating charge[b]	418	428	48	319	1,213
Analysis of the amount credited (charged) to other finance expense					
Expected return on plan assets	1,580	465	1	178	2,224
Interest on plan liabilities	(1,183)	(396)	(169)	(429)	(2,177)
Other finance income (expense)	397	69	(168)	(251)	47
Analysis of the amount recognized in other comprehensive income					
Actual return less expected return on pension plan assets	1,577	425	(1)	36	2,037
Change in assumptions underlying the present value of the plan liabilities	(1,144)	(498)	(132)	(489)	(2,263)
Experience gains and losses arising on the plan liabilities	12	(167)	(8)	69	(94)
Actuarial (loss) gain recognized in other comprehensive income	445	(240)	(141)	(384)	(320)

[a] The costs of managing the plan's investments are treated as being part of the investment return, 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] Included within production and manufacturing expenses and distribution and administration expenses.

At 31 December 2012, reimbursement balances due from or to other companies in respect of pensions amounted to $732 million reimbursement assets (2011 $546 million) and $15 million reimbursement liabilities (2011 $13 million). These balances are not included as part of the pension surpluses and deficits, but are reflected within other receivables and other payables in the group balance sheet.

					$ million
	2012	2011	2010	2009	2008
History of surplus (deficit) and of experience gains and losses					
Benefit obligation at 31 December	**52,203**	46,082	41,912	40,073	34,847
Fair value of plan assets at 31 December	**38,666**	34,081	34,231	31,453	26,154
Deficit	**(13,537)**	(12,001)	(7,681)	(8,620)	(8,693)
Experience losses on plan liabilities	**(222)**	(123)	(94)	(421)	(178)
Actual return less expected return on pension plan assets	**1,651**	(2,042)	2,037	2,549	(10,253)
Actual return on plan assets	**4,018**	460	4,261	4,528	(7,331)
Actuarial loss recognized in other comprehensive income	**(2,335)**	(5,960)	(320)	(682)	(8,430)
Cumulative amount recognized in other comprehensive income	**(12,237)**	(9,902)	(3,942)	(3,622)	(2,940)

Estimated future benefit payments

The expected benefit payments, which reflect expected future service, as appropriate, but exclude plan expenses, up until 2022 are as follows:

					$ million
	UK pension plans	**US pension plans**	**US other post-retirement benefit plans**	**Other plans**	**Total**
2013	**1,115**	**813**	**167**	**560**	**2,655**
2014	**1,163**	**829**	**169**	**568**	**2,729**
2015	**1,211**	**847**	**171**	**567**	**2,796**
2016	**1,268**	**851**	**173**	**561**	**2,853**
2017	**1,276**	**849**	**173**	**554**	**2,852**
2018-2022	**7,059**	**4,003**	**851**	**2,659**	**14,572**

38. Called-up share capital

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

Issued	2012 Shares thousand	2012 $ million	2011 Shares thousand	2011 $ million	2010 Shares thousand	2010 $ 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	**20,813,410**	**5,203**	20,647,160	5,162	20,629,665	5,158
Issue of new shares for the scrip dividend programme	**138,406**	**35**	165,601	41	–	–
Issue of new shares for employee share-based payment plans[b]	**7,343**	**2**	649	–	17,495	4
At 31 December	**20,959,159**	**5,240**	20,813,410	5,203	20,647,160	5,162
		5,261		5,224		5,183

[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 $47 million (2011 $4 million and 2010 $138 million).

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

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

Treasury shares

	2012 Shares thousand	2012 Nominal value $ million	2011 Shares thousand	2011 Nominal value $ million	2010 Shares thousand	2010 Nominal value $ million
At 1 January	**1,837,508**	**459**	1,850,699	462	1,869,777	467
Shares transferred to ESOPs at market price	**–**	**–**	–	–	(7,125)	(2)
Shares re-issued for employee share-based payment plans	**(14,100)**	**(4)**	(13,191)	(3)	(11,953)	(3)
At 31 December	**1,823,408**	**455**	1,837,508	459	1,850,699	462

For each year presented, the balance at 1 January represents the maximum number of shares held in treasury during the year, representing 8.8% (2011 9.0% and 2010 9.1%) of the called-up ordinary share capital of the company.

During 2012, the movement in treasury shares represented less than 0.1% (2011 less than 0.1% and 2010 less than 0.1%) of the ordinary share capital of the company.

39. Capital and reserves

	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**
Currency translation differences (including recycling)	**–**	**–**	**–**	**–**	**–**
Actuarial loss relating to pensions and other post-retirement benefits	**–**	**–**	**–**	**–**	**–**
Available-for-sale investments (including recycling)	**–**	**–**	**–**	**–**	**–**
Cash flow hedges (including recycling)	**–**	**–**	**–**	**–**	**–**
Share of equity-accounted entities' other comprehensive income, net of tax	**–**	**–**	**–**	**–**	**–**
Other	**–**	**–**	**–**	**–**	**–**
Profit for the year	**–**	**–**	**–**	**–**	**–**
Total comprehensive income	**–**	**–**	**–**	**–**	**–**
Dividends	**35**	**(35)**	**–**	**–**	**–**
Share-based payments[a]	**2**	**57**	**–**	**–**	**59**
Transactions involving minority 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
Currency translation differences (including recycling)	–	–	–	–	–
Actuarial loss relating to pensions and other post-retirement benefits	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	–	–	–
Profit for the year	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	41	(41)	–	–	–
Share-based payments[a]	–	6	–	–	6
Transactions involving minority interests	–	–	–	–	–
At 31 December 2011	5,224	9,952	1,072	27,206	43,454

	Share capital	Share premium account	Capital redemption reserve	Merger reserve	Total share capital and capital reserves
At 1 January 2010	5,179	9,847	1,072	27,206	43,304
Currency translation differences (including recycling)	–	–	–	–	–
Actuarial loss relating to pensions and other post-retirement benefits	–	–	–	–	–
Available-for-sale investments (including recycling)	–	–	–	–	–
Cash flow hedges (including recycling)	–	–	–	–	–
Profit (loss) for the year	–	–	–	–	–
Total comprehensive income	–	–	–	–	–
Dividends	–	–	–	–	–
Share-based payments[a]	4	140	–	–	144
Transactions involving minority interests	–	–	–	–	–
At 31 December 2010	5,183	9,987	1,072	27,206	43,448

[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	Minority interest	Total equity
(388)	**(20,935)**	**(21,323)**	**4,422**	**389**	**(122)**	**267**	**1,582**	**83,063**	**111,465**	**1,017**	**112,482**
–	**–**	**–**	**665**	**–**	**(5)**	**(5)**	**–**	**–**	**660**	**2**	**662**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(1,721)**	**(1,721)**	**2**	**(1,719)**
–	**–**	**–**	**–**	**296**	**–**	**296**	**–**	**–**	**296**	**–**	**296**
–	**–**	**–**	**–**	**–**	**1,217**	**1,217**	**–**	**–**	**1,217**	**–**	**1,217**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(98)**	**(98)**	**–**	**(98)**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**23**	**23**	**–**	**23**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**11,582**	**11,582**	**234**	**11,816**
–	**–**	**–**	**665**	**296**	**1,212**	**1,508**	**–**	**9,786**	**11,959**	**238**	**12,197**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**(5,294)**	**(5,294)**	**(82)**	**(5,376)**
108	**161**	**269**	**–**	**–**	**–**	**–**	**26**	**(70)**	**284**	**–**	**284**
–	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**–**	**33**	**33**
(280)	**(20,774)**	**(21,054)**	**5,087**	**685**	**1,090**	**1,775**	**1,608**	**87,485**	**118,414**	**1,206**	**119,620**

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	Minority interest	Total equity
(126)	(21,085)	(21,211)	4,937	463	6	469	1,586	65,758	94,987	904	95,891
–	–	–	(515)	–	(1)	(1)	–	–	(516)	(10)	(526)
–	–	–	–	–	–	–	–	(4,321)	(4,321)	(3)	(4,324)
–	–	–	–	(74)	–	(74)	–	–	(74)	–	(74)
–	–	–	–	–	(127)	(127)	–	–	(127)	–	(127)
–	–	–	–	–	–	–	–	(57)	(57)	–	(57)
–	–	–	–	–	–	–	–	25,700	25,700	397	26,097
–	–	–	(515)	(74)	(128)	(202)	–	21,322	20,605	384	20,989
–	–	–	–	–	–	–	–	(4,072)	(4,072)	(245)	(4,317)
(262)	150	(112)	–	–	–	–	(4)	102	(8)	–	(8)
–	–	–	–	–	–	–	–	(47)	(47)	(26)	(73)
(388)	(20,935)	(21,323)	4,422	389	(122)	267	1,582	83,063	111,465	1,017	112,482

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	Minority interest	Total equity
(214)	(21,303)	(21,517)	4,811	754	22	776	1,584	72,655	101,613	500	102,113
–	–	–	126	–	2	2	–	–	128	3	131
–	–	–	–	–	–	–	–	(418)	(418)	–	(418)
–	–	–	–	(291)	–	(291)	–	–	(291)	–	(291)
–	–	–	–	–	(18)	(18)	–	–	(18)	–	(18)
–	–	–	–	–	–	–	–	(3,719)	(3,719)	395	(3,324)
–	–	–	126	(291)	(16)	(307)	–	(4,137)	(4,318)	398	(3,920)
–	–	–	–	–	–	–	–	(2,627)	(2,627)	(315)	(2,942)
88	218	306	–	–	–	–	2	(113)	339	–	339
–	–	–	–	–	–	–	–	(20)	(20)	321	301
(126)	(21,085)	(21,211)	4,937	463	6	469	1,586	65,758	94,987	904	95,891

39. 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 2012, the ESOPs held 22,428,179 shares (2011 27,784,503 shares and 2010 11,477,253 shares) for potential future awards, which had a market value of $154 million (2011 $197 million and 2010 $82 million). At 31 December 2012, a further 18,673,926 ordinary share equivalents (2011 21,420,000 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. 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.

39. 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
			2012
	Pre-tax	**Tax**	**Net of tax**
Currency translation differences (including recycling)	**516**	**146**	**662**
Actuarial loss relating to pensions and other post-retirement benefits	**(2,335)**	**616**	**(1,719)**
Available-for-sale investments (including recycling)	**305**	**(9)**	**296**
Cash flow hedges (including recycling)	**1,547**	**(330)**	**1,217**
Share of equity-accounted entities' other comprehensive income	**(98)**	**–**	**(98)**
Other	**–**	**23**	**23**
Other comprehensive income	**(65)**	**446**	**381**

			$ million
			2011
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	(512)	(14)	(526)
Actuarial loss relating to pensions and other post-retirement benefits	(5,960)	1,636	(4,324)
Available-for-sale investments (including recycling)	(74)	–	(74)
Cash flow hedges (including recycling)	(164)	37	(127)
Share of equity-accounted entities' other comprehensive income	(57)	–	(57)
Other comprehensive income	(6,767)	1,659	(5,108)

			$ million
			2010
	Pre-tax	Tax	Net of tax
Currency translation differences (including recycling)	239	(108)	131
Actuarial loss relating to pensions and other post-retirement benefits	(320)	(98)	(418)
Available-for-sale investments (including recycling)	(341)	50	(291)
Cash flow hedges (including recycling)	(37)	19	(18)
Other comprehensive income	(459)	(137)	(596)

40. Share-based payments

Effect of share-based payment transactions on the group's result and financial position

			$ million
	2012	2011	2010
Total expense recognized for equity-settled share-based payment transactions	**669**	579	577
Total expense (credit) recognized for cash-settled share-based payment transactions	**5**	5	(1)
Total expense recognized for share-based payment transactions	**674**	584	576
Closing balance of liability for cash-settled share-based payment transactions	**12**	12	16
Total intrinsic value for vested cash-settled share-based payments	**–**	1	1

All share-based payment transactions relate to employee compensation.

For ease of presentation, options and share units detailed in the tables within this note are stated as UK ordinary share equivalents in US dollars. US employees are granted options or share units over the company's American Depositary Shares (ADSs) (one ADS is equivalent to six ordinary shares). The main share-based payment plans that existed during the year are detailed below.

Plans for executive directors

For information on the Executive Directors' Incentive Plan (EDIP) see the Directors' remuneration report on pages 127-145.

Plans for senior employees

The group operates a number of equity-settled share plans under which share units are granted to its 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. Grants are settled in cash where participants are located in a country whose regulatory environment prohibits the holding of BP shares.

Performance unit plans

The number of units granted is related to the level of seniority of employees and country of operation. The number of units converted to shares is determined by reference to performance measures over the three-year performance period. Performance measures used include BP's total shareholder return (TSR) compared with the other oil majors, balanced scorecard and individual rating. The relative weighting of these different measures is related to the level of seniority of the employee. Plans included in this category are the Competitive Performance Plan (CPP) (no further grants to be made under this plan after 2011) and the Share Value Plan (SVP).

40. Share-based payments continued

Restricted share unit plans

Share unit grants under the Restricted Share Plan (RSP) are used in special circumstances such as recruitment and retention of senior employees and normally have no performance conditions.

Share unit grants under BP's other restricted share plans typically take into account the employee's performance in either the current or the prior year, track record of delivery, business and leadership skills and potential. Plans included in this category are the Executive Performance Plan (EPP), the Performance Share Plan (PSP) (no further grants to be made under these plans after 2011) and the Deferred Annual Bonus Plan (DAB).

BP Share Option Plan (BPSOP)

Share options with an exercise price equivalent to the closing market price of a BP share immediately preceding the date of grant were granted to participants annually until 2006. These options are not subject to any performance conditions and are exercisable between the third and tenth anniversaries of the grant date.

BP Plan 2011

Share options with an exercise price equivalent to the closing market price of a BP share immediately preceding the date of grant were granted to participants in 2011. These options are not subject to any performance conditions and will be exercisable between the third and tenth anniversaries of the grant date, with special arrangements applying to participants who leave employment for qualifying reasons.

Matching and saving plans

BP ShareMatch plans

These matching share plans give employees the opportunity to buy ordinary shares in BP p.l.c. and receive free matching shares in BP p.l.c., up to a predetermined limit. The plans are run in the UK and in more than 50 other countries.

BP ShareSave Plan

This plan is open to all eligible UK employees. Participants can contribute up to a maximum of £250 per month from their net salary to a savings account over a three- or five-year contractual savings period. At the end of the savings period, they are entitled to purchase shares in BP p.l.c. at a preset price determined on the date when the invitations are sent to eligible employees. This price is usually set at a discount to the market price of a share of up to 20%.

Local plans

In some countries, BP provides local scheme benefits, the rules and qualifications for which vary according to local circumstances. Certain US employees may participate in a defined contribution (401k) plan in which BP matches employee contributions up to certain limits. Participants may invest in several investment options including a BP Stock Fund that holds BP ADSs and a small percentage of cash.

Share option transactions

Details of share option transactions for the year under the share option plans are as follows:

Share option transactions	**2012** Number of options	**2012** Weighted average exercise price $	2011 Number of options	2011 Weighted average exercise price $	2010 Number of options	2010 Weighted average exercise price $
Outstanding at 1 January	**374,500,712**	**7.73**	263,306,722	8.75	295,895,357	8.73
Granted[a]	**17,651,908**	**5.01**	152,472,556	6.03	10,420,287	6.08
Forfeited	**(17,501,294)**	**6.55**	(9,058,406)	7.22	(9,499,661)	7.88
Exercised	**(11,588,295)**	**6.46**	(2,502,306)	7.64	(31,839,034)	7.97
Expired	**(38,966,978)**	**8.29**	(29,717,854)	8.26	(1,670,227)	8.71
Outstanding at 31 December[b]	**324,096,053**	**7.62**	374,500,712	7.73	263,306,722	8.75
Exercisable at 31 December	**159,419,041**	**9.33**	209,776,014	9.01	242,530,635	8.90

[a] Share options granted during 2011 include 142.5 million options awarded under the BP Plan 2011 with a fair value of $1.02 per option at the date of grant, determined using a binomial option pricing model including assumptions for share price volatility, dividends, and cancellations.
[b] Share options outstanding at 31 December 2012 include 158 million options granted under the BPSOP (2011 208 million options and 2010 239 million options).

The weighted average share price at the date of exercise was $7.20 (2011 $7.71 and 2010 $9.54).

For options outstanding at 31 December 2012, the exercise price ranges and weighted average remaining contractual lives were as shown below.

Range of exercise prices	**Options outstanding** Number of shares	**Options outstanding** Weighted average remaining life Years	**Options outstanding** Weighted average exercise price $	**Options exercisable** Number of shares	**Options exercisable** Weighted average exercise price $
$5.01 – $6.73	**183,757,213**	**6.77**	**5.96**	**26,176,779**	**6.35**
$6.74 – $8.45	**49,881,487**	**2.08**	**7.83**	**43,881,487**	**7.94**
$8.46 – $10.18	**19,099,639**	**1.93**	**9.89**	**18,237,061**	**9.93**
$10.19 – $11.92	**71,357,714**	**2.80**	**11.13**	**71,123,714**	**11.13**
	324,096,053	**4.89**	**7.62**	**159,419,041**	**9.33**

At 31 December 2012 the quoted value of one BP ordinary share was $6.86.

40. Share-based payments continued

Fair values and associated details for share units granted

For share units granted in 2012, the number of units and weighted average fair value at the date of grant were as shown below:

Share units granted in 2012	SVP TSR	SVP non-TSR	RSP	DAB	
Number of share units granted (million)	**0.5**	**60.3**	**11.2**	**19.6**	
Weighted average fair value	**$8.96**	**$7.78**	**$7.21**	**$7.78**	
Fair value measurement basis	**Monte Carlo**	**Market value**	**Market value**	**Market value**	

Share units granted in 2011	CPP	EPP	RSP	DAB	PSP
Number of share units granted (million)	1.4	8.9	20.0	17.5	19.2
Weighted average fair value	$11.99	$7.51	$6.86	$7.51	$7.51
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Market value

Share units granted in 2010	CPP	EPP	RSP	DAB	PSP
Number of share units granted (million)	1.3	7.6	21.4	24.5	16.0
Weighted average fair value	$19.81	$9.43	$6.78	$9.43	$9.43
Fair value measurement basis	Monte Carlo	Market value	Market value	Market value	Market value

The group uses the observable market price for ordinary shares at the date of grant to determine the fair value of non-TSR share unit awards.

The group used a Monte Carlo simulation to determine the fair values of the TSR elements of the 2012 SVP grant, the 2012, 2011 and 2010 EDIP grants and the 2011 and 2010 CPP grants. In accordance with the plans' rules, the model simulates BP's TSR and compares it against its principal strategic competitors over the three-year period of the plans. The model takes into account the historical dividends, share price volatilities and covariances of BP and each comparator company to produce a predicted distribution of relative share performance. This is applied to the reward criteria to give an expected value of the TSR element.

Accounting expense does not necessarily represent the intended value of share-based payments made to recipients, which are determined by the remuneration committee according to established criteria.

41. Employee costs and numbers

			$ million
Employee costs	**2012**	2011	2010
Wages and salaries[a]	**10,357**	9,827	9,242
Social security costs	**898**	851	789
Share-based payments	**674**	584	576
Pension and other post-retirement benefit costs	**1,188**	1,065	1,166
	13,117	12,327	11,773

Number of employees at 31 December[b]	2012	2011	2010
Upstream	**24,000**	22,200	21,100
Downstream[c]	**51,300**	51,000	52,300
Other businesses and corporate	**10,300**	10,100	6,200
Gulf Coast Restoration Organization	**100**	100	100
	85,700	83,400	79,700
By geographical area			
US	**23,400**	22,900	22,100
Non-US[c]	**62,300**	60,500	57,600
	85,700	83,400	79,700

			2012			2011			2010
Average number of employees[b]	US	Non-US	Total	US	Non-US	Total	US	Non-US	Total
Upstream	**9,300**	**13,900**	**23,200**	8,500	13,200	21,700	8,100	13,500	21,600
Downstream	**12,000**	**39,400**	**51,400**	12,300	39,200	51,500	12,600	38,300	50,900
Other businesses and corporate	**1,900**	**8,700**	**10,600**	1,700	6,500	8,200	1,900	5,000	6,900
Gulf Coast Restoration Organization	**100**	**–**	**100**	100	–	100	–	–	–
	23,300	**62,000**	**85,300**	22,600	58,900	81,500	22,600	56,800	79,400

[a] Includes termination payments of $77 million (2011 $126 million and 2010 $166 million).
[b] Reported to the nearest 100.
[c] Includes 14,700 (2011 14,600 and 2010 15,200) service station staff.

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42. Remuneration of directors and senior management

Remuneration of directors

			$ million
	2012	2011	2010
Total for all directors			
Emoluments	**12**	10	15
Gains made on exercise of share options	**–**	–	2
Amounts awarded under incentive schemes	**3**	1	4
Total	**15**	11	21

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year. There was no compensation for loss of office in 2012 (2011 nil and 2010 $3 million).

Pension contributions

During 2012 two executive directors participated in a non-contributory pension scheme established for UK employees by a separate trust fund to which contributions are made by BP based on actuarial advice. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2012.

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 pages 127-145.

Remuneration of directors and senior management

			$ million
Total for all senior management	**2012**	2011	2010
Total for all senior management			
Short-term employee benefits	**27**	34	25
Pensions and other post-retirement benefits	**3**	3	3
Share-based payments	**34**	27	29
Total	**64**	64	57

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 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. There was no compensation for loss of office paid in 2012 (2011 $9 million and 2010 $3 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, SVP and RSP. For details of these plans refer to Note 40.

43. Contingent liabilities

Contingent liabilities relating to the Gulf of Mexico oil spill

As a consequence of the Gulf of Mexico oil spill, as described on pages 59-62, BP has incurred costs during the year and recognized provisions for certain future costs. Further information is provided in Note 2 and Note 36.

BP has provided for its best estimate of amounts expected to be paid from the $20-billion trust fund. This includes certain amounts expected to be paid pursuant to the Oil Pollution Act of 1990 (OPA 90) as described in Note 36. It is not possible, at this time, to measure reliably other obligations arising from the accident that are under the terms of the trust fund, namely any obligation in relation to Natural Resource Damages claims (except for the estimated costs of the assessment phase and the costs relating to early restoration agreements as described in Note 36), claims asserted in civil litigation including any further litigation through excluded parties from the PSC settlement, the cost of business economic loss claims under the PSC settlement not yet received or processed by the Deepwater Horizon Court Supervised Settlement Program (DHCSSP), any further obligation that may arise from state and local government presentment claims 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 2012. The $20-billion trust fund may not be sufficient to satisfy all claims under OPA 90 or otherwise that will ultimately be paid.

Natural resource damages resulting from the oil spill are currently being assessed (see Note 36 for further information). 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 mitigate 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 amounts have been provided as at 31 December 2012.

As set out more fully in Note 36, business economic loss claims received by the DHCSSP to date are being paid at a significantly higher average amount than previously assumed by BP. Further, BP has identified multiple business economic loss claim determinations under the PSC settlement that appeared to result from an interpretation of the Economic and Property Damages Settlement Agreement by the claims administrator that BP believes was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP assumed in making the initial estimate of the cost of the settlement. Pursuant to the mechanisms in the settlement agreement, the claims administrator sought clarification from the court on this matter and on 30 January 2013, the court initially upheld the claims administrator's interpretation of the agreement. On 6 February 2013, the court reconsidered and vacated this ruling and stayed the processing of certain types of claims. The court lifted the stay on 28 February 2013. On 5 March 2013, the court affirmed the claims administrator's interpretation of the agreement and rejected BP's position as it relates to business economic loss claims. BP strongly disagrees with the ruling of 5 March 2013 and the current implementation of the agreement by the claims administrator. BP intends to pursue all available legal options, including rights of appeal, to challenge this ruling. Management has concluded that it is not possible to determine whether the claims experience to date is, or is not, an appropriate basis for estimating the total cost. Therefore given the inherent uncertainty that exists as BP pursues all available legal options to challenge the ruling, including rights of appeal to challenge the decision, and the higher number of claims received and higher average claims payments than previously assumed by BP, which may or may not continue, management has concluded that no reliable estimate can be made of any business economic loss claims not yet received or processed by the DHCSSP. Therefore the potential cost of such claims is not provided for and is disclosed as a contingent liability. See Note 36 for further information.

In January 2013, the States of Alabama, Mississippi and Florida formally presented their claims to BP under OPA 90 for alleged losses including economic and property damage as a result of the Gulf of Mexico oil spill. BP is evaluating these claims. The State of Louisiana has also asserted similar claims. The amounts claimed, certain of which include punitive damages or other multipliers, are very substantial. However BP considers the methodologies used to calculate these claims to be seriously flawed, not supported by the legislation and to substantially overstate the claims. Claims have also been presented by various local governments which are substantial in aggregate and more claims are expected to be presented. The amounts alleged in the presentments for State and Local government claims total over $34 billion. BP will defend vigorously against these claims if adjudicated at trial.

BP is named as a defendant in approximately 750 civil lawsuits brought by individuals, businesses, insurers 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 claims. Therefore no amounts have been provided for these items as at 31 December 2012. See Legal proceedings on pages 162-171 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 in Note 36, 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 large number of 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.

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 2012.

The magnitude and timing of possible obligations in relation to the Gulf of Mexico oil spill are subject to a very high degree of uncertainty as described further in Risk factors on pages 38-44. Furthermore, for those items for which a provision has been recorded, as noted in Note 36, significant uncertainty also exists in relation to the ultimate exposure and cost to BP. 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.

43. Contingent liabilities continued

Other contingent liabilities

There were contingent liabilities at 31 December 2012 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 26.

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, premises-liability claims, 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 income tax returns in many jurisdictions throughout the world. Various tax authorities are currently examining the group's income 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 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 practical 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.

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.

44. Capital commitments

Authorized future capital expenditure for property, plant and equipment by group companies for which contracts had been signed at 31 December 2012 amounted to $14,068 million (2011 $12,517 million). In addition, at 31 December 2012, the group had contracts in place for future capital expenditure relating to investments in jointly controlled entities of $275 million (2011 $296 million) and investments in associates of nil (2011 $36 million). BP's share of capital commitments of jointly controlled entities amounted to $825 million (2011 $1,244 million). The group has also signed definitive and binding sale and purchase agreements for the sale of BP's 50% interest in TNK-BP to Rosneft and for BP's further investment in Rosneft, as described in Note 4.

45. Subsidiaries, jointly controlled entities and associates

The more important subsidiaries, jointly controlled entities and associates of the group at 31 December 2012 and the group percentage of ordinary share capital or joint venture 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. A complete list of investments in subsidiaries, jointly controlled entities 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 Europa	100	Germany	Refining and marketing and petrochemicals
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
*BP Shipping	100	England & Wales	Shipping
*Burmah Castrol	100	Scotland	Lubricants
Jupiter Insurance	100	Guernsey	Insurance
Algeria			
BP Amoco Exploration (In Amenas)	100	Scotland	Exploration and production
BP Exploration (El Djazair)	100	Bahamas	Exploration and production
Angola			
BP Exploration (Angola)	100	England & Wales	Exploration and production
Australia			
BP Australia Capital Markets	100	Australia	Finance
BP Developments Australia	100	Australia	Exploration and production
BP Finance Australia	100	Australia	Finance
BP Oil Australia	100	Australia	Integrated oil operations
Azerbaijan			
BP Exploration (Caspian Sea)	100	England & Wales	Exploration and production
Brazil			
BP Energy do Brazil	100	Brazil	Exploration and production
Canada			
BP Canada Energy	100	Canada	Exploration and production
BP Canada Finance	100	Canada	Finance
Egypt			
BP Egypt Company	100	US	Exploration and production
India			
BP Exploration (Alpha)	100	England & Wales	Exploration and production
Indonesia			
BP Berau	100	US	Exploration and production
New Zealand			
BP Oil New Zealand	100	New Zealand	Marketing
Norway			
BP Norge	100	Norway	Exploration and production
Spain			
BP España	100	Spain	Refining and marketing
South Africa			
*BP Southern Africa	75	South Africa	Refining and marketing
Trinidad & Tobago			
BP Trinidad and Tobago	70	US	Exploration and production
UK			
BP Capital Markets	100	England & Wales	Finance
BP Oil UK	100	England & Wales	Marketing
Britoil	100	Scotland	Exploration and production
US			
*BP Holdings North America	100	England & Wales	Investment holding
Atlantic Richfield Company	100	US	Exploration and production, refining and marketing, pipelines and petrochemicals
BP America	100	US	
BP America Production Company	100	US	
BP Amoco Chemical Company	100	US	
BP Company North America	100	US	
BP Corporation North America	100	US	
BP Exploration & Production	100	US	
BP Exploration (Alaska)	100	US	
BP Products North America	100	US	
BP West Coast Products	100	US	
Standard Oil Company	100	US	
BP Capital Markets America	100	US	Finance

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45. Subsidiaries, jointly controlled entities and associates continued

Jointly controlled entities	%	Country of incorporation	Principal activities
Angola			
Angola LNG Supply Services	14	US	LNG processing and transportation
Argentina			
Pan American Energy[a]	60	US	Exploration and production
Canada			
Sunrise Oil Sands	50	Canada	Exploration and production
China			
Shanghai SECCO Petrochemical Company	50	China	Petrochemicals
Germany			
Ruhr Oel	50	Germany	Refining and petrochemicals
Trinidad & Tobago			
Atlantic 4 Holdings	38	US	LNG manufacture
Atlantic LNG 2/3 Company of Trinidad and Tobago	43	Trinidad & Tobago	LNG manufacture
UK			
Vivergo Fuels	46	England & Wales	Biofuels
US			
BP-Husky Refining	50	US	Refining
Flat Ridge 2 Wind Holdings	50	US	Power generation
Watson Cogeneration[ab]	51	US	Power generation

[a] The entity is not controlled by BP as certain key business decisions require joint approval of both BP and the minority partner. It is therefore classified as a jointly controlled entity.
[b] As at 31 December 2012, the group's interests in Watson Cogeneration have been classified as assets held for sale.

Associates	%	Country of incorporation	Principal activities
Abu Dhabi			
Abu Dhabi Gas Liquefaction Company	10	United Arab Emirates	Crude oil production
Abu Dhabi Marine Areas	33	England & Wales	Crude oil production
Azerbaijan			
The Baku-Tbilisi-Ceyhan Pipeline Company	30	Cayman Islands	Pipelines
South Caucasus Pipeline Company	26	Cayman Islands	Pipelines
Russia			
TNK-BP[c]	50	British Virgin Islands	Integrated oil operations

[c] As at 31 December 2012, the group's interests in TNK-BP have been classified as assets held for sale. See Note 4 for further information.

46. 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.

46. Condensed consolidating information on certain US subsidiaries continued

Income statement

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2012 BP group
Sales and other operating revenues	5,501	–	375,580	(5,501)	375,580
Earnings from jointly controlled entities – after interest and tax	–	–	744	–	744
Earnings from associates – after interest and tax	–	–	3,675	–	3,675
Equity-accounted income of subsidiaries – after interest and tax	(59)	12,775	–	(12,716)	–
Interest and other revenues	12	187	1,677	(286)	1,590
Gains on sale of businesses and fixed assets	3,580	–	6,696	(3,580)	6,696
Total revenues and other income	9,034	12,962	388,372	(22,083)	388,285
Purchases	777	–	297,966	(5,501)	293,242
Production and manufacturing expenses	1,475	–	32,436	–	33,911
Production and similar taxes	1,374	–	6,784	–	8,158
Depreciation, depletion and amortization	457	–	12,024	–	12,481
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	11,196	21,075	(16,497)	19,733
Finance costs	48	43	1,235	(201)	1,125
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(431)	230	–	(201)
Profit before taxation	3,911	11,584	19,610	(16,296)	18,809
Taxation	203	2	6,788	–	6,993
Profit for the year	3,708	11,582	12,822	(16,296)	11,816
Attributable to					
BP shareholders	3,708	11,582	12,588	(16,296)	11,582
Minority interest	–	–	234	–	234
	3,708	11,582	12,822	(16,296)	11,816

Statement of comprehensive income

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2012 BP group
Profit (loss) for the year	3,708	11,582	12,822	(16,296)	11,816
Currency translation differences	–	(98)	629	–	531
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	–	–	(15)	–	(15)
Actuarial loss relating to pensions and other post-retirement benefits	–	(573)	(1,762)	–	(2,335)
Available-for-sale investments marked to market	–	–	306	–	306
Available-for-sale – recycled to the income statement	–	–	(1)	–	(1)
Cash flow hedges marked to market	–	–	1,466	–	1,466
Cash flow hedges – recycled to the income statement	–	–	62	–	62
Cash flow hedges – recycled to the balance sheet	–	–	19	–	19
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	(98)	–	(98)
Taxation	–	–	446	–	446
Other comprehensive income	–	(671)	1,052	–	381
Total comprehensive income	3,708	10,911	13,874	(16,296)	12,197
Attributable to					
BP shareholders	3,708	10,911	13,636	(16,296)	11,959
Minority interest	–	–	238	–	238
	3,708	10,911	13,874	(16,296)	12,197

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2011 BP group
Sales and other operating revenues	6,159	–	375,517	(6,159)	375,517
Earnings from jointly controlled entities – after interest and tax	–	–	1,304	–	1,304
Earnings from associates – after interest and tax	–	–	4,916	–	4,916
Equity-accounted income of subsidiaries – after interest and tax	313	26,158	–	(26,471)	–
Interest and other revenues	10	242	664	(320)	596
Gains on sale of businesses and fixed assets	–	1	4,129	–	4,130
Total revenues and other income	6,482	26,401	386,530	(32,950)	386,463
Purchases	978	–	290,799	(6,159)	285,618
Production and manufacturing expenses	1,280	–	22,865	–	24,145
Production and similar taxes	1,684	–	6,596	–	8,280
Depreciation, depletion and amortization	335	–	10,800	–	11,135
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	25,353	38,972	(26,682)	39,817
Finance costs	32	47	1,378	(211)	1,246
Net finance (income) expense relating to pensions and other post-retirement benefits	–	(533)	270	–	(263)
Profit before taxation	2,142	25,839	37,324	(26,471)	38,834
Taxation	729	139	11,869	–	12,737
Profit for the year	1,413	25,700	25,455	(26,471)	26,097
Attributable to					
BP shareholders	1,413	25,700	25,058	(26,471)	25,700
Minority interest	–	–	397	–	397
	1,413	25,700	25,455	(26,471)	26,097

Statement of comprehensive income continued

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2011 BP group
Profit for the year	1,413	25,700	25,455	(26,471)	26,097
Currency translation differences	–	164	(695)	–	(531)
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	–	–	19	–	19
Actuarial loss relating to pensions and other post-retirement benefits	–	(4,770)	(1,190)	–	(5,960)
Available-for-sale investments marked to market	–	–	(71)	–	(71)
Available-for-sale – recycled to the income statement	–	–	(3)	–	(3)
Cash flow hedges marked to market	–	–	44	–	44
Cash flow hedges – recycled to the income statement	–	–	(195)	–	(195)
Cash flow hedges – recycled to the balance sheet	–	–	(13)	–	(13)
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	(57)	–	(57)
Taxation	–	583	1,076	–	1,659
Other comprehensive income	–	(4,023)	(1,085)	–	(5,108)
Total comprehensive income	1,413	21,677	24,370	(26,471)	20,989
Attributable to					
BP shareholders	1,413	21,677	23,986	(26,471)	20,605
Minority interest	–	–	384	–	384
	1,413	21,677	24,370	(26,471)	20,989

46. Condensed consolidating information on certain US subsidiaries continued

Income statement continued

$ million

For the year ended 31 December					2010
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Sales and other operating revenues	4,793	–	297,107	(4,793)	297,107
Earnings from jointly controlled entities – after interest and tax	–	–	1,175	–	1,175
Earnings from associates – after interest and tax	–	–	3,582	–	3,582
Equity-accounted income of subsidiaries – after interest and tax	620	(3,567)	–	2,947	–
Interest and other revenues	–	188	714	(221)	681
Gains on sale of businesses and fixed assets	–	260	6,376	(253)	6,383
Total revenues and other income	5,413	(3,119)	308,954	(2,320)	308,928
Purchases	637	–	220,367	(4,793)	216,211
Production and manufacturing expenses	966	–	63,649	–	64,615
Production and similar taxes	998	–	4,246	–	5,244
Depreciation, depletion and amortization	351	–	10,813	–	11,164
Impairment and losses on sale of businesses and fixed assets	1,524	–	1,689	(1,524)	1,689
Exploration expense	–	–	843	–	843
Distribution and administration expenses	16	673	11,975	(109)	12,555
Fair value loss on embedded derivatives	–	–	309	–	309
Profit (loss) before interest and taxation	921	(3,792)	(4,937)	4,106	(3,702)
Finance costs	2	31	1,249	(112)	1,170
Net finance (income) expense relating to pensions and other post-retirement benefits	4	(388)	337	–	(47)
Profit (loss) before taxation	915	(3,435)	(6,523)	4,218	(4,825)
Taxation	143	31	(1,675)	–	(1,501)
Profit (loss) for the year	772	(3,466)	(4,848)	4,218	(3,324)
Attributable to					
BP shareholders	772	(3,466)	(5,243)	4,218	(3,719)
Minority interest	–	–	395	–	395
	772	(3,466)	(4,848)	4,218	(3,324)

Statement of comprehensive income continued

$ million

For the year ended 31 December					2010
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Profit (loss) for the year	772	(3,466)	(4,848)	4,218	(3,324)
Currency translation differences	–	(45)	304	–	259
Exchange (gains) or losses on translation of foreign operations transferred to gain or loss on sale of businesses and fixed assets	–	–	(20)	–	(20)
Actuarial loss relating to pensions and other post-retirement benefits	–	457	(777)	–	(320)
Available-for-sale investments marked to market	–	–	(191)	–	(191)
Available-for-sale – recycled to the income statement	–	–	(150)	–	(150)
Cash flow hedges marked to market	–	–	(65)	–	(65)
Cash flow hedges – recycled to the income statement	–	–	(25)	–	(25)
Cash flow hedges – recycled to the balance sheet	–	–	53	–	53
Share of equity-accounted entities' other comprehensive income, net of tax	–	–	–	–	–
Taxation	–	(123)	(14)	–	(137)
Other comprehensive income	–	289	(885)	–	(596)
Total comprehensive income	772	(3,177)	(5,733)	4,218	(3,920)
Attributable to					
BP shareholders	772	(3,177)	(6,131)	4,218	(4,318)
Minority interest	–	–	398	–	398
	772	(3,177)	(5,733)	4,218	(3,920)

46. Condensed consolidating information on certain US subsidiaries continued

Balance sheet

$ million

At 31 December					2012
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	8,343	–	112,105	–	120,448
Goodwill	–	–	11,861	–	11,861
Intangible assets	379	–	23,662	–	24,041
Investments in jointly controlled entities	–	–	15,724	–	15,724
Investments in associates	–	2	2,996	–	2,998
Other investments	–	–	2,702	–	2,702
Subsidiaries – equity-accounted basis	–	136,421	–	(136,421)	–
Fixed assets	8,722	136,423	169,050	(136,421)	177,774
Loans	–	–	4,977	(4,282)	695
Other receivables	–	–	4,754	–	4,754
Derivative financial instruments	–	–	4,294	–	4,294
Prepayments	34	–	775	–	809
Deferred tax assets	–	–	874	–	874
Defined benefit pension plan surpluses	–	–	12	–	12
	8,756	136,423	184,736	(140,703)	189,212
Current assets					
Loans	–	–	247	–	247
Inventories	174	–	27,693	–	27,867
Trade and other receivables	11,835	17,496	43,061	(34,728)	37,664
Derivative financial instruments	–	–	4,507	–	4,507
Prepayments	15	–	1,043	–	1,058
Current tax receivable	–	–	456	–	456
Other investments	–	–	319	–	319
Cash and cash equivalents	–	9	19,539	–	19,548
	12,024	17,505	96,865	(34,728)	91,666
Assets classified as held for sale	–	–	19,315	–	19,315
	12,024	17,505	116,180	(34,728)	110,981
Total assets	20,780	153,928	300,916	(175,431)	300,193
Current liabilities					
Trade and other payables	3,914	2,577	75,391	(34,728)	47,154
Derivative financial instruments	–	–	2,658	–	2,658
Accruals	140	27	6,643	–	6,810
Finance debt	–	–	10,030	–	10,030
Current tax payable	145	–	2,356	–	2,501
Provisions	1	–	7,586	–	7,587
	4,200	2,604	104,664	(34,728)	76,740
Liabilities directly associated with assets classified as held for sale	–	–	846	–	846
	4,200	2,604	105,510	(34,728)	77,586
Non-current liabilities					
Other payables	8	4,449	1,927	(4,282)	2,102
Derivative financial instruments	–	–	2,723	–	2,723
Accruals	–	38	410	–	448
Finance debt	–	–	38,767	–	38,767
Deferred tax liabilities	1,654	–	13,410	–	15,064
Provisions	1,887	–	28,447	–	30,334
Defined benefit pension plan and other post-retirement benefit plan deficits	–	1,913	11,636	–	13,549
	3,549	6,400	97,320	(4,282)	102,987
Total liabilities	7,749	9,004	202,830	(39,010)	180,573
Net assets	13,031	144,924	98,086	(136,421)	119,620
Equity					
BP shareholders' equity	13,031	144,924	96,880	(136,421)	118,414
Minority interest	–	–	1,206	–	1,206
Total equity	13,031	144,924	98,086	(136,421)	119,620

46. Condensed consolidating information on certain US subsidiaries continued

Balance sheet continued

$ million

At 31 December					2011
	Issuer	Guarantor			
	BP Exploration (Alaska) Inc.	BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	BP group
Non-current assets					
Property, plant and equipment	8,653	–	110,561	–	119,214
Goodwill	–	–	12,100	–	12,100
Intangible assets	456	–	20,646	–	21,102
Investments in jointly controlled entities	–	–	15,518	–	15,518
Investments in associates	–	2	13,289	–	13,291
Other investments	–	–	2,633	–	2,633
Subsidiaries – equity-accounted basis	4,802	129,042	–	(133,844)	–
Fixed assets	13,911	129,044	174,747	(133,844)	183,858
Loans	46	38	5,113	(4,313)	884
Other receivables	–	–	4,337	–	4,337
Derivative financial instruments	–	–	5,038	–	5,038
Prepayments	–	–	739	–	739
Deferred tax assets	–	–	611	–	611
Defined benefit pension plan surpluses	–	–	17	–	17
	13,957	129,082	190,602	(138,157)	195,484
Current assets					
Loans	–	–	244	–	244
Inventories	167	–	25,494	–	25,661
Trade and other receivables	4,109	17,698	49,753	(28,034)	43,526
Derivative financial instruments	–	–	3,857	–	3,857
Prepayments	7	–	1,279	–	1,286
Current tax receivable	–	–	235	–	235
Other investments	–	–	288	–	288
Cash and cash equivalents	(1)	–	14,068	–	14,067
	4,282	17,698	95,218	(28,034)	89,164
Assets classified as held for sale	–	–	8,420	–	8,420
	4,282	17,698	103,638	(28,034)	97,584
Total assets	18,239	146,780	294,240	(166,191)	293,068
Current liabilities					
Trade and other payables	5,035	2,390	73,014	(28,034)	52,405
Derivative financial instruments	–	–	3,220	–	3,220
Accruals	–	28	5,904	–	5,932
Finance debt	–	–	9,044	–	9,044
Current tax payable	287	–	1,654	–	1,941
Provisions	–	–	11,238	–	11,238
	5,322	2,418	104,074	(28,034)	83,780
Liabilities directly associated with assets classified as held for sale	–	–	538	–	538
	5,322	2,418	104,612	(28,034)	84,318
Non-current liabilities					
Other payables	9	4,264	3,477	(4,313)	3,437
Derivative financial instruments	–	–	3,773	–	3,773
Accruals	–	35	354	–	389
Finance debt	–	–	35,169	–	35,169
Deferred tax liabilities	1,966	–	13,112	–	15,078
Provisions	1,620	–	24,784	–	26,404
Defined benefit pension plan and other post-retirement benefit plan deficits	–	2,088	9,930	–	12,018
	3,595	6,387	90,599	(4,313)	96,268
Total liabilities	8,917	8,805	195,211	(32,347)	180,586
Net assets	9,322	137,975	99,029	(133,844)	112,482
Equity					
BP shareholders' equity	9,322	137,975	98,012	(133,844)	111,465
Minority interest	–	–	1,017	–	1,017
Total equity	9,322	137,975	99,029	(133,844)	112,482

46. Condensed consolidating information on certain US subsidiaries continued

Cash flow statement

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2012 BP group
Net cash provided by operating activities	**681**	**12,381**	**20,850**	**(13,515)**	**20,397**
Net cash used in investing activities	**(680)**	**(7,060)**	**(5,222)**	**–**	**(12,962)**
Net cash used in financing activities	**–**	**(5,312)**	**(10,221)**	**13,515**	**(2,018)**
Currency translation differences relating to cash and cash equivalents	**–**	**–**	**64**	**–**	**64**
Increase in cash and cash equivalents	**1**	**9**	**5,471**	**–**	**5,481**
Cash and cash equivalents at beginning of year	**(1)**	**–**	**14,068**	**–**	**14,067**
Cash and cash equivalents at end of year	**–**	**9**	**19,539**	**–**	**19,548**

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2011 BP group
Net cash provided by operating activities	661	8,321	25,114	(11,942)	22,154
Net cash used in investing activities	(661)	(3,710)	(22,262)	–	(26,633)
Net cash (used in) provided by financing activities	–	(4,615)	(6,845)	11,942	482
Currency translation differences relating to cash and cash equivalents	–	–	(492)	–	(492)
Decrease in cash and cash equivalents	–	(4)	(4,485)	–	(4,489)
Cash and cash equivalents at beginning of year	(1)	4	18,553	–	18,556
Cash and cash equivalents at end of year	(1)	–	14,068	–	14,067

For the year ended 31 December	Issuer BP Exploration (Alaska) Inc.	Guarantor BP p.l.c.	Other subsidiaries	Eliminations and reclassifications	$ million 2010 BP group
Net cash provided by (used in) operating activities	829	32,111	(4,584)	(14,740)	13,616
Net cash (used in) provided by investing activities	(752)	(29,325)	26,117	–	(3,960)
Net cash (used in) provided by financing activities	(56)	(2,810)	(11,034)	14,740	840
Currency translation differences relating to cash and cash equivalents	–	–	(279)	–	(279)
Increase (decrease) in cash and cash equivalents	21	(24)	10,220	–	10,217
Cash and cash equivalents at beginning of year	(22)	28	8,333	–	8,339
Cash and cash equivalents at end of year	(1)	4	18,553	–	18,556

Supplementary information on oil and natural gas (unaudited)

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

Oil and gas reserves – certain definitions

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

Proved oil and gas reserves

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

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

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

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

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

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

Undeveloped oil and gas reserves

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

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

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

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

Developed oil and gas reserves

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

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

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

For details on BP's proved reserves and production compliance and governance processes, see pages 84-86.

Financial statements

Oil and natural gas exploration and production activities

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries[a]										
Capitalized costs at 31 December[bj]										
Gross capitalized costs										
Proved properties	28,370	9,421	70,133	219	8,153	32,755	—	16,757	3,676	169,484
Unproved properties	400	199	7,084	1,659	3,590	4,524	—	4,920	1,540	23,916
	28,770	9,620	77,217	1,878	11,743	37,279	—	21,677	5,216	193,400
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	1,681	7,299	20,378	—	13,317	3,699	104,359
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[ck]										
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	191	758	1,024	—	814	241	4,317
Development	1,907	784	3,866	22	581	2,992	—	1,591	221	11,964
Total costs	2,080	831	6,302	213	1,417	4,255	—	2,337	462	17,897
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	60	109	221	(330)	84	264	2,517
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	243	1,815	4,159	(330)	9,691	934	27,794
Profit (loss) before taxation[g]	3,062	176	7,075	(223)	1,195	4,898	330	2,953	1,730	21,196
Allocable taxes	1,121	(313)	2,762	(67)	804	2,371	(13)	663	755	8,083
Results of operations	1,941	489	4,313	(156)	391	2,527	343	2,290	975	13,113
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	(223)	1,195	4,898	330	2,953	1,730	21,196
Midstream activities and other activities – subsidiaries[h]	(250)	(114)	(173)	774	4	(46)	11	32	370	608
Equity-accounted entities[i]	—	35	16	43	256	48	3,005	640	—	4,043
Total replacement cost profit before interest and tax	2,812	97	6,918	594	1,455	4,900	3,346	3,625	2,100	25,847

[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 $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 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 $227 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

										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia[g]	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	—	—	—	1,694	6,958	—	—	4,036	—	12,688
Unproved properties	—	—	—	583	21	—	—	16	—	620
	—	—	—	2,277	6,979	—	—	4,052	—	13,308
Accumulated depreciation	—	—	—	—	2,965	—	—	3,648	—	6,613
Net capitalized costs	—	—	—	2,277	4,014	—	—	404	—	6,695
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	—	—	—	—	—	—	4	—	—	4
Unproved	—	—	—	—	439	—	15	—	—	454
	—	—	—	—	439	—	19	—	—	458
Exploration and appraisal costs[d]	—	—	—	31	31	—	195	7	—	264
Development	—	—	—	568	599	—	1,560	556	—	3,283
Total costs	—	—	—	599	1,069	—	1,774	563	—	4,005
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
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)	—	—	—	(43)	(11)	—	(24)	(2)	—	(80)
Depreciation, depletion and amortization	—	—	—	—	328	—	786	538	—	1,652
Impairments and losses on sale of businesses and fixed assets	—	—	—	—	—	—	(27)	—	—	(27)
	—	—	—	(43)	1,862	—	6,833	4,077	—	12,729
Profit (loss) before taxation	—	—	—	43	405	—	3,278	189	—	3,915
Allocable taxes	—	—	—	—	294	—	536	54	—	884
Results of operations	—	—	—	43	111	—	2,742	135	—	3,031
Exploration and production activities – equity-accounted entities after tax (as above)	—	—	—	43	111	—	2,742	135	—	3,031
Midstream and other activities after tax[f]	—	35	16	—	145	48	263	505	—	1,012
Total replacement cost profit after interest and tax	—	35	16	43	256	48	3,005	640	—	4,043

[a] These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. 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. Capitalized costs exclude balances associated with assets held for sale.
[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, minority interest and the net results of equity-accounted entities of equity-accounted entities, and excludes inventory holding gains and losses.
[g] The Russia region includes BP's equity accounted share of TNK-BP's earnings. For 2012, equity accounted earnings are included until 21 October 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.

										$ 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	182	7,471	29,358	–	14,833	3,370	175,325
Unproved properties	368	180	6,198	1,471	2,986	3,689	–	4,495	1,279	20,666
	37,859	9,174	79,824	1,653	10,457	33,047	–	19,328	4,649	195,991
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	1,514	6,618	18,452	–	13,093	3,355	103,212
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	117	271	490	6	511	225	2,398
Development	1,361	889	3,016	–	405	2,933	–	1,340	251	10,195
Total costs	1,572	891	5,178	125	3,505	4,102	6	6,592	476	22,447
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	49	935	215	72	118	257	5,078
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	145	1,189	3,210	81	8,150	840	28,603
Profit (loss) before taxation[g]	4,468	806	6,343	(100)	2,483	5,001	(81)	4,111	1,738	24,769
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	59	1,278	2,817	(60)	3,110	1,061	14,863
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	(100)	2,483	5,001	(81)	4,111	1,738	24,769
Midstream activities – subsidiaries[h]	(118)	29	(157)	299	(58)	(4)	(1)	42	284	316
Equity-accounted entities[i]	–	12	10	58	598	69	4,095	573	–	5,415
Total replacement cost profit before interest and tax	4,350	847	6,196	257	3,023	5,066	4,013	4,726	2,022	30,500

[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 $352 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
										$ million 2011
	UK	Rest of Europe	US	Rest of North America[g]			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	1,125	6,562	–	16,214	3,684	–	27,585
Unproved properties	–	–	–	553	19	–	652	9	–	1,233
	–	–	–	1,678	6,581	–	16,866	3,693	–	28,818
Accumulated depreciation	–	–	–	–	2,644	–	6,978	3,017	–	12,639
Net capitalized costs	–	–	–	1,678	3,937	–	9,888	676	–	16,179
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]	–	–	–	19	2	–	167	9	–	197
Development	–	–	–	232	587	–	1,862	435	–	3,116
Total costs	–	–	–	251	595	–	2,066	490	–	3,402
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	58	168	69	280	509	–	1,106
Total replacement cost profit after interest and tax	–	12	10	58	598	69	4,095	573	–	5,415

[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, minority interest and the net results of equity-accounted entities of equity-accounted entities, and excludes inventory holding gains and losses.
[g] An amendment has been made to the classification of costs between proved and unproved properties.

Oil and natural gas exploration and production activities continued

	Europe		North America		South America	Africa	Asia		Australasia	Total
										$ million
										2010
	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	36,161	7,846	67,724	278	6,047	27,014	–	11,497	3,088	159,655
Unproved properties	787	179	5,968	1,363	220	2,694	–	1,113	1,149	13,473
	36,948	8,025	73,692	1,641	6,267	29,708	–	12,610	4,237	173,128
Accumulated depreciation	27,688	3,515	33,972	216	3,282	13,893	–	4,569	1,205	88,340
Net capitalized costs	9,260	4,510	39,720	1,425	2,985	15,815	–	8,041	3,032	84,788
Costs incurred for the year ended 31 December[b j]										
Acquisition of properties[c]										
Proved	–	–	655	1	–	–	–	1,121	–	1,777
Unproved	–	519	1,599	1,200	–	–	–	151	–	3,469
	–	519	2,254	1,201	–	–	–	1,272	–	5,246
Exploration and appraisal costs[d]	401	13	1,096	78	68	607	7	316	120	2,706
Development	726	816	3,034	251	414	3,003	–	1,244	187	9,675
Total costs	1,127	1,348	6,384	1,530	482	3,610	7	2,832	307	17,627
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	1,472	58	1,148	90	1,896	3,158	–	1,272	1,398	10,492
Sales between businesses	3,405	1,134	18,819	453	1,574	4,353	–	6,697	929	37,364
	4,877	1,192	19,967	543	3,470	7,511	–	7,969	2,327	47,856
Exploration expenditure	82	(2)	465	25	9	189	7	51	17	843
Production costs	1,018	152	2,867	240	445	938	9	365	124	6,158
Production taxes	52	–	1,093	2	249	–	–	3,764	109	5,269
Other costs (income)[f]	(316)	76	3,502	129	209	130	76	90	195	4,091
Depreciation, depletion and amortization	897	209	3,477	95	575	1,771	–	829	168	8,021
Impairments and (gains) losses on sale of businesses and fixed assets	(1)	–	(1,441)	(2,190)	(3)	(427)	341[k]	–	–	(3,721)
	1,732	435	9,963	(1,699)	1,484	2,601	433	5,099	613	20,661
Profit (loss) before taxation[g]	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Allocable taxes	1,333	530	3,504	610	1,084	1,771	(23)	813	410	10,032
Results of operations	1,812	227	6,500	1,632	902	3,139	(410)	2,057	1,304	17,163
Upstream segment and TNK-BP segment replacement cost profit before interest and tax										
Exploration and production activities – subsidiaries (as above)	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714	27,195
Midstream activities – subsidiaries[h]	23	42	(347)	3	49	(26)	4	(23)	(13)	(288)
Equity-accounted entities[i]	–	4	27	171	614	63	2,613	487	–	3,979
Total replacement cost profit before interest and tax	3,168	803	9,684	2,416	2,649	4,947	2,184	3,334	1,701	30,886

[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 loss on embedded derivatives of $309 million. The UK region includes a $822 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.
[g] Excludes the unwinding of the discount on provisions and payables amounting to $313 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] This amount represents the write-down of our investment in Sakhalin. A portion of these costs was previously reported within capitalized costs of equity-accounted entities with the remainder previously reported as a loan, which was not included in the disclosures of oil and natural gas exploration and production activities.

Oil and natural gas exploration and production activities continued

										$ million
										2010
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America[g]			Russia	Rest of Asia		
Equity-accounted entities (BP share)[a]										
Capitalized costs at 31 December[b]										
Gross capitalized costs										
Proved properties	–	–	–	893	5,778	–	14,486	3,192	–	24,349
Unproved properties	–	–	–	533	163	–	652	–	–	1,348
	–	–	–	1,426	5,941	–	15,138	3,192	–	25,697
Accumulated depreciation	–	–	–	–	2,250	–	6,300	2,674	–	11,224
Net capitalized costs	–	–	–	1,426	3,691	–	8,838	518	–	14,473
Costs incurred for the year ended 31 December[b]										
Acquisition of properties[c]										
Proved	–	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	9	–	66	–	–	75
	–	–	–	–	9	–	66	–	–	75
Exploration and appraisal costs[d]	–	–	–	28	2	–	94	–	–	124
Development	–	–	–	21	549	–	1,416	355	–	2,341
Total costs	–	–	–	49	560	–	1,576	355	–	2,540
Results of operations for the year ended 31 December										
Sales and other operating revenues[e]										
Third parties	–	–	–	–	2,268	–	5,610	2,557	–	10,435
Sales between businesses	–	–	–	–	–	–	3,432	19	–	3,451
	–	–	–	–	2,268	–	9,042	2,576	–	13,886
Exploration expenditure	–	–	–	–	22	–	40	–	–	62
Production costs	–	–	–	–	316	–	1,602	184	–	2,102
Production taxes	–	–	–	–	911	–	3,567	2,029	–	6,507
Other costs (income)	–	–	–	67	75	–	3	(2)	–	143
Depreciation, depletion and amortization	–	–	–	–	269	–	954	363	–	1,586
Impairments and losses on sale of businesses and fixed assets	–	–	–	–	–	–	43	–	–	43
	–	–	–	67	1,593	–	6,209	2,574	–	10,443
Profit (loss) before taxation	–	–	–	(67)	675	–	2,833	2	–	3,443
Allocable taxes	–	–	–	–	260	–	475	33	–	768
Results of operations	–	–	–	(67)	415	–	2,358	(31)	–	2,675
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	(67)	415	–	2,358	(31)	–	2,675
Midstream and other activities after tax[f]	–	4	27	238	199	63	255	518	–	1,304
Total replacement cost profit after interest and tax	–	4	27	171	614	63	2,613	487	–	3,979

[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, minority interest and the net results of equity-accounted entities of equity-accounted entities.
[g] An amendment has been made to the classification of costs between proved and unproved properties.

Movements in estimated net proved reserves

million barrels

Crude oil[a]	Europe		North America		South America	Africa	Asia		Australasia	2012 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% minority 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% minority 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 4,453 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

billion cubic feet

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 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% minority 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% minority 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]	Rest of North America	million barrels 2012 Total
Equity-accounted entities (BP share)		
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 hydrocrabons[a]	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2012										
Developed	531	76	3,362	5	522	522	–	355	675	6,048
Undeveloped	602	308	1,833	–	1,173	665	–	342	455	5,378
	1,133	384	5,195	5	1,695	1,187	–	697	1,130	11,426
Changes attributable to										
Revisions of previous estimates	(33)	(27)	(600)	(3)	(31)	(3)	–	5	(8)	(700)
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)	(4)	55	(92)	–	(61)	(67)	(1,213)
At 31 December 2012[f j]										
Developed	421	229	2,865	1	640	508	–	427	618	5,709
Undeveloped	546	103	1,504	–	1,110	587	–	209	445	4,504
	967	332	4,369	1	1,750	1,095	–	636	1,063	10,213
Equity-accounted entities (BP share)[g]										
At 1 January 2012										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	178	522	48	1,727	66	–	2,541
	–	–	–	178	1,068	48	4,688	340	–	6,322
Changes attributable to										
Revisions of previous estimates	–	–	–	17	13	34	560	(19)	–	605
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)
	–	–	–	17	(1)	34	520	(105)	–	465
At 31 December 2012[h i k]										
Developed	–	–	–	–	559	43	2,943	220	–	3,765
Undeveloped	–	–	–	195	508	39	2,265	15	–	3,022
	–	–	–	195	1,067	82	5,208	235	–	6,787
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% minority 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 minority 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% minority 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% minority 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.

Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a]										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% minority 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% minority 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
Equity-accounted entities (BP share)		
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 UK	Europe Rest of Europe	North America US[c]	North America Rest of North America	South America	Africa	Asia Russia	Asia Rest of Asia	Australasia	2011 Total
Subsidiaries										
At 1 January 2011										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	–	1,192	779	–	371	462	5,596
	1,182	379	5,289	10	1,852	1,379	–	862	1,124	12,077
Changes attributable to										
Revisions of previous estimates	28	10	27	(2)	41	(103)	–	(119)	55	(63)
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)	(5)	(157)	(192)	–	(165)	6	(651)
At 31 December 2011[f]										
Developed	531	76	3,362	5	522	522	–	355	675	6,048
Undeveloped	602	308	1,833	–	1,173	665	–	342	455	5,378
	1,133	384	5,195	5	1,695	1,187	–	697	1,130	11,426
Equity-accounted entities (BP share)[g]										
At 1 January 2011										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	179	613	43	1,441	27	–	2,303
	–	–	–	179	1,206	43	4,157	409	–	5,994
Changes attributable to										
Revisions of previous estimates	–	–	–	(1)	(25)	5	795	(5)	–	769
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)
	–	–	–	(1)	(138)	5	531	(69)	–	328
At 31 December 2011[h i]										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	178	522	48	1,727	66	–	2,541
	–	–	–	178	1,068	48	4,688	340	–	6,322
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% minority 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 minority 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.

Movements in estimated net proved reserves continued

										million barrels
Crude oil[a]										2010
	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 2010										
Developed	403	83	1,862	11	49	422	–	182	58	3,070
Undeveloped	291	184	1,211	1	56	454	–	334	57	2,588
	694	267	3,073	12	105	876	–	516	115	5,658
Changes attributable to										
Revisions of previous estimates	20	3	(45)	1	(1)	(62)	–	(62)	–	(146)
Improved recovery	100	9	133	–	17	14	–	145	3	421
Purchases of reserves-in-place	–	33	6	–	–	–	–	38	–	77
Discoveries and extensions	31	1	80	–	–	19	–	–	–	131
Production[c d]	(50)	(15)	(211)	(2)	(19)	(87)	–	(43)	(12)	(439)
Sales of reserves-in-place	–	–	(117)	(11)	–	(15)	–	–	–	(143)
	101	31	(154)	(12)	(3)	(131)	–	78	(9)	(99)
At 31 December 2010[e f]										
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
Equity-accounted entities (BP share)[g]										
At 1 January 2010										
Developed	–	–	–	–	407	–	2,351	363	–	3,121
Undeveloped	–	–	–	–	405	9	1,198	120	–	1,732
	–	–	–	–	812	9	3,549	483	–	4,853
Changes attributable to										
Revisions of previous estimates	–	–	–	–	4	3	248	(20)	–	235
Improved recovery	–	–	–	–	33	–	269	–	–	302
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	1	–	–	–	–	1
Production	–	–	–	–	(35)[h i]	–	(313)	(69)	–	(417)
Sales of reserves-in-place	–	–	–	–	–	–	(3)	–	–	(3)
	–	–	–	–	3	3	201	(89)	–	118
At 31 December 2010[j]										
Developed	–	–	–	–	408	–	2,388	370	–	3,166
Undeveloped	–	–	–	–	407	12	1,362	24	–	1,805
	–	–	–	–	815[k]	12	3,750	394	–	4,971
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
Developed	403	83	1,862	11	456	422	2,351	545	58	6,191
Undeveloped	291	184	1,211	1	461	463	1,198	454	57	4,320
	694	267	3,073	12	917	885	3,549	999	115	10,511
At 31 December 2010										
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

[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 78 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 29 thousand barrels per day.
[d] Includes 15 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010. Amounts by region are: 2 million barrels in US; 6 million barrels in South America; and 7 million barrels in Rest of Asia.
[e] Includes 643 million barrels of NGLs. Also includes 22 million barrels of crude oil in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[f] Includes 70 million barrels relating to assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels in US; 30 million barrels in South America; and 34 million barrels in Rest of Asia.
[g] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[h] Includes 2 million barrels of crude oil sold relating to production since classification of equity-accounted entities as held for sale.
[i] Includes 9 million barrels of crude oil sold relating to production from assets held for sale at 31 December 2010.
[j] Includes 18 million barrels of NGLs. Also includes 254 million barrels of crude oil in respect of the 7.03% minority interest in TNK-BP.
[k] Includes 213 million barrels relating to assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

Natural gas[a]	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		billion cubic feet 2010
Subsidiaries										
At 1 January 2010										
Developed	1,602	49	9,583	716	3,177	1,107	–	1,579	3,219	21,032
Undeveloped	670	397	5,633	453	7,393	1,454	–	249	3,107	19,356
	2,272	446	15,216	1,169	10,570	2,561	–	1,828	6,326	40,388
Changes attributable to										
Revisions of previous estimates	(8)	(5)	(1,854)	(11)	2	3	–	(142)	(191)	(2,206)
Improved recovery	152	6	830	–	512	18	–	83	58	1,659
Purchases of reserves-in-place	–	31	97	1	–	–	–	17	–	146
Discoveries and extensions	26	–	739	9	19	1,378	–	–	–	2,171
Production[b c]	(191)	(8)	(861)	(77)	(953)	(229)	–	(228)	(288)	(2,835)
Sales of reserves-in-place	(6)	–	(424)	(1,033)	–	(51)	–	–	–	(1,514)
	(27)	24	(1,473)	(1,111)	(420)	1,119	–	(270)	(421)	(2,579)
At 31 December 2010[d e]										
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
Equity-accounted entities (BP share)[f]										
At 1 January 2010										
Developed	–	–	–	–	1,252	–	1,703	80	–	3,035
Undeveloped	–	–	–	–	1,010	165	519	13	–	1,707
	–	–	–	–	2,262	165	2,222	93	–	4,742
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(141)	10	382	2	–	253
Improved recovery	–	–	–	–	291	–	–	12	–	303
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	23	–	–	–	–	23
Production[b]	–	–	–	–	(168)[g h]	–	(244)	(17)	–	(429)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	5	10	137	(3)	–	149
At 31 December 2010[i]										
Developed	–	–	–	–	1,075	–	1,900	71	–	3,046
Undeveloped	–	–	–	–	1,192	175	459	19	–	1,845
	–	–	–	–	2,267[j]	175	2,359	90	–	4,891
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2010										
Developed	1,602	49	9,583	716	4,429	1,107	1,703	1,659	3,219	24,067
Undeveloped	670	397	5,633	453	8,403	1,619	519	262	3,107	21,063
	2,272	446	15,216	1,169	12,832	2,726	2,222	1,921	6,326	45,130
At 31 December 2010										
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

[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 204 billion cubic feet of natural gas consumed in operations, 166 billion cubic feet in subsidiaries, 38 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 133 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 23 billion cubic feet in US; 27 billion cubic feet in South America; and 83 billion cubic feet in Rest of Asia.
[d] Includes 2,921 billion cubic feet of natural gas in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[e] Includes 740 billion cubic feet relating to assets held for sale at 31 December 2010. Amounts by region are: 158 billion cubic feet in US; 205 billion cubic feet in South America; and 377 billion cubic feet in Rest of Asia.
[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[g] Includes 1 billion cubic feet of gas sales relating to production since classification of equity-accounted entities as held for sale.
[h] Includes 3 billion cubic feet of gas (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.
[i] Includes 137 billion cubic feet of natural gas in respect of the 5.89% minority interest in TNK-BP.
[j] Includes 50 billion cubic feet relating to assets held for sale at 31 December 2010.

Movements in estimated net proved reserves continued

Bitumen[a]		million barrels 2010
	Rest of North America	Total
Equity-accounted entities (BP share)		
At 1 January 2010		
Developed	–	–
Undeveloped	–	–
	–	–
Changes attributable to		
Revisions of previous estimates	–	–
Improved recovery	–	–
Purchases of reserves-in-place	–	–
Discoveries and extensions	179	179
Production	–	–
Sales of reserves-in-place	–	–
	179	179
At 31 December 2010		
Developed	–	–
Undeveloped	179	179
	179	179

[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	2010 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2010										
Developed	680	91	3,514	135	596	613	–	455	612	6,696
Undeveloped	406	253	2,183	79	1,331	704	–	376	593	5,925
	1,086	344	5,697	214	1,927	1,317	–	831	1,205	12,621
Changes attributable to										
Revisions of previous estimates	18	2	(364)	(2)	(1)	(61)	–	(87)	(33)	(528)
Improved recovery	126	10	276	–	105	17	–	160	13	707
Purchases of reserves-in-place	–	38	22	–	–	–	–	41	–	101
Discoveries and extensions	36	1	207	2	4	257	–	–	–	507
Production[d e f]	(83)	(16)	(359)	(15)	(183)	(127)	–	(83)	(61)	(927)
Sales of reserves-in-place	(1)	–	(190)	(189)	–	(24)	–	–	–	(404)
	96	35	(408)	(204)	(75)	62	–	31	(81)	(544)
At 31 December 2010[g h]										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	–	1,192	779	–	371	462	5,596
	1,182	379	5,289	10	1,852	1,379	–	862	1,124	12,077
Equity-accounted entities (BP share)[i]										
At 1 January 2010										
Developed	–	–	–	–	623	–	2,645	377	–	3,645
Undeveloped	–	–	–	–	580	37	1,287	122	–	2,026
	–	–	–	–	1,203	37	3,932	499	–	5,671
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(20)	6	314	(19)	–	281
Improved recovery	–	–	–	–	83	–	269	2	–	354
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	179	4	–	–	–	–	183
Production[d e]	–	–	–	–	(64)[j k]	–	(354)	(73)	–	(491)
Sales of reserves-in-place	–	–	–	–	–	–	(4)	–	–	(4)
	–	–	–	179	3	6	225	(90)	–	323
At 31 December 2010[l]										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	179	613	43	1,441	27	–	2,303
	–	–	–	179	1,206[m]	43	4,157	409	–	5,994
Total subsidiaries and equity-accounted entities (BP share)[n]										
At 1 January 2010										
Developed	680	91	3,514	135	1,219	613	2,645	832	612	10,341
Undeveloped	406	253	2,183	79	1,911	741	1,287	498	593	7,951
	1,086	344	5,697	214	3,130	1,354	3,932	1,330	1,205	18,292
At 31 December 2010										
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

[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 78 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 29 thousand barrels of oil equivalent a day.
[e] Includes 35 million barrels of oil equivalent of natural gas consumed in operations, 28 million barrels of oil equivalent in subsidiaries, 7 million barrels of oil equivalent in equity-accounted entities and excludes 2 million barrels of oil equivalent of produced non-hydrocarbon components which meet regulatory requirements for sales.
[f] Includes 38 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010. Amounts by region are: 6 million barrels of oil equivalent in US; 11 million barrels of oil equivalent in South America; and 21 million barrels of oil equivalent in Rest of Asia.
[g] Includes 643 million barrels of NGLs. Also includes 526 million barrels of oil equivalent in respect of the 30% minority interest in BP Trinidad and Tobago LLC.
[h] Includes 197 million barrels of oil equivalent relating to assets held for sale at 31 December 2010. Amounts by region are: 34 million barrels of oil equivalent in US; 64 million barrels of oil equivalent in South America; and 99 million barrels of oil equivalent in Rest of Asia.
[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.
[j] Includes 2 million barrels of oil equivalent sold relating to production since classification of equity-accounted entities as held for sale.
[k] Includes 9 million barrels of oil equivalent (excluding gas consumed in operations) relating to production from assets held for sale at 31 December 2010.
[l] Includes 18 million barrels of NGLs. Also includes 278 million barrels of oil equivalent in respect of the minority interest in TNK-BP.
[m] Includes 222 million barrels of oil equivalent relating to assets held for sale at 31 December 2010.
[n] Includes 1,311 million barrels of oil equivalent (197 million barrels of oil equivalent for subsidiaries and 1,114 million barrels of oil equivalent for equity-accounted entities) associated with properties currently held for sale where the disposal has not yet been completed.

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
										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	–	30,400	75,800	–	54,200	54,300	594,600
Future production cost[b]	24,600	10,400	117,000	–	10,700	17,200	–	14,000	19,000	212,900
Future development cost[b]	7,400	2,400	29,600	–	7,700	13,000	–	10,900	3,700	74,700
Future taxation[c]	35,200	11,700	40,700	–	6,300	17,500	–	6,900	8,400	126,700
Future net cash flows	20,800	6,300	73,800	–	5,700	28,100	–	22,400	23,200	180,300
10% annual discount[d]	10,900	2,400	40,100	–	2,700	10,900	–	8,300	11,800	87,100
Standardized measure of discounted future net cash flows[e]	9,900	3,900	33,700	–	3,000	17,200	–	14,100	11,400	93,200
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,500	49,400	–	203,600	24,400	–	286,900
Future production cost[b]	–	–	–	4,600	24,800	–	133,400	21,000	–	183,800
Future development cost[b]	–	–	–	2,400	5,500	–	16,600	1,900	–	26,400
Future taxation[c]	–	–	–	400	6,600	–	10,100	200	–	17,300
Future net cash flows	–	–	–	2,100	12,500	–	43,500	1,300	–	59,400
10% annual discount[d]	–	–	–	2,000	7,600	–	21,600	300	–	31,500
Standardized measure of discounted future net cash flows[g h]	–	–	–	100	4,900	–	21,900	1,000	–	27,900
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	13,800	3,700	17,500
Extensions, discoveries and improved recovery, less related costs	8,000	1,200	9,200
Net changes in prices and production cost	(14,600)	2,200	(12,400)
Revisions of previous reserves estimates	(16,200)	(800)	(17,000)
Net change in taxation	23,000	500	23,500
Future development costs	(7,100)	(1,100)	(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]	(22,900)	100	(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] Minority 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] Minority 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 reserves 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	100	39,100	82,100	–	59,200	53,900	701,600
Future production cost[b]	30,500	10,900	140,700	100	10,500	16,800	–	16,000	15,600	241,100
Future development cost[b]	8,500	2,700	32,300	–	7,600	13,200	–	9,600	3,200	77,100
Future taxation[c]	37,100	15,200	57,000	–	11,400	19,800	–	8,100	9,000	157,600
Future net cash flows	21,800	7,600	102,900	–	9,600	32,300	–	25,500	26,100	225,800
10% annual discount[d]	11,200	3,100	55,500	–	4,100	12,500	–	9,800	13,500	109,700
Standardized measure of discounted future net cash flows[e]	10,600	4,500	47,400	–	5,500	19,800	–	15,700	12,600	116,100
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,100	46,700	–	188,900	34,200	–	278,900
Future production cost[b]	–	–	–	3,100	21,500	–	123,800	30,100	–	178,500
Future development cost[b]	–	–	–	1,900	5,000	–	15,600	2,400	–	24,900
Future taxation[c]	–	–	–	900	5,900	–	9,600	200	–	16,600
Future net cash flows	–	–	–	3,200	14,300	–	39,900	1,500	–	58,900
10% annual discount[d]	–	–	–	2,800	8,700	–	19,000	600	–	31,100
Standardized measure of discounted future net cash flows[g h]	–	–	–	400	5,600	–	20,900	900	–	27,800
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	12,800	2,900	15,700
Extensions, discoveries and improved recovery, less related costs	6,600	2,800	9,400
Net changes in prices and production cost	75,000	15,800	90,800
Revisions of previous reserves estimates	(22,000)	2,100	(19,900)
Net change in taxation	(18,200)	(1,400)	(19,600)
Future development costs	(10,800)	(2,700)	(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]	16,000	12,600	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] Minority 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] Minority 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.

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

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
										$ million
										2010
At 31 December 2010										
Subsidiaries										
Future cash inflows[a]	73,100	25,800	264,800	200	29,300	70,800	–	52,500	42,300	558,800
Future production cost[b]	25,700	9,800	111,400	200	6,800	14,000	–	13,400	12,800	194,100
Future development cost[b]	7,400	2,500	24,300	–	6,100	14,600	–	9,900	3,100	67,900
Future taxation[c]	19,900	8,100	41,900	–	8,200	14,100	–	7,000	6,200	105,400
Future net cash flows	20,100	5,400	87,200	–	8,200	28,100	–	22,200	20,200	191,400
10% annual discount[d]	9,800	2,300	45,500	–	3,300	11,900	–	8,200	10,300	91,300
Standardized measure of discounted future net cash flows[e]	10,300	3,100	41,700	–	4,900	16,200	–	14,000	9,900	100,100
Equity-accounted entities (BP share)[f]										
Future cash inflows[a]	–	–	–	9,700	45,500	–	110,500	31,000	–	196,700
Future production cost[b]	–	–	–	4,500	19,200	–	80,900	26,500	–	131,100
Future development cost[b]	–	–	–	2,000	4,300	–	11,000	2,800	–	20,100
Future taxation[c]	–	–	–	800	7,500	–	3,900	200	–	12,400
Future net cash flows	–	–	–	2,400	14,500	–	14,700	1,500	–	33,100
10% annual discount[d]	–	–	–	2,400	8,700	–	6,100	700	–	17,900
Standardized measure of discounted future net cash flows[g h]	–	–	–	–	5,800	–	8,600	800	–	15,200
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[j]	10,300	3,100	41,700	–	10,700	16,200	8,600	14,800	9,900	115,300

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

	Subsidiaries	Equity-accounted entities (BP share)	Total subsidiaries and equity-accounted entities
			$ million
Sales and transfers of oil and gas produced, net of production costs	(26,600)	(4,900)	(31,500)
Development costs for the current year as estimated in previous year	10,400	2,000	12,400
Extensions, discoveries and improved recovery, less related costs	9,600	1,600	11,200
Net changes in prices and production cost	52,800	1,900	54,700
Revisions of previous reserves estimates	(9,200)	200	(9,000)
Net change in taxation	(13,400)	(300)	(13,700)
Future development costs	(4,300)	(1,400)	(5,700)
Net change in purchase and sales of reserves-in-place	(1,500)	–	(1,500)
Addition of 10% annual discount	7,500	1,500	9,000
Total change in the standardized measure during the year[i]	25,300	600	25,900

[a] The marker prices used were Brent $79.02/bbl, Henry Hub $4.37/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] Minority interest in BP Trinidad and Tobago LLC amounted to $1,200 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] Minority interest in TNK-BP amounted to $600 million.
[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.
[j] Includes future net cash flows for assets held for sale at 31 December 2010.

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 2012, 2011 and 2010.

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
2012	**86**	**23**	**390**	**1**	**28**	**202**	**–**	**139**	**27**	**896**
2011	113	32	453	2	39	190	–	138	25	992
2010	137	40	594	7	54	246	–	119	32	1,229
Natural gas[c]										million cubic feet per day
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
2010	472	15	2,184	202	2,544	556	–	574	785	7,332
Equity-accounted entities (BP share)										
Crude oil[b]										thousand barrels per day
2012	**–**	**–**	**–**	**–**	**80**	**–**	**863**	**217**	**–**	**1,160**
2011	–	–	–	–	90	–	865	210	–	1,165
2010	–	–	–	–	98	–	856	191	–	1,145
Natural gas[c]										million cubic feet per day
2012	**–**	**–**	**–**	**–**	**394**	**–**	**734**	**72**	**–**	**1,200**
2011	–	–	–	–	392	–	699	34	–	1,125
2010	–	–	–	–	399	–	640	30	–	1,069

[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.

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 2012. 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 2012											
Oil wells[a]	– gross	**158**	**58**	**2,451**	**55**	**3,870**	**590**	**20,970**	**1,951**	**13**	**30,116**
	– net	**90**	**24**	**987**	**28**	**2,133**	**434**	**9,409**	**392**	**2**	**13,499**
Gas wells[b]	– gross	**122**	**5**	**22,866**	**377**	**506**	**130**	**72**	**687**	**70**	**24,835**
	– net	**52**	**1**	**10,483**	**186**	**171**	**49**	**36**	**256**	**14**	**11,248**
Oil and natural gas acreage at 31 December 2012											Thousands of acres
Developed	– gross	**168**	**39**	**6,516**	**228**	**1,702**	**605**	**1,597**	**2,023**	**162**	**13,040**
	– net	**85**	**16**	**3,463**	**111**	**461**	**220**	**712**	**400**	**35**	**5,503**
Undeveloped[c]	– gross	**1,273**	**180**	**7,469**	**6,074**	**27,755**	**30,684**	**26,291**	**26,505**	**17,854**	**144,085**
	– net	**730**	**77**	**4,935**	**4,154**	**14,032**	**18,419**	**11,061**	**9,339**	**13,098**	**75,845**

[a] Includes approximately 3,762 gross (1,660 net) multiple completion wells (more than one formation producing into the same well bore).
[b] Includes approximately 2,557 gross (1,549 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.

Operational and statistical information continued

Net oil and gas wells completed or abandoned

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

	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
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
2010										
Exploratory										
Productive	–	0.2	39.3	–	1.3	1.2	10.5	2.8	0.3	55.6
Dry	0.7	–	0.3	–	0.9	1.4	4.0	–	–	7.3
Development										
Productive	6.4	1.2	260.0	31.7	105.7	18.9	364.3	53.3	–	841.5
Dry	1.7	–	0.5	–	1.2	2.7	–	2.4	–	8.5

Drilling and production activities in progress

The following table shows the number of exploratory and development oil and natural gas wells in the process of being drilled by the group and its equity-accounted entities as at 31 December 2012. 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 2012										
Exploratory										
Gross	**1.0**	**–**	**76.0**	**3.0**	**7.0**	**4.0**	**25.0**	**2.0**	**–**	**118.0**
Net	**0.5**	**–**	**19.2**	**1.5**	**1.6**	**1.4**	**12.0**	**0.2**	**–**	**36.4**
Development										
Gross	**6.0**	**5.0**	**633.0**	**55.0**	**30.0**	**25.0**	**207.0**	**69.0**	**13.0**	**1,043.0**
Net	**4.4**	**1.6**	**203.8**	**27.5**	**13.9**	**7.8**	**100.5**	**22.7**	**1.3**	**383.5**

Signatures

The registrant hereby certifies that it meets all of the requirements for filing on Form 20-F and that it has duly caused and authorized the undersigned to sign this annual report on its behalf.

BP p.l.c.
(Registrant)

/s/ David J Jackson
Company Secretary
6 March 2013

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 2012 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 178, 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 to identify material inconsistencies with the audited parent company financial statements. 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 2012;
- have been properly prepared in accordance with applicable law and United Kingdom accounting standards (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 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 consolidated financial statements of BP p.l.c. for the year ended 31 December 2012. 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
Allister Wilson (Senior Statutory Auditor)
for and on behalf of Ernst & Young LLP, Statutory Auditor
London
6 March 2013

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 Kingdom 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 PC1–PC11 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	2012	2011
			$ million
Fixed assets			
Investments			
Subsidiary undertakings	3	**133,420**	126,360
Associated undertakings	3	**2**	2
Total fixed assets		**133,422**	126,362
Current assets			
Debtors – amounts falling due:			
Within one year	4	**17,496**	17,698
After more than one year	4	**–**	38
Cash at bank and in hand		**9**	–
		17,505	17,736
Creditors – amounts falling due within one year	5	**2,604**	2,418
Net current assets		**14,901**	15,318
Total assets less current liabilities		**148,323**	141,680
Creditors – amounts falling due after more than one year	5	**4,487**	4,299
Net assets excluding pension plan deficit		**143,836**	137,381
Defined benefit pension plan deficit	6	**1,913**	2,088
Net assets		**141,923**	135,293
Represented by			
Capital and reserves			
Called-up share capital	7	**5,261**	5,224
Share premium account	8	**9,974**	9,952
Capital redemption reserve	8	**1,072**	1,072
Merger reserve	8	**26,509**	26,509
Own shares	8	**(280)**	(388)
Treasury shares	8	**(20,774)**	(20,935)
Share-based payment reserve	8	**1,604**	1,574
Profit and loss account	8	**118,557**	112,285
		141,923	135,293

The financial statements on pages PC2–PC11 were approved and signed by the group chief executive on 6 March 2013 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 PC1–PC11 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	2012	2011
			$ million
Net cash outflow from operating activities	9	**(1,272)**	(3,799)
Servicing of finance and returns on investments			
Interest received		**183**	234
Interest paid		**(43)**	(47)
Dividends received		**13,515**	11,942
Net cash inflow from servicing of finance and returns on investments		**13,655**	12,129
Tax paid		**(2)**	(9)
Capital expenditure and financial investment			
Payments for fixed assets – investments		**(7,060)**	(3,719)
Proceeds from sale of fixed assets – investments		**–**	9
Net cash outflow for capital expenditure and financial investment		**(7,060)**	(3,710)
Equity dividends paid		**(5,294)**	(4,072)
Net cash inflow before financing		**27**	539
Financing			
Other share-based payment movements		**(18)**	(543)
Net cash outflow from financing		**(18)**	(543)
Increase (decrease) in cash	9	**9**	(4)

Company statement of total recognized gains and losses

For the year ended 31 December

	Note	2012	2011
			$ million
Profit for the year		**12,322**	11,484
Currency translation differences		**(98)**	164
Actuarial loss relating to pensions	6	**(573)**	(4,770)
Tax on actuarial loss relating to pensions	2	**–**	583
Total recognized gains and losses relating to the year		**11,651**	7,461

The parent company financial statements of BP p.l.c. on pages PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

Notes on 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 relevant 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 is treated as a cancellation, where this is within the control of the employee.

No expense is recognized for awards that do not ultimately vest, except for awards where vesting is conditional upon a market condition, which are treated as vesting irrespective of whether or not the market condition is satisfied, provided that all other performance conditions are satisfied.

At each balance sheet date before vesting, the cumulative expense is calculated, representing the extent to which the vesting period has expired and management's best estimate of the achievement or otherwise of non-market conditions and the number of equity instruments that will ultimately vest or, in the case of an instrument subject to a market condition, be treated as vesting as described above. The movement in cumulative expense since the previous balance sheet date is recognized in the income statement, with a corresponding entry in equity.

When the terms of an equity-settled award are modified or a new award is designated as replacing a cancelled or settled award, the cost based on the original award terms continues to be recognized over the original vesting period. In addition, an expense is recognized over the remainder of the new vesting period for the incremental fair value of any modification, based on the difference between the fair value of the original award and the fair value of the modified award, both as measured on the date of the modification. No reduction is recognized if this difference is negative.

When an equity-settled award is cancelled, it is treated as if it had vested on the date of cancellation and any cost not yet recognized in the income statement for the award is expensed immediately.

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 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 are recognized immediately when the company becomes committed to a change in pension plan design. When a settlement (eliminating all obligations for benefits already accrued) or a curtailment (reducing future obligations as a result of a material reduction in the scheme membership or a reduction in future entitlement) occurs, the obligation and related plan assets are remeasured using current actuarial assumptions and the resultant gain or loss is recognized in the income statement during the period in which the settlement or curtailment 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 PC1–PC11 do not form part of BP's Annual Report on Form 20-F as filed with the SEC.

2. Taxation

Tax charge included in the statement of total recognized gains and losses	2012	2011
		$ million
Deferred tax		
Origination and reversal of timing differences in the current year	–	(583)
This comprises:		
Actuarial loss relating to pensions and other post-retirement benefits	–	(583)

Deferred tax		
Net deferred tax liability (asset)	–	–
Analysis of movements during the year		
At 1 January	–	410
Exchange adjustments	–	34
Charge for the year on ordinary activities	–	139
Credit for the year in the statement of total recognized gains and losses	–	(583)
At 31 December	–	–

At 31 December 2012, deferred tax assets of $97 million on pensions (2011 $559 million) and $82 million on other timing differences (2011 $91 million) were not recognized as it is not considered more likely than not that suitable taxable profits will be available in the company from which the future reversal of the underlying timing differences can be deducted. It is anticipated that the reversal of these timing differences will benefit other group companies in the future.

3. Fixed assets – investments

	Subsidiary undertakings	Associated undertakings		$ million
	Shares	Shares	Loans	Total
Cost				
At 1 January 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**
Cost				
At 1 January 2011	122,723	2	2	122,727
Additions	3,719	–	–	3,719
Disposals	(8)	–	–	(8)
At 31 December 2011	126,434	2	2	126,438
Amounts provided				
At 1 January 2011	74	–	2	76
At 31 December 2011	74	–	2	76
Net book amount				
At 31 December 2012	**133,420**	**2**	**–**	**133,422**
At 31 December 2011	126,360	2	–	126,362

The more important subsidiary undertakings of the company at 31 December 2012 and the percentage holding of ordinary share capital (to the nearest whole number) are set out below. A complete list of investments in subsidiary undertakings, joint ventures and associated undertakings will be attached to the company's annual return made to the Registrar of Companies.

Subsidiary undertakings	%	Country of incorporation	Principal activities
International			
BP Corporate Holdings	100	England & Wales	Investment holding
BP Global Investments	100	England & Wales	Investment holding
BP International	100	England & Wales	Integrated oil operations
BP Shipping	100	England & Wales	Shipping
Burmah Castrol	100	Scotland	Lubricants
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 2012 was $62.63 billion (2011 $62.63 billion).

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4. Debtors

				$ million
	2012			2011
	Within 1 year	**After 1 year**	Within 1 year	After 1 year
Group undertakings	**17,496**	**–**	17,695	38
Other	**–**	**–**	3	–
	17,496	**–**	17,698	38

The carrying amounts of debtors approximate their fair value.

5. Creditors

				$ million
	2012			2011
	Within 1 year	**After 1 year**	Within 1 year	After 1 year
Group undertakings	**2,376**	**4,274**	2,334	4,264
Accruals and deferred income	**27**	**38**	28	35
Other creditors	**201**	**175**	56	–
	2,604	**4,487**	2,418	4,299

The carrying amounts of creditors approximate their fair value.

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.

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 $350 million payable in respect of the settlement with the US Securities and Exchange Commission described in Note 2 of the consolidated financial statements.

		$ million
	2012	2011
Due within		
1 to 2 years	**230**	49
2 to 5 years	**17**	14
More than 5 years	**4,240**	4,236
	4,487	4,299

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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. With effect from 1 April 2010, BP closed its UK plan to new joiners other than some of those joining the North Sea business. The plan remains open to those employees who joined BP on or before 31 March 2010. The majority of new joiners in the UK have the option to join 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 2012. 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 used to evaluate accrued pensions at 31 December in any year are used to determine pension expense for the following year, that is, the assumptions at 31 December 2012 are used to determine the pension liabilities at that date and the pension cost for 2013.

Financial assumptions			%
	2012	2011	2010
Expected long-term rate of return	**6.9**	7.0	7.3
Discount rate for plan liabilities	**4.4**	4.8	5.5
Rate of increase in salaries	**4.9**	5.1	5.4
Rate of increase for pensions in payment	**3.1**	3.2	3.5
Rate of increase in deferred pensions	**3.1**	3.2	3.5
Inflation	**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			
	2012	2011	2010
Life expectancy at age 60 for a male currently aged 60	**27.7**	27.6	26.1
Life expectancy at age 60 for a male currently aged 40	**30.6**	30.5	29.1
Life expectancy at age 60 for a female currently aged 60	**29.4**	29.3	28.7
Life expectancy at age 60 for a female currently aged 40	**32.1**	32.0	31.6

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

						$ million
		2012		2011		2010
	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
Equities	**8.0**	**19,612**	8.0	17,202	8.0	17,703
Bonds[a]	**3.8**	**4,885**	4.4	4,141	5.1	3,128
Property[b]	**6.5**	**1,783**	6.5	1,710	6.5	1,412
Cash	**0.9**	**1,066**	1.7	534	1.4	369
	6.9	**27,346**	7.0	23,587	7.3	22,612
Present value of plan liabilities		**29,259**		25,675		20,742
(Deficit) surplus in the plan		**(1,913)**		(2,088)		1,870

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

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6. Pensions continued

		$ million
	2012	2011
Analysis of the amount charged to operating profit		
Current service cost[a]	**477**	380
Settlement, curtailment and special termination benefits[b]	**(1)**	3
Payments to defined contribution plans	**14**	5
Total operating charge[c]	**490**	388
Analysis of the amount credited (charged) to other finance income		
Expected return on pension plan assets	**1,680**	1,773
Interest on pension plan liabilities	**(1,249)**	(1,240)
Other finance income	**431**	533
Analysis of the amount recognized in statement of total recognized gains and losses		
Actual return less expected return on pension plan assets	**989**	(1,976)
Change in assumptions underlying the present value of the plan liabilities	**(1,446)**	(2,710)
Experience gains and losses arising on the plan liabilities	**(116)**	(84)
Actuarial loss recognized in statement of total recognized gains and losses	**(573)**	(4,770)

		$ million
	2012	2011
Movements in benefit obligation during the year		
Benefit obligation at 1 January	**25,675**	20,742
Exchange adjustment	**1,313**	(204)
Current service cost[a]	**477**	380
Interest cost	**1,249**	1,240
Transfers of plans from other group companies[d]	**–**	1,671
Curtailments	**(8)**	–
Disposals	**(10)**	–
Special termination benefits	**7**	3
Contributions by plan participants	**39**	33
Benefit payments (funded plans)[e]	**(1,038)**	(980)
Benefit payments (unfunded plans)[e]	**(7)**	(4)
Actuarial loss on obligation	**1,562**	2,794
Benefit obligation at 31 December	**29,259**	25,675
Movements in fair value of plan assets during the year		
Fair value of plan assets at 1 January	**23,587**	22,612
Exchange adjustment	**1,215**	(41)
Expected return on plan assets[a f]	**1,680**	1,773
Contributions by plan participants[g]	**39**	33
Contributions by employers (funded plans)	**884**	423
Transfers of plans from other group companies[d]	**–**	1,743
Disposals	**(10)**	–
Benefit payments (funded plans)[e]	**(1,038)**	(980)
Actuarial gain (loss) on plan assets[f]	**989**	(1,976)
Fair value of plan assets at 31 December[h]	**27,346**	23,587
Deficit at 31 December	**(1,913)**	(2,088)

[a] The costs of managing the plan'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] Included within production and manufacturing expenses and distribution and administration expenses.
[d] Transfer of the Burmah Castrol Pension Fund and the Lubricants UK Limited pension plan.
[e] The benefit payments amount shown above comprises $1,022 million benefits plus $16 million of plan expenses incurred in the administration of the benefit.
[f] The actual return on plan assets is made up of the sum of the expected return on plan assets and the actuarial gain or loss on the plan assets as disclosed above.
[g] The contributions by plan participants for the UK mostly comprise contributions made under salary sacrifice arrangements.
[h] Reflects $27,220 million of assets held in the BP Pension Fund (2011 $23,482 million) and $94 million held in the BP Global Pension Trust (2011 $75 million), with $32 million representing the company's share of Merchant Navy Officers Pension Fund (2011 $30 million).

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6. Pensions continued

		$ million
	2012	2011
Reconciliation of plan deficit to balance sheet		
Deficit at 31 December	**(1,913)**	(2,088)
Deferred tax	**–**	–
	(1,913)	(2,088)
Represented by		
Liability recognized on balance sheet	**(1,913)**	(2,088)
	(1,913)	(2,088)

The aggregate level of employer contributions into the BP Pension Fund in 2013 is expected to be $496 million.

					$ million
	2012	2011	2010	2009	2008
History of (deficit) surplus and of experience gains and losses					
Benefit obligation at 31 December	**29,259**	25,675	20,742	19,882	15,414
Fair value of plan assets at 31 December	**27,346**	23,587	22,612	20,953	16,930
(Deficit) surplus	**(1,913)**	(2,088)	1,870	1,071	1,516
Experience gains and losses on plan liabilities					
Amount ($ million)	**(116)**	(84)	12	(146)	(65)
Percentage of benefit obligation	**0%**	0%	0%	(1%)	0%
Actual return less expected return on pension plan assets					
Amount ($ million)	**989**	(1,976)	1,479	1,634	(6,533)
Percentage of plan assets	**4%**	(8%)	7%	8%	(39%)
Actuarial (loss) gain recognized in statement of total recognized gains and losses					
Amount ($ million)	**(573)**	(4,770)	457	(585)	(5,122)
Percentage of benefit obligation	**(2%)**	(19%)	2%	(3%)	(33%)
Cumulative amount recognized in statement of total recognized gains and losses	**(6,578)**	(6,005)	(1,235)	(1,692)	(1,107)

7. Called-up share capital

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

	2012		2011	
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	**20,813,410**	**5,203**	20,647,160	5,162
Issue of new shares for the scrip dividend programme	**138,406**	**35**	165,601	41
Issue of new shares for employee share schemes[b]	**7,343**	**2**	649	–
31 December	**20,959,159**	**5,240**	20,813,410	5,203
		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 $46 million (2011 $4 million).

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.

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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 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**

$ 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 2011	5,183	9,987	1,072	26,509	(126)	(21,085)	1,585	108,794	131,919
Currency translation differences	–	–	–	–	–	–	–	164	164
Actuarial loss on pensions (net of tax)	–	–	–	–	–	–	–	(4,187)	(4,187)
Share-based payments	–	6	–	–	(262)	150	(11)	102	(15)
Profit for the year	–	–	–	–	–	–	–	11,484	11,484
Dividends	41	(41)	–	–	–	–	–	(4,072)	(4,072)
At 31 December 2011	5,224	9,952	1,072	26,509	(388)	(20,935)	1,574	112,285	135,293

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 (2011 $24,107 million), the distribution of which is limited by statutory or other restrictions.

The accounts for the year ended 31 December 2012 do not reflect the dividend announced on 5 February 2013 and payable in March 2013; this will be treated as an appropriation of profit in the year ended 31 December 2013.

9. Cash flow

Notes on cash flow statement

$ million

	2012	2011
Reconciliation of net cash flow to movement of funds		
Increase (decrease) in cash	**9**	(4)
Movement of funds	**9**	(4)
Net cash at 1 January	**–**	4
Net cash at 31 December	**9**	–
Notes on cash flow statement		
(a) Reconciliation of operating profit to net cash (outflow) inflow from operating activities	**2012**	2011
Operating profit	**11,936**	11,136
Net operating charge for pensions and other post-retirement benefits, less contributions	**(414)**	(117)
Dividends, interest and other income	**(13,758)**	(12,132)
Share-based payments	**350**	528
Decrease (increase) in debtors	**240**	(3,253)
Increase in creditors	**374**	39
Net cash outflow from operating activities	**(1,272)**	(3,799)

$ million

(b) Analysis of movements of funds	At 1 January 2012	Cash flow	At 31 December 2012
Cash at bank	–	**9**	**9**

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10. Contingent liabilities

The parent company has issued guarantees under which amounts outstanding at 31 December 2012 were $45,400 million (2011 $41,847 million), of which $45,370 million (2011 $40,449 million) related to guarantees in respect of subsidiary undertakings, including $44,629 million (2011 $39,708 million) in respect of borrowings by its subsidiary undertakings, and $30 million (2011 $30 million) in respect of liabilities of other third parties.

11. Share-based payments

Effect of share-based payment transactions on the company's result and financial position

		$ million
	2012	2011
Total expense recognized for equity-settled share-based payment transactions	**669**	579
Total expense recognized for cash-settled share-based payment transactions	**5**	5
Total expense recognized for share-based payment transactions	**674**	584
Closing balance of liability for cash-settled share-based payment transactions	**12**	12
Total intrinsic value for vested cash-settled share-based payments	**–**	1

Information on the company's share-based payment schemes is provided in Note 40 to the consolidated financial statements.

12. Auditor's remuneration

Note 16 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	**2012**	2011
Total for all directors		
Emoluments	**12**	10
Gains made on the exercise of share options	**–**	–
Amounts awarded under incentive schemes	**3**	1

Emoluments

These amounts comprise fees paid to the non-executive chairman and the non-executive directors and, for executive directors, salary and benefits earned during the relevant financial year, plus cash bonuses awarded for the year. There was no compensation for loss of office in 2012 (2011 nil and 2010 $3 million).

Pension contributions

During 2012, two executive directors participated in a non-contributory pension scheme established for UK staff by a separate trust fund to which contributions are made by BP based on actuarial advice. Two US executive directors participated in the US BP Retirement Accumulation Plan during 2012.

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 pages 127-145.

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