

Financial and Operating Information 2009-2013

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Cautionary statement

BP Financial and Operating Information 2009-2013 contains certain forward-looking statements – that is, statements related to future, not past events – with respect to the financial condition, results of operations and businesses of BP and certain of the plans and objectives of BP with respect to these items. These statements may generally, but not always, be identified by the use of words such as ‘will’, ‘expects’, ‘is expected to’, ‘aims’, ‘should’, ‘may’, ‘objective’, ‘is likely to’, ‘intends’, ‘believes’, ‘anticipates’, ‘plans’, ‘we see’ or similar expressions, in particular, statements regarding the expected expiry date of the Abu Dhabi offshore concession and plans to focus on optimizing performance at BP’s existing wind farms are forward looking in nature. By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including the receipt of relevant third party and/or government approvals; the timing of bringing new fields onstream; the timing of certain disposals; future levels of industry product supply, demand and pricing, including supply growth in North America; OPEC quota restrictions; PSA effects; operational problems; general economic conditions; political stability and economic growth in relevant areas of the world; changes in laws and governmental regulations; regulatory or legal actions including the types of enforcement action pursued and the nature of remedies sought; the actions of prosecutors, regulatory authorities and courts; the actions of

the claims administrator appointed under the Economic and Property Damages Settlement; the actions of all parties to the Deepwater Horizon oil spill-related litigation at various phases of the litigation; exchange rate fluctuations; development and use of new technology; the success or otherwise of partnering; the actions of competitors; the actions of contractors; natural disasters and adverse weather conditions; changes in public expectations and other changes to business conditions; wars and acts of terrorism, cyber-attacks or sabotage; and other factors discussed in the *BP Annual Report and Form 20-F 2013* filed with the US Securities and Exchange Commission (SEC), including under ‘Risk factors’ on pages 51-55 therein (the 20-F risk factors). In addition to factors set forth in the 20-F risk factors, those set out above are important factors, although not exhaustive, that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements. For more information you should refer to the *BP Annual Report and Form 20-F 2013* filed with the SEC.

Statements regarding competitive position

Statements referring to BP’s competitive position are based on the company’s belief and, in some cases, rely on a range of sources, including investment analysts’ reports, independent market studies and BP’s internal assessments of market share based on publicly available information about the financial results and performance of market participants.

Basis of preparation

BP prepares its consolidated financial statements included within *BP Financial and Operating Information 2009-2013* 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. Certain non-GAAP information is also presented as explained on the relevant pages.

To the greatest extent possible, the information in this book has been presented on the basis that BP will report its financial information in 2014, in accordance with the accounting policies expected to be used in preparing *BP Annual Report and Form 20-F 2014*. These accounting policies do not differ significantly from those used in the *BP Annual Report and Form 20-F 2013*.

BP adopted several new and amended standards issued by the IASB with effect from 1 January 2013. This included the new standard IFRS 11 'Joint arrangements'.

Under IFRS 11 certain of the group's jointly controlled entities, which were previously equity-accounted, now fall under the definition of a joint operation and so we now 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 material, the change impacts certain of the component lines of the income statement, balance sheet and cash flow statement.

Consistent with *BP Financial and Operating Information 2008-2012*, financial information in this book for 2011 and 2012 was restated to reflect the adoption of IFRS 11. However, financial information in this book for 2009 and 2010 was not restated.

Within this document, comparative financial information is colour-coded as follows:

Quarterly and annual information

2009-2010	Not restated for IFRS 11	30,000 30,000	Green type Annual total in bold
2011-2012	Restated for IFRS 11	30,000 30,000	Black type Annual total in bold

The financial information for 2009-2010 (quarterly and annual) has not been restated to reflect IFRS 11.

The financial information for 2011 and 2012 (quarterly and annual) has been restated to reflect the adoption of IFRS 11.

Interactive resources

Visit bp.com/investortools to chart our key financial and operating information for the past five years, on an annual or quarterly basis, for the BP group as a whole or by business segment.

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Spreadsheets containing the data in this document can be downloaded from www.bp.com/financialandoperating

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For a complete view of BP's performance, this document should be read in conjunction with *BP Annual Report and Form 20-F 2013* and *BP Sustainability Report 2013*. Copies may be obtained free of charge (see page 80).

Group information

Financial performance

Highlights

	2009	2010	2011	2012	2013
Underlying replacement cost profit for the year (\$ million) ^{a b}	14,362	20,177	21,170	17,071	13,428
per ordinary share (cents)	76.66	107.39	111.97	89.70	70.92
per American depositary share (dollars) ^c	4.60	6.44	6.72	5.38	4.26
Non-operating items and fair value accounting effects, net of tax (\$ million) ^a	(622)	(25,436)	2,242	(5,643)	10,253
Replacement cost profit (loss) for the year (\$ million) ^{a b}	13,740	(5,259)	23,412	11,428	23,681
per ordinary share (cents)	73.34	(28.01)	123.83	60.05	125.08
per American depositary share (dollars) ^c	4.40	(1.68)	7.43	3.60	7.50

^a Replacement cost (RC) profit or loss reflects the replacement cost of supplies. RC profit or loss for the group is a non-GAAP measure. Underlying RC profit is RC profit after adjusting for non-operating items and fair value accounting effects. Underlying RC profit and fair value accounting effects are not recognized GAAP measures. For further information see page 3.

^b Profit attributable to BP shareholders.

^c One American depositary share (ADS) is equivalent to six 25-cent ordinary shares.

External environment

	2009	2010	2011	2012	2013
BP average liquids realizations (\$ per barrel (\$/bbl)) ^{a b}	56.26	73.41	101.29	102.10	99.24
BP average natural gas realizations (\$ per thousand cubic feet (\$/mcf)) ^b	3.25	3.97	4.69	4.75	5.35
Refining marker margin (\$/bbl) ^c	9.8	10.7	14.5	18.2	15.4

^a Crude oil, condensate and natural gas liquids (NGLs).

^b Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

^c The refining marker margin (RMM) is the average of regional indicator margins weighted for BP's crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by BP in any period because of BP's particular refinery configurations and crude and product slate. In 2013, BP updated the RMM methodology; prior periods have been restated. See page 69 for further information.

Group income statement

For the year ended 31 December	\$ million				
	2009	2010	2011	2012	2013
Sales and other operating revenues	239,272	297,107	375,713	375,765	379,136
Earnings from joint ventures – after interest and tax	1,286	1,175	767	260	447
Earnings from associates – after interest and tax	2,615	3,582	4,916	3,675	2,742
Interest and other income	792	681	688	1,677	777
Gains on sale of businesses and fixed assets	2,173	6,383	4,132	6,697	13,115
Total revenues and other income	246,138	308,928	386,216	388,074	396,217
Purchases	(163,772)	(216,211)	(285,133)	(292,774)	(298,351)
Production and manufacturing expenses ^a	(23,202)	(64,615)	(24,163)	(33,926)	(27,527)
Production and similar taxes	(3,752)	(5,244)	(8,280)	(8,158)	(7,047)
Depreciation, depletion and amortization	(12,106)	(11,164)	(11,357)	(12,687)	(13,510)
Impairment and losses on sale of businesses and fixed assets	(2,333)	(1,689)	(2,058)	(6,275)	(1,961)
Exploration expense	(1,116)	(843)	(1,520)	(1,475)	(3,441)
Distribution and administration expenses	(14,038)	(12,555)	(13,958)	(13,357)	(13,070)
Fair value gain (loss) on embedded derivatives	607	(309)	68	347	459
Profit (loss) before interest and taxation	26,426	(3,702)	39,815	19,769	31,769
Finance costs ^a	(1,110)	(1,170)	(1,187)	(1,072)	(1,068)
Net finance income (expense) relating to pensions and other post-retirement benefits	(499)	(435)	(400)	(566)	(480)
Profit (loss) before taxation	24,817	(5,307)	38,228	18,131	30,221
Taxation ^a	(8,273)	1,638	(12,619)	(6,880)	(6,463)
Profit (loss) for the year	16,544	(3,669)	25,609	11,251	23,758
Attributable to					
BP shareholders	16,363	(4,064)	25,212	11,017	23,451
Non-controlling interests	181	395	397	234	307
	16,544	(3,669)	25,609	11,251	23,758
Earnings per share – cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	87.34	(21.64)	133.35	57.89	123.87
Diluted	86.40	(21.64)	131.74	57.50	123.12
Replacement cost results ^{b c d}					
Profit (loss) for the year	16,363	(4,064)	25,212	11,017	23,451
Inventory holding (gains) losses, net of tax	(2,623)	(1,195)	(1,800)	411	230
Replacement cost profit (loss) for the year	13,740	(5,259)	23,412	11,428	23,681
Non-operating items and fair value accounting effects, net of tax	622	25,436	(2,242)	5,643	(10,253)
Underlying replacement cost profit for the year	14,362	20,177	21,170	17,071	13,428
Research and development expenditure amounted to	587	780	636	674	707

^a See pages 16-17 for information on the impact of the Gulf of Mexico oil spill on these income statement line items in 2013, 2012, 2011 and 2010.

^b Replacement cost (RC) profit or loss reflects the replacement cost of supplies and is arrived at by excluding inventory holding gains and losses from profit or loss. 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, both RC profit or loss before interest and tax and underlying RC profit or loss before interest and tax are provided regularly to the chief operating decision maker. In such cases IFRS requires that the measure of profit disclosed for each operating segment is the measure that is closest to IFRS, which for BP is RC profit or loss before interest and tax. RC profit or loss for the group is not a recognized GAAP measure. The nearest equivalent GAAP measure is profit or loss for the year attributable to BP shareholders. BP believes that replacement cost profit before interest and taxation for the group is a useful measure for investors because it is a profitability measure used by management. A reconciliation is provided between the total of the operating segments' measures of profit or loss and the group profit or loss before taxation, as required under IFRS. See pages 4-5. 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. Management believes this information is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due principally to changes in oil prices as well as changes to underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of oil price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP's management believes it is helpful to disclose this information.

^c Profit (loss) attributable to BP shareholders.

^d Underlying RC profit or loss is RC profit or loss after adjusting for non-operating items and fair value accounting effects. Underlying RC profit or loss and fair value accounting effects are not recognized GAAP measures. On pages 10-11, we provide additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact. BP believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, year on year, by adjusting for the effects of these non-operating items and fair value accounting effects. The nearest equivalent measure on an IFRS basis for the group is profit or loss for the year attributable to BP shareholders. The nearest equivalent measure on an IFRS basis for segments is RC profit or loss before interest and taxation.

Analysis of RC profit (loss) before interest and tax

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
RC profit (loss) before interest and tax										
Upstream	4,186	4,500	6,197	7,969	22,852	7,749	5,754	7,620	7,146	28,269
Downstream	1,090	680	916	(1,943)	743	729	2,075	1,787	964	5,555
TNK-BP ^a	134	546	732	536	1,948	543	490	730	854	2,617
Rosneft ^b	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate	(761)	(583)	(586)	(392)	(2,322)	(328)	(70)	(568)	(550)	(1,516)
Gulf of Mexico oil spill response ^c	—	—	—	—	—	—	(32,192)	(7,656)	(1,010)	(40,858)
Consolidation adjustment - unrealized profit in inventory ^d	(405)	76	104	(492)	(717)	208	98	85	56	447
RC profit (loss) before interest and tax	4,244	5,219	7,363	5,678	22,504	8,901	(23,845)	1,998	7,460	(5,486)
Finance costs and net finance expense relating to pensions and other post-retirement benefits	(440)	(397)	(391)	(381)	(1,609)	(349)	(332)	(456)	(468)	(1,605)
RC profit (loss) before taxation	3,804	4,822	6,972	5,297	20,895	8,552	(24,177)	1,542	6,992	(7,091)
Taxation on a RC basis	(1,432)	(1,692)	(2,028)	(1,822)	(6,974)	(2,929)	7,224	300	(2,368)	2,227
RC profit (loss) for the period	2,372	3,130	4,944	3,475	13,921	5,623	(16,953)	1,842	4,624	(4,864)
Attributable to										
BP shareholders	2,337	3,086	4,925	3,392	13,740	5,514	(17,055)	1,754	4,528	(5,259)
Non-controlling interests	35	44	19	83	181	109	102	88	96	395
RC profit (loss) for the period	2,372	3,130	4,944	3,475	13,921	5,623	(16,953)	1,842	4,624	(4,864)
Earnings on RC profit (loss)										
per ordinary share – cents	12.48	16.47	26.29	18.09	73.34	29.38	(90.78)	9.33	24.09	(28.01)
per ADS – dollars	0.75	0.99	1.58	1.09	4.40	1.76	(5.45)	0.56	1.45	(1.68)
RC profit (loss) for the period	2,372	3,130	4,944	3,475	13,921	5,623	(16,953)	1,842	4,624	(4,864)
Inventory holding gains (losses)	254	1,874	538	1,256	3,922	705	(284)	(82)	1,445	1,784
Taxation (charge) credit on inventory holding gains and losses	(79)	(629)	(183)	(408)	(1,299)	(224)	107	20	(492)	(589)
Profit (loss) for the period	2,547	4,375	5,299	4,323	16,544	6,104	(17,130)	1,780	5,577	(3,669)
Earnings on profit (loss)										
per ordinary share – cents										
Basic	13.42	23.12	28.18	22.61	87.34	31.94	(91.73)	9.00	29.16	(21.64)
Diluted	13.28	22.87	27.88	22.35	86.40	31.54	(91.73)	8.90	28.83	(21.64)
per ADS – dollars										
Basic	0.81	1.39	1.69	1.36	5.24	1.92	(5.50)	0.54	1.75	(1.30)
Diluted	0.80	1.37	1.67	1.34	5.18	1.89	(5.50)	0.53	1.73	(1.30)

^a BP ceased equity accounting for its share of TNK-BP's earnings from 22 October 2012.

^b BP's investment in Rosneft is accounted under the equity method from 21 March 2013.

^c For more information see Gulf of Mexico oil spill.

^d Unrealized profit in inventory arising on inter-segment transactions.

Analysis of underlying RC profit (loss) before interest and tax

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
Underlying RC profit (loss) before interest and tax										
Upstream	3,717	3,858	5,546	6,547	19,668	7,645	5,815	5,811	5,802	25,073
Downstream	1,549	972	1,071	15	3,607	789	1,724	1,626	744	4,883
TNK-BP	134	546	732	536	1,948	543	490	730	854	2,617
Rosneft	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate	(440)	(544)	(522)	(327)	(1,833)	(210)	(141)	(482)	(483)	(1,316)
Consolidation adjustment - unrealized profit in inventory	(405)	76	104	(492)	(717)	208	98	85	56	447
Underlying RC profit before interest and tax	4,555	4,908	6,931	6,279	22,673	8,975	7,986	7,770	6,973	31,704
Finance costs and net finance expense relating to pensions and other post-retirement benefits	(440)	(397)	(391)	(381)	(1,609)	(349)	(332)	(409)	(438)	(1,528)
Underlying RC profit before taxation	4,115	4,511	6,540	5,898	21,064	8,626	7,654	7,361	6,535	30,176
Taxation on an underlying RC basis	(1,549)	(1,583)	(1,903)	(1,486)	(6,521)	(2,954)	(2,654)	(1,835)	(2,161)	(9,604)
Underlying RC profit for the period	2,566	2,928	4,637	4,412	14,543	5,672	5,000	5,526	4,374	20,572
Attributable to										
BP shareholders	2,531	2,884	4,618	4,329	14,362	5,563	4,898	5,438	4,278	20,177
Non-controlling interests	35	44	19	83	181	109	102	88	96	395
Underlying RC profit for the period	2,566	2,928	4,637	4,412	14,543	5,672	5,000	5,526	4,374	20,572
Earnings on underlying RC profit										
per ordinary share – cents	13.52	15.40	24.65	23.09	76.66	29.64	26.07	28.94	22.76	107.39
per ADS – dollars	0.81	0.92	1.48	1.39	4.60	1.78	1.56	1.74	1.37	6.44

Analysis of RC profit (loss) before interest and tax continued

\$ million														
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
7,419	5,629	6,747	6,563	26,358	6,983	2,913	4,907	7,688	22,491	5,562	4,400	4,158	2,537	16,657
2,082	1,339	1,492	557	5,470	859	(1,732)	2,408	1,329	2,864	1,647	1,016	616	(360)	2,919
1,127	1,081	939	987	4,134	1,064	452	1,282	575	3,373	12,500	—	—	-	12,500
—	—	—	—	—	—	—	—	—	—	85	218	792	1,058	2,153
(474)	(601)	(329)	(1,064)	(2,468)	(671)	(522)	(1,096)	(505)	(2,794)	(467)	(573)	(674)	(605)	(2,319)
(384)	617	(541)	4,108	3,800	30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)
(542)	515	(213)	127	(113)	(541)	457	(64)	(428)	(576)	427	129	263	(240)	579
9,228	8,580	8,095	11,278	37,181	7,724	725	7,381	4,533	20,363	19,732	4,991	5,125	2,211	32,059
(386)	(402)	(386)	(413)	(1,587)	(405)	(390)	(376)	(467)	(1,638)	(404)	(369)	(397)	(378)	(1,548)
8,842	8,178	7,709	10,865	35,594	7,319	335	7,005	4,066	18,725	19,328	4,622	4,728	1,833	30,511
(3,282)	(2,830)	(2,387)	(3,286)	(11,785)	(2,477)	(186)	(2,405)	(1,995)	(7,063)	(2,653)	(2,138)	(1,462)	(270)	(6,523)
5,560	5,348	5,322	7,579	23,809	4,842	149	4,600	2,071	11,662	16,675	2,484	3,266	1,563	23,988
5,499	5,278	5,145	7,490	23,412	4,781	104	4,534	2,009	11,428	16,596	2,400	3,178	1,507	23,681
61	70	177	89	397	61	45	66	62	234	79	84	88	56	307
5,560	5,348	5,322	7,579	23,809	4,842	149	4,600	2,071	11,662	16,675	2,484	3,266	1,563	23,988
29.22	27.94	27.15	39.49	123.83	25.19	0.54	23.82	10.53	60.05	86.67	12.62	16.84	8.06	125.08
1.75	1.68	1.63	2.37	7.43	1.51	0.03	1.43	0.63	3.60	5.20	0.76	1.01	0.48	7.50
5,560	5,348	5,322	7,579	23,809	4,842	149	4,600	2,071	11,662	16,675	2,484	3,266	1,563	23,988
2,412	493	(372)	101	2,634	1,437	(2,324)	1,059	(766)	(594)	406	(506)	444	(634)	(290)
(769)	(182)	139	(22)	(834)	(451)	701	(312)	245	183	(139)	148	(118)	169	60
7,203	5,659	5,089	7,658	25,609	5,828	(1,474)	5,347	1,550	11,251	16,942	2,126	3,592	1,098	23,758
37.96	29.59	25.93	39.90	133.35	30.39	(7.99)	27.74	7.80	57.89	88.07	10.73	18.57	5.57	123.87
37.51	29.23	25.60	39.38	131.74	29.97	(7.99)	27.59	7.75	57.50	87.61	10.68	18.47	5.54	123.12
2.28	1.78	1.56	2.39	8.00	1.82	(0.48)	1.66	0.47	3.47	5.28	0.64	1.11	0.33	7.43
2.25	1.75	1.54	2.36	7.90	1.80	(0.48)	1.66	0.46	3.45	5.26	0.64	1.11	0.33	7.39

Analysis of underlying RC profit (loss) before interest and tax continued

\$ million														
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
6,680	6,328	6,286	5,923	25,217	6,294	4,401	4,366	4,375	19,436	5,702	4,288	4,423	3,852	18,265
2,199	1,392	1,665	753	6,009	927	1,133	3,009	1,394	6,463	1,641	1,201	720	70	3,632
1,127	1,081	939	987	4,134	1,157	452	1,294	224	3,127	—	—	—	-	-
—	—	—	—	—	—	—	—	—	—	85	218	808	1,087	2,198
(293)	(338)	(405)	(610)	(1,646)	(435)	(540)	(573)	(448)	(1,996)	(461)	(438)	(385)	(614)	(1,898)
(542)	515	(213)	127	(113)	(541)	457	(64)	(428)	(576)	427	129	263	(240)	579
9,171	8,978	8,272	7,180	33,601	7,402	5,903	8,032	5,117	26,454	7,394	5,398	5,829	4,155	22,776
(370)	(387)	(372)	(400)	(1,529)	(399)	(386)	(373)	(461)	(1,619)	(394)	(359)	(388)	(368)	(1,509)
8,801	8,591	7,900	6,780	32,072	7,003	5,517	7,659	4,656	24,835	7,000	5,039	5,441	3,787	21,267
(3,348)	(2,946)	(2,391)	(1,820)	(10,505)	(2,291)	(1,921)	(2,576)	(742)	(7,530)	(2,706)	(2,243)	(1,661)	(922)	(7,532)
5,453	5,645	5,509	4,960	21,567	4,712	3,596	5,083	3,914	17,305	4,294	2,796	3,780	2,865	13,735
5,392	5,575	5,332	4,871	21,170	4,651	3,551	5,017	3,852	17,071	4,215	2,712	3,692	2,809	13,428
61	70	177	89	397	61	45	66	62	234	79	84	88	56	307
5,453	5,645	5,509	4,960	21,567	4,712	3,596	5,083	3,914	17,305	4,294	2,796	3,780	2,865	13,735
28.66	29.51	28.14	25.68	111.97	24.51	18.66	26.35	20.19	89.70	22.01	14.26	19.57	15.02	70.92
1.72	1.77	1.69	1.54	6.72	1.47	1.12	1.58	1.21	5.38	1.32	0.86	1.17	0.90	4.26

Replacement cost profit (loss) before interest and tax by segment and geographical area

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
By segment										
Upstream ^a										
US	1,143	1,161	1,864	2,517	6,685	2,762	1,798	3,602	1,522	9,684
Non-US	3,043	3,339	4,333	5,452	16,167	4,987	3,956	4,018	5,624	18,585
	4,186	4,500	6,197	7,969	22,852	7,749	5,754	7,620	7,146	28,269
Downstream										
US	308	(326)	(229)	(2,331)	(2,578)	(63)	757	220	21	935
Non-US	782	1,006	1,145	388	3,321	792	1,318	1,567	943	4,620
	1,090	680	916	(1,943)	743	729	2,075	1,787	964	5,555
TNK-BP ^b										
US	—	—	—	—	—	—	—	—	—	—
Non-US	134	546	732	536	1,948	543	490	730	854	2,617
	134	546	732	536	1,948	543	490	730	854	2,617
Rosneft ^c										
US	—	—	—	—	—	—	—	—	—	—
Non-US	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate										
US	(279)	(129)	(179)	(141)	(728)	(231)	(119)	(156)	(225)	(731)
Non-US	(482)	(454)	(407)	(251)	(1,594)	(97)	49	(412)	(325)	(785)
	(761)	(583)	(586)	(392)	(2,322)	(328)	(70)	(568)	(550)	(1,516)
	4,649	5,143	7,259	6,170	23,221	8,693	8,249	9,569	8,414	34,925
Gulf of Mexico oil spill response ^d	—	—	—	—	—	—	(32,192)	(7,656)	(1,010)	(40,858)
Consolidation adjustment - UPII ^e	(405)	76	104	(492)	(717)	208	98	85	56	447
Total for period	4,244	5,219	7,363	5,678	22,504	8,901	(23,845)	1,998	7,460	(5,486)
By geographical area^a										
US	854	730	1,516	(294)	2,806	2,590	(29,171)	(3,891)	385	(30,087)
Non-US	3,390	4,489	5,847	5,972	19,698	6,311	5,326	5,889	7,075	24,601
Total for period	4,244	5,219	7,363	5,678	22,504	8,901	(23,845)	1,998	7,460	(5,486)

^a A minor amendment has been made to the split between regions for 2013.

^b BP ceased equity accounting for its share of TNK-BP's earnings from 22 October 2012.

^c BP's investment in Rosneft is accounted under the equity method from 21 March 2013.

^d For more information see Gulf of Mexico oil spill.

^e Unrealized profit in inventory (UPII) arising on inter-segment transactions.

Replacement cost profit (loss) before interest and
tax by segment and geographical area continued

\$ million														
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
1,875	731	1,432	2,158	6,196	2,534	(1,584)	1,178	4,790	6,918	908	590	1,192	935	3,625
5,544	4,898	5,315	4,405	20,162	4,449	4,497	3,729	2,898	15,573	4,654	3,810	2,966	1,602	13,032
7,419	5,629	6,747	6,563	26,358	6,983	2,913	4,907	7,688	22,491	5,562	4,400	4,158	2,537	16,657
640	(17)	761	31	1,415	158	(1,984)	1,106	478	(242)	713	759	(86)	(628)	758
1,442	1,356	731	526	4,055	701	252	1,302	851	3,106	934	257	702	268	2,161
2,082	1,339	1,492	557	5,470	859	(1,732)	2,408	1,329	2,864	1,647	1,016	616	(360)	2,919
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
1,127	1,081	939	987	4,134	1,064	452	1,282	575	3,373	12,500	—	—	—	12,500
1,127	1,081	939	987	4,134	1,064	452	1,282	575	3,373	12,500	—	—	—	12,500
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	85	218	792	1,058	2,153
—	—	—	—	—	—	—	—	—	—	85	218	792	1,058	2,153
(188)	(168)	(294)	(580)	(1,230)	(307)	(277)	(712)	(345)	(1,641)	(125)	(276)	(606)	(242)	(1,249)
(286)	(433)	(35)	(484)	(1,238)	(364)	(245)	(384)	(160)	(1,153)	(342)	(297)	(68)	(363)	(1,070)
(474)	(601)	(329)	(1,064)	(2,468)	(671)	(522)	(1,096)	(505)	(2,794)	(467)	(573)	(674)	(605)	(2,319)
10,154	7,448	8,849	7,043	33,494	8,235	1,111	7,501	9,087	25,934	19,327	5,061	4,892	2,630	31,910
(384)	617	(541)	4,108	3,800	30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)
(542)	515	(213)	127	(113)	(541)	457	(64)	(428)	(576)	427	129	263	(240)	579
9,228	8,580	8,095	11,278	37,181	7,724	725	7,381	4,533	20,363	19,732	4,991	5,125	2,211	32,059
1,813	1,361	1,141	5,887	10,202	1,935	(4,246)	1,422	1,069	180	1,727	1,156	530	(299)	3,114
7,415	7,219	6,954	5,391	26,979	5,789	4,971	5,959	3,464	20,183	18,005	3,835	4,595	2,510	28,945
9,228	8,580	8,095	11,278	37,181	7,724	725	7,381	4,533	20,363	19,732	4,991	5,125	2,211	32,059

Underlying replacement cost profit before interest and tax by segment and geographical area

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
By segment										
Upstream^a										
US	864	951	1,760	2,278	5,853	2,743	1,989	1,835	1,786	8,353
Non-US	2,853	2,907	3,786	4,269	13,815	4,902	3,826	3,976	4,016	16,720
	3,717	3,858	5,546	6,547	19,668	7,645	5,815	5,811	5,802	25,073
Downstream										
US	377	(253)	(56)	(625)	(557)	(76)	569	65	6	564
Non-US	1,172	1,225	1,127	640	4,164	865	1,155	1,561	738	4,319
	1,549	972	1,071	15	3,607	789	1,724	1,626	744	4,883
TNK-BP^b										
US	–	–	–	–	–	–	–	–	–	–
Non-US	134	546	732	536	1,948	543	490	730	854	2,617
	134	546	732	536	1,948	543	490	730	854	2,617
Rosneft^c										
US	–	–	–	–	–	–	–	–	–	–
Non-US	–	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	–	–	–	–	–
Other businesses and corporate										
US	(163)	(96)	(150)	(155)	(564)	(125)	(112)	(85)	(171)	(493)
Non-US	(277)	(448)	(372)	(172)	(1,269)	(85)	(29)	(397)	(312)	(823)
	(440)	(544)	(522)	(327)	(1,833)	(210)	(141)	(482)	(483)	(1,316)
	4,960	4,832	6,827	6,771	23,390	8,767	7,888	7,685	6,917	31,257
	(405)	76	104	(492)	(717)	208	98	85	56	447
Consolidation adjustment - UPII^d										
Total for period	4,555	4,908	6,931	6,279	22,673	8,975	7,986	7,770	6,973	31,704
By geographical area^a										
US	760	626	1,614	1,159	4,159	2,664	3,031	1,914	1,698	9,307
Non-US	3,795	4,282	5,317	5,120	18,514	6,311	4,955	5,856	5,275	22,397
Total for period	4,555	4,908	6,931	6,279	22,673	8,975	7,986	7,770	6,973	31,704

^aA minor amendment has been made to the split between regions for 2013.

^bBP ceased equity accounting for its share of TNK-BP's earnings from 22 October 2012.

^cBP's investment in Rosneft is accounted under the equity method from 21 March 2013.

^dUnrealized profit in inventory (UPII) arising on inter-segment transactions.

Underlying replacement cost profit before interest and
tax by segment and geographical area continued

										\$ million				
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
1,846	1,479	1,473	1,310	6,108	1,658	628	741	827	3,854	954	561	1,271	1,050	3,836
4,834	4,849	4,813	4,613	19,109	4,636	3,773	3,625	3,548	15,582	4,748	3,727	3,152	2,802	14,429
6,680	6,328	6,286	5,923	25,217	6,294	4,401	4,366	4,375	19,436	5,702	4,288	4,423	3,852	18,265
704	151	927	196	1,978	289	450	1,723	583	3,045	750	557	(22)	(162)	1,123
1,495	1,241	738	557	4,031	638	683	1,286	811	3,418	891	644	742	232	2,509
2,199	1,392	1,665	753	6,009	927	1,133	3,009	1,394	6,463	1,641	1,201	720	70	3,632
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
1,127	1,081	939	987	4,134	1,157	452	1,294	224	3,127	—	—	—	—	—
1,127	1,081	939	987	4,134	1,157	452	1,294	224	3,127	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	85	218	808	1,087	2,198
—	—	—	—	—	—	—	—	—	—	85	218	808	1,087	2,198
(189)	(156)	(182)	(270)	(797)	(165)	(185)	(218)	(291)	(859)	(121)	(142)	(309)	(228)	(800)
(104)	(182)	(223)	(340)	(849)	(270)	(355)	(355)	(157)	(1,137)	(340)	(296)	(76)	(386)	(1,098)
(293)	(338)	(405)	(610)	(1,646)	(435)	(540)	(573)	(448)	(1,996)	(461)	(438)	(385)	(614)	(1,898)
9,713	8,463	8,485	7,053	33,714	7,943	5,446	8,096	5,545	27,030	6,967	5,269	5,566	4,395	22,197
(542)	515	(213)	127	(113)	(541)	457	(64)	(428)	(576)	427	129	263	(240)	579
9,171	8,978	8,272	7,180	33,601	7,402	5,903	8,032	5,117	26,454	7,394	5,398	5,829	4,155	22,776
2,231	1,672	2,001	1,406	7,310	1,302	1,335	2,152	1,391	6,180	1,836	1,258	1,000	475	4,569
6,940	7,306	6,271	5,774	26,291	6,100	4,568	5,880	3,726	20,274	5,558	4,140	4,829	3,680	18,207
9,171	8,978	8,272	7,180	33,601	7,402	5,903	8,032	5,117	26,454	7,394	5,398	5,829	4,155	22,776

Non-operating items^a by segment

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
Upstream										
Impairment and gain (loss) on sale of businesses and fixed assets	73	359	72	1,070	1,574	(13)	660	1,735	1,430	3,812
Environmental and other provisions	—	—	3	—	3	—	—	(54)	—	(54)
Restructuring, integration and rationalization costs	(1)	(6)	1	(4)	(10)	(104)	(13)	(6)	(14)	(137)
Fair value gain (loss) on embedded derivatives	243	154	370	(103)	664	146	(452)	20	(23)	(309)
Other	(4)	—	25	13	34	12	(134)	46	(37)	(113)
	311	507	471	976	2,265	41	61	1,741	1,356	3,199
Downstream										
Impairment and gain (loss) on sale of businesses and fixed assets ^b	(21)	(52)	(13)	(1,518)	(1,604)	(45)	270	507	145	877
Environmental and other provisions	—	—	(190)	(29)	(219)	—	—	(83)	(15)	(98)
Restructuring, integration and rationalization costs	(263)	(114)	(38)	(492)	(907)	12	(30)	(32)	(47)	(97)
Fair value gain (loss) on embedded derivatives	(57)	—	—	—	(57)	—	—	—	—	—
Other	(9)	—	—	193	184	(37)	(8)	(10)	3	(52)
	(350)	(166)	(241)	(1,846)	(2,603)	(70)	232	382	86	630
TNK-BP										
Impairment and gain (loss) on sale of businesses and fixed assets	—	—	—	—	—	—	—	—	—	—
Environmental and other provisions	—	—	—	—	—	—	—	—	—	—
Restructuring, integration and rationalization costs	—	—	—	—	—	—	—	—	—	—
Fair value gain (loss) on embedded derivatives	—	—	—	—	—	—	—	—	—	—
Other	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Rosneft										
Impairment and gain (loss) on sale of businesses and fixed assets	—	—	—	—	—	—	—	—	—	—
Environmental and other provisions	—	—	—	—	—	—	—	—	—	—
Restructuring, integration and rationalization costs	—	—	—	—	—	—	—	—	—	—
Fair value gain (loss) on embedded derivatives	—	—	—	—	—	—	—	—	—	—
Other	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate										
Impairment and gain (loss) on sale of businesses and fixed assets	(108)	(1)	(14)	(7)	(130)	(68)	97	(1)	(23)	5
Environmental and other provisions	(75)	—	(16)	16	(75)	—	(4)	(77)	(22)	(103)
Restructuring, integration and rationalization costs	(71)	(37)	(28)	(47)	(183)	(38)	(22)	(8)	(13)	(81)
Fair value gain (loss) on embedded derivatives	—	—	—	—	—	—	—	—	—	—
Other	(67)	(1)	(6)	(27)	(101)	(12)	—	—	(9)	(21)
	(321)	(39)	(64)	(65)	(489)	(118)	71	(86)	(67)	(200)
Gulf of Mexico oil spill response	—	—	—	—	—	—	(32,192)	(7,656)	(1,010)	(40,858)
Total before interest and taxation	(360)	302	166	(935)	(827)	(147)	(31,828)	(5,619)	365	(37,229)
Finance costs^c	—	—	—	—	—	—	—	(47)	(30)	(77)
Total before taxation	(360)	302	166	(935)	(827)	(147)	(31,828)	(5,666)	335	(37,306)
Taxation credit (charge)^d	135	(106)	(48)	(221)	(240)	50	9,877	2,097	(167)	11,857
Total after taxation	(225)	196	118	(1,156)	(1,067)	(97)	(21,951)	(3,569)	168	(25,449)

^a Non-operating items are charges and credits that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. These disclosures are provided in order to enable investors to understand better and evaluate the group's reported financial performance.

^b Includes the impairment of goodwill allocated to the US West Coast fuels value chain of \$1,579 million in the fourth quarter of 2009. The second quarter 2012 includes impairment charges of \$2,665 million in the fuels business, mainly relating to Texas City refinery and Carson refinery and their associated assets.

^c Finance costs relate to the Gulf of Mexico oil spill. For more information see page 16-17.

^d For the Gulf of Mexico oil spill and certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives, tax is based on statutory rates, except for non-deductible items. For dividends received from TNK-BP in the fourth quarter 2012, there is no tax arising. For other items reported by consolidated subsidiaries, tax is calculated using the group's discrete quarterly effective tax rate (adjusted for the items noted above, equity-accounted earnings from the first quarter 2012 onwards and the deferred tax adjustments relating to a reduction in UK corporation tax rates (\$99 million for the third quarter 2013), and changes to the taxation of UK oil and gas production (first quarter 2011 \$683 million and third quarter 2012 \$256 million)). Non-operating items arising within the equity-accounted earnings of TNK-BP and Rosneft are reported net of tax. In the fourth quarter and full year 2009, no tax credit was calculated on the goodwill impairment in Downstream because the charge is not tax deductible.

Non-operating items^a by segment continued

										\$ million				
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
1,089	(403)	321	1,124	2,131	928	(1,455)	492	3,673	3,638	(102)	65	(374)	(391)	(802)
—	—	(25)	(2)	(27)	—	—	(48)	—	(48)	—	—	(21)	1	(20)
—	—	1	(1)	—	—	—	—	—	—	—	—	—	—	—
(328)	142	211	166	191	(100)	271	73	103	347	31	135	238	55	459
(51)	(403)	(8)	(703)	(1,165)	(6)	(311)	(1)	(430)	(748)	(9)	(57)	(69)	(866)	(1,001)
710	(664)	500	584	1,130	822	(1,495)	516	3,346	3,189	(80)	143	(226)	(1,201)	(1,364)
5	(207)	(16)	(114)	(332)	(85)	(2,653)	(115)	(81)	(2,934)	34	(310)	(11)	(61)	(348)
—	(2)	(193)	(26)	(221)	—	—	(171)	—	(171)	(9)	—	(132)	7	(134)
(1)	(4)	(12)	13	(4)	(12)	(12)	(21)	13	(32)	(2)	(2)	—	(11)	(15)
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
(21)	(4)	(6)	(14)	(45)	(9)	(13)	(8)	(5)	(35)	(4)	(11)	(14)	(9)	(38)
(17)	(217)	(227)	(141)	(602)	(106)	(2,678)	(315)	(73)	(3,172)	19	(323)	(157)	(74)	(535)
—	—	—	—	—	(93)	—	38	—	(55)	12,500	—	—	—	12,500
—	—	—	—	—	—	—	(50)	(33)	(83)	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	384	384	—	—	—	—	—
—	—	—	—	—	(93)	—	(12)	351	246	12,500	—	—	—	12,500
—	—	—	—	—	—	—	—	—	—	—	—	(16)	(19)	(35)
—	—	—	—	—	—	—	—	—	—	—	—	—	(10)	(10)
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	(16)	(29)	(45)
35	4	274	(38)	275	(50)	29	(253)	(8)	(282)	(1)	(129)	(87)	21	(196)
—	(12)	(135)	(73)	(220)	(15)	—	(246)	—	(261)	—	(6)	(216)	(19)	(241)
1	2	(18)	(24)	(39)	—	(1)	—	(14)	(15)	(2)	—	(4)	3	(3)
(217)	7	87	—	(123)	1	(1)	(1)	1	—	—	—	—	—	—
—	(264)	(132)	(319)	(715)	(172)	(9)	(23)	(36)	(240)	(3)	—	18	4	19
(181)	(263)	76	(454)	(822)	(236)	18	(523)	(57)	(798)	(6)	(135)	(289)	9	(421)
(384)	617	(541)	4,108	3,800	30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)
128	(527)	(192)	4,097	3,506	417	(4,998)	(390)	(559)	(5,530)	12,411	(514)	(718)	(1,474)	9,705
(16)	(15)	(14)	(13)	(58)	(6)	(4)	(3)	(6)	(19)	(10)	(10)	(9)	(10)	(39)
112	(542)	(206)	4,084	3,448	411	(5,002)	(393)	(565)	(5,549)	12,401	(524)	(727)	(1,484)	9,666
44	160	9	(1,466)	(1,253)	(226)	1,663	72	(1,258)	251	23	158	205	481	867
156	(382)	(197)	2,618	2,195	185	(3,339)	(321)	(1,823)	(5,298)	12,424	(366)	(522)	(1,003)	10,533

Non-operating items by geographical area

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
Upstream										
US	71	118	(65)	21	145	(62)	(156)	1,681	(273)	1,190
Non-US	240	389	536	955	2,120	103	217	60	1,629	2,009
	311	507	471	976	2,265	41	61	1,741	1,356	3,199
Downstream										
US ^a	(134)	(27)	(179)	(1,697)	(2,037)	(3)	151	216	(12)	352
Non-US	(216)	(139)	(62)	(149)	(566)	(67)	81	166	98	278
	(350)	(166)	(241)	(1,846)	(2,603)	(70)	232	382	86	630
TNK-BP										
US	—	—	—	—	—	—	—	—	—	—
Non-US	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Rosneft										
US	—	—	—	—	—	—	—	—	—	—
Non-US	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate										
US	(116)	(33)	(29)	14	(164)	(106)	(7)	(71)	(54)	(238)
Non-US	(205)	(6)	(35)	(79)	(325)	(12)	78	(15)	(13)	38
	(321)	(39)	(64)	(65)	(489)	(118)	71	(86)	(67)	(200)
Gulf of Mexico oil spill response	—	—	—	—	—	—	(32,192)	(7,656)	(1,010)	(40,858)
Total before interest and taxation	(360)	302	166	(935)	(827)	(147)	(31,828)	(5,619)	365	(37,229)
Finance costs ^b	—	—	—	—	—	—	—	(47)	(30)	(77)
Total before taxation	(360)	302	166	(935)	(827)	(147)	(31,828)	(5,666)	335	(37,306)
Taxation credit (charge) ^c	135	(106)	(48)	(221)	(240)	50	9,877	2,097	(167)	11,857
Total after taxation	(225)	196	118	(1,156)	(1,067)	(97)	(21,951)	(3,569)	168	(25,449)

^a Includes the impairment of goodwill allocated to the US West Coast fuels value chain of \$1,579 million in the fourth quarter of 2009. The second quarter 2012 includes impairment charges of \$2,665 million in the fuels business, mainly relating to Texas City refinery and Carson refinery and their associated assets.

^b Finance costs relate to the Gulf of Mexico oil spill. For more information see page 16-17.

^c For the Gulf of Mexico oil spill, certain impairment losses in the second quarter 2012 and certain disposal gains in the fourth quarter 2012, tax is based on US statutory tax rates, except for non-deductible items. For dividends received from TNK-BP in the fourth quarter 2012, there is no tax arising. For other items reported by consolidated subsidiaries, tax is calculated using the group's discrete quarterly effective tax rate (adjusted for the items noted above, equity-accounted earnings from the first quarter 2012 onwards and the deferred tax adjustments relating to changes to the taxation of UK oil and gas production (first quarter 2011 \$683 million and third quarter 2012 \$256 million)). Non-operating items arising within the equity-accounted earnings of TNK-BP and Rosneft are reported net of tax. In the fourth quarter and full year 2009, no tax credit was calculated on the goodwill impairment in Downstream because the charge is not tax deductible.

Non-operating items by geographical area continued

														\$ million
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
4	(730)	(32)	831	73	947	(2,273)	465	3,992	3,131	(6)	62	5	(3)	58
706	66	532	(247)	1,057	(125)	778	51	(646)	58	(74)	81	(231)	(1,198)	(1,422)
710	(664)	500	584	1,130	822	(1,495)	516	3,346	3,189	(80)	143	(226)	(1,201)	(1,364)
(16)	(239)	(184)	(124)	(563)	(88)	(2,433)	(229)	(96)	(2,846)	28	(17)	(145)	(20)	(154)
(1)	22	(43)	(17)	(39)	(18)	(245)	(86)	23	(326)	(9)	(306)	(12)	(54)	(381)
(17)	(217)	(227)	(141)	(602)	(106)	(2,678)	(315)	(73)	(3,172)	19	(323)	(157)	(74)	(535)
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	(93)	-	(12)	351	246	12,500	-	-	-	12,500
-	-	-	-	-	(93)	-	(12)	351	246	12,500	-	-	-	12,500
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	(16)	(29)	(45)
-	-	-	-	-	-	-	-	-	-	-	-	(16)	(29)	(45)
1	(12)	(112)	(310)	(433)	(142)	(92)	(494)	(54)	(782)	(4)	(134)	(297)	(14)	(449)
(182)	(251)	188	(144)	(389)	(94)	110	(29)	(3)	(16)	(2)	(1)	8	23	28
(181)	(263)	76	(454)	(822)	(236)	18	(523)	(57)	(798)	(6)	(135)	(289)	9	(421)
(384)	617	(541)	4,108	3,800	30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)
128	(527)	(192)	4,097	3,506	417	(4,998)	(390)	(559)	(5,530)	12,411	(514)	(718)	(1,474)	9,705
(16)	(15)	(14)	(13)	(58)	(6)	(4)	(3)	(6)	(19)	(10)	(10)	(9)	(10)	(39)
112	(542)	(206)	4,084	3,448	411	(5,002)	(393)	(565)	(5,549)	12,401	(524)	(727)	(1,484)	9,666
44	160	9	(1,466)	(1,253)	(226)	1,663	72	(1,258)	251	23	158	205	481	867
156	(382)	(197)	2,618	2,195	185	(3,339)	(321)	(1,823)	(5,298)	12,424	(366)	(522)	(1,003)	10,533

Fair value accounting effects

BP uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products. Under IFRS, these inventories are recorded at historic cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in income because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories are not recognized until the commodity is sold in a subsequent accounting period. Gains and losses on the related derivative commodity contracts are recognized in the income statement from the time the derivative commodity contract is entered into on a fair value basis using forward prices consistent with the contract maturity.

BP enters into commodity contracts to meet certain business requirements, such as the purchase of crude for a refinery or the sale of BP's gas production. Under IFRS these contracts are treated as derivatives and are required to be fair valued when they are managed as part of a larger portfolio of similar transactions. Gains and losses arising are recognized in the income statement from the time the derivative commodity contract is entered into.

IFRS requires that inventory held for trading be recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices resulting in measurement differences.

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
By segment										
Upstream	158	135	180	446	919	63	(122)	68	(12)	(3)
Downstream	(109)	(126)	86	(112)	(261)	10	119	(221)	134	42
	49	9	266	334	658	73	(3)	(153)	122	39
Taxation credit (charge) ^a	(18)	(3)	(77)	(115)	(213)	(25)	1	38	(40)	(26)
	31	6	189	219	445	48	(2)	(115)	82	13
By geographical area										
Upstream										
US	208	92	169	218	687	81	(35)	86	9	141
Non-US	(50)	43	11	228	232	(18)	(87)	(18)	(21)	(144)
	158	135	180	446	919	63	(122)	68	(12)	(3)
Downstream										
US	65	(46)	6	(9)	16	16	37	(61)	27	19
Non-US	(174)	(80)	80	(103)	(277)	(6)	82	(160)	107	23
	(109)	(126)	86	(112)	(261)	10	119	(221)	134	42

^a Tax is calculated using the group's discrete quarterly effective tax rate (adjusted for the Gulf of Mexico oil spill, equity-accounted earnings, certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives and the deferred tax adjustment relating to a reduction in UK corporation tax rates (\$99 million for the third quarter 2013)).

Total of non-operating items and fair value accounting effects

	Q1	Q2	Q3	Q4	2009	Q1	Q2	Q3	Q4	2010
Upstream										
US	279	210	104	239	832	19	(191)	1,767	(264)	1,331
Non-US ^a	190	432	547	1,183	2,352	85	130	42	1,608	1,865
	469	642	651	1,422	3,184	104	(61)	1,809	1,344	3,196
Downstream										
US ^b	(69)	(73)	(173)	(1,706)	(2,021)	13	188	155	15	371
Non-US	(390)	(219)	18	(252)	(843)	(73)	163	6	205	301
	(459)	(292)	(155)	(1,958)	(2,864)	(60)	351	161	220	672
TNK-BP										
US	—	—	—	—	—	—	—	—	—	—
Non-US	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Rosneft										
US	—	—	—	—	—	—	—	—	—	—
Non-US	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate										
US	(116)	(33)	(29)	14	(164)	(106)	(7)	(71)	(54)	(238)
Non-US	(205)	(6)	(35)	(79)	(325)	(12)	78	(15)	(13)	38
	(321)	(39)	(64)	(65)	(489)	(118)	71	(86)	(67)	(200)
Gulf of Mexico oil spill response	—	—	—	—	—	—	(32,192)	(7,656)	(1,010)	(40,858)
Total before interest and taxation	(311)	311	432	(601)	(169)	(74)	(31,831)	(5,772)	487	(37,190)
Finance costs^c	—	—	—	—	—	—	—	(47)	(30)	(77)
Total before taxation	(311)	311	432	(601)	(169)	(74)	(31,831)	(5,819)	457	(37,267)
Taxation credit (charge)^d	117	(109)	(125)	(336)	(453)	25	9,878	2,135	(207)	11,831
Total after taxation for period	(194)	202	307	(937)	(622)	(49)	(21,953)	(3,684)	250	(25,436)

^a Fourth quarter 2013 includes \$845 million relating to the value ascribed to block BM-CAL-13 offshore Brazil, following the acquisition of upstream assets from Devon Energy in 2011, which was written off as a result of the Pitanga exploration well not encountering commercial quantities of oil or gas.

^b Includes the impairment of goodwill allocated to the US West Coast fuels value chain of \$1,579 million in the fourth quarter of 2009. The second quarter 2012 includes impairment charges of \$2,665 million in the fuels business, mainly relating to Texas City refinery and Carson refinery and their associated assets.

^c Finance costs relate to the Gulf of Mexico oil spill. For more information see pages 16-17.

^d For the Gulf of Mexico oil spill and certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives, tax is based on statutory rates, except for non-deductible items. For other items reported for consolidated subsidiaries, tax is calculated using the group's discrete quarterly effective tax rate (adjusted for the items noted above, equity-accounted earnings and the deferred tax adjustment relating to a reduction in UK corporation tax rates (\$99 million for the third quarter 2013 (first quarter 2011 \$683 million and third quarter 2012 \$256 million))). Non-operating items reported within the equity-accounted earnings of TNK-BP and Rosneft are reported net of tax. In the fourth quarter and full year 2009, no tax credit was calculated on the goodwill impairment in Downstream because the charge is not tax deductible.

Fair value accounting effects continued

BP enters into contracts for pipelines and storage capacity, oil and gas processing and liquefied natural gas (LNG) that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments, which are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance. Under management's internal measure of performance the inventory and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period, the fair values of certain derivative instruments used to risk manage LNG and oil and gas processing contracts are deferred to match with underlying exposure and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management's internal measure of performance, are shown in the table below.

														\$ million
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
29	(35)	(39)	56	11	(133)	7	25	(33)	(134)	(60)	(31)	(39)	(114)	(244)
(100)	164	54	(55)	63	38	(187)	(286)	8	(427)	(13)	138	53	(356)	(178)
(71)	129	15	1	74	(95)	(180)	(261)	(25)	(561)	(73)	107	14	(470)	(422)
22	(44)	(5)	—	(27)	40	72	99	5	216	30	(53)	(6)	171	142
(49)	85	10	1	47	(55)	(108)	(162)	(20)	(345)	(43)	54	8	(299)	(280)
														—
25	(18)	(9)	17	15	(71)	61	(28)	(29)	(67)	(40)	(33)	(84)	(112)	(269)
4	(17)	(30)	39	(4)	(62)	(54)	53	(4)	(67)	(20)	2	45	(2)	25
29	(35)	(39)	56	11	(133)	7	25	(33)	(134)	(60)	(31)	(39)	(114)	(244)
(48)	71	18	(41)	—	(43)	(1)	(388)	(9)	(441)	(65)	219	81	(446)	(211)
(52)	93	36	(14)	63	81	(186)	102	17	14	52	(81)	(28)	90	33
(100)	164	54	(55)	63	38	(187)	(286)	8	(427)	(13)	138	53	(356)	(178)

														\$ million
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
29	(748)	(41)	848	88	876	(2,212)	437	3,963	3,064	(46)	29	(79)	(115)	(211)
710	49	502	(208)	1,053	(187)	724	104	(650)	(9)	(94)	83	(186)	(1,200)	(1,397)
739	(699)	461	640	1,141	689	(1,488)	541	3,313	3,055	(140)	112	(265)	(1,315)	(1,608)
(64)	(168)	(166)	(165)	(563)	(131)	(2,434)	(617)	(105)	(3,287)	(37)	202	(64)	(466)	(365)
(53)	115	(7)	(31)	24	63	(431)	16	40	(312)	43	(387)	(40)	36	(348)
(117)	(53)	(173)	(196)	(539)	(68)	(2,865)	(601)	(65)	(3,599)	6	(185)	(104)	(430)	(713)
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	(93)	—	(12)	351	246	12,500	—	—	—	12,500
—	—	—	—	—	(93)	—	(12)	351	246	12,500	—	—	—	12,500
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	(16)	(29)	(45)
—	—	—	—	—	—	—	—	—	—	—	—	(16)	(29)	(45)
1	(12)	(112)	(310)	(433)	(142)	(92)	(494)	(54)	(782)	(4)	(134)	(297)	(14)	(449)
(182)	(251)	188	(144)	(389)	(94)	110	(29)	(3)	(16)	(2)	(1)	8	23	28
(181)	(263)	76	(454)	(822)	(236)	18	(523)	(57)	(798)	(6)	(135)	(289)	9	(421)
(384)	617	(541)	4,108	3,800	30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)
57	(398)	(177)	4,098	3,580	322	(5,178)	(651)	(584)	(6,091)	12,338	(407)	(704)	(1,944)	9,283
(16)	(15)	(14)	(13)	(58)	(6)	(4)	(3)	(6)	(19)	(10)	(10)	(9)	(10)	(39)
41	(413)	(191)	4,085	3,522	316	(5,182)	(654)	(590)	(6,110)	12,328	(417)	(713)	(1,954)	9,244
66	116	4	(1,466)	(1,280)	(186)	1,735	171	(1,253)	467	53	105	199	652	1,009
107	(297)	(187)	2,619	2,242	130	(3,447)	(483)	(1,843)	(5,643)	12,381	(312)	(514)	(1,302)	10,253

Gulf of Mexico oil spill

	Q1	Q2	Q3	Q4	2010
Income statement					
Production and manufacturing expenses	–	32,192	7,656	1,010	40,858
Profit (loss) before interest and taxation	–	(32,192)	(7,656)	(1,010)	(40,858)
Finance costs	–	–	47	30	77
Profit (loss) before taxation	–	(32,192)	(7,703)	(1,040)	(40,935)
Less: taxation	–	10,003	2,604	287	12,894
Profit (loss) for the period	–	(22,189)	(5,099)	(753)	(28,041)
Balance sheet					
Current assets					
Trade and other receivables	–	6,233	6,663	5,943	5,943
Current liabilities					
Trade and other payables	–	(8,276)	(7,272)	(6,587)	(6,587)
Provisions	–	(11,809)	(11,343)	(7,938)	(7,938)
Net current liabilities	–	(13,852)	(11,952)	(8,582)	(8,582)
Non-current assets					
Other receivables	–	1,693	352	3,601	3,601
Non-current liabilities					
Other payables	–	(12,080)	(11,010)	(9,899)	(9,899)
Provisions	–	(5,837)	(5,062)	(8,397)	(8,397)
Deferred tax	–	9,440	10,988	11,255	11,255
Net non-current assets (liabilities)	–	(6,784)	(4,732)	(3,440)	(3,440)
Net liabilities	–	(20,636)	(16,684)	(12,022)	(12,022)
Cash flow statement - operating activities					
Profit (loss) before taxation	–	(32,192)	(7,703)	(1,040)	(40,935)
Finance costs	–	–	47	30	77
Net charge for provisions, less payments	–	17,646	(409)	2,117	19,354
Movements in other current and non-current assets and liabilities	–	12,430	(2,042)	(6,542)	3,846
Pre-tax cash flows	–	(2,116)	(10,107)	(5,435)	(17,658)

Gulf of Mexico oil spill continued

														\$ million
Q1	Q2	Q3	Q4	2011	Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013
384	(617)	541	(4,108)	(3,800)	(30)	843	56	4,126	4,995	22	199	30	179	430
(384)	617	(541)	4,108	3,800	30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)
16	15	14	13	58	6	4	3	6	19	10	10	9	10	39
(400)	602	(555)	4,095	3,742	24	(847)	(59)	(4,132)	(5,014)	(32)	(209)	(39)	(189)	(469)
201	(234)	115	(1,469)	(1,387)	(26)	102	(51)	69	94	(5)	42	(44)	80	73
(199)	368	(440)	2,626	2,355	(2)	(745)	(110)	(4,063)	(4,920)	(37)	(167)	(83)	(109)	(396)
5,981	7,170	5,598	8,487	8,487	4,985	5,109	4,913	4,239	4,239	4,082	4,530	2,861	2,457	2,457
(6,031)	(6,796)	(5,495)	(5,425)	(5,425)	(3,800)	(2,377)	(1,118)	(522)	(522)	(1,082)	(1,063)	(1,029)	(1,030)	(1,030)
(7,379)	(7,414)	(7,078)	(9,437)	(9,437)	(5,877)	(6,177)	(6,181)	(5,449)	(5,449)	(4,810)	(5,183)	(3,457)	(2,951)	(2,951)
(7,429)	(7,040)	(6,975)	(6,375)	(6,375)	(4,692)	(3,445)	(2,386)	(1,732)	(1,732)	(1,810)	(1,716)	(1,625)	(1,524)	(1,524)
3,563	2,667	2,278	1,642	1,642	4,881	4,181	4,754	2,264	2,264	2,074	2,067	2,286	2,442	2,442
(8,667)	(6,307)	(5,071)	—	—	—	—	—	(175)	(175)	(3,160)	(3,144)	(2,977)	(2,986)	(2,986)
(8,098)	(6,964)	(6,611)	(5,896)	(5,896)	(9,048)	(8,745)	(8,909)	(9,751)	(9,751)	(5,984)	(6,057)	(6,159)	(6,395)	(6,395)
11,218	10,497	9,721	7,775	7,775	7,211	7,285	5,841	4,002	4,002	3,782	3,443	2,989	2,748	2,748
(1,984)	(107)	317	3,521	3,521	3,044	2,721	1,686	(3,660)	(3,660)	(3,288)	(3,691)	(3,861)	(4,191)	(4,191)
(9,413)	(7,147)	(6,658)	(2,854)	(2,854)	(1,648)	(724)	(700)	(5,392)	(5,392)	(5,098)	(5,407)	(5,486)	(5,715)	(5,715)
(400)	602	(555)	4,095	3,742	24	(847)	(59)	(4,132)	(5,014)	(32)	(209)	(39)	(189)	(469)
16	15	14	13	58	6	4	3	6	19	10	10	9	10	39
202	(90)	244	2,343	2,699	85	585	546	3,618	4,834	304	1,390	(576)	11	1,129
(2,864)	(2,912)	(1,523)	(8,106)	(15,405)	(1,861)	(1,439)	(2,017)	(771)	(6,088)	(828)	(1,430)	192	(33)	(2,099)
(3,046)	(2,385)	(1,820)	(1,655)	(8,906)	(1,746)	(1,697)	(1,527)	(1,279)	(6,249)	(546)	(239)	(414)	(201)	(1,400)

Sales and other operating revenues

	\$ million				
	2009	2010	2011	2012	2013
By segment					
Upstream	57,626	66,266	75,754	72,225	70,374
Downstream	213,050	266,751	344,033	346,391	351,195
Other businesses and corporate	2,843	3,328	2,957	1,985	1,805
	273,519	336,345	422,744	420,601	423,374
Less: sales and other operating revenues between segments					
Upstream	32,540	37,049	44,766	42,572	42,327
Downstream	821	1,358	1,396	1,365	1,045
Other businesses and corporate	886	831	869	899	866
	34,247	39,238	47,031	44,836	44,238
Third party sales and other operating revenues					
Upstream	25,086	29,217	30,988	29,653	28,047
Downstream	212,229	265,393	342,637	345,026	350,150
Other businesses and corporate	1,957	2,497	2,088	1,086	939
Total third party sales and other operating revenues	239,272	297,107	375,713	375,765	379,136
By geographical area^a					
US	87,283	107,256	140,223	138,304	137,662
Non-US	173,822	220,059	277,036	275,105	280,317
	261,105	327,315	417,259	413,409	417,979
Less: sales and other operating revenues between areas					
	21,833	30,208	41,546	37,644	38,843
	239,272	297,107	375,713	375,765	379,136

^a A minor amendment has been made to the split between regions for 2013.

Production and similar taxes

					\$ million
	2009	2010	2011	2012	2013
Production and similar taxes provided for					
US	649	1,093	1,854	1,472	1,112
Non-US	3,103	4,151	6,426	6,686	5,935
	3,752	5,244	8,280	8,158	7,047
Production and similar taxes paid					
US	766	1,059	1,879	1,585	1,194
Non-US	3,219	4,402	6,425	6,997	6,403
	3,985	5,461	8,304	8,582	7,597

Taxation

					\$ million
	2009	2010	2011	2012	2013
Tax on profit (loss)					
Current tax charge	5,745	6,692	7,611	6,916	5,785
Deferred tax charge (credit)	2,528	(8,330)	5,008	(36)	678
Total tax on profit (loss)	8,273	(1,638)	12,619	6,880	6,463
Taxation (charge) credit on inventory holdings gains and losses	(1,299)	(589)	(834)	183	60
Tax on replacement cost profit (loss)	6,974	(2,227)	11,785	7,063	6,523
Effective tax rates on					
Replacement cost profit (loss) for the year	33%	31%	33%	38%	21%
Profit (loss) for the year	33%	31%	33%	38%	21%
Income taxes paid	6,324	6,610	8,063	6,482	6,307

Depreciation, depletion and amortization

					\$ million
					2013
By segment					
Upstream					
US					3,538
Non-US					7,514
					11,052
Downstream					
US					747
Non-US					1,343
					2,090
Other businesses and corporate					
US					181
Non-US					187
					368
					12,106
					11,164
					11,357
					12,687
					13,510
By geographical area					
US					4,466
Non-US					9,044
Total					13,510

Group balance sheet

At 31 December	\$ million				
	2009	2010	2011	2012	2013
Non-current assets					
Property, plant and equipment	108,275	110,163	123,431	125,331	133,690
Goodwill	8,620	8,598	12,429	12,190	12,181
Intangible assets	11,548	14,298	21,653	24,632	22,039
Investments in joint ventures	15,296	14,927	8,303	8,614	9,199
Investments in associates	12,963	13,335	13,291	2,998	16,636
Other investments	2,033	1,689	2,635	2,704	1,565
Fixed assets	158,735	163,010	181,742	176,469	195,310
Loans	1,039	894	824	642	763
Trade and other receivables	1,729	6,298	5,738	5,961	5,985
Derivative financial instruments	3,965	4,210	5,038	4,294	3,509
Prepayments	941	934	739	830	922
Deferred tax assets	516	528	611	874	985
Defined benefit pension plan surpluses	1,390	2,176	17	12	1,376
	168,315	178,050	194,709	189,082	208,850
Current assets					
Loans	249	247	244	247	216
Inventories	22,605	26,218	26,073	28,203	29,231
Trade and other receivables	29,531	36,549	43,589	37,611	39,831
Derivative financial instruments	4,967	4,356	3,857	4,507	2,675
Prepayments	1,753	1,574	1,315	1,091	1,388
Current tax receivable	209	693	235	456	512
Other investments	—	1,532	288	319	467
Cash and cash equivalents	8,339	18,556	14,177	19,635	22,520
	67,653	89,725	89,778	92,069	96,840
Assets classified as held for sale	—	4,487	8,420	19,315	—
	67,653	94,212	98,198	111,384	96,840
Total assets	235,968	272,262	292,907	300,466	305,690
Current liabilities					
Trade and other payables	35,204	46,329	52,000	46,673	47,159
Derivative financial instruments	4,681	3,856	3,220	2,658	2,322
Accruals	6,202	5,612	6,016	6,875	8,960
Finance debt	9,109	14,626	9,039	10,033	7,381
Current tax payable	2,464	2,920	1,943	2,503	1,945
Provisions	1,660	9,489	11,238	7,587	5,045
	59,320	82,832	83,456	76,329	72,812
Liabilities directly associated with assets classified as held for sale	—	1,047	538	846	—
	59,320	83,879	83,994	77,175	72,812
Non-current liabilities					
Other payables	3,198	14,285	3,214	2,292	4,756
Derivative financial instruments	3,474	3,677	3,773	2,723	2,225
Accruals	703	637	400	491	547
Finance debt	25,518	30,710	35,169	38,767	40,811
Deferred tax liabilities	18,662	10,908	15,220	15,243	17,439
Provisions	12,970	22,418	26,462	30,396	26,915
Defined benefit pension plan and other post-retirement benefit plan deficits	10,010	9,857	12,090	13,627	9,778
	74,535	92,492	96,328	103,539	102,471
Total liabilities	133,855	176,371	180,322	180,714	175,283
Net assets	102,113	95,891	112,585	119,752	130,407
Equity					
BP shareholders' equity	101,613	94,987	111,568	118,546	129,302
Non-controlling interests	500	904	1,017	1,206	1,105
Total equity	102,113	95,891	112,585	119,752	130,407

Operating capital employed^a

	\$ million				
	2009	2010	2011	2012	2013
By segment					
Upstream					
US	39,209	40,065	41,347	38,437	41,320
Non-US	52,804	56,212	64,185	70,387	70,567
	92,013	96,277	105,532	108,824	111,887
Downstream					
US	20,114	23,463	24,627	24,835	23,835
Non-US	26,387	24,959	26,457	25,488	25,680
	46,501	48,422	51,084	50,323	49,515
TNK-BP					
US	—	—	—	—	—
Non-US	9,141	9,995	10,013	13,607	—
	9,141	9,995	10,013	13,607	—
Rosneft					
US	—	—	—	—	—
Non-US	—	—	—	—	13,681
	—	—	—	—	13,681
Other businesses and corporate					
US	(2,773)	(2,905)	(3,149)	(4,115)	(1,459)
Non-US	4,655	17,285	8,506	14,785	19,818
	1,882	14,380	5,357	10,670	18,359
Gulf of Mexico oil spill response	—	(23,277)	(10,629)	(9,394)	(8,464)
Consolidation adjustment	(1,016)	(561)	(676)	(1,252)	(673)
	148,521	145,236	160,681	172,778	184,305
By geographical area					
US	55,826	36,917	51,785	49,418	54,988
Non-US	92,695	108,319	108,896	123,360	129,317
Total operating capital employed ^a	148,521	145,236	160,681	172,778	184,305
Liabilities for current and deferred taxation	(20,401)	(12,607)	(16,317)	(16,416)	(17,887)
Goodwill	8,620	8,598	12,429	12,190	12,181
Capital employed	136,740	141,227	156,793	168,552	178,599
Financed by					
Finance debt	34,627	45,336	44,208	48,800	48,192
Non-controlling interests	500	904	1,017	1,206	1,105
BP shareholders' equity	101,613	94,987	111,568	118,546	129,302
Capital employed	136,740	141,227	156,793	168,552	178,599

^a Operating capital employed is total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation.

Property, plant and equipment

					\$ million
	2009	2010	2011	2012	2013
Net book amount by segment					
Upstream					
US	36,361	37,230	41,385	38,671	39,363
Non-US	42,583	42,542	51,827	53,303	58,972
	78,944	79,772	93,212	91,974	98,335
Downstream					
US	12,497	14,151	11,833	14,603	16,467
Non-US	14,616	13,996	15,246	15,320	15,131
	27,113	28,147	27,079	29,923	31,598
Other businesses and corporate					
US	1,385	1,495	1,770	1,683	1,532
Non-US	833	749	1,370	1,751	2,225
	2,218	2,244	3,140	3,434	3,757
Net book amount by geographical area					
US	50,243	52,876	54,988	54,957	57,362
Non-US	58,032	57,287	68,443	70,374	76,328
	108,275	110,163	123,431	125,331	133,690
Cost and accumulated depreciation					
Upstream					
Cost	176,332	177,537	195,533	190,645	206,882
Accumulated depreciation	(97,388)	(97,765)	(102,321)	(98,671)	(108,547)
	78,944	79,772	93,212	91,974	98,335
Downstream					
Cost	51,276	52,843	48,929	53,117	56,297
Accumulated depreciation	(24,163)	(24,696)	(21,850)	(23,194)	(24,699)
	27,113	28,147	27,079	29,923	31,598
Other businesses and corporate					
Cost	3,650	3,859	4,460	5,142	5,707
Accumulated depreciation	(1,432)	(1,615)	(1,320)	(1,708)	(1,950)
	2,218	2,244	3,140	3,434	3,757
Group					
Cost	231,258	234,239	248,922	248,904	268,886
Accumulated depreciation	(122,983)	(124,076)	(125,491)	(123,573)	(135,196)
	108,275	110,163	123,431	125,331	133,690

Analysis of inventories, receivables and payables

	\$ million				
	2009	2010	2011	2012	2013
Inventories					
Inventories	18,679	23,078	23,183	24,775	25,852
Supplies	1,661	1,669	2,075	2,428	2,735
	20,340	24,747	25,258	27,203	28,587
Trading inventories	2,265	1,471	815	1,000	644
	22,605	26,218	26,073	28,203	29,231
Current receivables					
Trade receivables	22,604	24,255	28,515	26,485	28,868
Amounts receivable from joint ventures	1,317	751	422	379	342
Amounts receivable from associates	417	448	492	492	871
Current tax receivable	209	693	235	456	512
Gulf of Mexico oil spill trust fund reimbursement asset	–	5,943	8,233	4,178	2,457
Other current receivables	12,162	12,861	11,631	12,241	12,039
	36,709	44,951	49,528	44,231	45,089
Non-current receivables					
Trade receivables	–	–	508	151	183
Amounts receivable from joint ventures	11	601	–	–	–
Amounts receivable from associates	298	220	159	102	47
Gulf of Mexico oil spill trust fund reimbursement asset	–	3,601	1,642	2,264	2,442
Other non-current receivables	7,365	7,914	10,030	9,210	8,507
	7,674	12,336	12,339	11,727	11,179
Current payables					
Trade payables	22,886	27,510	30,220	29,920	28,926
Amounts payable to joint ventures	304	1,361	62	133	51
Amounts payable to associates	692	712	876	972	3,525
Production and similar taxes	757	919	1,480	1,222	686
Current tax payable	2,464	2,920	1,943	2,503	1,945
Dividends	1	1	1	1	1
Gulf of Mexico oil spill trust fund liability	–	5,002	4,872	22	1
Other current payables	21,447	20,292	23,725	23,936	25,251
	48,551	58,717	63,179	58,709	60,386
Non-current payables					
Amounts payable to joint ventures	2,419	1,905	–	–	–
Amounts payable to associates	298	220	159	102	47
Production and similar taxes	286	471	283	242	317
Gulf of Mexico oil spill trust fund liability	–	9,899	–	–	–
Other non-current payables	4,372	6,104	6,945	5,162	7,164
	7,375	18,599	7,387	5,506	7,528

Group cash flow statement

	\$ million				
	2009	2010	2011	2012	2013
Operating activities					
Profit (loss) before taxation ^a	24,817	(5,307)	38,228	18,131	30,221
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	593	375	1,024	745	2,710
Depreciation, depletion and amortization	12,106	11,164	11,357	12,687	13,510
Impairment and (gain) loss on sale of businesses and fixed assets	160	(4,694)	(2,074)	(422)	(11,154)
Earnings from joint ventures and associates	(3,901)	(4,757)	(5,683)	(3,935)	(3,189)
Dividends received from joint ventures and associates	3,003	3,277	5,040	1,763	1,391
Interest receivable	(258)	(277)	(284)	(379)	(314)
Interest received	203	206	210	175	173
Finance costs	1,110	1,170	1,187	1,072	1,068
Interest paid	(909)	(912)	(1,125)	(1,166)	(1,084)
Net finance expense relating to pensions and other post-retirement benefits	499	435	400	566	480
Share-based payments	450	197	(88)	156	297
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	(887)	(959)	(1,003)	(858)	(920)
Net charge for provisions, less payments	650	19,217	2,988	5,338	1,061
(Increase) decrease in inventories	(5,363)	(3,895)	(4,079)	(1,720)	(1,193)
(Increase) decrease in other current and non-current assets	7,595	(15,620)	(9,860)	2,933	(2,718)
Increase (decrease) in other current and non-current liabilities	(5,828)	20,606	(5,957)	(8,125)	(2,932)
Income taxes paid	(6,324)	(6,610)	(8,063)	(6,482)	(6,307)
Net cash provided by operating activities	27,716	13,616	22,218	20,479	21,100
Investing activities					
Capital expenditure	(20,650)	(18,421)	(17,978)	(23,222)	(24,520)
Acquisitions, net of cash acquired	1	(2,468)	(10,909)	(116)	(67)
Investment in joint ventures	(578)	(461)	(855)	(1,526)	(451)
Investment in associates	(164)	(65)	(55)	(54)	(4,994)
Proceeds from disposals of fixed assets	1,715	7,492	3,504	9,992	18,115
Proceeds from disposals of businesses, net of cash disposed ^b	966	9,462	(663)	1,606	3,884
Proceeds from loan repayments	530	501	203	245	178
Other	47	—	—	—	—
Net cash used in investing activities	(18,133)	(3,960)	(26,753)	(13,075)	(7,855)
Financing activities					
Net issue (repurchase) of shares	207	169	74	122	(5,358)
Proceeds from long-term financing	11,567	11,934	11,600	11,087	8,814
Repayments of long-term financing	(6,021)	(4,702)	(9,102)	(7,177)	(5,959)
Net increase (decrease) in short-term debt	(4,405)	(3,619)	2,222	(666)	(2,019)
Net increase (decrease) in non-controlling interests	—	—	—	—	32
Dividends paid					
BP shareholders	(10,483)	(2,627)	(4,072)	(5,294)	(5,441)
Non-controlling interests	(416)	(315)	(245)	(82)	(469)
Net cash provided by (used in) financing activities	(9,551)	840	477	(2,010)	(10,400)
Currency translation differences relating to cash and cash equivalents	110	(279)	(493)	64	40
Increase (decrease) in cash and cash equivalents	142	10,217	(4,551)	5,458	2,885
Cash and cash equivalents at beginning of year	8,197	8,339	18,728	14,177	19,635
Cash and cash equivalents at end of year	8,339	18,556	14,177	19,635	22,520

^a 2012 included \$709 million of dividends received from TNK-BP.

^b 2011 included the repayment of a deposit received in advance of \$3,530 million following the termination of an agreement in respect of the expected sale of our interest in Pan American Energy LLC.

Movement in net debt^a

	2009	2010	2011	2012	\$ million 2013
Opening balance					
Finance debt	33,204	34,627	45,336	44,208	48,800
Fair value (asset) liability of hedges related to finance debt	34	(127)	(916)	(1,133)	(1,700)
Less: cash and cash equivalents	8,197	8,339	18,728	14,177	19,635
Opening net debt	25,041	26,161	25,692	28,898	27,465
Closing balance					
Finance debt	34,627	45,336	44,208	48,800	48,192
Fair value (asset) liability of hedges related to finance debt	(127)	(916)	(1,133)	(1,700)	(477)
Less: cash and cash equivalents	8,339	18,556	14,177	19,635	22,520
Closing net debt	26,161	25,864	28,898	27,465	25,195
Decrease (increase) in net debt	(1,120)	297	(3,206)	1,433	2,270
Movement in cash and cash equivalents (excluding exchange adjustments)	32	10,496	(4,058)	5,394	2,845
Net cash (inflow) outflow from financing (excluding share capital)	(1,141)	(3,613)	(4,720)	(3,244)	(836)
Movement in finance debt relating to investing activities ^b	—	(6,197)	6,167	(602)	632
Other movements	(61)	(304)	(132)	(104)	(192)
Movement in net debt before exchange effects	(1,170)	382	(2,743)	1,444	2,449
Exchange adjustments	50	(85)	(463)	(11)	(179)
Decrease (increase) in net debt	(1,120)	297	(3,206)	1,433	2,270

^a Net debt is a non-GAAP measure.

^b Deposits of \$632 million were received in 2012, in respect of disposal transactions not completed at 31 December 2012 and \$30 million was repaid in respect of assets no longer held for sale. 2010 includes \$6,197 million of deposits received from counterparties in respect of disposal transactions not completed at 31 December 2010, of which \$30 million related to transactions still not completed at 31 December 2011.

Capital expenditure, acquisitions and disposals

	2009	2010	2011	2012	\$ million 2013
By segment					
Upstream ^a					
US ^{b c}	6,169	6,632	5,363	6,385	6,410
Non-US ^{d e f g}	8,727	11,121	20,458	12,135	12,705
	14,896	17,753	25,821	18,520	19,115
Downstream					
US	2,625	2,761	2,691	3,475	2,535
Non-US	1,489	1,268	1,594	1,774	1,971
	4,114	4,029	4,285	5,249	4,506
Rosneft					
Non-US	–	–	–	–	11,941
	–	–	–	–	11,941
Other businesses and corporate					
US ^h	1,071	977	877	681	231
Non-US ⁱ	228	257	976	754	819
	1,299	1,234	1,853	1,435	1,050
By geographical area					
US ^{b c h}	9,865	10,370	8,931	10,541	9,176
Non-US ^{d e f g i}	10,444	12,646	23,028	14,663	27,436
	20,309	23,016	31,959	25,204	36,612
Included above					
Acquisitions and asset exchanges ^{b e f i}	308	3,406	11,283	200	71
Organic capital expenditure ^j	20,001	18,218	19,580	23,950	24,600
Disposal proceeds	2,681	16,954	2,841	11,598	21,999

^a A minor amendment has been made to the split between regions for 2013.

^b 2010 included \$1,767 million in Upstream in the US deepwater Gulf of Mexico as part of the transaction with Devon Energy.

^c 2012 and 2011 included \$899 million and \$1,096 million, respectively, associated with deepening our natural gas asset base.

^d 2010 included capital expenditure of \$900 million relating to the formation of a partnership with Value Creation Inc. to develop the Terre de Grace oil sands acreage in the Athabasca region of Alberta, Canada. 2010 also included \$492 million for the purchase of additional interests in the Valhall and Hod fields in the North Sea.

^e Includes capital expenditure of \$3,236 million in Brazil for 2011 and \$1,107 million in Azerbaijan for 2010 as part of the transaction with Devon Energy.

^f 2011 included \$7,026 million relating to the acquisition from Reliance Industries of interests in 21 oil and gas production-sharing agreements in India.

^g 2012 included \$155 million related to increasing our interest in North Sea assets.

^h Includes capital expenditure of \$557 million for 2010 and \$440 million for 2009 for wind turbines, incurred at the time for future wind projects.

ⁱ 2011 included \$680 million in Brazil relating to the acquisition of Companhia Nacional de Açúcar e Alcool.

^j Organic capital expenditure excludes acquisitions and asset exchanges. It also excluded: 2013 \$11,941 million relating to our investment in Rosneft; 2012, \$1,054 million associated with deepening our US natural gas asset bases; 2011, \$1,096 million associated with deepening our US natural gas asset bases and; 2010, \$900 million relating to the formation of a partnership with Value Creation Inc. to develop the Terre de Grace oil sands acreage and \$492 million for the purchase of additional interests in the Valhall and Hod fields in the North Sea.

Ratios^a

	2009	2010	2011	2012	\$ million 2013
Return on average capital employed					
Replacement cost profit (loss)	13,740	(5,259)	23,412	11,428	23,681
Interest expense ^b	467	770	866	977	549
Non-controlling interests	181	395	397	234	307
Adjusted replacement cost profit (loss)	14,388	(4,094)	24,675	12,639	24,537
Non-operating items and fair value accounting effects after taxation	622	25,436	(2,242)	5,643	(10,253)
Adjusted underlying replacement cost profit	15,010	21,342	22,433	18,282	14,284
Average capital employed (including goodwill)	131,027	138,982	149,080	162,674	173,576
Return on average capital employed (including goodwill, non-operating items and fair value accounting effects)	11.0%	(2.9%)	16.6%	7.8%	14.1%
Average capital employed (excluding goodwill)	121,778	130,373	138,402	150,364	161,390
Return on average capital employed (excluding goodwill, non-operating items and fair value accounting effects)	12.3%	16.4%	16.2%	12.2%	8.9%
Debt ratios					
Gross debt	34,627	45,336	44,208	48,800	48,192
Fair value (asset) liability of hedges related to finance debt	(127)	(916)	(1,133)	(1,700)	(477)
Less: cash and cash equivalents	34,500	44,420	43,075	47,100	47,715
Net debt	8,339	18,556	14,177	19,635	22,520
Equity	26,161	25,864	28,898	27,465	25,195
Debt to debt-plus-equity ratio	102,113	95,891	112,585	119,752	130,407
Debt to equity ratio	25.3%	31.7%	27.7%	28.2%	26.8%
Net debt to net debt-plus-equity ratio	33.8%	46.3%	38.3%	39.3%	36.6%
Net debt to equity ratio	20.4%	21.2%	20.4%	18.7%	16.2%
	25.6%	27.0%	25.7%	22.9%	19.3%

^a The ratios are defined on page 78.

^b Calculated on a post-tax basis using a deemed tax rate equal to the US statutory tax rate.

Employee numbers

Number of employees at 31 December ^a						
		2009	2010	2011	2012	2013
By segment						
Upstream		21,500	21,100	22,400	24,200	24,700
Downstream ^b		51,600	52,300	51,500	51,800	48,000
Other businesses and corporate ^c		7,200	6,200	10,100	10,300	11,100
Gulf Coast Restoration Organization		—	100	100	100	100
		80,300	79,700	84,100	86,400	83,900
By geographical area						
US		22,800	22,100	22,900	23,400	19,600
Non-US ^b		57,500	57,600	61,200	63,000	64,300
		80,300	79,700	84,100	86,400	83,900

^a Reported to the nearest 100.

^b 2013 includes 14,100 (2012 14,700, 2011 14,600, 2010 15,200, and 2009 13,900) service station staff. See page 69 for further information.

^c 2013 includes 4,300 (2012 3,600 and 2011 4,000) agricultural, operational and seasonal workers in Brazil. The number of workers in 2009-2010 was not included as the activity was within a joint venture.

Information for earnings per share

	\$ million				
	2009	2010	2011	2012	2013
Results for the period					
Profit (loss) for the year attributable to BP shareholders	16,363	(4,064)	25,212	11,017	23,451
Less: preference dividend	2	2	2	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	16,361	(4,066)	25,210	11,015	23,449
Profit (loss) for the year attributable to BP ordinary shareholders, as above					
Inventory holding (gains) losses, net of tax	(2,623)	(1,195)	(1,800)	411	230
Replacement cost profit (loss) attributable to ordinary shareholders	13,738	(5,261)	23,410	11,426	23,679
Average number of shares					
Basic weighted average number of shares outstanding (thousand) ^a	18,732,459	18,785,912	18,904,812	19,027,929	18,931,021
ADS equivalent (thousand) ^a	3,122,077	3,130,985	3,150,802	3,171,321	3,155,170
Diluted weighted average number of shares outstanding (thousand) ^a	18,935,691	18,997,807	19,136,200	19,157,888	19,046,173
ADS equivalent (thousand) ^a	3,155,949	3,166,301	3,189,367	3,192,981	3,174,362
Shares in issue at year end (thousand) ^a	18,755,378	18,796,498	18,977,214	19,119,757	18,611,489
ADS equivalent (thousand) ^a	3,125,896	3,132,750	3,162,869	3,186,626	3,101,914
Shares repurchased in the year (thousand) ^b	—	—	—	—	752,854

^a Excludes treasury shares and the shares held by the Employee Share Ownership Plans and includes certain shares that will be issuable in the future under employee share-based payment plans.

^b Purchased for a total consideration of \$5,493 million, including transaction costs of \$30 million. All shares purchased were for cancellation. The repurchased shares represented 3.6% of ordinary share capital.

BP shareholding information

Register of members holding BP ordinary shares as at 31 December 2013

Range of holdings	Number of ordinary shareholders	Percentage of total ordinary shareholders	Percentage of total ordinary share capital excluding shares held in treasury
1–200	58,190	20.46	0.02
201–1,000	101,442	35.68	0.29
1,001–10,000	112,294	39.49	1.82
10,001–100,000	10,920	3.84	1.18
100,001–1,000,000	823	0.29	1.67
Over 1,000,000 ^a	678	0.24	95.02
Totals	284,347	100.00	100.00

^a Includes JPMorgan Chase Bank, N.A. holding 28.70% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depositary for ADSs, a breakdown of which is shown in the table below.

Register of holders of American depositary shares (ADSs) as at 31 December 2013^a

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1–200	58,281	57.60	0.36
201–1,000	27,376	27.06	1.47
1,001–10,000	14,699	14.53	4.34
10,001–100,000	809	0.80	1.51
100,001–1,000,000	10	0.01	0.16
Over 1,000,000 ^b	1	0.00	92.16
Totals	101,176	100.00	100.00

^a One ADS represents six 25 cent ordinary shares.

^b One holder of ADSs represents 868,478 underlying shareholders.

As at 31 December 2013, there were also 1,510 preference shareholders. Preference shareholders represented 0.45% and ordinary shareholders represented 99.55% of the total issued nominal share capital of the company (excluding shares held in treasury) as at that date.

Share ownership as at 31 December 2013^a

By principal area	Percentage of shares in issue
UK	38
US	39
Rest of Europe	10
Rest of World	9
Miscellaneous ^b	4
Totals	100

^a Represents BP's best efforts to determine ownership of the group's shares, based on analysis of the year-end share register.

^b Miscellaneous represents unidentified shares that are awaiting confirmation of the identity of the holder and the nature of their interest in the shares following enquiries made under Section 793 of the Companies Act 2006.

BP share data

	2009	2010	2011	2012	2013
Share price and dividends					
Share price (pence per ordinary share) ^a					
High	613.40	658.20	514.90	512.00	494.20
Low	400.00	296.00	361.25	388.56	426.50
End year	600.00	465.55	460.50	424.80	488.05
Dividends paid (pence per ordinary share)					
First quarter	9.818	8.679	4.337	5.096	6.001
Second quarter	9.584	–	4.281	5.150	5.834
Third quarter	8.503	–	4.316	5.017	5.763
Fourth quarter	8.512	–	4.469	5.589	5.801
	36.417	8.679	17.404	20.852	23.399
Dividends paid (cents per ordinary share)					
First quarter	14.000	14.000	7.000	8.000	9.000
Second quarter	14.000	–	7.000	8.000	9.000
Third quarter	14.000	–	7.000	8.000	9.000
Fourth quarter	14.000	–	7.000	9.000	9.500
	56.000	14.000	28.000	33.000	36.500
ADS price (US dollars per ADS) ^a					
High	60.00	62.38	49.50	48.34	48.65
Low	33.70	26.75	33.62	36.25	39.99
End year	57.97	44.17	42.74	41.64	48.61
Dividends paid (US dollars per ADS)					
First quarter	0.8400	0.8400	0.4200	0.4800	0.5400
Second quarter	0.8400	–	0.4200	0.4800	0.5400
Third quarter	0.8400	–	0.4200	0.4800	0.5400
Fourth quarter	0.8400	–	0.4200	0.5400	0.5700
	3.3600	0.8400	1.6800	1.9800	2.1900
Dividend payout ratio ^b					
Based on replacement cost profit for the year	76%	n/a	23%	55%	29%
Based on profit for the year	64%	n/a	21%	57%	29%
Dividend cover ^b					
Dividend cover out of income ^c	1.31	n/a	4.43	1.82	3.43
Dividend cover out of cash flow ^d	2.64	5.19	4.20	3.26	3.05

^a Derived from the highest and lowest intra-day sales prices as reported on LSE and NYSE, respectively. Data source: Thomson Reuters Datastream.

^b The calculation is based on the assumption that all dividends, including scrip dividends, are paid in cash.

^c Based on replacement cost profit for the year.

^d Net cash provided by operating activities, divided by gross dividends paid.

Group hydrocarbon data

Oil and natural gas information

2013 reserves and production information for equity-accounted entities includes BP's share of TNK-BP from 1 January to 20 March, and Rosneft for the period 21 March to 31 December. For the period 22 October 2012 to 31 December 2012, and throughout all of 2013, financial information for equity-accounted entities does not include any information for TNK-BP, as equity accounting ceased on 22 October 2012.

The regional analysis presented below, on pages 32-60, 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 revised SEC and FASB requirements.

Oil and natural gas exploration and production activities

	\$ million									
	Europe		North America		South America	Africa	Asia		Australasia	2009 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries^a										
Capitalized costs at 31 December^b										
Gross capitalized costs										
Proved properties	35,096	6,644	64,366	3,967	8,346	24,476	–	10,900	2,894	156,689
Unproved properties	752	–	5,464	147	198	2,377	–	733	1,039	10,710
	35,848	6,644	69,830	4,114	8,544	26,853	–	11,633	3,933	167,399
Accumulated depreciation	26,794	3,306	31,728	2,309	4,837	12,492	–	4,798	1,038	87,302
Net capitalized costs	9,054	3,338	38,102	1,805	3,707	14,361	–	6,835	2,895	80,097
Costs incurred for the year ended 31 December^b										
Acquisition of properties ^c										
Proved	179	–	(17)	–	–	–	–	306	–	468
Unproved	(1)	–	370	1	–	18	–	–	10	398
	178	–	353	1	–	18	–	306	10	866
Exploration and appraisal costs ^d	183	–	1,377	79	78	712	8	315	53	2,805
Development	751	1,054	4,208	386	453	2,707	–	560	277	10,396
Total costs	1,112	1,054	5,938	466	531	3,437	8	1,181	340	14,067
Results of operations for the year ended 31 December										
Sales and other operating revenues ^e										
Third parties	2,239	68	972	99	1,525	1,846	–	636	785	8,170
Sales between segments	2,482	809	15,100	484	1,409	5,313	–	6,257	726	32,580
	4,721	877	16,072	583	2,934	7,159	–	6,893	1,511	40,750
Exploration expenditure	59	–	663	80	16	219	8	49	22	1,116
Production costs	1,243	164	2,821	284	395	908	15	361	70	6,261
Production taxes	(3)	–	649	1	220	–	–	2,854	72	3,793
Other costs (income) ^f	(1,259)	51	2,353	145	184	144	76	967	178	2,839
Depreciation, depletion and amortization	1,148	185	3,857	170	697	2,041	–	757	96	8,951
Impairments and (gains) losses on sale of businesses and fixed assets	(122)	(7)	(208)	–	(11)	(1)	–	(702) ^g	–	(1,051)
	1,066	393	10,135	680	1,501	3,311	99	4,286	438	21,909
Profit before taxation ^h	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Allocable taxes	1,568	76	1,902	(58)	916	1,517	(25)	682	2	6,580
Results of operations	2,087	408	4,035	(39)	517	2,331	(74)	1,925	1,071	12,261
Upstream segment and TNK-BP segment replacement cost profit before interest and tax										
Exploration and production activities - subsidiaries (as above)	3,655	484	5,937	(97)	1,433	3,848	(99)	2,607	1,073	18,841
Midstream activities - subsidiaries ⁱ	925	17	719	833	17	(27)	(37)	518	(315)	2,650
Equity-accounted entities ^j	–	5	29	134	630	56	1,924	531	–	3,309
Total replacement cost profit before interest and tax	4,580	506	6,685	870	2,080	3,877	1,788	3,656	758	24,800

^a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. 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 \$663 million. The UK region includes a \$783-million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

^g Includes the gain on disposal of upstream assets associated with the sale of our 46% stake in LukArco.

^h Excludes the unwinding of the discount on provisions and payables amounting to \$308 million, which is included in finance costs in the group income statement.

ⁱ Midstream activities exclude inventory holding gains and losses.

^j The profits of equity-accounted entities are included after interest and tax.

Oil and natural gas exploration and production activities continued

	\$ million							
	2009							
	Europe		North America		South America	Africa	Asia	"Australasia"
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia
Equity-accounted entities (BP share) ^a								
Capitalized costs at 31 December ^b								
Gross capitalized costs								
Proved properties	–	–	–	–	5,789	–	13,266	2,259
Unproved properties	–	–	–	1,378	197	–	737	–
Accumulated depreciation	–	–	–	1,378	5,986	–	14,003	2,259
Net capitalized costs	–	–	–	2,084	–	5,550	1,739	–
Costs incurred for the year ended 31 December ^b	–	–	–	1,378	3,902	–	8,453	520
Acquisition of properties ^c								
Proved	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	31	–	10	–
Exploration and appraisal costs ^d	–	–	–	–	21	–	77	3
Development	–	–	–	30	538	–	1,182	246
Total costs	–	–	–	30	590	–	1,269	249
Results of operations for the year ended 31 December								
Sales and other operating revenues ^e								
Third parties	–	–	–	–	1,977	–	4,919	1,874
Sales between segments	–	–	–	–	–	–	2,838	–
Exploration expenditure	–	–	–	–	23	–	37	–
Production costs	–	–	–	–	354	–	1,428	159
Production taxes	–	–	–	–	702	–	2,597	1,523
Other costs (income)	–	–	–	–	(69)	–	12	(2)
Depreciation, depletion and amortization	–	–	–	–	281	–	1,073	274
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	–	–	–	–	72	–
Profit (loss) before taxation	–	–	–	–	1,291	–	5,219	1,954
Allocable taxes	–	–	–	–	686	–	2,538	(80)
Results of operations	–	–	–	–	270	–	501	–
Exploration and production activities - equity-accounted entities after tax (as above)	–	–	–	–	416	–	2,037	(80)
Midstream and other activities after tax ^f	–	5	29	134	214	56	(113)	611
Total replacement cost profit after interest and tax	–	5	29	134	630	56	1,924	531

^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.

^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 interest, non-controlling interest and the net results of equity-accounted entities of equity-accounted entities.

Oil and natural gas exploration and production activities continued

	\$ million								
	Europe		North America		South America	Africa	Asia	Australasia	2010 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
Subsidiaries ^a									
Capitalized costs at 31 December ^{b c}									
Gross capitalized costs									
Proved properties	36,161	7,846	67,724	278	6,047	27,014	–	11,497	159,655
Unproved properties	787	179	5,968	1,363	220	2,694	–	1,113	13,473
	36,948	8,025	73,692	1,641	6,267	29,708	–	12,610	173,128
Accumulated depreciation	27,688	3,515	33,972	216	3,282	13,893	–	4,569	88,340
Net capitalized costs	9,260	4,510	39,720	1,425	2,985	15,815	–	8,041	84,788
Costs incurred for the year ended 31 December ^{b c}									
Acquisition of properties ^d									
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 ^e	401	13	1,096	78	68	607	7	316	2,706
Development	726	816	3,034	251	414	3,003	–	1,244	9,675
Total costs	1,127	1,348	6,384	1,530	482	3,610	7	2,832	17,627
Results of operations for the year ended 31 December									
Sales and other operating revenues ^f									
Third parties	1,472	58	1,148	90	1,896	3,158	–	1,272	10,492
Sales between segments	3,405	1,134	18,819	453	1,574	4,353	–	6,697	37,364
	4,877	1,192	19,967	543	3,470	7,511	–	7,969	47,856
Exploration expenditure	82	(2)	465	25	9	189	7	51	843
Production costs	1,018	152	2,867	240	445	938	9	365	6,158
Production taxes	52	–	1,093	2	249	–	–	3,764	5,269
Other costs (income) ^g	(316)	76	3,502	129	209	130	76	90	4,091
Depreciation, depletion and amortization	897	209	3,477	95	575	1,771	–	829	8,021
Impairments and (gains) losses on sale of businesses and fixed assets	(1)	–	(1,441)	(2,190)	(3)	(427)	341 ^h	–	(3,721)
	1,732	435	9,963	(1,699)	1,484	2,601	433	5,099	20,661
Profit (loss) before taxation ⁱ	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	27,195
Allocable taxes	1,333	530	3,504	610	1,084	1,771	(23)	813	10,032
Results of operations	1,812	227	6,500	1,632	902	3,139	(410)	2,057	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	27,195
Midstream activities - subsidiaries ^j	23	42	(347)	3	49	(26)	4	(23)	(288)
Equity-accounted entities ^k	–	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	30,886

^a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

^b Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

^c Excludes balances associated with assets held for sale.

^d Includes costs capitalized as a result of asset exchanges.

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

^f Presented net of transportation costs, purchases and sales taxes.

^g 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.

^h 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.

ⁱ 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.

^j Midstream activities exclude inventory holding gains and losses.

^k The profits of equity-accounted entities are included after interest and tax.

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			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
Accumulated depreciation	–	–	–	1,426	5,941	–	15,138	3,192	25,697
Net capitalized costs	–	–	–	2,250	–	6,300	2,674	–	11,224
	–	–	–	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
Exploration and appraisal costs ^d	–	–	–	–	9	–	66	–	75
Development	–	–	–	28	2	–	94	–	124
Total costs	–	–	–	21	549	–	1,416	355	2,341
	–	–	–	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 segments	–	–	–	–	–	–	3,432	19	3,451
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 (gains) losses on sale of businesses and fixed assets	–	–	–	–	–	–	43	–	43
Profit (loss) before taxation	–	–	–	67	1,593	–	6,209	2,574	10,443
Allocable taxes	–	–	–	(67)	675	–	2,833	2	3,443
Results of operations	–	–	–	–	260	–	475	33	768
	–	–	–	(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, non-controlling interest and the net results of equity-accounted entities of equity-accounted entities.

Oil and natural gas exploration and production activities continued

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

^a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

^b Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

^c Includes costs capitalized as a result of asset exchanges.

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

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

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

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

^h Midstream activities exclude inventory holding gains and losses.

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

^j Excludes balances associated with assets held for sale.

^k Excludes goodwill associated with business combinations.

Oil and natural gas exploration and production activities continued

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

^a These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

^b Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

^c Includes costs capitalized as a result of asset exchanges.

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

^e Presented net of transportation costs and sales taxes.

^f Includes interest, non-controlling interest and the net results of equity-accounted entities of equity-accounted entities, and excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities continued

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

^a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries. They do not include any costs relating to the Gulf of Mexico oil spill or assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

^b Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

^c Excludes balances associated with assets held for sale.

^d Includes costs capitalized as a result of asset exchanges.

^e Excludes goodwill associated with business combinations.

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

^g Presented net of transportation costs, purchases and sales taxes.

^h Includes property taxes, other government take and the fair value gain on embedded derivatives of \$347 million. The UK region includes a \$1,161 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme. The Russia region, for which equity accounting ceased on 22 October 2012, includes a net non-operating gain of \$351 million including dividend income of \$709 million partly offset by a settlement charge of \$325 million.

ⁱ Excludes the unwinding of the discount on provisions and payables amounting to \$173 million which is included in finance costs in the group income statement.

^j Midstream and other activities exclude inventory holding gains and losses.

^k The profits of equity-accounted entities are included after interest and tax and the results exclude balances associated with assets held for sale.

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

^a The Russia region includes BP's equity-accounted share of TNK-BP's earnings. For 2012, equity-accounted earnings are included until 21 October 2012 only, after which our investment was classified as an asset held for sale and therefore equity accounting ceased. The amounts shown exclude BP's share of costs incurred and results of operations for the period 22 October to 31 December 2012.

^b These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

^c Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year. Capitalized costs exclude balances associated with assets held for sale.

^d Includes costs capitalized as a result of asset exchanges.

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

^f Presented net of transportation costs and sales taxes.

^g Includes interest, non-controlling interest and the net results of equity-accounted entities, and excludes inventory holding gains and losses.

Oil and natural gas exploration and production activities continued

	\$ million									
	2013									
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries ^a										
Capitalized costs at 31 December ^b										
Gross capitalized costs										
Proved properties	29,314	10,040	75,313	2,501	8,809	35,720	–	20,726	4,681	187,104
Unproved properties	316	195	6,816	2,408	3,366	5,079	–	2,756	805	21,741
	29,630	10,235	82,129	4,909	12,175	40,799	–	23,482	5,486	208,845
Accumulated depreciation	18,707	3,650	38,236	193	5,063	20,082	–	10,069	1,962	97,962
Net capitalized costs	10,923	6,585	43,893	4,716	7,112	20,717	–	13,413	3,524	110,883
Costs incurred for the year ended 31 December ^b										
Acquisition of properties										
Proved	–	–	1	–	7	–	–	–	–	8
Unproved	–	–	158	–	284	30	–	7	–	479
	–	–	159	–	291	30	–	7	–	487
Exploration and appraisal costs ^c	178	14	1,291	194	951	883	–	1,090	210	4,811
Development	1,942	455	4,877	569	683	2,755	–	2,082	189	13,552
Total costs	2,120	469	6,327	763	1,925	3,668	–	3,179	399	18,850
Results of operations for the year ended 31 December										
Sales and other operating revenues ^d										
Third parties	1,129	183	934	5	2,413	3,195	–	1,005	1,784	10,648
Sales between segments	1,661	1,280	14,047	12	1,154	6,518	–	11,432	941	37,045
	2,790	1,463	14,981	17	3,567	9,713	–	12,437	2,725	47,693
Exploration expenditure	280	17	437	28	1,477	387	–	768	47	3,441
Production costs	1,102	430	3,691	42	892	1,623	–	1,091	187	9,058
Production taxes	(35)	–	1,112	–	184	–	–	5,660	126	7,047
Other costs (income) ^e	(1,731)	86	3,241	55	322	89	65	84	351	2,562
Depreciation, depletion and amortization	504	490	3,268	–	559	3,132	–	2,174	207	10,334
Impairments and (gains) losses on sale of businesses and fixed assets	118	15	(80)	–	129	29	–	(16)	230	425
	238	1,038	11,669	125	3,563	5,260	65	9,761	1,148	32,867
Profit (loss) before taxation ^f	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,577	14,826
Allocable taxes	554	475	1,204	(26)	642	1,925	(2)	682	641	6,095
Results of operations	1,998	(50)	2,108	(82)	(638)	2,528	(63)	1,994	936	8,731
Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax										
Exploration and production activities - subsidiaries (as above)	2,552	425	3,312	(108)	4	4,453	(65)	2,676	1,577	14,826
Midstream activities - subsidiaries ^g	244	(40)	296	(14)	153	(154)	(4)	(29)	347	799
TNK-BP - Gain On Sale	–	–	–	–	–	–	12,500	–	–	12,500
Equity-accounted entities ^h	–	28	17	–	405	24	2,158	553	–	3,185
Total replacement cost profit before interest and tax	2,796	413	3,625	(122)	562	4,323	14,589	3,200	1,924	31,310

^a These tables contain information relating to oil and natural gas exploration and production activities of subsidiaries, which includes our share of oil and natural gas exploration and production activities of joint operations. They do not include any costs relating to the Gulf of Mexico oil spill. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia, Australia and Angola.

^b Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

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

^d Presented net of transportation costs, purchases and sales taxes.

^e Includes property taxes, other government take and the fair value gain on embedded derivatives of \$459 million. The UK region includes a \$1,055 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

^f Excludes the unwinding of the discount on provisions and payables amounting to \$141 million which is included in finance costs in the group income statement.

^g Midstream and other activities excludes inventory holding gains and losses.

^h The profits of equity-accounted entities are included after interest and tax.

Oil and natural gas exploration and production activities continued

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

^a Amounts reported for Russia in this table include BP's share of Rosneft's worldwide activities, including insignificant amounts outside Russia.

^b These tables contain information relating to oil and natural gas exploration and production activities of equity-accounted entities. They do not include amounts relating to assets held for sale. Midstream activities relating to the management and ownership of crude oil and natural gas pipelines, processing and export terminals and LNG processing facilities and transportation as well as downstream activities of TNK-BP and Rosneft are excluded. The amounts reported for equity-accounted entities exclude the corresponding amounts for their equity-accounted entities.

^c Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

^d The amounts shown reflect BP's share of equity-accounted entities' costs incurred, and not the costs incurred by BP in acquiring an interest in equity-accounted entities.

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

^f Presented net of transportation costs and sales taxes.

^g Includes interest, non-controlling interest and the net results of equity-accounted entities, and excludes inventory holding gains and losses.

Movements in estimated net proved reserves

	million barrels									
Crude oil ^a	2009									
	Europe	Rest of Europe	North America	Rest of North America	South America	Africa	Asia	Russia	Australasia ^d	Total
Subsidiaries	UK	Rest of Europe	US ^b	Rest of North America					Rest of Asia	
At 1 January 2009										
Developed	410	81	1,717	11	47	464	—	195	56	2,981
Undeveloped	119	194	1,273	1	55	496	—	488	58	2,684
	529	275	2,990	12	102	960	—	683	114	5,665
Changes attributable to										
Revisions of previous estimates	7	(1)	165	2	18	(121)	—	(128)	3	(55)
Improved recovery	42	7	82	—	7	32	—	31	2	203
Purchases of reserves-in-place	1	—	—	—	—	—	—	1	—	2
Discoveries and extensions	184	—	73	—	—	114	—	—	7	378
Production ^c	(61)	(14)	(237)	(2)	(22)	(109)	—	(45)	(11)	(501)
Sales of reserves-in-place	(8)	—	—	—	—	—	—	(26)	—	(34)
	165	(8)	83	—	3	(84)	—	(167)	1	(7)
At 31 December 2009 ^d										
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
Equity-accounted entities (BP share) ^e										
At 1 January 2009										
Developed	—	—	—	—	399	—	2,227	499	—	3,125
Undeveloped	—	—	—	—	409	11	944	199	—	1,563
	—	—	—	—	808	11	3,171	698	—	4,688
Changes attributable to										
Revisions of previous estimates	—	—	—	—	2	(2)	590	(28)	—	562
Improved recovery	—	—	—	—	50	—	8	—	—	58
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	3	—	87	—	—	90
Production	—	—	—	—	(37)	—	(307)	(71)	—	(415)
Sales of reserves-in-place	—	—	—	—	(14)	—	—	(116)	—	(130)
	—	—	—	—	4	(2)	378	(215)	—	165
At 31 December 2009 ^f										
Developed	—	—	—	—	407	—	2,351	363	—	3,121
Undeveloped	—	—	—	—	405	9	1,198	120	—	1,732
	—	—	—	—	812	9	3,549	483	—	4,853
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	410	81	1,717	11	446	464	2,227	694	56	6,106
Undeveloped	119	194	1,273	1	464	507	944	687	58	4,247
	529	275	2,990	12	910	971	3,171	1,381	114	10,353
At 31 December 2009										
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

^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 68 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 26 thousand barrels per day.

^d Includes 819 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^f Includes 20 million barrels of NGLs. Also includes 243 million barrels of crude oil in respect of the 6.86% non-controlling interest in TNK-BP.

Movements in estimated net proved reserves continued

	billion cubic feet									
										2009 Total
	Europe		North America		South America	Africa	Asia		Australasia	
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Natural gas ^a										
Subsidiaries										
At 1 January 2009										
Developed	1,822	61	9,059	659	3,316	1,050	—	1,102	1,887	18,956
Undeveloped	582	402	5,473	468	7,434	1,382	—	1,308	4,000	21,049
	2,404	463	14,532	1,127	10,750	2,432	—	2,410	5,887	40,005
Changes attributable to										
Revisions of previous estimates	(114)	(8)	549	43	322	270	—	(231)	22	853
Improved recovery	34	—	550	5	322	49	—	82	75	1,117
Purchases of reserves-in-place	159	—	—	—	—	—	—	31	—	190
Discoveries and extensions	150	—	496	94	105	59	—	—	531	1,435
Production ^b	(243)	(9)	(907)	(100)	(929)	(249)	—	(241)	(189)	(2,867)
Sales of reserves-in-place	(118)	—	(4)	—	—	—	—	(223)	—	(345)
	(132)	(17)	684	42	(180)	129	—	(582)	439	383
At 31 December 2009 ^c										
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
Equity-accounted entities (BP share) ^d										
At 1 January 2009										
Developed	—	—	—	—	1,498	—	1,560	176	—	3,234
Undeveloped	—	—	—	—	1,023	182	653	111	—	1,969
	—	—	—	—	2,521	182	2,213	287	—	5,203
Changes attributable to										
Revisions of previous estimates	—	—	—	—	(26)	(17)	204	(19)	—	142
Improved recovery	—	—	—	—	314	—	1	4	—	319
Purchases of reserves-in-place	—	—	—	—	—	—	—	—	—	—
Discoveries and extensions	—	—	—	—	6	—	23	—	—	29
Production ^b	—	—	—	—	(165)	—	(219)	(25)	—	(409)
Sales of reserves-in-place	—	—	—	—	(388)	—	—	(154)	—	(542)
	—	—	—	—	(259)	(17)	9	(194)	—	(461)
At 31 December 2009 ^e										
Developed	—	—	—	—	1,252	—	1,703	80	—	3,035
Undeveloped	—	—	—	—	1,010	165	519	13	—	1,707
	—	—	—	—	2,262	165	2,222	93	—	4,742
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	1,822	61	9,059	659	4,814	1,050	1,560	1,278	1,887	22,190
Undeveloped	582	402	5,473	468	8,457	1,564	653	1,419	4,000	23,018
	2,404	463	14,532	1,127	13,271	2,614	2,213	2,697	5,887	45,208
At 31 December 2009										
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

^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 195 billion cubic feet of natural gas consumed in operations, 164 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities and excludes 16 billion cubic feet of produced non-hydrocarbon components that meet regulatory requirements for sales.

^c Includes 3,068 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^e Includes 131 billion cubic feet of natural gas in respect of the 5.79% non-controlling interest in TNK-BP.

Movements in estimated net proved reserves continued

Total hydrocarbons ^a	million barrels of oil equivalent ^b									
	2009									
	Europe	North America	South America	Africa	Asia	Australasia	Total			
	UK	Rest of Europe	US ^c	Rest of North America		Russia	Rest of Asia			
Subsidiaries										
At 1 January 2009										
Developed	724	91	3,279	126	617	645	–	385	382	6,249
Undeveloped	219	264	2,217	81	1,337	734	–	714	747	6,313
	943	355	5,496	207	1,954	1,379	–	1,099	1,129	12,562
Changes attributable to										
Revisions of previous estimates	(13)	(2)	260	9	74	(74)	–	(168)	7	93
Improved recovery	48	7	177	1	63	40	–	45	15	396
Purchases of reserves-in-place	28	–	–	–	–	–	–	6	–	34
Discoveries and extensions	210	–	158	17	18	124	–	–	98	625
Production ^{d,e}	(102)	(16)	(393)	(20)	(182)	(152)	–	(86)	(44)	(995)
Sales of reserves-in-place	(28)	–	(1)	–	–	–	–	(65)	–	(94)
	143	(11)	201	7	(27)	(62)	–	(268)	76	59
At 31 December 2009 ^f										
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
Equity-accounted entities (BP share) ^g										
At 1 January 2009										
Developed	–	–	–	–	658	–	2,495	529	–	3,682
Undeveloped	–	–	–	–	586	42	1,057	218	–	1,903
	–	–	–	–	1,244	42	3,552	747	–	5,585
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(2)	(5)	625	(32)	–	586
Improved recovery	–	–	–	–	104	–	8	1	–	113
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	4	–	92	–	–	96
Production ^{d,e}	–	–	–	–	(66)	–	(345)	(75)	–	(486)
Sales of reserves-in-place	–	–	–	–	(81)	–	–	(142)	–	(223)
	–	–	–	–	(41)	(5)	380	(248)	–	86
At 31 December 2009 ^h										
Developed	–	–	–	–	623	–	2,645	377	–	3,645
Undeveloped	–	–	–	–	580	37	1,287	122	–	2,026
	–	–	–	–	1,203	37	3,932	499	–	5,671
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2009										
Developed	724	91	3,279	126	1,275	645	2,495	914	382	9,931
Undeveloped	219	264	2,217	81	1,923	776	1,057	932	747	8,216
	943	355	5,496	207	3,198	1,421	3,552	1,846	1,129	18,147
At 31 December 2009										
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

^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 68 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 26 thousand barrels of oil equivalent per day.

^e Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 29 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities and excludes 3 million barrels of oil equivalent of produced non-hydrocarbon components that meet regulatory requirements for sales.

^f Includes 819 million barrels of NGLs. Also includes 552 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^h Includes 20 million barrels of NGLs. Also includes 266 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.

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% non-controlling 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% non-controlling 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

	billion cubic feet									
										2010
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		
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 that 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% non-controlling 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% non-controlling 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

	million barrels	
Bitumen ^a	2010	Total
	Rest of North America	
Equity-accounted entities (BP shares)		
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									
	Europe		North America		South America	Africa	Asia	Australasia	2010	Total
	UK	Rest of Europe	US ^c	Rest of North America			Russia	Rest of Asia		
Total hydrocarbons^a										
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 per 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 that 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% non-controlling 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 non-controlling 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.

Movements in estimated net proved reserves continued

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

^a Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

^c Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels per day.

^d Includes 616 million barrels of NGLs. Also includes 20 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^f Includes 19 million barrels of NGLs. Also includes 310 million barrels of crude oil in respect of the 7.37% non-controlling interest in TNK-BP.

^g Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,305 million barrels, comprising 95 million barrels in Venezuela, one million barrels in Vietnam and 4,209 million barrels in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved liquid reserves of 221 million barrels.

Movements in estimated net proved reserves continued

Natural gas ^a	billion cubic feet									
	Europe		North America		South America	Africa	Asia	Australasia	2011 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 that meet regulatory requirements for sales.

^c Includes 2,759 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^e Includes 174 billion cubic feet of natural gas in respect of the 6.27% non-controlling interest in TNK-BP.

^f Total proved gas reserves held as part of our equity interest in TNK-BP is 2,881 billion cubic feet, comprising 30 billion cubic feet in Venezuela, 73 billion cubic feet in Vietnam and 2,778 billion cubic feet in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved gas reserves of 185 billion cubic feet.

Movements in estimated net proved reserves continued

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

^a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

Movements in estimated net proved reserves continued

	million barrels of oil equivalent ^b									
Total hydrocarbons ^a										2011 Total
	Europe	Rest of Europe	North America	Rest of North America	South America	Africa	Asia	Rest of Asia	Australasia	
	UK		US ^c				Russia			
At 1 January 2011										
Developed	608	84	3,366	10	660	600	–	491	662	6,481
Undeveloped	574	295	1,923	179	1,192	779	–	371	462	5,775
	1,182	379	5,289	189	1,852	1,379	–	862	1,124	12,256
Changes attributable to										
Revisions of previous estimates	28	10	27	(3)	41	(103)	–	(119)	55	(64)
Improved recovery	24	8	200	–	15	12	–	75	10	344
Purchases of reserves-in-place	1	–	26	2	7	–	–	58	–	94
Discoveries and extensions	–	–	39	–	9	19	–	–	–	67
Production ^{d,e}	(66)	(13)	(289)	(1)	(153)	(108)	–	(92)	(59)	(781)
Sales of reserves-in-place	(36)	–	(97)	(4)	(76)	(12)	–	(87)	–	(312)
	(49)	5	(94)	(6)	(157)	(192)	–	(165)	6	(652)
At 31 December 2011 ^f										
Developed	531	76	3,362	5	522	522	–	355	675	6,048
Undeveloped	602	308	1,833	178	1,173	665	–	342	455	5,556
	1,133	384	5,195	183	1,695	1,187	–	697	1,130	11,604
Equity-accounted entities (BP share) ^g										
At 1 January 2011										
Developed	–	–	–	–	593	–	2,716	382	–	3,691
Undeveloped	–	–	–	–	613	43	1,441	27	–	2,124
	–	–	–	–	1,206	43	4,157	409	–	5,815
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(25)	5	795	(5)	–	770
Improved recovery	–	–	–	–	103	–	73	2	–	178
Purchases of reserves-in-place	–	–	–	–	103	–	–	14	–	117
Discoveries and extensions	–	–	–	–	–	–	25	–	–	25
Production ^{d,e}	–	–	–	–	(59)	–	(362)	(80)	–	(501)
Sales of reserves-in-place	–	–	–	–	(260)	–	–	–	–	(260)
	–	–	–	–	(138)	5	531	(69)	–	329
At 31 December 2011 ^{h,i}										
Developed	–	–	–	–	546	–	2,961	274	–	3,781
Undeveloped	–	–	–	–	522	48	1,727	66	–	2,363
	–	–	–	–	1,068	48	4,688	340	–	6,144
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2011										
Developed	608	84	3,366	10	1,253	600	2,716	873	662	10,172
Undeveloped	574	295	1,923	179	1,805	822	1,441	398	462	7,899
	1,182	379	5,289	189	3,058	1,422	4,157	1,271	1,124	18,071
At 31 December 2011										
Developed	531	76	3,362	5	1,068	522	2,961	629	675	9,829
Undeveloped	602	308	1,833	178	1,695	713	1,727	408	455	7,919
	1,133	384	5,195	183	2,763	1,235	4,688	1,037	1,130	17,748

^a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

^c Proved reserves in the Prudhoe Bay field in Alaska include an estimated 82 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

^d Excludes NGLs from processing plants in which an interest is held of 28 thousand barrels of oil equivalent per day.

^e Includes 34 million barrels of oil equivalent of natural gas consumed in operations, 27 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 that meet regulatory requirements for sales.

^f Includes 616 million barrels of NGLs. Also includes 496 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^h Includes 19 million barrels of NGLs. Also includes 340 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.

ⁱ Total proved reserves held as part of our equity interest in TNK-BP is 4,802 million barrels of oil equivalent, comprising 100 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 4,688 million barrels of oil equivalent in Russia. In 2011, BP aligned its reporting with TNK-BP by moving to a life of field reporting basis. Reasonable certainty of licence renewals is demonstrated by evidence of Russian subsoil law, track record of renewals within the industry and track record of success in obtaining renewals by TNK-BP. This has resulted in an increase in proved reserves of 253 million barrels of oil equivalent.

Movements in estimated net proved reserves continued

	million barrels									
Crude oil ^a										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US ^b	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2012										
Developed	288	69	1,685	–	27	311	–	177	59	2,616
Undeveloped	445	230	1,173	–	48	315	–	279	47	2,537
	733	299	2,858	–	75	626	–	456	106	5,153
Changes attributable to										
Revisions of previous estimates	(30)	(25)	(280)	–	(11)	(1)	–	(2)	–	(349)
Improved recovery	3	–	140	–	–	13	–	2	–	158
Purchases of reserves-in-place	4	–	21	–	–	–	–	–	–	25
Discoveries and extensions	–	1	23	–	–	2	–	–	–	26
Production ^c	(31)	(8)	(142)	–	(10)	(73)	–	(51)	(9)	(324)
Sales of reserves-in-place	(6)	(18)	(188)	–	–	–	–	–	–	(212)
	(60)	(50)	(426)	–	(21)	(59)	–	(51)	(9)	(676)
At 31 December 2012 ^{d,h}										
Developed	242	170	1,443	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	–	32	255	–	137	45	1,968
	673	249	2,432	–	54	567	–	405	97	4,477
Equity-accounted entities (BP share) ^e										
At 1 January 2012										
Developed	–	–	–	–	349	–	2,596	256	–	3,201
Undeveloped	–	–	–	–	348	14	1,613	58	–	2,033
	–	–	–	–	697	14	4,209	314	–	5,234
Changes attributable to										
Revisions of previous estimates	–	–	–	–	(2)	9	462	(23)	–	446
Improved recovery	–	–	–	–	24	–	47	–	–	71
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	67	–	–	67
Production	–	–	–	–	(29)	–	(316)	(80)	–	(425)
Sales of reserves-in-place	–	–	–	–	–	–	(15)	–	–	(15)
	–	–	–	–	(7)	9	245	(103)	–	144
At 31 December 2012 ^{f,g,i}										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	690	23	4,454	211	–	5,378
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2012										
Developed	288	69	1,685	–	376	311	2,596	433	59	5,817
Undeveloped	445	230	1,173	–	396	329	1,613	337	47	4,570
	733	299	2,858	–	772	640	4,209	770	106	10,387
At 31 December 2012										
Developed	242	170	1,443	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	–	383	266	1,962	150	45	4,305
	673	249	2,432	–	744	590	4,454	616	97	9,855

^a Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

^c Excludes NGLs from processing plants in which an interest is held of 13,500 barrels per day.

^d Includes 591 million barrels of NGLs. Also includes 14 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^f Includes 103 million barrels of NGLs. Also includes 328 million barrels of crude oil in respect of the 7.35% non-controlling interest in TNK-BP.

^g Total proved liquid reserves held as part of our equity interest in TNK-BP is 4,540 million barrels, comprising 87 million barrels in Venezuela and 4,454 million barrels in Russia.

^h Includes assets held for sale of 39 million barrels.

ⁱ Includes assets held for sale of 4,540 million barrels.

Movements in estimated net proved reserves continued

Natural gas ^a	billion cubic feet									
	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% non-controlling interest in BP Trinidad and Tobago LLC.

^d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^e Includes 270 billion cubic feet of natural gas in respect of the 6.17% non-controlling interest in TNK-BP.

^f Total proved gas reserves held as part of our equity interest in TNK-BP is 4,492 billion cubic feet, comprising 38 billion cubic feet in Venezuela, 78 billion cubic feet in Vietnam and 4,376 billion cubic feet in Russia.

^g Includes assets held for sale of 590 billion cubic feet.

^h Includes assets held for sale of 4,492 billion cubic feet.

Movements in estimated net proved reserves continued

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

^a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

Movements in estimated net proved reserves continued

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

^a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

^c Proved reserves in the Prudhoe Bay field in Alaska include an estimated 76 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

^d Excludes NGLs from processing plants in which an interest is held of 13,500 barrels of oil equivalent per day.

^e Includes 33 million barrels of oil equivalent of natural gas consumed in operations, 25 million barrels of oil equivalent in subsidiaries, 8 million barrels of oil equivalent in equity-accounted entities and excludes 2 million barrels of oil equivalent of produced non-hydrocarbon components that meet regulatory requirements for sales.

^f Includes 591 million barrels of NGLs. Also includes 512 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^h Includes 103 million barrels of NGLs. Also includes 374 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.

ⁱ Total proved reserves held as part of our equity interest in TNK-BP is 5,315 million barrels of oil equivalent, comprising 93 million barrels of oil equivalent in Venezuela, 14 million barrels of oil equivalent in Vietnam and 5,208 million barrels of oil equivalent in Russia.

^j Includes assets held for sale of 140 million barrels of oil equivalent.

^k Includes assets held for sale of 5,315 million barrels of oil equivalent.

Movements in estimated net proved reserves continued

	million barrels									
Crude oil ^a	Europe		North America		South America	Africa	Asia		Australasia ¹	2013 Total
	UK	Rest of Europe	US ^b	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January 2013										
Developed	242	170	1,443	–	22	312	–	268	52	2,509
Undeveloped	431	79	989	–	32	255	–	137	45	1,968
	673	249	2,432	–	54	567	–	405	97	4,477
Changes attributable to										
Revisions of previous estimates	(78)	(19)	(141)	–	30	26	–	65	(12)	(129)
Improved recovery	12	–	52	–	1	2	–	65	–	132
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	4	–	–	–	–	39	3	46
Production ^c	(22)	(12)	(132)	–	(11)	(80)	–	(52)	(9)	(318)
Sales of reserves-in-place	(36)	–	(11)	–	–	–	–	–	–	(47)
	(124)	(31)	(228)	–	20	(52)	–	117	(18)	(316)
At 31 December 2013 ^d										
Developed	169	163	1,297	–	29	320	–	320	57	2,355
Undeveloped	380	55	907	–	45	195	–	202	22	1,806
	549	218	2,204	–	74	515	–	522	79	4,161
Equity-accounted entities (BP share) ^e										
At 1 January 2013										
Developed	–	–	–	–	339	12	2,492	198	–	3,041
Undeveloped	–	–	–	–	351	11	1,962	13	–	2,337
	–	–	–	–	690	23	4,454	211	–	5,378
Changes attributable to										
Revisions of previous estimates	–	–	–	1	(21)	(3)	384	1	–	362
Improved recovery	–	–	–	–	27	–	–	–	–	27
Purchases of reserves-in-place	–	–	–	–	34	–	4,579	–	–	4,613
Discoveries and extensions	–	–	–	–	12	–	228	–	–	240
Production	–	–	–	–	(27)	–	(303)	(85)	–	(415)
Sales of reserves-in-place	–	–	–	–	(85)	–	(4,399)	–	–	(4,484)
	–	–	–	1	(60)	(3)	489	(84)	–	343
At 31 December 2013 ^{f,g}										
Developed	–	–	–	–	316	10	3,064	120	–	3,510
Undeveloped	–	–	–	1	314	10	1,879	7	–	2,211
	–	–	–	1	630	20	4,943	127	–	5,721
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January 2013										
Developed	242	170	1,443	–	361	324	2,492	466	52	5,550
Undeveloped	431	79	989	–	383	266	1,962	150	45	4,305
	673	249	2,432	–	744	590	4,454	616	97	9,855
At 31 December 2013										
Developed	169	163	1,297	–	345	330	3,064	440	57	5,865
Undeveloped	380	55	907	1	359	205	1,879	209	22	4,017
	549	218	2,204	1	704	535	4,943	649	79	9,882

^a Crude oil includes NGLs and condensate. Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

^c Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.

^d Includes 551 million barrels of NGLs. Also includes 21 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^e Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^f Includes 131 million barrels of NGLs. Also includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.

^g Total proved liquid reserves held as part of our equity interest in Rosneft is 4,975 million barrels, comprising less than 1 mmbbl in Vietnam and Canada, 32 million barrels in Venezuela and 4,943 million barrels in Russia.

Movements in estimated net proved reserves continued

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

^a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b Includes 180 billion cubic feet of natural gas consumed in operations, 149 billion cubic feet in subsidiaries, 31 billion cubic feet in equity-accounted entities.

^c Includes 2,685 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^d Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^e Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.

^f Total proved gas reserves held as part of our equity interest in Rosneft is 9,271 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 31 billion cubic feet in Vietnam and 9,225 billion cubic feet in Russia.

Movements in estimated net proved reserves continued

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

^a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

Movements in estimated net proved reserves continued

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

^a Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

^c Proved reserves in the Prudhoe Bay field in Alaska include an estimated 72 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

^d Excludes NGLs from processing plants in which an interest is held of 5,500 barrels of oil equivalent per day.

^e Includes 31 million barrels of oil equivalent of natural gas consumed in operations, 26 million barrels of oil equivalent in subsidiaries, 5 million barrels of oil equivalent in equity-accounted entities.

^f Includes 551 million barrels of NGLs. Also includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

^g Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

^h Includes 131 million barrels of NGLs. Also includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

ⁱ Total proved reserves held as part of our equity interest in Rosneft is 6,574 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 34 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,533 million barrels of oil equivalent in Russia.

Group production by major field – liquids

		thousand barrels per day BP net share of production ^a				
	Field or area	2009	2010	2011	2012	2013
Subsidiaries						
UK ^b	ETAP ^c	34	28	22	11	22
	Foinaven (BP-operated)	29	24	26	14	17
	Other	105	85	65	61	22
Total UK		168	137	113	86	61
Norway ^b	Various	40	40	32	23	34
Total Rest of Europe		40	40	32	23	34
Total Europe		208	177	145	109	96
Alaska ^b	Greater Prudhoe Bay (BP-operated)	86	81	78	77	73
	Kuparuk	45	42	39	36	36
	Milne Point (BP-operated)	24	23	19	15	16
	Other	26	20	17	11	12
Total Alaska		181	166	153	139	137
Lower 48 onshore ^b	Various	97	90	69	60	56
Gulf of Mexico deepwater ^b	Great White	–	–	9	19	23
	Thunder Horse (BP-operated)	133	120	77	49	27
	Atlantis (BP-operated)	54	49	34	23	40
	Mad Dog (BP-operated)	35	30	8	9	18
	Mars	29	23	19	15	14
	Na Kika (BP-operated)	27	25	14	21	28
	Horn Mountain (BP-operated)	25	14	8	6	–
	King (BP-operated)	22	21	15	14	–
	Other	62	56	47	35	20
Total Gulf of Mexico deepwater		387	338	231	191	170
Total US		665	594	453	390	363
Canada ^b	Various (BP-operated)	8	7	2	1	–
Total Rest of North America		8	7	2	1	–
Total North America		673	601	455	391	363
Colombia ^b	Various (BP-operated)	23	18	1	–	–
Trinidad & Tobago	Various (BP-operated)	38	36	31	21	23
Brazil ^b	Polvo	–	–	7	7	7
Total South America		61	54	39	28	30
Angola	Greater Plutonio (BP-operated)	70	73	51	59	59
	Kizomba C Dev	43	31	21	9	9
	Dalia	32	20	12	11	11
	Girassol FPSO	22	18	12	11	11
	Pazflor	–	–	5	29	32
	PSVM	–	–	–	1	24
	Other	44	28	22	29	34
Total Angola		211	170	123	149	180
Egypt	Gupco	55	47	34	32	29
	Other	16	12	11	9	9
Total Egypt		71	59	45	41	38
Algeria ^b	Various	22	17	22	12	7
Total Africa		304	246	190	202	225
Azerbaijan ^b	Azeri-Chirag-Gunashli (BP-operated)	94	94	86	82	83
	Other	7	9	8	10	13
Total Azerbaijan		101	103	94	92	96
Western Indonesia	Various	5	2	2	1	1
Iraq	Rumaila	–	–	31	39	39
Other	Various	17	14	11	7	5
Total Rest of Asia ^b		123	119	138	139	141
Total Asia		123	119	138	139	141
Australia	Various	31	30	23	24	23
Other	Various	–	2	2	3	2
Total Australasia		31	32	25	27	25
Total subsidiaries ^d		1,400	1,229	992	896	879
Equity-accounted entities (BP share)						
TNK-BP (Russia, Venezuela, Vietnam) ^{b,e}	Various	840	856	871	877	187
Rosneft (Russia, Canada, Venezuela, Vietnam) ^{b,f}	Various	–	–	–	–	650
Abu Dhabi ^g	Various	182	190	209	216	231
Argentina	Various	75	75	74	65	63
Bolivia	Various	1	–	–	1	2
Venezuela ^b	Various	25	23	10	–	–
Other	Various	12	1	1	1	1
Total equity-accounted entities		1,135	1,145	1,165	1,160	1,134
Total subsidiaries and equity-accounted entities		2,535	2,374	2,157	2,056	2,013

^a Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b In 2013, BP divested its interests in TNK-BP, its interests in the Harding, Devenick, Maclure, Braes and Braemar fields in the North Sea and its interests in the US onshore Moxa upstream operation in Wyoming. It also acquired an interest in Rosneft. In 2012, BP divested its interests in the Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of its interest in the Gulf of Mexico Mad Dog asset, its interests in the US onshore Jonah and Pinedale upstream operation in Wyoming, and associated gas gathering system, its interests in the Canadian natural gas liquid business, its interests in the Alba and Britannia fields in the UK North Sea, its interests in the Draugen field in the Norwegian Sea, and TNK-BP disposed of its interests in OJSC Novosibirskneftegaz, with interests in Novosibirsk region, Omsk region, and Irkutsk region, and its interests in OJSC Severoanheftegaz, with interests in Novosibirsk region. BP also increased its interest in the US onshore Eagle Ford Shale in south Texas, its interests in certain UK North Sea assets, and in certain US Alaska assets. In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint arrangement with Reliance, Brazil and additional volumes in the Gulf of Mexico and UK North Sea. BP divested its holdings in Pompano along with other interests in the Gulf of Mexico, Tuscaloosa and interests in South Texas in the US onshore, a portion of our interest in the Azeri-Chirag-Gunashli development in Azerbaijan, Wytch Farm in the UK, our interests in the REB field in Algeria, and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din and Western Desert concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Azeri-Chirag-Gunashli development in Azerbaijan and the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011. In 2009, BP assumed ownership of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia's Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy's shares of Chaco. In 2008, BP concluded the migration of the Cerro Negro operations to an incorporated joint venture with Petróleos de Venezuela, S.A. (PDVSA) while retaining its equity position, and TNK-BP disposed of some non-core interests.

^c Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.

^d Includes 5.5 net mboe/d of NGLs from processing plants in which BP has an interest (2012 13.5mboe/d and 2011 28mboe/d).

^e Estimated production for 2013 represents BP's share of TNK-BP's estimated production from 1 January to 20 March, averaged over the full year.

^f 2013 reflects production for the period 21 March to 31 December, averaged over the full year.

^g In 2013 BP held interests, through associates, in onshore and offshore concessions in Abu Dhabi, of which the onshore concession expired in 2014 and the offshore concession expires in 2018.

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

Group production by major field – natural gas

		million cubic feet per day BP net share of production ^a				
	Field or area	2009	2010	2011	2012	2013
Subsidiaries						
UK ^b	Bruce/Rhum (BP-operated)	110	100	20	15	25
	Other	508	372	335	399	132
Total UK		618	472	355	414	157
Norway	Various	16	15	13	8	80
Total Rest of Europe		16	15	13	8	80
Total Europe		634	487	368	422	237
Lower 48 onshore ^b	San Juan (BP-operated)	659	629	603	561	529
	Jonah (BP-operated)	227	185	145	69	–
	Anadarko	146	137	141	142	129
	Arkoma Central	194	164	136	118	107
	Arkoma West	65	128	109	98	110
	Arkoma East	67	112	115	112	115
	Wamsutter (BP-operated)	146	126	122	141	159
	Other	451	394	274	258	255
Total Lower 48 onshore		1,955	1,875	1,645	1,499	1,404
Gulf of Mexico deepwater ^b	Various	303	263	176	134	114
Alaska	Various	58	46	22	18	21
Total US		2,316	2,184	1,843	1,651	1,539
Canada ^b	Various	263	202	14	13	11
Total Rest of North America		263	202	14	13	11
Total North America		2,579	2,386	1,857	1,664	1,551
Trinidad & Tobago	Manqo (BP-operated)	664	544	308	181	119
	Cashima/NEQB (BP-operated)	571	679	570	305	138
	Kapok (BP-operated)	540	541	464	360	358
	Cannonball (BP-operated)	225	156	99	56	27
	Amherstia (BP-operated)	197	252	296	324	257
	Serrette (BP-operated)	–	–	35	367	527
	Savonette (BP-operated)	11	203	327	320	545
	Immortelle (BP-operated)	–	–	68	95	200
	Other (BP-operated)	222	98	26	89	50
Total Trinidad		2,430	2,473	2,193	2,097	2,221
Colombia ^c	Various	62	71	4	–	–
Total South America		2,492	2,544	2,197	2,097	2,221
Egypt	Temsah	118	90	74	34	30
	Ha'py (BP-operated)	94	73	99	88	72
	Taurt (BP-operated)	73	75	61	67	50
	Denis	–	–	77	138	99
	Other	177	192	133	143	193
Total Egypt		462	430	444	470	444
Algeria	Various	159	126	114	120	117
Total Africa		621	556	558	590	561
Pakistan ^b	Various (BP-operated)	173	150	73	–	–
Azerbaijan	Various (BP-operated)	126	132	140	158	203
Western Indonesia	Sangka-Sangka	71	69	59	59	55
	Other	35	1	–	–	–
Total Western Indonesia		106	70	59	59	55
India ^b	D1 D3	–	–	121	253	117
	D26	–	–	25	59	38
	Other	–	–	–	1	1
Total India		–	–	146	313	156
China ^b	Yacheng	83	95	70	54	34
Vietnam ^b	Various (BP-operated)	63	77	69	–	–
Oman	Various (BP-operated)	–	–	20	14	22
Sharjah	Various (BP-operated)	59	50	41	35	25
Total Rest of Asia		610	574	618	633	494
Total Asia		610	574	618	633	494
Australia	Perseus/Athena	142	165	170	141	139
	Goodwyn	139	118	72	73	57
	Anqel	120	133	126	110	89
	Other	39	46	87	111	146
Total Australia		440	462	455	435	431
Eastern Indonesia	Tangguh (BP-operated)	74	323	340	352	349
Total Australasia		514	785	795	787	780
Total subsidiaries ^c		7,450	7,332	6,393	6,193	5,845
Equity-accounted entities (BP share)						
TNK-BP (Russia, Venezuela, Vietnam) ^{b, d}	Various	601	640	710	785	184
Russia – Rosneft ^{b, e}	Various	–	–	–	–	617
Angola	ALNG	–	–	–	–	8
Argentina	Various	378	379	371	355	329
Bolivia	Various	11	11	14	34	55
Kazakhstan ^b	Various	11	–	–	–	–
Venezuela ^b	Various	3	9	4	–	–
Western Indonesia	Various	31	30	26	26	22
Total equity-accounted entities ^c		1,035	1,069	1,125	1,200	1,216
Total subsidiaries and equity-accounted entities		8,485	8,401	7,518	7,393	7,060

^a Production excludes royalties due to others whether payable in cash or in kind where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently.

^b In 2013, BP divested its interests in TNK-BP, its interests in the Harding, Devenick, Maclure, Braes, Braemar and Sean fields in the North Sea, its interests in the US onshore Moxa upstream operation in Wyoming and its interests in the Yacheng gas field in the South China Sea. It also acquired an interest in Rosneft. In 2012, BP divested its interests in the US Hugoton basin including the Jayhawk NGL plant, its interests in the Gulf of Mexico Marlin, Dorado, King, Horn Mountain, Holstein, Ram Powell and Diana Hoover assets, a portion of its interest in the Gulf of Mexico Mad Dog asset, its interests in the US onshore Jonah and Pinedale upstream operation in Wyoming, its interests in the Sunray and Hemphill gas processing plants in Texas, and associated gas gathering system, its interests in the UK North Sea southern gas fields including associated pipeline infrastructure and the Dimlington terminal (including the integrated Easington terminal), and its interests in the Alba and Britannia fields in the UK North Sea. BP also increased its interest in the US onshore Eagle Ford Shale in South Texas, and its interests in certain UK North Sea assets. In 2011, BP sold its holdings in Venezuela and Vietnam to TNK-BP. It also made acquisitions in India through a joint operation with Reliance, in the Eagle Ford shale in North America and additional volumes in the Gulf of Mexico. BP divested its holdings in Pompano along with other interests in the Gulf of Mexico, Tuscaloosa and interests in south Texas in the US onshore, Wytch Farm in the UK, minor volumes in Canada and the remainder of our interests in Colombia and Pakistan. In 2010, BP divested its Permian Basin assets in Texas and south-east New Mexico, the East Badr El-Din concession in Egypt, its Canada gas assets and reduced its interest in the King field in the Gulf of Mexico. It also acquired an increased holding in the Valhall and Hod fields in the Norwegian North Sea. Four other producing fields in the Gulf of Mexico that were acquired during 2010 were subsequently disposed of in early 2011. In 2009, BP assumed ownership of the Mirpurkhas and Khipro blocks in Pakistan, swapped a number of assets with BG Group plc in the UK sector of the North Sea, divested some minor interests in the US Lower 48, divested its holdings in Indonesia's Offshore Northwest Java to Pertamina, divested its interests in LukArco to Lukoil and the Bolivian government nationalized, with compensation payable, Pan American Energy's shares of Chaco.

^c Natural gas production volumes exclude gas consumed in operations within the lease boundaries of the producing field, but the related reserves are included in the group's reserves.

^d Estimated production for 2013 represents BP's share of TNK-BP's estimated production from 1 January to 20 March, averaged over the full year.

^e 2013 reflects production for the period 21 March to 31 December, averaged over the full year.

Group production interests – total hydrocarbons

Oil and natural gas production (net of royalty)

	thousand barrels oil equivalent per day				
	2009	2010	2011	2012	2013
US	1,064	970	771	675	628
Europe	317	261	209	182	137
Russia	944	967	985	989	963
Rest of World	1,673	1,624	1,489	1,484	1,502
Total group including equity-accounted entities	3,998	3,822	3,454	3,330	3,230

BP average liquids realizations^a

	\$ per barrel				
US	53.68	70.79	96.34	96.35	91.88
Europe	61.91	77.39	107.10	109.05	104.77
Rest of World	57.29	75.23	104.83	105.84	104.20
BP average	56.26	73.41	101.29	102.10	99.24

^a Crude oil, condensate and NGLs.

BP average natural gas realizations

	\$ per thousand cubic feet				
US	3.07	3.88	3.34	2.32	3.07
Europe	4.75	5.49	8.09	8.63	9.68
Rest of World	3.14	3.86	4.98	5.33	5.97
BP average	3.25	3.97	4.69	4.75	5.35

Liquefied natural gas projects

Liquefaction project participation

Country	Project/train	Gross capacity (mtpa)	BP % equity	BP net capacity (mtpa)	Markets served
Trinidad & Tobago	Atlantic LNG Train 1	3.3	34.0	1.1	US, Spain
	Atlantic LNG Trains 2-3	6.7	42.5	2.8	US, Spain
	Atlantic LNG Train 4	5.2	37.8	2.0	US, Dominican Republic
	North West Shelf Trains 1-5	16.3	16.7	2.7	Japan, China, Korea
Australia	ADGAS Trains 1-3	6.0	10.0	0.6	Japan
Abu Dhabi	Tangguh Trains 1-2	7.6	37.2	2.8	Mexico, China, Korea
Indonesia					
Total		45.1		12.0	

Regasification terminal participation

Country	Facility	Gross capacity (million standard cubic feet/d)	BP % equity	BP net ownership (million standard cubic feet/d)	BP capacity rights (million standard cubic feet/d)
China	Dapeng LNG (Guangdong)	860	30.0	260	—
US	Cove Point	960	0.0	—	320
UK	Isle of Grain Phase 1	450	0.0	—	225
Italy	Adriatic LNG (Rovigo)	800	0.0	—	100
Total		3,070		260	645

Equity gas production into LNG plant

	Trinidad & Tobago Atlantic LNG Trains 1-4	Australia North West Shelf Trains 1-5	Indonesia Bontang Tangguh Ph1	Egypt SEGAS Train 1	BP total (million standard cubic feet/d)
2009	1,605	346	197	54	2,202
2010	1,649	371	413	63	2,496
2011	1,561	364	416	67	2,408
2012	1,575	353	428	80	2,436
2013	1,652	344	419	80	2,495

LNG shipping^a

Vessel name	Status	Ownership	Delivery date	Capacity (m ³)
British Trader	Operational	Operating lease	4Q 2002	138,000
British Innovator	Operational	Operating lease	1Q 2003	138,000
British Merchant	Operational	Operating lease	3Q 2003	138,000
British Emerald	Operational	Operating lease	3Q 2007	155,000
British Ruby	Operational	Operating lease	3Q 2008	155,000
British Sapphire	Operational	Operating lease	3Q 2008	155,000
British Diamond	Operational	Operating lease	4Q 2008	155,000
Celestine River	Operational	Time-charter	2Q 2012	147,000
Methane Spirit	Operational	Time-charter	2Q 2012	165,000
Total				1,346,000

^a Excludes shipping owned and operated within joint-arrangement projects.

Exploration interests

By geographical area

Oil and natural gas acreage at 31 December

Oil and natural gas acreage at 31 December			thousand acres								
			Europe		North America		South America	Africa	Asia	Australasia	Total
			UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
2013											
Developed	- gross		128	39	6,340	223	1,634	621	4,380	1,982	15,509
	- net		71	16	3,334	109	453	221	831	355	5,425
Undeveloped ^a	- gross		1,118	1,196	6,669	9,710	29,100	26,538	257,896	20,141	368,389
	- net		672	403	4,585	7,638	12,943	17,142	50,285	7,258	112,180
2012											
Developed	- gross		168	39	6,516	228	1,702	605	1,597	2,023	13,040
	- net		85	16	3,463	111	461	220	712	400	5,503
Undeveloped ^a	- gross		1,273	180	7,469	6,074	27,755	30,684	26,291	26,505	144,085
	- net		730	77	4,935	4,154	14,032	18,419	11,061	9,339	75,845
2011											
Developed	- gross		334	65	7,350	228	1,718	560	1,618	1,952	13,987
	- net		182	21	4,266	111	450	207	723	384	6,379
Undeveloped ^a	- gross		1,276	186	7,210	6,273	10,064	27,000	33,704	56,189	160,543
	- net		764	79	4,798	4,253	4,571	17,895	14,712	17,890	78,414
2010											
Developed	- gross		346	65	6,920	198	1,738	497	2,282	2,434	14,642
	- net		189	21	4,184	157	471	195	885	935	7,072
Undeveloped ^a	- gross		1,311	186	6,970	7,185	12,434	21,373	32,137	18,366	107,292
	- net		775	79	4,663	4,380	6,398	16,072	15,475	8,955	59,593
2009											
Developed	- gross		366	65	7,587	1,186	1,740	539	4,123	2,191	17,997
	- net		201	19	4,609	850	470	222	1,794	842	9,046
Undeveloped ^a	- gross		1,602	486	7,985	6,967	7,361	21,979	10,357	15,191	76,037
	- net		919	226	4,979	5,009	3,471	16,463	4,683	6,597	43,258

^a Undeveloped acreage includes leases and concessions.

Exploration and development wells^a

		Europe		North America		South America	Africa	Asia	Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
2013										
Exploratory	Productive	1.0	—	12.7	—	4.5	1.5	4.0	3.5	27.2
	Dry	—	—	1.1	—	1.4	0.6	—	0.9	4.5
Development	Productive	1.0	1.2	285.7	—	94.6	12.6	395.0	58.0	848.3
	Dry	—	0.2	0.4	—	2.7	0.2	—	0.7	4.6
2012										
Exploratory	Productive	—	0.3	17.1	—	5.8	2.3	14.7	—	40.2
	Dry	0.2	—	0.6	—	1.0	0.5	5.0	—	7.3
Development	Productive	1.6	—	317.8	—	78.9	17.7	552.5	43.1	1,011.6
	Dry	—	—	—	—	—	1.0	—	9.5	10.5
2011										
Exploratory	Productive	0.4	—	34.1	—	4.4	2.1	16.7	1.0	58.9
	Dry	—	—	2.1	—	0.2	—	7.2	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	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
2009										
Exploratory	Productive	0.1	—	47.2	—	3.0	4.5	7.0	5.3	67.7
	Dry	0.2	—	4.2	—	—	1.4	4.5	6.0	16.5
Development	Productive	9.3	1.5	403.8	17.9	135.4	20.8	293.0	45.8	929.1
	Dry	—	—	3.3	—	—	0.5	4.0	0.4	8.8

^a 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.

Number of productive wells at 31 December 2013

		Europe		North America		South America	Africa	Asia	Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
Oil wells ^a	Gross	115	63	2,456	55	4,681	608	41,541	2,166	51,698
	Net	71	25	975	28	2,583	441	7,779	439	12,343
Gas wells ^b	Gross	68	6	21,445	364	688	135	72	761	23,613
	Net	29	1	9,367	179	239	52	14	280	10,175

^a Includes approximately 7,639 gross (1,491 net) multiple completion wells (more than one formation producing into the same well bore).

^b Includes approximately 2,859 gross (1,350 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

Drilling and production activities in progress at 31 December 2013^a

		Europe		North America		South America	Africa	Asia	Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
Exploratory	Gross	2.0	—	32.0	3.0	6.0	10.0	—	4.0	57.0
	Net	0.8	—	9.2	1.5	2.2	5.2	—	0.8	19.7
Development	Gross	6.0	3.0	780.0	55.0	33.0	20.0	100.0	58.0	1,065.0
	Net	4.0	1.1	169.1	27.5	16.6	6.1	19.8	20.7	266.3

^a Includes suspended development and long-term suspended exploratory wells.

Upstream

Key indicators^a

	2009	2010	2011	2012	2013
Result and oil price					
Replacement cost profit before interest and tax (\$ million) ^b	22,852	28,269	26,358	22,491	16,657
Underlying replacement cost profit before interest and tax (\$ million) ^b	19,668	25,073	25,217	19,436	18,265
BP average liquids realizations (\$/bbl) ^{c,d}	56.26	73.41	101.29	102.10	99.24
Finding and development costs (\$ per barrel of oil equivalent (\$/boe), five-year rolling average) ^{e,f,g}	16.32	17.25	17.70	21.59	25.62
Finding costs (\$/boe, five-year rolling average) ^{e,g,h}	5.31	5.33	5.89	7.63	9.29
Production costs (\$/boe) ^{i,j}	6.39	6.77	10.08	12.50	13.16
Cost of supply (\$/boe) ^k	16.66	16.51	22.69	28.00	32.10
Net income per barrel of oil equivalent (\$/boe)					
BP subsidiaries and equity-accounted entities excluding TNK-BP and Rosneft (\$/boe) ^l	11.08	15.33	16.97	15.70	14.55
Range of other oil majors ^m					
Maximum (\$/boe)	11.80	17.30	25.14	22.62	21.71
Minimum (\$/boe)	7.20	11.90	16.20	13.34	12.95
Reserves replacement ^l					
BP subsidiaries (%)	112	74	44	(2)	105
BP subsidiaries and equity-accounted entities (%) ^{n,o}	129	106	103	77	129
Range of other oil majors ^{m,p}					
Maximum (%)	252	138	171	160	127
Minimum (%)	70	22	84	40	83

^a Except where indicated, all the data in this table relates to BP subsidiaries only.

^b Includes equity-accounted entities in the Upstream segment.

^c Crude oil, condensate and NGLs.

^d Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

^e Reserves calculated on an SEC basis.

^f Finding costs are described in footnote h. Development costs as disclosed in the exploration and production activities on pages 32-41, include expenditure on construction, installation or completion of infrastructure facilities such as platforms, pipelines and the drilling of development wells, including service and unsuccessful development wells.

^g Based on additions to reserves including revisions of previous estimates, improved recovery, discoveries and extensions.

^h Finding costs are exploration and appraisal drilling expenditures, which are capitalized within intangible assets, and geological and geophysical exploration costs, which are charged to income as incurred as disclosed in the exploration and production activities tables on pages 32-41.

ⁱ Production costs are costs incurred to operate and maintain wells and related equipment and facilities. Amounts do not include ad valorem and severance taxes.

^j Based on production volumes.

^k Cost of supply comprises exploration expenditure, production costs and depreciation, depletion and amortization as disclosed in the exploration and production activities tables on pages 32-41.

^l Post-tax income derived from upstream activities divided by the number of barrels of oil equivalent produced (including equity-accounted entities but excluding TNK-BP and Rosneft).

^m The 2013 peer group includes ExxonMobil, Shell, Chevron and Total (2009, 2010, 2011 and 2012 also include ConocoPhillips).

ⁿ For 2013, this includes BP's share of TNK-BP's production and reserves additions from 1 January 2013 to 20 March 2013, and BP's share of Rosneft production and reserves additions from 21 March 2013 to 31 December 2013.

^o Includes reserves replacement in TNK-BP, which from 2011 included the effect of moving from life of licence measurement to life of field measurement, reflecting TNK-BP's track record of successful licence renewal.

^p BP estimates of reserves replacement of other oil majors.

Financial statistics

	\$ million				
	2009	2010	2011	2012	2013
Replacement cost profit before interest and tax ^a					
US	6,685	9,684	6,196	6,918	3,625
Non-US	16,167	18,585	20,162	15,573	13,032
	22,852	28,269	26,358	22,491	16,657
Underlying replacement cost profit before interest and tax ^a					
US	5,853	8,353	6,108	3,854	3,836
Non-US	13,815	16,720	19,109	15,582	14,429
	19,668	25,073	25,217	19,436	18,265
Operating capital employed					
US	39,209	40,065	41,347	38,437	41,320
Non-US	52,804	56,212	64,185	70,387	70,567
	92,013	96,277	105,532	108,824	111,887
Sales and other operating revenues ^b	57,626	66,266	75,754	72,225	70,374
Capital expenditure and acquisitions ^a					
US	6,169	6,632	5,363	6,385	6,410
Non-US	8,727	11,121	20,458	12,135	12,705
	14,896	17,753	25,821	18,520	19,115
Employee numbers at year end	21,500	21,100	22,400	24,200	24,700
BP average realizations					
BP average liquids realizations (\$/bbl) ^c	56.26	73.41	101.29	102.10	99.24
BP average natural gas realizations (\$/mcf)	3.25	3.97	4.69	4.75	5.35
Marker prices					
Brent oil (\$/bbl)	61.67	79.50	111.26	111.67	108.66
Alaska North Slope oil (\$/bbl)	62.49	79.92	110.12	111.08	107.67
West Texas Intermediate (\$/bbl)	61.92	79.45	95.04	94.13	97.99
Mars oil (\$/bbl)	60.50	78.04	107.54	106.79	102.23
Henry Hub gas price (\$ per million British thermal units) ^d	3.99	4.39	4.04	2.79	3.65

^a A minor amendment has been made to the split between regions for 2013.

^b Includes sales to other segments.

^c Crude oil, condensate and NGLs.

^d Henry Hub First of Month Index.

Downstream

Key indicators

	2009	2010	2011	2012	2013
Result and refining margin					
Replacement cost profit before interest and tax (\$ million)	743	5,555	5,470	2,864	2,919
Underlying replacement cost profit before interest and tax (\$ million)	3,607	4,883	6,009	6,463	3,632
Refining marker margin ^a (\$/bbl)	9.8	10.7	14.5	18.2	15.4
Refining availability ^b (%)	93.6	95.0	94.8	94.8	95.3
Petrochemicals production (thousand tonnes)	12,660	15,594	14,866	14,727	13,943

Refining marker margin by region^{a c}

	2009	2010	2011	2012	2013
					\$ per barrel
US North West	13.1	13.9	14.1	18.0	15.2
US South West	13.4	13.1	13.6	17.4	n/a
US Gulf Coast	9.2	10.2	11.9	16.1	n/a
US Midwest	8.6	9.3	24.7	27.8	21.7
North West Europe	9.0	10.4	11.9	16.1	12.9
Mediterranean	7.9	8.8	9.0	12.7	10.5
Australia	9.5	10.4	12.2	14.8	13.4
BP Average RMM	9.8	10.7	14.5	18.2	15.4

^a The refining marker margin (RMM) is the average of regional indicator margins weighted for BP's crude refining capacity in each region. Each regional marker margin is based on product yields and a marker crude oil deemed appropriate for the region. The regional indicator margins may not be representative of the margins achieved by BP in any period because of BP's particular refinery configurations and crude and product slate. In 2013 BP updated the RMM methodology; prior periods have been restated.

^b Refining availability represents Solomon Associates' operational availability, which is defined as the percentage of the year that a unit is available for processing after subtracting the annualized time lost due to turnaround activity and all planned mechanical, process and regulatory downtime.

^c In 2013, BP updated the RMM methodology and regions to reflect the changes to our US portfolio after the refinery divestments and trends in regional crude markets since the RMM was established (further information can be found on: bp.com/tradingconditions). The RMMs shown here have been restated to reflect this updated methodology and have been adjusted to reflect BP's historical refining capacity and regional weighting within the portfolio for each respective period.

Employee numbers at year end

	2009	2010	2011	2012	2013
Non-service station staff	37,700	37,100	36,900	37,100	33,900
Service station staff ^a	13,900	15,200	14,600	14,700	14,100
	51,600	52,300	51,500	51,800	48,000

^a Service station staff are those employed directly by BP at BP-owned retail sites. It excludes staff at BP-branded sites operated by dealers, jobbers and franchisees.

Financial statistics

	\$ million				
	2009	2010	2011	2012	2013
Replacement cost profit (loss) before interest and tax					
US	(2,578)	935	1,415	(242)	758
Non-US	3,321	4,620	4,055	3,106	2,161
	743	5,555	5,470	2,864	2,919
Underlying replacement cost profit (loss) before interest and tax					
US	(557)	564	1,978	3,045	1,123
Non-US	4,164	4,319	4,031	3,418	2,509
	3,607	4,883	6,009	6,463	3,632
Replacement cost profit (loss) before interest and tax ^a					
Fuels	(914)	2,628	2,999	1,403	1,518
Lubricants	1,059	1,357	1,350	1,276	1,274
Petrochemicals	598	1,570	1,121	185	127
	743	5,555	5,470	2,864	2,919
Non-operating items and fair value accounting effects ^b					
Fuels	(2,655)	381	(640)	(3,609)	(712)
Lubricants	(171)	(47)	100	(9)	2
Petrochemicals	(38)	338	1	19	(3)
	(2,864)	672	(539)	(3,599)	(713)
Underlying replacement cost profit before interest and tax ^a					
Fuels	1,741	2,247	3,639	5,012	2,230
Lubricants	1,230	1,404	1,250	1,285	1,272
Petrochemicals	636	1,232	1,120	166	130
	3,607	4,883	6,009	6,463	3,632
Operating capital employed					
US	20,114	23,463	24,627	24,835	23,835
Non-US	26,387	24,959	26,457	25,488	25,680
	46,501	48,422	51,084	50,323	49,515
Sales and other operating revenues ^c	213,050	266,751	344,033	346,391	351,195
Property, plant and equipment (net book value)					
US	12,497	14,151	11,833	14,603	16,468
Non-US	14,616	13,996	15,246	15,320	15,131
	27,113	28,147	27,079	29,923	31,599
Capital expenditure and acquisitions					
US	2,625	2,761	2,691	3,475	2,535
Non-US	1,489	1,268	1,594	1,774	1,971
	4,114	4,029	4,285	5,249	4,506

^a BP's share of income from petrochemicals at our Gelsenkirchen and Mülheim sites in Germany is reported in the fuels business. Segment-level overhead expenses are included in the fuels business result.

^b Fair value accounting effects represent the favourable (unfavourable) impact relative to management's measure of performance. For Downstream, these arise solely in the fuels business.

^c Includes sales to other segments.

Refinery throughputs and utilization

Refinery throughputs^a

	thousand barrels per day				
	2009	2010	2011	2012	2013
US	1,238	1,350	1,277	1,310	726
Europe	755	775	771	751	766
Rest of World	294	301	304	293	299
	2,287	2,426	2,352	2,354	1,791
Crude distillation capacity at 31 December ^b	2,666	2,667	2,679	2,681	1,955
Refinery capacity utilization ^c	86%	91%	88%	88%	86%

^a Refinery throughputs reflect crude oil and other feedstock volumes.

^b Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

^c Refinery utilization is annual throughput (thousands of barrels per day) divided by the average crude distillation capacity, expressed as a percentage.

Crude oil input

					%
	2009	2010	2011	2012	2013
Low sulphur crude ^a	44	42	43	46	48
High sulphur crude	56	58	57	54	52

^a Low sulphur crude is a crude which has sulphur content of less than 0.5%.

Refinery yield^a

	thousand barrels per day				
	2009	2010	2011	2012	2013
Aviation fuels	276	290	304	316	236
Gasolines	818	881	844	880	616
Middle distillates	674	723	691	700	598
Fuel oil	123	93	114	86	71
Other products ^b	447	497	425	420	274
	2,338	2,484	2,378	2,402	1,795

^a Refinery yields exceed throughputs because of volumetric expansion.

^b Other products include lubricants, petrochemicals, bitumen, petroleum coke and LPG.

Refineries

Refinery capacities

		thousand barrels per day																	
		Crude distillation capacities ^a										Major upgrading plant capacities ^b							
Wholly and partly owned refineries at 31 December 2013		Group interest % ^c	Total	BP share	Vacuum distillation	Fluid catalytic cracking	Hydro-cracking	Catalytic reforming	Alkylation and polymerization	Hydro-treating gasoline and naphtha	Hydro-treating jet, distillates and heavier	Vis-breaking	Coker	Aromatics and isomerization	Asphalt	Hydrogen ^d	Sulphur ^e	Other ^f	Nelson Complexity Index ^g
US																			
Washington	Cherry Point	100.0	234	234	112	–	65	65	–	97	68	–	56	24	–	179	245	–	10.1
Indiana	Whiting	100.0	428	428	259	165	–	64	31	106	349	–	102	26	30	30	1,684	–	11.3
Ohio	Toledo	50.0	160	80	36	28	16	21	6	20	34	–	17	–	5	–	176	–	11.1
			822	742	407	193	81	150	37	223	451	–	175	50	35	209	2,105	–	10.9
Europe																			
Germany	Bayernoil ^h	22.5	217	49	21	11	10	9	–	24	20	4	–	–	3	17	82	1	8.9
	Gelsenkirchen	50.0	265	132	80	16	29	16	–	39	51	10	17	10	8	106	348	–	10.6
	Karlsruhe ^h	12.0	322	39	16	10	–	7	2	15	27	–	4	4	–	8	47	1	8.9
	Lingen	100.0	95	95	45	–	29	30	–	31	45	–	23	25	–	128	140	–	14.8
Netherlands	Schwedt ^h	18.8	239	45	29	11	–	7	2	18	35	9	–	5	1	7	90	1	9.9
	Rotterdam	100.0	377	377	82	59	–	32	8	73	270	34	–	–	–	20	231	3	5.7
	Spain	100.0	110	110	47	30	–	17	3	57	85	–	20	19	–	45	65	–	9.9
			1,625	847	320	137	68	118	15	257	533	57	64	63	12	331	1,003	6	8.6
Rest of World																			
Australia	Bulwer	100.0	102	102	39	23	20	16	–	22	43	–	–	–	–	32	90	–	7.3
	Kwinana	100.0	146	146	22	35	–	25	7	44	52	–	–	21	2	–	70	–	6.2
New Zealand	Whangarei ^h	23.7	118	28	11	–	7	7	–	10	12	–	–	–	–	13	40	–	7.5
South Africa	Durban ^h	50.0	180	90	28	19	–	17	1	25	44	13	–	8	1	1	118	3	8.8
			546	366	100	77	27	65	8	101	151	13	–	29	3	46	318	3	7.2
			2,993	1,955	827	407	176	333	60	581	1,135	70	239	142	50	586	3,426	9	9.2

^a Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.

^b These are shown as BP share of capacities; BP has varying interests.

^c BP share of equity, which is not necessarily the same as BP share of processing entitlements.

^d Reported as standard cubic feet per day.

^e Reported as tonnes per day.

^f Other consists of ethyl tertiary butyl ether, methyl tertiary butyl ether and lubricants units.

^g Nelson Complexity Index is calculated as defined by the Oil and Gas Journal survey 2013. In general, the higher a refinery's Nelson Complexity Index, the greater that refinery's ability to make higher-value products from a given feedstock.

^h Indicates refineries not operated by BP.

Regional refining distillation capacity

		thousand barrels per day				
		2009	2010	2011	2012	2013
US Gulf Coast ^a		475	475	475	475	–
US Midwest		485	485	493	493	508
US West Coast ^b		499	500	500	500	234
Total US		1,459	1,460	1,468	1,468	742
Europe		851	844	845	847	847
Rest of World		356	363	366	366	366
Total		2,666	2,667	2,679	2,681	1,955

^a Texas City refinery was classified as an asset held for sale at 31 December 2013 and divested in February 2013.

^b 266 kbd of West Coast capacity relating to Carson refinery was classified as an asset held for sale at 31 December 2012

Retail sites^{a b}

	at 31 December				
	2009	2010	2011	2012	2013
US	11,500	11,300	11,300	10,100	7,700
Europe	8,600	8,400	8,200	8,300	8,000
Rest of World	2,300	2,400	2,300	2,300	2,100
	22,400	22,100	21,800	20,700	17,800

^a The number of retail sites includes sites not operated by BP but instead operated by dealers, jobbers, franchisees or brand licensees that operate under a BP brand. These may move to or from the BP brand as their fuel supply or brand licence agreements expire and are renegotiated in the normal course of business. Retail sites are primarily branded BP, Arco and Aral.

^b Excludes our interest in equity-accounted entities which are dual branded.

Oil sales volumes^a

	thousand barrels per day				
	2009	2010	2011	2012	2013
Refined product marketing sales volumes by region					
US					
Aviation fuels	173	188	190	210	231
Gasolines	1,010	958	927	914	786
Middle distillates	186	228	217	204	176
Fuel oil	30	30	38	36	35
Other products ^b	27	29	29	32	54
	1,426	1,433	1,401	1,396	1,282
Europe					
Aviation fuels	231	264	251	253	254
Gasolines	324	259	240	225	222
Middle distillates	670	627	602	586	599
Fuel oil	158	147	109	70	80
Other products ^b	121	105	103	96	82
	1,504	1,402	1,305	1,230	1,237
Rest of World					
Aviation fuels	91	94	95	95	104
Gasolines	110	109	106	106	98
Middle distillates	156	157	156	156	170
Fuel oil	230	214	215	199	164
Other products ^b	43	36	33	31	29
	630	610	605	587	565
Total marketing sales volumes by product					
Aviation fuels	495	546	536	558	589
Gasolines	1,444	1,326	1,273	1,245	1,105
Middle distillates	1,012	1,012	975	946	945
Fuel oil	418	391	362	305	280
Other products ^b	191	170	165	159	165
Total marketing sales ^c	3,560	3,445	3,311	3,213	3,084
Trading/supply sales ^d	2,327	2,482	2,465	2,444	2,485
Total refined product sales	5,887	5,927	5,776	5,657	5,569
Crude oil sales ^e	1,824	1,658	1,532	1,518	2,142
Total oil sales	7,711	7,585	7,308	7,175	7,711

^a Excludes sales to other BP businesses and sales of petrochemicals products.

^b Other products include lubricants, petroleum coke, bitumen and LPG.

^c Marketing sales are sales of refined products including lubricants to service stations, end-consumers, bulk buyers and jobbers (i.e. third parties who own networks of a number of service stations and small resellers).

^d Trading/supply sales are sales of refined products to other oil companies.

^e Crude oil sales relate to transactions executed by our integrated supply and trading function, primarily for optimizing crude supplies to our refineries and other trading. In addition, crude oil sales include 73,000 barrels per day relating to revenues reported by Upstream segment.

Sales and other operating revenues of refined product

	\$ million				
	2009	2010	2011	2012	2013
US	63,442	80,576	111,020	108,490	90,917
Europe	71,189	88,347	108,302	107,902	108,585
Rest of World	31,457	40,298	54,618	59,528	58,513
	166,088	209,221	273,940	275,920	258,015

Petrochemicals production capacities^{a b}

Geographical area	Site	Product	Group interest %	BP share of capacity thousand tonnes per annum ^c
US				
	Cooper River	Purified terephthalic acid (PTA)	100.0	1,300
	Decatur ^d	PTA	100.0	1,000
		Paraxylene (PX)	100.0	1,100
	Texas City	Acetic acid	100.0 ^e	600 ^e
		PX	100.0	1,300
		Metaxylene	100.0	100
				5,400
Europe				
UK	Hull ^d	Acetic acid	100.0	500
		Acetic anhydride	100.0	200
Belgium	Geel	PTA	100.0	1,300
		PX	100.0	700
Germany	Gelsenkirchen ^f	Olefins and Derivatives	50.0 to 61.0	1,800 ^{bg}
	Mülheim ^f	Solvents	50.0	100 ^b
				4,600
Rest of World				
China	Caojing	Olefins and derivatives	50.0	3,300 ^b
	Chongqing	Acetic acid	51.0	200 ^b
		Esters	51.0	100 ^b
	Nanjing	Acetic acid	50.0	300 ^b
	Zhuhai	PTA	85.0	1,800 ^h
Indonesia	Merak	PTA	50.0	300 ^b
South Korea	Ulsan	Acetic acid	51.0	300 ^b
		Vinyl acetate monomer	34.0	100 ^b
Malaysia	Kertih	Acetic acid	70.0	400 ^b
Taiwan	Kaohsiung	PTA	61.4	900 ^b
	Taichung	PTA	61.4	500 ^b
	Mai Liao	Acetic acid	50.0	200 ^b
				8,400
Total BP share of capacity at 31 December 2013				18,400

Petrochemicals production capacities summary

By geographical area	BP share of capacity, thousand tonnes per year					
	PTA	PX	Acetic acid	O&D	Other	Total
US	2,300	2,400	600	—	100	5,400
Europe	1,300	700	500	1,800	300	4,600
Rest of World	3,500	—	1,400	3,300	200	8,400
Total BP share of capacity at 31 December 2013	7,100	3,100	2,500	5,100	600	18,400

^a Petrochemicals production capacity is the proven maximum sustainable daily rate (MSDR) multiplied by the number of days in the respective period, where MSDR is the highest average daily rate ever achieved over a sustained period.

^b Includes BP share of equity-accounted entities, as indicated.

^c Capacities are shown to the nearest 100,000 tonnes per annum.

^d These sites have a capacity under 100,000 tonnes per annum for a speciality product (e.g. naphthalene dicarboxylate and ethylidene diacetate).

^e Group interest is quoted at 100%, reflecting the capacity entitlement, that is marketed by BP.

^f Due to the integrated nature of the plants with our Gelsenkirchen refinery, the income and expenditure of these plants is managed and reported through the fuels business.

^g Group interest varies by product.

^h BP Zhuhai Chemical Company Ltd is a subsidiary of BP, the capacity of which is shown above at 100%.

Petrochemicals production^a

By geographical area	thousand tonnes				
	2009	2010	2011	2012	2013
US	3,110	4,146	4,029	4,047	4,264
Europe	3,724	4,051	3,854	3,927	3,779
Rest of World	5,826	7,397	6,983	6,753	5,900
	12,660	15,594	14,866	14,727	13,943

^a Comprises actual production in respect of the products listed in the capacity table above.

TNK-BP

Operational and financial information

	\$ million				
	2009	2010	2011	2012	2013
Financial statistics					
Profit before interest and tax ^a	1,948	2,617	4,185	3,370	12,500
Inventory holdings gains and losses	–	–	(51)	3	–
Replacement cost profit before interest and tax	1,948	2,617	4,134	3,373	12,500
Net (favourable) unfavourable impact of non-operating items	–	–	–	(246)	(12,500)
Underlying replacement cost profit before tax	1,948	2,617	4,134	3,127	–
^a The TNK-BP segment includes equity-accounted earnings from associates, in which all amounts shown relate to BP's 50% share in TNK-BP, as follows:					
	\$ million				
	2009	2010	2011	2012	2013
Income statement (BP share)					
Profit before interest and tax	3,178	3,866	5,992	4,405	–
Finance costs	(220)	(128)	(132)	(84)	–
Taxation	(871)	(913)	(1,333)	(979)	–
Non-controlling interest	(139)	(208)	(342)	(356)	–
Net income ^b	1,948	2,617	4,185	2,986	–
Inventory holding gains, net of tax	–	–	(51)	3	–
Net income on a replacement cost basis	1,948	2,617	4,134	2,989	–
Net charge (credit) for non-operating items, net of tax ^c	–	–	–	138	–
Net income on an underlying RC basis	1,948	2,617	4,134	3,127	–
Balance sheet					
Investment in associates ^d	9,141	9,995	10,013	–	–
Cash flow					
Dividends received ^e	1,656	1,780	3,747	1,399	–
Production (net of royalties)(BP Share)^{f,g}					
Crude oil (thousand barrels per day)	840	856	871	876	187
Natural gas (million cubic feet per day)	601	640	710	784	184
Total hydrocarbons (thousand barrels of oil equivalent per day (mboe/d)) ^h	944	967	994	1,012	218
Average oil marker prices					
	\$ per barrel				
	2009	2010	2011	2012	2013
Urals (north-west Europe – CIF)	61.15	78.26	109.08	110.19	107.38
Russian domestic oil	31.32	36.96	49.57	53.98	54.97

^b Until 22 October 2012, TNK-BP was an associate accounted for using the equity method and therefore BP's share of TNK-BP's earnings after interest and tax was included in the group income statement within BP's profit before interest and tax.

^c Disclosure of non-operating items for TNK-BP began in the first quarter of 2012.

^d On 22 October 2012, BP announced that it had signed heads of terms to sell its 50% share in TNK-BP to Rosneft. Consequently, BP ceased accounting for its interest in TNK-BP using the equity method and the investment was classified as an asset held for sale from that date.

^e 2012 includes the dividend of \$709 million received after the date equity accounting ceased.

^f BP continued to report its share of TNK-BP's production and reserves until the transaction to sell its 50% share to Rosneft completed in March 2013.

^g BP continued to report its share of TNK-BP's production and reserves following the agreement to sell its 50% share of Rosneft until the sale completed on 21 March 2013. Estimated hydrocarbon production for the full year 2013 represents BP's share of TNK-BP's estimated production from 1 January to 20 March, averaged over the full year.

^h Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Rosneft

Operational and financial information

	\$ million				
	2009	2010	2011	2012	2013 ^a
Financial statistics					
Profit before interest and tax ^{b c}	—	—	—	—	2,053
Inventory holding (gains) losses	—	—	—	—	100
Replacement cost profit before interest and tax ^b	—	—	—	—	2,153
Net charge (credit) for non-operating items	—	—	—	—	45
Underlying replacement cost profit before interest and tax ^b	—	—	—	—	2,198

^a From 21 March 2013.

^b BP's share of Rosneft's earnings after finance costs, taxation and non-controlling interests is included in the BP group income statement within profit before interest and taxation.

^c Includes \$5 million of foreign exchange losses arising on the dividend received. This amount is not reflected in the following table.

The Rosneft segment result included equity-accounted earnings from Rosneft, representing BP's 19.75% share in Rosneft. BP's share of the components of Rosneft's net income is shown in the table below.

	\$ million				
	2009	2010	2011	2012	2013
Income statement (BP share)					
Profit before interest and tax	—	—	—	—	2,786
Finance costs	—	—	—	—	(264)
Taxation	—	—	—	—	(422)
Non-controlling interests	—	—	—	—	(42)
Net income	—	—	—	—	2,058
Inventory holding losses, net of tax	—	—	—	—	100
Net income on a replacement cost basis	—	—	—	—	2,158
Net charge (credit) for non-operating items, net of tax	—	—	—	—	45
Net income on an underlying RC basis	—	—	—	—	2,203

Balance sheet

Investment in associates	—	—	—	—	13,681
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Cash flow

Dividends received	—	—	—	—	456
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	2009	2010	2011	2012	2013
Production (net of royalties)(BP Share)^d					
Liquids (thousand barrels per day) ^e	—	—	—	—	650
Natural gas (million cubic feet per day)	—	—	—	—	617
Total hydrocarbons (thousand barrels of oil equivalent per day (mboe/d)) ^f	—	—	—	—	756

Average oil marker prices

	\$ per barrel				
	2009	2010	2011	2012	2013
Urals (north-west Europe – CIF)	61.15	78.26	109.08	110.19	107.38
Russian domestic oil	31.32	36.96	49.57	53.98	54.97

^d Reflects production for the period 21 March to 31 December 2013, averaged over the full year.

^e Liquids comprise crude oil, condensate and natural gas liquids.

^f Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

Other businesses and corporate

Financial statistics

	2009	2010	2011	2012	\$ million 2013
Replacement cost profit (loss) before interest and tax					
US	(728)	(731)	(1,230)	(1,641)	(1,249)
Non-US	(1,594)	(785)	(1,238)	(1,153)	(1,070)
	(2,322)	(1,516)	(2,468)	(2,794)	(2,319)
Underlying replacement cost profit (loss) before interest and tax					
US	(564)	(493)	(797)	(859)	(800)
Non-US	(1,269)	(823)	(849)	(1,137)	(1,098)
	(1,833)	(1,316)	(1,646)	(1,996)	(1,898)
Operating capital employed					
US	(2,773)	(2,905)	(3,149)	(4,115)	(1,459)
Non-US	4,655	17,285	8,506	14,785	19,818
	1,882	14,380	5,357	10,670	18,359
Sales and other operating revenues ^a	2,843	3,328	2,957	1,985	1,805
Capital expenditure and acquisitions					
US	1,071	977	877	681	231
Non-US	228	257	976	754	819
	1,299	1,234	1,853	1,435	1,050
Employee numbers at year end	7,200	6,200	10,100	10,300	11,100

^a Includes sales to other segments.

Alternative Energy

	2009	2010	2011	2012	2013
Biofuels					
Total net ethanol-equivalent production (million litres per annum) ^a	70	105	314	404	521
Crush capacity (million tonnes per annum)	1.2	1.2	7.2	7.2	7.4
Wind capacity ^b					
US	679	742	1,016	1,558	1,558
Non-US	32	32	32	32	32
	711	774	1,048	1,590	1,590

^a Ethanol-equivalent production includes ethanol and sugar.

^b Net wind generation capacity is the sum of the rated capacities of the assets/turbines that have entered into commercial operation, including BP's share of equity-accounted entities. The equivalent capacities on a gross-joint-arrangement basis (which includes 100% of the capacity of equity-accounted entities where BP has partial ownership) were 2,619 megawatts (MW) in 2013 and 2012, 1,763MW in 2011, 1,362MW in 2010, and 1,237MW in 2009. This includes 32MW of capacity in the Netherlands which is managed by our Downstream segment.

Certain definitions

In this document, unless the context otherwise requires, the following terms shall have the meaning set out below.

Associate

An entity over which the group has significant influence and that is neither a subsidiary nor a joint arrangement. Significant influence is the power to participate in the financial and operating policy decisions of the investee but is not control or joint control of those policies.

Barrel (bbl)

42 US gallons.

boe

Barrels of oil equivalent. 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

CIF

Cost insurance and freight.

Debt to debt plus equity ratio

The ratio of finance debt (borrowings, including the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, plus obligations under finance leases) to the total of finance debt plus shareholders' interest.

Debt to equity ratio

The ratio of finance debt (borrowings, including the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, plus obligations under finance leases) to shareholders' interest.

Dividend cover

The dividend cover out of income is calculated as the replacement cost profit for the period, divided by the dividend paid in the period. The dividend cover out of cash is calculated as the net cash provided by operating activities divided by the gross dividends paid. The calculation is based on the assumption that all dividends are paid in cash.

Dividend payout ratio

The ratio of dividend paid for the period to replacement cost profit, expressed as a percentage.

Earnings per share

The profit in cents attributable to each equity share, based on the appropriate consolidated profit of the period after tax and after deducting non-controlling interests and preference dividends, divided by the weighted average number of equity shares in issue during the period.

Effective tax rate

The ratio of the tax charge to the profit after interest expense but before tax.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

Hydrocarbons

Crude oil and natural gas.

IFRS

International Financial Reporting Standards.

Joint arrangement

A joint arrangement is an arrangement of which two or more parties have joint control.

Joint control

Joint control is the contractually agreed sharing of control over an arrangement, which exists only when decisions about the relevant activities require the unanimous consent of the parties sharing control.

Joint operation

A joint 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.

Joint venture

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.

Liquids

Crude oil, condensate and natural gas liquids.

LNG

Liquefied natural gas.

LPG

Liquefied petroleum gas.

mb/d

Thousand barrels per day.

mboe/d

Thousand barrels of oil equivalent per day.

mmboe

Million barrels of oil equivalent.

mmBtu

Million British thermal units.

mmcf

Million cubic feet.

mmcf/d

Million cubic feet per day.

MW

Megawatt.

Gearing (net debt)

Net debt equals finance debt, including 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 claimed, less cash and cash equivalents.

NGLs

Natural gas liquids.

Ordinary shares

Ordinary fully paid shares in BP p.l.c. of 25c each.

Power

Power is defined as the existing rights that give the current ability to direct the relevant activities.

Preference shares

Cumulative first preference shares and cumulative second preference shares in BP p.l.c. of £1 each.

Pre-tax cash returns

The ratio of replacement cost profit before interest and tax and excluding equity-accounted interest and tax, non-operating items and depreciation, depletion and amortization to the average operating capital employed (which excludes goodwill).

Return on average capital employed

The ratio of replacement cost profit before interest expense and non-controlling interest but after tax to the average of opening and closing capital employed. Capital employed is BP shareholders' interest plus finance debt and non-controlling interest. Another return on average capital employed measure is presented based on average capital employed after deducting goodwill from the denominator in the calculation and excluding non-operating items and fair value accounting effects from the numerator.

SEC

The United States Securities and Exchange Commission.

Subsidiary

An entity that is controlled by the BP group. Control of an investee exists when an investor is exposed, or has rights, to variable returns from its involvement with the investee and has the ability to affect those returns through its power over the investee.

Tonne

2,204.6 pounds.



Certain definitions

Additional information can be found on page 269 of the BP Annual Report and Form 20-F 2013.

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BP's corporate reporting suite includes information about our financial and operating performance, sustainability performance and also on global energy trends and projections.



Annual Report and Form 20-F 2013

Details of our financial and operating performance in print or online.
Published in March.
bp.com/annualreport



Strategic Report 2013

A summary of our financial and operating performance in print or online.
Published in March.
bp.com/annualreport



Energy Outlook 2035

Projections for world energy markets, considering the potential evolution of global economy, population, policy and technology.
Published in January.
bp.com/energyoutlook



Sustainability Review 2013

A summary of our sustainability reporting with additional information online.
Published in March.
bp.com/sustainability



Financial and Operating Information 2009-2013

Five-year financial and operating data in PDF or Excel format.
Published in April.
bp.com/financialandoperating



Statistical Review of World Energy 2014

An objective review of key global energy trends.
Published in June.
bp.com/statisticalreview

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