

# Financial and Operating Information 2010-2014

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## Cautionary statement

*BP Financial and Operating Information 2010-2014* 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. 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 2014* filed with the US Securities and Exchange Commission (SEC), including under 'Risk factors' on pages 48-50 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 2014* 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 2010-2014* 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 2015, in accordance with the accounting policies expected to be used in preparing *BP Annual Report and Form 20-F 2015*. These accounting policies do not differ significantly from those used in the *BP Annual Report and Form 20-F 2014*.

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. While 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.

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 2010 was not restated.

Within this document, comparative financial information is colour-coded as follows:				
Quarterly and annual information				
2010	Not restated for IFRS 11	30,000 30,000	Green type Annual total in bold	This financial information for 2010 (quarterly and annual) has not been restated to reflect IFRS 11.
2011-2014	On an IFRS 11 basis	30,000 30,000	Black type Annual total in bold	The financial information for 2011 to 2014 (quarterly and annual) is on an IFRS 11 basis.

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## Online

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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 2014* and *BP Sustainability Report 2014*. Copies may be obtained free of charge (see page 80).

# Group information

## Financial performance

### Highlights

	2010	2011	2012	2013	2014
Underlying replacement cost profit for the year (\$ million) <sup>a b</sup>	20,177	21,170	17,071	13,428	12,136
per ordinary share (cents)	107.39	111.97	89.70	70.92	66.00
per American depositary share (dollars) <sup>c</sup>	6.44	6.72	5.38	4.26	3.96
Non-operating items and fair value accounting effects, net of tax (\$ million) <sup>a</sup>	(25,436)	2,242	(5,643)	10,253	(4,063)
Replacement cost profit (loss) for the year (\$ million) <sup>a b</sup>	(5,259)	23,412	11,428	23,681	8,073
per ordinary share (cents)	(28.01)	123.83	60.05	125.08	43.90
per American depositary share (dollars) <sup>c</sup>	(1.68)	7.43	3.60	7.50	2.63

<sup>a</sup> Replacement cost (RC) profit or loss reflects the replacement cost of inventories sold in the period. RC profit or loss for the group is not a recognized 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.

<sup>b</sup> Profit attributable to BP shareholders.

<sup>c</sup> One American depositary share (ADS) is equivalent to six 25-cent ordinary shares.

### External environment

	2010	2011	2012	2013	2014
BP average liquids realizations (\$ per barrel (\$/bbl)) <sup>a b</sup>	73.41	101.29	102.10	99.24	87.96
BP average natural gas realizations (\$ per thousand cubic feet (\$/mcf)) <sup>b</sup>	3.97	4.69	4.75	5.35	5.70
Refining marker margin (\$/bbl) <sup>c</sup>	10.7	14.5	18.2	15.4	14.4

<sup>a</sup> Liquids comprises crude oil, condensate and natural gas liquids (NGLs).

<sup>b</sup> Realizations are based on sales by consolidated subsidiaries only, which excludes equity-accounted entities.

<sup>c</sup> 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.

## Group income statement

For the year ended 31 December	\$ million				
	2010	2011	2012	2013	2014
Sales and other operating revenues	297,107	375,713	375,765	379,136	353,568
Earnings from joint ventures – after interest and tax	1,175	767	260	447	570
Earnings from associates – after interest and tax	3,582	4,916	3,675	2,742	2,802
Interest and other income	681	688	1,677	777	843
Gains on sale of businesses and fixed assets	6,383	4,132	6,697	13,115	895
Total revenues and other income	308,928	386,216	388,074	396,217	358,678
Purchases	(216,211)	(285,133)	(292,774)	(298,351)	(281,907)
Production and manufacturing expenses <sup>a</sup>	(64,615)	(24,163)	(33,926)	(27,527)	(27,375)
Production and similar taxes	(5,244)	(8,280)	(8,158)	(7,047)	(2,958)
Depreciation, depletion and amortization	(11,164)	(11,357)	(12,687)	(13,510)	(15,163)
Impairment and losses on sale of businesses and fixed assets	(1,689)	(2,058)	(6,275)	(1,961)	(8,965)
Exploration expense	(843)	(1,520)	(1,475)	(3,441)	(3,632)
Distribution and administration expenses	(12,555)	(13,958)	(13,357)	(13,070)	(12,696)
Fair value gain (loss) on embedded derivatives	(309)	68	347	459	430
Profit (loss) before interest and taxation	(3,702)	39,815	19,769	31,769	6,412
Finance costs <sup>a</sup>	(1,170)	(1,187)	(1,072)	(1,068)	(1,148)
Net finance expense relating to pensions and other post-retirement benefits	(435)	(400)	(566)	(480)	(314)
Profit (loss) before taxation	(5,307)	38,228	18,131	30,221	4,950
Taxation <sup>a</sup>	1,638	(12,619)	(6,880)	(6,463)	(947)
Profit (loss) for the year	(3,669)	25,609	11,251	23,758	4,003
Attributable to					
BP shareholders	(4,064)	25,212	11,017	23,451	3,780
Non-controlling interests	395	397	234	307	223
	(3,669)	25,609	11,251	23,758	4,003
Earnings per share – cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	(21.64)	133.35	57.89	123.87	20.55
Diluted	(21.64)	131.74	57.50	123.12	20.42
Replacement cost results <sup>b c d</sup>					
Profit (loss) for the year	(4,064)	25,212	11,017	23,451	3,780
Inventory holding (gains) losses, net of tax	(1,195)	(1,800)	411	230	4,293
Replacement cost profit (loss) for the year	(5,259)	23,412	11,428	23,681	8,073
Non-operating items and fair value accounting effects, net of tax	25,436	(2,242)	5,643	(10,253)	4,063
Underlying replacement cost profit for the year	20,177	21,170	17,071	13,428	12,136
Research and development expenditure amounted to	780	636	674	707	663

<sup>a</sup> See pages 16-17 for information on the impact of the Gulf of Mexico oil spill on these income statement line items.

<sup>b</sup> Replacement cost (RC) profit or loss reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit or loss. RC profit or loss is the measure of profit or loss that is required to be disclosed for each operating segment under International Financial Reporting Standards (IFRS). RC profit or loss for the group is not a recognized GAAP measure. Management believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP's management believes it is helpful to disclose this measure.

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

<sup>c</sup> Profit (loss) attributable to BP shareholders.

<sup>d</sup> 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. See pages 10 and 11 for additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact.

BP believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, period on period, 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	2010	Q1	Q2	Q3	Q4	2011
RC profit (loss) before interest and tax										
Upstream	7,749	5,754	7,620	7,146	28,269	7,419	5,629	6,747	6,563	26,358
Downstream	729	2,075	1,787	964	5,555	2,082	1,339	1,492	557	5,470
TNK-BP <sup>a</sup>	543	490	730	854	2,617	1,127	1,081	939	987	4,134
Rosneft <sup>b</sup>	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate	(328)	(70)	(568)	(550)	(1,516)	(474)	(601)	(329)	(1,064)	(2,468)
Gulf of Mexico oil spill response <sup>c</sup>	—	(32,192)	(7,656)	(1,010)	(40,858)	(384)	617	(541)	4,108	3,800
Consolidation adjustment – unrealized profit in inventory <sup>d</sup>	208	98	85	56	447	(542)	515	(213)	127	(113)
RC profit (loss) before interest and tax	8,901	(23,845)	1,998	7,460	(5,486)	9,228	8,580	8,095	11,278	37,181
Finance costs and net finance expense relating to pensions and other post-retirement benefits	(349)	(332)	(456)	(468)	(1,605)	(386)	(402)	(386)	(413)	(1,587)
RC profit (loss) before taxation	8,552	(24,177)	1,542	6,992	(7,091)	8,842	8,178	7,709	10,865	35,594
Taxation on a RC basis	(2,929)	7,224	300	(2,368)	2,227	(3,282)	(2,830)	(2,387)	(3,286)	(11,785)
RC profit (loss) for the period	5,623	(16,953)	1,842	4,624	(4,864)	5,560	5,348	5,322	7,579	23,809
Attributable to										
BP shareholders	5,514	(17,055)	1,754	4,528	(5,259)	5,499	5,278	5,145	7,490	23,412
Non-controlling interests	109	102	88	96	395	61	70	177	89	397
RC profit (loss) for the period	5,623	(16,953)	1,842	4,624	(4,864)	5,560	5,348	5,322	7,579	23,809
Earnings on RC profit (loss)										
per ordinary share – cents	29.38	(90.78)	9.33	24.09	(28.01)	29.22	27.94	27.15	39.49	123.83
per ADS – dollars	1.76	(5.45)	0.56	1.45	(1.68)	1.75	1.68	1.63	2.37	7.43
RC profit (loss) for the period	5,623	(16,953)	1,842	4,624	(4,864)	5,560	5,348	5,322	7,579	23,809
Inventory holding gains (losses)	705	(284)	(82)	1,445	1,784	2,412	493	(372)	101	2,634
Taxation (charge) credit on inventory holding gains and losses	(224)	107	20	(492)	(589)	(769)	(182)	139	(22)	(834)
Profit (loss) for the period	6,104	(17,130)	1,780	5,577	(3,669)	7,203	5,659	5,089	7,658	25,609
Earnings on profit (loss)										
per ordinary share – cents										
Basic	31.94	(91.73)	9.00	29.16	(21.64)	37.96	29.59	25.93	39.90	133.35
Diluted	31.54	(91.73)	8.90	28.83	(21.64)	37.51	29.23	25.60	39.38	131.74
per ADS – dollars										
Basic	1.92	(5.50)	0.54	1.75	(1.30)	2.28	1.78	1.56	2.39	8.00
Diluted	1.89	(5.50)	0.53	1.73	(1.30)	2.25	1.75	1.54	2.36	7.90

<sup>a</sup> BP ceased equity accounting for its share of TNK-BP's earnings from 22 October 2012.

<sup>b</sup> BP's investment in Rosneft is accounted under the equity method from 21 March 2013.

<sup>c</sup> For more information see Gulf of Mexico oil spill.

<sup>d</sup> Unrealized profit in inventory arising on inter-segment transactions.

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

	Q1	Q2	Q3	Q4	2010	Q1	Q2	Q3	Q4	2011
Underlying RC profit (loss) before interest and tax										
Upstream	7,645	5,815	5,811	5,802	25,073	6,680	6,328	6,286	5,923	25,217
Downstream	789	1,724	1,626	744	4,883	2,199	1,392	1,665	753	6,009
TNK-BP	543	490	730	854	2,617	1,127	1,081	939	987	4,134
Rosneft	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate	(210)	(141)	(482)	(483)	(1,316)	(293)	(338)	(405)	(610)	(1,646)
Consolidation adjustment - unrealized profit in inventory	208	98	85	56	447	(542)	515	(213)	127	(113)
Underlying RC profit before interest and tax	8,975	7,986	7,770	6,973	31,704	9,171	8,978	8,272	7,180	33,601
Finance costs and net finance expense relating to pensions and other post-retirement benefits	(349)	(332)	(409)	(438)	(1,528)	(370)	(387)	(372)	(400)	(1,529)
Underlying RC profit before taxation	8,626	7,654	7,361	6,535	30,176	8,801	8,591	7,900	6,780	32,072
Taxation on an underlying RC basis	(2,954)	(2,654)	(1,835)	(2,161)	(9,604)	(3,348)	(2,946)	(2,391)	(1,820)	(10,505)
Underlying RC profit for the period	5,672	5,000	5,526	4,374	20,572	5,453	5,645	5,509	4,960	21,567
Attributable to										
BP shareholders	5,563	4,898	5,438	4,278	20,177	5,392	5,575	5,332	4,871	21,170
Non-controlling interests	109	102	88	96	395	61	70	177	89	397
Underlying RC profit for the period	5,672	5,000	5,526	4,374	20,572	5,453	5,645	5,509	4,960	21,567
Earnings on underlying RC profit										
per ordinary share – cents	29.64	26.07	28.94	22.76	107.39	28.66	29.51	28.14	25.68	111.97
per ADS – dollars	1.78	1.56	1.74	1.37	6.44	1.72	1.77	1.69	1.54	6.72

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

\$ million														
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
6,983	2,913	4,907	7,688	22,491	5,562	4,400	4,158	2,537	16,657	4,659	4,049	3,311	(3,085)	8,934
859	(1,732)	2,408	1,329	2,864	1,647	1,016	616	(360)	2,919	794	933	1,231	780	3,738
1,064	452	1,282	575	3,373	12,500	—	—	—	12,500	—	—	—	—	—
—	—	—	—	—	85	218	792	1,058	2,153	518	1,024	107	451	2,100
(671)	(522)	(1,096)	(505)	(2,794)	(467)	(573)	(674)	(605)	(2,319)	(497)	(434)	(432)	(647)	(2,010)
30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)	(29)	(251)	(33)	(468)	(781)
(541)	457	(64)	(428)	(576)	427	129	263	(240)	579	90	(76)	370	257	641
7,724	725	7,381	4,533	20,363	19,732	4,991	5,125	2,211	32,059	5,535	5,245	4,554	(2,712)	12,622
(405)	(390)	(376)	(467)	(1,638)	(404)	(369)	(397)	(378)	(1,548)	(367)	(356)	(358)	(381)	(1,462)
7,319	335	7,005	4,066	18,725	19,328	4,622	4,728	1,833	30,511	5,168	4,889	4,196	(3,093)	11,160
(2,477)	(186)	(2,405)	(1,995)	(7,063)	(2,653)	(2,138)	(1,462)	(270)	(6,523)	(1,602)	(1,643)	(1,777)	2,158	(2,864)
4,842	149	4,600	2,071	11,662	16,675	2,484	3,266	1,563	23,988	3,566	3,246	2,419	(935)	8,296
4,781	104	4,534	2,009	11,428	16,596	2,400	3,178	1,507	23,681	3,475	3,182	2,385	(969)	8,073
61	45	66	62	234	79	84	88	56	307	91	64	34	34	223
4,842	149	4,600	2,071	11,662	16,675	2,484	3,266	1,563	23,988	3,566	3,246	2,419	(935)	8,296
25.19	0.54	23.82	10.53	60.05	86.67	12.62	16.84	8.06	125.08	18.80	17.25	12.97	(5.32)	43.90
1.51	0.03	1.43	0.63	3.60	5.20	0.76	1.01	0.48	7.50	1.13	1.03	0.78	(0.32)	2.63
4,842	149	4,600	2,071	11,662	16,675	2,484	3,266	1,563	23,988	3,566	3,246	2,419	(935)	8,296
1,437	(2,324)	1,059	(766)	(594)	406	(506)	444	(634)	(290)	102	258	(1,585)	(4,985)	(6,210)
(451)	701	(312)	245	183	(139)	148	(118)	169	60	(49)	(71)	490	1,547	1,917
5,828	(1,474)	5,347	1,550	11,251	16,942	2,126	3,592	1,098	23,758	3,619	3,433	1,324	(4,373)	4,003
30.39	(7.99)	27.74	7.80	57.89	88.07	10.73	18.57	5.57	123.87	19.09	18.26	7.01	(24.18)	20.55
29.97	(7.99)	27.59	7.75	57.50	87.61	10.68	18.47	5.54	123.12	18.97	18.15	6.97	(24.18)	20.42
1.82	(0.48)	1.66	0.47	3.47	5.28	0.64	1.11	0.33	7.43	1.15	1.10	0.42	(1.45)	1.23
1.80	(0.48)	1.66	0.46	3.45	5.26	0.64	1.11	0.33	7.39	1.14	1.09	0.42	(1.45)	1.23

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

														\$ million
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
6,294	4,401	4,366	4,375	19,436	5,702	4,288	4,423	3,852	18,265	4,401	4,655	3,899	2,246	15,201
927	1,133	3,009	1,394	6,463	1,641	1,201	720	70	3,632	1,011	733	1,484	1,213	4,441
1,157	452	1,294	224	3,127	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	85	218	808	1,087	2,198	271	1,024	110	470	1,875
(435)	(540)	(573)	(448)	(1,996)	(461)	(438)	(385)	(614)	(1,898)	(489)	(438)	(293)	(120)	(1,340)
(541)	457	(64)	(428)	(576)	427	129	263	(240)	579	90	(76)	370	257	641
7,402	5,903	8,032	5,117	26,454	7,394	5,398	5,829	4,155	22,776	5,284	5,898	5,570	4,066	20,818
(399)	(386)	(373)	(461)	(1,619)	(394)	(359)	(388)	(368)	(1,509)	(357)	(347)	(348)	(372)	(1,424)
7,003	5,517	7,659	4,656	24,835	7,000	5,039	5,441	3,787	21,267	4,927	5,551	5,222	3,694	19,394
(2,291)	(1,921)	(2,576)	(742)	(7,530)	(2,706)	(2,243)	(1,661)	(922)	(7,532)	(1,611)	(1,852)	(2,151)	(1,421)	(7,035)
4,712	3,596	5,083	3,914	17,305	4,294	2,796	3,780	2,865	13,735	3,316	3,699	3,071	2,273	12,359
4,651	3,551	5,017	3,852	17,071	4,215	2,712	3,692	2,809	13,428	3,225	3,635	3,037	2,239	12,136
61	45	66	62	234	79	84	88	56	307	91	64	34	34	223
4,712	3,596	5,083	3,914	17,305	4,294	2,796	3,780	2,865	13,735	3,316	3,699	3,071	2,273	12,359
24.51	18.66	26.35	20.19	89.70	22.01	14.26	19.57	15.02	70.92	17.45	19.71	16.51	12.28	66.00
1.47	1.12	1.58	1.21	5.38	1.32	0.86	1.17	0.90	4.26	1.05	1.18	0.99	0.74	3.96

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

	Q1	Q2	Q3	Q4	2010	Q1	Q2	Q3	Q4	2011
<b>By segment</b>										
Upstream										
US	2,762	1,798	3,602	1,522	9,684	1,875	731	1,432	2,158	6,196
Non-US	4,987	3,956	4,018	5,624	18,585	5,544	4,898	5,315	4,405	20,162
	7,749	5,754	7,620	7,146	28,269	7,419	5,629	6,747	6,563	26,358
Downstream										
US	(63)	757	220	21	935	640	(17)	761	31	1,415
Non-US	792	1,318	1,567	943	4,620	1,442	1,356	731	526	4,055
	729	2,075	1,787	964	5,555	2,082	1,339	1,492	557	5,470
TNK-BP <sup>a</sup>										
US	—	—	—	—	—	—	—	—	—	—
Non-US	543	490	730	854	2,617	1,127	1,081	939	987	4,134
	543	490	730	854	2,617	1,127	1,081	939	987	4,134
Rosneft <sup>b</sup>										
US	—	—	—	—	—	—	—	—	—	—
Non-US	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate										
US	(231)	(119)	(156)	(225)	(731)	(188)	(168)	(294)	(580)	(1,230)
Non-US	(97)	49	(412)	(325)	(785)	(286)	(433)	(35)	(484)	(1,238)
	(328)	(70)	(568)	(550)	(1,516)	(474)	(601)	(329)	(1,064)	(2,468)
	8,693	8,249	9,569	8,414	34,925	10,154	7,448	8,849	7,043	33,494
Gulf of Mexico oil spill response <sup>c</sup>	—	(32,192)	(7,656)	(1,010)	(40,858)	(384)	617	(541)	4,108	3,800
Consolidation adjustment – UPII <sup>d</sup>	208	98	85	56	447	(542)	515	(213)	127	(113)
<b>Total for period</b>	<b>8,901</b>	<b>(23,845)</b>	<b>1,998</b>	<b>7,460</b>	<b>(5,486)</b>	<b>9,228</b>	<b>8,580</b>	<b>8,095</b>	<b>11,278</b>	<b>37,181</b>
<b>By geographical area</b>										
US	2,590	(29,171)	(3,891)	385	(30,087)	1,813	1,361	1,141	5,887	10,202
Non-US	6,311	5,326	5,889	7,075	24,601	7,415	7,219	6,954	5,391	26,979
<b>Total for period</b>	<b>8,901</b>	<b>(23,845)</b>	<b>1,998</b>	<b>7,460</b>	<b>(5,486)</b>	<b>9,228</b>	<b>8,580</b>	<b>8,095</b>	<b>11,278</b>	<b>37,181</b>

<sup>a</sup> BP ceased equity accounting for its share of TNK-BP's earnings from 22 October 2012.

<sup>b</sup> BP's investment in Rosneft is accounted under the equity method from 21 March 2013.

<sup>c</sup> For more information see Gulf of Mexico oil spill.

<sup>d</sup> Consolidation adjustment – UPII is unrealized profit in inventory arising on inter-segment transactions.



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

\$ million														
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
2,534	(1,584)	1,178	4,790	<b>6,918</b>	908	590	1,192	935	<b>3,625</b>	623	1,316	1,257	1,129	<b>4,325</b>
4,449	4,497	3,729	2,898	<b>15,573</b>	4,654	3,810	2,966	1,602	<b>13,032</b>	4,036	2,733	2,054	(4,214)	<b>4,609</b>
6,983	2,913	4,907	7,688	<b>22,491</b>	5,562	4,400	4,158	2,537	<b>16,657</b>	4,659	4,049	3,311	(3,085)	<b>8,934</b>
158	(1,984)	1,106	478	<b>(242)</b>	713	759	(86)	(628)	<b>758</b>	502	717	660	380	<b>2,259</b>
701	252	1,302	851	<b>3,106</b>	934	257	702	268	<b>2,161</b>	292	216	571	400	<b>1,479</b>
859	(1,732)	2,408	1,329	<b>2,864</b>	1,647	1,016	616	(360)	<b>2,919</b>	794	933	1,231	780	<b>3,738</b>
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
1,064	452	1,282	575	<b>3,373</b>	12,500	–	–	–	<b>12,500</b>	–	–	–	–	–
1,064	452	1,282	575	<b>3,373</b>	12,500	–	–	–	<b>12,500</b>	–	–	–	–	–
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	–	–	85	218	792	1,058	<b>2,153</b>	518	1,024	107	451	<b>2,100</b>
–	–	–	–	–	85	218	792	1,058	<b>2,153</b>	518	1,024	107	451	<b>2,100</b>
(307)	(277)	(712)	(345)	<b>(1,641)</b>	(125)	(276)	(606)	(242)	<b>(1,249)</b>	(100)	(222)	(246)	(386)	<b>(954)</b>
(364)	(245)	(384)	(160)	<b>(1,153)</b>	(342)	(297)	(68)	(363)	<b>(1,070)</b>	(397)	(212)	(186)	(261)	<b>(1,056)</b>
(671)	(522)	(1,096)	(505)	<b>(2,794)</b>	(467)	(573)	(674)	(605)	<b>(2,319)</b>	(497)	(434)	(432)	(647)	<b>(2,010)</b>
8,235	1,111	7,501	9,087	<b>25,934</b>	19,327	5,061	4,892	2,630	<b>31,910</b>	5,474	5,572	4,217	(2,501)	<b>12,762</b>
30	(843)	(56)	(4,126)	<b>(4,995)</b>	(22)	(199)	(30)	(179)	<b>(430)</b>	(29)	(251)	(33)	(468)	<b>(781)</b>
(541)	457	(64)	(428)	<b>(576)</b>	427	129	263	(240)	<b>579</b>	90	(76)	370	257	<b>641</b>
7,724	725	7,381	4,533	<b>20,363</b>	19,732	4,991	5,125	2,211	<b>32,059</b>	5,535	5,245	4,554	(2,712)	<b>12,622</b>
1,935	(4,246)	1,422	1,069	<b>180</b>	1,727	1,156	530	(299)	<b>3,114</b>	1,125	1,643	1,800	683	<b>5,251</b>
5,789	4,971	5,959	3,464	<b>20,183</b>	18,005	3,835	4,595	2,510	<b>28,945</b>	4,410	3,602	2,754	(3,395)	<b>7,371</b>
7,724	725	7,381	4,533	<b>20,363</b>	19,732	4,991	5,125	2,211	<b>32,059</b>	5,535	5,245	4,554	(2,712)	<b>12,622</b>

## Underlying replacement cost profit (loss) before interest and tax by segment and geographical area

	Q1	Q2	Q3	Q4	2010	Q1	Q2	Q3	Q4	2011
<b>By segment</b>										
Upstream										
US	2,743	1,989	1,835	1,786	8,353	1,846	1,479	1,473	1,310	6,108
Non-US	4,902	3,826	3,976	4,016	16,720	4,834	4,849	4,813	4,613	19,109
	7,645	5,815	5,811	5,802	25,073	6,680	6,328	6,286	5,923	25,217
Downstream										
US	(76)	569	65	6	564	704	151	927	196	1,978
Non-US	865	1,155	1,561	738	4,319	1,495	1,241	738	557	4,031
	789	1,724	1,626	744	4,883	2,199	1,392	1,665	753	6,009
TNK-BP <sup>a</sup>										
US	—	—	—	—	—	—	—	—	—	—
Non-US	543	490	730	854	2,617	1,127	1,081	939	987	4,134
	543	490	730	854	2,617	1,127	1,081	939	987	4,134
Rosneft <sup>b</sup>										
US	—	—	—	—	—	—	—	—	—	—
Non-US	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
Other businesses and corporate										
US	(125)	(112)	(85)	(171)	(493)	(189)	(156)	(182)	(270)	(797)
Non-US	(85)	(29)	(397)	(312)	(823)	(104)	(182)	(223)	(340)	(849)
	(210)	(141)	(482)	(483)	(1,316)	(293)	(338)	(405)	(610)	(1,646)
Consolidation adjustment – UPII <sup>c</sup>	208	98	85	56	447	(542)	515	(213)	127	(113)
<b>Total for period</b>	<b>8,975</b>	<b>7,986</b>	<b>7,770</b>	<b>6,973</b>	<b>31,704</b>	<b>9,171</b>	<b>8,978</b>	<b>8,272</b>	<b>7,180</b>	<b>33,601</b>
<b>By geographical area</b>										
US	2,664	3,031	1,914	1,698	9,307	2,231	1,672	2,001	1,406	7,310
Non-US	6,311	4,955	5,856	5,275	22,397	6,940	7,306	6,271	5,774	26,291
<b>Total for period</b>	<b>8,975</b>	<b>7,986</b>	<b>7,770</b>	<b>6,973</b>	<b>31,704</b>	<b>9,171</b>	<b>8,978</b>	<b>8,272</b>	<b>7,180</b>	<b>33,601</b>

<sup>a</sup> BP ceased equity accounting for its share of TNK-BP's earnings from 22 October 2012.

<sup>b</sup> BP's investment in Rosneft is accounted under the equity method from 21 March 2013.

<sup>c</sup> Consolidation adjustment – UPII is unrealized profit in inventory arising on inter-segment transactions.

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

														\$ million
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
1,658	628	741	827	<b>3,854</b>	954	561	1,271	1,050	<b>3,836</b>	731	1,419	1,181	1,007	<b>4,338</b>
4,636	3,773	3,625	3,548	<b>15,582</b>	4,748	3,727	3,152	2,802	<b>14,429</b>	3,670	3,236	2,718	1,239	<b>10,863</b>
6,294	4,401	4,366	4,375	<b>19,436</b>	5,702	4,288	4,423	3,852	<b>18,265</b>	4,401	4,655	3,899	2,246	<b>15,201</b>
289	450	1,723	583	<b>3,045</b>	750	557	(22)	(162)	<b>1,123</b>	412	331	603	338	<b>1,684</b>
638	683	1,286	811	<b>3,418</b>	891	644	742	232	<b>2,509</b>	599	402	881	875	<b>2,757</b>
927	1,133	3,009	1,394	<b>6,463</b>	1,641	1,201	720	70	<b>3,632</b>	1,011	733	1,484	1,213	<b>4,441</b>
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
1,157	452	1,294	224	<b>3,127</b>	—	—	—	—	—	—	—	—	—	—
1,157	452	1,294	224	<b>3,127</b>	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	85	218	808	1,087	<b>2,198</b>	271	1,024	110	470	<b>1,875</b>
—	—	—	—	—	85	218	808	1,087	<b>2,198</b>	271	1,024	110	470	<b>1,875</b>
(165)	(185)	(218)	(291)	<b>(859)</b>	(121)	(142)	(309)	(228)	<b>(800)</b>	(99)	(226)	(102)	(167)	<b>(594)</b>
(270)	(355)	(355)	(157)	<b>(1,137)</b>	(340)	(296)	(76)	(386)	<b>(1,098)</b>	(390)	(212)	(191)	47	<b>(746)</b>
(435)	(540)	(573)	(448)	<b>(1,996)</b>	(461)	(438)	(385)	(614)	<b>(1,898)</b>	(489)	(438)	(293)	(120)	<b>(1,340)</b>
(541)	457	(64)	(428)	<b>(576)</b>	427	129	263	(240)	<b>579</b>	90	(76)	370	257	<b>641</b>
7,402	5,903	8,032	5,117	<b>26,454</b>	7,394	5,398	5,829	4,155	<b>22,776</b>	5,284	5,898	5,570	4,066	<b>20,818</b>
1,302	1,335	2,152	1,391	<b>6,180</b>	1,836	1,258	1,000	475	<b>4,569</b>	1,173	1,607	1,844	1,206	<b>5,830</b>
6,100	4,568	5,880	3,726	<b>20,274</b>	5,558	4,140	4,829	3,680	<b>18,207</b>	4,111	4,291	3,726	2,860	<b>14,988</b>
7,402	5,903	8,032	5,117	<b>26,454</b>	7,394	5,398	5,829	4,155	<b>22,776</b>	5,284	5,898	5,570	4,066	<b>20,818</b>

## Non-operating items<sup>a</sup> by segment

	Q1	Q2	Q3	Q4	2010	Q1	Q2	Q3	Q4	2011
<b>Upstream</b>										
Impairment and gain (loss) on sale of businesses and fixed assets	(13)	660	1,735	1,430	3,812	1,089	(403)	321	1,124	2,131
Environmental and other provisions	—	—	(54)	—	(54)	—	—	(25)	(2)	(27)
Restructuring, integration and rationalization costs	(104)	(13)	(6)	(14)	(137)	—	—	1	(1)	—
Fair value gain (loss) on embedded derivatives	146	(452)	20	(23)	(309)	(328)	142	211	166	191
Other <sup>b</sup>	12	(134)	46	(37)	(113)	(51)	(403)	(8)	(703)	(1,165)
	41	61	1,741	1,356	3,199	710	(664)	500	584	1,130
<b>Downstream</b>										
Impairment and gain (loss) on sale of businesses and fixed assets <sup>c,d</sup>	(45)	270	507	145	877	5	(207)	(16)	(114)	(332)
Environmental and other provisions	—	—	(83)	(15)	(98)	—	(2)	(193)	(26)	(221)
Restructuring, integration and rationalization costs	12	(30)	(32)	(47)	(97)	(1)	(4)	(12)	13	(4)
Fair value gain (loss) on embedded derivatives	—	—	—	—	—	—	—	—	—	—
Other	(37)	(8)	(10)	3	(52)	(21)	(4)	(6)	(14)	(45)
	(70)	232	382	86	630	(17)	(217)	(227)	(141)	(602)
<b>TNK-BP</b>										
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	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
<b>Rosneft</b>										
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	—	—	—	—	—	—	—	—	—	—
	—	—	—	—	—	—	—	—	—	—
<b>Other businesses and corporate</b>										
Impairment and gain (loss) on sale of businesses and fixed assets	(68)	97	(1)	(23)	5	35	4	274	(38)	275
Environmental and other provisions	—	(4)	(77)	(22)	(103)	—	(12)	(135)	(73)	(220)
Restructuring, integration and rationalization costs	(38)	(22)	(8)	(13)	(81)	1	2	(18)	(24)	(39)
Fair value gain (loss) on embedded derivatives	—	—	—	—	—	(217)	7	87	—	(123)
Other	(12)	—	—	(9)	(21)	—	(264)	(132)	(319)	(715)
	(118)	71	(86)	(67)	(200)	(181)	(263)	76	(454)	(822)
<b>Gulf of Mexico oil spill response</b>	—	(32,192)	(7,656)	(1,010)	(40,858)	(384)	617	(541)	4,108	3,800
<b>Total before interest and taxation</b>	(147)	(31,828)	(5,619)	365	(37,229)	128	(527)	(192)	4,097	3,506
<b>Finance costs<sup>e</sup></b>	—	—	(47)	(30)	(77)	(16)	(15)	(14)	(13)	(58)
<b>Total before taxation</b>	(147)	(31,828)	(5,666)	335	(37,306)	112	(542)	(206)	4,084	3,448
<b>Taxation credit (charge)<sup>f</sup></b>	50	9,877	2,097	(167)	11,857	44	160	9	(1,466)	(1,253)
<b>Total after taxation</b>	(97)	(21,951)	(3,569)	168	(25,449)	156	(382)	(197)	2,618	2,195

<sup>a</sup> Non-operating items are charges and credits arising in consolidated entities and in TNK-BP and Rosneft that are included in the financial statements and that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers not to be part of underlying business operations and are disclosed in order to enable investors better to understand and evaluate the group's reported financial performance.

<sup>b</sup> Third quarter, fourth quarter and full year 2014 include write-offs of \$375 million, \$20 million and \$395 million respectively relating to Block KG D6 in India. Fourth quarter and full year 2013 include \$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.

<sup>c</sup> 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.

<sup>d</sup> Included within the line item in the income statement for Impairment and losses on sale of businesses and fixed assets is a net impairment loss for the fourth quarter and full year 2014 of \$6,491 million and \$8,216 million respectively. The fourth-quarter net impairment loss comprised \$5,663 million in Upstream, \$517 million in Downstream, and \$311 million in Other businesses and corporate. The full-year net impairment loss comprised \$6,635 million in Upstream, \$1,264 million in Downstream, and \$317 million in Other businesses and corporate. The main elements of Upstream impairment losses were in the North Sea (fourth quarter 2014 \$4,518 million, and full year 2014 \$4,774 million) and in Angola (fourth quarter and full year 2014 \$968 million). The impairments arose for various reasons, including the impact of a lower price environment in the near term, technical reserves revisions, and increases in expected decommissioning cost estimates.

<sup>e</sup> Finance costs relate to the Gulf of Mexico oil spill. For more information see page 16.

<sup>f</sup> From the first quarter 2014, tax is based on statutory rates except for non-deductible or non-taxable items. For earlier periods tax for the Gulf of Mexico oil spill and certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives, 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 from the first quarter 2012 onwards and a deferred tax adjustment of \$99 million in the third quarter 2013 relating to a reduction in UK corporation tax rates, and changes to the taxation of UK oil and gas production (first quarter 2011 \$683 million and third quarter 2012 \$256 million)). For dividends received from TNK-BP in the fourth quarter 2012, there is no tax arising. Non-operating items reported within the equity-accounted earnings of TNK-BP and Rosneft are reported net of income tax.

Non-operating items<sup>a</sup> by segment continued

										\$ million				
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
928	(1,455)	492	3,673	<b>3,638</b>	(102)	65	(374)	(391)	<b>(802)</b>	(116)	(527)	(248)	(5,685)	<b>(6,576)</b>
–	–	(48)	–	<b>(48)</b>	–	–	(21)	1	<b>(20)</b>	–	–	(59)	(1)	<b>(60)</b>
–	–	–	–	–	–	–	–	–	–	–	–	–	(100)	<b>(100)</b>
(100)	271	73	103	<b>347</b>	31	135	238	55	<b>459</b>	98	32	113	187	<b>430</b>
(6)	(311)	(1)	(430)	<b>(748)</b>	(9)	(57)	(69)	(866)	<b>(1,001)</b>	294	(21)	(307)	42	<b>8</b>
822	(1,495)	516	3,346	<b>3,189</b>	(80)	143	(226)	(1,201)	<b>(1,364)</b>	276	(516)	(501)	(5,557)	<b>(6,298)</b>
(85)	(2,653)	(115)	(81)	<b>(2,934)</b>	34	(310)	(11)	(61)	<b>(348)</b>	(255)	79	(400)	(614)	<b>(1,190)</b>
–	–	(171)	–	<b>(171)</b>	(9)	–	(132)	7	<b>(134)</b>	–	–	(128)	(5)	<b>(133)</b>
(12)	(12)	(21)	13	<b>(32)</b>	(2)	(2)	–	(11)	<b>(15)</b>	(1)	(1)	(5)	(158)	<b>(165)</b>
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
(9)	(13)	(8)	(5)	<b>(35)</b>	(4)	(11)	(14)	(9)	<b>(38)</b>	(22)	(28)	(19)	(13)	<b>(82)</b>
(106)	(2,678)	(315)	(73)	<b>(3,172)</b>	19	(323)	(157)	(74)	<b>(535)</b>	(278)	50	(552)	(790)	<b>(1,570)</b>
(93)	–	38	–	<b>(55)</b>	12,500	–	–	–	<b>12,500</b>	–	–	–	–	–
–	–	(50)	(33)	<b>(83)</b>	–	–	–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	384	<b>384</b>	–	–	–	–	–	–	–	–	–	–
(93)	–	(12)	351	<b>246</b>	12,500	–	–	–	<b>12,500</b>	–	–	–	–	–
–	–	–	–	–	–	–	(16)	(19)	<b>(35)</b>	247	–	(3)	(19)	<b>225</b>
–	–	–	–	–	–	–	–	(10)	<b>(10)</b>	–	–	–	–	–
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
–	–	–	–	–	–	–	(16)	(29)	<b>(45)</b>	247	–	(3)	(19)	<b>225</b>
(50)	29	(253)	(8)	<b>(282)</b>	(1)	(129)	(87)	21	<b>(196)</b>	(6)	4	6	(308)	<b>(304)</b>
(15)	–	(246)	–	<b>(261)</b>	–	(6)	(216)	(19)	<b>(241)</b>	–	–	(145)	(35)	<b>(180)</b>
–	(1)	–	(14)	<b>(15)</b>	(2)	–	(4)	3	<b>(3)</b>	(1)	–	–	(175)	<b>(176)</b>
1	(1)	(1)	1	–	–	–	–	–	–	–	–	–	–	–
(172)	(9)	(23)	(36)	<b>(240)</b>	(3)	–	18	4	<b>19</b>	(1)	–	–	(9)	<b>(10)</b>
(236)	18	(523)	(57)	<b>(798)</b>	(6)	(135)	(289)	9	<b>(421)</b>	(8)	4	(139)	(527)	<b>(670)</b>
30	(843)	(56)	(4,126)	<b>(4,995)</b>	(22)	(199)	(30)	(179)	<b>(430)</b>	(29)	(251)	(33)	(468)	<b>(781)</b>
417	(4,998)	(390)	(559)	<b>(5,530)</b>	12,411	(514)	(718)	(1,474)	<b>9,705</b>	208	(713)	(1,228)	(7,361)	<b>(9,094)</b>
(6)	(4)	(3)	(6)	<b>(19)</b>	(10)	(10)	(9)	(10)	<b>(39)</b>	(10)	(9)	(10)	(9)	<b>(38)</b>
411	(5,002)	(393)	(565)	<b>(5,549)</b>	12,401	(524)	(727)	(1,484)	<b>9,666</b>	198	(722)	(1,238)	(7,370)	<b>(9,132)</b>
(226)	1,663	72	(1,258)	<b>251</b>	23	158	205	481	<b>867</b>	26	241	440	3,805	<b>4,512</b>
185	(3,339)	(321)	(1,823)	<b>(5,298)</b>	12,424	(366)	(522)	(1,003)	<b>10,533</b>	224	(481)	(798)	(3,565)	<b>(4,620)</b>

## Non-operating items by geographical area

	Q1	Q2	Q3	Q4	2010	Q1	Q2	Q3	Q4	2011
Upstream <sup>a</sup>										
US	(62)	(156)	1,681	(273)	1,190	4	(730)	(32)	831	73
Non-US <sup>b</sup>	103	217	60	1,629	2,009	706	66	532	(247)	1,057
	41	61	1,741	1,356	3,199	710	(664)	500	584	1,130
Downstream <sup>a</sup>										
US <sup>c</sup>	(3)	151	216	(12)	352	(16)	(239)	(184)	(124)	(563)
Non-US	(67)	81	166	98	278	(1)	22	(43)	(17)	(39)
	(70)	232	382	86	630	(17)	(217)	(227)	(141)	(602)
TNK-BP										
US	–	–	–	–	–	–	–	–	–	–
Non-US	–	–	–	–	–	–	–	–	–	–
Rosneft										
US	–	–	–	–	–	–	–	–	–	–
Non-US	–	–	–	–	–	–	–	–	–	–
Other businesses and corporate <sup>a</sup>										
US	(106)	(7)	(71)	(54)	(238)	1	(12)	(112)	(310)	(433)
Non-US	(12)	78	(15)	(13)	38	(182)	(251)	188	(144)	(389)
	(118)	71	(86)	(67)	(200)	(181)	(263)	76	(454)	(822)
Gulf of Mexico oil spill response	–	(32,192)	(7,656)	(1,010)	(40,858)	(384)	617	(541)	4,108	3,800
Total before interest and taxation	(147)	(31,828)	(5,619)	365	(37,229)	128	(527)	(192)	4,097	3,506
Finance costs <sup>d</sup>	–	–	(47)	(30)	(77)	(16)	(15)	(14)	(13)	(58)
Total before taxation	(147)	(31,828)	(5,666)	335	(37,306)	112	(542)	(206)	4,084	3,448
Taxation credit (charge) <sup>e</sup>	50	9,877	2,097	(167)	11,857	44	160	9	(1,466)	(1,253)
Total after taxation	(97)	(21,951)	(3,569)	168	(25,449)	156	(382)	(197)	2,618	2,195

<sup>a</sup> Included within the line item in the income statement for impairment and losses on sale of businesses and fixed assets is a net impairment loss for the fourth quarter and full year 2014 of \$6,491 million and \$8,216 million respectively. The fourth-quarter net impairment loss comprised \$5,663 million in Upstream, \$517 million in Downstream, and \$311 million in Other businesses and corporate. The full-year net impairment loss comprised \$6,635 million in Upstream, \$1,264 million in Downstream, and \$317 million in Other businesses and corporate. The main elements of Upstream impairment losses were in the North Sea (fourth quarter 2014 \$4,518 million and full year 2014 \$4,774 million) and in Angola (fourth quarter and full year 2014 \$968 million). The impairments arose for various reasons, including the impact of a lower price environment in the near term, technical reserves revisions, and increases in expected decommissioning cost estimates.

<sup>b</sup> Third quarter, fourth quarter and full year 2014 include write-offs of \$375 million, \$20 million and \$395 million respectively relating to Block KG D6 in India. This is classified in the 'other' category of non-operating items (see page 10). In addition, impairment charges of \$395 million, \$20 million and \$415 million for the same periods were also recorded in relation to this block. Fourth quarter and full year 2013 include an \$845-million write-off relating to the value ascribed to block BM-CAL-13 offshore Brazil as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011 and \$216 million of costs relating to the Pitanga exploration well, which was drilled in this block and did not encounter commercial quantities of oil or gas. The \$845-million write-off has been classified in the 'other' category of non-operating items (see page 10).

<sup>c</sup> 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.

<sup>d</sup> Finance costs relate to the Gulf of Mexico oil spill. For more information see page 16-17.

<sup>e</sup> From the first quarter 2014, tax is based on statutory rates except for non-deductible or non-taxable items. For earlier periods tax for the Gulf of Mexico oil spill and certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives 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 from the first quarter 2012 onwards and a deferred tax adjustment of \$99 million in the third quarter 2013 relating to a reduction in UK corporation tax rates, and changes to the taxation of UK oil and gas production (first quarter 2011 \$683 million and third quarter 2012 \$256 million)). For dividends received from TNK-BP in the fourth quarter 2012, there is no tax arising. Non-operating items reported within the equity-accounted earnings of TNK-BP and Rosneft are reported net of income tax.

## Non-operating items by geographical area continued

										\$ million				
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
947	(2,273)	465	3,992	<b>3,131</b>	(6)	62	5	(3)	<b>58</b>	(59)	(72)	125	(30)	<b>(36)</b>
(125)	778	51	(646)	<b>58</b>	(74)	81	(231)	(1,198)	<b>(1,422)</b>	335	(444)	(626)	(5,527)	<b>(6,262)</b>
822	(1,495)	516	3,346	<b>3,189</b>	(80)	143	(226)	(1,201)	<b>(1,364)</b>	276	(516)	(501)	(5,557)	<b>(6,298)</b>
(88)	(2,433)	(229)	(96)	<b>(2,846)</b>	28	(17)	(145)	(20)	<b>(154)</b>	(1)	180	(181)	(337)	<b>(339)</b>
(18)	(245)	(86)	23	<b>(326)</b>	(9)	(306)	(12)	(54)	<b>(381)</b>	(277)	(130)	(371)	(453)	<b>(1,231)</b>
(106)	(2,678)	(315)	(73)	<b>(3,172)</b>	19	(323)	(157)	(74)	<b>(535)</b>	(278)	50	(552)	(790)	<b>(1,570)</b>
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
(93)	—	(12)	351	<b>246</b>	12,500	—	—	—	<b>12,500</b>	—	—	—	—	—
(93)	—	(12)	351	<b>246</b>	12,500	—	—	—	<b>12,500</b>	—	—	—	—	—
—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
—	—	—	—	—	—	—	(16)	(29)	<b>(45)</b>	247	—	(3)	(19)	<b>225</b>
—	—	—	—	—	—	—	(16)	(29)	<b>(45)</b>	247	—	(3)	(19)	<b>225</b>
(142)	(92)	(494)	(54)	<b>(782)</b>	(4)	(134)	(297)	(14)	<b>(449)</b>	(1)	4	(144)	(219)	<b>(360)</b>
(94)	110	(29)	(3)	<b>(16)</b>	(2)	(1)	8	23	<b>28</b>	(7)	—	5	(308)	<b>(310)</b>
(236)	18	(523)	(57)	<b>(798)</b>	(6)	(135)	(289)	9	<b>(421)</b>	(8)	4	(139)	(527)	<b>(670)</b>
30	(843)	(56)	(4,126)	<b>(4,995)</b>	(22)	(199)	(30)	(179)	<b>(430)</b>	(29)	(251)	(33)	(468)	<b>(781)</b>
417	(4,998)	(390)	(559)	<b>(5,530)</b>	12,411	(514)	(718)	(1,474)	<b>9,705</b>	208	(713)	(1,228)	(7,361)	<b>(9,094)</b>
(6)	(4)	(3)	(6)	<b>(19)</b>	(10)	(10)	(9)	(10)	<b>(39)</b>	(10)	(9)	(10)	(9)	<b>(38)</b>
411	(5,002)	(393)	(565)	<b>(5,549)</b>	12,401	(524)	(727)	(1,484)	<b>9,666</b>	198	(722)	(1,238)	(7,370)	<b>(9,132)</b>
(226)	1,663	72	(1,258)	<b>251</b>	23	158	205	481	<b>867</b>	26	241	440	3,805	<b>4,512</b>
185	(3,339)	(321)	(1,823)	<b>(5,298)</b>	12,424	(366)	(522)	(1,003)	<b>10,533</b>	224	(481)	(798)	(3,565)	<b>(4,620)</b>

## 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 historical cost. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in the income statement. This is because hedge accounting is either not permitted or not followed, principally due to the impracticability 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	2010	Q1	Q2	Q3	Q4	2011
<b>By segment</b>										
Upstream	63	(122)	68	(12)	(3)	29	(35)	(39)	56	11
Downstream	10	119	(221)	134	42	(100)	164	54	(55)	63
	73	(3)	(153)	122	39	(71)	129	15	1	74
	(25)	1	38	(40)	(26)	22	(44)	(5)	–	(27)
<b>Taxation credit (charge)<sup>a</sup></b>	<b>48</b>	<b>(2)</b>	<b>(115)</b>	<b>82</b>	<b>13</b>	<b>(49)</b>	<b>85</b>	<b>10</b>	<b>1</b>	<b>47</b>
<b>By geographical area</b>										
Upstream										
US	81	(35)	86	9	141	25	(18)	(9)	17	15
Non-US	(18)	(87)	(18)	(21)	(144)	4	(17)	(30)	39	(4)
	63	(122)	68	(12)	(3)	29	(35)	(39)	56	11
Downstream										
US	16	37	(61)	27	19	(48)	71	18	(41)	–
Non-US	(6)	82	(160)	107	23	(52)	93	36	(14)	63
	10	119	(221)	134	42	(100)	164	54	(55)	63

<sup>a</sup> From the first quarter 2014, tax is calculated using statutory rates. For earlier periods tax is calculated using the group's discrete quarterly effective tax rate (adjusted for certain non-operating items, equity-accounted earnings and a deferred tax adjustment in the third quarter 2013 relating to a reduction in UK corporation tax rates).

## Total of non-operating items and fair value accounting effects

	Q1	Q2	Q3	Q4	2010	Q1	Q2	Q3	Q4	2011
<b>Upstream<sup>a</sup></b>										
US	19	(191)	1,767	(264)	1,331	29	(748)	(41)	848	88
Non-US <sup>b</sup>	85	130	42	1,608	1,865	710	49	502	(208)	1,053
	104	(61)	1,809	1,344	3,196	739	(699)	461	640	1,141
<b>Downstream<sup>a</sup></b>										
US <sup>c</sup>	13	188	155	15	371	(64)	(168)	(166)	(165)	(563)
Non-US	(73)	163	6	205	301	(53)	115	(7)	(31)	24
	(60)	351	161	220	672	(117)	(53)	(173)	(196)	(539)
<b>TNK-BP</b>										
US	–	–	–	–	–	–	–	–	–	–
Non-US	–	–	–	–	–	–	–	–	–	–
<b>Rosneft</b>										
US	–	–	–	–	–	–	–	–	–	–
Non-US	–	–	–	–	–	–	–	–	–	–
<b>Other businesses and corporate<sup>a</sup></b>										
US	(106)	(7)	(71)	(54)	(238)	1	(12)	(112)	(310)	(433)
Non-US	(12)	78	(15)	(13)	38	(182)	(251)	188	(144)	(389)
	(118)	71	(86)	(67)	(200)	(181)	(263)	76	(454)	(822)
<b>Gulf of Mexico oil spill response</b>										
Total before interest and taxation	–	(32,192)	(7,656)	(1,010)	(40,858)	(384)	617	(541)	4,108	3,800
Finance costs <sup>d</sup>	(74)	(31,831)	(5,772)	487	(37,190)	57	(398)	(177)	4,098	3,580
Total before taxation	–	–	(47)	(30)	(77)	(16)	(15)	(14)	(13)	(58)
Taxation credit (charge) <sup>e</sup>	(74)	(31,831)	(5,819)	457	(37,267)	41	(413)	(191)	4,085	3,522
	25	9,878	2,135	(207)	11,831	66	116	4	(1,466)	(1,280)
<b>Total after taxation for period</b>	<b>(49)</b>	<b>(21,953)</b>	<b>(3,684)</b>	<b>250</b>	<b>(25,436)</b>	<b>107</b>	<b>(297)</b>	<b>(187)</b>	<b>2,619</b>	<b>2,242</b>

<sup>a</sup> Included within the line item in the income statement for impairment and losses on sale of businesses and fixed assets is a net impairment loss for the fourth quarter and full year 2014 of \$6,491 million and \$8,216 million respectively. The fourth-quarter net impairment loss comprised \$5,663 million in Upstream, \$517 million in Downstream, and \$311 million in Other businesses and corporate. The full-year net impairment loss comprised \$6,635 million in Upstream, \$1,264 million in Downstream, and \$317 million in Other businesses and corporate. The main elements of Upstream impairment losses were in the North Sea (fourth quarter 2014 \$4,518 million and full year 2014 \$4,774 million) and in Angola (fourth quarter and full year 2014 \$968 million). The impairments arose for various reasons, including the impact of a lower price environment in the near term, technical reserves revisions, and increases in expected decommissioning cost estimates.

<sup>b</sup> Third quarter, fourth quarter and full year 2014 include write-offs of \$375 million, \$20 million and \$395 million respectively relating to Block KG D6 in India. This is classified in the 'other' category of non-operating items (see page 10). In addition, impairment charges of \$395 million, \$20 million and \$415 million for the same periods were also recorded in relation to this block. Fourth quarter and full year 2013 include an \$845-million write-off relating to the value ascribed to block BM-CAL-13 offshore Brazil as part of the accounting for the acquisition of upstream assets from Devon Energy in 2011 and \$216 million of costs relating to the Pitanga exploration well, which was drilled in this block and did not encounter commercial quantities of oil or gas. The \$845-million write-off has been classified in the 'other' category of non-operating items (see page 10).

<sup>c</sup> 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.

<sup>d</sup> Finance costs relate to the Gulf of Mexico oil spill. For more information see page 16.

<sup>e</sup> From the first quarter 2014, tax is based on statutory rates except for non-deductible or non-taxable items. For earlier periods tax for the Gulf of Mexico oil spill and certain impairment losses, disposal gains and fair value gains and losses on embedded derivatives, 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 from the first quarter 2012 onwards and a deferred tax adjustment of \$99 million in the third quarter 2013 relating to a reduction in UK corporation tax rates, and changes to the taxation of UK oil and gas production (first quarter 2011 \$683 million and third quarter 2012 \$256 million)). For dividends received from TNK-BP in the fourth quarter 2012, there is no tax arising. Non-operating items reported within the equity-accounted earnings of TNK-BP and Rosneft are

Group information



## 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, that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance. Under management's internal measure of performance the inventory 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 the underlying exposure and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management's internal measure of performance, are shown in the table below. A reconciliation to GAAP information is also set out below.

										\$ million				
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
(133)	7	25	(33)	(134)	(60)	(31)	(39)	(114)	(244)	(18)	(90)	(87)	226	31
38	(187)	(286)	8	(427)	(13)	138	53	(356)	(178)	61	150	299	357	867
(95)	(180)	(261)	(25)	(561)	(73)	107	14	(470)	(422)	43	60	212	583	898
40	72	99	5	216	30	(53)	(6)	171	142	(17)	(32)	(66)	(226)	(341)
(55)	(108)	(162)	(20)	(345)	(43)	54	8	(299)	(280)	26	28	146	357	557
(71)	61	(28)	(29)	(67)	(40)	(33)	(84)	(112)	(269)	(49)	(31)	(49)	152	23
(62)	(54)	53	(4)	(67)	(20)	2	45	(2)	25	31	(59)	(38)	74	8
(133)	7	25	(33)	(134)	(60)	(31)	(39)	(114)	(244)	(18)	(90)	(87)	226	31
(43)	(1)	(388)	(9)	(441)	(65)	219	81	(446)	(211)	91	206	238	379	914
81	(186)	102	17	14	52	(81)	(28)	90	33	(30)	(56)	61	(22)	(47)
38	(187)	(286)	8	(427)	(13)	138	53	(356)	(178)	61	150	299	357	867

										\$ million				
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
876	(2,212)	437	3,963	3,064	(46)	29	(79)	(115)	(211)	(108)	(103)	76	122	(13)
(187)	724	104	(650)	(9)	(94)	83	(186)	(1,200)	(1,397)	366	(503)	(664)	(5,453)	(6,254)
689	(1,488)	541	3,313	3,055	(140)	112	(265)	(1,315)	(1,608)	258	(606)	(588)	(5,331)	(6,267)
(131)	(2,434)	(617)	(105)	(3,287)	(37)	202	(64)	(466)	(365)	90	386	57	42	575
63	(431)	16	40	(312)	43	(387)	(40)	36	(348)	(307)	(186)	(310)	(475)	(1,278)
(68)	(2,865)	(601)	(65)	(3,599)	6	(185)	(104)	(430)	(713)	(217)	200	(253)	(433)	(703)
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
(93)	-	(12)	351	246	12,500	-	-	-	12,500	-	-	-	-	-
(93)	-	(12)	351	246	12,500	-	-	-	12,500	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	(16)	(29)	(45)	247	-	(3)	(19)	225
-	-	-	-	-	-	-	(16)	(29)	(45)	247	-	(3)	(19)	225
(142)	(92)	(494)	(54)	(782)	(4)	(134)	(297)	(14)	(449)	(1)	4	(144)	(219)	(360)
(94)	110	(29)	(3)	(16)	(2)	(1)	8	23	28	(7)	-	5	(308)	(310)
(236)	18	(523)	(57)	(798)	(6)	(135)	(289)	9	(421)	(8)	4	(139)	(527)	(670)
30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)	(29)	(251)	(33)	(468)	(781)
322	(5,178)	(651)	(584)	(6,091)	12,338	(407)	(704)	(1,944)	9,283	251	(653)	(1,016)	(6,778)	(8,196)
(6)	(4)	(3)	(6)	(19)	(10)	(10)	(9)	(10)	(39)	(10)	(9)	(10)	(9)	(38)
316	(5,182)	(654)	(590)	(6,110)	12,328	(417)	(713)	(1,954)	9,244	241	(662)	(1,026)	(6,787)	(8,234)
(186)	1,735	171	(1,253)	467	53	105	199	652	1,009	9	209	374	3,579	4,171
130	(3,447)	(483)	(1,843)	(5,643)	12,381	(312)	(514)	(1,302)	10,253	250	(453)	(652)	(3,208)	(4,063)

## Gulf of Mexico oil spill

	Q1	Q2	Q3	Q4	2010	Q1	Q2	Q3	Q4	2011
<b>Income statement</b>										
Production and manufacturing expenses	–	32,192	7,656	1,010	<b>40,858</b>	384	(617)	541	(4,108)	<b>(3,800)</b>
Profit (loss) before interest and taxation	–	(32,192)	(7,656)	(1,010)	<b>(40,858)</b>	(384)	617	(541)	4,108	<b>3,800</b>
Finance costs	–	–	47	30	<b>77</b>	16	15	14	13	<b>58</b>
Profit (loss) before taxation	–	(32,192)	(7,703)	(1,040)	<b>(40,935)</b>	(400)	602	(555)	4,095	<b>3,742</b>
Less: taxation	–	10,003	2,604	287	<b>12,894</b>	201	(234)	115	(1,469)	<b>(1,387)</b>
Profit (loss) for the period	–	(22,189)	(5,099)	(753)	<b>(28,041)</b>	(199)	368	(440)	2,626	<b>2,355</b>
<b>Balance sheet</b>										
Current assets										
Trade and other receivables	–	6,233	6,663	5,943	<b>5,943</b>	5,981	7,170	5,598	8,487	<b>8,487</b>
Current liabilities										
Trade and other payables	–	(8,276)	(7,272)	(6,587)	<b>(6,587)</b>	(6,031)	(6,796)	(5,495)	(5,425)	<b>(5,425)</b>
Provisions	–	(11,809)	(11,343)	(7,938)	<b>(7,938)</b>	(7,379)	(7,414)	(7,078)	(9,437)	<b>(9,437)</b>
Net current liabilities	–	(13,852)	(11,952)	(8,582)	<b>(8,582)</b>	(7,429)	(7,040)	(6,975)	(6,375)	<b>(6,375)</b>
Non-current assets										
Other receivables	–	1,693	352	3,601	<b>3,601</b>	3,563	2,667	2,278	1,642	<b>1,642</b>
Non-current liabilities										
Other payables	–	(12,080)	(11,010)	(9,899)	<b>(9,899)</b>	(8,667)	(6,307)	(5,071)	–	<b>–</b>
Accruals	–	–	–	–	<b>–</b>	–	–	–	–	<b>–</b>
Provisions	–	(5,837)	(5,062)	(8,397)	<b>(8,397)</b>	(8,098)	(6,964)	(6,611)	(5,896)	<b>(5,896)</b>
Deferred tax	–	9,440	10,988	11,255	<b>11,255</b>	11,218	10,497	9,721	7,775	<b>7,775</b>
Net non-current assets (liabilities)	–	(6,784)	(4,732)	(3,440)	<b>(3,440)</b>	(1,984)	(107)	317	3,521	<b>3,521</b>
Net liabilities	–	(20,636)	(16,684)	(12,022)	<b>(12,022)</b>	(9,413)	(7,147)	(6,658)	(2,854)	<b>(2,854)</b>
<b>Cash flow statement – operating activities</b>										
Profit (loss) before taxation	–	(32,192)	(7,703)	(1,040)	<b>(40,935)</b>	(400)	602	(555)	4,095	<b>3,742</b>
Finance costs	–	–	47	30	<b>77</b>	16	15	14	13	<b>58</b>
Net charge for provisions, less payments	–	17,646	(409)	2,117	<b>19,354</b>	202	(90)	244	2,343	<b>2,699</b>
Movements in other current and non-current assets and liabilities	–	12,430	(2,042)	(6,542)	<b>3,846</b>	(2,864)	(2,912)	(1,523)	(8,106)	<b>(15,405)</b>
Pre-tax cash flows	–	(2,116)	(10,107)	(5,435)	<b>(17,658)</b>	(3,046)	(2,385)	(1,820)	(1,655)	<b>(8,906)</b>

Gulf of Mexico oil spill continued

\$ million														
Q1	Q2	Q3	Q4	2012	Q1	Q2	Q3	Q4	2013	Q1	Q2	Q3	Q4	2014
(30)	843	56	4,126	4,995	22	199	30	179	430	29	251	33	468	781
30	(843)	(56)	(4,126)	(4,995)	(22)	(199)	(30)	(179)	(430)	(29)	(251)	(33)	(468)	(781)
6	4	3	6	19	10	10	9	10	39	10	9	10	9	38
24	(847)	(59)	(4,132)	(5,014)	(32)	(209)	(39)	(189)	(469)	(39)	(260)	(43)	(477)	(819)
(26)	102	(51)	69	94	(5)	42	(44)	80	73	10	44	45	163	262
(2)	(745)	(110)	(4,063)	(4,920)	(37)	(167)	(83)	(109)	(396)	(29)	(216)	2	(314)	(557)
4,985	5,109	4,913	4,239	4,239	4,082	4,530	2,861	2,457	2,457	1,931	1,944	1,566	1,154	1,154
(3,800)	(2,377)	(1,118)	(522)	(522)	(1,082)	(1,063)	(1,029)	(1,030)	(1,030)	(887)	(838)	(653)	(655)	(655)
(5,877)	(6,177)	(6,181)	(5,449)	(5,449)	(4,810)	(5,183)	(3,457)	(2,951)	(2,951)	(2,375)	(2,345)	(1,942)	(1,702)	(1,702)
(4,692)	(3,445)	(2,386)	(1,732)	(1,732)	(1,810)	(1,716)	(1,625)	(1,524)	(1,524)	(1,331)	(1,239)	(1,029)	(1,203)	(1,203)
4,881	4,181	4,754	2,264	2,264	2,074	2,067	2,286	2,442	2,442	2,799	2,569	3,289	2,701	2,701
—	—	—	(175)	(175)	(3,160)	(3,144)	(2,977)	(2,986)	(2,986)	(2,404)	(2,397)	(2,406)	(2,412)	(2,412)
—	—	—	—	—	—	—	—	—	—	(161)	(170)	(166)	(169)	(169)
(9,048)	(8,745)	(8,909)	(9,751)	(9,751)	(5,984)	(6,057)	(6,159)	(6,395)	(6,395)	(6,701)	(6,653)	(7,328)	(6,903)	(6,903)
7,211	7,285	5,841	4,002	4,002	3,782	3,443	2,989	2,748	2,748	2,638	2,285	1,995	1,723	1,723
3,044	2,721	1,686	(3,660)	(3,660)	(3,288)	(3,691)	(3,861)	(4,191)	(4,191)	(3,829)	(4,366)	(4,616)	(5,060)	(5,060)
(1,648)	(724)	(700)	(5,392)	(5,392)	(5,098)	(5,407)	(5,486)	(5,715)	(5,715)	(5,160)	(5,605)	(5,645)	(6,263)	(6,263)
24	(847)	(59)	(4,132)	(5,014)	(32)	(209)	(39)	(189)	(469)	(39)	(260)	(43)	(477)	(819)
6	4	3	6	19	10	10	9	10	39	10	9	10	9	38
85	585	546	3,618	4,834	304	1,390	(576)	11	1,129	(97)	116	586	334	939
(1,861)	(1,439)	(2,017)	(771)	(6,088)	(828)	(1,430)	192	(33)	(2,099)	(578)	(33)	(846)	3	(1,454)
(1,746)	(1,697)	(1,527)	(1,279)	(6,249)	(546)	(239)	(414)	(201)	(1,400)	(704)	(168)	(293)	(131)	(1,296)

## Sales and other operating revenues

	\$ million				
	2010	2011	2012	2013	2014
<b>By segment</b>					
Upstream	66,266	75,754	72,225	70,374	65,424
Downstream	266,751	344,033	346,391	351,195	323,486
Other businesses and corporate	3,328	2,957	1,985	1,805	1,989
	336,345	422,744	420,601	423,374	390,899
<b>Less: sales and other operating revenues between segments</b>					
Upstream	37,049	44,766	42,572	42,327	36,643
Downstream	1,358	1,396	1,365	1,045	(173)
Other businesses and corporate	831	869	899	866	861
	39,238	47,031	44,836	44,238	37,331
<b>Third-party sales and other operating revenues</b>					
Upstream	29,217	30,988	29,653	28,047	28,781
Downstream	265,393	342,637	345,026	350,150	323,659
Other businesses and corporate	2,497	2,088	1,086	939	1,128
<b>Total third party sales and other operating revenues</b>	<b>297,107</b>	<b>375,713</b>	<b>375,765</b>	<b>379,136</b>	<b>353,568</b>
<b>By geographical area<sup>a</sup></b>					
US	107,256	140,223	138,304	137,539	132,310
Non-US	220,059	277,036	275,105	280,317	251,943
	327,315	417,259	413,409	417,856	384,253
<b>Less: sales and other operating revenues between areas</b>					
	30,208	41,546	37,644	38,720	30,685
	297,107	375,713	375,765	379,136	353,568

<sup>a</sup> A minor amendment has been made to the analysis by region for the comparative periods in 2013.

## Production and similar taxes

	\$ million				
	2010	2011	2012	2013	2014
Production and similar taxes provided for					
US	1,093	1,854	1,472	1,112	690
Non-US	4,151	6,426	6,686	5,935	2,268
	5,244	8,280	8,158	7,047	2,958
Production and similar taxes paid					
US	1,059	1,879	1,585	1,194	739
Non-US	4,402	6,425	6,997	6,403	2,454
	5,461	8,304	8,582	7,597	3,193

## Taxation

	\$ million				
	2010	2011	2012	2013	2014
Tax on profit (loss)					
Current tax charge	6,692	7,611	6,916	5,785	4,492
Deferred tax charge (credit)	(8,330)	5,008	(36)	678	(3,545)
Total tax on profit (loss)	(1,638)	12,619	6,880	6,463	947
Taxation (charge) credit on inventory holdings gains and losses	(589)	(834)	183	60	1,917
Tax on replacement cost profit (loss)	(2,227)	11,785	7,063	6,523	2,864
Effective tax rates on					
Replacement cost profit (loss) for the year	31%	33%	38%	21%	26%
Profit (loss) for the year	31%	33%	38%	21%	19%
Income taxes paid	6,610	8,063	6,482	6,307	4,787

## Depreciation, depletion and amortization

	\$ million				
	2010	2011	2012	2013	2014
<b>By segment</b>					
Upstream					
US	3,751	3,201	3,437	3,538	4,129
Non-US	4,865	5,540	6,918	7,514	8,404
	8,616	8,741	10,355	11,052	12,533
Downstream					
US	955	860	586	747	984
Non-US	1,303	1,431	1,343	1,343	1,336
	2,258	2,291	1,929	2,090	2,320
Other businesses and corporate					
US	140	151	213	181	97
Non-US	150	174	190	187	213
	290	325	403	368	310
	11,164	11,357	12,687	13,510	15,163
<b>By geographical area</b>					
US	4,846	4,212	4,236	4,466	5,210
Non-US	6,318	7,145	8,451	9,044	9,953
Total	11,164	11,357	12,687	13,510	15,163

## Group balance sheet

At 31 December	\$ million				
	2010	2011	2012	2013	2014
<b>Non-current assets</b>					
Property, plant and equipment	110,163	123,431	125,331	133,690	130,692
Goodwill	8,598	12,429	12,190	12,181	11,868
Intangible assets	14,298	21,653	24,632	22,039	20,907
Investments in joint ventures	14,927	8,303	8,614	9,199	8,753
Investments in associates	13,335	13,291	2,998	16,636	10,403
Other investments	1,689	2,635	2,704	1,565	1,228
<b>Fixed assets</b>	<b>163,010</b>	<b>181,742</b>	<b>176,469</b>	<b>195,310</b>	<b>183,851</b>
Loans	894	824	642	763	659
Trade and other receivables	6,298	5,738	5,961	5,985	4,787
Derivative financial instruments	4,210	5,038	4,294	3,509	4,442
Prepayments	934	739	830	922	964
Deferred tax assets	528	611	874	985	2,309
Defined benefit pension plan surpluses	2,176	17	12	1,376	31
	178,050	194,709	189,082	208,850	197,043
<b>Current assets</b>					
Loans	247	244	247	216	333
Inventories	26,218	26,073	28,203	29,231	18,373
Trade and other receivables	36,549	43,589	37,611	39,831	31,038
Derivative financial instruments	4,356	3,857	4,507	2,675	5,165
Prepayments	1,574	1,315	1,091	1,388	1,424
Current tax receivable	693	235	456	512	837
Other investments	1,532	288	319	467	329
Cash and cash equivalents	18,556	14,177	19,635	22,520	29,763
	89,725	89,778	92,069	96,840	87,262
<b>Assets classified as held for sale</b>	<b>4,487</b>	<b>8,420</b>	<b>19,315</b>	<b>–</b>	<b>–</b>
	94,212	98,198	111,384	96,840	87,262
<b>Total assets</b>	<b>272,262</b>	<b>292,907</b>	<b>300,466</b>	<b>305,690</b>	<b>284,305</b>
<b>Current liabilities</b>					
Trade and other payables	46,329	52,000	46,673	47,159	40,118
Derivative financial instruments	3,856	3,220	2,658	2,322	3,689
Accruals	5,612	6,016	6,875	8,960	7,102
Finance debt	14,626	9,039	10,033	7,381	6,877
Current tax payable	2,920	1,943	2,503	1,945	2,011
Provisions	9,489	11,238	7,587	5,045	3,818
	82,832	83,456	76,329	72,812	63,615
<b>Liabilities directly associated with assets classified as held for sale</b>	<b>1,047</b>	<b>538</b>	<b>846</b>	<b>–</b>	<b>–</b>
	83,879	83,994	77,175	72,812	63,615
<b>Non-current liabilities</b>					
Other payables	14,285	3,214	2,292	4,756	3,587
Derivative financial instruments	3,677	3,773	2,723	2,225	3,199
Accruals	637	400	491	547	861
Finance debt	30,710	35,169	38,767	40,811	45,977
Deferred tax liabilities	10,908	15,220	15,243	17,439	13,893
Provisions	22,418	26,462	30,396	26,915	29,080
Defined benefit pension plan and other post-retirement benefit plan deficits	9,857	12,090	13,627	9,778	11,451
	92,492	96,328	103,539	102,471	108,048
<b>Total liabilities</b>	<b>176,371</b>	<b>180,322</b>	<b>180,714</b>	<b>175,283</b>	<b>171,663</b>
<b>Net assets</b>	<b>95,891</b>	<b>112,585</b>	<b>119,752</b>	<b>130,407</b>	<b>112,642</b>
<b>Equity</b>					
BP shareholders' equity	94,987	111,568	118,546	129,302	111,441
Non-controlling interests	904	1,017	1,206	1,105	1,201
<b>Total equity</b>	<b>95,891</b>	<b>112,585</b>	<b>119,752</b>	<b>130,407</b>	<b>112,642</b>

## Operating capital employed<sup>a</sup>

	\$ million				
	2010	2011	2012	2013	2014
<b>By segment</b>					
Upstream					
US	40,065	41,347	38,437	41,320	40,971
Non-US	56,212	64,185	70,387	70,567	66,553
	96,277	105,532	108,824	111,887	107,524
Downstream					
US	23,463	24,627	24,835	23,835	19,079
Non-US	24,959	26,457	25,488	25,680	19,799
	48,422	51,084	50,323	49,515	38,878
TNK-BP					
US	—	—	—	—	—
Non-US	9,995	10,013	13,607	—	—
	9,995	10,013	13,607	—	—
Rosneft					
US	—	—	—	—	—
Non-US	—	—	—	13,681	7,312
	—	—	—	13,681	7,312
Other businesses and corporate					
US	(2,905)	(3,149)	(4,115)	(1,459)	(2,334)
Non-US	17,285	8,506	14,785	19,818	23,023
	14,380	5,357	10,670	18,359	20,689
Gulf of Mexico oil spill response	(23,277)	(10,629)	(9,394)	(8,464)	(7,985)
Consolidation adjustment	(561)	(676)	(1,252)	(673)	(32)
	145,236	160,681	172,778	184,305	166,386
<b>By geographical area</b>					
US	36,917	51,785	49,418	54,988	49,723
Non-US	108,319	108,896	123,360	129,317	116,663
Total operating capital employed <sup>a</sup>	145,236	160,681	172,778	184,305	166,386
Liabilities for current and deferred taxation	(12,607)	(16,317)	(16,416)	(17,887)	(12,758)
Goodwill	8,598	12,429	12,190	12,181	11,868
Capital employed	141,227	156,793	168,552	178,599	165,496
Financed by					
Finance debt	45,336	44,208	48,800	48,192	52,854
Non-controlling interests	904	1,017	1,206	1,105	1,201
BP shareholders' equity	94,987	111,568	118,546	129,302	111,441
Capital employed	141,227	156,793	168,552	178,599	165,496

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



## Property, plant and equipment

	\$ million				
	2010	2011	2012	2013	2014
<b>Net book amount by segment</b>					
Upstream					
US	37,230	41,385	38,671	39,363	41,215
Non-US	42,542	51,827	53,303	58,972	56,535
	79,772	93,212	91,974	98,335	97,750
Downstream					
US	14,151	11,833	14,603	16,467	16,033
Non-US	13,996	15,246	15,320	15,131	13,647
	28,147	27,079	29,923	31,598	29,680
Other businesses and corporate					
US	1,495	1,770	1,683	1,532	822
Non-US	749	1,370	1,751	2,225	2,440
	2,244	3,140	3,434	3,757	3,262
<b>Net book amount by geographical area</b>					
US	52,876	54,988	54,957	57,362	58,070
Non-US	57,287	68,443	70,374	76,328	72,622
	110,163	123,431	125,331	133,690	130,692
<b>Cost and accumulated depreciation</b>					
Upstream					
Cost	177,537	195,533	190,645	206,882	220,991
Accumulated depreciation	(97,765)	(102,321)	(98,671)	(108,547)	(123,241)
	79,772	93,212	91,974	98,335	97,750
Downstream					
Cost	52,843	48,929	53,117	56,867	55,665
Accumulated depreciation	(24,696)	(21,850)	(23,194)	(25,269)	(25,985)
	28,147	27,079	29,923	31,598	29,680
Other businesses and corporate					
Cost	3,859	4,460	5,142	5,707	5,045
Accumulated depreciation	(1,615)	(1,320)	(1,708)	(1,950)	(1,783)
	2,244	3,140	3,434	3,757	3,262
Group					
Cost	234,239	248,922	248,904	269,456	281,701
Accumulated depreciation	(124,076)	(125,491)	(123,573)	(135,766)	(151,009)
	110,163	123,431	125,331	133,690	130,692

## Analysis of inventories, receivables and payables

	\$ million				
	2010	2011	2012	2013	2014
<b>Inventories</b>					
Inventories	23,078	23,183	24,775	25,852	14,874
Supplies	1,669	2,075	2,428	2,735	3,051
	24,747	25,258	27,203	28,587	17,925
Trading inventories	1,471	815	1,000	644	448
	26,218	26,073	28,203	29,231	18,373
<b>Current receivables</b>					
Trade receivables	24,255	28,515	26,485	28,868	19,671
Amounts receivable from joint ventures	751	422	379	342	300
Amounts receivable from associates	448	492	492	871	1,258
Current tax receivable	693	235	456	512	837
Gulf of Mexico oil spill trust fund reimbursement asset	5,943	8,233	4,178	2,457	1,154
Other current receivables	12,861	11,631	12,241	12,039	15,906
	44,951	49,528	44,231	45,089	39,126
<b>Non-current receivables</b>					
Trade receivables	—	508	151	183	166
Amounts receivable from joint ventures	601	—	—	—	—
Amounts receivable from associates	220	159	102	47	—
Gulf of Mexico oil spill trust fund reimbursement asset	3,601	1,642	2,264	2,442	2,701
Other non-current receivables	7,914	10,030	9,210	8,507	7,985
	12,336	12,339	11,727	11,179	10,852
<b>Current payables</b>					
Trade payables	27,510	30,220	29,920	28,926	23,074
Amounts payable to joint ventures	1,361	62	133	51	129
Amounts payable to associates	712	876	972	3,525	2,307
Production and similar taxes	919	1,480	1,222	686	420
Current tax payable	2,920	1,943	2,503	1,945	2,011
Dividends	1	1	1	1	1
Gulf of Mexico oil spill trust fund liability	5,002	4,872	22	1	1
Other current payables	20,292	23,725	23,936	25,251	24,977
	58,717	63,179	58,709	60,386	52,920
<b>Non-current payables</b>					
Amounts payable to joint ventures	1,905	—	—	—	—
Amounts payable to associates	220	159	102	47	—
Production and similar taxes	471	283	242	317	369
Gulf of Mexico oil spill trust fund liability	9,899	—	—	—	—
Other non-current payables	6,104	6,945	5,162	7,164	7,278
	18,599	7,387	5,506	7,528	7,647

## Group cash flow statement

	\$ million				
	2010	2011	2012	2013	2014
<b>Operating activities</b>					
Profit (loss) before taxation <sup>a</sup>	(5,307)	38,228	18,131	30,221	<b>4,950</b>
Adjustments to reconcile profit (loss) before taxation to net cash provided by operating activities					
Exploration expenditure written off	375	1,024	745	2,710	<b>3,029</b>
Depreciation, depletion and amortization	11,164	11,357	12,687	13,510	<b>15,163</b>
Impairment and (gain) loss on sale of businesses and fixed assets	(4,694)	(2,074)	(422)	(11,154)	<b>8,070</b>
Earnings from joint ventures and associates	(4,757)	(5,683)	(3,935)	(3,189)	<b>(3,372)</b>
Dividends received from joint ventures and associates	3,277	5,040	1,763	1,391	<b>1,911</b>
Interest receivable	(277)	(284)	(379)	(314)	<b>(276)</b>
Interest received	206	210	175	173	<b>81</b>
Finance costs	1,170	1,187	1,072	1,068	<b>1,148</b>
Interest paid	(912)	(1,125)	(1,166)	(1,084)	<b>(937)</b>
Net finance expense relating to pensions and other post-retirement benefits	435	400	566	480	<b>314</b>
Share-based payments	197	(88)	156	297	<b>379</b>
Net operating charge for pensions and other post-retirement benefits, less contributions and benefit payments for unfunded plans	(959)	(1,003)	(858)	(920)	<b>(963)</b>
Net charge for provisions, less payments	19,217	2,988	5,338	1,061	<b>1,119</b>
(Increase) decrease in inventories	(3,895)	(4,079)	(1,720)	(1,193)	<b>10,169</b>
(Increase) decrease in other current and non-current assets	(15,620)	(9,860)	2,933	(2,718)	<b>3,566</b>
Increase (decrease) in other current and non-current liabilities	20,606	(5,957)	(8,125)	(2,932)	<b>(6,810)</b>
Income taxes paid	(6,610)	(8,063)	(6,482)	(6,307)	<b>(4,787)</b>
<b>Net cash provided by operating activities</b>	<b>13,616</b>	<b>22,218</b>	<b>20,479</b>	<b>21,100</b>	<b>32,754</b>
<b>Investing activities</b>					
Capital expenditure	(18,421)	(17,978)	(23,222)	(24,520)	<b>(22,546)</b>
Acquisitions, net of cash acquired	(2,468)	(10,909)	(116)	(67)	<b>(131)</b>
Investment in joint ventures	(461)	(855)	(1,526)	(451)	<b>(179)</b>
Investment in associates	(65)	(55)	(54)	(4,994)	<b>(336)</b>
Proceeds from disposals of fixed assets	7,492	3,504	9,992	18,115	<b>1,820</b>
Proceeds from disposals of businesses, net of cash disposed <sup>b</sup>	9,462	(663)	1,606	3,884	<b>1,671</b>
Proceeds from loan repayments	501	203	245	178	<b>127</b>
<b>Net cash used in investing activities</b>	<b>(3,960)</b>	<b>(26,753)</b>	<b>(13,075)</b>	<b>(7,855)</b>	<b>(19,574)</b>
<b>Financing activities</b>					
Net issue (repurchase) of shares	169	74	122	(5,358)	<b>(4,589)</b>
Proceeds from long-term financing	11,934	11,600	11,087	8,814	<b>12,394</b>
Repayments of long-term financing	(4,702)	(9,102)	(7,177)	(5,959)	<b>(6,282)</b>
Net increase (decrease) in short-term debt	(3,619)	2,222	(666)	(2,019)	<b>(693)</b>
Net increase (decrease) in non-controlling interests	—	—	—	32	<b>9</b>
Dividends paid					
BP shareholders	(2,627)	(4,072)	(5,294)	(5,441)	<b>(5,850)</b>
Non-controlling interests	(315)	(245)	(82)	(469)	<b>(255)</b>
<b>Net cash provided by (used in) financing activities</b>	<b>840</b>	<b>477</b>	<b>(2,010)</b>	<b>(10,400)</b>	<b>(5,266)</b>
Currency translation differences relating to cash and cash equivalents	(279)	(493)	64	40	<b>(671)</b>
Increase (decrease) in cash and cash equivalents	10,217	(4,551)	5,458	2,885	<b>7,243</b>
Cash and cash equivalents at beginning of year	8,339	18,728	14,177	19,635	<b>22,520</b>
<b>Cash and cash equivalents at end of year</b>	<b>18,556</b>	<b>14,177</b>	<b>19,635</b>	<b>22,520</b>	<b>29,763</b>

<sup>a</sup> 2012 included \$709 million of dividends received from TNK-BP.

<sup>b</sup> 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<sup>a</sup>

	\$ million				
	2010	2011	2012	2013	2014
Opening balance					
Finance debt	34,627	45,336	44,208	48,800	48,192
Fair value asset of hedges related to finance debt	(127)	(916)	(1,133)	(1,700)	(477)
Less: cash and cash equivalents	8,339	18,728	14,177	19,635	22,520
Opening net debt	26,161	25,692	28,898	27,465	25,195
Closing balance					
Finance debt	45,336	44,208	48,800	48,192	52,854
Fair value asset of hedges related to finance debt	(916)	(1,133)	(1,700)	(477)	(445)
Less: cash and cash equivalents	18,556	14,177	19,635	22,520	29,763
Closing net debt	25,864	28,898	27,465	25,195	22,646
Decrease (increase) in net debt	297	(3,206)	1,433	2,270	2,549
Movement in cash and cash equivalents (excluding exchange adjustments)	10,496	(4,058)	5,394	2,845	7,914
Net cash (inflow) outflow from financing (excluding share capital)	(3,613)	(4,720)	(3,244)	(836)	(5,419)
Movement in finance debt relating to investing activities <sup>b</sup>	(6,197)	6,167	(602)	632	—
Other movements	(304)	(132)	(104)	(192)	(435)
Movement in net debt before exchange effects	382	(2,743)	1,444	2,449	2,060
Exchange adjustments	(85)	(463)	(11)	(179)	489
Decrease (increase) in net debt	297	(3,206)	1,433	2,270	2,549

<sup>a</sup> Net debt is a non-GAAP measures. Net debt includes 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. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. We believe that net debt provides useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total.

<sup>b</sup> 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

	\$ million				
	2010	2011	2012	2013	2014
<b>By segment</b>					
Upstream					
US <sup>a b</sup>	6,632	5,363	6,385	6,410	6,203
Non-US <sup>c d e f g</sup>	11,121	20,458	12,135	12,705	13,569
	17,753	25,821	18,520	19,115	19,772
Downstream					
US	2,761	2,691	3,475	2,535	942
Non-US	1,268	1,594	1,774	1,971	2,164
	4,029	4,285	5,249	4,506	3,106
Rosneft					
Non-US	–	–	–	11,941	–
	–	–	–	11,941	–
Other businesses and corporate					
US <sup>h</sup>	977	877	681	231	82
Non-US <sup>i</sup>	257	976	754	819	821
	1,234	1,853	1,435	1,050	903
<b>By geographical area</b>					
US <sup>a b h</sup>	10,370	8,931	10,541	9,176	7,227
Non-US <sup>c d e f g i</sup>	12,646	23,028	14,663	27,436	16,554
	23,016	31,959	25,204	36,612	23,781
Included above					
Acquisitions and asset exchanges <sup>a e f i</sup>	3,406	11,283	200	71	420
Organic capital expenditure <sup>j</sup>	18,218	19,580	23,950	24,600	22,892
Disposal proceeds	16,954	2,841	11,598	21,999	3,491

<sup>a</sup> 2010 includes \$1,767 million in Upstream in the US deepwater Gulf of Mexico as part of the transaction with Devon Energy.

<sup>b</sup> 2012 and 2011 includes \$899 million and \$1,096 million, respectively, associated with deepening our natural gas asset base.

<sup>c</sup> 2010 includes 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.

<sup>d</sup> 2014 includes \$27 million and \$469 million respectively relating to the purchase of additional 3.3% equity in Shah Deniz, Azerbaijan and the South Caucasus Pipeline.

<sup>e</sup> 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.

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

<sup>g</sup> 2012 includes \$155 million related to increasing our interest in North Sea assets.

<sup>h</sup> Includes capital expenditure of \$557 million in 2010 for wind turbines, incurred at the time for future wind projects.

<sup>i</sup> 2011 includes \$680 million in Brazil relating to the acquisition of Companhia Nacional de Açúcar e Alcool.

<sup>j</sup> Organic capital expenditure excludes acquisitions and asset exchanges. It also excludes: 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<sup>a</sup>

	\$ million				
	2010	2011	2012	2013	2014
<b>Return on average capital employed</b>					
Replacement cost profit (loss)	(5,259)	23,412	11,428	23,681	<b>8,073</b>
Interest expense <sup>b</sup>	770	866	977	549	<b>546</b>
Non-controlling interests	395	397	234	307	<b>223</b>
Adjusted replacement cost profit (loss)	(4,094)	24,675	12,639	24,537	<b>8,842</b>
Non-operating items and fair value accounting effects after taxation	25,436	(2,242)	5,643	(10,253)	<b>4,063</b>
Adjusted underlying replacement cost profit	21,342	22,433	18,282	14,284	<b>12,905</b>
Average capital employed (including goodwill)	138,982	149,080	162,674	173,576	<b>172,048</b>
Return on average capital employed (including goodwill, non-operating items and fair value accounting effects)	(2.9)%	16.6%	7.8%	14.1%	<b>5.1%</b>
Average capital employed (excluding goodwill)	130,373	138,402	150,364	161,390	<b>159,862</b>
Return on average capital employed (excluding goodwill, non-operating items and fair value accounting effects)	16.4%	16.2%	12.2%	8.9%	<b>8.1%</b>
<b>Debt ratios</b>					
Gross debt	45,336	44,208	48,800	48,192	<b>52,854</b>
Fair value asset of hedges related to finance debt	(916)	(1,133)	(1,700)	(477)	<b>(445)</b>
	44,420	43,075	47,100	47,715	<b>52,409</b>
Less: cash and cash equivalents	18,556	14,177	19,635	22,520	<b>29,763</b>
Net debt	25,864	28,898	27,465	25,195	<b>22,646</b>
Equity	95,891	112,585	119,752	130,407	<b>112,642</b>
Debt to debt-plus-equity ratio	31.7%	27.7%	28.2%	26.8%	<b>31.8%</b>
Debt to equity ratio	46.3%	38.3%	39.3%	36.6%	<b>46.5%</b>
Net debt to net debt-plus-equity ratio	21.2%	20.4%	18.7%	16.2%	<b>16.7%</b>
Net debt to equity ratio	27.0%	25.7%	22.9%	19.3%	<b>20.1%</b>

<sup>a</sup> The ratios are defined on page 77.

<sup>b</sup> 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 <sup>a</sup>	2010	2011	2012	2013	2014
<b>By segment</b>					
Upstream	21,100	22,400	24,200	24,700	24,400
Downstream <sup>b</sup>	52,300	51,500	51,800	48,000	48,000
Other businesses and corporate <sup>c,d</sup>	6,300	10,200	10,400	11,200	12,100
	<b>79,700</b>	<b>84,100</b>	<b>86,400</b>	<b>83,900</b>	<b>84,500</b>
<b>By geographical area</b>					
US	22,100	22,900	23,400	19,600	18,500
Non-US <sup>b</sup>	57,600	61,200	63,000	64,300	66,000
	<b>79,700</b>	<b>84,100</b>	<b>86,400</b>	<b>83,900</b>	<b>84,500</b>

<sup>a</sup> Reported to the nearest 100.

<sup>b</sup> 2014 includes 14,400 (2013 14,100 2012 14,700, 2011 14,700, and 2010 15,200) service station staff. See page 68 for further information.

<sup>c</sup> 2014 includes 5,300 (2013 4,300 2012 3,500 and 2011 3,300) agricultural, operational and seasonal workers in Brazil. The number of workers in 2010 was not included as the activity was within a joint venture.

<sup>d</sup> Includes employees of the Gulf Coast Restoration Organization.

## Information for earnings per share

	\$ million				
	2010	2011	2012	2013	2014
<b>Results for the period</b>					
Profit (loss) for the year attributable to BP shareholders	(4,064)	25,212	11,017	23,451	3,780
Less: preference dividend	2	2	2	2	2
Profit (loss) for the year attributable to BP ordinary shareholders	(4,066)	25,210	11,015	23,449	3,778
Profit (loss) for the year attributable to BP ordinary shareholders, as above	(4,066)	25,210	11,015	23,449	3,778
Inventory holding (gains) losses, net of tax	(1,195)	(1,800)	411	230	4,293
Replacement cost profit (loss) attributable to ordinary shareholders	(5,261)	23,410	11,426	23,679	8,071
<b>Average number of shares</b>					
Basic weighted average number of shares outstanding (thousand) <sup>a</sup>	18,785,912	18,904,812	19,027,929	18,931,021	18,385,458
ADS equivalent (thousand) <sup>a</sup>	3,130,985	3,150,802	3,171,321	3,155,170	3,064,243
Diluted weighted average number of shares outstanding (thousand) <sup>a</sup>	18,997,807	19,136,200	19,157,888	19,046,173	18,497,294
ADS equivalent (thousand) <sup>a</sup>	3,166,301	3,189,367	3,192,981	3,174,362	3,082,882
Shares in issue at year end (thousand) <sup>a</sup>	18,796,498	18,977,214	19,119,757	18,611,489	18,199,882
ADS equivalent (thousand) <sup>a</sup>	3,132,750	3,162,869	3,186,626	3,101,914	3,033,313
Shares repurchased in the year (thousand) <sup>b</sup>	—	—	—	752,854	611,913

<sup>a</sup> 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.

<sup>b</sup> Purchased for a total consideration of \$4,796 million, including transaction costs of \$26 million (2013 \$5,493 million, including transaction costs of \$30 million). All shares purchased were for cancellation. The repurchased shares represented 3.0% of ordinary share capital.

## BP shareholding information

### Register of members holding BP ordinary shares as at 31 December 2014

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	56,090	20.67	0.02
201–1,000	95,613	35.24	0.28
1,001–10,000	107,541	39.63	1.79
10,001–100,000	10,659	3.93	1.18
100,001–1,000,000	773	0.29	1.59
Over 1,000,000 <sup>a</sup>	659	0.24	95.14
Totals	271,335	100.00	100.00

<sup>a</sup> Includes JPMorgan Chase Bank, N.A. holding 28.79% of the total ordinary issued share capital (excluding shares held in treasury) as the approved depository for ADSs, a breakdown of which is shown in the table below.

### Register of holders of American depositary shares (ADSs) as at 31 December 2014<sup>a</sup>

Range of holdings	Number of ADS holders	Percentage of total ADS holders	Percentage of total ADSs
1–200	55,981	58.01	0.35
201–1,000	25,960	26.90	1.42
1,001–10,000	13,816	14.32	4.14
10,001–100,000	740	0.77	1.42
100,001–1,000,000	8	0.00	0.13
Over 1,000,000 <sup>b</sup>	1	0.00	92.54
Totals	96,506	100.00	100.00

<sup>a</sup> One ADS represents six 25-cent ordinary shares.

<sup>b</sup> One holder of ADSs represents 979,038 underlying shareholders.

As at 31 December 2014, there were also 1,483 preference shareholders. Preference shareholders represented 0.46% and ordinary shareholders represented 99.54% 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 2014<sup>a</sup>

By principal area	Percentage of shares in issue
UK	38
US	38
Rest of Europe	10
Rest of world	9
Miscellaneous <sup>b</sup>	5
	100

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

<sup>b</sup> 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

	2010	2011	2012	2013	2014
<b>Share price and dividends</b>					
Share price (pence per ordinary share) <sup>a</sup>					
High	658.20	514.90	512.00	494.20	<b>526.80</b>
Low	296.00	361.25	388.56	426.50	<b>364.40</b>
End year	465.55	460.50	424.80	488.05	<b>411.00</b>
Dividends paid (pence per ordinary share)					
First quarter	8.6790	4.3372	5.0958	6.0013	<b>5.7065</b>
Second quarter	–	4.2809	5.1498	5.8342	<b>5.8071</b>
Third quarter	–	4.3160	5.0171	5.7630	<b>5.9593</b>
Fourth quarter	–	4.4694	5.5890	5.8008	<b>6.3769</b>
	<b>8.6790</b>	<b>17.4035</b>	<b>20.8517</b>	<b>23.3993</b>	<b>23.8498</b>
Dividends paid (cents per ordinary share)					
First quarter	14.00	7.00	8.00	9.00	<b>9.50</b>
Second quarter	–	7.00	8.00	9.00	<b>9.75</b>
Third quarter	–	7.00	8.00	9.00	<b>9.75</b>
Fourth quarter	–	7.00	9.00	9.50	<b>10.00</b>
	<b>14.00</b>	<b>28.00</b>	<b>33.00</b>	<b>36.50</b>	<b>39.00</b>
ADS price (US dollars per ADS) <sup>a</sup>					
High	62.38	49.50	48.34	48.65	<b>53.48</b>
Low	26.75	33.62	36.25	39.99	<b>34.88</b>
End year	44.17	42.74	41.64	48.61	<b>38.12</b>
Dividends paid (US dollars per ADS)					
First quarter	0.840	0.420	0.480	0.540	<b>0.570</b>
Second quarter	–	0.420	0.480	0.540	<b>0.585</b>
Third quarter	–	0.420	0.480	0.540	<b>0.585</b>
Fourth quarter	–	0.420	0.540	0.570	<b>0.600</b>
	<b>0.840</b>	<b>1.680</b>	<b>1.980</b>	<b>2.190</b>	<b>2.340</b>
<b>Ratios</b>					
Dividend payout ratio <sup>b</sup>					
Based on replacement cost profit for the year	n/a	23%	55%	29%	<b>89%</b>
Based on profit for the year	n/a	21%	57%	29%	<b>190%</b>
Dividend cover <sup>b</sup>					
Dividend cover out of income <sup>c</sup>	n/a	4.43	1.82	3.43	<b>1.13</b>
Dividend cover out of cash flow <sup>d</sup>	5.19	4.20	3.26	3.05	<b>4.57</b>
Dividend payout ratio <sup>e</sup>					
Based on replacement cost profit for the year	n/a	17%	46%	23%	<b>72%</b>
Based on profit for the year	n/a	16%	48%	23%	<b>155%</b>
Dividend cover <sup>e</sup>					
Dividend cover out of income <sup>c</sup>	n/a	5.75	2.16	4.35	<b>1.38</b>
Dividend cover out of cash flow <sup>d</sup>	5.19	5.46	3.87	3.88	<b>5.60</b>

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

<sup>b</sup> The calculation is based on the assumption that all dividends, including scrip dividends, are paid in cash.

<sup>c</sup> Based on replacement cost profit for the year.

<sup>d</sup> Net cash provided by operating activities, divided by gross dividends paid.

<sup>e</sup> The calculation is based on the assumption that all dividends, excluding scrip dividends, are paid in cash.

## Group hydrocarbon data

The regional analysis presented on pages 32-59 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.

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.

## Oil and natural gas exploration and production activities

	\$ million								
	Europe		North America		South America	Africa	Asia	Australasia	2010 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia	
<b>Subsidiaries<sup>a</sup></b>									
<b>Capitalized costs at 31 December<sup>a,c</sup></b>									
Gross capitalized costs									
Proved properties	36,161	7,846	67,724	278	6,047	27,014	–	11,497	3,088 159,655
Unproved properties	787	179	5,968	1,363	220	2,694	–	1,113	1,149 13,473
	36,948	8,025	73,692	1,641	6,267	29,708	–	12,610	4,237 173,128
Accumulated depreciation	27,688	3,515	33,972	216	3,282	13,893	–	4,569	1,205 88,340
Net capitalized costs	9,260	4,510	39,720	1,425	2,985	15,815	–	8,041	3,032 84,788
<b>Costs incurred for the year ended 31 December<sup>a,c</sup></b>									
Acquisition of properties <sup>d</sup>									
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 <sup>e</sup>	401	13	1,096	78	68	607	7	316	120 2,706
Development	726	816	3,034	251	414	3,003	–	1,244	187 9,675
Total costs	1,127	1,348	6,384	1,530	482	3,610	7	2,832	307 17,627
<b>Results of operations for the year ended 31 December</b>									
Sales and other operating revenues <sup>f</sup>									
Third parties	1,472	58	1,148	90	1,896	3,158	–	1,272	1,398 10,492
Sales between segments	3,405	1,134	18,819	453	1,574	4,353	–	6,697	929 37,364
	4,877	1,192	19,967	543	3,470	7,511	–	7,969	2,327 47,856
Exploration expenditure	82	(2)	465	25	9	189	7	51	17 843
Production costs	1,018	152	2,867	240	445	938	9	365	124 6,158
Production taxes	52	–	1,093	2	249	–	–	3,764	109 5,269
Other costs (income) <sup>g</sup>	(316)	76	3,502	129	209	130	76	90	195 4,091
Depreciation, depletion and amortization	897	209	3,477	95	575	1,771	–	829	168 8,021
Impairments and (gains) losses on sale of businesses and fixed assets	(1)	–	(1,441)	(2,190)	(3)	(427)	34 <sup>h</sup>	–	– (3,721)
	1,732	435	9,963	(1,699)	1,484	2,601	433	5,099	613 20,661
Profit (loss) before taxation <sup>i</sup>	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714 27,195
Allocable taxes	1,333	530	3,504	610	1,084	1,771	(23)	813	410 10,032
Results of operations	1,812	227	6,500	1,632	902	3,139	(410)	2,057	1,304 17,163
<b>Upstream segment and TNK-BP segment replacement cost profit before interest and tax</b>									
Exploration and production activities – subsidiaries (as above)	3,145	757	10,004	2,242	1,986	4,910	(433)	2,870	1,714 27,195
Midstream activities – subsidiaries <sup>j</sup>	23	42	(347)	3	49	(26)	4	(23)	(13) (288)
Equity-accounted entities <sup>k</sup>	–	4	27	171	614	63	2,613	487	– 3,979
Total replacement cost profit before interest and tax	3,168	803	9,684	2,416	2,649	4,947	2,184	3,334	1,701 30,886

<sup>a</sup> 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.

<sup>b</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>c</sup> Excludes balances associated with assets held for sale.

<sup>d</sup> Includes costs capitalized as a result of asset exchanges.

<sup>e</sup> 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.

<sup>f</sup> Presented net of transportation costs, purchases and sales taxes.

<sup>g</sup> 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.

<sup>h</sup> 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.

<sup>i</sup> 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.

<sup>j</sup> Midstream activities exclude inventory holding gains and losses.

<sup>k</sup> 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) <sup>a</sup>													
Capitalized costs at 31 December <sup>b</sup>													
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 <sup>b</sup>													
Acquisition of properties <sup>c</sup>													
Proved	–	–	–	–	–	–	–	–	–	–	–	–	–
Unproved	–	–	–	–	9	–	–	–	66	–	–	–	75
Exploration and appraisal costs <sup>d</sup>	–	–	–	–	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 <sup>e</sup>													
Third parties	–	–	–	–	2,268	–	–	–	5,610	2,557	–	–	10,435
Sales between segments	–	–	–	–	–	–	–	–	3,432	19	–	–	3,451
	–	–	–	–	2,268	–	–	–	9,042	2,576	–	–	13,886
Exploration expenditure	–	–	–	–	22	–	–	–	40	–	–	–	62
Production costs	–	–	–	–	316	–	–	–	1,602	184	–	–	2,102
Production taxes	–	–	–	–	911	–	–	–	3,567	2,029	–	–	6,507
Other costs (income)	–	–	–	67	75	–	–	–	3	(2)	–	–	143
Depreciation, depletion and amortization	–	–	–	–	269	–	–	–	954	363	–	–	1,586
Impairments and (gains) losses on sale of businesses and fixed assets	–	–	–	–	–	–	–	–	43	–	–	–	43
	–	–	–	67	1,593	–	–	–	6,209	2,574	–	–	10,443
Profit (loss) before taxation	–	–	–	(67)	675	–	–	–	2,833	2	–	–	3,443
Allocable taxes	–	–	–	–	260	–	–	–	475	33	–	–	768
Results of operations	–	–	–	(67)	415	–	–	–	2,358	(31)	–	–	2,675
Exploration and production activities – equity-accounted entities after tax (as above)	–	–	–	(67)	415	–	–	–	2,358	(31)	–	–	2,675
Midstream and other activities after tax <sup>f</sup>	–	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

<sup>a</sup> 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.

<sup>b</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>c</sup> Includes costs capitalized as a result of asset exchanges.

<sup>d</sup> 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.

<sup>e</sup> Presented net of transportation costs and sales taxes.

<sup>f</sup> 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 <sup>a</sup>									
Capitalized costs at 31 December <sup>b,c</sup>									
Gross capitalized costs									
Proved properties	37,491	8,994	73,626	1,296	7,471	29,358	–	14,833	3,370
Unproved properties	368	180	6,198	2,017	2,986	3,689	–	4,495	1,279
Accumulated depreciation	37,859	9,174	79,824	3,313	10,457	33,047	–	19,328	4,649
Net capitalized costs	26,953	3,715	36,009	139	3,839	14,595	–	6,235	1,294
	10,906	5,459	43,815	3,174	6,618	18,452	–	13,093	3,355
Costs incurred for the year ended 31 December <sup>b,c</sup>									
Acquisition of properties <sup>d,e</sup>									
Proved	–	–	1,178	8	237	–	–	1,733	–
Unproved	–	1	418	–	2,592	679	–	3,008	–
Exploration and appraisal costs <sup>f</sup>	–	1	1,596	8	2,829	679	–	4,741	–
Development	211	1	566	132	271	490	6	511	225
Total costs	1,361	889	3,016	227	405	2,933	–	1,340	251
	1,572	891	5,178	367	3,505	4,102	6	6,592	476
Results of operations for the year ended 31 December									
Sales and other operating revenues <sup>g</sup>									
Third parties	1,997	–	751	25	2,263	3,353	–	1,450	1,611
Sales between segments	3,495	1,273	19,089	20	1,409	4,858	–	10,811	967
	5,492	1,273	19,840	45	3,672	8,211	–	12,261	2,578
Exploration expenditure	37	1	1,065	9	35	163	6	134	70
Production costs	1,372	230	3,402	66	503	1,146	4	787	194
Production taxes	72	–	1,854	–	278	–	–	5,956	147
Other costs (income) <sup>h</sup>	(1,357)	101	4,688	62	935	215	72	118	257
Depreciation, depletion and amortization	874	199	2,980	6	523	1,668	–	1,692	172
Impairments and (gains) losses on sale of businesses and fixed assets	26	(64)	(492)	15	(1,085)	18	(1)	(537)	–
	1,024	467	13,497	158	1,189	3,210	81	8,150	840
Profit (loss) before taxation <sup>i</sup>	4,468	806	6,343	(113)	2,483	5,001	(81)	4,111	1,738
Allocable taxes	2,483	384	2,152	(159)	1,205	2,184	(21)	1,001	677
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
Midstream activities – subsidiaries <sup>j</sup>	(118)	29	(157)	299	78	(4)	(1)	42	284
Equity-accounted entities <sup>k</sup>	–	12	10	–	525	69	4,095	573	–
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

<sup>a</sup> 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.

<sup>b</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>c</sup> Excludes balances associated with assets held for sale.

<sup>d</sup> Includes costs capitalized as a result of asset exchanges.

<sup>e</sup> Excludes goodwill associated with business combinations.

<sup>f</sup> 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.

<sup>g</sup> Presented net of transportation costs, purchases and sales taxes.

<sup>h</sup> 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.

<sup>i</sup> 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.

<sup>j</sup> Midstream activities exclude inventory holding gains and losses.

<sup>k</sup> The profits of equity-accounted entities are included after interest and tax.

## 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) <sup>a</sup>									
Capitalized costs at 31 December <sup>b</sup>									
Gross capitalized costs									
Proved properties	–	–	–	–	6,562	–	16,214	3,571	– 26,347
Unproved properties	–	–	–	–	19	–	652	9	– 680
	–	–	–	–	6,581	–	16,866	3,580	– 27,027
Accumulated depreciation	–	–	–	–	2,644	–	6,978	3,017	– 12,639
Net capitalized costs	–	–	–	–	3,937	–	9,888	563	– 14,388
Costs incurred for the year ended 31 December <sup>b</sup>									
Acquisition of properties <sup>c</sup>									
Proved	–	–	–	–	–	–	46	–	46
Unproved	–	–	–	–	6	– 37	–	–	43
	–	–	–	–	6	– 37	46	–	89
Exploration and appraisal costs <sup>d</sup>	–	–	–	–	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 <sup>e</sup>									
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 <sup>f</sup>	–	12	10	–	95	69 280	509	–	975
Total replacement cost profit after interest and tax	–	12	10	–	525	69 4,095	573	–	5,284

<sup>a</sup> 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.

<sup>b</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>c</sup> Includes costs capitalized as a result of asset exchanges.

<sup>d</sup> 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.

<sup>e</sup> Presented net of transportation costs and sales taxes.

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

<sup>a</sup> 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.

<sup>b</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>c</sup> Excludes balances associated with assets held for sale.

<sup>d</sup> Includes costs capitalized as a result of asset exchanges.

<sup>e</sup> Excludes goodwill associated with business combinations.

<sup>f</sup> 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.

<sup>g</sup> Presented net of transportation costs, purchases and sales taxes.

<sup>h</sup> 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.

<sup>i</sup> 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.

<sup>j</sup> Midstream and other activities exclude inventory holding gains and losses.

<sup>k</sup> 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 <sup>1</sup>	Total		
	UK	Rest of Europe	US	Rest of North America	Russia <sup>a</sup>	Rest of Asia			
Equity-accounted entities (BP share) <sup>b</sup>									
Capitalized costs at 31 December <sup>c</sup>									
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 <sup>c</sup>									
Acquisition of properties <sup>d</sup>									
Proved	–	–	–	–	–	4	–	–	4
Unproved	–	–	–	–	439	15	–	–	454
Exploration and appraisal costs <sup>e</sup>	–	–	–	–	439	19	–	–	458
Development	–	–	–	–	31	195	7	–	233
Total costs	–	–	–	–	599	1,560	556	–	2,715
	–	–	–	–	1,069	1,774	563	–	3,406
Results of operations for the year ended 31 December									
Sales and other operating revenues <sup>f</sup>									
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 <sup>g</sup>	–	35	16	–	49	48	263	505	916
Total replacement cost profit after interest and tax	–	35	16	–	160	48	3,005	640	3,904

<sup>a</sup> 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.

<sup>b</sup> 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.

<sup>c</sup> 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.

<sup>d</sup> Includes costs capitalized as a result of asset exchanges.

<sup>e</sup> 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.

<sup>f</sup> Presented net of transportation costs and sales taxes.

<sup>g</sup> Includes interest, non-controlling interests 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		
<b>Subsidiaries<sup>a</sup></b>										
<b>Capitalized costs at 31 December<sup>b</sup></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
<b>Net capitalized costs</b>	<b>10,923</b>	<b>6,585</b>	<b>43,893</b>	<b>4,716</b>	<b>7,112</b>	<b>20,717</b>	<b>–</b>	<b>13,413</b>	<b>3,524</b>	<b>110,883</b>
<b>Costs incurred for the year ended 31 December<sup>b</sup></b>										
Acquisition of properties										
Proved	–	–	1	–	7	–	–	–	–	8
Unproved	–	–	158	–	284	30	–	7	–	479
	–	–	159	–	291	30	–	7	–	487
Exploration and appraisal costs <sup>c</sup>	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
<b>Total costs</b>	<b>2,120</b>	<b>469</b>	<b>6,327</b>	<b>763</b>	<b>1,925</b>	<b>3,668</b>	<b>–</b>	<b>3,179</b>	<b>399</b>	<b>18,850</b>
<b>Results of operations for the year ended 31 December</b>										
Sales and other operating revenues <sup>d</sup>										
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) <sup>e</sup>	(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 <sup>f</sup>	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
<b>Results of operations</b>	<b>1,998</b>	<b>(50)</b>	<b>2,108</b>	<b>(82)</b>	<b>(638)</b>	<b>2,528</b>	<b>(63)</b>	<b>1,994</b>	<b>936</b>	<b>8,731</b>
<b>Upstream, Rosneft and TNK-BP segments replacement cost profit before interest and tax</b>										
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 <sup>g</sup>	244	(40)	296	(14)	153	(154)	(4)	(29)	347	799
TNK-BP gain on sale	–	–	–	–	–	–	12,500	–	–	12,500
Equity-accounted entities <sup>h</sup>	–	28	17	–	405	24	2,158	553	–	3,185
<b>Total replacement cost profit before interest and tax</b>	<b>2,796</b>	<b>413</b>	<b>3,625</b>	<b>(122)</b>	<b>562</b>	<b>4,323</b>	<b>14,589</b>	<b>3,200</b>	<b>1,924</b>	<b>31,310</b>

<sup>a</sup> 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.

<sup>b</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>c</sup> 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.

<sup>d</sup> Presented net of transportation costs, purchases and sales taxes.

<sup>e</sup> 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.

<sup>f</sup> 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.

<sup>g</sup> Midstream and other activities excludes inventory holding gains and losses.

<sup>h</sup> 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 <sup>1</sup>	Total			
	UK	Rest of Europe	US	Rest of North America		Russia <sup>a</sup>	Rest of Asia			
Equity-accounted entities (BP share) <sup>b</sup>										
Capitalized costs at 31 December <sup>c</sup>										
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 <sup>d</sup>										
Acquisition of properties										
Proved	–	–	–	–	–	–	1,816	–	–	1,816
Unproved	–	–	–	–	–	–	657	–	–	657
Exploration and appraisal costs <sup>e</sup>	–	–	–	–	–	–	2,473	–	–	2,473
Development	–	–	–	–	8	–	133	12	–	153
Total costs	–	–	–	–	714	–	1,860	538	–	3,112
	–	–	–	–	722	–	4,466	550	–	5,738
Results of operations for the year ended 31 December										
Sales and other operating revenues <sup>f</sup>										
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 <sup>g</sup>	–	28	17	–	110	24	(412)	402	–	169
Total replacement cost profit after interest and tax	–	28	17	–	405	24	2,158	553	–	3,185

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

<sup>b</sup> 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.

<sup>c</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>d</sup> 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.

<sup>e</sup> 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.

<sup>f</sup> Presented net of transportation costs and sales taxes.

<sup>g</sup> Includes interest, non-controlling interests and excludes inventory holding gains and losses.

## Oil and natural gas exploration and production activities continued

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

<sup>a</sup> 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.

<sup>b</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>c</sup> 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.

<sup>d</sup> Presented net of transportation costs, purchases and sales taxes.

<sup>e</sup> Includes property taxes, other government take and the fair value gain on embedded derivatives of \$430 million. The UK region includes a \$1,016 million gain offset by corresponding charges primarily in the US, relating to the group self-insurance programme.

<sup>f</sup> Excludes the unwinding of the discount on provisions and payables amounting to \$207 million which is included in finance costs in the group income statement.

<sup>g</sup> Midstream and other activities excludes inventory holding gains and losses.

<sup>h</sup> The profits of equity-accounted entities are included after interest and tax.

## Oil and natural gas exploration and production activities continued

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

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

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

<sup>c</sup> Decommissioning assets are included in capitalized costs at 31 December but are excluded from costs incurred for the year.

<sup>d</sup> 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.

<sup>e</sup> Presented net of transportation costs and sales taxes.

<sup>f</sup> Includes interest, non-controlling interests and excludes inventory holding gains and losses.

## Movements in estimated net proved reserves

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

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

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 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.

<sup>d</sup> Includes 9 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Includes assets held for sale of 39 million barrels.

<sup>f</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>g</sup> Includes 328 million barrels of crude oil in respect of the 7.35% non-controlling interest in TNK-BP.

<sup>h</sup> Total proved crude oil reserves held as part of our equity interest in TNK-BP is 4,463 million barrels, comprising 87 million barrels in Venezuela and 4,376 million barrels in Russia.

<sup>i</sup> Includes assets held for sale of 4,463 million barrels.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

<sup>d</sup> Includes 5 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>f</sup> Total proved NGL reserves held as part of our equity interest in TNK-BP is 78 million barrels, all in Russia.

<sup>g</sup> Includes assets held for sale of 78 million barrels.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 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.

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

<sup>e</sup> Also includes 14 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>f</sup> Includes assets held for sale of 4,540 million barrels.

<sup>g</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>h</sup> Includes 328 million barrels in respect of the non-controlling interest in TNK-BP.

<sup>i</sup> 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.

<sup>j</sup> Includes assets held for sale of 39 million barrels.

## Movements in estimated net proved reserves continued

	billion cubic feet									
Natural gas <sup>a b</sup>	2012									
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	1,411	43	9,721	28	2,869	1,224	–	1,034	3,570	19,900
Undeveloped	909	450	3,831	–	6,529	2,033	–	364	2,365	16,481
	2,320	493	13,552	28	9,398	3,257	–	1,398	5,935	36,381
Changes attributable to										
Revisions of previous estimates	(18)	(13)	(1,853)	(19)	(116)	(14)	–	38	(41)	(2,036)
Improved recovery	95	–	885	–	756	69	–	156	–	1,961
Purchases of reserves-in-place	17	(1)	232	–	–	–	–	–	–	248
Discoveries and extensions	–	7	225	–	598	1	–	–	–	831
Production <sup>c</sup>	(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 <sup>d e</sup>										
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) <sup>f</sup>										
At 1 January										
Developed	–	–	–	–	1,144	–	2,119	104	–	3,367
Undeveloped	–	–	–	–	1,006	195	659	51	–	1,911
	–	–	–	–	2,150	195	2,778	155	–	5,278
Changes attributable to										
Revisions of previous estimates	–	–	–	–	86	144	569	25	–	824
Improved recovery	–	–	–	–	110	–	–	1	–	111
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	3	–	1,310	–	–	1,313
Production <sup>c</sup>	–	–	–	–	(169)	–	(280)	(35)	–	(484)
Sales of reserves-in-place	–	–	–	–	–	–	(1)	–	–	(1)
	–	–	–	–	30	144	1,598	(9)	–	1,763
At 31 December <sup>g h i</sup>										
Developed	–	–	–	–	1,276	175	2,617	128	–	4,196
Undeveloped	–	–	–	–	904	164	1,759	18	–	2,845
	–	–	–	–	2,180	339	4,376	146	–	7,041
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	1,411	43	9,721	28	4,013	1,224	2,119	1,138	3,570	23,267
Undeveloped	909	450	3,831	–	7,535	2,228	659	415	2,365	18,392
	2,320	493	13,552	28	11,548	3,452	2,778	1,553	5,935	41,659
At 31 December										
Developed	1,038	340	8,245	4	4,864	1,314	2,617	1,054	3,282	22,758
Undeveloped	666	141	2,986	–	7,154	2,087	1,759	431	2,323	17,547
	1,704	481	11,231	4	12,018	3,401	4,376	1,485	5,605	40,305

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 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.

<sup>d</sup> Includes 2,890 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Includes assets held for sale of 590 billion cubic feet.

<sup>f</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>g</sup> Includes 270 billion cubic feet of natural gas in respect of the 6.17% non-controlling interest in TNK-BP.

<sup>h</sup> 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.

<sup>i</sup> Includes assets held for sale of 4,492 billion cubic feet.



## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

<sup>d</sup> 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.

<sup>e</sup> Excludes NGLs from processing plants in which an interest is held of 13,500 barrels of oil equivalent per day.

<sup>f</sup> 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.

<sup>g</sup> Includes 591 million barrels of NGLs and 512 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>h</sup> Includes assets held for sale of 140 million barrels of oil equivalent.

<sup>i</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>j</sup> Includes 103 million barrels of NGLs. Also includes 374 million barrels of oil equivalent in respect of the non-controlling interest in TNK-BP.

<sup>k</sup> 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.

<sup>l</sup> Includes assets held for sale of 5,315 million barrels of oil equivalent.

## Movements in estimated net proved reserves continued

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

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

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 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.

<sup>d</sup> Includes 8 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>f</sup> Includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.

<sup>g</sup> Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,860 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 32 million barrels in Venezuela and 4,827 million barrels in Russia.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

<sup>d</sup> Includes 13 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>f</sup> Total proved NGL reserves held as part of our equity interest in Rosneft is 115 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 115 million barrels in Russia.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 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.

<sup>d</sup> Excludes NGLs from processing plants in which an interest is held of 5,500 barrels per day.

<sup>e</sup> Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>f</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>g</sup> Includes 23 million barrels in respect of the non-controlling interest in Rosneft.

<sup>h</sup> Total proved liquid reserves held as part of our equity interest in Rosneft is 4,975 million barrels, comprising 1 million barrels in Canada, 32 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,943 million barrels in Russia.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 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.

<sup>d</sup> Includes 2,685 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>f</sup> Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.

<sup>g</sup> 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 of oil equivalent <sup>c</sup>									
Total hydrocarbons <sup>a b</sup>										2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US <sup>d</sup>	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	421	229	2,865	1	640	508	—	427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587	—	209	445	4,699
	967	332	4,369	196	1,750	1,095	—	636	1,063	10,408
Changes attributable to										
Revisions of previous estimates	(89)	(27)	(342)	(5)	41	3	—	435	(36)	(20)
Improved recovery	20	—	161	—	25	7	—	81	—	294
Purchases of reserves-in-place	2	—	—	—	—	—	—	—	—	2
Discoveries and extensions	—	—	10	—	—	9	—	363	91	473
Production <sup>e f</sup>	(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 <sup>g</sup>										
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) <sup>h</sup>										
At 1 January										
Developed	—	—	—	—	559	43	2,943	220	—	3,765
Undeveloped	—	—	—	—	508	39	2,265	15	—	2,827
	—	—	—	—	1,067	82	5,208	235	—	6,592
Changes attributable to										
Revisions of previous estimates	—	—	—	1	(20)	2	502	1	—	486
Improved recovery	—	—	—	—	38	—	—	1	—	39
Purchases of reserves-in-place	—	—	—	—	36	—	6,108	6	—	6,150
Discoveries and extensions	—	—	—	—	20	—	272	—	—	292
Production <sup>f</sup>	—	—	—	—	(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 <sup>j</sup>										
Developed	—	—	—	—	552	50	3,782	133	—	4,517
Undeveloped	—	—	—	1	442	33	2,751	9	—	3,236
	—	—	—	1	994	83	6,533	142	—	7,753
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	421	229	2,865	1	1,199	551	2,943	647	618	9,474
Undeveloped	546	103	1,504	195	1,618	626	2,265	224	445	7,526
	967	332	4,369	196	2,817	1,177	5,208	871	1,063	17,000
At 31 December										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

<sup>d</sup> 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.

<sup>e</sup> Excludes NGLs from processing plants in which an interest is held of 5,500 barrels of oil equivalent per day.

<sup>f</sup> 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.

<sup>g</sup> Includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>h</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>i</sup> Includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

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

## Movements in estimated net proved reserves continued

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

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

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels upon which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

<sup>d</sup> Includes 10 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>f</sup> Includes 38 million barrels of crude oil in respect of the 0.15% non-controlling interest in Rosneft.

<sup>g</sup> Total proved crude oil reserves held as part of our equity interest in Rosneft is 4,961 million barrels, comprising less than 1 million barrels in Vietnam and Canada, 30 million barrels in Venezuela and 4,930 million barrels in Russia.



## Movements in estimated net proved reserves continued

	million barrels								
Natural gas liquids <sup>a b</sup>	2014								
	Europe	Rest of Europe	North America	Rest of North America	South America	Africa	Asia	Rest of Asia	Australasia
	UK		US				Russia		
Subsidiaries									
At 1 January									
Developed	9	16	290	–	14	4	–	–	8
Undeveloped	6	2	155	–	28	15	–	–	3
	15	18	444	–	43	20	–	–	10
Changes attributable to									
Revisions of previous estimates	(6)	(2)	15	–	–	(6)	–	–	–
Improved recovery	–	–	13	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–
Production <sup>c</sup>	(1)	(2)	(27)	–	(4)	(2)	–	–	(1)
Sales of reserves-in-place	–	–	(18)	–	–	–	–	–	–
	(6)	(4)	(17)	–	(4)	(8)	–	–	(1)
At 31 December <sup>d</sup>									
Developed	6	13	323	–	11	5	–	–	6
Undeveloped	3	1	104	–	28	7	–	–	3
	9	14	427	–	39	12	–	–	10
Equity-accounted entities (BP share) <sup>e</sup>									
At 1 January									
Developed	–	–	–	–	–	8	94	–	–
Undeveloped	–	–	–	–	–	8	21	–	–
	–	–	–	–	–	16	115	–	–
Changes attributable to									
Revisions of previous estimates	–	–	–	–	–	–	(69)	–	–
Improved recovery	–	–	–	–	–	–	–	–	–
Purchases of reserves-in-place	–	–	–	–	–	–	–	–	–
Discoveries and extensions	–	–	–	–	–	–	–	–	–
Production	–	–	–	–	–	–	–	–	–
Sales of reserves-in-place	–	–	–	–	–	–	–	–	–
	–	–	–	–	–	(1)	(69)	–	–
At 31 December <sup>f</sup>									
Developed	–	–	–	–	–	15	30	–	–
Undeveloped	–	–	–	–	–	–	16	–	–
	–	–	–	–	–	15	46	–	–
Total subsidiaries and equity-accounted entities (BP share)									
At 1 January									
Developed	9	16	290	–	14	13	94	–	8
Undeveloped	6	2	155	–	28	23	21	–	3
	15	18	444	–	43	36	115	–	10
At 31 December									
Developed	6	13	323	–	11	20	30	–	6
Undeveloped	3	1	104	–	28	7	16	–	3
	9	14	427	–	39	27	46	–	10

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.

<sup>d</sup> Includes 12 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>f</sup> Total proved NGL reserves held as part of our equity interest in Rosneft is 47 million barrels, comprising less than 1 million barrels in Venezuela, Vietnam and Canada, and 46 million barrels in Russia.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

<sup>d</sup> Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.

<sup>e</sup> Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>f</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>g</sup> Includes 38 million barrels in respect of the non-controlling interest in Rosneft.

<sup>h</sup> Total proved liquid reserves held as part of our equity interest in Rosneft is 5,007 million barrels, comprising 1 million barrels in Canada, 30 million barrels in Venezuela, less than 1 million barrels in Vietnam and 4,976 million barrels in Russia.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> Includes 181 billion cubic feet of natural gas consumed in operations, 151 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.

<sup>d</sup> Includes 2,519 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>e</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>f</sup> Includes 91 billion cubic feet of natural gas in respect of the 0.18% non-controlling interest in Rosneft.

<sup>g</sup> Total proved gas reserves held as part of our equity interest in Rosneft is 9,827 billion cubic feet, comprising 1 billion cubic feet in Canada, 14 billion cubic feet in Venezuela, 26 billion cubic feet in Vietnam and 9,785 billion cubic feet in Russia.

## Movements in estimated net proved reserves continued

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

<sup>a</sup> 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.

<sup>b</sup> Because of rounding, some totals may not exactly agree with the sum of their counterparts.

<sup>c</sup> 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

<sup>d</sup> Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels of oil equivalent upon which a net profits royalty will be payable, over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

<sup>e</sup> Excludes NGLs from processing plants in which an interest is held of less than 1 thousand barrels per day for subsidiaries and 7 thousand barrels per day for equity-accounted entities.

<sup>f</sup> 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.

<sup>g</sup> Includes 456 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

<sup>h</sup> Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

<sup>i</sup> Includes 54 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

<sup>j</sup> Total proved reserves held as part of our equity interest in Rosneft is 6,702 million barrels of oil equivalent, comprising 1 million barrels of oil equivalent in Canada, 33 million barrels of oil equivalent in Venezuela, 5 million barrels of oil equivalent in Vietnam and 6,663 million barrels of oil equivalent in Russia.

## BP's net production by country<sup>a</sup> – crude oil<sup>b</sup> and natural gas liquids

	Crude oil					Natural gas liquids				
	2010	2011	2012	2013	2014	2010	2011	2012	2013	2014
<b>Subsidiaries</b>										
UK <sup>d,e</sup>	126	107	81	58	46	11	6	5	3	2
Norway <sup>d</sup>	38	31	22	31	41	2	1	1	4	5
Total Rest of Europe	38	31	22	31	41	2	1	1	4	5
Total Europe	164	138	103	89	87	12	8	6	7	7
Alaska <sup>d</sup>	166	153	139	137	127	–	–	–	–	–
Lower 48 onshore <sup>d</sup>	17	11	11	12	14	73	58	49	45	45
Gulf of Mexico deepwater <sup>d</sup>	313	212	176	156	206	26	19	15	13	18
Total US	495	376	327	305	347	99	78	64	58	63
Canada <sup>d</sup>	1	–	–	–	–	6	2	1	–	–
Total Rest of North America	1	–	–	–	–	6	2	1	–	–
Total North America	496	376	327	305	347	105	79	65	58	63
Trinidad & Tobago	19	15	8	10	13	16	15	13	12	12
Brazil <sup>d</sup>	–	7	7	7	–	–	–	–	–	–
Colombia <sup>d</sup>	18	1	–	–	–	–	–	–	–	–
Total South America	37	23	16	17	13	16	15	13	12	12
Angola	170	123	149	180	181	–	–	–	–	–
Egypt <sup>d</sup>	54	40	36	33	37	–	–	–	–	–
Algeria <sup>d</sup>	10	14	6	3	5	7	8	7	3	5
Total Africa	233	178	191	217	222	7	8	7	3	5
Azerbaijan <sup>d</sup>	103	94	92	96	98	–	–	–	–	–
Western Indonesia	2	2	1	1	2	–	–	–	–	–
Iraq	–	31	39	39	55	–	–	–	–	–
Vietnam <sup>d</sup>	1	–	–	–	2	–	–	–	–	–
Other <sup>d</sup>	12	9	6	4	2	2	2	2	1	–
Total Rest of Asia	117	135	137	141	156	2	2	2	1	–
Total Asia	117	135	137	141	156	2	2	2	1	–
Australia	25	18	20	19	17	5	5	4	4	3
Other	2	2	1	2	2	–	–	–	–	–
Total Australasia	27	20	22	21	19	5	5	4	4	3
Total subsidiaries <sup>f</sup>	1,075	869	795	789	844	149	117	96	86	91
<b>Equity-accounted entities (BP share)</b>										
TNK-BP (Russia, Venezuela, Vietnam) <sup>d,g</sup>	856	871	857	183	–	–	–	20	4	–
Rosneft (Russia, Canada, Venezuela, Vietnam) <sup>d,h</sup>	–	–	–	643	816	–	–	–	7	5
Abu Dhabi <sup>i</sup>	190	209	216	231	97	–	–	–	–	–
Argentina	69	69	63	60	62	5	5	3	3	3
Bolivia	1	1	1	2	3	–	–	–	–	–
Egypt	–	–	–	–	–	5	5	5	5	4
Venezuela <sup>d</sup>	23	10	–	–	–	–	–	–	–	–
Other	1	1	1	1	1	–	–	–	–	–
Total equity-accounted entities	1,140	1,161	1,137	1,120	979	9	9	27	19	12
Total subsidiaries and equity-accounted entities	2,215	2,030	1,932	1,909	1,823	158	126	123	105	104

<sup>a</sup> Because of rounding, some totals may not agree exactly with the sum of their component parts.

<sup>b</sup> Includes condensate.

<sup>c</sup> 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.

<sup>d</sup> In 2014, BP divested its interests in the Endicott and Northstar fields, and 50% of its interests in the Milne Point field, in Alaska, its interest in the US onshore Hugoton upstream operation and its interest in the Polvo asset in Brazil. BP also reduced its interest in certain wells in the US onshore Eagle Ford Shale in south Texas. It increased its interest in the Shah Deniz asset in Azerbaijan, in certain UK North Sea assets, and in certain US onshore assets. 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 Severnoenftegaz, 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.

<sup>e</sup> Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.

<sup>f</sup> Includes 7 net mboe/d of NGLs from processing plants in which BP has an interest (2013 5.5mboe/d, 2012 13.5mboe/d, 2011 28mboe/d, 2010 29mboe/d).

<sup>g</sup> 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.

<sup>h</sup> 2014 is based on preliminary operational results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts. 2013 reflects production for the period 21 March to 31 December, averaged over the full year.

## BP's net production by country<sup>a</sup> – natural gas

	million cubic feet per day				
	BP net share of production <sup>b</sup>				
					Natural gas liquids
	2010	2011	2012	2013	2014
<b>Subsidiaries</b>					
UK <sup>c</sup>	472	356	414	157	71
Norway	15	13	8	80	102
Total Rest of Europe	15	13	8	80	102
Total Europe	487	368	422	237	173
Lower 48 onshore <sup>c</sup>	1,874	1,646	1,499	1,404	1,350
Gulf of Mexico deepwater <sup>c</sup>	264	175	134	114	159
Alaska	46	22	18	21	11
Total US	2,184	1,843	1,651	1,539	1,519
Canada <sup>c</sup>	202	14	13	11	10
Total Rest of North America	202	14	13	11	10
Total North America	2,385	1,857	1,664	1,551	1,529
Trinidad & Tobago	2,473	2,193	2,097	2,221	2,147
Columbia <sup>c</sup>	71	4	–	–	–
Total South America	2,545	2,197	2,097	2,221	2,147
Egypt	430	444	470	444	406
Algeria	126	114	120	117	107
Total Africa	556	558	590	561	513
Azerbaijan <sup>c</sup>	132	139	158	203	230
Western Indonesia	69	59	59	51	47
India <sup>c</sup>	–	146	313	156	131
Vietnam <sup>c</sup>	78	69	–	–	–
Other <sup>c</sup>	294	204	103	81	–
Total Rest of Asia	572	617	633	490	408
Total Asia	572	617	633	490	408
Australia	462	455	435	431	450
Eastern Indonesia	325	340	352	353	364
Total Australasia	787	795	787	784	814
Total subsidiaries <sup>d</sup>	7,332	6,393	6,193	5,845	5,585
<b>Equity-accounted entities (BP share)</b>					
TNK-BP (Russia, Venezuela, Vietnam) <sup>c,e</sup>	640	710	785	184	–
Rosneft (Russia, Canada, Venezuela, Vietnam) <sup>c,f</sup>	–	–	–	617	1,084
Argentina	379	371	355	329	323
Bolivia	11	14	34	55	80
Venezuela <sup>c</sup>	9	5	–	–	–
Other	30	26	26	30	28
Total equity-accounted entities <sup>d</sup>	1,069	1,126	1,200	1,216	1,515
Total subsidiaries and equity-accounted entities	8,401	7,518	7,393	7,060	7,100

<sup>a</sup> Because of rounding, some totals may not agree exactly with the sum of their component parts.

<sup>b</sup> 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.

<sup>c</sup> In 2014, BP divested its interest in the US onshore Hugoton upstream operation. BP also reduced its interest in certain wells in the US onshore Eagle Ford Shale in south Texas. It increased its interest in the Shah Deniz asset in Azerbaijan, in certain UK North Sea assets, and in certain US onshore assets. 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.

<sup>d</sup> 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.

<sup>e</sup> 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.

<sup>f</sup> 2014 is based on preliminary operational results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts. 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				
	2010	2011	2012	2013	2014
US	970	771	675	628	<b>673</b>
Europe	261	209	182	137	<b>123</b>
Russia	967	985	989	963	<b>1,008</b>
Rest of world	1,624	1,489	1,484	1,502	<b>1,347</b>
Total group including equity-accounted entities	3,822	3,454	3,330	3,230	<b>3,151</b>

### BP average liquids realizations<sup>a</sup>

	\$ per barrel				
	2010	2011	2012	2013	2014
US	70.79	96.34	96.35	91.88	<b>84.24</b>
Europe	77.39	107.10	109.05	104.77	<b>93.84</b>
Rest of world	75.23	104.83	105.84	104.20	<b>90.19</b>
BP average	73.41	101.29	102.10	99.24	<b>87.96</b>

<sup>a</sup> Crude oil, condensate and NGLs.

### BP average natural gas realizations

	\$ per thousand cubic feet				
	2010	2011	2012	2013	2014
US	3.88	3.34	2.32	3.07	<b>3.80</b>
Europe	5.49	8.09	8.63	9.68	<b>8.18</b>
Rest of world	3.86	4.98	5.33	5.97	<b>6.35</b>
BP average	3.97	4.69	4.75	5.35	<b>5.70</b>



## 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, South America
	Atlantic LNG Trains 2-3	6.7	42.5	2.8	US, Spain, South America
	Atlantic LNG Train 4	5.2	37.8	2.0	US, Spain, South America
	North West Shelf Trains 1-5	16.3	16.7	2.7	Japan, China, S. Korea
Australia	SEGAS LNG Train 1	5.0	0.0	—	Spain
Egypt	Tangguh Trains 1-2	7.6	37.2	2.8	China, S. Korea, Mexico, Japan
Indonesia	ADGAS Trains 1-3	6.0	10.0	0.6	Japan
Abu Dhabi	Angola LNG	5.2	13.6	0.7	Global
Angola					
<b>Total</b>		<b>55.3</b>		<b>12.7</b>	

### 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)
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
<b>Total</b>		<b>2,210</b>		<b>—</b>	<b>645</b>

### 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)
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
<b>2014</b>	<b>1,431</b>	<b>373</b>	<b>364</b>	<b>59</b>	<b>2,227</b>

### LNG shipping<sup>a</sup>

Vessel name	Status	Ownership	Delivery date	Capacity (m <sup>3</sup> )
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
<b>Total</b>				<b>1,181,000</b>

<sup>a</sup> 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			Thousands of acres									
			Europe		North America		South America	Africa	Asia		Australasia	Total
			UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2014												
Developed	- gross		131	39	6,355	232	1,365	637	4,581	837	194	14,371
	- net		73	16	3,285	110	407	223	865	259	36	5,274
Undeveloped <sup>a</sup>	- gross		1,208	1,754	7,378	9,702	28,183	33,833	378,899	6,988	20,050	487,995
	- net		755	648	5,365	5,564	11,593	21,799	74,009	2,302	10,755	132,790
2013												
Developed	- gross		128	39	6,340	223	1,634	621	4,380	1,982	162	15,509
	- net		71	16	3,334	109	453	221	831	355	35	5,425
Undeveloped <sup>a</sup>	- gross		1,118	1,196	6,669	9,710	29,100	26,538	257,896	20,141	16,021	368,389
	- net		672	403	4,585	7,638	12,943	17,142	50,285	7,258	11,254	112,180
2012												
Developed	- gross		168	39	6,516	228	1,702	605	1,597	2,023	162	13,040
	- net		85	16	3,463	111	461	220	712	400	35	5,503
Undeveloped <sup>a</sup>	- gross		1,273	180	7,469	6,074	27,755	30,684	26,291	26,505	17,854	144,085
	- net		730	77	4,935	4,154	14,032	18,419	11,061	9,339	13,098	75,845
2011												
Developed	- gross		334	65	7,350	228	1,718	560	1,618	1,952	162	13,987
	- net		182	21	4,266	111	450	207	723	384	35	6,379
Undeveloped <sup>a</sup>	- gross		1,276	186	7,210	6,273	10,064	27,000	33,704	56,189	18,641	160,543
	- net		764	79	4,798	4,253	4,571	17,895	14,712	17,890	13,452	78,414
2010												
Developed	- gross		346	65	6,920	198	1,738	497	2,282	2,434	162	14,642
	- net		189	21	4,184	157	471	195	885	935	35	7,072
Undeveloped <sup>a</sup>	- gross		1,311	186	6,970	7,185	12,434	21,373	32,137	18,366	7,330	107,292
	- net		775	79	4,663	4,380	6,398	16,072	15,475	8,955	2,796	59,593

<sup>a</sup> Undeveloped acreage includes leases and concessions.

## Exploration and development wells<sup>a</sup>

		Europe		North America		South America	Africa	Asia		Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
2014											
Exploratory	Productive	2.9	—	5.3	—	3.7	0.7	5.3	0.6	—	18.5
	Dry	0.5	—	7.9	—	1.4	1.6	—	1.4	0.2	13.0
Development	Productive	3.1	1.8	294.1	1.5	100.5	13.8	76.2	46.3	—	537.3
	Dry	—	0.8	—	0.1	3.9	1.0	—	0.4	0.4	6.6
2013											
Exploratory	Productive	1.0	—	12.7	—	4.5	1.5	4.0	3.5	—	27.2
	Dry	—	—	1.1	—	1.4	0.6	—	0.9	0.5	4.5
Development	Productive	1.0	1.2	285.7	—	94.6	12.6	395.0	58.0	0.2	848.3
	Dry	—	0.2	0.4	—	2.7	0.2	—	0.7	0.4	4.6
2012											
Exploratory	Productive	—	0.3	17.1	—	5.8	2.3	14.7	—	—	40.2
	Dry	0.2	—	0.6	—	1.0	0.5	5.0	—	—	7.3
Development	Productive	1.6	—	317.8	—	78.9	17.7	552.5	43.1	—	1,011.6
	Dry	—	—	—	—	—	1.0	—	9.5	—	10.5
2011											
Exploratory	Productive	0.4	—	34.1	—	4.4	2.1	16.7	1.0	0.2	58.9
	Dry	—	—	2.1	—	0.2	—	7.2	0.3	0.3	10.1
Development	Productive	1.7	—	199.4	—	101.3	16.0	582.0	45.1	—	945.5
	Dry	—	—	0.2	—	3.0	2.7	—	0.4	—	6.3
2010											
Exploratory	Productive	—	0.2	39.3	—	1.3	1.2	10.5	2.8	0.3	55.6
	Dry	0.7	—	0.3	—	0.9	1.4	4.0	—	—	7.3
Development	Productive	6.4	1.2	260.0	31.7	105.7	18.9	364.3	53.3	—	841.5
	Dry	1.7	—	0.5	—	1.2	2.7	—	2.4	—	8.5

<sup>a</sup> 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 2014

		Europe		North America		South America	Africa	Asia		Australasia	Total
		UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Oil wells <sup>a</sup>	Gross	116	65	2,407	119	4,752	634	44,548	936	12	53,589
	Net	71	26	823	31	2,620	446	8,798	302	2	13,119
Gas wells <sup>b</sup>	Gross	67	6	22,676	363	728	139	383	833	61	25,256
	Net	28	1	9,339	180	262	53	76	314	13	10,266

<sup>a</sup> Includes approximately 11,271 gross (2,237 net) multiple completion wells (more than one formation producing into the same well bore).

<sup>b</sup> Includes approximately 3,239 gross (1,482 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

### Drilling and production activities in progress at 31 December 2014<sup>a</sup>

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

<sup>a</sup> Includes suspended development and long-term suspended exploratory wells.

# Upstream

## Key indicators<sup>a</sup>

	2010	2011	2012	2013	2014
Result and oil price					
Replacement cost profit before interest and tax (\$ million) <sup>b</sup>	28,269	26,358	22,491	16,657	8,934
Underlying replacement cost profit before interest and tax (\$ million) <sup>b</sup>	25,073	25,217	19,436	18,265	15,201
BP average liquids realizations (\$/bbl) <sup>c d</sup>	73.41	101.29	102.10	99.24	87.96
Finding and development costs (\$ per barrel of oil equivalent (\$/boe), five-year rolling average) <sup>e f g</sup>	17.25	17.70	21.59	25.62	39.81
Finding costs (\$/boe, five-year rolling average) <sup>e g h</sup>	5.33	5.89	7.63	9.29	12.85
Production costs (\$/boe) <sup>i j</sup>	6.77	10.08	12.50	13.16	12.68
Cost of supply (\$/boe) <sup>k</sup>	16.51	22.69	28.00	32.10	33.99
Net income per barrel of oil equivalent (\$/boe)					
BP subsidiaries and equity-accounted entities excluding TNK-BP and Rosneft (\$/boe) <sup>l</sup>	15.33	16.97	15.70	14.55	11.25
Range of other oil majors <sup>m</sup>					
Maximum (\$/boe)	17.30	25.14	22.62	21.71	18.24
Minimum (\$/boe)	11.90	16.20	13.34	12.95	13.84
Reserves replacement					
BP subsidiaries (%)	74	44	(2)	105	29
BP subsidiaries and equity-accounted entities (%) <sup>n o</sup>	106	103	77	129	116
Range of other oil majors <sup>m p</sup>					
Maximum (%)	138	171	160	127	118
Minimum (%)	22	84	40	83	49

<sup>a</sup> Except where indicated, all the data in this table relates to BP subsidiaries only.

<sup>b</sup> Includes equity-accounted entities in the Upstream segment.

<sup>c</sup> Crude oil, condensate and NGLs.

<sup>d</sup> Realizations are based on sales of consolidated subsidiaries only, which excludes equity-accounted entities.

<sup>e</sup> Reserves calculated on an SEC basis.

<sup>f</sup> 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.

<sup>g</sup> Based on additions to reserves including revisions of previous estimates, improved recovery, discoveries and extensions.

<sup>h</sup> 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.

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

<sup>j</sup> Based on production volumes.

<sup>k</sup> 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.

<sup>l</sup> 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).

<sup>m</sup> The 2014 and 2013 peer group include ExxonMobil, Shell, Chevron and Total (2010, 2011 and 2012 also include ConocoPhillips).

<sup>n</sup> 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.

<sup>o</sup> 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.

<sup>p</sup> BP estimates of reserves replacement of other oil majors.

## Financial statistics

	\$ million				
	2010	2011	2012	2013	2014
Replacement cost profit before interest and tax <sup>a</sup>					
US	9,684	6,196	6,918	3,625	4,325
Non-US	18,585	20,162	15,573	13,032	4,609
	28,269	26,358	22,491	16,657	8,934
Underlying replacement cost profit before interest and tax <sup>a</sup>					
US	8,353	6,108	3,854	3,836	4,338
Non-US	16,720	19,109	15,582	14,429	10,863
	25,073	25,217	19,436	18,265	15,201
Operating capital employed					
US	40,065	41,347	38,437	41,320	40,971
Non-US	56,212	64,185	70,387	70,567	66,553
	96,277	105,532	108,824	111,887	107,524
Sales and other operating revenues <sup>b</sup>	66,266	75,754	72,225	70,374	65,424
Capital expenditure and acquisitions <sup>a c</sup>					
US	6,632	5,363	6,385	6,410	6,203
Non-US	11,121	20,458	12,135	12,705	13,569
	17,753	25,821	18,520	19,115	19,772
Employee numbers at year end	21,100	22,400	24,200	24,700	24,400
BP average realizations					
BP average liquids realizations (\$/bbl) <sup>d</sup>	73.41	101.29	102.10	99.24	87.96
BP average natural gas realizations (\$/mcf)	3.97	4.69	4.75	5.35	5.70
Marker prices					
Brent oil (\$/bbl)	79.50	111.26	111.67	108.66	98.95
Alaska North Slope oil (\$/bbl)	79.92	110.12	111.08	107.67	97.52
West Texas Intermediate oil (\$/bbl)	79.45	95.04	94.13	97.99	93.28
Western Canadian Select oil (\$/bbl)	65.72	79.41	72.12	73.33	73.65
Mars oil (\$/bbl)	78.04	107.54	106.79	102.23	92.93
Henry Hub gas price (\$ per million British thermal units) <sup>e</sup>	4.39	4.04	2.79	3.65	4.43

<sup>a</sup> A minor amendment has been made to the split between regions for 2013.

<sup>b</sup> Includes sales to other segments.

<sup>c</sup> Full year 2014 include \$469 million respectively relating to the purchase of additional 3.3% equity in Shah Deniz, Azerbaijan and the South Caucasus Pipeline.

<sup>d</sup> Crude oil, condensate and NGLs.

<sup>e</sup> Henry Hub First of Month Index.

# Downstream

## Key indicators

	2010	2011	2012	2013	2014
Result and refining margin					
Replacement cost profit before interest and tax (\$ million)	5,555	5,470	2,864	2,919	3,738
Underlying replacement cost profit before interest and tax (\$ million)	4,883	6,009	6,463	3,632	4,441
Refining marker margin <sup>a</sup> (\$/bbl)	10.7	14.5	18.2	15.4	14.4
Refining availability <sup>b</sup> (%)	95.0	94.8	94.8	95.3	94.9
Petrochemicals production (thousand tonnes)	15,594	14,866	14,727	13,943	14,014

### Refining marker margin by region<sup>a</sup>

	\$ per barrel				
	2010	2011	2012	2013	2014
US North West	13.9	14.1	18.0	15.2	16.6
US South West	13.1	13.6	17.4	n/a	n/a
US Gulf Coast	10.2	11.9	16.1	n/a	n/a
US Midwest	9.3	24.7	27.8	21.7	17.4
North West Europe	10.4	11.9	16.1	12.9	12.5
Mediterranean	8.8	9.0	12.7	10.5	10.6
Australia	10.4	12.2	14.8	13.4	13.5
BP average RMM	10.7	14.5	18.2	15.4	14.4

<sup>a</sup> 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.

<sup>b</sup> 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.

### Employee numbers at year end

	2010	2011	2012	2013	2014
Non-service station staff	37,100	36,900	37,100	33,900	33,600
Service station staff <sup>a</sup>	15,200	14,600	14,700	14,100	14,400
	52,300	51,500	51,800	48,000	48,000

<sup>a</sup> 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				
	2010	2011	2012	2013	2014
Replacement cost profit (loss) before interest and tax					
US	935	1,415	(242)	758	2,259
Non-US	4,620	4,055	3,106	2,161	1,479
	5,555	5,470	2,864	2,919	3,738
Underlying replacement cost profit (loss) before interest and tax					
US	564	1,978	3,045	1,123	1,684
Non-US	4,319	4,031	3,418	2,509	2,757
	4,883	6,009	6,463	3,632	4,441
Replacement cost profit (loss) before interest and tax <sup>a</sup>					
Fuels	2,628	2,999	1,403	1,518	2,830
Lubricants	1,357	1,350	1,276	1,274	1,407
Petrochemicals	1,570	1,121	185	127	(499)
	5,555	5,470	2,864	2,919	3,738
Non-operating items and fair value accounting effects <sup>b</sup>					
Fuels	381	(640)	(3,609)	(712)	(389)
Lubricants	(47)	100	(9)	2	136
Petrochemicals	338	1	19	(3)	(450)
	672	(539)	(3,599)	(713)	(703)
Underlying replacement cost profit before interest and tax <sup>a</sup>					
Fuels	2,247	3,639	5,012	2,230	3,219
Lubricants	1,404	1,250	1,285	1,272	1,271
Petrochemicals	1,232	1,120	166	130	(49)
	4,883	6,009	6,463	3,632	4,441
Operating capital employed					
US	23,463	24,627	24,835	23,835	19,079
Non-US	24,959	26,457	25,488	25,680	19,799
	48,422	51,084	50,323	49,515	38,878
Sales and other operating revenues <sup>c</sup>	266,751	344,033	346,391	351,195	323,486
Property, plant and equipment (net book value)					
US	14,151	11,833	14,603	16,468	16,033
Non-US	13,996	15,246	15,320	15,131	13,647
	28,147	27,079	29,923	31,599	29,680
Capital expenditure and acquisitions					
US	2,761	2,691	3,475	2,535	942
Non-US	1,268	1,594	1,774	1,971	2,164
	4,029	4,285	5,249	4,506	3,106

<sup>a</sup> 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.

<sup>b</sup> 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.

<sup>c</sup> Includes sales to other segments.

## Refinery throughputs and utilization

### Refinery throughputs<sup>a</sup>

	thousand barrels per day				
	2010	2011	2012	2013	2014
US	1,350	1,277	1,310	726	<b>642</b>
Europe	775	771	751	766	<b>782</b>
Rest of world	301	304	293	299	<b>297</b>
	<b>2,426</b>	<b>2,352</b>	<b>2,354</b>	<b>1,791</b>	<b>1,721</b>
Crude distillation capacity at 31 December <sup>b</sup>	2,667	2,679	2,681	1,955	<b>1,957</b>
Refinery capacity utilization <sup>c</sup>	91%	88%	88%	86%	<b>88%</b>

<sup>a</sup> Refinery throughputs reflect crude oil and other feedstock volumes.

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

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

### Crude oil input

	%				
	2010	2011	2012	2013	2014
Low sulphur crude <sup>a</sup>	42	43	46	48	<b>45</b>
High sulphur crude	58	57	54	52	<b>55</b>

<sup>a</sup> Low sulphur crude is a crude which has sulphur content of less than 0.5%.

### Refinery yield<sup>a</sup>

	thousand barrels per day				
	2010	2011	2012	2013	2014
Aviation fuels	290	304	316	236	<b>211</b>
Gasolines	881	844	880	616	<b>578</b>
Middle distillates	723	691	700	598	<b>582</b>
Fuel oil	93	114	86	71	<b>91</b>
Other products <sup>b</sup>	497	425	420	274	<b>282</b>
	<b>2,484</b>	<b>2,378</b>	<b>2,402</b>	<b>1,795</b>	<b>1,744</b>

<sup>a</sup> Refinery yields exceed throughputs because of volumetric expansion.

<sup>b</sup> Other products include lubricants, petrochemicals, bitumen, petroleum coke and LPG.



## Refineries

### Refinery capacities

Refinery capacities		thousand barrels per day																	
		Crude distillation capacities <sup>a</sup>										Major upgrading plant capacities <sup>b</sup>							
		Group interest % <sup>c</sup>	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 <sup>d</sup>	Sulphur <sup>e</sup>	Other <sup>f</sup>	Nelson Complexity Index <sup>g</sup>
Wholly and partly owned refineries at 31 December 2014																			
US																			
Washington	Cherry Point	100.0	234	234	112	–	65	65	–	97	74	–	58	24	–	179	245	–	10.2
Indiana	Whiting	100.0	430	430	264	168	–	65	31	129	351	–	102	26	30	30	1,700	–	11.5
Ohio	Toledo	50.0	160	80	36	28	16	21	6	20	34	–	18	–	5	–	176	–	11.2
			824	744	412	196	81	151	37	246	459	–	178	50	35	209	2,121	–	11.1
Europe																			
Germany	Bayernoil <sup>h</sup>	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 <sup>h</sup>	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	19	–	128	140	–	13.4
	Schwedt <sup>h</sup>	18.8	239	45	29	11	–	7	2	18	35	9	–	5	1	7	90	1	9.9
Netherlands	Rotterdam	100.0	377	377	82	59	–	32	8	73	270	34	–	–	–	20	231	3	5.7
Spain	Castellón	100.0	110	110	47	30	–	17	3	57	87	–	22	19	–	45	65	–	10.1
			1,625	847	320	137	68	118	15	257	535	57	66	57	12	331	1,003	6	8.4
Rest of world																			
Australia	Bulwer	100.0	102	102	39	23	20	16	–	22	43	–	–	–	–	32	60	–	7.2
	Kwinana	100.0	146	146	22	35	–	25	7	44	52	–	–	21	2	–	70	–	6.2
New Zealand	Whangarei <sup>h</sup>	23.7	118	28	11	–	7	7	–	10	12	–	–	–	–	13	40	–	7.5
South Africa	Durban <sup>h</sup>	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	288	3	7.2
			2,995	1,957	832	410	176	334	60	604	1,145	70	244	136	50	586	3,412	9	9.2

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

<sup>b</sup> These are shown as BP share of capacities; BP has varying interests.

<sup>c</sup> BP share of equity, which is not necessarily the same as BP share of processing entitlements.

<sup>d</sup> Reported as standard cubic feet per day.

<sup>e</sup> Reported as tonnes per day.

<sup>f</sup> Other consists of ethyl tertiary butyl ether, methyl tertiary butyl ether and lubricants units.

<sup>g</sup> 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.

<sup>h</sup> Indicates refineries not operated by BP.

### Regional refining distillation capacity

		thousand barrels per day				
		2010	2011	2012	2013	2014
US Gulf Coast <sup>a</sup>		475	475	475	–	–
US Midwest		485	493	493	508	510
US West Coast <sup>b</sup>		500	500	500	234	234
Total US		1,460	1,468	1,468	742	744
Europe		844	845	847	847	847
Rest of world		363	366	366	366	366
Total		2,667	2,679	2,681	1,955	1,957

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

<sup>b</sup> 266 kbd of West Coast capacity relating to Carson refinery was classified as an asset held for sale at 31 December 2012.

## Retail sites<sup>a</sup>

	at 31 December				
	2010	2011	2012	2013	2014
US	11,300	11,300	10,100	7,700	<b>7,100</b>
Europe	8,400	8,200	8,300	8,000	<b>8,000</b>
Rest of world	2,400	2,300	2,300	2,100	<b>2,100</b>
	<b>22,100</b>	<b>21,800</b>	<b>20,700</b>	<b>17,800</b>	<b>17,200</b>

<sup>a</sup> The number of retail sites includes sites not operated by BP but instead operated by dealers, jobbers, franchisees or brand licensees 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*. Excludes our interests in equity-accounted entities that are dual-branded.

## Oil sales volumes<sup>a</sup>

	thousand barrels per day				
	2010	2011	2012	2013	2014
Refined product marketing sales volumes by region					
US					
Aviation fuels	188	190	210	231	<b>214</b>
Gasolines	958	927	914	786	<b>726</b>
Middle distillates	228	217	204	176	<b>145</b>
Fuel oil	30	38	36	35	<b>28</b>
Other products <sup>b</sup>	29	29	32	54	<b>53</b>
	<b>1,433</b>	<b>1,401</b>	<b>1,396</b>	<b>1,282</b>	<b>1,166</b>
Europe					
Aviation fuels	264	251	253	254	<b>218</b>
Gasolines	259	240	225	222	<b>212</b>
Middle distillates	627	602	586	599	<b>577</b>
Fuel oil	147	109	70	80	<b>106</b>
Other products <sup>b</sup>	105	103	96	82	<b>64</b>
	<b>1,402</b>	<b>1,305</b>	<b>1,230</b>	<b>1,237</b>	<b>1,177</b>
Rest of world					
Aviation fuels	94	95	95	104	<b>93</b>
Gasolines	109	106	106	98	<b>96</b>
Middle distillates	157	156	156	170	<b>175</b>
Fuel oil	214	215	199	164	<b>140</b>
Other products <sup>b</sup>	36	33	31	29	<b>25</b>
	<b>610</b>	<b>605</b>	<b>587</b>	<b>565</b>	<b>529</b>
Total marketing sales volumes by product					
Aviation fuels	546	536	558	589	<b>525</b>
Gasolines	1,326	1,273	1,245	1,105	<b>1,033</b>
Middle distillates	1,012	975	946	945	<b>896</b>
Fuel oil	391	362	305	280	<b>274</b>
Other products <sup>d</sup>	170	165	159	165	<b>144</b>
Total marketing sales <sup>c</sup>	<b>3,445</b>	<b>3,311</b>	<b>3,213</b>	<b>3,084</b>	<b>2,872</b>
Trading/supply sales <sup>d</sup>	<b>2,482</b>	<b>2,465</b>	<b>2,444</b>	<b>2,485</b>	<b>2,448</b>
Total refined product sales	<b>5,927</b>	<b>5,776</b>	<b>5,657</b>	<b>5,569</b>	<b>5,320</b>
Crude oil sales <sup>e</sup>	<b>1,658</b>	<b>1,532</b>	<b>1,518</b>	<b>2,142</b>	<b>2,360</b>
Total oil sales	<b>7,585</b>	<b>7,308</b>	<b>7,175</b>	<b>7,711</b>	<b>7,680</b>

<sup>a</sup> Excludes sales to other BP businesses and sales of petrochemicals products.

<sup>b</sup> Other products include lubricants, petroleum coke, bitumen and LPG.

<sup>c</sup> Marketing sales include sales 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.

<sup>d</sup> Trading/supply sales are sales to large unbranded resellers and other oil companies.

<sup>e</sup> Crude oil sales relate to transactions executed by our integrated supply and trading function, primarily for optimizing crude oil supplies to our refineries and in other trading. 88,000 barrels per day relate to revenues reported by the Upstream segment.

## Sales and other operating revenues of refined product

	\$ million				
	2010	2011	2012	2013	2014
US	80,576	111,020	108,196	90,917	<b>79,795</b>
Europe	88,347	108,302	107,325	108,585	<b>94,806</b>
Rest of world	40,298	54,618	59,145	58,513	<b>52,481</b>
	<b>209,221</b>	<b>273,940</b>	<b>274,666</b>	<b>258,015</b>	<b>227,082</b>

## Petrochemicals production capacity<sup>a</sup>

			BP share of capacity thousand tonnes per annum <sup>b</sup>				
			Product				
Geographical area	Site	Group interest % <sup>c</sup>	PTA	PX	Acetic acid	Olefins and derivatives	Others
<b>US</b>							
	Cooper River	100.0	1,300	–	–	–	–
	Decatur <sup>d</sup>	100.0	1,000	700	–	–	–
	Texas City	100.0	–	1,300	600 <sup>e</sup>	–	100
			2,300	2,000	600	–	100
<b>Europe</b>							
UK	Hull	100.0	–	–	500	–	200
Belgium	Geel	100.0	1,300	700	–	–	–
Germany	Gelsenkirchen <sup>f</sup>	50-61.0	–	–	–	1,800 <sup>g</sup>	–
	Mülheim <sup>f</sup>	50.0	–	–	–	–	100
			1,300	700	500	1,800	300
<b>Rest of world</b>							
Trinidad & Tobago	Point Lisas	36.9	–	–	–	–	700
China	Caojing	50.0	–	–	–	3,300	–
	Chongqing	51.0	–	–	200	–	100
	Nanjing	50.0	–	–	300	–	–
	Zhuhai <sup>h</sup>	85.0	1,800	–	–	–	–
Indonesia	Merak	100.0	500	–	–	–	–
South Korea	Ulsan	51.0	–	–	300	–	100
Malaysia	Kertih	70.0	–	–	400	–	–
Taiwan	Kaohsiung	61.4	300	–	–	–	–
	Mai Liao	50.0	–	–	200	–	–
	Taichung	61.4	500	–	–	–	–
			3,100	–	1,400	3,300	900
			6,700	2,700	2,500	5,100	1,300
<b>Total BP share of capacity at 31 December 2014</b>							<b>18,300</b>

### Petrochemicals production capacities summary

BP share of capacity, thousand tonnes per annum						
By geographical area	PTA	PX	Acetic acid	Olefins and derivatives	Others	Total
US	2,300	2,000	600	–	100	<b>5,000</b>
Europe	1,300	700	500	1,800	300	<b>4,600</b>
Rest of world	3,100	–	1,400	3,300	900	<b>8,700</b>
<b>Total BP share of capacity at 31 December 2014</b>	<b>6,700</b>	<b>2,700</b>	<b>2,500</b>	<b>5,100</b>	<b>1,300</b>	<b>18,300</b>

<sup>a</sup> 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.

<sup>b</sup> Capacities are shown to the nearest hundred thousand tonnes per annum.

<sup>c</sup> Includes BP share of equity-accounted entities, as indicated.

<sup>d</sup> This site has capacity under 100,000 tonnes per annum for a speciality product (e.g. naphthalene dicarboxylate and ethylidene diacetate).

<sup>e</sup> Group interest is quoted at 100%, reflecting the capacity entitlement, which is marketed by BP.

<sup>f</sup> 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.

<sup>g</sup> Group interest varies by product.

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

## Petrochemicals production<sup>a</sup>

thousand tonnes					
By geographical area	2010	2011	2012	2013	2014
US	4,146	4,029	4,047	4,264	<b>3,844</b>
Europe	4,051	3,854	3,927	3,779	<b>3,851</b>
Rest of world	7,397	6,983	6,753	5,900	<b>6,319</b>
	15,594	14,866	14,727	13,943	<b>14,014</b>

<sup>a</sup> Comprises actual production in respect of the products listed in the capacity table above.

## Operational and financial information

	\$ million				
	2010	2011	2012	2013 <sup>a</sup>	2014
<b>Financial statistics</b>					
Profit before interest and tax <sup>b</sup>	–	–	–	2,053	<b>2,076</b>
Inventory holding (gains) losses	–	–	–	100	<b>24</b>
Replacement cost profit before interest and tax <sup>b</sup>	–	–	–	2,153	<b>2,100</b>
Net charge (credit) for non-operating items	–	–	–	45	<b>(225)</b>
Underlying replacement cost profit before interest and tax <sup>b</sup>	–	–	–	2,198	<b>1,875</b>

<sup>a</sup> From 21 March 2013.

<sup>b</sup> 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.

<sup>c</sup> 2014 includes \$25 million of foreign exchange losses arising on the dividend received (\$5 million loss in 2013). This amount is not reflected in the following table.

The Rosneft segment result includes 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				
	2010	2011	2012	2013	2014
<b>Income statement (BP share)</b>					
Profit before interest and tax	–	–	–	2,786	<b>3,825</b>
Finance costs	–	–	–	(264)	<b>(1,033)</b>
Taxation	–	–	–	(422)	<b>(677)</b>
Non-controlling interests	–	–	–	(42)	<b>(14)</b>
Net income	–	–	–	2,058	<b>2,101</b>
Inventory holding losses, net of tax	–	–	–	100	<b>24</b>
Net income on a replacement cost basis	–	–	–	2,158	<b>2,125</b>
Net charge (credit) for non-operating items, net of tax	–	–	–	45	<b>(225)</b>
Net income on an underlying RC basis	–	–	–	2,203	<b>1,900</b>
<b>Balance sheet</b>					
Investment in associates	–	–	–	13,681	<b>7,312</b>
<b>Cash flow</b>					
Dividends received	–	–	–	456	<b>693</b>
<b>Production (net of royalties)(BP Share)<sup>d</sup></b>					
Liquids (thousand barrels per day) <sup>e</sup>	–	–	–	650	<b>821</b>
Natural gas (million cubic feet per day)	–	–	–	617	<b>1,084</b>
Total hydrocarbons (thousand barrels of oil equivalent per day (mboe/d)) <sup>f</sup>	–	–	–	756	<b>1,008</b>
<b>Average oil marker prices</b>					
	\$ per barrel				
	2010	2011	2012	2013	2014
Urals (north-west Europe – CIF)	78.26	109.08	110.19	107.38	<b>97.23</b>
Russian domestic oil	36.96	49.57	53.98	54.97	<b>50.40</b>

<sup>d</sup> 2013 reflects production for the period 21 March to 31 December 2013, averaged over the full year.

<sup>e</sup> Liquids comprise crude oil, condensate and natural gas liquids.

<sup>f</sup> Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

# Other businesses and corporate

## Financial statistics

	\$ million				
	2010	2011	2012	2013	2014
Replacement cost profit (loss) before interest and tax					
US	(731)	(1,230)	(1,641)	(1,249)	(954)
Non-US	(785)	(1,238)	(1,153)	(1,070)	(1,056)
	(1,516)	(2,468)	(2,794)	(2,319)	(2,010)
Underlying replacement cost profit (loss) before interest and tax					
US	(493)	(797)	(859)	(800)	(594)
Non-US	(823)	(849)	(1,137)	(1,098)	(746)
	(1,316)	(1,646)	(1,996)	(1,898)	(1,340)
Operating capital employed					
US	(2,905)	(3,149)	(4,115)	(1,459)	(2,334)
Non-US	17,285	8,506	14,785	19,818	23,023
	14,380	5,357	10,670	18,359	20,689
Sales and other operating revenues <sup>a</sup>	3,328	2,957	1,985	1,805	1,989
Capital expenditure and acquisitions					
US	977	877	681	231	82
Non-US	257	976	754	819	821
	1,234	1,853	1,435	1,050	903
Employee numbers at year end <sup>b c</sup>	6,300	10,200	10,400	11,200	12,100

<sup>a</sup> Includes sales to other segments.

<sup>b</sup> 2014 includes 5,300 (2013 4,300 2012 3,500 and 2011 3,300) agricultural, operational and seasonal workers in Brazil. The number of workers in 2010 was not included as the activity was within a joint venture.

<sup>c</sup> Includes employees of the Gulf Coast Restoration Organization.

## Biofuels and wind

	2010	2011	2012	2013	2014
Biofuels					
Total net ethanol-equivalent production (million litres per annum) <sup>a</sup>	105	314	404	521	653
Crush capacity (million tonnes per annum)	1.2	7.2	7.2	7.4	10.0
Wind capacity <sup>b</sup>					
US	742	1,016	1,558	1,558	1,556
Non-US	32	32	32	32	32
	774	1,048	1,590	1,590	1,588

<sup>a</sup> Ethanol-equivalent production includes ethanol and sugar.

<sup>b</sup> 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 2014, 2013 and 2012; 1,763MW in 2011; and 1,362MW in 2010. This includes 32MW of capacity in the Netherlands which is managed by our Downstream segment.

# TNK-BP

## Operational and financial information

	\$ million				
	2010	2011	2012	2013	2014
<b>Financial statistics</b>					
Profit before interest and tax <sup>a</sup>	2,617	4,185	3,370	12,500	–
Inventory holdings gains and losses	–	(51)	3	–	–
Replacement cost profit before interest and tax	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	2,617	4,134	3,127	–	–

<sup>a</sup> 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				
	2010	2011	2012	2013	2014
<b>Income statement (BP share)</b>					
Profit before interest and tax	3,866	5,992	4,405	–	–
Finance costs	(128)	(132)	(84)	–	–
Taxation	(913)	(1,333)	(979)	–	–
Non-controlling interest	(208)	(342)	(356)	–	–
Net income <sup>b</sup>	2,617	4,185	2,986	–	–
Inventory holding gains, net of tax	–	(51)	3	–	–
Net income on a replacement cost basis	2,617	4,134	2,989	–	–
Net charge (credit) for non-operating items, net of tax <sup>c</sup>	–	–	138	–	–
Net income on an underlying RC basis	2,617	4,134	3,127	–	–

	\$ million				
	2010	2011	2012	2013	2014
<b>Balance sheet</b>					
Investment in associates <sup>d</sup>	9,995	10,013	–	–	–

	\$ million				
	2010	2011	2012	2013	2014
<b>Cash flow</b>					
Dividends received <sup>e</sup>	1,780	3,747	1,399	–	–

	2010	2011	2012	2013	2014
<b>Production (net of royalties)(BP share)<sup>f,g</sup></b>					
Crude oil (thousand barrels per day)	856	871	876	187	–
Natural gas (million cubic feet per day)	640	710	784	184	–
Total hydrocarbons (thousand barrels of oil equivalent per day (mboe/d)) <sup>h</sup>	967	994	1,012	218	–

	\$ per barrel				
	2010	2011	2012	2013	2014
<b>Average oil marker prices</b>					
Urals (north-west Europe – CIF)	78.26	109.08	110.19	107.38	97.23
Russian domestic oil	36.96	49.57	53.98	54.97	50.40

<sup>b</sup> 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.

<sup>c</sup> Disclosure of non-operating items for TNK-BP began in the first quarter of 2012.

<sup>d</sup> 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.

<sup>e</sup> 2012 includes the dividend of \$709 million received after the date equity accounting ceased.

<sup>f</sup> 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.

<sup>g</sup> 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.

<sup>h</sup> Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

## Abbreviations

### ADS

American depositary share. 1 ADS = 6 ordinary shares.

### Barrel (bbl)

159 litres, 42 US gallons.

### GAAP

Generally accepted accounting practice.

### IFRS

International Financial Reporting Standards.

### LNG

Liquefied natural gas.

### LPG

Liquefied petroleum gas.

### mb/d

Thousand barrels per day.

### mboe/d

Thousand barrels of oil equivalent per day.

### mmb/d

Million barrels of oil equivalent per day.

### MWh

Megawatt per hour.

### NGLs

Natural gas liquids.

### PX

Paraxylene.

### PTA

Purified terephthalic acid.

### RC

Replacement cost.

### SEC

The United States Securities and Exchange Commission.

## Glossary

Unless the context indicates otherwise, the definitions for the following glossary terms are given below.

### Associate

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

### Consolidation adjustment – UPII

Unrealized profit in inventory arising on inter-segment transactions.

### Fair value accounting effects

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

BP enters into 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 require that inventory held for trading is recorded at its fair value using period-end spot prices, whereas any related derivative commodity instruments are required to be recorded at values based on forward prices consistent with the contract maturity. Depending on market conditions, these forward prices can be either higher or lower than spot prices, resulting in measurement differences. BP enters into contracts for pipelines and storage capacity, oil and gas processing and liquefied natural gas (LNG) that, under IFRS, are recorded on an accruals basis. These contracts are risk-managed using a variety of derivative instruments that are fair valued under IFRS. This results in measurement differences in relation to recognition of gains and losses.

The way 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 the underlying exposure and the commodity contracts for business requirements are accounted for on an accruals basis. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole.

### Gearing

See Net debt and net debt ratio definition.

### Inventory holding gains and losses

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

### Joint arrangement

An arrangement in which two or more parties have joint control.

### Joint operation

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement.

### Joint venture

A joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the arrangement.

### Liquids

Comprises crude oil, condensate and natural gas liquids. For reserves, it also includes bitumen.

### Net debt and net debt ratio (gearing)

Non-GAAP measures. Net debt includes 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. The derivatives are reported on the balance sheet within the headings 'Derivative financial instruments'. We believe that net debt and net debt ratio provide useful information to investors. Net debt enables investors to see the economic effect of gross debt, related hedges and cash and cash equivalents in total. The net debt ratio enables investors to see how significant net debt is relative to equity from shareholders. The net debt ratio is defined as 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. See BP Annual Report and Form 20-F, Financial statements – Note 25 for information on gross debt, which is the nearest equivalent measure to net debt on an IFRS basis.

### Non-operating items

Charges and credits arising in consolidated entities and in TNK-BP and Rosneft that are included in the financial statements and that BP discloses separately because it considers such disclosures to be meaningful and relevant to investors. They are items that management considers not to be part of underlying business operations and are disclosed in order to enable investors better to understand and evaluate the group's reported financial performance.

### Organic capital expenditure

Excludes acquisitions, asset exchanges, and other inorganic capital expenditure. An analysis of capital expenditure by segment and region is shown in the *BP Annual Report 2014*, Financial statements – Note 4.

### Production-sharing agreement (PSA)

An arrangement through which an oil company bears the risks and costs of exploration, development and production. In return, if exploration is successful, the oil company receives entitlement to variable physical volumes of hydrocarbons, representing recovery of the costs incurred and a stipulated share of the production remaining after such cost recovery.

### Replacement cost (RC) profit or loss

Reflects the replacement cost of inventories sold in the period and is arrived at by excluding inventory holding gains and losses from profit or loss. RC profit or loss is the measure of profit or loss that is required to be disclosed for each operating segment under International Financial Reporting Standards (IFRS). RC profit or loss for the group is not a recognized GAAP measure.

Management believes this measure is useful to illustrate to investors the fact that crude oil and product prices can vary significantly from period to period and that the impact on our reported result under IFRS can be significant. Inventory holding gains and losses vary from period to period due to changes in prices as well as changes in underlying inventory levels. In order for investors to understand the operating performance of the group excluding the impact of price changes on the replacement of inventories, and to make comparisons of operating performance between reporting periods, BP's management believes it is helpful to disclose this measure. See *BP Annual Report and Form 20-F*, Financial statements – Note 4.

### 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.

### Underlying production

2014 underlying production, when compared with 2013, is after adjusting for the effects of the Abu Dhabi onshore concession expiry in January 2014, divestments and entitlement impacts in our production-sharing agreements. 2015 underlying production, when comparing with 2014, is after adjusting for divestments and entitlement impacts in our production-sharing agreements.

### Underlying RC profit or loss

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. See BP Annual Report and Form 20-F, pages 209 and 210 for additional information on the non-operating items and fair value accounting effects that are used to arrive at underlying RC profit or loss in order to enable a full understanding of the events and their financial impact. BP believes that underlying RC profit or loss is a useful measure for investors because it is a measure closely tracked by management to evaluate BP's operating performance and to make financial, strategic and operating decisions and because it may help investors to understand and evaluate, in the same manner as management, the underlying trends in BP's operational performance on a comparable basis, year on year, by adjusting for the effects of these non-operating items and fair value accounting effects. The nearest equivalent measure on an IFRS basis for the group is profit or loss for the year attributable to BP shareholders. The nearest equivalent measure on an IFRS basis for segments is RC profit or loss before interest and taxation.



See [bp.com/investorglossary](http://bp.com/investorglossary) for more information.



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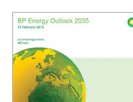
#### **Annual Report and Form 20-F 2014**

Details of our financial and operating performance in print and online. Published in March.  
[bp.com/annualreport](http://bp.com/annualreport)



#### **Strategic Report 2014**

A summary of our financial and operating performance in print and online. Published in March.  
[bp.com/annualreport](http://bp.com/annualreport)



#### **Energy Outlook 2035**

Projections for world energy markets, considering the potential evolution of global economy, population, policy and technology. Published in February.  
[bp.com/energyoutlook](http://bp.com/energyoutlook)



#### **Sustainability Report 2014**

Details of our sustainability performance with additional information online. Published in March.  
[bp.com/sustainability](http://bp.com/sustainability)



#### **Financial and Operating Information 2010-2014**

Five-year financial and operating data in PDF and Excel format. Published in April.  
[bp.com/financialandoperating](http://bp.com/financialandoperating)



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