HEWLETT PACKARD CO
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Subject Company: Compaq Computer Corporation
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This filing relates to a planned merger (the "Merger") between Hewlett-Packard Company ("HP") and Compaq Computer Corporation ("Compaq") pursuant to the terms of an Agreement and Plan of Reorganization, dated as of September 4, 2001 (the "Merger Agreement"), by and among HP, Heloise Merger Corporation and Compaq. The Merger Agreement is on file with the Securities and Exchange Commission as an exhibit to the Current Report on Form 8-K, as amended, filed by Hewlett-Packard Company on September 4, 2001, and is incorporated by reference into this filing.

SETTING THE RECORD STRAIGHT

Mr. Hewlett's press release merely recycles prior assertions in an attempt to breathe life into arguments that have been previously discredited.

A detailed analysis filed by Hewlett-Packard Company with the SEC on December 19, 2001 discusses in detail why this merger creates significant shareowner value and highlights many of the central flaws in Mr. Hewlett's financial presentation.

HP's analysis incorporates careful consideration of the costs required to acquire Compaq Computer Corporation, as well as the impact of potential revenue loss, potential cost savings and potential integration costs. The HP analysis also reflects detailed, business-by-business analysis involving highly experienced management teams and their business, legal and financial advisors.

The HP/Compaq merger will create near and long-term shareowner value for the following reasons:

- HP conservatively anticipates $2.5 billion of annual pretax cost savings by FY2004, adding $5 and $9 to the net present value of each HP share.

- HP expects the merger to facilitate broad improvement in financial performance across all key business segments leading to a more balanced, profitable combined company. For example, overall operating margins are expected to improve from 5% to 9% by FY2003, and the Enterprise and Access segments, which posted operating losses in fiscal 2001, are reasonably expected to show significant margin improvements, achieving 9% and 3% operating margins, respectively, by FY2003.

- The merger is expected to lead to substantial accretion to HP's earnings: 13% accretion in first full year (FY03) earnings per share.

- HP's financial case is based on credible, experience-tested, detailed analysis. For example, the revenue forecast reflects conservative assumptions on revenue loss, is based on detailed segment analysis and assumes no revenue upside.

Illustrative of the flaws in Mr. Hewlett's argument are several statements in his press release:

MR. HEWLETT'S ASSERTION: That the transaction will be dilutive.

THE FACTS: Based on carefully prepared financial analysis, HP reasonably expects the value of its stock to increase. In the first full year of combined operations (FY2003), the transaction is expected to be 13% accretive to HP EPS. As cost savings reach full realization in FY2004, the transaction is expected to be more accretive to EPS thereafter. Mr. Hewlett's counterclaims are unreliable because they are based on faulty assumptions as illustrated below.

MR. HEWLETT'S ASSERTION: That the $2.5 billion in annual cost savings is unrealistic and the calculation of $5-$9 per share present value of the cost savings is misleading.

THE FACTS: To the contrary, HP's cost savings estimates are, if anything, conservative. HP, working closely with Compaq, reviewed detailed cost saving opportunities in purchasing, administration, sales management and other areas. The present value of these cost savings, net of the revenue loss is $5 and $9 per share, assuming price/earnings multiples ranging between 15X (creating the $5) and 25X (creating the $9). Mr. Hewlett's press release shows that HP's P/E multiple is 23X, suggesting HP's multiple assumptions are reasonable to conservative. The expected benefits are based on detailed analysis and integration work, not generalization, and will drive significant value for HP shareowners.

MR. HEWLETT'S ASSERTION: That HP's revenue loss assumptions are unrealistic.

THE FACTS: HP assumptions regarding revenue loss reflect an in-depth, product-by-product analysis. HP's analysis assumes 18% revenue loss in Home PCs, 8% in Consumer PCs, 7% in Appliances, 11% in UNIX servers, 6% in NT servers and 5% in Storage, which leads to cumulative revenue loss of 10% in exposed Enterprise and Access segments, 5% overall revenue loss. These estimates reflect the judgment of operating managers with input from McKinsey & Co. By contrast, the $8 billion of projected revenue loss that Mr. Hewlett's filing references would imply an unrealistically high 18% revenue loss on business segments HP considers exposed to merger-related revenue loss.

MR. HEWLETT'S CLAIM: In preparing financial analysis relating to the merger, a 25% contribution margin should be applied.

THE FACTS: As noted in HP's filing of December 19, 2001, HP believes that Mr. Hewlett's arguments regarding the contribution margin on revenue loss are significantly overstated. HP performed a careful, business-by-business analysis to estimate the proper contribution margin to apply to

each business. The 12% contribution margin HP applied reflects a blending of the various contribution margins by product and segment. These estimates reflect the judgment of operating managers, with input from McKinsey & Co and Accenture. By contrast, the analysis of the "independent analyst" cited in Mr. Hewlett's argument, does not reflect product-by-product level of product overlap and profitability. Given that revenue loss is expected to be "concentrated in PCs" (quoted from Mr. Hewlett's SEC filing) which have comparatively low contribution margins far below 25%, a weighted average of 25% is implausible to impossible.

MR. HEWLETT'S ASSERTION: That HP has failed to acknowledge the risks of the integration.

THE FACTS: HP fully appreciates the challenge of integration and has consistently acknowledged that the integration process is complex, requiring extensive program management, continuous oversight and careful execution. Members of HP's board and management team have overseen multiple large mergers as well as other significant complex transactions. As a result, the team began addressing integration plans and challenges prior to even completing the agreement to merge. The resulting program has dedicated two senior executives to full-time oversight, with a team of more than 450 employees dedicated to integration planning. This team is currently in its third, and final, phase of integration planning. At the same time, both the management teams of HP and Compaq have beaten expectations in their most recently reported quarters, demonstrating their ability to keep the businesses focused during the merger even with the distractions created by Mr. Hewlett.

In sum, this transaction will be a source of substantial value creation over both the near and long-term. HP intends to review the filing in detail and will provide supplemental response as appropriate.

FORWARD-LOOKING STATEMENTS

This document contains forward-looking statements that involve risks, uncertainties and assumptions. If any of these risks or uncertainties materializes or any of these assumptions proves incorrect, the results of HP and its consolidated subsidiaries could differ materially from those expressed or implied by such forward-looking statements.

All statements other than statements of historical fact are statements that could be deemed forward-looking statements, including any projections of earnings, revenues, synergies, accretion or other financial items; any statements of the plans, strategies, and objectives of management for future operations, including the execution of integration and restructuring plans and the anticipated timing of filings, approvals and closings relating to the Merger or other planned acquisitions; any statements concerning proposed new products, services, developments or industry rankings; any statements regarding future economic conditions or performance; any statements of belief and any statements of assumptions underlying any of the foregoing.

The risks, uncertainties and assumptions referred to above include the ability of HP to retain and motivate key employees; the timely development, production and acceptance of products and services and their feature sets; the challenge of managing asset levels, including inventory; the flow of products into third-party distribution channels; the difficulty of keeping expense growth at modest levels while increasing revenues; the challenges of integration and restructuring associated with the Merger or other planned acquisitions and the challenges of achieving anticipated synergies; the possibility that the Merger or other planned acquisitions may not close or that HP, Compaq or other parties to planned acquisitions may be required to modify some aspects of the acquisition transactions in order to obtain regulatory approvals; the assumption of maintaining revenues on a combined company basis following the close of the Merger or other planned acquisitions; and other risks that are described from time to time in HP's Securities and Exchange Commission reports, including but not limited to the annual report on Form 10-K for the year ended October 31, 2000 and HP's amended registration statement on Form S-4 filed on January 14, 2002.

HP assumes no obligation and does not intend to update these forward-looking statements.

ADDITIONAL INFORMATION ABOUT THE MERGER AND WHERE TO FIND IT

On January 14, 2002, HP filed an amended registration statement with the SEC containing an amended preliminary joint proxy statement/prospectus regarding the Merger. Investors and security holders of HP and Compaq are urged to read the amended preliminary joint proxy statement/prospectus filed with the SEC on January 14, 2002 and the definitive joint proxy statement/prospectus when it becomes available and any other relevant materials filed by HP or Compaq with the SEC because they contain, or will contain, important information about HP, Compaq and the Merger. The definitive joint proxy statement/prospectus will be sent to the security holders of HP and Compaq seeking their approval of the proposed transaction. The amended preliminary joint proxy statement/prospectus filed with the SEC on January 14, 2002, the definitive joint proxy statement/prospectus and other relevant materials (when they become available), and any other documents filed by HP or Compaq with the SEC, may be obtained free of charge at the SEC's web site at www.sec.gov. In addition, investors and security holders may obtain free copies of the documents filed with the SEC by HP by contacting HP Investor Relations, 3000 Hanover Street, Palo Alto, California 94304, 650-857-1501. Investors and security holders may obtain free copies of the documents filed with the SEC by Compaq by contacting Compaq Investor Relations, P.O. Box 692000, Houston, Texas 77269-2000, 800-433-2391. Investors and security holders are urged to read the definitive joint proxy statement/prospectus and the other relevant materials when they become available before making any voting or investment decision with respect to the Merger.

HP, Carleton S. Fiorina, HP's Chairman of the Board and Chief Executive Officer, Robert P. Wayman, HP's Executive Vice President, Finance and Administration and Chief Financial Officer, and certain of HP's other executive officers and directors may be deemed to be participants in the solicitation of proxies from the shareowners of HP and Compaq in favor of the Merger. The other executive officers and directors of HP who may be participants in the solicitation of proxies in connection with the Merger have not been determined as of the date of this filing. A description of the interests of Ms. Fiorina, Mr. Wayman and HP's other executive officers and directors in HP is set forth in the proxy statement for HP's 2001 Annual Meeting of Shareowners, which was filed with the SEC on January 25, 2001. Investors and security holders may obtain more detailed information regarding the direct and indirect interests of Ms. Fiorina, Mr. Wayman and HP's other executive officers and directors in the Merger by reading the amended preliminary joint proxy statement/prospectus filed with the SEC on January 14, 2002 and the definitive joint proxy statement/prospectus when it becomes available.

Pursuant to an engagement letter dated July 25, 2001, HP retained Goldman, Sachs & Co. ("Goldman Sachs") to act as its financial advisor in connection with the Merger. In connection with the engagement of Goldman Sachs as financial advisor, HP anticipates that employees of Goldman Sachs may communicate in person, by telephone or otherwise with certain institutions, brokers or other persons who are shareowners for the purpose of assisting in the solicitation of proxies in favor of the Merger. Although Goldman Sachs does not admit that it or any of its directors, officers, employees or affiliates is a "participant," as defined in Schedule 14A under the Securities and Exchange Act of 1934, as amended, or that Schedule 14A requires the disclosure of certain information concerning them in connection with the Merger, Gene Sykes (Managing Director), Matthew L'Heureux (Managing Director), George Lee (Vice President) and Jean Manas (Vice President), in each case of Goldman Sachs, may assist HP in the solicitation of proxies in favor of the Merger.

Compaq and Michael D. Capellas, Compaq's Chairman and Chief Executive Officer, and certain of Compaq's other executive officers and directors may be deemed to be participants in the solicitation of proxies from the shareowners of Compaq and HP in favor of the Merger. The other executive officers and directors of

Compaq who may be participants in the solicitation of proxies in connection with the Merger have not been determined as of the date of this filing. A description of the interests of Mr. Capellas and Compaq's other executive officers and directors in Compaq is set forth in the proxy statement for Compaq's 2001 Annual Meeting of Shareholders, which was filed with the SEC on March 12, 2001. Investors and security holders may obtain more detailed information regarding the direct and indirect interests of Mr. Capellas and Compaq's other executive officers and directors in the Merger by reading the amended preliminary joint proxy statement/prospectus filed with the SEC on January 14, 2002 and the definitive joint proxy statement/prospectus when it becomes available.

* * * * *

gas pipelines, processing and export terminals and LNG processing facilities and transportation are excluded. In addition, our midstream activities of marketing and trading of natural gas, power and NGLs in the US, Canada, UK and Europe are excluded. The most significant midstream pipeline interests include the Trans-Alaska Pipeline System, the Forties Pipeline System, the Central Area Transmission System pipeline, the South Caucasus Pipeline and the Baku-Tbilisi-Ceyhan pipeline. Major LNG activities are located in Trinidad, Indonesia and Australia and BP is also investing in the LNG business in Angola.

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

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

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

[e] Excludes goodwill associated with business combinations.

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

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

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

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

[j] Midstream and other activities exclude inventory holding gains and losses.

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

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Oil and natural gas exploration and production activities continued

$ million

	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US	Rest of North America			Russia[a]	Rest of Asia		
Equity-accounted entities (BP share)[b]										
Capitalized costs at 31 December[c]										
Gross capitalized costs										
Proved properties					6,958			4,036		10,994
Unproved properties					21			16		37
					6,979			4,052		11,031
Accumulated depreciation					2,965			3,648		6,613
Net capitalized costs					4,014			404		4,418
Costs incurred for the year ended 31 December[c]										
Acquisition of properties[d]										
Proved							4			4
Unproved					439		15			454
					439		19			458
Exploration and appraisal costs[e]					31		195	7		233
Development					599		1,560	556		2,715
Total costs					1,069		1,774	563		3,406
Results of operations for the year ended 31 December										
Sales and other operating revenues[f]										
Third parties					2,267		6,472	4,245		12,984
Sales between businesses							3,639	21		3,660
					2,267		10,111	4,266		16,644
Exploration expenditure					31		93	1		125
Production costs					555		1,605	295		2,455
Production taxes					959		4,400	3,245		8,604
Other costs (income)					(11)		(24)	(2)		(37)
Depreciation, depletion and amortization					328		786	538		1,652
Impairments and losses on sale of businesses and fixed assets							(27)			(27)

			1,862		6,833	4,077	12,772
Profit (loss) before taxation			405		3,278	189	3,872
Allocable taxes			294		536	54	884
Results of operations			111		2,742	135	2,988
Exploration and production activities equity-accounted entities after tax (as above)			111		2,742	135	2,988
Midstream and other activities after tax[g]	35	16	49	48	263	505	916
Total replacement cost profit after interest and tax	35	16	160	48	3,005	640	3,904

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

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

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

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

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

[f] Presented net of transportation costs and sales taxes.

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

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Movements in estimated net proved reserves

million barrels

Crude oil[a b]										2014
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	160	147	1,007		15	316		320	49	2,013
Undeveloped	374	53	752		17	180		202	19	1,597
	534	200	1,760		31	495		522	69	3,610
Changes attributable to										
Revisions of previous estimates	(41)	(68)	87		9	20		96	(2)	101
Improved recovery	2		16		1	3				23
Purchases of reserves-in-place	5							12		17
Discoveries and extensions	5				1			8		13
Production[d]	(17)	(15)	(123)		(5)	(81)		(57)	(7)	(305)
Sales of reserves-in-place			(45)		(5)					(50)
	(46)	(82)	(66)		1	(58)		59	(9)	(201)
At 31 December[e]										
Developed	159	95	1,030		10	317		384	40	2,035
Undeveloped	329	22	664		22	120		197	19	1,375
	488	117	1,694		32	437		581	59	3,409
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					316	2	2,970	120		3,407
Undeveloped				1	314	2	1,858	7		2,182
				1	630	4	4,828	127		5,590
Changes attributable to										
Revisions of previous estimates					4	(2)	213	9		224
Improved recovery					12					12
Purchases of reserves-in-place										
Discoveries and extensions					10		187			197
Production					(26)		(297)	(36)		(359)

Sales of reserves-in-place						(2)	103	(27)		74
At 31 December[g]										
Developed					316	2	2,997	89		3,405
Undeveloped					314		1,933	11		2,258
				1	630	2	4,930	101		5,663
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	160	147	1,007		331	317	2,970	440	49	5,421
Undeveloped	374	53	752	1	331	182	1,858	209	19	3,779
	534	200	1,760	1	661	499	4,828	649	69	9,200
At 31 December										
Developed	159	95	1,030		326	319	2,997	473	40	5,440
Undeveloped	329	22	664		336	120	1,933	208	19	3,632
	488	117	1,694	1	662	439	4,930	682	59	9,072

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

[d] Includes 10 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[f] Includes 38 million barrels of crude oil in respect of the 0.15% non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

million barrels

Natural gas liquids[a] [b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	**9**	**16**	**290**		**14**	**4**			**8**	**342**
Undeveloped	**6**	**2**	**155**		**28**	**15**			**3**	**209**
	15	**18**	**444**		**43**	**20**			**10**	**551**
Changes attributable to										
Revisions of previous estimates	**(6)**	**(2)**	**15**			**(6)**				**1**
Improved recovery			**13**							**13**
Purchases of reserves-in-place										**1**
Discoveries and extensions										
Production[c]	**(1)**	**(2)**	**(27)**		**(4)**	**(2)**			**(1)**	**(36)**
Sales of reserves-in-place			**(18)**							**(18)**
	(6)	**(4)**	**(17)**		**(4)**	**(8)**			**(1)**	**(40)**
At 31 December[d]										
Developed	**6**	**13**	**323**		**11**	**5**			**6**	**364**
Undeveloped	**3**	**1**	**104**		**28**	**7**			**3**	**146**
	9	**14**	**427**		**39**	**12**			**10**	**510**
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed						**8**	**94**			**103**
Undeveloped						**8**	**21**			**29**
						16	**115**			**131**
Changes attributable to										
Revisions of previous estimates							**(69)**			**(69)**
Improved recovery										
Purchases of reserves-in-place										
Discoveries and extensions										
Production										
Sales of reserves-in-place										
						(1)	**(69)**			**(69)**
At 31 December[f]										
Developed						**15**	**30**			**46**

Undeveloped						**16**		**16**
					15	**46**		**62**
Total subsidiaries and equity-accounted entities (BP share)								
At 1 January								
Developed	**9**	**16**	**290**	**14**	**13**	**94**	**8**	**444**
Undeveloped	**6**	**2**	**155**	**28**	**23**	**21**	**3**	**238**
	15	**18**	**444**	**43**	**36**	**115**	**10**	**682**
At 31 December								
Developed	**6**	**13**	**323**	**11**	**20**	**30**	**6**	**410**
Undeveloped	**3**	**1**	**104**	**28**	**7**	**16**	**3**	**163**
	9	**14**	**427**	**39**	**27**	**46**	**10**	**572**

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

[d] Includes 12 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

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

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Movements in estimated net proved reserves continued

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

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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Movements in estimated net proved reserves continued

million barrels

Total liquids[a b]	Europe		North America		South America	Africa	Asia		Australasia	2014 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	169	163	1,297		29	320		320	57	2,354
Undeveloped	380	55	907	188	46	195		202	22	1,994
	549	217	2,204	188	74	515		523	78	4,348
Changes attributable to										
Revisions of previous estimates	(47)	(70)	101	(16)	9	14		96	(2)	86
Improved recovery	2		28		1	3				36
Purchases of reserves-in-place	5							12		18
Discoveries and extensions	5				1			8		14
Production[d]	(17)	(17)	(150)		(9)	(83)		(57)	(8)	(341)
Sales of reserves-in-place			(63)		(5)					(68)
	(52)	(86)	(83)	(16)	(3)	(66)		59	(10)	(257)
At 31 December[e]										
Developed	166	108	1,352	9	21	322		384	46	2,407
Undeveloped	332	23	769	163	50	127		197	22	1,684
	497	131	2,121	172	71	449		581	68	4,092
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					316	10	3,063	120		3,510
Undeveloped				1	314	10	1,879	7		2,210
				1	630	20	4,943	127		5,721
Changes attributable to										
Revisions of previous estimates					4	(3)	144	9		155
Improved recovery					12					12
Purchases of reserves-in-place										
Discoveries and extensions					10		187			197
Production					(26)		(297)	(36)		(359)
Sales of reserves-in-place										

						(3)	**34**	**(27)**		**4**
At 31 December[g h]										
Developed					**316**	**17**	**3,028**	**89**		**3,451**
Undeveloped					**314**		**1,949**	**11**		**2,274**
				1	**630**	**17**	**4,976**	**101**		**5,725**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	**169**	**163**	**1,297**		**345**	**331**	**3,063**	**440**	**57**	**5,865**
Undeveloped	**380**	**55**	**907**	**188**	**359**	**205**	**1,879**	**209**	**22**	**4,204**
	549	**217**	**2,204**	**189**	**704**	**535**	**4,943**	**650**	**78**	**10,069**
At 31 December										
Developed	**166**	**108**	**1,352**	**9**	**337**	**339**	**3,028**	**473**	**46**	**5,858**
Undeveloped	**332**	**23**	**769**	**164**	**364**	**127**	**1,949**	**208**	**22**	**3,958**
	497	**131**	**2,121**	**173**	**701**	**466**	**4,976**	**682**	**68**	**9,817**

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

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

[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 38 million barrels in respect of the non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	2014 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[c]	(30)	(40)	(625)	(4)	(792)	(218)		(165)	(302)	(2,177)
Sales of reserves-in-place			(266)							(266)
	(189)	(85)	(332)	7	(559)	(271)		389	(652)	(1,691)
At 31 December[d]										
Developed	382	300	7,168	17	2,352	901		1,688	3,316	16,124
Undeveloped	386	19	2,447		6,313	1,597		3,892	1,719	16,372
	768	318	9,615	17	8,666	2,497		5,580	5,035	32,496
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed					1,364	230	4,171	72		5,837
Undeveloped				1	747	135	5,054	14		5,951
				1	2,111	365	9,225	86		11,788
Changes attributable to										
Revisions of previous estimates				1	(87)	38	767	1		720
Improved recovery					23					23
Purchases of reserves-in-place					69		183			252

Discoveries and extensions										
Production[c]					**(172)**	**(3)**	**(390)**	**(18)**		**(583)**
Sales of reserves-in-place										
					(166)	**35**	**560**	**(17)**		**412**
At 31 December[f g]										
Developed				**1**	**1,228**	**400**	**4,674**	**60**		**6,363**
Undeveloped				**1**	**717**		**5,111**	**9**		**5,837**
				1	**1,945**	**400**	**9,785**	**69**		**12,200**
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	**643**	**364**	**7,122**	**10**	**4,473**	**1,191**	**4,171**	**1,591**	**3,932**	**23,497**
Undeveloped	**314**	**39**	**2,825**	**1**	**6,863**	**1,942**	**5,054**	**3,685**	**1,755**	**22,478**
	957	**403**	**9,947**	**11**	**11,336**	**3,133**	**9,225**	**5,276**	**5,687**	**45,975**
At 31 December										
Developed	**382**	**300**	**7,168**	**18**	**3,581**	**1,301**	**4,674**	**1,748**	**3,316**	**22,487**
Undeveloped	**386**	**19**	**2,447**	**1**	**7,030**	**1,597**	**5,111**	**3,901**	**1,719**	**22,209**
	768	**318**	**9,615**	**18**	**10,610**	**2,897**	**9,785**	**5,648**	**5,035**	**44,695**

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Includes 181 billion cubic feet of natural gas consumed in operations, 151 billion cubic feet in subsidiaries, 29 billion cubic feet in equity-accounted entities.

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

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

[f] Includes 91 billion cubic feet of natural gas in respect of the 0.18% non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]										2014
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	280	225	2,525	2	564	486		582	735	5,399
Undeveloped	434	62	1,394	188	1,100	507		835	324	4,844
	714	287	3,919	190	1,664	993		1,417	1,059	10,243
Changes attributable to										
Revisions of previous estimates	(91)	(78)	96	(14)	(36)	(1)		90	(62)	(96)
Improved recovery	3		129		39	8				180
Purchases of reserves-in-place	6		1					68		74
Discoveries and extensions	21		1		47	1		54		123
Production[e f]	(23)	(24)	(258)	(1)	(146)	(121)		(86)	(60)	(717)
Sales of reserves-in-place			(109)		(5)					(114)
	(84)	(101)	(140)	(14)	(99)	(113)		126	(122)	(548)
At 31 December[g]										
Developed	232	160	2,588	12	426	477		675	618	5,187
Undeveloped	398	26	1,191	163	1,139	403		868	319	4,507
	630	186	3,779	175	1,565	880		1,543	937	9,694
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed					552	50	3,782	133		4,517
Undeveloped				1	442	33	2,751	9		3,236
				1	994	83	6,533	142		7,753
Changes attributable to										
Revisions of previous estimates					(11)	4	276	9		278
Improved recovery					16					16
Purchases of reserves-in-place										
Discoveries and extensions					22		219			241

Production[f]					(56)	(1)	(365)	(39)		(460)
Sales of reserves-in-place					(29)	3	130	(29)		75
At 31 December[i j]										
Developed					528	86	3,834	100		4,548
Undeveloped				1	438		2,830	13		3,280
				1	965	86	6,663	112		7,828
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996
At 31 December										
Developed	232	160	2,588	12	954	563	3,834	775	618	9,735
Undeveloped	398	26	1,191	164	1,576	403	2,830	881	319	7,788
	630	186	3,779	176	2,530	966	6,663	1,656	937	17,523

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

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

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

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

[g] Includes 456 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[i] Includes 54 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

million barrels

Crude oil[a b]										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	228	153	1,127		16	306		268	45	2,143
Undeveloped	426	73	818		20	236		137	34	1,743
	654	226	1,945		36	542		405	79	3,886
Changes attributable to										
Revisions of previous estimates	(79)	(15)	(111)		1	30		65	(5)	(114)
Improved recovery	11		33		1	2		65		112
Purchases of reserves-in-place										
Discoveries and extensions			2					39	3	44
Production	(21)	(11)	(108)		(7)	(79)		(52)	(8)	(285)
Sales of reserves-in-place	(31)		(1)							(32)
	(120)	(26)	(185)		(5)	(47)		117	(10)	(276)
At 31 December[d]										
Developed	160	147	1,007		15	316		320	49	2,013
Undeveloped	374	53	752		17	180		202	19	1,597
	534	200	1,760		31	495		522	69	3,610
Equity-accounted entities (BP share)[e f]										
At 1 January										
Developed					336	3	2,433	198		2,970
Undeveloped					347	2	1,943	13		2,305
					683	5	4,376	211		5,275
Changes attributable to										
Revisions of previous estimates				1	(14)	(1)	295	1		281
Improved recovery					27					27
Purchases of reserves-in-place					34		4,550			4,584
Discoveries and extensions					12		228			240
Production					(27)		(301)	(85)		(412)

Sales of reserves-in-place					(85)		(4,321)			(4,406)
				1	(53)	(1)	451	(84)		314
At 31 December[g]										
Developed					316	2	2,970	120		3,407
Undeveloped				1	314	2	1,858	7		2,182
				1	630	4	4,828	127		5,590
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	228	153	1,127		352	309	2,433	466	45	5,113
Undeveloped	426	73	818		367	239	1,943	150	34	4,048
	654	226	1,945		719	547	4,376	616	79	9,162
At 31 December										
Developed	160	147	1,007		331	317	2,970	440	49	5,421
Undeveloped	374	53	752	1	331	182	1,858	209	19	3,779
	534	200	1,760	1	661	499	4,828	649	69	9,200

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

[d] Includes 8 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

[f] Includes 23 million barrels of crude oil in respect of the 0.47% non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

million barrels

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

Developed					8	94		103
Undeveloped					8	21		29
					16	115		131
Total subsidiaries and equity-accounted entities (BP share)								
At 1 January								
Developed	14	17	316	9	15	59	7	437
Undeveloped	5	6	171	16	27	19	11	257
	19	23	487	25	43	78	18	693
At 31 December								
Developed	9	16	290	14	13	94	8	444
Undeveloped	6	2	155	28	23	21	3	238
	15	18	444	43	36	115	10	682

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

[d] Includes 13 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

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

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Movements in estimated net proved reserves continued

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

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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Movements in estimated net proved reserves continued

										million barrels
Total liquids[a] [b]										2013
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	242	170	1,444		22	312		268	52	2,509
Undeveloped	431	79	989	195	32	255		137	45	2,164
	673	249	2,433	195	54	567		405	96	4,673
Changes attributable to										
Revisions of previous estimates	(78)	(19)	(141)	(7)	30	26		65	(12)	(136)
Improved recovery	12		52		1	2		65		132
Purchases of reserves-in-place										
Discoveries and extensions			3					39	3	45
Production[d]	(22)	(13)	(132)		(11)	(80)		(52)	(9)	(319)
Sales of reserves-in-place	(36)		(12)							(48)
	(124)	(31)	(229)	(7)	20	(52)		117	(18)	(324)
At 31 December[e]										
Developed	169	163	1,297		29	320		320	57	2,354
Undeveloped	380	55	907	188	46	195		202	22	1,994
	549	217	2,204	188	74	515		523	78	4,348
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					339	12	2,492	198		3,041
Undeveloped					351	11	1,962	13		2,337
					691	23	4,453	211		5,378
Changes attributable to										
Revisions of previous estimates				1	(21)	(3)	384	1		362
Improved recovery					27					27
Purchases of reserves-in-place					34		4,579			4,613
Discoveries and extensions					11		228			239
Production					(27)		(302)	(85)		(414)

Sales of reserves-in-place					(85)		(4,399)			(4,485)
				1	(61)	(3)	490	(84)		343
At 31 December[g h]										
Developed					316	10	3,063	120		3,510
Undeveloped				1	314	10	1,879	7		2,210
				1	630	20	4,943	127		5,721
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	242	170	1,444		361	324	2,492	466	52	5,550
Undeveloped	431	79	989	195	384	266	1,962	150	45	4,501
	673	249	2,433	195	745	590	4,453	616	96	10,051
At 31 December										
Developed	169	163	1,297		345	331	3,063	440	57	5,865
Undeveloped	380	55	907	188	359	205	1,879	209	22	4,204
	549	217	2,204	189	704	535	4,943	650	78	10,069

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

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

[e] Also includes 21 million barrels in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 23 million barrels in respect of the non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	1,038	340	8,245	4	3,588	1,139		926	3,282	18,562
Undeveloped	666	141	2,986		6,250	1,923		413	2,323	14,702
	1,704	481	11,231	4	9,838	3,062		1,339	5,605	33,264
Changes attributable to										
Revisions of previous estimates	(62)	(47)	(1,166)	10	62	(138)		2,148	(140)	667
Improved recovery	49		630		144	28		94		945
Purchases of reserves-in-place	9									9
Discoveries and extensions			39			55		1,875	511	2,480
Production[c]	(66)	(31)	(635)	(4)	(819)	(239)		(199)	(289)	(2,282)
Sales of reserves-in-place	(677)		(152)					(67)		(896)
	(747)	(78)	(1,284)	6	(613)	(294)		3,851	82	923
At 31 December[d]										
Developed	643	364	7,122	10	3,109	961		1,519	3,932	17,660
Undeveloped	314	39	2,825		6,116	1,807		3,671	1,755	16,527
	957	403	9,947	10	9,225	2,768		5,190	5,687	34,187
Equity-accounted entities (BP share)[e]										
At 1 January										
Developed					1,276	175	2,617	128		4,196
Undeveloped					904	164	1,759	18		2,845
					2,180	339	4,376	146		7,041
Changes attributable to										
Revisions of previous estimates				1	3	29	685	1		719
Improved recovery					64			3		67
Purchases of reserves-in-place					14		8,871	33		8,918
					51		254			305

Discoveries and extensions										
Production[c]					(163)	(3)	(292)	(23)		(481)
Sales of reserves-in-place					(38)		(4,669)	(74)		(4,781)
				1	(69)	26	4,849	(60)		4,747
At 31 December[f g]										
Developed					1,364	230	4,171	72		5,837
Undeveloped				1	747	135	5,054	14		5,951
				1	2,111	365	9,225	86		11,788
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	1,038	340	8,245	4	4,864	1,314	2,617	1,054	3,282	22,758
Undeveloped	666	141	2,986		7,154	2,087	1,759	431	2,323	17,547
	1,704	481	11,231	4	12,018	3,401	4,376	1,485	5,605	40,305
At 31 December										
Developed	643	364	7,122	10	4,473	1,191	4,171	1,591	3,932	23,497
Undeveloped	314	39	2,825	1	6,863	1,942	5,054	3,685	1,755	22,478
	957	403	9,947	11	11,336	3,133	9,225	5,276	5,687	45,975

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

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

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

[f] Includes 41 billion cubic feet of natural gas in respect of the 0.44% non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]	Europe		North America		South America	Africa	Asia		Australasia	2013 Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	421	229	2,865	1	640	508		427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587		209	445	4,699
	967	332	4,369	196	1,750	1,095		636	1,063	10,408
Changes attributable to										
Revisions of previous estimates	(89)	(27)	(342)	(5)	41	3		435	(36)	(20)
Improved recovery	20		161		25	7		81		294
Purchases of reserves-in-place	2									2
Discoveries and extensions			10			9		363	91	473
Production[e f]	(34)	(18)	(241)	(1)	(152)	(121)		(86)	(59)	(712)
Sales of reserves-in-place	(152)		(38)					(12)		(202)
	(253)	(45)	(450)	(6)	(86)	(102)		781	(4)	(165)
At 31 December[g]										
Developed	280	225	2,525	2	564	486		582	735	5,399
Undeveloped	434	62	1,394	188	1,100	507		835	324	4,844
	714	287	3,919	190	1,664	993		1,417	1,059	10,243
Equity-accounted entities (BP share)[h]										
At 1 January										
Developed					559	43	2,943	220		3,765
Undeveloped					508	39	2,265	15		2,827
					1,067	82	5,208	235		6,592
Changes attributable to										
Revisions of previous estimates				1	(20)	2	502	1		486
Improved recovery					38			1		39
Purchases of reserves-in-place					36		6,108	6		6,150
Discoveries and extensions					20		272			292

Production[f]					(55)	(1)	(353)	(88)		(497)
Sales of reserves-in-place					(92)		(5,204)	(13)		(5,309)
				1	(73)	1	1,325	(93)		1,161
At 31 December[i j]										
Developed					552	50	3,782	133		4,517
Undeveloped				1	442	33	2,751	9		3,236
				1	994	83	6,533	142		7,753
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	421	229	2,865	1	1,199	551	2,943	647	618	9,474
Undeveloped	546	103	1,504	195	1,618	626	2,265	224	445	7,526
	967	332	4,369	196	2,817	1,177	5,208	871	1,063	17,000
At 31 December										
Developed	280	225	2,525	2	1,116	536	3,782	715	735	9,916
Undeveloped	434	62	1,394	189	1,542	540	2,751	844	324	8,080
	714	287	3,919	191	2,658	1,076	6,533	1,559	1,059	17,996

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

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

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

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

[g] Includes 484 million barrels of oil equivalent in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[i] Includes 30 million barrels of oil equivalent in respect of the non-controlling interest in Rosneft.

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

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Movements in estimated net proved reserves continued

million barrels

Crude oil[a b]	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US[c]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	276	66	1,337		23	304		176	50	2,233
Undeveloped	436	208	1,021		30	294		279	36	2,304
	712	274	2,357		53	598		455	86	4,537
Changes attributable to										
Revisions of previous estimates	(30)	(23)	(288)		(11)	(1)		(2)		(354)
Improved recovery	3		77			13		2		95
Purchases of reserves-in-place	4		4							8
Discoveries and extensions		1	10			2				12
Production	(30)	(8)	(115)		(6)	(70)		(51)	(8)	(287)
Sales of reserves-in-place	(6)	(18)	(101)							(124)
	(59)	(48)	(412)		(17)	(56)		(51)	(8)	(650)
At 31 December[d e]										
Developed	228	153	1,127		16	306		268	45	2,143
Undeveloped	426	73	818		20	236		137	34	1,743
	654	226	1,945		36	542		405	79	3,886
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					345		2,596	256		3,197
Undeveloped					344	3	1,613	58		2,018
					689	3	4,209	314		5,215
Changes attributable to										
Revisions of previous estimates					(2)	3	377	(23)		355
Improved recovery					24		47			71
Purchases of reserves-in-place										

Discoveries and extensions						67			67
Production				(29)		(309)	(80)		(418)
Sales of reserves-in-place						(15)			(15)
				(7)	3	167	(103)		60
At 31 December[g h i]									
Developed				336	3	2,433	198		2,970
Undeveloped				347	2	1,943	13		2,305
				683	5	4,376	211		5,275
Total subsidiaries and equity-accounted entities (BP share)									
At 1 January									
Developed	276	66	1,337	368	304	2,596	432	50	5,430
Undeveloped	436	208	1,021	375	297	1,613	337	36	4,322
	712	274	2,357	743	601	4,209	769	86	9,752
At 31 December									
Developed	228	153	1,127	352	309	2,433	466	45	5,113
Undeveloped	426	73	818	367	239	1,943	150	34	4,048
	654	226	1,945	719	547	4,376	616	79	9,162

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

[d] Includes 9 million barrels of crude oil in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[e] Includes assets held for sale of 39 million barrels.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

[g] Includes 328 million barrels of crude oil in respect of the 7.35% non-controlling interest in TNK-BP.

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

[i] Includes assets held for sale of 4,463 million barrels.

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Movements in estimated net proved reserves continued

million barrels

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

Undeveloped				4	9	19			32
				7	18	78			103
Total subsidiaries and equity-accounted entities (BP share)									
At 1 January									
Developed	12	3	348	8	7		1	9	387
Undeveloped	9	22	152	21	32			11	248
	21	25	501	29	39		1	20	635
At 31 December									
Developed	14	17	316	9	15	59		7	437
Undeveloped	5	6	171	16	27	19		11	257
	19	23	487	25	43	78		18	693

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

[d] Includes 5 million barrels of NGL in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

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

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

[g] Includes assets held for sale of 78 million barrels.

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Movements in estimated net proved reserves continued

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

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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Movements in estimated net proved reserves continued

million barrels

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

At 31 December[h i j]										
Developed					339	12	2,492	198		3,041
Undeveloped					351	11	1,962	13		2,337
					691	23	4,453	211		5,378
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	287	69	1,686		376	311	2,595	433	59	5,817
Undeveloped	445	230	1,173	178	396	328	1,614	337	47	4,748
	733	299	2,859	178	772	640	4,209	770	106	10,565
At 31 December										
Developed	242	170	1,444		361	324	2,492	466	52	5,550
Undeveloped	431	79	989	195	384	266	1,962	150	45	4,501
	673	249	2,433	195	745	590	4,453	616	96	10,051

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

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

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

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

[f] Includes assets held for sale of 4,540 million barrels.

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

[h] Includes 328 million barrels in respect of the non-controlling interest in TNK-BP.

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

[j] Includes assets held for sale of 39 million barrels.

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Movements in estimated net proved reserves continued

billion cubic feet

Natural gas[a b]	Europe		North America		South America	Africa	Asia		Australasia	2012 Total
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	1,411	43	9,721	28	2,869	1,224		1,034	3,570	19,900
Undeveloped	909	450	3,831		6,529	2,033		364	2,365	16,481
	2,320	493	13,552	28	9,398	3,257		1,398	5,935	36,381
Changes attributable to										
Revisions of previous estimates	(18)	(13)	(1,853)	(19)	(116)	(14)		38	(41)	(2,036)
Improved recovery	95		885		756	69		156		1,961
Purchases of reserves-in-place	17	(1)	232							248
Discoveries and extensions		7	225		598	1				831
Production[c]	(164)	(5)	(661)	(5)	(775)	(251)		(253)	(289)	(2,403)
Sales of reserves-in-place	(546)		(1,149)		(23)					(1,718)
	(616)	(12)	(2,321)	(24)	440	(195)		(59)	(330)	(3,117)
At 31 December[d e]										
Developed	1,038	340	8,245	4	3,588	1,139		926	3,282	18,562
Undeveloped	666	141	2,986		6,250	1,923		413	2,323	14,702
	1,704	481	11,231	4	9,838	3,062		1,339	5,605	33,264
Equity-accounted entities (BP share)[f]										
At 1 January										
Developed					1,144		2,119	104		3,367
Undeveloped					1,006	195	659	51		1,911
					2,150	195	2,778	155		5,278
Changes attributable to										
Revisions of previous estimates					86	144	569	25		824
Improved recovery					110			1		111
Purchases of reserves-in-place										

Discoveries and extensions					3		1,310			1,313
Production[c]					(169)		(280)	(35)		(484)
Sales of reserves-in-place							(1)			(1)
					30	144	1,598	(9)		1,763
At 31 December[g h i]										
Developed					1,276	175	2,617	128		4,196
Undeveloped					904	164	1,759	18		2,845
					2,180	339	4,376	146		7,041

Total subsidiaries and equity-accounted entities (BP share)

At 1 January										
Developed	1,411	43	9,721	28	4,013	1,224	2,119	1,138	3,570	23,267
Undeveloped	909	450	3,831		7,535	2,228	659	415	2,365	18,392
	2,320	493	13,552	28	11,548	3,452	2,778	1,553	5,935	41,659
At 31 December										
Developed	1,038	340	8,245	4	4,864	1,314	2,617	1,054	3,282	22,758
Undeveloped	666	141	2,986		7,154	2,087	1,759	431	2,323	17,547
	1,704	481	11,231	4	12,018	3,401	4,376	1,485	5,605	40,305

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] Includes 190 billion cubic feet of natural gas consumed in operations, 145 billion cubic feet in subsidiaries, 45 billion cubic feet in equity-accounted entities and excludes 9 billion cubic feet of produced non-hydrocarbon components that meet regulatory requirements for sales.

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

[e] Includes assets held for sale of 590 billion cubic feet.

[f] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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

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

[i] Includes assets held for sale of 4,492 billion cubic feet.

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Movements in estimated net proved reserves continued

million barrels of oil equivalent[c]

Total hydrocarbons[a b]										2012
	Europe		North America		South America	Africa	Asia		Australasia	Total
	UK	Rest of Europe	US[d]	Rest of North America			Russia	Rest of Asia		
Subsidiaries										
At 1 January										
Developed	531	76	3,362	5	522	522		355	675	6,048
Undeveloped	602	308	1,833	178	1,173	665		342	455	5,556
	1,133	384	5,195	183	1,695	1,187		697	1,130	11,604
Changes attributable to										
Revisions of previous estimates	(33)	(27)	(600)	14	(31)	(3)		5	(8)	(683)
Improved recovery	19		293		130	25		29		496
Purchases of reserves-in-place	7		61							68
Discoveries and extensions		2	62		103	2				169
Production[e f]	(59)	(9)	(256)	(1)	(143)	(116)		(95)	(59)	(738)
Sales of reserves-in-place	(100)	(18)	(386)		(4)					(508)
	(166)	(52)	(826)	13	55	(92)		(61)	(67)	(1,196)
At 31 December[g h]										
Developed	421	229	2,865	1	640	508		427	618	5,709
Undeveloped	546	103	1,504	195	1,110	587		209	445	4,699
	967	332	4,369	196	1,750	1,095		636	1,063	10,408
Equity-accounted entities (BP share)[i]										
At 1 January										
Developed					546		2,961	274		3,781
Undeveloped					522	48	1,727	66		2,363
					1,068	48	4,688	340		6,144
Changes attributable to										
Revisions of previous estimates					13	34	560	(19)		588
Improved recovery					43		47			90
Purchases of reserves-in-place										
Discoveries and extensions					1		292			293

Production[e f]					(58)		(364)	(86)		(508)
Sales of reserves-in-place							(15)			(15)
					(1)	34	520	(105)		448
At 31 December[j k l]										
Developed					559	43	2,943	220		3,765
Undeveloped					508	39	2,265	15		2,827
					1,067	82	5,208	235		6,592
Total subsidiaries and equity-accounted entities (BP share)										
At 1 January										
Developed	531	76	3,362	5	1,068	522	2,961	629	675	9,829
Undeveloped	602	308	1,833	178	1,695	713	1,727	408	455	7,919
	1,133	384	5,195	183	2,763	1,235	4,688	1,037	1,130	17,748
At 31 December										
Developed	421	229	2,865	1	1,199	551	2,943	647	618	9,474
Undeveloped	546	103	1,504	195	1,618	626	2,265	224	445	7,526
	967	332	4,369	196	2,817	1,177	5,208	871	1,063	17,000

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

[b] Because of rounding, some totals may not exactly agree with the sum of their counterparts.

[c] 5.8 billion cubic feet of natural gas = 1 million barrels of oil equivalent.

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

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

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

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

[h] Includes assets held for sale of 140 million barrels of oil equivalent.

[i] Volumes of equity-accounted entities include volumes of equity-accounted investments of those entities.

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

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

[l] Includes assets held for sale of 5,315 million barrels of oil equivalent.

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

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

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

$ millio

	Europe		North America		South America	Africa	Asia		Australasia	201 Tota
	UK	Rest of Europe	US	Rest of North America			Russia	Rest of Asia		
At 31 December										
Subsidiaries										
Future cash inflows[a]	**54,400**	**14,900**	**216,600**	**11,000**	**35,300**	**55,800**		**90,300**	**54,800**	**533,10**
Future production cost[b]	**21,400**	**8,100**	**90,500**	**4,800**	**11,300**	**15,600**		**41,500**	**17,600**	**210,80**
Future development cost[b]	**7,300**	**1,400**	**24,500**	**1,600**	**8,000**	**9,600**		**23,000**	**5,700**	**81,10**
Future taxation[c]	**16,400**	**3,000**	**32,900**	**700**	**8,400**	**10,100**		**5,100**	**9,400**	**86,00**
Future net cash flows	**9,300**	**2,400**	**68,700**	**3,900**	**7,600**	**20,500**		**20,700**	**22,100**	**155,20**
10% annual discount[d]	**4,700**	**700**	**33,100**	**2,500**	**3,100**	**7,800**		**11,000**	**11,800**	**74,70**
Standardized measure of discounted future net cash flows[e]	**4,600**	**1,700**	**35,600**	**1,400**	**4,500**	**12,700**		**9,700**	**10,300**	**80,50**

Equity-accounted entities (BP share)[f]										
Future cash inflows[a]					**47,300**		**349,200**	**10,200**		**406,70**
Future production cost[b]					**22,300**		**200,000**	**7,800**		**230,10**
Future development cost[b]					**5,700**		**17,400**	**2,100**		**25,20**
Future taxation[c]					**6,700**		**24,200**	**100**		**31,00**
Future net cash flows					**12,600**		**107,600**	**200**		**120,40**
10% annual discount[d]					**8,000**		**65,500**			**73,50**
Standardized measure of discounted future net cash flows[g h]					**4,600**		**42,100**	**200**		**46,90**
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	**4,600**	**1,700**	**35,600**	**1,400**	**9,100**	**12,700**	**42,100**	**9,900**	**10,300**	**127,40**

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

$ million

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

[a] The marker prices used were Brent $101.27/bbl, Henry Hub $4.31/mmBtu.

[b]

Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.

[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,400 million.

[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

[g] Non-controlling interests in Rosneft amounted to $100 million in Russia.

[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[i] Total change in the standardized measure during the year includes the effect of exchange rate movements. Exchange rate effects arising from the translation of our share of Rosneft changes to US dollars are included within Net changes in prices and production cost.

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

$ million

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

10% annual discount[d]										
Standardized measure of discounted future net cash flows[g h]					4,500		33,000	200		37,700
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows	7,100	2,900	36,500	500	10,000	15,200	33,000	11,000	9,800	126,000

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

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

[a] The marker prices used were Brent $108.02/bbl, Henry Hub $3.66/mmBtu.

[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.

[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $1,700 million.

[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

[g] Non-controlling interests in Rosneft amounted to $200 million in Russia.

[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[i] Total change in the standardized measure during the year includes the effect of exchange rate movements.

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

$ million

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

Future net cash flows										
10% annual discount[d]					7,600		21,600	300		29,500
Standardized measure of discounted future net cash flows[g h]					4,900		21,900	1,000		27,800
Total subsidiaries and equity-accounted entities										
Standardized measure of discounted future net cash flows[i]	9,900	3,900	33,700	100	7,900	17,200	21,900	15,100	11,400	121,100

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

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

[a] The marker prices used were Brent $111.13/bbl, Henry Hub $2.75/mmBtu.

[b] Production costs, which include production taxes, and development costs relating to future production of proved reserves are based on the continuation of existing economic conditions. Future decommissioning costs are included.

[c] Taxation is computed using appropriate year-end statutory corporate income tax rates.

[d] Future net cash flows from oil and natural gas production are discounted at 10% regardless of the group assessment of the risk associated with its producing activities.

[e] Non-controlling interests in BP Trinidad and Tobago LLC amounted to $900 million.

[f] The standardized measure of discounted future net cash flows of equity-accounted entities includes standardized measure of discounted future net cash flows of equity-accounted investments of those entities.

[g] Non-controlling interests in TNK-BP amounted to $1,600 million in Russia.

[h] No equity-accounted future cash flows in Africa because proved reserves are received as a result of contractual arrangements, with no associated costs.

[i] Includes future net cash flows for assets held for sale at 31 December 2012.

[j] Total change in the standardized measure during the year includes the effect of exchange rate movements.

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Operational and statistical information

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

Crude oil and natural gas production

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

Production for the year[a b]

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

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

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

[c] Amounts reported for Russia include BP s share of Rosneft (2014, 2013), and TNK-BP (2012) worldwide activities, including insignificant amounts outside Russia.

[d] Crude oil includes condensate.

[e] Natural gas production excludes gas consumed in operations.

Productive oil and gas wells and acreage

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

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

[a] Based on information received from Rosneft as at 31 December 2014.

[b] Includes approximately 11,271 gross (2,237 net) multiple completion wells (more than one formation producing into the same well bore).

[c] Includes approximately 3,239 gross (1,482 net) multiple completion wells. If one of the multiple completions in a well is an oil completion, the well is classified as an oil well.

[d] Undeveloped acreage includes leases and concessions.

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Operational and statistical information continued

Net oil and gas wells completed or abandoned

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

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

Drilling and production activities in progress

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

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

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Pages 197-206 have been removed as they do not form part of BP S Annual Report on Form 20-F as filed with the SEC.

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Selected financial information

This information, insofar as it relates to 2014, has been extracted or derived from the audited consolidated financial statements of the BP group presented on page 89. Note 1 to the financial statements includes details on the basis of preparation of these financial statements. The selected information should be read in conjunction with the audited financial statements and related notes elsewhere herein.

$ million except per share amounts	2014	2013	2012	2011	2010
Income statement data					
Sales and other operating revenues	**353,568**	379,136	375,765	375,713	297,107
Underlying replacement cost (RC) profit before interest and taxation*	**20,818**	22,776	26,454	33,601	31,704
Net favourable (unfavourable) impact of non-operating items* and fair value accounting effects*	**(8,196)**	9,283	(6,091)	3,580	(37,190)
RC profit (loss) before interest and taxation*	**12,622**	32,059	20,363	37,181	(5,486)
Inventory holding gains (losses)*	**(6,210)**	(290)	(594)	2,634	1,784
Profit (loss) before interest and taxation	**6,412**	31,769	19,769	39,815	(3,702)
Finance costs and net finance expense relating to pensions and other post-retirement benefits	**(1,462)**	(1,548)	(1,638)	(1,587)	(1,605)
Taxation	**(947)**	(6,463)	(6,880)	(12,619)	1,638
Profit (loss) for the year	**4,003**	23,758	11,251	25,609	(3,669)
Profit (loss) for the year attributable to BP shareholders	**3,780**	23,451	11,017	25,212	(4,064)
Inventory holding (gains) losses, net of taxation	**4,293**	230	411	(1,800)	(1,195)
RC profit (loss) for the year attributable to BP shareholders	**8,073**	23,681	11,428	23,412	(5,259)
Non-operating items and fair value accounting effects, net of taxation	**4,063**	(10,253)	5,643	(2,242)	25,436
Underlying RC profit for the year attributable to BP shareholders	**12,136**	13,428	17,071	21,170	20,177
Per ordinary share cents					
Profit (loss) for the year attributable to BP shareholders					
Basic	**20.55**	123.87	57.89	133.35	(21.64)
Diluted	**20.42**	123.12	57.50	131.74	(21.64)
RC profit (loss) for the year attributable to BP shareholders	**43.90**	125.08	60.05	123.83	(28.01)
Underlying RC profit for the year attributable to BP shareholders	**66.00**	70.92	89.70	111.97	107.39
Dividends paid per share cents	**39.00**	36.50	33.00	28.00	14.00
pence	**23.850**	23.399	20.852	17.404	8.679
Capital expenditure and acquisitions, on an accruals basis	**23,781**	36,612	25,204	31,959	23,016
Acquisitions and asset exchanges, on an accruals basis	**420**	71	200	11,283	3,406

Organic capital expenditure*[a], on an accruals basis	**22,892**	24,600	23,950	19,580	18,218
Balance sheet data (at 31 December)					
Total assets	**284,305**	305,690	300,466	292,907	272,262
Net assets	**112,642**	130,407	119,752	112,585	95,891
Share capital	**5,023**	5,129	5,261	5,224	5,183
BP shareholders equity	**111,441**	129,302	118,546	111,568	94,987
Finance debt due after more than one year	**45,977**	40,811	38,767	35,169	30,710
Net debt to net debt plus equity*	**16.7%**	16.2%	18.7%	20.4%	21.2%
Ordinary share data[b]					Shares million
Basic weighted average number of shares	**18,385**	18,931	19,028	18,905	18,786
Diluted weighted average number of shares	**18,497**	19,046	19,158	19,136	18,998

[a] Organic capital expenditure excludes acquisitions and asset exchanges, and: in 2014 $469 million relating to the purchase of an additional 3.3% equity in Shah Deniz, Azerbaijan and the South Caucasus Pipeline; in 2013 $11,941 million relating to our investment in Rosneft; in 2012 $1,054 million associated with deepening our US natural gas and North Sea asset bases; in 2011 $1,096 million associated with deepening our US natural gas bases; in 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.

[b] The number of ordinary shares shown has been used to calculate the per share amounts.

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Non-operating items

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 to understand better and evaluate the group s reported financial performance. An analysis of non-operating items is shown in the table below.

			$ million
	2014	2013	2012
Upstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(6,576)**	(802)	3,638
Environmental and other provisions	**(60)**	(20)	(48)
Restructuring, integration and rationalization costs	**(100)**		
Fair value gain (loss) on embedded derivatives	**430**	459	347
Other[b]	**8**	(1,001)	(748)
	(6,298)	(1,364)	3,189
Downstream			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(1,190)**	(348)	(2,934)
Environmental and other provisions	**(133)**	(134)	(171)
Restructuring, integration and rationalization costs	**(165)**	(15)	(32)
Fair value gain (loss) on embedded derivatives			
Other	**(82)**	(38)	(35)
	(1,570)	(535)	(3,172)
TNK-BP			
Impairment and gain (loss) on sale of businesses and fixed assets		12,500	(55)
Environmental and other provisions			(83)
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other[c]			384
		12,500	246
Rosneft			
Impairment and gain (loss) on sale of businesses and fixed assets	**225**	(35)	
Environmental and other provisions		(10)	
Restructuring, integration and rationalization costs			
Fair value gain (loss) on embedded derivatives			
Other			
	225	(45)	
Other businesses and corporate			
Impairment and gain (loss) on sale of businesses and fixed assets[a]	**(304)**	(196)	(282)
Environmental and other provisions	**(180)**	(241)	(261)
Restructuring, integration and rationalization costs	**(176)**	(3)	(15)
Fair value gain (loss) on embedded derivatives			
Other[d]	**(10)**	19	(240)
	(670)	(421)	(798)

Gulf of Mexico oil spill response	**(781)**	(430)	(4,995)
Total before interest and taxation	**(9,094)**	9,705	(5,530)
Finance costs[e]	**(38)**	(39)	(19)
Taxation credit (charge)[f]	**4,512**	867	251
Total after taxation	**(4,620)**	10,533	(5,298)

[a] See Financial statements Note 3 for further information on impairments.

[b] 2014 included a $395-million write-off relating to Block KG D6 in India. 2013 included $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. 2012 included a charge of $370 million relating to onerous gas marketing and trading contracts and $308 million relating to exploration expense associated with our US natural gas assets.

[c] 2012 included dividend income from TNK-BP of $709 million and a charge of $325 million to settle disputes with Alfa, Access and Renova.

[d] 2012 included charges of $244 million relating to our exit from the solar business.

[e] Finance costs relate to the Gulf of Mexico oil spill. See Financial statements Note 2 for further details.

[f] From 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 and certain deferred tax adjustments relating to changes in UK taxation). For dividends received from TNK-BP in 2012, there is no tax arising. Non-operating items reported within the equity-accounted earnings of Rosneft and TNK-BP are reported net of income tax.

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Non-GAAP information on fair value accounting effects

The impacts of fair value accounting effects, relative to management s internal measure of performance, and a reconciliation to GAAP information is set out below. Further information on fair value accounting effects is provided on page 253.

			$ million
	2014	2013	2012
Upstream			
Unrecognized gains (losses) brought forward from previous period	**(160)**	(404)	(538)
Unrecognized (gains) losses carried forward	**191**	160	404
Favourable (unfavourable) impact relative to management s measure of performance	**31**	(244)	(134)
Downstream[a]			
Unrecognized gains (losses) brought forward from previous period	**679**	501	74
Unrecognized (gains) losses carried forward	**188**	(679)	(501)
Favourable (unfavourable) impact relative to management s measure of performance	**867**	(178)	(427)
	898	(422)	(561)
Taxation credit (charge)[b]	**(341)**	142	216
	557	(280)	(345)
By region			
Upstream			
US	**23**	(269)	(67)
Non-US	**8**	25	(67)
	31	(244)	(134)
Downstream[a]			
US	**914**	(211)	(441)
Non-US	**(47)**	33	14
	867	(178)	(427)

[a] Fair value accounting effects arise solely in the fuels business.
[b] From 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 certain deferred tax adjustments relating to changes in UK taxation).

Reconciliation of non-GAAP information

			$ million
	2014	2013	2012
Upstream			
RC profit before interest and tax adjusted for fair value accounting effects	**8,903**	16,901	22,625
Impact of fair value accounting effects	**31**	(244)	(134)

RC profit before interest and tax	**8,934**	16,657	22,491
Downstream			
RC profit before interest and tax adjusted for fair value accounting effects	**2,871**	3,097	3,291
Impact of fair value accounting effects	**867**	(178)	(427)
RC profit before interest and tax	**3,738**	2,919	2,864
Total group			
Profit before interest and tax adjusted for fair value accounting effects	**5,514**	32,191	20,330
Impact of fair value accounting effects	**898**	(422)	(561)
Profit before interest and tax	**6,412**	31,769	19,769

Operating capital employed*

	$ million
	2014
Upstream	**107,524**
Downstream	**38,878**
TNK-BP	
Rosneft	**7,312**
Other businesses and corporate	**20,689**
Gulf of Mexico oil spill response	**(7,986)**
Consolidation adjustment - UPII*	**(31)**
Total operating capital employed	**166,386**
Liabilities for current and deferred taxation	**(12,758)**
Goodwill	**11,868**
Finance debt	**(52,854)**
Net assets	**112,642**

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Liquidity and capital resources

Financial framework

We maintain our financial framework to support the pursuit of value growth for shareholders, while ensuring a secure financial base. BP s objective over time is to grow sustainable free cash flow* through a combination of material growth in underlying operating cash flow* and a strong focus on capital discipline, providing a sound platform to grow shareholder distributions. The priority is to grow dividend per share progressively in accordance with the growth in sustainable underlying operating cash flow from our businesses over time. Any surplus cash over and above that required for capital investment and dividend payments will be biased towards further shareholder distributions through buybacks or other mechanisms.

In the near term, and reflecting the weaker oil price environment, the focus is to manage the business through a period of low oil prices and support the dividend, which remains a priority. We aim to achieve this by completing the $10-billion divestment programme (announced in the fourth quarter of 2013), re-sizing the cost base and re-setting capital expenditure to $20 billion, from the previously advised level of $24-26 billion.

We aim to operate within a gearing* range of 10-20% and maintain a significant liquidity buffer. As well as uncertainties relating to current lower oil prices, the group also faces uncertainties relating to the Gulf of Mexico oil spill as explained in Financing the group s activities below.

Dividends and other distributions to shareholders

Since resuming dividend payments in 2011, we have steadily increased the dividend. From the quarterly dividend of 7 cents per share paid in 2011, it increased by 43% to 10 cents per share paid in the fourth quarter of 2014. The dividend level is reviewed by the board in the first and third quarter of each year.

The total dividend paid in cash to BP shareholders in 2014 was $5.9 billion (2013 $5.4 billion) with shareholders also having the option to receive a scrip dividend. The dividend is determined in US dollars, the economic currency of BP.

During 2013 we started to buy back shares as part of an $8-billion share repurchase programme, fulfilling a commitment to offset any dilution to earnings per share from the Rosneft transaction. The initial buyback programme completed during the third quarter of 2014. Further surplus cash, beyond capital and dividend payments, was applied to additional buybacks, such that total cash paid for share buybacks in 2014 was $4.8 billion (2013 $5.5 billion). Details of share repurchases to satisfy the requirements of certain employee share-based payment plans are set out on page 250.

Financing the group s activities

The group s principal commodities, oil and gas, are priced internationally in US dollars. Group policy has generally been to minimize economic exposure to currency movements by financing operations with US dollar debt. Where debt is issued in other currencies, including euros, it is generally swapped back to US dollars using derivative contracts, or else hedged by maintaining offsetting cash positions in the same currency. The cash balances of the group are mainly held in US dollars or swapped to US dollars, and holdings are well-diversified to reduce concentration risk. The group is not, therefore, exposed to significant

currency risk regarding its borrowings. Also see Risk factors on page 48 for further information on risks associated with prices and markets and Financial statements Note 27.

The group s gross debt at 31 December 2014 amounted to $52.9 billion (2013 $48.2 billion). Of the total gross debt, $6.9 billion is classified as short term at the end of 2014 (2013 $7.4 billion). None of the capital market bond issuances since the Gulf of Mexico oil spill contain any additional financial covenants compared with the group s capital markets issuances prior to the incident. See Financial statements Note 24 for more information on the short-term balance.

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

Net debt was $22.6 billion at the end of 2014 a reduction of $2.6 billion from the 2013 year-end position of $25.2 billion. The ratio of net debt to net debt plus equity* was 16.7% at the end of 2014 (2013 16.2%). See Financial statements Note 25 for gross debt, which is the nearest equivalent measure on an IFRS basis, and for further information on net debt.

Cash and cash equivalents of $29.8 billion at 31 December 2014 (2013 $22.5 billion) are included in net debt. We manage our cash position to ensure the group has adequate cover to respond to potential short-term market illiquidity, and expect to maintain a strong cash position.

The group also has undrawn committed bank facilities of $7.4 billion (see Financial statements Note 27 for more information).

We believe that the group has sufficient working capital for foreseeable requirements, taking into account the amounts of undrawn borrowing facilities and increased levels of cash and cash equivalents, and the ongoing ability to generate cash.

The group s sources of funding, its access to capital markets and maintaining a strong cash position are described in Financial statements Note 23 and Note 27. Further information on the management of liquidity risk and credit risk, and the maturity profile and fixed/floating rate characteristics of the group s debt are also provided in Financial statements Note 24 and Note 27.

Uncertainty remains regarding the amount and timing of future expenditures relating to the Gulf of Mexico oil spill and the implications for future activities. See Risk factors on page 48 and Financial statements Note 2 for further information.

Off-balance sheet arrangements

At 31 December 2014, the group s share of third-party finance debt of equity-accounted entities was $14.7 billion (2013 $17.0 billion). These amounts are not reflected in the group s debt on the balance sheet. The group has issued third-party guarantees under which amounts outstanding at 31 December 2014 were $83 million (2013 $199 million) in respect of liabilities of joint ventures* and associates* and $244 million (2013 $305 million) in respect of liabilities of other third parties. Of these amounts, $64 million (2013 $115 million) of the joint ventures and associates guarantees relate to borrowings and for other third-party guarantees, $126 million (2013 $143 million) relate to guarantees of borrowings. Details of operating lease commitments, which are not recognized on the balance sheet, are shown in the table below and provided in Financial statements Note 26.

*Defined on page 252.

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Contractual obligations

The following table summarizes the group s capital expenditure commitments for property, plant and equipment at 31 December 2014 and the proportion of that expenditure for which contracts have been placed.

							$ million
							Payments due by period
Capital expenditure	Total	2015	2016	2017	2018	2019	2020 and thereafter
Committed	39,708	18,009	9,591	5,445	3,483	2,265	915
of which is contracted	15,635	8,061	3,441	2,163	1,423	442	105

Capital expenditure is considered to be committed when the project has received the appropriate level of internal management approval. For joint operations, the net BP share is included in the amounts above.

In addition, at 31 December 2014, the group had committed to capital expenditure relating to investments in equity-accounted entities amounting to $2,068 million. Contracts were in place for $2,025 million of this total.

The following table summarizes the group s principal contractual obligations at 31 December 2014, distinguishing between those for which a liability is recognized on the balance sheet and those for which no liability is recognized. Further information on borrowings is given in Financial statements Note 24 and more information on operating leases is given in Financial statements Note 26.

							$ million
							Payments due by period
Expected payments by period under contractual obligations	Total	2015	2016	2017	2018	2019	2020 and thereafter
Balance sheet obligations							
Borrowings[a]	56,161	7,653	6,981	6,220	5,702	6,437	23,168
Finance lease future minimum lease payments[b]	1,722	116	106	104	102	98	1,196
Decommissioning liabilities[c]	21,591	1,076	896	689	813	733	17,384
Environmental liabilities[c]	2,908	935	349	603	208	178	635
Pensions and other post-retirement benefits[d]	27,282	1,880	1,871	1,864	1,858	2,099	17,710
	109,664	11,660	10,203	9,480	8,683	9,545	60,093
Off-balance sheet obligations							
Operating lease future minimum lease payments[e]	18,785	5,401	4,047	2,682	1,857	1,330	3,468
Unconditional purchase obligations[f]	166,250	69,805	19,164	12,193	10,703	9,442	44,943
	185,035	75,206	23,211	14,875	12,560	10,772	48,411
Total	294,699	86,866	33,414	24,355	21,243	20,317	108,504

[a] Expected payments include interest totalling $4,090 million ($822 million in 2015, $711 million in 2016, $610 million in 2017, $519 million in 2018, $424 million in 2019 and $1,004 million thereafter).

[b] Expected payments include interest totalling $939 million ($70 million in 2015, $65 million in 2016, $62 million in 2017, $59 million in 2018, $55 million in 2019 and $628 million thereafter).

[c] The amounts are undiscounted. Environmental liabilities include those relating to the Gulf of Mexico oil spill.

[d] Represents the expected future contributions to funded pension plans and payments by the group for unfunded pension plans and the expected future payments for other post-retirement benefits.

[e] The future minimum lease payments are before deducting related rental income from operating sub-leases. In the case of an operating lease entered into solely by BP as the operator of a joint operation, the amounts shown in the table represent the net future minimum lease payments, after deducting amounts reimbursed, or to be reimbursed, by joint operation partners. Where BP is not the operator of a joint operation, BP s share of the future minimum lease payments are included in the amounts shown, whether BP has co-signed the lease or not. Where operating lease costs are incurred in relation to the hire of equipment used in connection with a capital project, some or all of the cost may be capitalized as part of the capital cost of the project.

[f] Represents any agreement to purchase goods or services that is enforceable and legally binding and that specifies all significant terms (such as fixed or minimum purchase volumes, timing of purchase and pricing provisions). Agreements that do not specify all significant terms, or that are not enforceable, are excluded. The amounts shown include arrangements to secure long-term access to supplies of crude oil, natural gas, feedstocks and pipeline systems. In addition, the amounts shown for 2015 include purchase commitments existing at 31 December 2014 entered into principally to meet the group s short-term manufacturing and marketing requirements. The price risk associated with these crude oil, natural gas and power contracts is discussed in Financial statements Note 27.

The following table summarizes the nature of the group s unconditional purchase obligations.

$ million

Unconditional purchase obligations	Total	2015	2016	2017	2018	2019	Payments due by period 2020 and thereafter
Crude oil and oil products	78,063	43,714	9,723	5,418	4,725	3,530	10,953
Natural gas	29,982	17,741	4,245	2,552	2,090	1,604	1,750
Chemicals and other refinery feedstocks	12,836	3,097	2,508	2,145	2,192	2,228	666
Power	3,610	2,425	759	262	74	28	62
Utilities	731	219	167	108	97	50	90
Transportation	21,799	1,423	1,013	1,062	1,064	926	16,311
Use of facilities and services	19,229	1,186	749	646	461	1,076	15,111
Total	166,250	69,805	19,164	12,193	10,703	9,442	44,943

The information above contains forward-looking statements, which by their nature 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. You are urged to read the cautionary statement on page 241 and Risk factors on page 48, which describe the risks and uncertainties that may cause actual results and developments to differ materially from those expressed or implied by these forward-looking statements.

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Upstream analysis by region

Our upstream operations are listed by geographical area, with associated significant events for 2014. BP s percentage working interest in oil and gas assets is shown in parenthesis. Working interest is the cost-bearing ownership share of an oil or gas lease. Consequently, the percentages disclosed for certain agreements do not necessarily reflect the percentage interests in reserves and production.

In addition to exploration, development and production activities, our Upstream business also includes midstream and LNG activities. Midstream activities involve the ownership and management of crude oil and natural gas pipelines, processing facilities and export terminals, LNG processing facilities and transportation, and our natural gas liquids (NGLs) extraction business.

Our LNG supply activities are located in Abu Dhabi, Angola, Australia, Indonesia and Trinidad. We market around 20% of our LNG production using BP LNG shipping and contractual rights to access import terminal capacity in the liquid markets of the US (via Cove Point), the UK (via the Isle of Grain), Spain (in Bilbao) and Italy (in Rovigo), with the remainder marketed directly to customers. LNG is supplied to customers in multiple markets including Japan, South Korea, China, the Dominican Republic, Argentina, Brazil and Mexico. In September, BP and Tokyo Electric Power Company (TEPCO) signed an agreement for TEPCO to purchase up to 1.2 million tonnes of LNG per year from BP for 17 years starting in 2017.

Europe

BP is active in the North Sea and the Norwegian Sea. Our activities focus on maximizing recovery from existing producing fields and selected new field developments. BP s production is generated from three key areas; the Shetland Area comprising Magnus, Clair, Foinaven and Schiehallion fields; the Central Area comprising Bruce, Andrew and ETAP fields; and Norway, comprising Valhall, Ula and Skarv fields.

In March 2013 BP and its partners, ConocoPhillips, Chevron and Shell, announced the decision to proceed with a two-year appraisal programme to evaluate a potential third phase of the Clair field (BP 28.6%), west of the Shetland Islands. By the end of 2014, five of the planned six appraisal wells had been completed, with drilling started on the sixth well.

Activity continued on the major redevelopment of the Schiehallion and Loyal fields to the west of Shetland during 2014. Following work to preserve the existing wells and subsea infrastructure, the risers and moorings were disconnected, allowing the Schiehallion floating production storage and offloading unit (FPSO) to be towed off-station in May. Construction continues on the replacement FPSO, the Glen Lyon.

Operations at the Rhum gas field recommenced in October under a temporary management scheme announced by the UK government in 2013. Production had been suspended since November 2010 following the imposition of EU sanctions on Iran. The field is owned by BP (50%) and the Iranian Oil Company (IOC) under a joint operating agreement. See International trade sanctions on page 238.

BP announced the Vorlich discovery in the central North Sea in October. It spans the GDF SUEZ E&P UK Ltd-operated block 30/1f and the BP-operated (BP 50%) block 30/1c.

Production started up from the Kinnoull field (BP 77.06%) in the central North Sea in December. The Kinnoull reservoir, developed as part of a wider rejuvenation of the Andrew field area, is tied back to BP s Andrew platform and will enable production there to be extended. BP has been granted three licences in the UK government s 28th licensing round. The licences are located in three of our core areas: to the north of our Magnus field in the northern North Sea; next to our recent Vorlich discovery; and west of our Kinnoull development. The government is still to award some licences in this round as they are undergoing environmental assessment.

In December, a number of North Sea fields were subject to impairment charges, primarily as a result of reductions in proved reserves, decreases in short-term oil and gas price assumptions and increases in expected decommissioning cost estimates. The total impairment charge for 2014 was $4,774 million, of which $1,964 million related to the Valhall asset, $660 million related to the Andrew area assets, and $515 million related to the ETAP asset. There were a number of other impairment charges that were not individually significant.

In the UK sector of the North Sea, BP operates the Forties Pipeline System (FPS) (BP 100%), an integrated oil and NGLs transportation and processing system that handles production from around 80 fields in the central North Sea. The system has a capacity of more than 675mboe/d, with average throughput in 2014 of 363mboe/d. BP also operates and has a 36% interest in the Central Area Transmission System (CATS), a 400-kilometre natural gas pipeline system in the central UK sector of the North Sea providing transport and processing services. The pipeline has a transportation capacity of 293mboe/d to a natural gas terminal at Teesside in north-east England. Average throughput in 2014 was 134mboe/d. BP also operates the Sullom Voe oil and gas terminal in Shetland. In December, BP announced the intent to sell our equity in the CATS business.

North America

Our upstream activities in North America take place in four main areas: deepwater Gulf of Mexico, Lower 48 states, Alaska and Canada. For further information on BP s activities in connection with its responsibilities following the Deepwater Horizon oil spill, see page 36.

BP has around 600 lease blocks in the deepwater Gulf of Mexico, more than any other company, and operates four production hubs.

BP had 10 rigs in the Gulf of Mexico at the end of 2014.

The BP-operated Na Kika Phase 3 project (BP 50%) and the Shell-operated Mars B major project (BP 28.5%) started up in February. A second Na Kika Phase 3 well started up in April.

The Atlantis North expansion Phase 2 major project (BP 56%) started up in April.

BP announced an oil discovery at the Guadalupe prospect (BP 42.5%) in the deepwater Gulf of Mexico in October. Project operator Chevron drilled the discovery well on Keathley Canyon block 10 on behalf of the Guadalupe co-owners. The well encountered significant economically producible hydrocarbons in Paleogene age Wilcox Sands.

In January 2015 BP announced it had formed a new ownership and operating model with Chevron and ConocoPhillips to focus on moving two significant BP Paleogene discoveries closer to development and provide expanded exploration access in the deepwater Gulf of Mexico. BP sold approximately half of its current equity interests in the Gila field to Chevron in December and sold approximately half of its equity interest in the Tiber field in January 2015. BP, Chevron and ConocoPhillips also have agreed to joint ownership interests in exploration blocks east of Gila known as Gibson, where they plan to drill in 2015. As a result of the agreements, BP, Chevron and ConocoPhillips will have the same working interests across Gila and Gibson and any future centralized production facility. Chevron will hold equity interest of 36%, BP 34% and ConocoPhillips 30%. In Tiber, BP and Chevron will each hold equity interest of 31%, Petrobras 20% and ConocoPhillips 18%. Chevron will operate Tiber, Gila and Gibson. Operatorship is expected to be transferred after BP finishes drilling appraisal wells at Gila and Tiber. BP believes combining the technical strengths and financial resources of these three companies will provide greater efficiency through scale, reduce subsurface risk and increase the likelihood of achieving a future commercial development.

BP was the apparent high bidder in 27 out of 32 blocks in the Gulf of Mexico western lease sales in August, all of which have been awarded. This is in addition to 24 blocks awarded in the Gulf of Mexico in March lease sales. See also Significant estimate or judgement: oil and natural gas accounting on page 102 for further information on leases.

The US Lower 48 onshore business has significant activities producing natural gas, NGLs and condensate across seven states, including production from unconventional gas, coalbed methane (CBM) and shale gas assets.

BP has an extensive resource base across 3.0 million net (5.5 million gross) developed acres and over 22,815 gross wells, with daily production around 300mboe/d. We believe there is potential to unlock significant value from this resource base and we have decades of experience in the necessary technologies.

Starting in 2015 our US Lower 48 onshore business began operating as a separate business, with its own governance, processes and systems. This is designed to promote faster decision making and adoption of innovation so that BP can be more competitive in the US onshore market. David Lawler was named chief executive officer in August.

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- BP and Pantera Acquisition Group, LLC (Pantera) signed an agreement under which Pantera agreed to acquire BP s interests in the Panhandle West and Texas Hugoton gas fields for a purchase price of $390 million in June. See page 26 for more information.
- Following on from the decision to create a separate BP business around our US Lower 48 onshore oil and gas activities, and as a consequence of disappointing appraisal results, we decided not to proceed with development plans in the Utica shale, incurring a $544-million write-off relating to this acreage.

For further information on the use of hydraulic fracturing in our shale gas assets see page 43. BP s onshore US crude oil and product pipelines and related transportation assets are included in the Downstream segment.

In Alaska, at the end of 2014, BP operated nine North Slope oilfields in the Greater Prudhoe Bay area and owned significant interests in six producing fields operated by others. BP also owns significant non-operating interests in the Point Thomson development project and the Liberty prospect.

- In April BP announced the agreement to sell interests in four BP-operated oilfields on the North Slope of Alaska to Hilcorp. The sale agreement included all of BP s interests in the Endicott and Northstar oilfields and a 50% interest in each of the Milne Point field and the Liberty prospect, together with BP s interests in the oil and gas pipelines associated with these fields. The sales price was $1.25 billion plus an additional carry of up to $250 million if the Liberty field is developed. The sale completed in November. See page 26 for more information.
- Development of the Point Thomson initial production facility continued throughout 2014. Engineering design is complete and construction of field infrastructure and fabrication of the four main process modules is in progress. Overall, the project is on track to commence production in 2016. BP holds a 32% working interest in the field, and ExxonMobil is the operator.
- BP continued to work jointly with ExxonMobil, ConocoPhillips, TransCanada, the Alaska Gasline Development Corporation and the State of Alaska throughout 2014 to advance the Alaska LNG project. In February 2013 a lead concept for the project was announced, consisting of a North Slope gas treatment plant, an 800-mile (approximately) pipeline to tidewater and a three-train liquefaction facility, with an estimated capacity of 3bcf/d (up to 20 million tonnes per annum). In October 2013 selection of the lead site for the liquefaction facility was announced as Nikiski, Alaska, located on the south-central Alaskan coast. In January BP, ExxonMobil, ConocoPhillips and TransCanada, and the Alaska Gasline Development Corporation signed a heads of agreement (HOA) with the State of Alaska enabling state participation in the $45-$65 billion Alaska LNG project. The HOA sets out guiding principles for the parties to negotiate project-enabling contracts, and provided a roadmap for State of Alaska participation in the project. In April the Alaska Legislature passed legislation (SB-138) which approved State participation in the project as a 25% co-investor, and allowed payment of gas production tax in the form of gas volumes. On 30 June 2014 the Alaska LNG co-venturers, including the State of Alaska, executed commercial agreements and launched the pre-front end engineering and design (pre-FEED) phase of the project, which is expected to extend into 2016 with gross spend more than $500 million. A decision point for progressing to front end engineering and design (FEED) phase of the project will be considered at the completion of the pre-FEED phase. In July the Alaska LNG project submitted an export application with the US Department of Energy, and in September submitted a pre-file notice of application with the Federal Energy Regulatory Commission (FERC), which was approved by the FERC later that month. The US Department of Energy issued a Free Trade Agreement Export Authorization to the project in November. First commercial gas is planned between 2023 and 2025.

BP owns a 49% interest in the Trans-Alaska Pipeline System (TAPS). The TAPS transports crude oil from Prudhoe Bay on the Alaska North Slope to the port of Valdez in south-east Alaska. In April 2012 the two non-controlling owners of TAPS, Koch (3.08%) and Unocal (1.37%) gave notice to BP, ExxonMobil (21.1%) and ConocoPhillips (29.1%) of their intention to withdraw as an owner of TAPS. The transfer of Koch s interest to the remaining owners (BP, ExxonMobil and ConocoPhillips) was agreed and approved by regulatory authorities and closed in July with an effective date of August 2012. The remaining owners and Unocal

have not yet reached agreement regarding the terms for the transfer of Unocal s interest in TAPS and related litigation will continue in 2015.

In Canada, BP is currently focused on oil sands development and intends to use in situ steam-assisted gravity drainage (SAGD) technology, which uses the injection of steam into the reservoir to warm the bitumen so that it can flow to the surface through producing wells. We hold interests in three oil sands leases through the Sunrise Oil Sands and Terre de Grace partnerships and the Pike Oil Sands joint operation. In addition, we have significant offshore exploration interests in the Canadian Beaufort Sea and in Nova Scotia.

- Phase 1 of the Sunrise Oil Sands SAGD development, in which BP has a 50% non-operated interest, achieved first steam in the reservoir in December 2014. The production capacity of Sunrise Phase 1 is expected to be 60mb/d of bitumen.
- A major seismic programme on the Nova Scotia exploration licenses was conducted over the summer of 2014 with 7,090km^2 of wide azimuth 3D seismic data acquired. The processing of this seismic data will be completed by the end of 2015 to identify possible exploration well locations. During the fourth quarter of 2014 BP expanded the Nova Scotia licence participation to include Hess Canada Oil and Gas ULC and Woodside Energy International (Canada). The new participating interests are BP 40% (operator), Hess 40% and Woodside 20%.

South America

BP has upstream activities in Brazil, Argentina, Bolivia, Chile, Uruguay and Trinidad & Tobago.

In Brazil, BP has interests in 22 exploration and production concessions across six basins, five of which are operated by BP. BP s entry into five of these concessions is subject to government and regulatory approvals.

- BP completed the sale of interest in the Polvo oil field (BP 60%) in Brazil to HRT Oil & Gas Ltda for $135 million in January.
- During the year BP continued appraisal of the Itaipu discovery, located in the deepwater sector of the Campos basin offshore Brazil, in line with the appraisal plan approved by the Brazilian National Petroleum Agency (ANP).
- In October the ANP approved the appraisal plan submitted by the operator, Petróleo Brasileiro S.A. (Petrobras) for BM-POT-16 and BM-POT-17 (two blocks in the deepwater Potiguar basin located in the Brazilian equatorial margin), covering activities to 2018. BP s farm-in to a 40% interest in the blocks announced in July 2013 is subject to final regulatory approvals.
- In July BP had a discovery at Xerelete (BP 18%) in Brazil s Campos basin, operated by Total.

In Argentina, Bolivia and Chile, BP conducts activity through Pan American Energy LLC (PAE), an equity-accounted joint venture* with Bridas Corporation, in which BP has a 60% interest.

In Uruguay, BP has interests in three offshore deepwater exploration blocks: blocks 11 and 12 in the Pelotas basin and block 6 in the Punta del Este basin, together covering an area of almost 26,000km^2. BP holds a 100% interest in the blocks and the Uruguayan state oil company, ANCAP, has a right to participate in up to 30% of any discoveries. BP has already completed its commitment to acquire over 13,000km^2 of 3D seismic data and 3,000km of 2D seismic data by December 2015.

In Trinidad & Tobago, BP holds licences and production-sharing contracts covering 1.8 million acres offshore of the east and north-east coast. Facilities include 13 offshore platforms and two onshore processing facilities. Production is comprised of gas and associated liquids. In August, the Juniper project was sanctioned and subsequently a key contract for the development of the project was awarded. Fabrication began in November.

BP also has a shareholding in Atlantic LNG (ALNG), an LNG liquefication plant that averages 39% across four LNG trains[a] with a combined capacity of 15 million tonnes per annum. BP sells gas to each of the LNG trains, supplying 100% of the gas for train 1, 50% for train 2, 75% for train 3 and around 67% of the gas for train 4. All the LNG from Atlantic train 1 and most of the LNG from trains 2 and 3 is sold to third parties in the US and Europe under long-term contracts. BP s equity LNG entitlement from trains 2, 3 and 4 is marketed via BP s LNG marketing and trading function to markets in the US, UK, Spain and South America.

[a] An LNG train is a processing facility used to liquefy and purify natural gas in the formation of LNG.

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Africa

BP s upstream activities in Africa are located in Angola, Algeria, Libya, Egypt and Morocco.

In Angola, BP is present in nine major deepwater licences offshore and is operator in four of these. Two of these are in production (blocks 18 and 31), and two are in the exploration phase (blocks 19 and 24). The first exploration well on block 24 (Katambi-1) is currently being drilled.

- Following a successful drill-stem test in May, BP had another oil and gas discovery in the pre-salt play of Angola in block 20 (BP 30%) operated by Cobalt International Energy, Inc. This discovery (the Orca-1 well) is the second pre-salt discovery in block 20. The Orca-2 appraisal well is currently being drilled.
- Production commenced from the Total-operated CLOV (Cravo, Lirio, Orquidea and Violeta) major project in Angola (BP 16.67%) in June. Plateau production of 160,000 barrels of oil was achieved in September.
- In the first quarter the Angola LNG plant (BP 13.6%) produced and sold a number of LNG cargoes, along with its first LPG, pressurised butane and condensate cargoes. Following a technical incident in April 2014, which caused an unplanned interruption to production, the plant s planned shutdown was brought forward to address both technical and plant capacity issues. The plant is projected to re-start fully in 2016.
- In December, several fields in Angola were subject to impairment charges, primarily as a result of changes in estimates of reserves and resources and decreases in near-term oil price assumptions. The total impairment charge during the year was $968 million, of which the Plutão, Saturno, Vénus and Marte (PSVM) area was subject to an impairment charge of $859 million.

In Algeria, BP, Sonatrach and Statoil are partners in the In Salah (BP 33.15%) and In Amenas (BP 45.89%) projects which supply gas to the domestic and European markets. BP s total assets in Algeria at 31 December 2014 were $1,717 million ($290 million current and $1,427 million non-current).

- The security assessment following the terrorist attack in January 2013 has been completed.
- BP also had an appraisal and exploitation agreement with Sonatrach in the Bourarhat Sud block, located to the south west of In Amenas. This asset was in the exploration phase and was BP-operated. The Bourarhat agreement with Sonatrach expired on 23 September 2014. Sonatrach and BP were granted a six-month period to negotiate new terms and those negotiations commenced in the fourth quarter. With insufficient certainty of success, BP recorded an exploration write-off of $524 million.

In Libya, BP is in partnership with the Libyan Investment Authority (LIA) to explore acreage in the onshore Ghadames and offshore Sirt basins, covered under the exploration and production-sharing agreement (EPSA) ratified in December 2007 (BP 85%). BP s total assets in Libya at 31 December 2014 were $515 million ($38 million current and $477 million non-current).

BP served the National Oil Corporation with notices of force majeure on 17 August. This is the result of continued civil unrest in Libya, which has made it impossible for BP to undertake its obligations under the EPSA safely and securely. If the period of force majeure continues for two years, the EPSA may terminate if the parties have failed to reach an agreeable arrangement.

In Egypt, BP and its partners currently produce 10% of Egypt s liquids production and more than 30% of its gas production. BP s total assets in Egypt at 31 December 2014 were $7,715 million, of which $2,266 million were current and $5,449 million were non-current. The current assets include trade receivables and Egyptian pound denominated cash.

Egypt is moving forward towards the completion of the political roadmap set out in June 2013. The government is committed to completing the current transitional period and has already completed the first two milestones, the adoption of the Constitution by a majority vote earlier this year and the election of President Al Sisi in June. These are to be followed by Parliament elections scheduled to take place through two phases in March and April of 2015. Economic conditions remain

challenging despite the government s clear focus on triggering economic recovery and embarking on widescale national projects (such as the Suez Canal). Egypt is also holding an Economic Summit in March with the attendance of major foreign investors and with the government targeting significant investments in projects across the various sectors. Another key priority for the government is improving general security conditions and combating extremist elements in North Sinai.

- We achieved first gas from the DEKA project offshore Egypt in August with the start of production from the Denise South-6 well. The DEKA project is centred on the Denise and Karawan gas fields in the Temsah concession (BP 50%) in the East Nile.
- In September, we were awarded the El Matariya and Karawan concessions in Egyptian Natural Gas Holding Company s bid rounds through partnering (50%) with Dana Gas and ENI respectively. Karawan is located in the Mediterranean Sea in the northwestern part of Egypt s economic waters. El Mataria is an onshore block and BP is an operator. BP and its partners have committed to invest a total of $105 million in the blocks during the first phase.
- BP started drilling the Atoll-1 HPHT deepwater exploration well, the second exploration well in the North Damietta offshore concession, in September. Well performance is currently exceeding target pace and drilling operations are expected to be completed in second half of 2015.
- West Nile Delta Project Concessions amendment was approved by the Egyptian cabinet in December and will now proceed to the ratification process in 2015.

In Morocco, BP has a non-operating interest in each of the Essaouira Offshore (BP 45%), Foum Assaka Offshore (BP 26.325%) and Tarhazoute Offshore (BP 45%) blocks in the Agadir Basin, offshore Morocco. The exploration periods run until 2017.

Asia

BP has activities in Western Indonesia, China, Azerbaijan, Oman, Abu Dhabi, India and Iraq.

In Western Indonesia, BP participates in LNG exports through our interest in Virginia Indonesia Company LLC (VICO), the operator of Sanga-Sanga PSA (BP 38%) supplying gas to the Bontang LNG plant in Kalimantan. Sanga-Sanga currently delivers around 14% of the total gas feed to Bontang, Indonesia s largest LNG export facility and one of the world s largest LNG plants. It has a capacity of 22 million tonnes of LNG per annum and output of more than 18 million tonnes.

In addition, BP participates in the Sanga-Sanga CBM PSA (BP 38%). Another CBM PSA, Tanjung IV (BP 44%), in the Barito basin of Central Kalimantan, will be relinquished pending the approval from the government of Indonesia.

In China, during the year BP has exited blocks 42/05 (BP 40.82%), 43/11 (BP 40.82%) and 54/11 (BP 100%) in the South China Sea in accordance with the PSAs and with government approvals. BP has a 30% equity stake in the 7 million tonnes per annum capacity Guangdong LNG regasification and pipeline project in south-east China, making it the first foreign partner in China s LNG import business. The terminal is supplied under a long-term contract with Australia s North West Shelf venture.

BP and the China National Offshore Oil Corporation (CNOOC) announced a heads of agreement in June for the supply of up to 1.5 million tonnes of LNG per year over 20 years starting in 2019.

In Azerbaijan, BP invests more than any other foreign investor, operates two PSAs, Azeri-Chirag-Gunashli (ACG) (BP 35.8%) and Shah Deniz (BP 28.83%), and also holds other exploration leases.

In 2012 further EU and US regulations concerning restrictive measures against Iran were issued. The Shah Deniz joint operation and its gas marketing and pipeline entities, in which Naftiran Intertrade Co. Ltd (NICO) has an interest, were excluded from the main operative provisions of the EU regulations as well as from the application of the new US sanctions, and fall within the exception for certain natural gas projects under Section 603 of the US Iran Threat Reduction and Syria Human Rights Act of 2012. The Shah Deniz Stage 2 project (referred to below) is also excluded from the EU and US sanctions. For further information see International trade sanctions on page 238.
The West Chirag platform came online in January, completing the Chirag oil project (BP 35.8%), sanctioned in 2010.

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- In March BP completed the purchase of an additional 3.33% equity in Shah Deniz and the South Caucasus Pipeline (SCP) from Statoil for $469 million.
- A ceremony to mark the groundbreaking for the Southern Gas Corridor was held in September as part of the BP-operated Azerbaijan International Operating Company celebration of the 20th anniversary of the Azeri-Chirag-Gunashli production-sharing contract. This is a milestone in the realization of the Shah Deniz Stage 2 project, which is planned to deliver gas through the Southern Corridor comprising some 3,500 kilometres of pipeline to customers in Georgia, Turkey, Greece, Bulgaria and Italy.
- In December BP and the State Oil Company of the Republic of Azerbaijan signed a new PSA to jointly explore for and develop potential prospects in the shallow water area around the Absheron Peninsula in the Azerbaijan sector of the Caspian Sea.

BP, as operator, holds a 30.1% interest in and manages the Baku-Tbilisi-Ceyhan (BTC) oil pipeline. The 1,768-kilometre pipeline transports oil from the BP-operated ACG oilfield and gas condensate from the Shah Deniz gas field in the Caspian Sea, along with other third-party oil, to the eastern Mediterranean port of Ceyhan. The BTC pipeline has a capacity of 1mmboe/d with average throughput in 2014 of 712mboe/d.

BP is technical operator of, and currently holds a 28.83% interest in, the 693-kilometre SCP. The pipeline takes gas from Azerbaijan through Georgia to the Turkish border and has a capacity of 134mboe/d with average throughput in 2014 of 111mboe/d. BP (as operator of Azerbaijan International Operating Company) also operates the Western Export Route Pipeline which transports ACG oil to the Black Sea coast of Georgia.

In Oman, BP currently has appraisal programmes and development activities. In December 2013, BP and the Sultanate of Oman government signed a gas sales agreement and an amended EPSA for the development of the Khazzan field in block 61 with BP as operator.

- In February the Sultan of Oman issued a royal decree approving the amended EPSA and the government acquired a 40% stake in block 61 through Makarim Gas Development LLC, a wholly owned subsidiary of the state-owned Oman Oil Company Exploration & Production.

- In October we announced the award of two long-term drilling contracts for the Oman Khazzan project in block 61. KCA Deutag was awarded more than $400 million in contracts for the construction and operation of five new build land rigs for Khazzan. Oman s Abraj Energy Service was awarded more than $330 million in contracts to supply three drilling rigs for the full field development of the Khazzan project. Gas production is expected to start in late 2017.

In Abu Dhabi, we had equity interests of 9.5% and 14.67% in onshore and offshore concessions respectively in 2013. The Abu Dhabi onshore concession expired in January 2014 with a consequent impact on production of approximately 140mboe/d. BP participated in the tender process for the new onshore concession.

We also have a 10% equity shareholding in the Abu Dhabi Gas Liquefaction Company, which in 2014 supplied 5.9 million tonnes of LNG (305.7bcfe regasified).

In India, BP has a 30% interest in four oil and gas PSAs operated by Reliance Industries Limited (RIL), and is a partner with RIL in a 50:50 joint operation for the sourcing and marketing of gas in India.

During the year a number of activities continued to manage the existing producing fields in the KG D6 block, with a focus on sustaining production and extending the life of these fields. Activities included well work-overs, side-tracks and new wells as well as progress on the installation of additional compression capacity.

In October the government of India announced new gas price guidelines for domestic gas, effective 1 November 2014. The new guidelines replace the earlier guidelines issued by the government in January 2014.

During the year we recorded an $810-million charge (comprising a $415 million impairment charge and $395 million exploration write-off) to write down the value ascribed to block KG D6 in India as part of the acquisition of upstream interests from RIL in 2011. The charge arises as a result of uncertainty in the future long-term gas price outlook, following the introduction of a new formula for Indian gas prices, although we do see the commencement of a transition to market-based pricing as a positive step. We expect further clarity on the new pricing policy and the premiums for future developments to emerge in due course.

In Iraq, BP holds a 47.6% working interest and is the lead contractor in the Rumaila technical service contract. Rumaila is one of the world s largest oil fields, comprising five producing reservoirs. BP s total assets in Iraq at 31 December 2014 were $1,606 million ($1,235 million current and $371 million non-current).

In September we signed an amendment to the Rumaila contract terms, which include, among other things, the increase of BP equity and a five-year term extension until 2034. BP is also working with the government of Iraq and North Oil Company on studies in support of the stabilization and redevelopment of two producing reservoirs of the Kirkuk field. Despite instability and sectarian violence in the north and west of the country, BP operations are continuing in the south.

Australasia

We are active in Australia and Eastern Indonesia.

In Australia, BP is one of seven participants in the North West Shelf (NWS) venture, which has been producing LNG, pipeline gas, condensate, LPG and oil since the 1980s. Six partners (including BP) hold an equal 16.67% interest in the gas infrastructure and an equal 15.78% interest in the gas and condensate reserves, with a seventh partner owning the remaining 5.32%. BP also has a 16.67% interest in some of the NWS oil reserves and related infrastructure. The NWS venture is currently the principal supplier to the domestic market in Western Australia and one of the largest LNG export projects in Asia, with five LNG trains in operation. BP s net share of the capacity of NWS LNG trains 1-5 is 2.7 million tonnes of LNG per annum.

BP also holds a 5.375% interest in the Jansz-lo field and 12.5% interests in the Geryon, Orthrus and Maenad fields which are part of the Greater Gorgon project. BP s Jansz-Io interest is in the reserves and wells which will provide the initial feed gas to the Gorgon LNG plant scheduled to commence production late 2015.

BP holds a 70% interest in four deepwater offshore exploration blocks in the Ceduna Sub Basin. BP, as operator, expects to drill four deepwater wells beginning in 2016 in this frontier exploration basin located within the Great Australian Bight off the coast of southern Australia.

BP is also one of five participants in the Browse LNG venture (operated by Woodside) and holds a 17% interest. Browse is currently in the pre-FEED stage of an offshore floating LNG development and remains subject to regulatory, joint operation and internal BP approvals.

We accessed new acreage in the offshore Outer Canning basin in Western Australia in September by farming in to two exploration permits (BP 21%).

In Eastern Indonesia, BP operates the Tangguh LNG plant. Tangguh (BP 37.16%), is located in Papua Barat. The asset comprises 14 producing wells, two offshore platforms, two pipelines and an LNG plant with two production trains. It has a total capacity of 7.6 million tonnes of LNG per annum. Tangguh supplies LNG to customers in

Indonesia, China, South Korea, Mexico and Japan through a combination of long, medium and short-term contracts. Plans for a third train remain on track.

In August BP announced that the government of Indonesia, through the Ministry of Environment, approved the Tangguh expansion project integrated environment and social impact assessment and issued the project (BP 37.16%) an environmental permit. This was followed by the award of dual onshore FEED to two separate consortia, announced in October. In addition, BP and the Tangguh partners signed a long-term LNG sales agreement with PT PLN (Persero), Indonesia s state-owned electricity company, to supply up to 1.5 million tonnes of LNG each year from 2015 to 2033. Supply will initially be provided from Tangguh s existing LNG trains. The agreement commits 40% of annual production from train 3 to the domestic market.

BP has 100% interests in two deepwater PSAs: West Aru I and II and 32% interest in the Chevron-operated West Papua I and Ill PSAs. These PSAs will be relinquished pending approval from the government of Indonesia.

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Downstream plant capacity

The following table summarizes BP group s interests in refineries and average daily crude distillation capacities as at 31 December 2014.

Fuels value chain	Country	Refinery	Group interest[b] (%)	Crude distillation capacities[a] BP share thousand barrels per day
US				
US North West	US	Cherry Point	100	234
US East of Rockies		Whiting	100	430
		Toledo	50	80
				744
Europe				
Rhine	Germany	Bayernoil[c]	22.5	49
		Gelsenkirchen	50	132
		Karlsruhe[c]	12	39
		Lingen	100	95
		Schwedt[c]	18.8	45
	Netherlands	Rotterdam	100	377
Iberia	Spain	Castellón	100	110
				847
Rest of world				
Australia New Zealand	Australia	Bulwer[d]	100	102
		Kwinana	100	146
	New Zealand	Whangarei[c]	23.7	28
Southern Africa	South Africa	Durban[c]	50	90
				366
Total BP share of capacity at 31 December 2014				1,957

[a] Crude distillation capacity is gross rated capacity, which is defined as the highest average sustained unit rate for a consecutive 30-day period.
[b] BP share of equity, which is not necessarily the same as BP share of processing entitlements.
[c] Indicates refineries not operated by BP.
[d] We announced that we will halt refining operations at Bulwer in 2015.

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Petrochemicals production capacity[a]

The following table summarizes BP group s share of petrochemicals production capacities as at 31 December 2014.

			BP share of capacity thousand tonnes per annum[b]				
							Product
Geographical area	Site	Group interest (%)[c]	PTA	PX	Acetic acid	Olefins and derivatives	Others
US							
	Cooper River	100.0	1,300				
	Decatur[d]	100.0	1,000	700			
	Texas City	100.0		1,300	600[e]		100
			2,300	2,000	600		100
Europe							
UK	Hull	100.0			500		200
Belgium	Geel	100.0	1,300	700			
Germany	Gelsenkirchen[f]	50-61.0				1,800[g]	
	Mülheim[f]	50.0					100
			1,300	700	500	1,800	300
Rest of world							
Trinidad & Tobago	Point Lisas	36.9					700
China	Caojing	50.0				3,300	
	Chongqing	51.0			200		100
	Nanjing	50.0			300		
	Zhuhai[h]	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
Total BP share of capacity at 31 December 2014							18,300

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

[b] Capacities are shown to the nearest hundred thousand tonnes per annum.

[c] Includes BP share of equity-accounted entities, as indicated.

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

[e] Group interest is quoted at 100%, reflecting the capacity entitlement, which is marketed by BP.

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

[g] Group interest varies by product.

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

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Oil and gas disclosures for the group

Resource progression

BP manages its hydrocarbon resources in three major categories: prospect inventory, contingent resources and reserves. When a discovery is made, volumes usually transfer from the prospect inventory to the contingent resources category. The contingent resources move through various sub-categories as their technical and commercial maturity increases through appraisal activity.

At the point of final investment decision, most proved reserves will be categorized as proved undeveloped (PUD). Volumes will subsequently be recategorized from PUD to proved developed (PD) as a consequence of development activity. When part of a well s proved reserves depends on a later phase of activity, only that portion of proved reserves associated with existing, available facilities and infrastructure moves to PD. The first PD bookings will typically occur at the point of first oil or gas production. Major development projects typically take one to five years from the time of initial booking of PUD to the start of production. Changes to proved reserves bookings may be made due to analysis of new or existing data concerning production, reservoir performance, commercial factors and additional reservoir development activity.

Volumes can also be added or removed from our portfolio through acquisition or divestment of properties and projects. When we dispose of an interest in a property or project, the volumes associated with our adopted plan of development for which we have a final investment decision will be removed from our proved reserves upon completion. When we acquire an interest in a property or project, the volumes associated with the existing development and any committed projects will be added to our proved reserves if BP has made a final investment decision and they satisfy the SEC s criteria for attribution of proved status. Following the acquisition, additional volumes may be progressed to proved reserves from non-proved reserves or contingent resources.

Non-proved reserves and contingent resources in a field will only be recategorized as proved reserves when all the criteria for attribution of proved status have been met and the volumes are included in the business plan and scheduled for development, typically within five years. BP will only book proved reserves where development is scheduled to commence after more than five years, if these proved reserves satisfy the SEC s criteria for attribution of proved status and BP management has reasonable certainty that these proved reserves will be produced.

At the end of 2014 BP had material volumes of proved undeveloped reserves held for more than five years in Trinidad, the North Sea and the Gulf of Mexico. These are part of ongoing infrastructure-led development activities for which BP has a historical track record of completing comparable projects in these countries. We have no proved undeveloped reserves held for more than five years in our onshore US developments.

In each case the volumes are being progressed as part of an adopted development plan where there are physical limits to the development timing such as infrastructure limitations, contractual limits including gas delivery commitments, late life compression and the complex nature of working in remote locations.

Over the past five years, BP has annually progressed on average 19% of our proved undeveloped reserves (accounting for disposals) to proved developed reserves. This equates to a turnover time of about five years. We expect the turnover time to remain at or below five years and anticipate the volume of proved undeveloped reserves held for more than five years to remain about the same.

In 2014 we progressed 1,031mmboe of proved undeveloped reserves (483mmboe for our subsidiaries alone) to proved developed reserves through ongoing investment in our subsidiaries and equity-accounted entities upstream development activities. Total development expenditure in Upstream, excluding midstream activities, was $18,704 million in 2014 ($15,096 million for subsidiaries and $3,608 million for equity-accounted entities). The major areas with progressed volumes in 2014 were Angola, Azerbaijan, Russia, Trinidad, UK and US. Revisions of previous estimates for proved undeveloped reserves are due to changes relating to field performance or well results. The following tables describe the changes to our proved undeveloped

reserves position through the year for our subsidiaries and equity-accounted entities and for our subsidiaries alone.

Subsidiaries and equity-accounted entities	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2014	8,080
Revisions of previous estimates	371
Improved recovery	196
Discoveries and extensions	146
Purchases	42
Sales	(15)
Total in year proved undeveloped reserves changes	8,819
Progressed to proved developed reserves	(1,031)
Proved undeveloped reserves at 31 December 2014	7,788

Subsidiaries only	volumes in mmboe[a]
Proved undeveloped reserves at 1 January 2014	4,844
Revisions of previous estimates	(183)
Improved recovery	180
Discoveries and extensions	123
Purchases	42
Sales	(15)
Total in year proved undeveloped reserves changes	4,990
Progressed to proved developed reserves	(483)
Proved undeveloped reserves at 31 December 2014	4,507

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

BP bases its proved reserves estimates on the requirement of reasonable certainty with rigorous technical and commercial assessments based on conventional industry practice and regulatory requirements. BP only applies technologies that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. BP applies high-resolution seismic data for the identification of reservoir extent and fluid contacts only where there is an overwhelming track record of success in its local application. In certain cases BP uses numerical simulation as part of a holistic assessment of recovery factor for its fields, where these simulations have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. In certain deepwater fields BP has booked proved reserves before production flow tests are conducted, in part because of the significant safety, cost and environmental implications of conducting these tests. The industry has made substantial technological improvements in understanding, measuring and delineating reservoir properties without the need for flow tests. To determine reasonable certainty of commercial recovery, BP employs a general method of reserves assessment that relies on the integration of three types of data:

1. Well data used to assess the local characteristics and conditions of reservoirs and fluids.

2. Field scale seismic data to allow the interpolation and extrapolation of these characteristics outside the immediate area of the local well control.

3. Data from relevant analogous fields. Well data includes appraisal wells or sidetrack holes, full logging suites, core data and fluid samples. BP considers the integration of this data in certain cases to be superior to a flow test in providing understanding of overall reservoir performance. The collection of data from logs, cores, wireline formation testers, pressures and fluid samples calibrated to each other and to the seismic data can allow reservoir properties to be determined over a greater volume than the localized volume of investigation associated with a short-term flow test. There is a strong track record of proved reserves recorded using these methods, validated by actual production levels.

Governance

BP s centrally controlled process for proved reserves estimation approval forms part of a holistic and integrated system of internal control. It consists of the following elements:

Accountabilities of certain officers of the group to ensure that there is review and approval of proved reserves bookings independent of the operating business and that there are effective controls in the approval

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process and verification that the proved reserves estimates and the related financial impacts are reported in a timely manner.

Capital allocation processes, whereby delegated authority is exercised to commit to capital projects that are consistent with the delivery of the group s business plan. A formal review process exists to ensure that both technical and commercial criteria are met prior to the commitment of capital to projects.

Group audit, whose role is to consider whether the group s system of internal control is adequately designed and operating effectively to respond appropriately to the risks that are significant to BP.

Approval hierarchy, whereby proved reserves changes above certain threshold volumes require central authorization and periodic reviews. The frequency of review is determined according to field size and ensures that more than 80% of the BP proved reserves base undergoes central review every two years, and more than 90% is reviewed centrally every four years.

BP s vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has more than 30 years of diversified industry experience with the past 10 spent managing the governance and compliance of BP s reserves estimation. He is a past member of the Society of Petroleum Engineers Oil and Gas Reserves Committee and of the American Association of Petroleum Geologists Committee on Resource Evaluation and is the current chair of the bureau of the United Nations Economic Commission for Europe Expert Group on Resource Classification.

No specific portion of compensation bonuses for senior management is directly related to proved reserves targets. Additions to proved reserves is one of several indicators by which the performance of the Upstream segment is assessed by the remuneration committee for the purposes of determining compensation bonuses for the executive directors. Other indicators include a number of financial and operational measures.

BP s variable pay programme for the other senior managers in the Upstream segment is based on individual performance contracts. Individual performance contracts are based on agreed items from the business performance plan, one of which, if chosen, could relate to proved reserves.

Compliance

International Financial Reporting Standards (IFRS) do not provide specific guidance on reserves disclosures. BP estimates proved reserves in accordance with SEC Rule 4-10 (a) of Regulation S-X and relevant Compliance and Disclosure Interpretations (C&DI) and Staff Accounting Bulletins as issued by the SEC staff.

By their nature, there is always some risk involved in the ultimate development and production of proved reserves including, but not limited to: final regulatory approval; the installation of new or additional infrastructure, as well as changes in oil and gas prices; changes in operating and development costs; and the continued availability of additional development capital. All the group s proved reserves held in subsidiaries and equity-accounted entities with the exception of those proved reserves held by our Russian equity-accounted entity, Rosneft are estimated by the group s petroleum engineers.

DeGolyer & MacNaughton (D&M), an independent petroleum engineering consulting firm, has estimated the net proved crude oil, condensate, natural gas liquids (NGLs) and natural gas reserves, as of 31 December 2014, of certain properties owned by Rosneft. The properties evaluated by D&M account for 100% of Rosneft s net proved reserves as of 31 December 2014. The net proved reserves estimates prepared by D&M were prepared in accordance with the reserves definitions of Rule 4-10(a)(1)-(32) of Regulation S-X. All reserves estimates involve some degree of uncertainty. BP has filed D&M s independent report on its reserves estimates as an exhibit to its Annual Report on Form 20-F filed with the SEC.

Our proved reserves are associated with both concessions (tax and royalty arrangements) and agreements where the group is exposed to the upstream risks and rewards of ownership, but where our entitlement to the hydrocarbons is calculated using a more complex formula, such as with PSAs. In a concession, the consortium of which we are a part is entitled to the proved reserves that can be produced over the licence period, which may be the life of the field. In a PSA, we are entitled to

recover volumes that equate to costs incurred to develop and produce the proved reserves and an agreed share of the remaining volumes or the economic equivalent. As part of our entitlement is driven by the monetary amount of costs to be recovered, price fluctuations will have an impact on both production volumes and reserves.

We disclose our share of proved reserves held in equity-accounted entities (joint ventures* and associates*), although we do not control these entities or the assets held by such entities.

BP s estimated net proved reserves and proved reserves replacement

Eighty-four per cent of our total proved reserves of subsidiaries at 31 December 2014 were held through joint operations (83% in 2013), and 33% of the proved reserves were held through such joint operations where we were not the operator (31% in 2013).

Estimated net proved reserves of crude oil at 31 December 2014[a b c]

			million barrels
	Developed	Undeveloped	Total
UK	159	329	488
Rest of Europe	95	22	117
US	1,030	664	1,694
Rest of North America	9	163	172
South America	10	22	32
Africa	317	120	437
Rest of Asia	384	197	581
Australasia	40	19	59
Subsidiaries*	2,043	1,538	3,582
Equity-accounted entities	3,405	2,258	5,663
Total	5,448	3,796	9,244

Estimated net proved reserves of natural gas liquids at 31 December 2014[a b]

			million barrels
	Developed	Undeveloped	Total
UK	6	3	9
Rest of Europe	13	1	14
US	323	104	427
Rest of North America			
South America	11	28	39
Africa	5	7	12
Rest of Asia			
Australasia	6	3	10
Subsidiaries	364	146	510

Equity-accounted entities	46	16	62
Total	410	163	572

Estimated net proved reserves of liquids*

			million barrels
	Developed	Undeveloped	Total
Subsidiaries	2,407	1,684	4,092[d e]
Equity-accounted entities	3,451	2,274	5,725[f]
Total	5,858	3,958	9,817

Estimated net proved reserves of natural gas at 31 December 2014[a b]

			billion cubic feet
	Developed	Undeveloped	Total
UK	382	386	768
Rest of Europe	300	19	318
US	7,168	2,447	9,615
Rest of North America	17		17
South America	2,352	6,313	8,666
Africa	901	1,597	2,497
Rest of Asia	1,688	3,892	5,580
Australasia	3,316	1,719	5,035
Subsidiaries	16,124	16,372	32,496[g]
Equity-accounted entities	6,363	5,837	12,200[h]
Total	22,487	22,209	44,695

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Estimated net proved reserves on an oil equivalent basis

	million barrels of oil equivalent		
	Developed	Undeveloped	Total
Subsidiaries	5,187	4,507	9,694
Equity-accounted entities	4,548	3,280	7,828
Total	9,735	7,788	17,523

[a] Proved reserves exclude royalties due to others, whether payable in cash or in kind, where the royalty owner has a direct interest in the underlying production and the option and ability to make lifting and sales arrangements independently, and include non-controlling interests in consolidated operations. We disclose our share of reserves held in joint ventures and associates that are accounted for by the equity method although we do not control these entities or the assets held by such entities.

[b] The 2014 marker prices used were Brent $101.27/bbl (2013 $108.02/bbl and 2012 $111.13/bbl) and Henry Hub $4.31/mmBtu (2013 $3.66/mmBtu and 2012 $2.75/mmBtu).

[c] Includes condensate and bitumen.

[d] Proved reserves in the Prudhoe Bay field in Alaska include an estimated 65 million barrels on which a net profits royalty will be payable over the life of the field under the terms of the BP Prudhoe Bay Royalty Trust.

[e] Includes 21 million barrels of liquids in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[f] Includes 38 million barrels of crude oil in respect of the 0.16% non-controlling interest in Rosneft held assets in Russia.

[g] Includes 2,519 billion cubic feet of natural gas in respect of the 30% non-controlling interest in BP Trinidad and Tobago LLC.

[h] Includes 91 billion cubic feet of natural gas in respect of the 0.18% non-controlling interest in Rosneft held assets in Russia.

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

Proved reserves replacement

Total hydrocarbon proved reserves at 31 December 2014, on an oil equivalent basis including equity-accounted entities, decreased by 3% (decrease of 5% for subsidiaries and increase of 1% for equity-accounted entities) compared with 31 December 2013. Natural gas represented about 44% (58% for subsidiaries and 27% for equity-accounted entities) of these reserves. The change includes a net decrease from acquisitions and disposals of 39mmboe (all within our subsidiaries). Acquisition activity in our subsidiaries occurred in Azerbaijan, the US and the UK, and divestment activity in our subsidiaries in the US and Brazil.

The proved reserves replacement ratio is the extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries. For 2014, the proved reserves replacement ratio excluding acquisitions and disposals was 63% (129% in 2013 and 77% in 2012) for subsidiaries and equity-accounted entities, 29% for subsidiaries alone and 116% for equity-accounted entities alone. The decreased ratio reflected lower reserves bookings as a result of fewer final investment decisions in 2014 and revisions of previous estimates.

In 2014 net additions to the group s proved reserves (excluding production and sales and purchases of reserves-in-place) amounted to 743mmboe (208mmboe for subsidiaries and 535mmboe for equity-accounted entities), through revisions to previous estimates, improved recovery from, and extensions to, existing fields and discoveries of new fields. The subsidiary additions through improved recovery from, and extensions to, existing fields and discoveries of new fields were in existing developments where they represented a mixture of proved developed and proved undeveloped reserves. Volumes added in 2014 principally resulted from the application of conventional technologies. The principal proved reserves additions in our subsidiaries were in Angola, Azerbaijan, Iraq, Oman, Trinidad and the US. We had material reductions in our proved reserves in Norway, the UK, Indonesia and Australia, principally due to activity reduction and reservoir performance. The principal reserves additions in our equity-accounted entities were in Argentina and Russia.

Sixteen per cent of our proved reserves are associated with PSAs. The countries in which we operated under PSAs in 2014 were Algeria, Angola, Azerbaijan, Egypt, India, Indonesia, Oman and a non-material volume of our proved reserves in Trinidad. In addition, the technical service contract (TSC) governing our investment in the Rumaila field in Iraq functions as a PSA.

The Abu Dhabi onshore concession expired in January 2014 with a consequent reduction in production of approximately 140mboe/d. Our Abu Dhabi offshore concession is due to expire in 2018. The group holds no other licences due to expire within the next three years that would have a significant impact on BP s reserves or production.

For further information on our reserves see page 174.

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BP s net production by country crude oil[a] and natural gas liquids

						thousand barrels per day
				BP net share of production[b]		
			Crude oil			Natural gas liquids
	2014	2013	2012	**2014**	2013	2012
Subsidiaries	**46**	58	81			
UK[c d]				**2**	3	5
Norway[c]	**41**	31	22	**5**	4	1
Total Rest of Europe	**41**	31	22	**5**	4	1
Total Europe	**87**	89	103	**7**	7	6
Alaska[c]	**127**	137	139			
Lower 48 onshore[c]	**14**	12	11	**45**	45	49
Gulf of Mexico deepwater[c]	**206**	156	176	**18**	13	15
Total US	**347**	305	327	**63**	58	64
Canada[c]						1
Total Rest of North America						1
Total North America	**347**	305	327	**63**	58	65
Trinidad & Tobago	**13**	10	8	**12**	12	13
Brazil[c]		7	7			
Total South America	**13**	17	16	**12**	12	13
Angola	**181**	180	149			
Egypt	**37**	33	36			
Algeria	**5**	3	6	**5**	3	7
Total Africa	**222**	217	191	**5**	3	7
Azerbaijan[c]	**98**	96	92			
Western Indonesia	**2**	1	1			
Iraq	**55**	39	39			
Other	**2**	4	6		1	2
Total Rest of Asia	**156**	141	137		1	2
Total Asia	**156**	141	137		1	2
Australia	**17**	19	20	**3**	4	4
Other	**2**	2	1			
Total Australasia	**19**	21	22	**3**	4	4
Total subsidiaries[e]	**844**	789	795	**91**	86	96
Equity-accounted entities (BP share)						
TNK-BP (Russia, Venezuela, Vietnam)[c f]		183	857		4	20
Rosneft (Russia, Canada, Venezuela, Vietnam)[c g]	**816**	643		**5**	7	
Abu Dhabi[h]	**97**	231	216			
Argentina	**62**	60	63	**3**	3	3
Bolivia	**3**	2	1			
Egypt				**4**	5	5
Other	**1**	1	1			

Total equity-accounted entities	**979**	1,120	1,137	**12**	19	27
Total subsidiaries and equity-accounted entities	**1,823**	1,909	1,932	**104**	105	123

[a] Includes condensate.
[b] 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.
[c] 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 Severnoeneftegaz, 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.
[d] Volumes relate to six BP-operated fields within ETAP. BP has no interests in the remaining three ETAP fields, which are operated by Shell.
[e] Includes 7 net mboe/d of NGLs from processing plants in which BP has an interest (2013 5.5mboe/d and 2012 13.5mboe/d).
[f] 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.
[g] 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.
[h] BP holds interests, through associates, in offshore concessions in Abu Dhabi which expire in 2018. We similarly held onshore concessions which expired in 2014.

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

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BP s net production by country natural gas

	million cubic feet per day		
	BP net share of production[a]		
	2014	2013	2012
Subsidiaries			
UK[b]	**71**	157	414
Norway	**102**	80	8
Total Rest of Europe	**102**	80	8
Total Europe	**173**	237	422
Lower 48 onshore[b]	**1,350**	1,404	1,499
Gulf of Mexico deepwater[b]	**159**	114	134
Alaska	**11**	21	18
Total US	**1,519**	1,539	1,651
Canada	**10**	11	13
Total Rest of North America	**10**	11	13
Total North America	**1,529**	1,551	1,664
Trinidad & Tobago	**2,147**	2,221	2,097
Total South America	**2,147**	2,221	2,097
Egypt	**406**	444	470
Algeria	**107**	117	120
Total Africa	**513**	561	590
Azerbaijan[b]	**230**	203	158
Western Indonesia	**47**	51	59
India	**131**	156	313
Other[b]		81	103
Total Rest of Asia	**408**	490	633
Total Asia	**408**	490	633
Australia	**450**	431	435
Eastern Indonesia	**364**	353	352
Total Australasia	**814**	784	787
Total subsidiaries[c]	**5,585**	5,845	6,193
Equity-accounted entities (BP share)			
TNK-BP (Russia, Venezuela, Vietnam)[b d]		184	785
Rosneft (Russia, Canada, Venezuela, Vietnam)[b e]	**1,084**	617	
Argentina	**323**	329	355
Bolivia	**80**	55	34
Other	**28**	30	26
Total equity-accounted entities[c]	**1,515**	1,216	1,200
Total subsidiaries and equity-accounted entities	**7,100**	7,060	7,393

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

independently.

[b] In 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.

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

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

[e] 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.

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

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The following tables provide additional data and disclosures in relation to our oil and gas operations.

Average sales price per unit of production[a]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia[b]	Rest of Asia		
Subsidiaries										
2014										
Crude oil[c]	**96.02**	**97.77**	**93.66**		**96.85**	**93.99**		**91.05**	**94.04**	**93.65**
Natural gas liquids	**58.11**	**52.97**	**32.28**		**41.62**	**53.67**			**65.70**	**36.15**
Gas	**8.13**	**8.22**	**3.80**		**4.65**	**5.92**		**6.28**	**11.20**	**5.70**
2013										
Crude oil[c]	107.83	107.78	102.07		106.37	107.02		108.26	105.89	105.38
Natural gas liquids	62.53	61.82	30.95		54.92	69.39			68.13	38.38
Gas	9.43	10.18	3.07		4.66	5.75		4.99	10.55	5.35
2012										
Crude oil[c]	111.76	109.07	107.55		105.83	110.08		109.74	106.47	108.94
Natural gas liquids	74.38	60.36	34.65		52.46	75.82			84.96	42.75
Gas	8.62	9.43	2.32		3.53	6.05		5.08	10.08	4.75
Equity-accounted entities[d]										
2014										
Crude oil[c]					**73.87**		**84.19**	**14.70**		**72.53**
Natural gas liquids					**15.75**		**n/a**			**15.75**
Gas					**4.73**		**2.18**	**12.83**		**3.01**
2013										
Crude oil[c]					74.01		95.28	11.58		63.51
Natural gas liquids					29.63		n/a			29.63
Gas					4.05		2.47	13.21		3.26
2012										
Crude oil[c]					81.32		86.76	10.15		62.11
Natural gas liquids					22.36		7.63			9.70
Gas					2.35		2.35	5.08		2.52

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Realizations include transfers between businesses, except in the case of Russia in 2014 and 2013.

[b] Amounts reported for Russia in 2014 and 2013 include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia. The operational and financial information of the Rosneft segment for 2014 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts. Crude oil includes natural gas liquids in 2014 and 2013.

[c] Includes condensate.

[d] It is common for equity-accounted entities agreements to include pricing clauses that require selling a significant portion of the entitled production to local governments or markets at discounted prices.

Average production cost per unit of production[a]

$ per unit of production

	Europe		North America		South America	Africa	Asia		Australasia	Total group average
	UK	Rest of Europe	US	Rest of North America			Russia[b]	Rest of Asia		
Subsidiaries										
2014	**44.67**	**18.85**	**14.22**		**5.43**	**13.37**		**15.55**	**3.92**	**12.68**
2013	34.10	24.48	16.11		5.92	13.84		13.20	3.21	13.16
2012	22.77	39.10	15.60		5.69	11.89		11.85	3.23	12.50
Equity-accounted entities										
2014					**11.28**		**3.82**	**4.34**		**4.75**
2013					12.16		4.36	4.19		5.28
2012					11.33		5.72	2.88		5.76

[a] Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts do not include ad valorem and severance taxes.

[b] Amounts reported for Russia in 2014 and 2013 include BP s share of Rosneft s worldwide activities, including insignificant amounts outside Russia. The operational and financial information of the Rosneft segment for 2014 is based on preliminary operational and financial results of Rosneft for the three months ended 31 December 2014. Actual results may differ from these amounts.

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Environmental expenditure

			$ million
	2014	2013	2012
Environmental expenditure relating to the Gulf of Mexico oil spill	**190**	(66)[a]	919
Operating expenditure	**624**	657	742
Capital expenditure	**590**	1,091	1,207
Clean-ups	**33**	42	47
Additions to environmental remediation provision	**371**	472	549
Additions to decommissioning provision	**2,216**	2,092	3,766

[a] The environmental expenditure credit of $66 million in 2013 arises primarily from the write-back of a spill response provision.

Environmental expenditure relating to the Gulf of Mexico oil spill

For full details of all environmental activities in relation to the Gulf of Mexico oil spill, see Financial statements Note 2.

Other environmental expenditure

Operating and capital expenditure on the prevention, control, abatement or elimination of air, water and solid waste pollution is often not incurred as a separately identifiable transaction. Instead, it forms part of a larger transaction that includes, for example, normal maintenance expenditure. The figures for environmental operating and capital expenditure in the table are therefore estimates, based on the definitions and guidelines of the American Petroleum Institute.

Environmental operating expenditure of $624 million in 2014 was at a similar level to 2013.

Capital expenditure in 2014 was lower than in 2013 principally due to reduced levels of construction activity at our Whiting refinery in 2014 as compared to 2013. The final major units associated with the Whiting refinery modernization project were commissioned in December 2013.

Clean-up costs in 2014 were lower than in 2013 primarily due to an overall reduction in clean-up activities and services required across sites.

In addition to operating and capital expenditures, we also establish provisions for future environmental remediation. Expenditure against such provisions normally occurs in subsequent periods and is not included in environmental operating expenditure reported for such periods.

Provisions for environmental remediation are made when a clean-up is probable and the amount of the obligation can be reliably estimated. Generally, this coincides with the commitment to a formal plan of action or, if earlier, on divestment or on closure of inactive sites.

The extent and cost of future environmental restoration, remediation and abatement programmes are inherently difficult to estimate. They often depend on the extent of contamination, and the associated impact and timing of the corrective actions required, technological feasibility and BP s share of liability. Though the costs of future programmes could be significant and may be material to the results of operations in the period in which they are recognized, it is not expected that such costs will be material to the group s overall results of operations or financial position.

Additions to our environmental remediation provision decreased in 2014 largely due to scope reassessments of the remediation plans of a number of our sites in the US and Canada. The charge for environmental remediation provisions in 2014 included $13 million in respect of provisions for new sites (2013 $13 million and 2012 $19 million).

In addition, we make provisions on installation of our oil- and gas-producing assets and related pipelines to meet the cost of eventual decommissioning. On installation of an oil or natural gas production facility, a provision is established that represents the discounted value of the expected future cost of decommissioning the asset.

In 2014 additions to the decommissioning provision were greater than in 2013, and occurred as a result of detailed reviews of expected future costs, and to a lesser extent increases to the asset base. The majority of these additions related to our sites in the North Sea, the Gulf of Mexico and Angola. The additions in 2012 and 2013 were driven by changes in estimation and detailed reviews of expected future costs.

In 2012 and 2013, the Gulf of Mexico was impacted by the Bureau of Ocean Energy Management, Regulation and Enforcement s (BOEMRE) Notice to Lessees (NTL) 2010-G05, issued in October 2010, which requires that idle infrastructure on active leases be decommissioned earlier than previously was required and establishes guidelines to determine the future utility of idle infrastructure on active leases.

We undertake periodic reviews of existing provisions. These reviews take account of revised cost assumptions, changes in decommissioning requirements and any technological developments.

Provisions for environmental remediation and decommissioning are usually established on a discounted basis, as required by IAS 37 Provisions, Contingent Liabilities and Contingent Assets . Further details of decommissioning and environmental provisions appear in the financial statements Note 21.

Regulation of the group s business

BP s activities, including its oil and gas exploration and production, pipelines and transportation, refining and marketing, petrochemicals production, trading, biofuels, wind and shipping activities, are conducted in almost 80 countries and are subject to a broad range of EU, US, international, regional and local legislation and regulations, including legislation that implements international conventions and protocols. These cover virtually all aspects of BP s activities and include matters such as licence acquisition, production rates, royalties, environmental, health and safety protection, fuel specifications and transportation, trading, pricing, anti-trust, export, taxes and foreign exchange.

The terms and conditions of the leases, licences and contracts under which our oil and gas interests are held vary from country to country. These leases, licences and contracts are generally granted by or entered into with a government entity or state-owned or controlled company and are sometimes entered into with private property owners. Arrangements with governmental or state entities usually take the form of licences or production-sharing agreements (PSAs), although arrangements with the US government can be by lease. Arrangements with private property owners are usually in the form of leases.

Licences (or concessions) give the holder the right to explore for and exploit a commercial discovery. Under a licence, the holder bears the risk of exploration, development and production activities and provides the financing for these operations. In principle, the licence holder is entitled to all production, minus any royalties that are payable in kind. A licence holder is generally required to pay production taxes or royalties, which may be in cash or in kind. Less typically, BP may explore for and exploit hydrocarbons under a service agreement with the host entity in exchange for reimbursement of costs and/or a fee paid in cash rather than production.

PSAs entered into with a government entity or state-owned or controlled company generally require BP to provide all the financing and bear the risk of exploration and production activities in exchange for a share of the production remaining after royalties, if any.

In certain countries, separate licences are required for exploration and production activities, and in some cases production licences are limited to only a portion of the area covered by the original exploration licence. Both exploration and production licences are generally for a specified period of time. In the US, leases from the US government typically remain in effect for a specified term, but may be extended beyond that term as long as there is production in paying quantities. The term of BP s licences and the extent to which these licences may be renewed vary from country to country.

BP frequently conducts its exploration and production activities in joint arrangements* or co-ownership arrangements with other international oil companies, state-owned or controlled companies and/or private companies. These joint arrangements may be incorporated or unincorporated arrangements, while the co-ownerships are typically unincorporated. Whether incorporated or unincorporated, relevant agreements set out each party s level of participation or ownership interest in the joint arrangement or co-ownership. Conventionally, all costs, benefits, rights, obligations, liabilities and risks incurred in carrying out joint-arrangement or co-ownership operations under a lease or licence are shared among the joint-arrangement or co-owning parties according to these agreed ownership interests. Ownership of joint-arrangement or co-owned property and hydrocarbons to which the joint arrangement or co-ownership is entitled is also shared in these proportions. To the extent that any liabilities arise, whether to governments or third parties, or as between the joint arrangement parties or co-owners themselves, each joint arrangement party or co-owner will generally be liable to meet these in proportion to its ownership interest. In many upstream operations, a party (known as the operator) will be appointed (pursuant to a joint operating agreement) to carry out day-to-day operations on behalf of the joint arrangement or co-ownership. The operator is typically one of the joint arrangement parties or a co-owner and will carry out its duties either through its own staff, or by contracting out various elements to third-party contractors or service providers. BP acts as operator on behalf of joint arrangements and co-ownerships in a number of countries where it has exploration and production activities.

Frequently, work (including drilling and related activities) will be contracted out to third-party service providers who have the relevant expertise and equipment not available within the joint arrangement or the co-owning operator s organization. The relevant contract will specify the work to be done and the remuneration to be paid and will typically set out how major risks will be allocated between the joint arrangement or co-ownership and the service provider. Generally, the joint arrangement or co-owner and the contractor would respectively allocate responsibility for and provide reciprocal indemnities to each other for harm caused to their respective staff and property. Depending on the service to be provided, an oil and gas industry service contract may also contain provisions allocating risks and liabilities associated with pollution and environmental damage, damage to a well or hydrocarbon reservoir and for claims from third parties or other losses. The allocation of those risks vary among contracts and are determined through negotiation between the parties.

In general, BP incurs income tax on income generated from production activities (whether under a licence or PSA). In addition, depending on the area, BP s production activities may be subject to a range of other taxes, levies and assessments, including special petroleum taxes and revenue taxes. The taxes imposed on oil and gas production profits and activities may be substantially higher than those imposed on other activities, for example in Abu Dhabi, Angola, Egypt, Norway, the UK, the US, Russia and Trinidad & Tobago.

Environmental regulation

Current and proposed fuel and product specifications, emission controls, climate change programmes and regulation of unconventional oil and gas extraction under a number of environmental laws may have a significant effect on the production, sale and profitability of many of BP s products.

There are also environmental laws that require BP to remediate and restore areas affected by the release of hazardous substances or hydrocarbons associated with our operations. These laws may apply to sites that BP currently owns or operates, sites that it previously owned or operated, or sites used for the disposal of its and other parties waste. See Financial Statements Note 21 for information on provisions for environmental restoration and remediation.

A number of pending or anticipated governmental proceedings against certain BP group companies under environmental laws could result in monetary or other sanctions. Group companies are also subject to environmental claims for personal injury and property damage alleging the release of, or exposure to, hazardous substances. The costs associated with future environmental remediation obligations, governmental proceedings and claims could be significant and may be material to the results of operations in the period in which they are recognized. We cannot accurately predict the effects of future developments, such as stricter environmental laws or enforcement policies, or future events at our facilities, on the group, and there can be no assurance that material liabilities and costs will not be incurred in the future. For a discussion of the group s environmental expenditure see page 225.

A significant proportion of our fixed assets are located in the US and the EU. US and EU environmental, health and safety regulations significantly affect BP s operations. Significant legislation and regulation in the US and the EU affecting our businesses and profitability includes the following:

United States

- The Clean Air Act (CAA) regulates air emissions, permitting, fuel specifications and other aspects of our production, distribution and marketing activities. Stricter limits on sulphur in fuels will affect us in future, as will actions on greenhouse gas (GHG) emissions and other air pollutants. States may also have separate, stricter air emission laws in addition to the CAA.
- The Energy Policy Act of 2005 and the Energy Independence and Security Act of 2007 affect our US fuel markets by, among other things, imposing renewable fuel mandates and imposing GHG emissions thresholds for certain renewable fuels. States such as California also impose additional fuel carbon standards.
- The Clean Water Act regulates wastewater and other effluent discharges from BP s facilities, and BP is required to obtain discharge permits, install control equipment and implement operational controls and preventative measures.
- The Resource Conservation and Recovery Act regulates the generation, storage, transportation and disposal of wastes associated with our operations and can require corrective action at locations where such wastes have been disposed of or released.
- The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) can, in certain circumstances, impose the entire cost of investigation and remediation on a party who owned or operated a site contaminated with a hazardous substance, or arranged for disposal of a hazardous substance at a site. BP has incurred, or is likely to incur, liability under the CERCLA or similar state laws, including costs attributed to insolvent or unidentified parties. BP is also subject to claims for remediation costs under other federal and state laws, and to claims for natural resource damages under the CERCLA, the Oil Pollution Act of 1990 (OPA 90) (discussed below) and other federal and state laws. CERCLA also requires hazardous substance release notification.
- The Toxic Substances Control Act regulates BP s manufacture, import, export, sale and use of chemical substances and products.
- The Occupational Safety and Health Act imposes workplace safety and health requirements on BP operations along with significant process safety management obligations.
- In May 2012, the US adopted the UN Global Harmonization System (GHS) for hazard classification and labelling of chemicals and products, with the modification of the Occupational Safety & Health Administration (OSHA) Hazard Communication Standard. This requires BP to reassess the hazards of all our chemicals and products against new GHS criteria as adopted or modified by OSHA and to update warning labels and safety data sheets accordingly by 1 June 2015.
- The US Department of Transportation (DOT) regulates the transport of BP s petroleum products such as crude oil, gasoline, petrochemicals and other hydrocarbon liquids.
- The Maritime Transportation Security Act (MTSA), the DOT Hazardous Materials (HAZMAT) and the Chemical Facility Anti-Terrorism Standard (CFATS) regulations impose security compliance regulations on around 30 BP facilities.
- OPA 90 is implemented through regulations issued by the US Environmental Protection Agency (EPA), the US Coast Guard, the DOT, OSHA, the Bureau of Safety and Environmental Enforcement and various states. Alaska and the West Coast states currently have the most demanding state requirements.

As a consequence of the Deepwater Horizon incident, BP has become subject to claims under OPA 90 and other laws and has established a $20-billion trust fund for legitimate state and local government response claims, final judgments and settlement claims, legitimate state and local response costs, natural resource damages and related costs and legitimate individual and business claims (see Gulf of Mexico oil spill on page 36). BP is also subject to natural resource damages claims, claims for civil penalties under the Clean Water Act, and numerous civil lawsuits by individuals, businesses and governmental entities. The ultimate costs for these claims cannot be determined at this time. For further disclosures relating to the 2010 Deepwater Horizon oil spill, see Legal proceedings on page 228.

BP has also been in discussions with the EPA regarding alleged CAA violations at the Toledo refinery and the EPA has alleged certain CAA violations at the Cherry Point refinery and the Carson refinery which BP sold to Tesoro Corporation on 1 June 2013.

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European Union

In October 2014, the European Council agreed on new climate and energy targets for the period up to 2030.
The 2008 EU Climate and Energy Package is expected to remain in place until 2020 and includes an updated EU Emissions Trading System (EU ETS) Directive and the Renewable Energy Directive. The updated EU ETS has been expanded to include, among others, the petrochemical sector. Installations in sectors at risk of carbon leakage (i.e. production transfers out of the EU ETS trading area) are partially compensated with free allocation of emission allowances based on sector benchmarks used to calculate the number of free emissions per installation.
The Energy Efficiency Directive (EED) was adopted in 2012. It requires EU Member States to implement an indicative 2020 energy saving target and apply a framework of measures as part of a national energy efficiency programme, including mandatory industrial energy efficiency surveys. This directive is being implemented in the UK by the Energy Savings Opportunity Scheme (ESOS), which affects our offshore and onshore assets. ISO50001 is being implemented in some EU states to meet some elements of the Energy Efficiency Directive.
The Industrial Emissions Directive (IED) provides the framework for granting permits for major industrial sites. It lays down rules on integrated prevention and control of air, water and soil pollution arising from industrial activities. This may result in requirements for BP to further reduce its emissions, particularly its air and water emissions. As part of the IED framework, additional emission limit values are informed by the sector specific and cross-sector Best Available Technology (BAT) Conclusions, such as the recently published BAT Conclusions for the refining sector. Further BAT Conclusions that may result in additional emission reduction requirements are expected within the next two years.
The European Commission s Clean Air Policy Package (including a new directive for medium-sized combustion plants, a revised National Emission Ceilings Directive and a ratification proposal for the amended Gothenburg Protocol) may once adopted wholly or in part result in requirements for further emission reductions at BP s EU sites.
The implementation of the Water Framework Directive and the Environmental Quality Directive may mean that BP has to take further steps to manage freshwater withdrawals and discharges from its EU operations.
The EU regulation on ozone depleting substances (ODS) requires BP to reduce the use of ODS and phase out use of certain ODSs. BP continues to replace ODS in refrigerants and/or equipment, in the EU and elsewhere, in accordance with the Montreal Protocol and related legislation. In addition, the EU regulation on fluorinated gases with high global warming potential came into force on 1 January 2015. This might further limit the use of some refrigerants, such as in gas processing facilities.
The EU Fuel Quality Directive affects our production and marketing of transport fuels. Revisions adopted in 2009 mandate reductions in the life cycle GHG emissions per unit of energy and tighter environmental fuel quality standards for petrol and diesel.
The EU Registration, Evaluation and Authorization of Chemicals (REACH) Regulation requires registration of chemical substances manufactured in or imported into the EU, together with the submission of relevant hazard and risk data. REACH affects our refining, petrochemicals, exploration and production, biofuels, lubricants and other manufacturing or trading/import operations. In accordance with the required phase-in timetable, BP has completed registration of all substances in tonnage bands equal to or greater than 100 tonnes per annum/legal entity, and is in the process of preparing registration dossiers for substances manufactured or imported in amounts in the range 1-100 tonnes per annum/legal entity that are currently due to be submitted before 31 May 2018. Some substances registered previously, including substances supplied to us by third parties for our use, are now subject to thorough evaluation and review for potential authorization and restriction procedures, and possible banning, by the European Chemicals Agency and EU member state authorities.
In addition, the EU is implementing the UN Global Harmonization System for hazard classification and labelling of chemicals and products through the Classification Labelling and Packaging (CLP) Regulation. This requires BP to

reassess the hazards of all our
chemicals and products against the new GHS criteria as adopted or modified by the EU and to update warning labels and safety data sheets accordingly. The CLP will come into effect for mixtures (e.g. lubricants) in 2015. A separate EU regulation on export and import of hazardous chemicals requires warning labels and safety data sheets accompanying EU exports to be compliant with relevant CLP and REACH requirements (unless this conflicts with requirements in the importing country) and, as far as practicable, in the official or one or more principal languages of the intended area of use. Safety data sheets for the EU market have been or are being updated to include both REACH and CLP information.

The EU Offshore Safety Directive, adopted in 2013, is required to be transposed into national legislation by Member States, including the UK, by 19 July 2015. Its purpose is to introduce a harmonized regime aimed at reducing the potential environmental, health and safety impacts of the offshore oil and gas industry throughout EU waters. Implementation into UK legislation will involve alignment of the regime currently operating in the UK.

Environmental maritime regulations

BP s shipping operations are subject to extensive national and international regulations governing liability, operations, training, spill prevention and insurance. These include:

In US waters, OPA 90 imposes liability and spill prevention and planning requirements governing, among others, tankers, barges and offshore facilities. It also mandates a levy on imported and domestically produced oil to fund oil spill responses. Some states, including Alaska, Washington, Oregon and California, impose additional liability for oil spills. Outside US territorial waters, BP shipping tankers are subject to international liability, spill response and preparedness regulations under the UN s International Maritime Organization, including the International Convention on Civil Liability for Oil Pollution, the International Convention for the Prevention of Pollution from Ships (MARPOL) Convention, the International Convention on Oil Pollution, Preparedness, Response and Co-operation and the International Convention on Civil Liability for Bunker Oil Pollution Damage. In April 2010, the Hazardous and Noxious Substance (HNS) Protocol 2010 was adopted to address issues that have inhibited ratification of the International Convention on Liability and Compensation for Damage in Connection with the Carriage of Hazardous and Noxious Substances by Sea 1996. As of 6 January 2015, the number of contracting states to the HNS Convention remained at 14, so it has not yet entered into force.

Changes to the permitted level of sulphur in marine fuels under EU mandated reductions and International Maritime Organization guidelines over the next 5-10 years are intended to result in the reduction of sulphur oxides emissions from ships, either through the burning of low sulphur marine fuels or the use of approved on-board abatement technology. These restrictions are expected to place additional costs on refineries producing marine fuel, including costs to dispose of sulphur, as well as increased GHG emissions and energy costs for additional refining.

To meet its financial responsibility requirements, BP shipping maintains marine liability pollution insurance in respect of its operated ships to a maximum limit of $1 billion for each occurrence through mutual insurance associations (P&I Clubs), although there can be no assurance that a spill will necessarily be adequately covered by insurance or that liabilities will not exceed insurance recoveries.

Greenhouse gas regulation

Increasing concerns about climate change have led to a number of international climate agreements and negotiations that are ongoing.

In 2011, parties to the UN Framework Convention on Climate Change conference in Durban (COP17) agreed to several measures. One was a roadmap for negotiating a legal framework for action on climate change by 2015 that would involve all countries by 2020 and would close the ambition gap between existing GHG reduction pledges and what is required to achieve the goal of limiting global temperature rise to 2°C. Another was a second commitment period for the Kyoto Protocol to begin immediately after the first period. An amendment was subsequently adopted at the 2012 conference of parties (COP18) in Doha

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establishing a second commitment period to run until the end of 2020. However, it will not include the US, Canada, Japan and Russia and thus covers only about 15% of global emissions.

The 2014 conference (COP20) in Lima adopted the Lima Call for Climate Action. This included the elements of a negotiating text for a new international agreement, as specified in Durban in 2011, to be finalized at COP21 in Paris in December 2015. This text covers long-term ambitions and pathways and a framework for reaching it. COP20 also agreed on the rules for providing and assessing information about each country s Intended Nationally Determined Contributions (INDCs) towards reaching the overall ambition. The world s three largest emitters China, the US and the EU have all announced their intentions to limit their GHG emissions.

Additional, more stringent, measures can be expected in the future. These measures could increase BP s production costs for certain products, increase demand for competing energy alternatives or products with lower-carbon intensity, and affect the sales and specifications of many of BP s products. Current and announced measures and developments potentially affecting BP s businesses include the following:

- The EU has agreed to an overall GHG reduction target of 20% by 2020. To meet this, a Climate and Energy Package of regulatory measures has been adopted that includes: a collective national reduction target for emissions not covered by the EU ETS; binding national renewable energy targets to double usage of renewable energy sources in the EU including at least a 10% share of renewable energy in the transport sector; a legal framework to promote carbon capture and storage (CCS); and a revised EU ETS Phase 3. EU ETS revisions include a GHG reduction of 21% from 2005 levels; a significant increase in allowance auctioning; an expansion in the scope of the EU ETS to encompass more industrial sectors and gases and no free allocation for electricity generation or production but benchmarked free allocation for energy-intensive and trade-exposed industrial sectors. EU energy efficiency policy is currently implemented via national energy efficiency action plans and the Energy Efficiency Directive adopted in 2012. The EU has also recently agreed to the framework of the 2030 Climate and Energy Policies with a goal of at least a 40% reduction in GHGs from 1990 and measures to achieve a 27% share of renewable energy and a 27% increase in energy efficiency. The GHG reduction target is to be achieved by a 43% reduction of emissions from sectors covered by the EU ETS, and a 30% GHG reduction by Member States for all other GHG emissions.
- New Zealand s emission trading scheme (NZ ETS) commenced on 1 July 2010 for transport fuels, industrial processes and stationary energy. New Zealand also employs a portfolio of mandatory and voluntary complementary measures aimed at GHG reductions.
- Canada s highest emitting province, Alberta, has regulations targeting large final emitters (sites with over 100,000 tonnes CO2e/per annum) with intensity targets of 2% improvement per year up to 12%. Compliance is possible via direct reductions, the purchase of offsets or the payment of C$15/tonne to a technology fund.
- In the US, the US Environmental Protection Agency (EPA) continues to pursue regulatory measures to address GHGs under the Clean Air Act (CAA).

  - EPA regulations impose light duty vehicle emissions standards for GHGs and permitting requirements for certain large GHG emission sources.
  - Under the GHG mandatory reporting rule (GHGMRR), annual reports on GHG emissions must be filed. In addition to direct emissions from affected facilities, producers and importers/exporters of petroleum products, certain natural gas liquids and GHGs are required to report product volumes and notional GHG emissions as if these products were fully combusted.
  - The EPA proposed regulations establishing GHG emission limits for new and modified power plants in September 2013. In June 2014, the EPA proposed a very complex Clean Energy Plan Regulation that establishes

GHG reduction requirements, at a state or regional level, for existing power plants. The EPA announced its intention to finalize both rules in or around June 2015. These rules are important due to potential impacts on electricity prices, reliability of electricity supply, precedents for similar rules targeting other sectors and potential impacts on combined heat and power installations.

A number of additional state and regional initiatives in the US will affect our operations. California implemented a low-carbon fuel standard in 2010. The California cap and trade programme started in January 2012 with the first auctions of carbon allowances held in November 2012 and obligations commencing from 2013. The California cap and trade programme was broadened to include transport fuels on 1 January 2015.

In the recent US-China joint announcement on climate change addressing post-2020 actions, the US committed to reducing its GHG emissions by 26-28% below its 2005 level by 2025. Achieving these reductions will require expanded efforts to reduce emissions, which likely will include regulatory measures. China announced it intends to achieve a peak in CO2 emissions around 2030, with the intention to try to peak earlier and to increase the non-fossil fuel share of all energy to around 20% by 2030. Currently, China has targets to reduce carbon intensity of GDP 40-45% below 2005 levels by 2020 and increase the share of non-fossil fuels in total energy consumption from 7.5% in 2005 to 15% by 2020.

China is operating emission trading pilots in five cities and two provinces. A number of BP joint venture* companies in China are participating in these schemes. The Chinese government is also considering a plan for a national cap and trade system in 2016.

South Africa has delayed implementation of a carbon tax on carbon intensive emitters until 2016.

South Korea commenced its carbon emissions trading scheme in January 2015.

For information on the steps that BP is taking in relation to climate change issues and for details of BP s GHG reporting see Environment and society on page 42.

Legal proceedings

Proceedings relating to the Deepwater Horizon oil spill

BP s potential liabilities resulting from threatened, pending and potential future claims, lawsuits and enforcement actions relating to the 20 April 2010 explosions and fire on the semi-submersible rig Deepwater Horizon and resulting oil spill (the Incident), together with the potential cost of implementing remedies sought in the various proceedings, cannot be fully estimated at this time, but they have had and could continue to have a material adverse impact on the group s business, competitive position, financial performance, cash flows, prospects, liquidity, shareholder returns and/or implementation of its strategic agenda, particularly in the US. The potential liabilities may continue to have a material adverse effect on the group s results and financial condition. See Financial statements Note 2 for information regarding the financial impact of the Incident.

BP p.l.c., BP Exploration & Production Inc. (BPXP) and various other BP entities (collectively referred to as BP) are among the companies named as defendants in approximately 3,000 pending civil lawsuits relating to the Incident and further actions are likely to be brought. BPXP was lease operator of Mississippi Canyon, Block 252 in the Gulf of Mexico (Macondo), where the Deepwater Horizon was deployed at the time of the Incident. The other working interest owners at the time of the Incident were Anadarko Petroleum Company (Anadarko) and MOEX Offshore 2007

LLC (MOEX). The Deepwater Horizon, which was owned and operated by certain affiliates of Transocean Ltd. (Transocean), sank on 22 April 2010. The pending lawsuits and/or claims arising from the Incident have generally been brought in US federal and state courts. The plaintiffs include individuals, corporations, insurers and governmental entities and many of the lawsuits purport to be class actions. The lawsuits assert, among others, claims under the Oil Pollution Act of 1990 (OPA 90), claims for personal injury in connection with the Incident itself and the response to it, wrongful death, commercial and economic injury, breach of contract and violations of statutes. Many of the lawsuits assert claims which are excluded from the Economic and Property Damages Settlement Agreement (discussed below), including claims for recovery for losses allegedly resulting from the 2010 federal deepwater drilling moratoria and/or the related permitting process. The lawsuits seek various remedies including compensation to injured workers, recovery for commercial losses and property damage, compensation for personal injuries and medical monitoring, claims for environmental damage,

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remediation costs, claims for unpaid wages, injunctive and declaratory relief, treble damages and punitive damages. Purported classes of claimants include residents of the states of Louisiana, Mississippi, Alabama, Florida and Texas; property owners and rental agents, fishermen and persons dependent on the fishing industry, charter boat owners and deck hands, marina owners, gasoline distributors, shipping interests, restaurant and hotel owners, cruise lines and others who are property and/or business owners alleged to have suffered economic loss; and response workers and residents claiming injuries due to exposure to the components of oil and/or chemical dispersants. Among other claims arising from the spill response efforts, lawsuits have been filed claiming that additional payments are due by BP under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident. Purported class action and individual lawsuits have also been filed in US state and federal courts, as well as one suit in Canada, against BP entities and/or various current and former officers and directors alleging, among other things, shareholder derivative claims, securities fraud claims, violations of the Employee Retirement Income Security Act (ERISA) and contractual and quasi-contractual claims related to the cancellation of the dividend on 16 June 2010.

Many of the lawsuits pending in federal court have been consolidated by the Federal Judicial Panel on Multidistrict Litigation into two multi-district litigation proceedings, one in federal district court in Houston for the securities, derivative and ERISA cases (MDL 2185) and another in federal district court in New Orleans for the remaining cases (MDL 2179).

MDL 2179 and related matters

DoJ Action; liability limitation-, contribution- and indemnity-related proceedings; and Trial of Liability, Limitation, Exoneration and Fault Allocation

On 13 May 2010, Transocean and certain affiliates filed a complaint under admiralty law in federal court in Texas seeking exoneration from or limitation of liability as managing owners and operators of the Deepwater Horizon. That action (the Limitation Action) was consolidated with MDL 2179 on 24 August 2010.

The US filed a civil complaint in MDL 2179 against BPXP and others on 15 December 2010 (the DoJ Action). The complaint seeks an order finding liability under OPA 90 and civil penalties under the Clean Water Act and sets forth a purported reservation of rights on behalf of the US to amend the complaint or file additional complaints seeking various remedies under various US federal laws and statutes.

On 18 February 2011, Transocean filed a third-party complaint against BP, the US government, and other corporations involved in the Incident, naming those entities as formal parties in the Limitation Action. On 20 April 2011, Transocean filed claims in the Limitation Action alleging that BP had breached BP America Production Company s (BPAPC) contract with Transocean Holdings LLC by BP not agreeing to indemnify Transocean against liability related to the Incident and by not paying certain invoices. Transocean also asserted claims against BP under state law, maritime law, and OPA 90 for contribution.

On 20 April 2011, BP filed claims against Cameron International Corporation (Cameron), Halliburton Energy Services, Inc. (Halliburton), and Transocean in the DoJ Action, seeking contribution for any assessments against BP under OPA 90 based on those entities fault. On 20 June 2011, Cameron and Halliburton moved to dismiss BP s claims against them in the DoJ Action. BP s claim against Cameron has been resolved pursuant to settlement (described below), but Halliburton s motion remains pending.

Also on 20 April 2011, BP asserted claims against Cameron, Halliburton and Transocean in the Limitation Action. BP s claims against Transocean include breach of contract, unseaworthiness of the Deepwater Horizon vessel, negligence (or gross negligence and/or gross fault as may be established at trial based upon the evidence), contribution and subrogation for costs (including those arising from litigation claims) resulting from the Incident, as well as a declaratory claim that Transocean is wholly or partly at fault for the Incident and responsible for its proportionate share of the costs and damages. BP asserted claims against Halliburton for fraud and fraudulent concealment based on Halliburton s misrepresentations to BP concerning, among other things,

the stability testing on the foamed cement used at the Macondo well; for negligence (or, if established by the evidence at trial, gross negligence) based on Halliburton s performance of its professional services, including cementing and mud logging services; and for contribution and subrogation for amounts that BP has paid in responding to the Incident, as well as in OPA 90 assessments and in payments to the plaintiffs. BP filed a similar complaint against Halliburton in federal court in the Southern District of Texas, Houston Division, and the action was transferred to MDL 2179 on 4 May 2011.

Also on 20 April 2011, Halliburton filed claims in the Limitation Action seeking indemnification from BP for claims brought against Halliburton in that action. Halliburton also asserted a claim for negligence, gross negligence and wilful misconduct against BP and others.

On 31 January 2012, the judge ruled on BP s and Halliburton s indemnity motions, holding that BP is required to indemnify Halliburton for third-party claims for compensatory damages resulting from pollution that did not originate from property or equipment of Halliburton located above the surface of the land or water, regardless of whether the claims result from Halliburton s gross negligence. The court, however, ruled that BP does not owe Halliburton indemnity to the extent that Halliburton is held liable for punitive damages or for civil penalties under the Clean Water Act. The court further held that BP s obligation to defend Halliburton for third-party claims does not require BP to fund Halliburton s defence of third-party claims at this time, nor does it include Halliburton s expenses in proving its right to indemnity. The court deferred ruling on whether BP is required to indemnify Halliburton for any penalties or fines under the Outer Continental Shelf Lands Act. It also deferred ruling on whether Halliburton acted so as to invalidate the indemnity by breaching its contract with BP, by committing fraud, or by committing another act that materially increased the risk to BP or prejudiced the rights of BP as an indemnitor. On 4 September 2014, as part of its findings of fact and conclusions of law for Phase one of the Trial of Liability Limitation Exoneration and Fault Allocation in MDL 2179 (Phase 1 Ruling), the court ruled that Halliburton s indemnity and release clauses in its contract with BP are valid and enforceable against BP.

On 30 May 2011, Transocean filed claims against BP in the DoJ Action alleging that BPAPC had breached its contract with Transocean Holdings LLC by not agreeing to indemnify Transocean against liability related to the Incident. Transocean also asserted claims against BP under state law, maritime law and OPA 90 for contribution.

On 1 November 2011, Transocean filed a motion for partial summary judgment on certain claims filed in the Limitation Action and the DoJ Action between BP and Transocean, seeking an order that would bar BP s contribution claims against Transocean and require BP to defend and indemnify Transocean against all pollution claims, including those resulting from any gross negligence, and from civil fines and penalties sought by the government. On 7 December 2011, BP filed a cross-motion for summary judgment seeking an order that BP is not required to indemnify Transocean for any civil fines and penalties sought by the government or for punitive damages. On 26 January 2012, the judge ruled on BP s and Transocean s indemnity motions, holding that BP is required to indemnify Transocean for third-party claims for compensatory damages resulting from pollution originating beneath the surface of the water, regardless of whether the claim results from Transocean s strict liability, negligence or gross negligence. The court, however, ruled that BP is not required to indemnify Transocean for such claims to the extent Transocean is held liable for punitive damages or for civil penalties under the Clean Water Act, or if Transocean acted with intentional or wilful misconduct in excess of gross negligence. The court further held that BP s obligation to defend Transocean for third-party claims does not require BP to fund Transocean s defence of third-party claims at this time, nor does it include Transocean s expenses in proving its right to indemnity. The court deferred a final ruling on the question of whether Transocean breached its drilling contract with BP so as to invalidate the contract s indemnity clause. On 4 September 2014, as part of its Phase 1 Ruling, the court ruled that Transocean s indemnity and release clauses in its contract with BP are valid and enforceable against BP.

On 8 December 2011, the US brought a motion for partial summary judgment in the DoJ Action seeking, among other things, an order finding that BPXP, Transocean and Anadarko are strictly liable for a civil penalty

« Defined on page 252.

under Section 311(b) (7)(A) of the Clean Water Act. On 22 February 2012, the judge ruled on motions filed in the DoJ Action by the US, Anadarko, and Transocean seeking early rulings regarding the liability of BPXP, Anadarko and Transocean under OPA 90 and the Clean Water Act, but limited the order to addressing the discharge of hydrocarbons occurring under the surface of the water. Regarding OPA 90, the judge held that BPXP and Anadarko are responsible parties under OPA 90 with regard to the subsurface discharge. The judge ruled that BPXP and Anadarko have joint and several liability under OPA 90 for removal costs and damages for such discharge, but did not rule on whether such liability under OPA 90 is unlimited. While the judge held that Transocean is not a responsible party under OPA 90 for subsurface discharge, the judge left open the question of whether Transocean may be liable under OPA 90 for removal costs for such discharge as the owner/operator of the Deepwater Horizon. Regarding the Clean Water Act, the judge held that the subsurface discharge was from the Macondo well, rather than from the Deepwater Horizon, and that BPXP and Anadarko are liable for civil penalties under Section 311 of the Clean Water Act as owners of the well. Anadarko, BPXP and the US each appealed to the US Court of Appeals for the Fifth Circuit (the Fifth Circuit), and on 4 June 2014 the Fifth Circuit unanimously affirmed the district court s decision. On 21 July 2014, Anadarko and BPXP filed petitions requesting that all active judges of the Fifth Circuit review the 4 June 2014 decision. On 9 January 2015, the Fifth Circuit issued an order denying the petition for rehearing, on a 7-6 vote. Absent an extension, BPXP s deadline for seeking US Supreme Court review is 9 April 2015.

On 18 December 2012, Transocean filed a motion seeking an early ruling that it is not liable in connection with claims for compensatory or punitive damages, or claims for contribution, brought by private, state, or local government entities and based on the subsurface discharge of oil. Transocean s motion has been fully briefed but remains pending.

Also on 18 December 2012, Transocean filed a motion seeking an early ruling that it is not liable in connection with punitive damages claims brought by members of the Economic and Property Damages Settlement Class (for a description of the Economic and Property Damages Settlement Agreement, see below). On 20 December 2012, Transocean filed a motion seeking an early ruling that it is not liable in connection with BP s claims for reimbursement of payments made under the Economic and Property Damages Settlement Agreement and BP s separate claims for spill-related damages, such as lost profits from the Macondo well, which claims were assigned by BP to the Economic and Property Damages Settlement Class. On 17 January 2013, Halliburton filed motions seeking early rulings that it is not liable in connection with punitive damages claims brought by members of the Economic and Property Damages Settlement Class; that it is not liable in connection with any contribution claim for punitive damages, whether asserted by BP or by the Economic and Property Damages Settlement Class as BP s assignee; and that it is not liable in connection with claims assigned by BP to the Economic and Property Damages Settlement Class. Transocean s and Halliburton s motions have been fully briefed but remain pending.

On 1 March 2013, Transocean sought the district court s leave to supplement its pleadings to include an affirmative defence asserting that BP s representations regarding the flow rate at the Macondo well constituted an intervening and superseding cause of the oil spill for the majority of its duration. Transocean s defence claims that BP fraudulently misrepresented and concealed information regarding the flow rate at the Macondo well in late April and May 2010, as well as the likelihood of success of a top-kill approach to stopping the flow of hydrocarbons from the well, and thus prevented the implementation of alternative means of source control that Transocean asserts could have capped the well as early as May 2010. Also on 1 March 2013, Halliburton filed a motion for leave to amend its answers to assert a similar defence. On 4 March 2013, the court granted Transocean s motion to file amended answers, and it granted Halliburton s motion the following day.

Trial phases

To address certain issues asserted in or relevant to the claims, counterclaims, cross-claims, third-party claims, and comparative fault defences raised in the DoJ Action and the Limitation Action, a Trial of Liability, Limitation, Exoneration and Fault Allocation commenced in MDL 2179 on 25 February 2013. The presentation of evidence in Phase 1

addressed issues arising out of the conduct of various parties allegedly relevant to the loss of well control at the Macondo well, the ensuing fire and explosion on the Deepwater Horizon on 20 April 2010, the sinking of the vessel on 22 April 2010 and the initiation of the release of oil from the Deepwater Horizon or the Macondo well during those time periods, including whether BP or any other party was grossly negligent. After the completion of post-trial briefing, BP moved for leave to supplement the Phase 1 record to include Halliburton s agreement to plead guilty to destroying evidence relating to Halliburton s internal examination of the Incident and the US government s press release announcing the Halliburton plea agreement. The US government, the PSC and Halliburton also submitted briefs addressing the implications of Halliburton s plea agreement. On 4 September 2014 the court granted BP s motion in part, supplementing the Phase 1 trial record with the Halliburton plea agreement, the US press release, and certain other documents related to Halliburton s criminal plea. The court also found that the simulations at issue in Halliburton s criminal plea, if not deleted by Halliburton employees, would have indicated that using 6 centralizers, as opposed to 21, would not have caused cement channeling in the Macondo well and that Halliburton s deletion of the simulations was done intentionally and in bad faith.

On 4 September 2014, the court issued its Phase 1 Ruling. The court found that BPXP, BPAPC, Transocean Holdings LLC, Transocean Deepwater Inc., Transocean Offshore Deepwater Drilling Inc. (Transocean Entities), and Halliburton are each liable under general maritime law for the blowout, explosion, and oil spill from the Macondo well. The court found that the conduct of BPXP and BPAPC was reckless, and it apportioned to them 67% of the fault for the blowout, explosion, and oil spill. The court found that the conduct of the Transocean Entities was negligent and apportioned to them 30% of the fault for the blowout, explosion, and oil spill. The court found that Halliburton s conduct was negligent and apportioned to it 3% of the fault for the blowout, explosion, and oil spill.

The district court ruled that under Fifth Circuit precedent BPXP and BPAPC cannot be liable for punitive damages under general maritime law, but to the extent the standards of the First Circuit or Ninth Circuit Courts of Appeals would apply to a particular claim, the court found that BPXP would be liable for punitive damages under those rules.

With respect to the US claims against BPXP under the Clean Water Act, the district court found that the discharge of oil was the result of BPXP s gross negligence and wilful misconduct and that BPXP is therefore subject to enhanced civil penalties. The court further found that BPXP was an operator and person in charge of the Macondo well and the Deepwater Horizon vessel for the purposes of the Clean Water Act.

The district court did not find BP p.l.c. to be at fault in connection with the blowout, explosion, and oil spill, and it ruled that BP p.l.c., Transocean Ltd., and Triton Asset Leasing GmbH are not liable under general maritime law.

The district court ruled that Transocean Entities are not entitled to limit liability under the Limitation of Liability Act and that they are liable to the US for removal costs under OPA 90.

In addition, the district court ruled that the indemnity and release clauses in BP s contracts with Halliburton and Transocean Entities are valid and enforceable against BP and granted BP s motion to supplement the Phase 1 trial record with Halliburton s agreement to plead guilty to destroying evidence relating to Halliburton s internal examination of the Incident and the US government s press release announcing the Halliburton plea agreement.

On 2 October 2014, BPXP and BPAPC filed a motion with the district court to amend the findings in the Phase 1 Ruling, to alter or amend the judgment, or for a new trial on the grounds that the court s allocation of fault and findings of gross negligence and wilful misconduct relied upon testimony which had been excluded from the evidence presented at the Phase 1 trial and as to which BPXP and BPAPC did not have adequate notice and opportunity to present evidence in rebuttal. The court denied BPXP s and BPAPC s motion to amend to the Phase 1 Ruling on 13 November 2014. On 11 December 2014, BPXP and BPAPC filed a notice of appeal of the Phase 1 Ruling to the

Fifth Circuit, and subsequently notices of appeal were also filed by the PSC, Transocean, Halliburton and the State of Alabama.

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Phase 2, which commenced on 30 September 2013, addressed (1) source control issues pertaining to the conduct or inaction of BP, Transocean Entities or other relevant parties regarding stopping the release of hydrocarbons stemming from the Incident from 22 April 2010 through to approximately 19 September 2010, and (2) quantification of discharge issues pertaining to the amount of oil actually released into the Gulf of Mexico as a result of the Incident from the time when these releases began until the Macondo well was capped on approximately 15 July 2010 and then permanently cemented shut on approximately 19 September 2010. On 15 January 2015 the district court issued its Findings of Fact and Conclusions of Law for Phase 2 of the Trial of Liability, Limitation, Exoneration and Fault Allocation in MDL 2179, finding that 3.19 million barrels of oil were discharged into the Gulf of Mexico and therefore subject to a Clean Water Act penalty. In addition, the district court found that BP was not grossly negligent in its source control efforts. On 23 February 2015, BPXP filed a notice of appeal of the Phase 2 ruling to the Fifth Circuit.

In the penalty phase of the Trial of Liability, Limitation, Exoneration and Fault Allocation in MDL 2179 the district court will determine the amount of civil penalties to be assessed against BPXP and Anadarko arising under the Clean Water Act based on the court s application of the penalty factors under the Clean Water Act. The penalty phase trial commenced on 20 January 2015 and concluded on 2 February 2015. The court has established a post-trial briefing schedule for the penalty phase under which briefing is to be concluded on 24 April 2015. BP is not currently aware of the timing of the district court s ruling for the penalty phase.

The district court has wide discretion in the application of statutory penalty factors.

MOEX, Anadarko and Cameron settlements

BP announced settlement agreements in respect of all claims related to the Incident with MOEX, Anadarko and Cameron on 20 May 2011, 17 October 2011 and 16 December 2011, respectively. Under the settlement agreement with MOEX, MOEX paid BP $1.065 billion and also agreed to transfer all its 10% interest in the MC252 lease to BP. Under the settlement agreement with Anadarko, Anadarko paid BP $4 billion and also agreed to transfer all its 25% interest in the MC252 lease to BP. The settlement agreement with Anadarko grants Anadarko the opportunity for a 12.5% participation in certain future recoveries from third parties and certain insurance proceeds in the event that such recoveries and proceeds exceed $1.5 billion in aggregate. Any such payments to Anadarko are capped at a total of $1 billion. BP agreed to indemnify MOEX, Anadarko and Cameron for certain claims arising from the Incident (excluding civil, criminal or administrative fines and penalties, claims for punitive damages, and certain other claims). The settlement agreements with MOEX, Anadarko and Cameron are not an admission of liability by any party regarding the Incident.

PSC settlements

The Economic and Property Damages Settlement resolves certain economic and property damage claims, and the Medical Benefits Class Action Settlement resolves certain medical claims by response workers and certain Gulf Coast residents. The Economic and Property Damages Settlement includes a $2.3 billion BP commitment to help resolve economic loss claims related to the Gulf seafood industry (for further information see PSC Settlements Seafood Compensation Fund below) and a $57-million fund to support continued advertising that promotes Gulf Coast tourism. It also resolves property damage in certain areas along the Gulf Coast, as well as claims for additional payments under certain Master Vessel Charter Agreements entered into in the course of the Vessels of Opportunity Program implemented as part of the response to the Incident. The Economic and Property Damages Settlement does not include claims made against BP by the DoJ or other federal agencies (including under the Clean Water Act and for Natural Resource Damages under OPA 90) or by the states and local governments. Also excluded are certain other claims against BP, such as securities and shareholder claims pending in MDL 2185, and claims based solely on the deepwater drilling moratorium and/or the related permitting process.

The Medical Benefits Class Action Settlement involves payments to qualifying class members based on a matrix for certain Specified Physical Conditions, as well as a 21-year Periodic Medical Consultation Program for qualifying class members. The deadline for submitting claims under

the Medical Benefits Class Action Settlement passed on 12 February 2015. The settlement also provides that class members claiming Later-Manifested Physical Conditions may pursue their claims through a mediation/litigation process, but waive, among other things, the right to seek punitive damages. Consistent with its commitment to the Gulf, BP has also agreed as part of the Medical Benefits Class Action Settlement to provide $105 million to the Gulf Region Health Outreach Program to improve the availability, scope and quality of healthcare in certain Gulf Coast communities. This healthcare outreach programme will be available to, and is intended to benefit, class members and other individuals in those communities. BP has already funded $79.1 million for projects sponsored by this programme.

Each agreement provides that class members will be compensated for their claims on a claims-made basis, according to agreed compensation protocols in separate court-supervised claims processes. The compensation protocols under the Economic and Property Damages Settlement provide for the payment of class members economic losses and property damages related to the oil spill. In addition many economic and property damages class members will receive payments based on negotiated risk transfer premiums, which are multiplication factors designed, in part, to compensate claimants for potential future damages that are not currently known, relating to the Incident. The Economic and Property Damages Settlement and the Medical Benefits Class Action Settlement are not an admission of liability by BP. The settlements are uncapped except for economic loss claims related to the Gulf seafood industry under the Economic and Property Damages Settlement and the $105 million to be provided to the Gulf Region Health Outreach Program under the Medical Benefits Class Action Settlement.

All class member settlements under the settlement agreements are payable under the terms of the Deepwater Horizon Oil Spill Trust (Trust). Other costs to be paid from the Trust include state and local government claims, state and local response costs, natural resource damages and related claims, and final judgments and settlements. As at 31 December 2014, the aggregate cash balances in the Trust and the qualified settlement funds amounted to $5.1 billion, including $1.1 billion remaining in the Seafood Compensation Fund, from which a further $0.5 billion partial distribution started in early 2015, and $0.4 billion held for natural resource damage early restoration projects. When the cash balances in the Trust are exhausted, payments in respect of legitimate claims and other costs will be made directly by BP. See Financial statements Note 2.

The economic and property damages claims process is under court supervision through the settlement claims process established by the Economic and Property Damages Settlement. This provides that class members release and dismiss their claims against BP not expressly reserved by that agreement. The Economic and Property Damages Settlement also provides that, to the extent permitted by law, BP assigns to the PSC certain of its claims, rights and recoveries against Transocean and Halliburton for damages with protections such that Transocean and Halliburton cannot pass those damages through to BP. Under the Medical Benefits Class Action Settlement, class members release and dismiss their claims against BP covered by that settlement, except that class members do not release claims for Later-Manifested Physical Conditions.

PSC settlements appeals

Under US federal law, there is an established procedure for determining the fairness, reasonableness and adequacy of class action settlements. Pursuant to this procedure, an extensive notice programme to the public was implemented to explain the settlement agreements and class members rights, including the right to opt out of the classes, and the processes for making claims. The court conducted a fairness hearing on 8 November 2012 in which to consider, among other things, whether to grant final approval of the Economic and Property Damages Settlement and the

Medical Benefits Class Action Settlement, whether to certify the classes for settlement purposes only, and the merits of any objections to the settlement agreements. On 21 November 2012, the parties to the settlement filed a list of 13,123 individuals and entities who had submitted timely requests to opt out of the Economic and Property Damages Settlement Class and 1,638 individuals who had submitted timely requests to opt out of the Medical Benefits Settlement Class. As a result of revocations, the number of opt-outs for the Economic and Property Damages Settlement and the Medical Benefits Class Action Settlement is fewer than those reported figures.

Following the fairness hearing, the Economic and Property Damages Settlement was approved by the district court in a final order and judgment on 21 December 2012, and the Medical Benefits Class Action Settlement was approved in a final order and judgment on 11 January 2013.

Subsequent to the district court s final order and judgment approving the Economic and Property Damages Settlement, groups of purported members of the Economic and Property Damages Settlement Class (the Appellants) appealed from the district court s approval of that settlement to the Fifth Circuit. Additionally, a coalition of fishing and community groups (the Coalition) appealed to the Fifth Circuit from an order of the district court denying it permission to intervene in the civil action serving as the vehicle for the Economic and Property Damages Settlement and further denying it permission to take discovery regarding the fairness of that settlement. On 11 November 2013, the Fifth Circuit affirmed the district court s rulings in respect of the Coalition. On 10 January 2014, a panel of the Fifth Circuit affirmed the district court s approval of the Economic and Property Damages Settlement but left to another panel of the Fifth Circuit (the business economic loss panel, discussed further below) the question of how to interpret the Economic and Property Damages Settlement, including the meaning of the causation requirements of that agreement. BP and several Appellants filed petitions requesting that all the active judges of the Fifth Circuit review the decision to uphold approval of the settlement. On 19 May 2014, BP s en banc petition to the full court was denied by a vote of 8-5. As explained in further detail below, BP filed a certiorari petition with the US Supreme Court on 1 August 2014, which was denied on 8 December 2014.

PSC settlements Deepwater Horizon Court Supervized Settlement Program (DHCSSP) and interpretation of the Economic and Property Damages Settlement Agreement

The DHCSSP, the claims facility operating under the framework established by the Economic and Property Damages Settlement, commenced operation on 4 June 2012 under the oversight of Claims Administrator Patrick Juneau.

As part of its monitoring of payments made by the court-supervized claims processes operated by the DHCSSP, BP identified multiple business economic loss claim determinations that appeared to result from an interpretation of the Economic and Property Damages Settlement Agreement by that settlement s claims administrator that BP believed was incorrect. This interpretation produced a higher number and value of awards than the interpretation BP used in making its initial estimate of the total cost of the Economic and Property Damages Settlement. Pursuant to the mechanisms in the Economic and Property Damages Settlement Agreement, the claims administrator sought clarification on this matter from the district court in MDL 2179, and on 5 March 2013 the district court affirmed the claims administrator s interpretation of the agreement and rejected BP s position as it relates to business economic loss claims (the March 2013 Ruling).

BP appealed the district court s March 2013 Ruling and related rulings to the Fifth Circuit. On 2 October 2013, the business economic loss panel of the Fifth Circuit (by a 2-1 vote) reversed the district court s denial of BP s motion for a preliminary injunction and the district court s order affirming the claims administrator s interpretation of the settlement, remanded the case for further proceedings and ordered the district court to enter a narrowly-tailored injunction that suspended payment to claimants affected by the misinterpretation issue and who did not have actual injury traceable to loss from the Deepwater Horizon accident . The business economic loss panel also retained jurisdiction to review the district court s conclusions on remand.

On 18 October 2013, the district court issued a preliminary injunction that, amongst other things, required the claims administrator to temporarily suspend payments of business economic loss claims other than those claims supported by sufficiently matched accrual-basis accounting or any other business economic loss claim for which the claims administrator determines that the matching of revenue and expenses is not an issue.

On 24 December 2013, the district court ruled on the two issues remanded to it in October 2013 by the business economic loss panel of the Fifth Circuit (the December 2013 Ruling): (1) requiring the claims administrator, in administering business economic loss claims, to match

revenue with corresponding variable expenses (the matching issue), and (2) determining whether the settlement agreement can properly be interpreted to permit payment to business economic loss claimants whose losses (if any) were not caused by the spill (the causation issue).

As to the matching issue, the district court ordered the claims administrator to develop a revised policy addressing the matching of revenue and expenses for business economic loss claims, which would require the matching of revenue with the expenses incurred by claimants to generate that revenue, even where the revenue and expenses were recorded at different times. On 13 March 2014, the claims administrator issued a revised matching policy reflecting this order. On 5 May 2014, the district court approved the revised policy. The PSC filed a motion on 27 May 2014 seeking to alter or amend the revised policy. On 27 June 2014, the district court issued an order establishing the process for the parties and claims administrator to determine which already-determined but unpaid claims should be subject to the revised policy.

As to the causation issue, the district court ruled that the Economic and Property Damages Settlement Agreement contained no causation requirement beyond the revenue and related tests set forth in an exhibit to that agreement. The district court also held that the absence of a further causation requirement does not defeat class certification or invalidate the settlement under the federal class certification rule or Article III of the US Constitution. On 30 December 2013, BP filed a motion with the Fifth Circuit requesting an injunction that would prevent the claims administrator from making awards to claimants whose alleged injuries are not fairly traceable to the spill. In a 2-1 decision on 3 March 2014, the business economic loss panel affirmed the district court s ruling on causation and denied BP s motion for a permanent injunction.

BP filed a petition on 17 March 2014 requesting that all active Fifth Circuit judges review the business economic loss panel s 3 March 2014 decision. On 19 May 2014, the Fifth Circuit declined (in a 5-8 decision) to grant further review of the 3 March 2014 decision.

On 21 May 2014, BP asked the Fifth Circuit to stay the issuance of the mandate transferring the case back to the district court until the US Supreme Court could decide whether to review the Fifth Circuit s decision. The Fifth Circuit denied BP s request for a stay on 27 May 2014, and issued its mandate on 28 May 2014. On the same day, the district court dissolved the injunction that had halted the processing and payment of business economic loss claims and instructed the claims administrator to resume the processing and payment of claims.

On 28 May, BP filed an application with the US Supreme Court seeking to recall and stay the Fifth Circuit s mandate in order to halt the processing and payment of business economic loss claims pending further review. The US Supreme Court denied BP s application on 9 June 2014.

On 1 August 2014, BP filed a petition for certiorari with the US Supreme Court for review of the Fifth Circuit s decision upholding the district court s ruling that the Economic and Property Damages Settlement Agreement contained no causation requirement beyond the revenue and related tests set forth in an exhibit to that agreement, as well as a related decision by a different panel of the Fifth Circuit similarly interpreting the Economic and Property Damages Settlement Agreement to permit payment to business economic loss claimants whose losses (if any) were not caused by the spill. The US Supreme Court denied BP s petition for certiorari on 8 December 2014. Accordingly, the effective date of the Economic and Property Damages Settlement Agreement is 8 December 2014, and the final deadline for filing all claims other than those that fall into the Seafood Compensation Program is 8 June 2015.

On 2 September 2014, BP filed a motion seeking an order removing Patrick Juneau from his roles as claims administrator and settlement trustee for the Economic and Property Damages Settlement. On 10 November 2014, the district court denied BP s motion. BP appealed this decision to the Fifth Circuit on 18 November 2014.

For more information about BP s current estimate of the total cost of the PSC settlements, see Financial statements Note 2.

PSC settlements investigation of the DHCSSP

On 2 July 2013, the district court in MDL 2179 appointed former federal district court judge Louis Freeh as Special Master to lead an independent investigation of the DHCSSP in connection with allegations of potential ethical violations or misconduct in the DHCSSP. On 6 September 2013,

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Judge Freeh submitted a written report to the district court in which he presented his findings that the conduct of two attorneys in the office of the claims administrator may have violated federal criminal statutes regarding fraud, money laundering, conspiracy or perjury. In an order issued the same day, the court instructed Judge Freeh to promptly recommend, design, and test enhanced internal compliance, anti-corruption, anti-fraud and conflicts of interest policies and procedures, and assist the claims administrator in the implementation of such policies and procedures. On 17 January 2014, Judge Freeh submitted a second written report that described the behaviour at the DHCSSP that led to the resignations of senior staff members.

PSC settlements Seafood Compensation Fund

On 17 December 2013, BP filed a civil lawsuit in MDL 2179 against former PSC lawyer Mikal C Watts, accusing him of having fraudulently claimed to represent more than 40,000 deckhands who allegedly suffered economic injuries as a result of the Incident. BP s action alleges that BP relied on Mr Watts s representations when it agreed to pay $2.3 billion to the Seafood Compensation Fund (the Fund), which was established under the Economic and Property Damages Settlement to compensate those who earn their livelihood from Gulf waters and were directly affected by the spill, and that the Economic and Property Damages Class stands to benefit unjustly from the full distribution of the money remaining in the Fund. In addition, BP filed two motions asking the district court to suspend further distributions from the Fund and to determine the extent of the fraud and what portion, if any, of the Fund should be returned as a result. On 17 January 2014, Mr Watts filed a motion to stay the litigation pending a parallel criminal investigation and the PSC also filed a brief opposing BP s motion seeking an injunction. On 26 February 2014, the district court granted Mr Watts s motion to stay the litigation and denied BP s motion to suspend further distributions, on the basis that no further payment from the Fund was imminent. The district court deferred ruling on BP s motion seeking to determine the extent of the fraud and what portion, if any, of the Fund should be returned as a result.

On 19 September 2014, the district court designated-neutrals appointed to preside over the settlement of the seafood program (the Neutrals) submitted to the district court their report on recommendations for the Seafood Compensation Program supplement distribution (Recommendations). The Neutrals observed that there remain some claims against the Fund which have not been paid, and that BP has filed a motion which seeks a return of part of the Fund, on the basis that it is currently impossible to fully distribute the balance of the Fund. The Neutrals recommended that the district court target a $500 million partial distribution in the second round of payments using a proportionate distribution method. The district court issued an order filing the Recommendations into the court record and requiring that any objections to or comments on the Recommendations to be filed by 20 October 2014. BP filed a response asserting that the district court should not yet order second round distributions on the basis that, amongst other things, the first round distributions are not complete. On 18 November 2014, the district court approved the Neutrals Recommendations and disbursement of funds commenced in early 2015.

Medical Benefits Class Action Settlement (Medical Settlement)

The district court approved the Medical Settlement Agreement (MSA) in a final order and judgment on 11 January 2013. The effective date was 12 February 2014. As of 9 January 2015, the claims administrator under the Medical Settlement (the Medical Claims Administrator) had received 12,418 claim forms, including 11,703 for certain Specified Physical Conditions (SPCs), and has determined 774 claims to be eligible for monetary compensation totalling approximately $1,542,500. For those claimants seeking benefits under the Periodic Medical Consultation Program, approximately 8,411 claims have been determined to be eligible. The deadline for submitting claims for SPCs under the MSA was 12 February 2015. BP does not yet know the total number of claims submitted, however a large volume of such claims is anticipated. The Medical Claims Administrator issued a policy statement, with which BP agrees, classifying physical conditions first diagnosed after 16 April 2012 as Later-Manifested Physical Conditions (LMPC), which requires a class member seeking compensation to file a notice of intent to sue that allows BP the option to mediate the claim in lieu of litigation. On 23 July 2014, the district court issued an order affirming the policy statement. On 26 November 2014, the district court directed the Medical Claims

Administrator to issue another policy statement regarding the impact of the release provisions under the MSA on the filing of SPC claims and LMPC claims, which was filed on 17 December. The district court s decision to either adopt, modify or reject the policy statement remains pending.

State and local civil claims, including under OPA 90

On 12 August 2010, the State of Alabama filed a lawsuit seeking damages for alleged economic and environmental harms, including natural resource damages, civil penalties under state law, declaratory and injunctive relief, and punitive damages as a result of the Incident. On 3 March 2011, the State of Louisiana filed a lawsuit to declare various BP entities (as well as other entities) liable for removal costs and damages, including natural resource damages under federal and state law, to recover civil penalties, attorney s fees and response costs under state law, and to recover for alleged negligence, nuisance, trespass, fraudulent concealment and negligent misrepresentation of material facts regarding safety procedures and BP s (and other defendants) ability to manage the oil spill, unjust enrichment from economic and other damages to the State of Louisiana and its citizens, and punitive damages.

On 10 December 2010, the Mississippi Department of Environmental Quality issued a Complaint and Notice of Violation alleging violations of several state environmental statutes.

The Louisiana Department of Environmental Quality has issued an administrative order seeking environmental civil penalties and other relief under state law. On 23 September 2011, BP removed this matter to federal district court, and it has been consolidated with MDL 2179.

District Attorneys of 11 parishes in the State of Louisiana filed suits under state wildlife statutes seeking penalties for damage to wildlife as a result of the Incident. On 9 December 2011 and 28 December 2011, the district court in MDL 2179 granted BP s motions to dismiss the District Attorneys complaints, holding that those claims are pre-empted by the Clean Water Act. The Fifth Circuit affirmed the district court s ruling on 24 February 2014. Several of the parishes sought Supreme Court review, which BP opposed. On 20 October 2014, the US Supreme Court declined to hear the appeal.

On 14 November 2011, the district court in MDL 2179 granted in part BP s motion to dismiss the complaints filed by the states of Alabama and Louisiana. The court s order dismissed the states claims brought under state law, including claims for civil penalties and the State of Louisiana s request for a declaratory judgment under the Louisiana Oil Spill Prevention and Response Act, holding that those claims were pre-empted by federal law. It also dismissed the State of Louisiana s claims of nuisance and trespass under general maritime law. The court s order further held that the states have stated claims for negligence and products liability under general maritime law, have sufficiently alleged presentment of their claims under OPA 90 and may seek punitive damages under general maritime law.

On 9 December 2011, the district court in MDL 2179 granted in part BP s motion to dismiss a master complaint brought on behalf of local government entities. The court s order dismissed the plaintiffs state law claims and limited the types of maritime law claims the plaintiffs may pursue, but also held that the plaintiffs have sufficiently alleged presentment of their claims under OPA 90 and that certain local government entity claimants may seek punitive damages under general maritime law. The court did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply his dismissal of the master complaint to those individual complaints.

In January 2013, the states of Alabama, Mississippi and Florida submitted or asserted claims to BP under OPA 90 for alleged losses including economic losses and property damage as a result of the Incident. The states of Louisiana and Texas have also asserted similar claims. The amounts claimed, certain of which include punitive damages or other multipliers, are very substantial. However, BP considers these claims unsubstantiated and the methodologies used to calculate these claims to be seriously flawed, not supported by OPA 90, not supported by documentation, and to substantially overstate the claims. Similar claims have also been submitted by various local government entities and a non-US government. These claims under OPA 90 are substantial in aggregate, and more claims are expected to be submitted. The amounts alleged in the submissions for state and local government claims total

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approximately $35 billion. BP will defend vigorously against these claims if adjudicated at trial. Certain of these states (including the states of Alabama, Florida, Texas and Mississippi, as described below) and local government entities have filed civil lawsuits that pertain to claims asserted by them under their earlier OPA 90 submissions to BP.

In April 2013, the states of Alabama, Florida and Mississippi each filed actions against BP related to the Incident, which have been consolidated with MDL 2179. On 19 April 2013, the State of Alabama filed an action against BP alleging general maritime law claims of negligence, gross negligence, and wilful misconduct; claims under OPA 90 seeking damages for removal costs, natural resource damages, property damage, lost tax and other revenue and damages for providing increased public services during or after removal activities; and various state law claims. The State of Alabama s complaint also seeks punitive damages.

On 20 April 2013, the State of Florida filed suit against BP and Halliburton in federal court in Florida, and its case has also been transferred to MDL 2179. Florida s complaint alleges general maritime law claims for negligence and gross negligence; OPA 90 claims for alleged lost tax revenue, other economic damages and natural resource damages; and various state law claims. Florida also seeks punitive damages.

The State of Mississippi filed both federal court and state court complaints in Mississippi against BP in April 2013. Mississippi s federal court complaint alleges OPA 90 claims against BP, Transocean and Anadarko for natural resource damages, property damage, lost tax revenue and damages for providing increased public services during or after removal activities. It asserts general maritime law claims for negligence and gross negligence against Halliburton only. Mississippi s state court complaint alleges various state law claims, including negligence, gross negligence and willful misconduct. Both Mississippi complaints seek punitive damages. The State of Mississippi s federal court action and state court action have both been consolidated with MDL 2179.

On 17 May 2013, the State of Texas filed suit against BP and others in federal court in Texas. Its complaint asserts claims under OPA 90 for natural resource damages, lost sales tax and state park revenue; claims for natural resource damages under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); and claims for natural resource damages, cost recovery, civil penalties and economic damages under state environmental statutes. The State of Texas s action has been consolidated with MDL 2179.

On 14 February 2014, BP moved to strike the State of Alabama s jury trial demand as to its claim for compensatory damages under OPA 90. BP s motion remains pending.

On 5 March 2014, the State of Florida filed a lawsuit (which has since been consolidated with MDL 2179) to declare various BP entities (and other entities) liable for removal costs and natural resource damages.

OPA Test Case Proceedings

Seven OPA test cases will address certain OPA 90 liability questions focusing on, among other issues, whether plaintiffs alleged losses tied to the 2010 federal government moratoria on deepwater drilling and federal permit delays are compensable. On 3 June 2014 the district court entered an Agreed Upon Scheduling Order for these test cases. That scheduling order has now been suspended indefinitely with no new deadlines being established.

State of Alabama Damages Case Proceedings

On 16 July 2014 the district court issued a scheduling order for the State of Alabama s economic damages claims against BP and other parties and a request by the district court for the parties to set aside the month of November 2015 for a trial. That scheduling order has now been suspended indefinitely with no new deadlines being established.

Agreement for early natural resource restoration

On 21 April 2011, BP announced an agreement with natural resource trustees for the US and five Gulf Coast states, providing for up to $1 billion to be spent on early restoration projects to address natural resource injuries resulting from the Incident. Funding for these projects will come from the $20-billion Trust fund. BP and the trustees have reached agreement on a total of 54 early restoration projects that are expected to cost approximately $698 million. These include 10 projects that are already in place or underway, and 44 projects that were filed with

the court on 2 October 2014, following a regulatory review and public comment process. As part of the project agreements, BP will receive Natural Resource Damages (NRD) restoration credits that can be used to offset related NRD restoration obligations, either in whole or in part.

Other civil complaints

On 26 August 2011, the district court in MDL 2179 granted in part BP s motion to dismiss a master complaint raising claims for economic loss by private plaintiffs, dismissing the plaintiffs state law claims and limiting the types of maritime law claims the plaintiffs may pursue, but also held that certain classes of claimants may seek punitive damages under general maritime law. The court did not, however, lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply its dismissal of the master complaint to those individual complaints. On 30 September 2011, the court granted in part BP s motion to dismiss a master complaint asserting personal injury claims on behalf of persons exposed to crude oil or chemical dispersants, dismissing the plaintiffs state law claims, claims by seamen for punitive damages, claims for medical monitoring damages by asymptomatic plaintiffs, claims for battery and nuisance under maritime law, and claims alleging negligence per se. As with its other rulings on motions to dismiss master complaints, the court did not lift an earlier stay on the underlying individual complaints raising those claims or otherwise apply its dismissal of the master complaint to those individual complaints.

Citizens groups have also filed either lawsuits or notices of intent to file lawsuits seeking civil penalties and injunctive relief under the Clean Water Act and other environmental statutes. On 16 June 2011, the district court in MDL 2179 granted BP s motion to dismiss a master complaint raising claims for injunctive relief under various federal environmental statutes brought by various citizens groups and others.

The court did not, however, lift an earlier stay on the underlying individual complaints raising those claims for injunctive relief or otherwise apply its dismissal of the master complaint to those individual complaints. In addition, a different set of environmental groups filed a motion to reconsider dismissal of their Endangered Species Act claims on 14 July 2011. That motion remains pending.

On 31 January 2012, the district court in MDL 2179, on motion by the Center for Biological Diversity, entered final judgment on the basis of the 16 June 2011 order with respect to two actions brought against BP by that plaintiff. On 2 February 2012, the Center for Biological Diversity filed a notice of appeal of both actions to the Fifth Circuit. Following oral argument, the Fifth Circuit ruled in BP s favour on 9 January 2013 in virtually all respects, though it remanded the Center for Biological Diversity s claim under the Emergency Planning and Community Right to Know Act (EPCRA) to the district court. On 22 January 2013, the Center for Biological Diversity filed a Petition for Panel Rehearing in the Fifth Circuit, which was denied on 4 February 2013. In January 2014, the district court in MDL 2179 set a schedule for proceedings on remand of the EPCRA claim under which limited discovery has taken place, and the parties filed cross-motions for summary judgment that were fully briefed by 19 May 2014. The district court has not acted and the cross motions remain to be decided.

Halliburton lawsuits

On 19 April 2011, Halliburton filed a lawsuit in Texas state court seeking indemnification from BPXP for certain tort and pollution-related liabilities resulting from the Incident. On 3 May 2011, BPXP removed Halliburton s case to federal court, and on 9 August 2011, the action was transferred to MDL 2179.

On 1 September 2011, Halliburton filed an additional lawsuit against BP in Texas state court alleging that BP did not identify the existence of a purported hydrocarbon zone at the Macondo well to Halliburton in connection with Halliburton s cement work performed before the Incident and that BP has concealed the existence of this purported hydrocarbon zone following the Incident. Halliburton claims that the alleged failure to identify this information has harmed its business ventures and reputation and resulted in lost profits and other damages. On 7 February 2012, the lawsuit was transferred to MDL 2179.

Non-US government lawsuits

On 15 September 2010, three Mexican states bordering the Gulf of Mexico (Veracruz, Quintana Roo and Tamaulipas) filed lawsuits in federal court in Texas against several BP entities. These lawsuits were subsequently transferred to MDL 2179 on 4 November 2010. These lawsuits allege that the Incident harmed their tourism, fishing and commercial shipping industries (resulting in, among other things, diminished tax revenue), damaged natural resources and the environment and caused the states to incur expenses in preparing a response to the Incident. On 9 December 2011, the district court in MDL 2179 granted in part BP s motion to dismiss the three Mexican states complaints, dismissing their claims under OPA 90 and for nuisance and negligence per se, and preserving their claims for negligence and gross negligence only to the extent there has been a physical injury to a proprietary interest of the states. On 12 September 2013, the court issued a final judgment dismissing the three Mexican states claims with prejudice. On 4 October 2013, the three Mexican states filed notices of appeal from the judgment to the Fifth Circuit. Following briefing, oral argument was heard on the appeal on 27 October 2014 and the appeal is now under review.

On 5 April 2011, the State of Yucatan submitted a claim to the Gulf Coast Claims Facility (GCCF) alleging potential damage to its natural resources and environment, and seeking to recover the cost of assessing the alleged damage. On 18 September 2013, the State of Yucatan filed suit against BP in federal court in Florida and, on 13 December 2013, its action was transferred to MDL 2179.

On 19 April 2013, the Mexican federal government filed a civil action against BP and others in MDL 2179. The complaint seeks a determination that each defendant bears liability under OPA 90 for damages that include the costs of responding to the spill; natural resource damages allegedly recoverable by Mexico as an OPA 90 trustee; and the net loss of taxes, royalties, fees or net profits.

Insurance-related matters

On 1 March 2012, the district court in MDL 2179 issued a partial final judgment dismissing with prejudice certain claims by BP, Anadarko and MOEX for additional insured coverage under insurance policies issued to Transocean for the sub-surface pollution liabilities BP, Anadarko and MOEX have incurred and will incur with respect to the Macondo well oil release. BP filed a notice of appeal from the district court s judgment to the Fifth Circuit and on 1 March 2013, the Fifth Circuit reversed the district court s judgment, rejecting the district court s ruling that the insurance that BP is entitled to receive as an additional insured under the Transocean insurance policies at issue is limited to the scope of the indemnity in the drilling contract between BP and Transocean. On 29 August 2013, the Fifth Circuit withdrew its 1 March 2013 opinion and certified two questions of Texas law at issue in the appeal to the Supreme Court of Texas. On 13 February 2015 the Supreme Court of Texas held that the insurance BP is entitled to receive as an additional assured is limited to the liabilities that Transocean assumed in the drilling contract which does not include liabilities for damages arising from sub-surface pollution.

False Claims Act actions

BP is aware that actions have been or may be brought under the Qui Tam (whistle-blower) provisions of the False Claims Act (FCA). On 17 December 2012, the court ordered unsealed one complaint that had been filed in the US District Court for the Eastern District of Louisiana by an individual under the FCA s Qui Tam provisions. The complaint alleged that BP and another defendant had made false reports and certifications of the amount of oil released into the Gulf of Mexico following the Incident. On 17 December 2012, the DoJ filed with the court a notice that the DoJ elected to decline to intervene in the action. On 31 January 2013, the complaint was transferred to MDL 2179 and remains stayed.

MDL 2185 and other securities-related litigation

Since the Incident, shareholders have sued BP and various of its current and former officers and directors asserting shareholder derivative claims and class and individual securities fraud claims. Many of these lawsuits have been consolidated or co-ordinated in federal district court in Houston (MDL 2185).

Securities class action

On 13 February 2012, the federal district court in Houston in MDL 2185 issued two decisions (the February 2012 ruling) on the defendants motions to dismiss the two consolidated securities fraud complaints filed on behalf of purported classes of BP ordinary shareholders and ADS holders. The February 2012 ruling dismissed all the claims of the ordinary shareholders, and the claims of the lead class of ADS holders against

most of the individual defendants while holding that a subset of the claims against two individual defendants and the corporate defendants could proceed. In addition, all of the claims of a smaller purported subclass were dismissed with leave to re-plead in 20 days. On 2 April 2012, the plaintiffs in the lead class and subclass filed an amended consolidated complaint with claims based on (1) the 12 alleged misstatements that the court held were actionable in the February 2012 ruling; and (2) 13 alleged misstatements concerning BP s operating management system that the judge either rejected with leave to re-plead or did not address in the February 2012 ruling. On 2 May 2012, defendants moved to dismiss the claims based on the 13 statements in the amended complaint that the judge did not already rule are actionable. On 6 February 2013, the court granted in part this motion to dismiss, rejecting the plaintiffs claims based on eight of the statements at issue in the motion and also dismissing all claims against former BP employee Andrew Inglis. On 20 May 2014, the judge denied plaintiffs motion to certify a proposed class of ADS purchasers before the Deepwater Horizon explosion (from 8 November 2007 to 20 April 2010) and granted plaintiffs motions to certify a class of post-explosion ADS purchasers from 26 April 2010 to 28 May 2010 and to amend their complaint to add one additional alleged misstatement. Both parties sought permission to appeal from the district court s class certification decisions and on 3 July 2014, the Fifth Circuit granted both parties requests. Briefing on those appeals is expected to conclude in March 2015.

The trial of the securities fraud claims of the class of post-explosion ADS purchasers has been scheduled to commence on 11 January 2016.

Individual securities litigation

In April and May 2012, six cases (three of which were consolidated into one action) were filed in state and federal courts by one or more state, county or municipal pension funds against BP entities and several current and former officers and directors seeking damages for alleged losses those funds suffered because of their purchases of BP ordinary shares and, in two cases, ADSs. The funds assert various state law and federal law claims. From July 2012 to April 2014, 27 additional cases were filed in Texas state and federal courts (later consolidated into 24 actions) by pension or investment funds or advisers against BP entities and current and former officers and directors, asserting state, federal, and non-US law claims and seeking damages for alleged losses that those funds suffered because of their purchases of BP ordinary shares and/or ADSs. Two cases were filed in New York federal court by funds that purchased BP ordinary shares and ADSs, asserting state and federal law claims. All the cases have been transferred to federal court in Houston and, with the exception of one case that has been stayed, the judge presiding over MDL 2185. One case was voluntarily dismissed on 9 May 2013. On 3 October 2013, the judge granted in part and denied in part the defendants motion to dismiss three of the remaining 29 cases dismissing a subset of the claims. The judge held that English law governs the plaintiffs remaining claims (with the exception of the federal law claims based on purchases of ADSs and a potential claim under Ohio state law against BP p.l.c. by certain Ohio funds). On 11 December 2013, defendants moved to dismiss 10 of the remaining cases and answered the complaints in two others. On 5 December 2013, the Ohio funds (plaintiffs in one of the first three cases defendants moved to dismiss) filed an amended complaint withdrawing their English law claim and asserting only a claim under Ohio state law. On 6 January 2014, BP moved to dismiss that case for a second time, and on 7 April 2014, the judge dismissed the Ohio action with leave to replead English law claims within 30 days. On 8 June 2014, the Ohio funds filed a second amended complaint asserting only English law claims. On 30 September 2014, the court granted in part and denied in part the defendants motion to dismiss 10 cases. The court dismissed the negligent misstatement claims in all but one of the 10 cases and dismissed claims in these cases based on certain public and private misstatements. The court also rejected BP s arguments that the ordinary share claims of the non-US plaintiffs should be heard in England. On 29 October 2014, the case brought by the Ohio funds was transferred to federal court in Houston for all purposes. On 30 December 2014, defendants answered the complaints in 11 cases. Amended complaints in the remaining 15 cases are due by 1 April 2015.

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Canadian class action

On 20 July 2012, a BP entity received an amended statement of claim for an action in Alberta, Canada, filed by three plaintiffs seeking to assert claims under Canadian law against BP on behalf of a class of Canadian residents who allegedly suffered losses because of their purchase of BP ordinary shares and ADSs. This case was dismissed on jurisdictional grounds on 14 November 2012. On 15 November 2012, one of the plaintiffs re-filed a statement of claim against BP in Ontario, Canada, seeking to assert the same claims against BP. BP moved to dismiss that action for lack of jurisdiction, and on 9 October 2013 the Ontario court denied BP s motion. On 7 November 2013, BP filed a notice of appeal from that decision. On 14 August 2014, the Ontario Court of Appeal held that the case should be stayed and that the claims made on behalf of Canadian residents who purchased BP ordinary shares and ADSs on exchanges outside of Canada should be litigated in those countries, and granted leave for the plaintiff to amend the complaint to assert claims only on behalf of Canadian residents who purchased ADSs on the Toronto Stock Exchange. On 10 October 2014, the plaintiff filed an application for leave to appeal to the Supreme Court of Canada. Briefing on that application concluded on 25 November 2014.

Dividend-related proceedings

On 5 July 2012, the federal district court in Houston in MDL 2185 issued a decision granting BP s motion to dismiss, for lack of personal jurisdiction, the lawsuit against BP p.l.c. for cancelling its dividend payment in June 2010. On 10 August 2012, the plaintiffs filed an amended complaint, which BP moved to dismiss on 9 October 2012. On 12 April 2013, the court granted BP s motion and dismissed the lawsuit for lack of personal jurisdiction and on the alternative grounds of failure to state a claim and that the courts of England are the more appropriate forum for the litigation. On 16 June 2013, the court granted the plaintiff s motion to amend its decision so as to eliminate the alternative grounds for dismissal. On 22 November 2013, the plaintiffs filed an additional and substantially identical action against BP p.l.c. in federal court in New York, which was transferred to the judge presiding over MDL 2185. BP p.l.c. moved to dismiss that action on 19 February 2014. On 18 June 2014, the court dismissed the case on the ground that the courts of England are the more appropriate forum for the litigation. On 18 July 2014, the plaintiff appealed that decision to the Fifth Circuit. Briefing on that appeal concluded on 24 December 2014.

ERISA

On 30 March 2012, the federal district court in Houston in MDL 2185 issued a decision granting the defendants motions to dismiss the ERISA case related to BP share funds in several employee benefit savings plans. On 11 April 2012, the plaintiffs requested leave to file an amended complaint, which was denied on 27 August 2012. Final judgment dismissing the case was entered on 4 September 2012 and, on 25 September 2012, the plaintiffs filed a notice of appeal to the Fifth Circuit. On 15 July 2014, the Fifth Circuit remanded the case to the district court in light of new pleading standards recently set forth by the US Supreme Court. On 18 September 2014, the plaintiffs filed a motion seeking leave to amend their complaint. Defendants opposed that motion. On 15 January 2015, the district court granted in part and denied in part the motion to amend, permitting plaintiffs to amend their complaint to allege some of their proposed claims against certain defendants. Plaintiffs filed an amended complaint on 12 February 2015.

Settlements with the DoJ and SEC

On 1 June 2010, the DoJ announced that it was conducting an investigation into the Incident encompassing possible violations of US civil or criminal laws, and subsequently created a unified task force of federal agencies to investigate the Incident. On 15 November 2012, BP announced that it reached agreement with the US government, subject to court approval, to resolve all federal criminal charges and all claims by the SEC against BP arising from the Deepwater Horizon accident, oil spill and response.

On 29 January 2013, the US District Court for the Eastern District of Louisiana accepted BP s pleas regarding the federal criminal charges, and BP was sentenced in connection with the criminal plea agreement. BP pleaded guilty to 11 felony counts of Misconduct or Neglect of Ships Officers relating to the loss of 11 lives; one misdemeanour count under

the Clean Water Act; one misdemeanour count under the Migratory Bird Treaty Act; and one felony count of obstruction of Congress.

Pursuant to that sentence, BP will pay $4 billion, including $1,256 million in criminal fines, in instalments over five years. Under the terms of the criminal plea agreement, a total of $2,394 million will be paid to the National Fish & Wildlife Foundation (NFWF) over five years. In addition, $350 million will be paid to the National Academy of Sciences (NAS) over five years. BP made its required payments that were due in March and April 2013, January 2014, and January 2015 totalling $1.521 billion. The court also ordered, as previously agreed with the US government, that BP serve a term of five years probation. Pursuant to the terms of the plea agreement, the court also ordered certain equitable relief, including additional actions, enforceable by the court, to further enhance the safety of drilling operations in the Gulf of Mexico. These requirements relate to BP s risk management processes, such as third-party auditing and verification, BP s oil spill response plan, training, and well control equipment and processes such as blowout preventers and cementing. BP also agreed to maintain a real-time drilling operations monitoring centre in Houston or another appropriate location. In addition, BP will undertake several initiatives with academia and regulators to develop new technologies related to deepwater drilling safety. The resolution also provides for the appointment of two monitors, both with terms of up to four years. A process safety monitor will review, and provide recommendations concerning BPXP s process safety and risk management procedures for deepwater drilling in the Gulf of Mexico. An ethics monitor will review and provide recommendations concerning BP s ethics and compliance programme. BP has also agreed to retain an independent third-party auditor who will review and report to the probation officer, the DoJ and BP regarding BPXP s compliance with the key terms of the plea agreement including the completion of safety and environmental management systems audits, operational oversight enhancements, oil spill response training and drills and the implementation of best practices. Under the plea agreement, BP has also agreed to co-operate in ongoing criminal actions and investigations, including prosecutions of four former employees who have been separately charged.

In its resolution with the SEC, BP has resolved the SEC s Deepwater Horizon-related claims against the company under Sections 10(b) and 13(a) of the Securities Exchange Act of 1934 and the associated rules. BP has agreed to a civil penalty of $525 million, payable in three instalments over a period of three years, and has consented to the entry of an injunction prohibiting it from violating certain US securities laws and regulations. The SEC s claims are premised on oil flow rate estimates contained in three reports provided by BP to the SEC during a one-week period (on 29 and 30 April 2010 and 4 May 2010), within the first 14 days after the accident. BP s consent was incorporated in a final judgment and court order on 10 December 2012, and BP made its first payment of $175 million on 11 December 2012, its second payment of $175 million on 1 August 2013, and the final instalment of $175 million, plus accrued interest, on 1 August 2014.

BP s November 2012 agreement with the US government does not resolve the DoJ s civil claims, such as those for civil penalties under the Clean Water Act or claims for natural resource damages under OPA 90. Neither does it resolve the private securities claims pending in MDL 2185.

US Environmental Protection Agency matters

On 28 November 2012, the US Environmental Protection Agency (EPA) notified BP that it had temporarily suspended BP p.l.c., BPXP and a number of other BP subsidiaries from participating in new federal contracts. As a result of the temporary suspension, the BP entities listed in the notice were ineligible to receive any US government contracts either through the award of a new contract, or the extension of the term of or renewal of an expiring contract.

In addition, the charges to which BPXP pleaded guilty included one misdemeanour count under the Clean Water Act that, by operation of law, triggered a statutory debarment, also referred to as mandatory debarment, of the facility where the Clean Water Act violation occurred. On 1 February 2013, the EPA issued a notice that BPXP was mandatorily debarred at its Houston headquarters. Mandatory debarment prevents a company from entering into new contracts or new leases with the US government that would be performed at the facility where the Clean Water Act violation occurred.

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On 13 March 2014, BP, BPXP, and all other temporarily suspended BP entities entered into an administrative agreement with the EPA resolving all issues related to suspension or debarment arising from the Incident, allowing BP entities to enter into new contracts or leases with the US government. Under the terms and conditions of the administrative agreement, which will apply for five years, BP has agreed to a set of safety and operations, ethics and compliance and corporate governance requirements.

US Department of Interior matters

On 14 September 2011, the US Coast Guard and Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) issued a report regarding the causes of the 20 April 2010 Macondo well blowout (the BOEMRE Report). The BOEMRE Report states that decisions by BP, Halliburton and Transocean increased the risk or failed to fully consider or mitigate the risk of a blowout on 20 April 2010. The BOEMRE Report also states that BP, Transocean and Halliburton violated certain regulations related to offshore drilling. In itself, the BOEMRE Report does not constitute the initiation of enforcement proceedings relating to any violation. On 12 October 2011, the US Department of the Interior Bureau of Safety and Environmental Enforcement issued to BPXP, Transocean, and Halliburton Notification of Incidents of Noncompliance (INCs). The notification issued to BPXP is for a number of alleged regulatory violations concerning Macondo well operations. The Department of Interior has indicated that this list of violations may be supplemented as additional evidence is reviewed, and on 7 December 2011, the Bureau of Safety and Environmental Enforcement issued to BPXP a second INC. This notification was issued to BP for five alleged violations related to drilling and abandonment operations at the Macondo well. BP has filed an administrative appeal with respect to the first and second INCs. BP has filed a joint stay of proceedings with the Department of Interior with respect to both INCs.

Louisiana Department of Natural Resources

On 21 August 2013, the Louisiana Department of Natural Resources (LDNR) issued a Cease and Desist Order (the Order) directing BP to apply for a Coastal Use Permit to remove certain orphan anchors that had been placed in coastal waters to secure the containment boom during oil spill response operations in 2010. On 18 September 2013, BP filed a complaint in the US District Court for the Middle District of Louisiana seeking to enjoin the State of Louisiana from enforcing the Order on grounds including that the Order is pre-empted by federal law. On 7 August 2014, the court entered a final judgment providing that the Order was pre-empted on the basis of impossibility and obstacle pre-emption. The LDNR did not file a notice of appeal and the time period to file such notice has expired.

Pending investigations and reports relating to the Deepwater Horizon oil spill CSB investigation

The US Chemical Safety and Hazard Investigation Board (CSB) conducted an investigation of the Incident that is focused on the explosions and fire, and not the resulting oil spill or response efforts. As part of this effort, on 24 July 2012, the CSB conducted a hearing at which it released its preliminary findings on, among other things, the use of safety indicators by industry (including BP and Transocean) and government regulators in offshore operations prior to the Incident. On 18 September 2014, in response to Transocean s challenge to the CSB s jurisdiction to investigate the Incident, the Fifth Circuit affirmed the district court s order enforcing CSB s administrative subpoenas against Transocean. BP has produced documents in compliance with the CSB s document subpoenas. Separately the CSB released the first two volumes of its three-volume report on its investigation into the Incident at a public hearing in Houston on 5 June 2014. The first two volumes provide an introduction to the Incident as well as the CSB s findings regarding the operation of the blowout preventer and other technical issues. The CSB has indicated that it plans to release Volume 3 (concerning the role of the regulator in the oversight of the offshore industry and organizational and cultural factors) in or around March 2015.

Other legal proceedings

FERC and CFTC matters

The US Federal Energy Regulatory Commission (FERC) and the US Commodity Futures Trading Commission (CFTC) have been investigating

several BP entities regarding trading in the next-day natural gas market at Houston Ship Channel during September, October and November 2008. On 28 July 2011, FERC staff issued a Notice of Alleged Violations stating that it had preliminarily determined that several BP entities fraudulently traded physical natural gas in the Houston Ship Channel and Katy markets and trading points to increase the value of their financial swing spread positions. On 5 August 2013, the FERC issued an Order to Show Cause and Notice of Proposed Penalty directing BP to respond to a FERC Enforcement Staff report, which FERC issued on the same day, alleging that BP manipulated the next-day, fixed price gas market at Houston Ship Channel from mid-September 2008 to 30 November 2008. The FERC Enforcement Staff report proposes a civil penalty of $28 million and the surrender of $800,000 of alleged profits. BP filed its answer on 4 October 2013 denying the allegations and moving for dismissal. On 15 May 2014, FERC denied the motion to dismiss and the matter has been set for a hearing before an Administrative Law Judge in March 2015.

Canadian Natural Resource

The US Commodity Futures Trading Commission (CFTC) is currently investigating certain practices relating to crude oil pipeline nominations procedures on Canadian pipelines. On 17 November 2014, the CFTC Enforcement Staff notified BP that it intends to recommend an enforcement action naming certain parties, including several BP entities, alleging violations of the anti-fraud and false reporting provisions of the Commodity Exchange Act in connection with these nomination procedures and related trades. On 17 December 2014 BP submitted a detailed defence responding to the allegations in the notice and challenging the CFTC s jurisdiction over the alleged conduct.

Investigations by the FERC and CFTC into BP s trading activities continue to be conducted from time to time.

CSB matters

On 23 March 2005, an explosion and fire occurred at the Texas City refinery. Fifteen workers died in the incident and many others were injured. BP Products North America, Inc. (BP Products) has resolved all civil injury claims and all civil and criminal governmental claims arising from the March 2005 incident. In March 2007, the US Chemical Safety and Hazard Investigation Board (CSB) issued a report on the incident. The report contained recommendations to the Texas City refinery and to the board of directors of BP. To date, the CSB has accepted that the majority of BP s responses to its recommendations have been satisfactorily addressed. BP and the CSB are continuing to discuss the remaining open recommendations with the objective of the CSB agreeing to accept these as satisfactorily addressed as well.

OSHA matters

On 29 October 2009, the US Occupational Safety and Health Administration (OSHA) issued citations to the Texas City refinery related to the Process Safety Management (PSM) standard. On 12 July 2012, OSHA and BP resolved 409 of the 439 citations. The agreement required that BP pay a civil penalty of $13,027,000 and that BP abate the alleged violations by 31 December 2012. BP completed these requirements and the agreement has terminated. The settlement excluded 30 citations for which BP and OSHA could not reach agreement. However, the parties agreed that BP s penalty liability will not exceed $1 million if those citations are resolved through litigation. On 4 March 2014, the parties reached agreement in relation to the remaining Texas City citations. The agreement links the outcome of the remaining Texas City citations to the ultimate outcome of the remaining Toledo citations (see below). If the 31 July 2013 decision of the Administrative Law Judge in relation to the remaining Toledo citations is ultimately upheld, OSHA has agreed to dismiss the remaining Texas City citations.

If the 31 July 2013 decision is ultimately overturned, BP has agreed to pay a penalty not exceeding $1 million to resolve the remaining Texas City citations.

On 8 March 2010, OSHA issued 65 citations to BP Products and BP-Husky for alleged violations of the PSM standard at the Toledo refinery, with penalties of approximately $3 million. These citations resulted from an inspection conducted pursuant to OSHA s Petroleum Refinery Process Safety Management National Emphasis Program. Both BP Products and BP-Husky contested the citations. The parties resolved 23 citations in a pre-trial settlement for an aggregate amount of $45,000. A trial of the remaining 42 citations was completed in June 2012 before an Administrative Law Judge from the OSH Review Commission. The Administrative Law Judge rendered her decision on 31 July 2013. Of the 42 remaining citations, OSHA voluntarily dismissed one of them and the judge vacated 36 additional citations. The remaining five citations were downgraded and assessed an aggregate penalty of $35,000. In addition, the judge accepted the parties pre-trial settlement of the 23 citations. As a result of the settlement and the judge s decision, the total penalty in respect of the citations was reduced from the original amount of approximately $3 million to $80,000. The Review Commission has granted OSHA s petition for review and briefing was completed in the first half of 2014. The Review Commission is not expected to issue its decision until 2015 at the earliest.

Prudhoe Bay leak

In March and August 2006, oil leaked from oil transit pipelines operated by BP Exploration (Alaska) Inc. (BPXA) at the Prudhoe Bay unit on the North Slope of Alaska. On 12 May 2008, a BP p.l.c. shareholder filed a consolidated complaint alleging violations of federal securities law on behalf of a putative class of BP p.l.c. shareholders, based on alleged misrepresentations concerning the integrity of the Prudhoe Bay pipeline before its shutdown on 6 August 2006. The BP p.l.c. shareholder filed an amended complaint, in response to which BP filed a motion to dismiss, which was granted by the trial court on 14 March 2012. The plaintiff appealed the court s dismissal of the case, and on 13 February 2014 the Ninth Circuit affirmed in part and reversed in part, ruling that claims based on four alleged misrepresentations should not have been dismissed. The case has been remanded to the trial court for further proceedings.

Exxon Valdez matters

Approximately 200 lawsuits were filed in state and federal courts in Alaska seeking compensatory and punitive damages arising out of the Exxon Valdez oil spill in Prince William Sound in March 1989. Most of those suits named Exxon (now ExxonMobil), Alyeska Pipeline Service Company (Alyeska), which operates the oil terminal at Valdez, and the other oil companies that own Alyeska. Alyeska initially responded to the spill until the response was taken over by Exxon. BP owns a 46.9% interest (reduced during 2001 from 50% by a sale of 3.1% to Phillips) in Alyeska through a subsidiary of BP America Inc. and briefly indirectly owned a further 20% interest in Alyeska following BP s combination with Atlantic Richfield. Alyeska and its owners have settled all the claims against them under these lawsuits. Exxon has indicated that it may file a claim for contribution against Alyeska for a portion of the costs and damages that it has incurred. If any claims are asserted by Exxon that affect Alyeska and its owners, BP will defend the claims vigorously.

Lead paint matters

Since 1987, Atlantic Richfield Company (Atlantic Richfield), a subsidiary of BP, has been named as a co-defendant in numerous lawsuits brought in the US alleging injury to persons and property caused by lead pigment in paint. The majority of the lawsuits have been abandoned or dismissed against Atlantic Richfield. Atlantic Richfield is named in these lawsuits as alleged successor to International Smelting and Refining and another company that manufactured lead pigment during the period 1920-1946. The plaintiffs include individuals and governmental entities. Several of the lawsuits purport to be class actions. The lawsuits seek various remedies including compensation to lead-poisoned children, cost to find and remove lead paint from buildings, medical monitoring and screening programmes, public warning and education of lead hazards, reimbursement of government healthcare costs and special education for lead-poisoned citizens and punitive damages. No lawsuit against Atlantic Richfield has been settled nor has Atlantic Richfield been subject to a final adverse judgment in any proceeding. The amounts claimed and, if such suits were successful, the costs of implementing the remedies sought in the various cases could be substantial. While it is not possible to predict the outcome of these legal actions, Atlantic Richfield believes that it has valid defences. It intends to defend such actions vigorously and believes that the incurrence of liability is remote. Consequently, BP believes that the impact of these lawsuits on the group s results, financial position or liquidity will not be material.

Abbott Atlantis related matters

In April 2009, Kenneth Abbott, as relator, filed a US False Claims Act lawsuit against BP, alleging that BP violated federal regulations, and made false statements in connection with its compliance with those regulations, by failing to have necessary documentation for the Atlantis

subsea and other systems. BP is the operator and 56% interest owner of the Atlantis unit which is in production in the Gulf of Mexico. On 21 August 2014, the court granted BP s motions for summary judgment. On 28 August 2014, the court entered final judgment in favour of BP. In September 2014 the plaintiff filed a motion for reconsideration, which BP opposed. The judge took this on advisement. A decision of the court is awaited.

Bolivia

In respect of Pan American Energy s arbitration case for compensation for the expropriation of its shares in Empresa Petrolera Chaco S.A. (Chaco) which commenced in March 2012 against the Republic of Bolivia, on 18 December 2014, the Republic of Bolivia and Pan American Energy signed a $357 million settlement agreement and agreed to terminate the arbitration.

EC investigation and related matters

On 14 May 2013, European Commission officials made a series of unannounced inspections at the offices of BP and other companies involved in the oil industry acting on concerns that anticompetitive practices may have occurred in connection with oil price reporting practices and the reference price assessment process. Related inquiries and requests for information have also been received from US and other regulators following the European Commission s actions, including from the Japanese Fair Trade Commission, the Korean Fair Trade Commission, the Federal Trade Commission (FTC) and the CFTC. On 1 October 2014, BP was informed by the FTC that it was closing its investigation. The other investigations remain open and there is no deadline for the completion of the inquiries.

In addition, fifteen purported class actions related to these matters have been filed in US district courts alleging manipulation and antitrust violations under the Commodity Exchange Act and US antitrust laws, and these purported class actions have been consolidated in federal court in New York.

California False Claims Act matters

On 4 November 2014 the California Attorney General filed a notice in California state court that it was intervening in a previously-sealed California False Claims Act (CFCA) lawsuit filed by relator Christopher Schroen against BP, BP Energy Company, BP Corporation North America Inc., BP Products and BPAPC. On 7 January 2015, the California Attorney General filed a complaint in intervention alleging that BP violated the CFCA and the California Unfair Competition Law by falsely and fraudulently overcharging California state entities for natural gas. The relator s complaint makes similar allegations, in addition to individual claims. The complaints seek treble damages, punitive damages, penalties and injunctive relief.

See Financial statements Note 31 for additional information on the group s legal proceedings.

International trade sanctions

During the period covered by this report, non-US subsidiaries or other non-US entities of BP conducted limited activities in, or with persons from, certain countries identified by the US Department of State as State Sponsors of

Terrorism or otherwise subject to US and EU sanctions (Sanctioned Countries). Sanctions restrictions continue to be insignificant to the group s financial condition and results of operations. BP monitors its activities with Sanctioned Countries, persons from Sanctioned Countries and individuals and companies subject to US and EU sanctions and seeks to comply with applicable sanctions laws and regulations.

Both the US and the EU have enacted strong sanctions against Iran, including: in the US, sanctions against persons involved with Iran s energy, shipping and petrochemicals industries, and sanctions against financial institutions that engage in significant transactions with the Iran Central Bank; and in the EU, a prohibition on the import, purchase and transport of Iranian-origin crude oil, petroleum products and natural gas. Additionally, the Iran Threat Reduction and Syria Human Rights Act of 2012 (ITRA) added Section 13(r) to the Securities Exchange Act of 1934, as amended (the Exchange Act), and requires that issuers must file annual or quarterly reports under the Exchange Act to disclose in such reports whether, during the period covered by the report, the registrant

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or its affiliates have knowingly engaged in certain, principally Iran-related, activities.

Both the US and the EU have enacted strong sanctions against Syria, including a prohibition on the purchase of Syrian-origin crude and a US prohibition on the provision of services to Syria by US persons. The EU sanctions against Syria include a prohibition on supplying certain equipment used in the production, refining, or liquefaction of petroleum resources as well as restrictions on dealing with the Central Bank of Syria and numerous other Syrian financial institutions.

With effect from 20 January 2014, the US and the EU implemented temporary, limited and reversible relief of certain sanctions related to Iran pursuant to a Joint Plan of Action entered by Iran, China, France, Germany, Russia, the UK and the US. BP has not changed its policy in relation to Iran as a result of the Joint Plan of Action and has no plans to engage in any new business with Iran which would now be permitted as a result of the Joint Plan of Action.

BP has interests in and operates the North Sea Rhum field (Rhum) and the Azerbaijan Shah Deniz field (Shah Deniz), in which Naftiran Intertrade Co. Limited and NICO SPV Limited (collectively, NICO) or Iranian Oil Company (U.K.) Limited (IOC UK) have interests. Additionally, BP has interests in a gas marketing entity and a gas pipeline entity in which NICO or IOC UK have interests, although both entities (and their related assets) are located outside Iran. Production was suspended at Rhum (in which IOC UK has a 50% interest) in November 2010. On 22 October 2013, the UK government announced a temporary management scheme (the Temporary Scheme) under The Hydrocarbon (Temporary Management Scheme) Regulations 2013 under which the UK government assumed control of and now manages IOC UK s interest in the Rhum field, thereby permitting Rhum operations to recommence in accordance with applicable EU regulations and in compliance with US laws and regulations. Operations at the Rhum gas field recommenced in mid-October 2014 in accordance with this Temporary Scheme.

Shah Deniz, its gas marketing entity and the gas pipeline entity (in which NICO has a 10% or less non-operating interest) continue in operation. The Shah Deniz joint operation and its gas marketing and pipeline entities were excluded from the main operative provisions of the EU regulations as well as from the application of the new US sanctions, and fall within the exception for certain natural gas projects under Section 603 of ITRA.

BP has no operations in Iran and BP s policy is that it shall not purchase or ship crude oil or other products of Iranian origin. Participants in non-BP controlled or operated joint arrangements* may purchase Iranian-origin crude oil or other components as feedstock for facilities located outside the EU and US. It is also BP s policy that it shall not sell crude oil or other products into Iran. BP currently holds an interest in a non-BP operated Indian joint venture* which sold crude oil to an Indian entity in which NICO holds a minority, non-controlling stake. Those sales ceased in January 2014.

In 2012, BP became aware that a Canadian university had been using graduate students, some of whom were nationals of Iran, on a research programme funded in part by BP. BP suspended the programme and made a voluntary disclosure to OFAC. Also in 2012, BP became aware that in 2010, as consideration for certain auditing services, BP effected a transfer of funds to a local Iranian consulting firm which may have been in violation of relevant EU notification requirements. BP has made a voluntary disclosure to the applicable EU regulator of such transfer.

Following the imposition in 2011 of further US and EU sanctions against Syria, BP terminated all sales of crude oil and petroleum products into Syria, though BP continues to supply aviation fuel to non-governmental Syrian resellers outside of Syria.

BP has equity interests in non-operated joint arrangements with air fuel sellers, resellers, and fuel delivery services around the world. From time to time, the joint arrangement operator or other partners may sell or deliver fuel to airlines from Sanctioned Countries or flights to Sanctioned Countries without BP s prior knowledge or consent. BP has registered and paid required fees for patents and trade marks in Sanctioned Countries.

BP sells lubricants in Cuba through a 50:50 joint arrangement and trades in small quantities of lubricants.

During 2014 the US and the EU have imposed sanctions on certain Russian activities, individuals and entities, including Rosneft. Certain sectoral sanctions also apply to entities owned 50% or more by entities on the relevant sectoral sanctions list. Ruhr Oel GmbH (ROG) is a 50:50 joint operation with Rosneft, operated by BP, which holds interests in a number of refineries in Germany. To date, these sanctions have had no material adverse impact on BP or ROG.

Disclosure pursuant to Section 219 of ITRA

To our knowledge, none of BP s activities, transactions or dealings are required to be disclosed pursuant to ITRA Section 219, with the following possible exception:

Rhum, located in the UK sector of the North Sea, is operated by BP Exploration Operating Company Limited (BPEOC), a non-US subsidiary of BP. Rhum is owned under a 50:50 unincorporated joint arrangement between BPEOC and Iranian Oil Company (U.K.) Limited (IOC). The Rhum joint arrangement was originally formed in 1974. During the period of production from the field, the Rhum joint arrangement supplied natural gas and certain associated liquids to the UK. On 16 November 2010, production from Rhum was suspended in response to relevant EU sanctions. Operations at the Rhum gas field recommenced in mid-October 2014 in accordance with the UK government s Temporary Scheme (see above). During the year ended 31 December 2014, BP recorded gross revenues of $8.86 million related to its interests in Rhum. BP had no net profits related to Rhum during the year ended 31 December 2014, recording an overall loss of $204.5 million (net) following an impairment write-off of $198 million in the fourth quarter of 2014.

BP currently intends to continue to hold its ownership stake in the Rhum joint arrangement.

Material contracts

On 13 March 2014, BP, BPXP, and other BP entities entered into an administrative agreement with the US Environmental Protection Agency, which resolved all issues related to the suspension or debarment of BP entities arising from the 20 April 2010 explosions and fire on the semi-submersible rig Deepwater Horizon and resulting oil spill. The administrative agreement allows BP entities to enter into new contracts or leases with the US government. Under the terms and conditions of this agreement, which will apply for five years, BP has agreed to a set of safety and operations, ethics and compliance and corporate governance requirements. The agreement is governed by federal law.

Property, plant and equipment

BP has freehold and leasehold interests in real estate and other tangible assets in numerous countries, but no individual property is significant to the group as a whole. For more on the significant subsidiaries* of the group at 31 December 2014 and the group percentage of ordinary share capital see Financial statements Note 35. For information on significant joint ventures* and associates* of the group see Financial statements Notes 14 and 15.

Related-party transactions

Transactions between the group and its significant joint ventures and associates are summarized in Financial statements Note 14 and Note 15. In the ordinary course of its business, the group enters into transactions with various organizations with which some of its directors or executive officers are associated. Except as described in this report, the group did not have material transactions or transactions of an unusual nature with, and did not make loans to, related parties in the period commencing 1 January 2014 to 17 February 2015.

Corporate governance practices

In the US, BP ADSs are listed on the New York Stock Exchange (NYSE). The significant differences between BP s corporate governance practices as a UK company and those required by NYSE listing standards for US companies are listed as follows:

Independence

BP has adopted a robust set of board governance principles, which reflect the UK Corporate Governance Code and its principles-based

*Defined on page 252.

approach to corporate governance. As such, the way in which BP makes determinations of directors independence differs from the NYSE rules.

BP s board governance principles require that all non-executive directors be determined by the board to be independent in character and judgement and free from any business or other relationship which could materially interfere with the exercise of their judgement . The BP board has determined that, in its judgement, all of the non-executive directors are independent. In doing so, however, the board did not explicitly take into consideration the independence requirements outlined in the NYSE s listing standards.

Committees

BP has a number of board committees that are broadly comparable in purpose and composition to those required by NYSE rules for domestic US companies. For instance, BP has a chairman s (rather than executive) committee, nomination (rather than nominating/corporate governance) committee and remuneration (rather than compensation) committee. BP also has an audit committee, which NYSE rules require for both US companies and foreign private issuers. These committees are composed solely of non-executive directors whom the board has determined to be independent, in the manner described above.

The BP board governance principles prescribe the composition, main tasks and requirements of each of the committees (see the board committee reports on page 64). BP has not, therefore, adopted separate charters for each committee.

Under US securities law and the listing standards of the NYSE, BP is required to have an audit committee that satisfies the requirements of Rule 10A-3 under the Exchange Act and Section 303A.06 of the NYSE Listed Company Manual. BP s audit committee complies with these requirements. The BP audit committee does not have direct responsibility for the appointment, re-appointment or removal of the independent auditors instead, it follows the UK Companies Act 2006 by making recommendations to the board on these matters for it to put forward for shareholder approval at the AGM.

One of the NYSE s additional requirements for the audit committee states that at least one member of the audit committee is to have accounting or related financial management expertise . The board determined that Brendan Nelson possessed such expertise and also possesses the financial and audit committee experiences set forth in both the UK Corporate Governance Code and SEC rules (see Audit committee report on page 64). Mr Nelson is the audit committee financial expert as defined in Item 16A of Form 20-F.

Shareholder approval of equity compensation plans

The NYSE rules for US companies require that shareholders must be given the opportunity to vote on all equity-compensation plans and material revisions to those plans. BP complies with UK requirements that are similar to the NYSE rules. The board, however, does not explicitly take into consideration the NYSE s detailed definition of what are considered material revisions .

Code of ethics

The NYSE rules require that US companies adopt and disclose a code of business conduct and ethics for directors, officers and employees. BP has adopted a code of conduct, which applies to all employees, and has board governance principles that address the conduct of directors. In addition BP has adopted a code of ethics for senior financial officers as required by the SEC. BP considers that these codes and policies address the matters specified in the NYSE rules for US companies.

Code of ethics

The company has adopted a code of ethics for its group chief executive, chief financial officer, group controller, general auditor and chief accounting officer as required by the provisions of Section 406 of the Sarbanes-Oxley Act of 2002 and the rules issued by the SEC. There have been no waivers from the code of ethics relating to any officers.

BP also has a code of conduct, which is applicable to all employees, officers and members of the board. This was updated (and published) in July 2014.

Controls and procedures

Evaluation of disclosure controls and procedures

The company maintains disclosure controls and procedures , as such term is defined in Exchange Act Rule 13a-15(e), that are designed to ensure that information required to be disclosed in reports the company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and that such information is accumulated and communicated to management, including the company s group chief executive and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

In designing and evaluating our disclosure controls and procedures, our management, including the group chief executive and chief financial officer, recognize that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the disclosure controls and procedures are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. Further, in the design and evaluation of our disclosure controls and procedures our management necessarily was required to apply its judgement in evaluating the cost-benefit relationship of possible controls and procedures. Also, we have investments in certain unconsolidated entities. As we do not control these entities, our disclosure controls and procedures with respect to such entities are necessarily substantially more limited than those we maintain with respect to our consolidated subsidiaries. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. The company s disclosure controls and procedures have been designed to meet, and management believes that they meet, reasonable assurance standards.

The company s management, with the participation of the company s group chief executive and chief financial officer, has evaluated the effectiveness of the company s disclosure controls and procedures pursuant to Exchange Act Rule 13a-15(b) as of the end of the period covered by this annual report. Based on that evaluation, the group chief executive and chief financial officer have concluded that the company s disclosure controls and procedures were effective at a reasonable assurance level.

Management s report on internal control over financial reporting

Management of BP is responsible for establishing and maintaining adequate internal control over financial reporting. BP s internal control over financial reporting is a process designed under the supervision of the principal executive and financial officers to provide reasonable assurance regarding the reliability of financial reporting and the preparation of BP s financial statements for external reporting purposes in accordance with IFRS.

As of the end of the 2014 fiscal year, management conducted an assessment of the effectiveness of internal control over financial reporting in accordance with the Internal Control Revised Guidance for Directors (Turnbull). Based on this assessment, management has determined that BP s internal control over financial reporting as of 31 December

2014 was effective.

The company s internal control over financial reporting includes policies and procedures that pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets; provide reasonable assurances that transactions are recorded as necessary to permit preparation of financial statements in accordance with IFRS and that receipts and expenditures are being made only in accordance with authorizations of management and the directors of BP; and provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of BP s assets that could have a material effect on our financial statements. BP s internal control over financial reporting as of 31 December 2014 has been audited by Ernst & Young, an independent registered public accounting firm, as stated in their report appearing on page 95 of *BP Annual Report and Form 20-F 2014*.

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Changes in internal control over financial reporting

There were no changes in the group s internal controls over financial reporting that occurred during the period covered by the Form 20-F that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

Principal accountants fees and services

The audit committee has established policies and procedures for the engagement of the independent registered public accounting firm, Ernst & Young LLP, to render audit and certain assurance and tax services. The policies provide for pre-approval by the audit committee of specifically defined audit, audit-related, tax and other services that are not prohibited by regulatory or other professional requirements. Ernst & Young are engaged for these services when its expertise and experience of BP are important. Most of this work is of an audit nature. Tax services were awarded either through a full competitive tender process or following an assessment of the expertise of Ernst & Young relative to that of other potential service providers. These services are for a fixed term.

Under the policy, pre-approval is given for specific services within the following categories: advice on accounting, auditing and financial reporting matters; internal accounting and risk management control reviews (excluding any services relating to information systems design and implementation); non-statutory audit; project assurance and advice on business and accounting process improvement (excluding any services relating to information systems design and implementation relating to BP s financial statements or accounting records); due diligence in connection with acquisitions, disposals and joint arrangements (excluding valuation or involvement in prospective financial information); income tax and indirect tax compliance and advisory services; employee tax services (excluding tax services that could impair independence); provision of, or access to, Ernst & Young publications, workshops, seminars and other training materials; provision of reports from data gathered on non-financial policies and information; and assistance with understanding non-financial regulatory requirements. BP operates a two-tier system for audit and non-audit services. For audit related services, the audit committee has a pre-approved aggregate level, within which specific work may be approved by management. Non-audit services, including tax services, are pre-approved for management to authorize per individual engagement, but above a defined level must be approved by the chairman of the audit committee or the full committee. The audit committee has delegated to the chairman of the audit committee authority to approve permitted services provided that the chairman reports any decisions to the committee at its next scheduled meeting. Any proposed service not included in the approved service list must be approved in advance by the audit committee chairman and reported to the committee, or approved by the full audit committee in advance of commencement of the engagement.

The audit committee evaluates the performance of the auditors each year. The audit fees payable to Ernst & Young are reviewed by the committee in the context of other global companies for cost effectiveness. The committee keeps under review the scope and results of audit work and the independence and objectivity of the auditors. External regulation and BP policy requires the auditors to rotate their lead audit partner every five years. (See Financial statements Note 34 and Audit committee report on page 64 for details of fees for services provided by auditors.)

Directors report information

This section of *BP Annual Report and Form 20-F 2014* forms part of, and includes certain disclosures which are required by law to be included in, the Directors report.

Indemnity provisions

In accordance with BP s Articles of Association, on appointment each director is granted an indemnity from the company in respect of liabilities incurred as a result of their office, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report. In respect of those liabilities for which directors may not be indemnified, the company maintained a directors and officers liability

insurance policy throughout 2014. During the year, a review of the terms and scope of the policy was undertaken. The 2013 policy was extended into 2014 and subsequently renewed during 2014 into 2015. Although their defence costs may be met, neither the company s indemnity nor insurance provides cover in the event that the director is proved to have acted fraudulently or dishonestly. In addition, each director of the company s subsidiaries which subsidiaries are trustees of the group s pension schemes, is granted an indemnity from the company in respect of liabilities incurred as a result of such a subsidiary s activities as a trustee of the pension scheme, to the extent permitted by law. These indemnities were in force throughout the financial year and at the date of this report.

Financial risk management objectives and policies

The disclosures in relation to financial risk management objectives and policies, including the policy for hedging, are included in Our management of risk on page 46, Liquidity and capital resources on page 211 and Financial statements Notes 27 and 28.

Exposure to price risk, credit risk, liquidity risk and cash flow risk

The disclosures in relation to exposure to price risk, credit risk, liquidity risk and cash flow risk are included in Financial statements Note 27.

Important events since the end of the financial year

Disclosures of the particulars of the important events affecting BP which have occurred since the end of the financial year are included in the Strategic report as well as in other places in the Directors report.

Likely future developments in the business

An indication of the likely future developments of the business is included in the Strategic report.

Research and development

An indication of the activities of the company in the field of research and development is included in Our strategy on page 13.

Branches

As a global group our interests and activities are held or operated through subsidiaries*, branches, joint arrangements* or associates* established in and subject to the laws and regulations of many different jurisdictions.

Employees

The disclosures concerning policies in relation to the employment of disabled persons and employee involvement are included in Corporate responsibility Employees on page 44.

Employee share schemes

Certain shares held by the Employee Share Ownership Plan trusts (ESOPs) carry voting rights. Voting rights in respect of such shares are exercisable via a nominee.

Greenhouse gas emissions

The disclosures in relation to greenhouse gas emissions are included in Corporate responsibility Environment and society on page 42.

Disclosures required under Listing Rule 9.8.4R

The information required to be disclosed by Listing Rule 9.8.4R can be located as set out below:

Information required	Page
(1) Amount of interest capitalized	123
(2) (14)	Not applicable

Cautionary statement

This document contains certain forecasts, projections and 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 believes , anticipates , plans , we see or similar expressions. In particular, among other statements, (1) certain stateme in the Chairman s letter (pages 6-7), the Group chief executive s letter (pages 8-9), the Strategic report

*Defined on page 252.

(inside front cover and pages 1-50) and Additional disclosures (pages 207- 242), including but not limited to statements under the headings Our market outlook , Beyond 2035 , Our business model , Our strategy , Outlook an Outlook for 2015 , and including but not limited to statements regarding plans and prospects relating to future value creation, capital discipline and growth in sustainable free cash flow; plans to develop resources, increase production, strengthen BP s portfolio of high-return and longer-life assets and unlock value from BP s resource base; plans relating to future workforce size, initiatives and composition, including workforce diversity; expectations regarding the future level of oil and gas prices and industry product supply, demand and pricing in the near term and long term and BP s outlook and projections of future energy trends, including the role of oil, gas and renewables therein; plans to form key partnerships and relationships with governments, customers, partners, communities, suppliers and other institutions; expectations regarding and timing of planned and future acquisitions and divestments, including the completion of $10 billion of divestments in 2015; expectations regarding the current and future prospects of BP s discoveries, resources, reserves and positions; expectations regarding BP s reported and underlying production in 2015; the timing and composition of planned and future projects including expected final investment decisions, start-up, construction, commissioning, completion, timing of production, level of production and margins of such projects; expectations regarding Rosneft s future share price and dividend growth and BP s plans to explore future opportunities with Rosneft; plans regarding growing operating cash flow and returns in Downstream, including by leveraging assets, portfolio management, customer relationships, technology and trading activity; expectations regarding the 2015 environment for refining and petrochemicals margins; expectations regarding 2015 refinery turnarounds and future refinery operations; expectations regarding improvements in cash break-even performance, earnings potential and future plant events in the petrochemicals business; expectations regarding future safety performance and plans to enhance safety, cybersecurity, compliance and risk management; Air BP s strategic aims; the future strategy for and planned investments in alternative energies; the expected annual charges of Other business and corporate for 2015; expectations regarding the actions of contractors and partners and their terms of service; expectations regarding future environmental regulations, their impact on BP s business and plans to reduce BP s environmental impact; expectations regarding changes in laws and regulations and their impact on BP s business; plans to increase efficiency, reliability and product quality, improve margins and create new market opportunities; expectations regarding future Upstream operations, including agreements or contracts with or relating to TEPCO, BP s CATS business, Tangguh and CNOOC, BP s joint-ownership interests in exploration blocks and plans to drill therein; plans to transfer operatorship of certain fields, expectations of awards from award rounds; plans related to the Alaska LNG project and the Canadian oil sands; plans and expectations regarding the Point Thomson production facility, the Angola LNG plant, the exploration and production-sharing agreement in Libya, the North Damietta offshore concession, exploration in Morocco, exploration in India, the Sanga-Sanga CBM PSA, the Southern Gas Corridor, the Khazzan field, the Gorgon LNG plant and the Ceduna Sub Basin; expected expirations of concessions, contracts and exploration periods; projections regarding oil and gas reserves, including recovery and turnover time thereof; plans regarding compliance with ITRA rules, sanctions and reporting requirements, including in relation to BP s stake in the Rhum joint arrangement and future engagement in business with Iran; plans to take action under and comply with the EPA Administrative Agreement; plans with regard to the timing of and actions to be taken at the AGM, including amendments to the proposal of amendments to the Articles of Association; expectations regarding future restoration or other actions to be taken as a result of the Deepwater Horizon incident and related proceedings and their impact on BP s business; and expectations regarding legal and trial proceedings, court decisions, potential investigations and civil actions by regulators, government entities and/or other entities or parties, and the risks associated with such proceedings and BP s intentions in respect thereof; (2) certain statements in Corporate governance (pages 51-71) and the Directors remuneration report (pages 72-88) with regard to the anticipated future composition of the board of directors; the board s goals and areas of focus stemming from the board s annual evaluation; plans regarding and the timing of

future audit contract tendering and areas of focus for the audit committee; the expected percentage of performance shares that will vest based on performance outcomes; and plans and expectations with regard to the remuneration, pensions and other benefits of executive directors, including disclosure of targets, future review schedules, prospective scenarios for total remuneration opportunities for executive directors in the future, changes in the metrics used to calculate remuneration and changes to the limits of aggregate annual remuneration; and (3) certain statements in the Strategic report (inside front cover and pages 1-50) and Additional disclosures (pages 211-212), with regard to future dividend and optional scrip dividend payments; future capital expenditures and capital investment, including estimated 2015 levels thereof, 2015 taxation, future working capital and cash management, gearing and the net debt ratio; BP s intention to maintain a strong cash position; and expected payments under contractual and commercial commitments and purchase obligations; are all forward looking in nature.

By their nature, forward-looking statements involve risk and uncertainty because they relate to events and depend on circumstances that will or may occur in the future and are outside the control of BP. Actual results may differ materially from those expressed in such statements, depending on a variety of factors, including: the specific factors identified in the discussions accompanying such forward-looking statements; the receipt of relevant third party and/or regulatory approvals; the timing and level of maintenance and/or turnaround activity; the timing and volume of refinery additions and outages; the timing of bringing new fields onstream; the timing, quantum and nature of certain divestments; future levels of industry product supply, demand and pricing, including supply growth in North America; OPEC quota restrictions; production-sharing agreements effects; operational and safety problems; potential lapses in product quality; economic and financial market conditions generally or in various countries and regions; 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 or imposed; the actions of prosecutors, regulatory authorities and courts; the impact on our reputation following the Gulf of Mexico oil spill; the actions of the Claims Administrator appointed under the Economic and Property Damages Settlement; the actions of all parties to the Gulf of Mexico oil spill-related litigation at various phases of the litigation; the timing and amount of future payments relating to the Gulf of Mexico oil spill; exchange rate fluctuations; development and use of new technology; recruitment and retention of a skilled workforce; the success or otherwise of partnering; the actions of competitors, trading partners, contractors, subcontractors, creditors, rating agencies and others; our access to future credit resources; business disruption and crisis management; the impact on our reputation of ethical misconduct and non-compliance with regulatory obligations; trading losses; major uninsured losses; decisions by Rosneft s management and board of directors; 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 elsewhere in this report including under Risk factors (pages 48-50). In addition to factors set forth elsewhere in this report, 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.

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.

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Share prices and listings

Markets and market prices

The primary market for BP s ordinary shares is the London Stock Exchange (LSE). BP s ordinary shares are a constituent element of the Financial Times Stock Exchange 100 Index. BP s ordinary shares are also traded on the Frankfurt Stock Exchange in Germany.

Trading of BP s shares on the LSE is primarily through the use of the Stock Exchange Electronic Trading Service (SETS), introduced in 1997 for the largest companies in terms of market capitalization whose primary listing is the LSE. Under SETS, buy and sell orders at specific prices may be sent electronically to the exchange by any firm that is a member of the LSE, on behalf of a client or on behalf of itself acting as a principal. The orders are then anonymously displayed in the order book. When there is a match on a buy and a sell order, the trade is executed and automatically reported to the LSE. Trading is continuous from 8.00am to 4.30pm UK time but, in the event of a 20%

movement in the share price either way, the LSE may impose a temporary halt in the trading of that company s shares in the order book to allow the market to re-establish equilibrium. Dealings in ordinary shares may also take place between an investor and a market-maker, via a member firm, outside the electronic order book.

In the US, BP s securities are traded on the New York Stock Exchange (NYSE) in the form of ADSs, for which JPMorgan Chase Bank, N.A. is the depositary (the Depositary) and transfer agent. The Depositary s principal office is 4 New York Plaza, Floor 12, New York, NY, 10004, US. Each ADS represents six ordinary shares. ADSs are listed on the NYSE. ADSs are evidenced by American depositary receipts (ADRs), which may be issued in either certificated or book entry form.

The following table sets forth, for the periods indicated, the highest and lowest middle market quotations for BP s ordinary shares and ADSs for the periods shown. These are derived from the highest and lowest intra-day sales prices as reported on the LSE and NYSE, respectively.

		Pence		Dollars
	Ordinary shares		American depositary shares[a]	
	High	Low	High	Low
Year ended 31 December				
2010	658.20	296.00	62.38	26.75
2011	514.90	361.25	49.50	33.62
2012	512.00	388.56	48.34	36.25
2013	494.20	426.50	48.65	39.99
2014	**526.80**	**364.40**	**53.48**	**34.88**
Year ended 31 December				
2013: First quarter	482.33	426.50	45.45	39.99
Second quarter	485.43	437.25	44.27	40.12
Third quarter	477.53	430.30	43.75	40.51
Fourth quarter	494.20	426.55	48.65	41.30
2014: First quarter	**510.00**	**462.64**	**51.02**	**45.83**
Second quarter	**526.80**	**467.10**	**53.48**	**47.14**

Third quarter	**525.80**	**440.72**	**53.48**	**43.80**
Fourth quarter	**455.45**	**364.40**	**44.14**	**34.88**
2015: First quarter (to 17 February)	**463.10**	**376.70**	**42.10**	**34.93**
Month of				
September 2014	**494.90**	**440.72**	**48.11**	**43.80**
October 2014	**455.45**	**405.35**	**44.14**	**39.45**
November 2014	**452.45**	**408.80**	**43.08**	**39.19**
December 2014	**439.80**	**364.40**	**41.59**	**34.88**
January 2015	**445.68**	**376.70**	**40.44**	**34.93**
February 2015 (to 17 February)	**463.10**	**426.35**	**42.10**	**39.19**

[a] One ADS is equivalent to six 25 cent ordinary shares.
Source: Thomson Reuters Datastream.

Market prices for the ordinary shares on the LSE and in after-hours trading off the LSE, in each case while the NYSE is open, and the market prices for ADSs on the NYSE, are closely related due to arbitrage among the various markets, although differences may exist from time to time.

On 17 February 2015, 883,647,170.5 ADSs (equivalent to approximately 5,301,883,023 ordinary shares or some 29.07% of the total issued share capital, excluding shares held in treasury) were outstanding and were held by approximately 95,858 ADS holders. Of these, about 94,687 had registered addresses in the US at that date. One of the registered holders of ADSs represents some 979,038 underlying holders.

On 17 February 2015, there were approximately 270,163 ordinary shareholders. Of these shareholders, around 1,570 had registered addresses in the US and held a total of some 4,005,034 ordinary shares.

Since a number of the ordinary shares and ADSs were held by brokers and other nominees, the number of holders in the US may not be representative of the number of beneficial holders of their respective country of residence.

Dividends

BP s current policy is to pay interim dividends on a quarterly basis on its ordinary shares.

Its policy is also to announce dividends for ordinary shares in US dollars and state an equivalent sterling dividend. Dividends on BP ordinary shares will be paid in sterling and on BP ADSs in US dollars. The rate of exchange used to determine the sterling amount equivalent is the average of the market exchange rates in London over the four business days prior to the sterling equivalent announcement date. The directors may choose to declare dividends in any currency provided that a sterling equivalent is announced. It is not the company s intention to change its current policy of announcing dividends on ordinary shares in US dollars.

Information regarding dividends announced and paid by the company on ordinary shares and preference shares is provided in Financial statements Note 8.

A Scrip Dividend Programme (Scrip Programme) was approved by shareholders in 2010. It enables BP ordinary shareholders and ADS holders to elect to receive dividends by way of new fully paid BP ordinary shares (or ADSs in the case of ADS holders) instead of cash. The company intends to propose a resolution to the shareholders at the

next AGM that the Scrip Programme be renewed for a further three years. The operation of the Scrip Programme is always subject to the directors decision to make the Scrip Programme offer available in respect of any particular dividend. Should the directors decide not to offer the Scrip Programme in respect of any particular dividend, cash will be paid automatically instead.

Future dividends will be dependent on future earnings, the financial condition of the group, the Risk factors set out on page 48 and other matters that may affect the business of the group set out in Our strategy on page 13 and in Liquidity and capital resources on page 211.

The following table shows dividends announced and paid by the company per ADS for the past five years.

Dividends per ADS[a]		March	June	September	December	Total
2010	UK pence	52.07				52.07
	US cents	84				84
2011	UK pence	26.02	25.68	25.90	26.82	104.42
	US cents	42	42	42	42	168
2012	UK pence	30.57	30.90	30.10	33.53	125.10
	US cents	48	48	48	54	198
2013	UK pence	36.01	35.01	34.58	34.80	140.40
	US cents	54	54	54	57	219
2014	**UK pence**	**34.24**	**34.84**	**35.76**	**38.26**	**143.10**
	US cents	**57**	**58.5**	**58.5**	**60**	**234**

[a] Dividends announced and paid by the company on ordinary and preference shares are provided in Financial statements Note 8.

UK foreign exchange controls on dividends

There are currently no UK foreign exchange controls or restrictions on remittances of dividends on the ordinary shares or on the conduct of the company s operations, other than restrictions applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

There are no limitations, either under the laws of the UK or under the company s Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Shareholder taxation information

This section describes the material US federal income tax and UK taxation consequences of owning ordinary shares or ADSs to a US holder who holds the ordinary shares or ADSs as capital assets for tax purposes. It does not apply, however, interalia to members of special classes of holders some of which may be subject to other rules, including: tax-exempt entities, life insurance companies, dealers in securities, traders in securities that elect a mark-to-market method of accounting for securities holdings, investors liable for alternative minimum tax, holders that, directly or indirectly, hold 10% or more of the company s voting stock, holders that hold the shares or ADSs as part of a straddle or a hedging or conversion transaction, holders that purchase or sell the shares or ADSs as part of a wash sale for US federal income tax purposes, or holders whose functional currency is not the US dollar. In addition, if a partnership holds the shares or ADSs, the US federal income tax treatment of a partner will generally depend on the status of the partner and the tax treatment of the partnership and may not be described fully below.

A US holder is any beneficial owner of ordinary shares or ADSs that is for US federal income tax purposes (i) a citizen or resident of the US, (ii) a US domestic corporation, (iii) an estate whose income is subject to US federal income taxation regardless of its source, or (iv) a trust if a US court can exercise primary supervision over the trust s administration and one or more US persons are authorized to control all substantial decisions of the trust.

This section is based on the tax laws of the United States, including the Internal Revenue Code of 1986, as amended, its legislative history, existing and proposed US Treasury regulations thereunder, published rulings and court decisions, and the taxation laws of the UK, all as currently in effect, as well as the income tax convention between the US and the UK that entered into force on 31 March 2003 (the Treaty). These laws are subject to change, possibly on a retroactive basis. This section further assumes that each obligation in the Deposit Agreement and any related agreement will be performed in accordance with its terms.

For purposes of the Treaty and the estate and gift tax Convention (the Estate Tax Convention) and for US federal income tax and UK taxation purposes, a holder of ADRs evidencing ADSs will be treated as the owner of the company s ordinary shares represented by those ADRs. Exchanges of ordinary shares for ADRs and ADRs for ordinary shares generally will not be subject to US federal income tax or to UK taxation other than stamp duty or stamp duty reserve tax, as described below.

Investors should consult their own tax adviser regarding the US federal, state and local, UK and other tax consequences of owning and disposing of ordinary shares and ADSs in their particular circumstances, and in particular whether they are eligible for the benefits of the Treaty in respect of their investment in the shares or ADSs.

Taxation of dividends

UK taxation

Under current UK taxation law, no withholding tax will be deducted from dividends paid by the company, including dividends paid to US holders. A shareholder that is a company resident for tax purposes in the UK or trading in the UK through a permanent establishment generally will not be taxable in the UK on a dividend it receives from the company. A shareholder who is an individual resident for tax purposes in the UK is subject to UK tax but entitled to a tax credit on cash dividends paid on ordinary shares or ADSs of the company equal to one-ninth of the cash dividend.

US federal income taxation

A US holder is subject to US federal income taxation on the gross amount of any dividend paid by the company out of its current or accumulated earnings and profits (as determined for US federal income tax purposes). Dividends paid to a non-corporate US holder that constitute qualified dividend income will be taxable to the holder at a preferential rate, provided that the holder has a holding period in the ordinary shares or ADSs of more than 60 days during the 121-day period beginning 60 days before the ex-dividend date and meets other holding period requirements. Dividends paid by the company with respect to the ordinary shares or ADSs will generally be qualified dividend income.

As noted above in UK taxation, a US holder will not be subject to UK withholding tax. Accordingly, a US holder will include only the dividend actually received from the company in gross income for US federal income tax purposes, and the receipt of a dividend will not entitle the US holder to a foreign tax credit.

For US federal income tax purposes, a dividend must be included in income when the US holder, in the case of ordinary shares, or the Depositary, in the case of ADSs, actually or constructively receives the dividend and will not be eligible for the dividends-received deduction generally allowed to US corporations in respect of dividends received from other US corporations. Dividends will be income from sources outside the US and generally will be passive category income or, in the case of certain US holders, general category income , each of which is treated separately for purposes of computing a US holder s foreign tax credit limitation.

The amount of the dividend distribution on the ordinary shares that is paid in pounds sterling will be the US dollar value of the pounds sterling payments made, determined at the spot pounds sterling/US dollar rate on the date the dividend distribution is includible in income, regardless of whether the payment is, in fact, converted into US dollars. Generally, any gain or loss resulting from currency exchange fluctuations during the period from the date the pounds sterling dividend payment is includible in income to the date the payment is converted into US dollars will be treated as ordinary income or loss and will not be eligible for the

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preferential tax rate on qualified dividend income. The gain or loss generally will be income or loss from sources within the US for foreign tax credit limitation purposes.

Distributions in excess of the company s earnings and profits, as determined for US federal income tax purposes, will be treated as a return of capital to the extent of the US holder s basis in the ordinary shares or ADSs and thereafter as capital gain, subject to taxation as described in Taxation of capital gains US federal income taxation section below.

In addition, the taxation of dividends may be subject to the rules for passive foreign investment companies (PFIC), described below under Taxation of capital gains US federal income taxation . Distributions made by a PFIC do not constitute qualified dividend income and are not eligible for the preferential tax rate applicable to such income.

Taxation of capital gains

UK taxation

A US holder may be liable for both UK and US tax in respect of a gain on the disposal of ordinary shares or ADSs if the US holder is (i) a citizen of the US resident or ordinarily resident in the UK, (ii) a US domestic corporation resident in the UK by reason of its business being managed or controlled in the UK or (iii) a citizen of the US that carries on a trade or profession or vocation in the UK through a branch or agency or a corporation that carries on a trade, profession or vocation in the UK, through a permanent establishment, and that has used, held, or acquired the ordinary shares or ADSs for the purposes of such trade, profession or vocation of such branch, agency or permanent establishment. However, such persons may be entitled to a tax credit against their US federal income tax liability for the amount of UK capital gains tax or UK corporation tax on chargeable gains (as the case may be) that is paid in respect of such gain.

Under the Treaty, capital gains on dispositions of ordinary shares or ADSs generally will be subject to tax only in the jurisdiction of residence of the relevant holder as determined under both the laws of the UK and the US and as required by the terms of the Treaty.

Under the Treaty, individuals who are residents of either the UK or the US and who have been residents of the other jurisdiction (the US or the UK, as the case may be) at any time during the six years immediately preceding the relevant disposal of ordinary shares or ADSs may be subject to tax with respect to capital gains arising from a disposition of ordinary shares or ADSs of the company not only in the jurisdiction of which the holder is resident at the time of the disposition but also in the other jurisdiction.

US federal income taxation

A US holder who sells or otherwise disposes of ordinary shares or ADSs will recognize a capital gain or loss for US federal income tax purposes equal to the difference between the US dollar value of the amount realized on the disposition and the US holder s tax basis, determined in US dollars, in the ordinary shares or ADSs. Any such capital gain or loss generally will be long-term gain or loss, subject to tax at a preferential rate for a non-corporate US holder, if the US holder s holding period for such ordinary shares or ADSs exceeds one year.

Gain or loss from the sale or other disposition of ordinary shares or ADSs will generally be income or loss from sources within the US for foreign tax credit limitation purposes. The deductibility of capital losses is subject to limitations.

We do not believe that ordinary shares or ADSs will be treated as stock of a passive foreign investment company, or PFIC, for US federal income tax purposes, but this conclusion is a factual determination that is made annually and thus is subject to change. If we are treated as a PFIC, unless a US holder elects to be taxed annually on a mark-to-market basis with respect to ordinary shares or ADSs, any gain realized on the sale or other disposition of ordinary shares or ADSs would in general not be treated as capital gain. Instead, a US holder would be treated as if he or she had realized such gain rateably over the holding period for ordinary shares or ADSs and would be taxed at the highest tax rate in effect for each such year to which the gain was allocated, in addition to which an interest charge in respect of the tax attributable to each such year would apply. Certain excess distributions would be similarly treated if we were treated as a PFIC.

Additional tax considerations

Scrip Dividend Programme

The company has an optional Scrip Programme, wherein holders of BP ordinary shares or ADSs may elect to receive any dividends in the form of new fully paid ordinary shares or ADSs of the company instead of cash. Please consult your tax adviser for the consequences to you.

UK inheritance tax

The Estate Tax Convention applies to inheritance tax. ADSs held by an individual who is domiciled for the purposes of the Estate Tax Convention in the US and is not for the purposes of the Estate Tax Convention a national of the UK will not be subject to UK inheritance tax on the individual s death or on transfer during the individual s lifetime unless, among other things, the ADSs are part of the business property of a permanent establishment situated in the UK used for the performance of independent personal services. In the exceptional case where ADSs are subject to both inheritance tax and US federal gift or estate tax, the Estate Tax Convention generally provides for tax payable in the US to be credited against tax payable in the UK or for tax paid in the UK to be credited against tax payable in the US, based on priority rules set forth in the Estate Tax Convention.

UK stamp duty and stamp duty reserve tax

The statements below relate to what is understood to be the current practice of HM Revenue & Customs in the UK under existing law.

Provided that any instrument of transfer is not executed in the UK and remains at all times outside the UK and the transfer does not relate to any matter or thing done or to be done in the UK, no UK stamp duty is payable on the acquisition or transfer of ADSs. Neither will an agreement to transfer ADSs in the form of ADRs give rise to a liability to stamp duty reserve tax.

Purchases of ordinary shares, as opposed to ADSs, through the CREST system of paperless share transfers will be subject to stamp duty reserve tax at 0.5%. The charge will arise as soon as there is an agreement for the transfer of the shares (or, in the case of a conditional agreement, when the condition is fulfilled). The stamp duty reserve tax will apply to agreements to transfer ordinary shares even if the agreement is made outside the UK between two non-residents. Purchases of ordinary shares outside the CREST system are subject either to stamp duty at a rate of £5 per £1,000 (or part, unless the stamp duty is less than £5, when no stamp duty is charged), or stamp duty reserve tax at 0.5%. Stamp duty and stamp duty reserve tax are generally the liability of the purchaser.

A subsequent transfer of ordinary shares to the Depositary s nominee will give rise to further stamp duty at the rate of £1.50 per £100 (or part) or stamp duty reserve tax at the rate of 1.5% of the value of the ordinary shares at the time of the transfer. For ADR holders electing to receive ADSs instead of cash, after the 2012 first quarter dividend payment HM Revenue & Customs no longer seeks to impose 1.5% stamp duty reserve tax on issues of UK shares and securities to non-EU clearance services and depositary receipt systems.

US Medicare Tax

A US holder that is an individual or estate, or a trust that does not fall into a special class of trusts that is exempt from such tax, is subject to a 3.8% tax on the lesser of (1) the US holder s net investment income (or undistributed net investment income in the case of an estate or trust) for the relevant taxable year and (2) the excess of the US holder s modified adjusted gross income for the taxable year over a certain threshold (which in the case of individuals is between $125,000 and $250,000, depending on the individual s circumstances). A holder s net investment income generally includes its dividend income and its net gains from the disposition of shares or ADSs, unless such dividend income or net gains are derived in the ordinary course of the conduct of a trade or business (other than a trade or business that consists of certain passive or trading activities). If you are a US holder that is an individual, estate or trust, you are urged to consult your tax advisors regarding the applicability of the Medicare tax to your income and gains in respect of your investment in the shares or ADSs.

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Major shareholders

The disclosure of certain major and significant shareholdings in the share capital of the company is governed by the Companies Act 2006, the UK Financial Conduct Authority s Disclosure and Transparency Rules (DTR) and the US Securities Exchange Act of 1934.

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[a]	659	0.24	95.14
Totals	271,335	100.00	100.00

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

Register of holders of American depositary shares (ADSs) as at 31 December 2014[a]

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[b]	1	0.00	92.54
Totals	96,506	100.00	100.00

[a] One ADS represents six 25 cent ordinary shares.

[b] 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.

In accordance with DTR 5, we have received notification that as at 31 December 2014 BlackRock, Inc held 5.91%, The Capital Group Companies, Inc held 3.31% and Legal & General Group plc held 3.21% of the voting rights of the issued share capital of the company. As at 17 February 2015 BlackRock, Inc held 6.25%, The Capital Group Companies, Inc held 3.51% and Legal & General Group plc held 3.27% of the voting rights of the issued share capital of the company.

Under the US Securities Exchange Act of 1934 BP has received notification of the following interests as at 17 February 2015:

Holder	Holding of ordinary shares	Percentage of ordinary share capital excluding shares held in treasury
JPMorgan Chase Bank N.A., depositary for ADSs, through its nominee Guaranty Nominees Limited	5,301,883,023	29.07
BlackRock, Inc.	1,139,520,000	6.25

The company s major shareholders do not have different voting rights.

The company has also been notified of the following interests in preference shares as at 17 February 2015:

Holder	Holding of 8% cumulative first preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	945,000	13.07
M & G Investment Management Ltd.	528,150	7.30
Duncan Lawrie Ltd.	364,876	5.04

Holder	Holding of 9% cumulative second preference shares	Percentage of class
The National Farmers Union Mutual Insurance Society	987,000	18.03
M & G Investment Management Ltd.	644,450	11.77
Smith & Williamson Investment Management Ltd.	333,200	6.09
Bank Julius Baer	294,000	5.37
Barclays Bank PLC.	279,172	5.10

In accordance with DTR 5.8.12, The Capital Group of Companies, Inc. notified the company on 24 September 2012 that due to their group reorganization their holdings would not be reported separately but as combined holdings, thereby taking their interest in shares above the 3% threshold as of 1 September 2012.

Smith and Williamson Holdings Limited disposed of its interest in 32,500 8% cumulative first preference shares during 2014.

In accordance with DTR 5.6, BlackRock, Inc. notified the company that its indirect interest in ordinary shares decreased below 5% during 2014.

UBS Investment Bank notified the company that its indirect interest in ordinary shares increased above 3% on 9 February 2015 and that it decreased below the notifiable threshold on 16 February 2015.

As at 17 February 2015, the total preference shares in issue comprised only 0.46% of the company s total issued nominal share capital (excluding shares held in treasury), the rest being ordinary shares.

Annual general meeting

The 2015 AGM will be held on Thursday 16 April 2015 at 11.30am at ExCeL London, One Western Gateway, Royal Victoria Dock, London, E16 1XL. A separate notice convening the meeting is distributed to shareholders, which includes an explanation of the items of business to be considered at the meeting.

All resolutions for which notice has been given will be decided on a poll. Ernst & Young LLP have expressed their willingness to continue in office as auditors and a resolution for their reappointment is included in the *Notice of BP Annual General Meeting 2015*.

Memorandum and Articles of Association

The following summarizes certain provisions of the company s Memorandum and Articles of Association and applicable English law. This summary is qualified in its entirety by reference to the UK Companies Act 2006 (the Act) and the company s Memorandum and Articles of Association. For information on where investors can obtain copies of the Memorandum and Articles of Association see Documents on display on page 251.

At the AGM held on 17 April 2008 shareholders voted to adopt new Articles of Association, largely to take account of changes in UK company law brought about by the Act. Further amendments to the Articles of Association were approved by shareholders at the AGM held on 15 April 2010. New Articles of Association are being proposed at our AGM in 2015.

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Objects and purposes

BP is incorporated under the name BP p.l.c. and is registered in England and Wales with the registered number 102498. The provisions regulating the operations of the company, known as its objects , were historically stated in a company s memorandum. The Act abolished the need to have object provisions and so at the AGM held on 15 April 2010 shareholders approved the removal of its objects clause together with all other provisions of its Memorandum that, by virtue of the Act, are treated as forming part of the company s Articles of Association.

Directors

The business and affairs of BP shall be managed by the directors. The company s Articles of Association provide that directors may be appointed by the existing directors or by the shareholders in a general meeting. Any person appointed by the directors will hold office only until the next general meeting and will then be eligible for re-election by the shareholders. A director may be removed by BP as provided for by applicable law and shall vacate office in certain circumstances as set out in the Articles of Association. There is no requirement for a director to retire on reaching any age.

The Articles of Association place a general prohibition on a director voting in respect of any contract or arrangement in which the director has a material interest other than by virtue of such director s interest in shares in the company. However, in the absence of some other material interest not indicated below, a director is entitled to vote and to be counted in a quorum for the purpose of any vote relating to a resolution concerning the following matters:

- The giving of security or indemnity with respect to any money lent or obligation taken by the director at the request or benefit of the company or any of its subsidiaries.
- Any proposal in which the director is interested, concerning the underwriting of company securities or debentures or the giving of any security to a third party for a debt or obligation of the company or any of its subsidiaries.
- Any proposal concerning any other company in which the director is interested, directly or indirectly (whether as an officer or shareholder or otherwise) provided that the director and persons connected with such director are not the holder or holders of 1% or more of the voting interest in the shares of such company.
- Any proposal concerning the purchase or maintenance of any insurance policy under which the director may benefit.

The Act requires a director of a company who is in any way interested in a contract or proposed contract with the company to declare the nature of the director s interest at a meeting of the directors of the company. The definition of interest includes the interests of spouses, children, companies and trusts. The Act also requires that a director must avoid a situation where a director has, or could have, a direct or indirect interest that conflicts, or possibly may conflict, with the company s interests. The Act allows directors of public companies to authorize such conflicts where appropriate, if a company s Articles of Association so permit. BP s Articles of Association permit the authorization of such conflicts. The directors may exercise all the powers of the company to borrow money, except that the amount remaining undischarged of all moneys borrowed by the company shall not, without approval of the shareholders, exceed the amount paid up on the share capital plus the aggregate of the amount of the capital and revenue reserves of the company. Variation of the borrowing power of the board may only be affected by amending the Articles of Association.

Remuneration of non-executive directors shall be determined in the aggregate by resolution of the shareholders. Remuneration of executive directors is determined by the remuneration committee. This committee is made up of non-executive directors only. There is no requirement of share ownership for a director s qualification.

Dividend rights; other rights to share in company profits; capital calls

If recommended by the directors of BP, BP shareholders may, by resolution, declare dividends but no such dividend may be declared in excess of the amount recommended by the directors. The directors may also pay interim dividends without obtaining shareholder approval. No dividend may be paid other than out of profits available for distribution, as

determined under IFRS and the Act. Dividends on ordinary shares are payable only after payment of dividends on BP preference shares. Any dividend unclaimed after a period of 12 years from the date of declaration of such dividend shall be forfeited and reverts to BP.

The directors have the power to declare and pay dividends in any currency provided that a sterling equivalent is announced. It is not the company s intention to change its current policy of paying dividends in US dollars. At the company s AGM held on 15 April 2010, shareholders approved the introduction of a Scrip Dividend Programme (Scrip Programme) and to include provisions in the Articles of Association to enable the company to operate the Scrip Programme. The Scrip Programme enables ordinary shareholders and BP ADS holders to elect to receive new fully paid ordinary shares (or BP ADSs in the case of BP ADS holders) instead of cash. The operation of the Scrip Programme is always subject to the directors decision to make the scrip offer available in respect of any particular dividend. Should the directors decide not to offer the scrip in respect of any particular dividend, cash will automatically be paid instead.

Apart from shareholders rights to share in BP s profits by dividend (if any is declared or announced), the Articles of Association provide that the directors may set aside:

- A special reserve fund out of the balance of profits each year to make up any deficit of cumulative dividend on the BP preference shares.
- A general reserve out of the balance of profits each year, which shall be applicable for any purpose to which the profits of the company may properly be applied. This may include capitalization of such sum, pursuant to an ordinary shareholders resolution, and distribution to shareholders as if it were distributed by way of a dividend on the ordinary shares or in paying up in full unissued ordinary shares for allotment and distribution as bonus shares.

Any such sums so deposited may be distributed in accordance with the manner of distribution of dividends as described above.

Holders of shares are not subject to calls on capital by the company, provided that the amounts required to be paid on issue have been paid off. All shares are fully paid.

Voting rights

The Articles of Association of the company provide that voting on resolutions at a shareholders meeting will be decided on a poll other than resolutions of a procedural nature, which may be decided on a show of hands. If voting is on a poll, every shareholder who is present in person or by proxy has one vote for every ordinary share held and two votes for every £5 in nominal amount of BP preference shares held. If voting is on a show of hands, each shareholder who is present at the meeting in person or whose duly appointed proxy is present in person will have one vote, regardless of the number of shares held, unless a poll is requested.

Shareholders do not have cumulative voting rights.

Holders on record of ordinary shares may appoint a proxy, including a beneficial owner of those shares, to attend, speak and vote on their behalf at any shareholders meeting.

Record holders of BP ADSs are also entitled to attend, speak and vote at any shareholders meeting of BP by the appointment by the approved depositary, JPMorgan Chase Bank N.A., of them as proxies in respect of the ordinary shares represented by their ADSs. Each such proxy may also appoint a proxy. Alternatively, holders of BP ADSs are entitled to vote by supplying their voting instructions to the depositary, who will vote the ordinary shares represented by their ADSs in accordance with their instructions.

Proxies may be delivered electronically.

Matters are transacted at shareholders meetings by the proposing and passing of resolutions, of which there are two types: ordinary or special. An annual general meeting must be held once in every year.

An ordinary resolution requires the affirmative vote of a majority of the votes of those persons voting at a meeting at which there is a quorum. A special resolution requires the affirmative vote of not less than three quarters of the persons voting at a meeting at which there is a quorum.

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Any AGM requires 21 days notice. The notice period for a general meeting is 14 days subject to the company obtaining annual shareholder approval, failing which, a 21-day notice period will apply.

Liquidation rights; redemption provisions

In the event of a liquidation of BP, after payment of all liabilities and applicable deductions under UK laws and subject to the payment of secured creditors, the holders of BP preference shares would be entitled to the sum of (1) the capital paid up on such shares plus, (2) accrued and unpaid dividends and (3) a premium equal to the higher of (a) 10% of the capital paid up on the BP preference shares and (b) the excess of the average market price over par value of such shares on the LSE during the previous six months. The remaining assets (if any) would be divided pro rata among the holders of ordinary shares.

Without prejudice to any special rights previously conferred on the holders of any class of shares, BP may issue any share with such preferred, deferred or other special rights, or subject to such restrictions as the shareholders by resolution determine (or, in the absence of any such resolutions, by determination of the directors), and may issue shares that are to be or may be redeemed.

Variation of rights

The rights attached to any class of shares may be varied with the consent in writing of holders of 75% of the shares of that class or on the adoption of a special resolution passed at a separate meeting of the holders of the shares of that class. At every such separate meeting, all of the provisions of the Articles of Association relating to proceedings at a general meeting apply, except that the quorum with respect to a meeting to change the rights attached to the preference shares is 10% or more of the shares of that class, and the quorum to change the rights attached to the ordinary shares is one third or more of the shares of that class.

Shareholders meetings and notices

Shareholders must provide BP with a postal or electronic address in the UK to be entitled to receive notice of shareholders meetings. Holders of BP ADSs are entitled to receive notices under the terms of the deposit agreement relating to BP ADSs. The substance and timing of notices are described on page 248 under the heading Voting rights.

Under the Act, the AGM of shareholders must be held within the six-month period once every year. All general meetings shall be held at a

time and place determined by the directors in the UK. If any shareholders meeting is adjourned for lack of quorum, notice of the time and place of the meeting may be given in any lawful manner, including electronically. Powers exist for action to be taken either before or at the meeting by authorized officers to ensure its orderly conduct and safety of those attending.

Limitations on voting and shareholding

There are no limitations, either under the laws of the UK or under the company s Articles of Association, restricting the right of non-resident or foreign owners to hold or vote BP ordinary or preference shares in the company other than limitations that would generally apply to all of the shareholders and limitations applicable to certain countries and persons subject to EU economic sanctions or those sanctions adopted by the UK government which implement resolutions of the Security Council of the United Nations.

Disclosure of interests in shares

The Act permits a public company to give notice to any person whom the company believes to be or, at any time during the three years prior to the issue of the notice, to have been interested in its voting shares requiring them to disclose certain information with respect to those interests. Failure to supply the information required may lead to disenfranchisement of the relevant shares and a prohibition on their transfer and receipt of dividends and other payments in respect of those shares. In this context the term interest is widely defined and will generally include an interest of any kind whatsoever in voting shares, including any interest of a holder of BP ADSs.

Called-up share capital

Details of the allotted, called-up and fully-paid share capital at 31 December 2014 are set out in Financial statements Note 29.

At the AGM on 10 April 2014, authorization was given to the directors to allot shares up to an aggregate nominal amount equal to $3,076 million. Authority was also given to the directors to allot shares for cash and to dispose of treasury shares, other than by way of rights issue, up to a maximum of $231 million, without having to offer such shares to existing shareholders. These authorities were given for the period until the next AGM in 2015 or 10 July 2015, whichever is the earlier. These authorities are renewed annually at the AGM.

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Purchases of equity securities by the issuer and affiliated purchasers

In March 2013 BP began a share repurchase, or buyback, programme (the buyback programme) with an expected total value of up to $8 billion. The decision to buy back shares followed the completion of the sale of BP s 50% interest in TNK-BP to Rosneft. The programme expected to return to BP shareholders an amount equivalent to the value of BP s original investment in TNK-BP and to exceed that required to offset the earnings per share dilution expected as a result of the sale of TNK-BP. It also reflected the reduction in BP s asset base following its $38-billion divestment programme. The buyback programme was completed in July 2014.

A further $2.3 billion of share repurchases were carried out in 2014 after the completion of the previously announced programme, funded by BP s continuing divestment of assets as announced in October 2013, and under the authority granted by shareholders at the 2014 AGM for BP to repurchase up to 1.8 billion ordinary shares.

The following table provides details of share repurchase, or buyback, activity as well as details of ordinary share purchases made by the Employee Share Ownership Plans (ESOPs) and other purchases of ordinary shares and ADSs made to satisfy the requirements of certain employee share-based payment plans.

	Total number of shares purchased[a]	**Average price paid per share $**	Number of shares purchased by ESOPs or for certain employee share-based payment plans[b]	Number of shares purchased as part of the programme[c]	Maximum approximate dollar value of shares yet to be purchased under the programme $ million
2014					
January 2 January 31	**162,240,000**	**8.09**		162,240,000	1,194
February 3 February 28	**48,436,545**	**8.06**	2,000,000	46,436,545	819
March 3 March 31	**36,410,000**	**8.03**		36,410,000	527
April 1 April 30	**17,980,000**	**8.16**		17,980,000	380
May 1 May 30	**17,386,000**	**8.54**		17,386,000	232
June 2 June 30	**18,082,500**	**8.68**		18,082,500	75
July 1 July 31	**23,927,485**	**8.57**		23,927,485	
August 1 August 29	**70,519,200**	**8.05**	8,300,000	62,219,200	
September 1 September 30	**123,054,453**	**7.66**		123,054,453	
October 1 October 31	**75,398,500**	**7.02**		75,398,500	
November 3 November 7	**8,029,320**	**7.02**		8,029,320	
December 2 December 22	**51,149,002**	**6.28**	30,400,000	20,749,002	
2015					
January 9 January 30	**31,600,000**	**6.27**	31,600,000		
February 2 to February 5	**6,960,000**	**6.50**	6,960,000		

[a] All share purchases were of ordinary shares of 25 cents each and/or ADSs (each representing six ordinary shares) and were on/open market transactions.

[b] Transactions represent the purchase of ordinary shares by ESOPs and other purchases of ordinary shares and ADSs made to satisfy requirements of certain employee share-based payment plans.

[c] At the AGMs on 11 April 2013 and 10 April 2014, authorization was given to the company to repurchase up to 1.9 billion and 1.8 billion ordinary shares, respectively, for the periods until the next AGM in 2014 and 2015 or 11 July 2014 and 10 July 2015 respectively, being the latest dates by which an AGM must be held for the relevant year. This authorization is renewed annually at the AGM. The total number of ordinary shares repurchased during 2014 was 611,913,005 at a cost of $4,796 million (including transaction costs) representing 3.36% of BP s issued share capital excluding shares held in treasury on 31 December 2014. All ordinary shares repurchased in 2013 and 2014 were cancelled in order to reduce BP s issued share capital.

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Fees and charges payable by ADSs holders

The Depositary collects fees for delivery and surrender of ADSs directly from investors depositing shares or surrendering ADSs for the purpose of withdrawal or from intermediaries acting for them. The Depositary collects fees for making distributions to investors by deducting those fees from the amounts distributed or by selling a portion of the distributable property to pay the fees.

The charges of the Depositary payable by investors are as follows:

Type of service	Depositary actions	Fee
Depositing or substituting the underlying shares	Issuance of ADSs against the deposit of shares, including deposits and issuances in respect of: Share distributions, stock splits, rights, merger. Exchange of securities or other transactions or event or other distribution affecting the ADSs or deposited securities.	\$5.00 per 100 ADSs (or portion thereof) evidenced by the new ADSs delivered.
Selling or exercising rights	Distribution or sale of securities, the fee being an amount equal to the fee for the execution and delivery of ADSs that would have been charged as a result of the deposit of such securities.	\$5.00 per 100 ADSs (or portion thereof).
Withdrawing an underlying share	Acceptance of ADSs surrendered for withdrawal of deposited securities.	\$5.00 for each 100 ADSs (or portion thereof) evidenced by the ADSs surrendered.
Expenses of the Depositary	Expenses incurred on behalf of holders in connection with: Stock transfer or other taxes and governmental charges. Delivery by cable, telex, electronic and facsimile transmission. Transfer or registration fees, if applicable, for the registration of transfers of underlying shares. Expenses of the Depositary in connection with the conversion of foreign currency into US dollars (which are paid out of such foreign currency).	Expenses payable are subject to agreement between the company and the Depositary by billing holders or by deducting charges from one or more cash dividends or other cash distributions.

Fees and payments made by the Depositary to the issuer

The Depositary has agreed to reimburse certain company expenses related to the company s ADS programme and incurred by the company in connection with the ADS programme arising during the year ended 31 December 2014. The Depositary reimbursed to the company, or paid amounts on the company s behalf to third parties, or waived its fees and expenses, of $3,612,749.32 for the year ended 31 December 2014.

The table below sets out the types of expenses that the Depositary has agreed to reimburse and the fees it has agreed to waive for standard costs associated with the administration of the ADS programme relating to the year ended 31 December 2014. The Depositary has also paid certain expenses directly to third parties on behalf of the company.

Category of expense reimbursed, waived or paid directly to third parties	Amount reimbursed, waived or paid directly to third parties for the year ended 31 December 2014 $
NYSE listing fees reimbursed	400,000.00
Service fees and out of pocket expenses waived[a]	2,223,141.13
Broker fees reimbursed[b]	901,224.03
Other third-party mailing costs reimbursed[c]	88,384.16
Total	3,612,749.32

[a] Includes fees in relation to transfer agent costs and costs of the BP Scrip Dividend Programme operated by JPMorgan Chase Bank, N.A.

[b] Broker reimbursements are fees payable to Broadridge for the distribution of hard copy material to ADR beneficial holders in the Depository Trust Company. Corporate materials include information related to shareholders meetings and related voting instructions. These fees are SEC approved.

[c] Payment of fees to Precision IR for investor support.

Under certain circumstances, including removal of the Depositary or termination of the ADR programme by the company, the company is required to repay the Depositary amounts reimbursed and/or expenses paid to or on behalf of the company during the 12-month period prior to notice of removal or termination.

Documents on display

BP Annual Report and Form 20-F 2014 and *BP Strategic Report 2014* are available online at *bp.com/annualreport*. To obtain a hard copy of BP s complete audited financial statements, free of charge, UK based shareholders should contact BP Distribution Services by calling +44 (0)870 241 3269 or by emailing *bpdistributionservices@bp.com*. If based in the US or Canada shareholders should contact Issuer Direct by calling +1 888 301 2505 or by emailing *bpreports@precisionir.com.*

The company is subject to the information requirements of the US Securities Exchange Act of 1934 applicable to foreign private issuers. In accordance with these requirements, the company files its Annual Report and Form 20-F and other related documents with the SEC. It is possible to read and copy documents that have been filed with the SEC at its headquarters located at 100 F Street, NE, Washington, DC 20549, US. You may also call the SEC at +1 800-SEC-0330. In addition, BP s SEC filings are available to the public at the SEC s website. BP discloses on its website at *bp.com/NYSEcorporategovernancerules* and in this report (see Corporate governance practices (Form 20-F Item 16G) on page 239) significant ways (if any) in which its corporate governance practices differ from those mandated for US companies under NYSE listing standards.

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Shareholding administration

If you have any queries about the administration of shareholdings, such as change of address, change of ownership, dividend payments, the Scrip Programme or to change the way you receive your company documents (such as the *BP Annual Report and Form 20-F, BP Strategic Report* and *Notice of BP Annual General Meeting*) please contact the BP Registrar or the BP ADS Depositary.

Ordinary and preference shareholders

The BP Registrar

Capita Asset Services

The Registry, 34 Beckenham Road

Beckenham, Kent BR3 4TU, UK

Freephone in UK 0800 701107

From outside the UK +44 (0)20 3170 3678

Fax +44 (0)1484 601512

ADS holders

JPMorgan Chase Bank, N.A. PO Box 64504

St Paul, MN 55164-0504, US

Toll-free in US and Canada +1 877 638 5672

From outside the US and Canada +1 651 306 4383

Exhibits

The following documents are filed in the Securities and Exchange Commission (SEC) EDGAR system, as part of this Annual Report on Form 20-F, and can be viewed on the SEC s website.

Exhibit 1	Memorandum and Articles of Association of BP p.l.c.*
Exhibit 4.1	The BP Executive Directors Incentive Plan
Exhibit 4.2	Amended BP Deferred Annual Bonus Plan 2005**
Exhibit 4.3	Amended Director s Secondment Agreement for R W Dudley******
Exhibit 4.4	Amended Director s Service Contract and Secondment Agreement for R W Dudley*
Exhibit 4.6	Director s Service Contract for I C Conn***
Exhibit 4.7	Director s Service Contract for Dr B Gilvary****
Exhibit 7	Computation of Ratio of Earnings to Fixed Charges (Unaudited)

Exhibit 8	Subsidiaries (included as Note 35 to the Financial Statements)
Exhibit 10.1	Administrative Agreement dated as of 13 March 2014 among the US Environmental Protection Agency, BP p.l.c., and other BP subsidiaries
Exhibit 11	Code of Ethics*****
Exhibit 12	Rule 13a 14(a) Certifications
Exhibit 13	Rule 13a 14(b) Certifications#
Exhibit 15.1	Consent of DeGolyer and MacNaughton
Exhibit 15.2	Report of DeGolyer and MacNaughton

* Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2010.
** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2012.
*** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2004.
**** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2011.
***** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2009.
****** Incorporated by reference to the company s Annual Report on Form 20-F for the year ended 31 December 2013.
# Furnished only.
Included only in the annual report filed in the Securities and Exchange Commission EDGAR system.

The total amount of long-term securities of the Registrant and its subsidiaries authorized under any one instrument does not exceed 10% of the total assets of BP p.l.c. and its subsidiaries on a consolidated basis. The company agrees to furnish copies of any or all such instruments to the SEC on request.

Abbreviations, glossary and trade marks

ADR

American depositary receipt.

ADS

American depositary share. 1 ADS = 6 ordinary shares.

Barrel (bbl)

159 litres, 42 US gallons.

bcf/d

Billion cubic feet per day.

bcfe

Billion cubic feet equivalent.

bcma

Billion cubic metres per annum.

b/d

Barrels per day.

boe/d

Barrels of oil equivalent per day.

DoJ

US Department of Justice.

GAAP

Generally accepted accounting practice.

Gas

Natural gas.

GWh

Gigawatts per hour.

IFRS

International Financial Reporting Standards.

KPIs

Key performance indicators.

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 per day.

mmboe/d

Million barrels of oil equivalent per day.

mmBtu

Million British thermal units.

mmcf/d

Million cubic feet per day.

mmte

Million tonnes.

MWh

Megawatt per hour.

NGLs

Natural gas liquids.

PSA

Production-sharing agreement.

PTA

Purified terephthalic acid.

RC

Replacement cost.

SEC

The United States Securities and Exchange Commission.

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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.

Commodity trading contracts

BP s Upstream and Downstream segments both participate in regional and global commodity trading markets in order to manage, transact and hedge the crude oil, refined products and natural gas that the group either produces or consumes in its manufacturing operations. These physical trading activities, together with associated incremental trading opportunities, are discussed in Upstream on page 28 and in Downstream on page 31. The range of contracts the group enters into in its commodity trading operations is described below. Using these contracts, in combination with rights to access storage and transportation capacity, allows the group to access advantageous pricing differences between locations, time periods and arbitrage between markets.

Exchange-traded commodity derivatives

Contracts that are typically in the form of futures and options traded on a recognized exchange, such as Nymex, SGX and ICE. Such contracts are traded in standard specifications for the main marker crude oils, such as Brent and West Texas Intermediate; the main product grades, such as gasoline and gasoil; and for natural gas and power. Gains and losses, otherwise referred to as variation margins, are settled on a daily basis with the relevant exchange. These contracts are used for the trading and risk management of crude oil, refined products, and natural gas and power. Realized and unrealized gains and losses on exchange-traded commodity derivatives are included in sales and other operating revenues for accounting purposes.

Over-the-counter contracts

Contracts that are typically in the form of forwards, swaps and options. Some of these contracts are traded bilaterally between counterparties or through brokers, others may be cleared by a central clearing counterparty. These contracts can be used both for trading and risk management activities. Realized and unrealized gains and losses on over-the-counter (OTC) contracts are included in sales and other operating revenues for accounting purposes. Many grades of crude oil bought and sold use standard contracts including US domestic light sweet crude oil, commonly referred to as West Texas Intermediate, and a standard North Sea crude blend Brent, Forties, Oseberg and Ekofisk (BFOE). Forward contracts are used in connection with the purchase of crude oil supplies for refineries, products for marketing and sales of the group s oil production and refined products. The contracts typically contain standard delivery and settlement terms. These transactions call for physical delivery of oil with consequent operational and price risk. However, various means exist and are used from time to time, to settle obligations under the contracts in cash rather than through physical delivery. Because the physically settled transactions are delivered by cargo, the BFOE contract additionally specifies a standard volume and tolerance.

Gas and power OTC markets are highly developed in North America and the UK, where commodities can be bought and sold for delivery in future periods. These contracts are negotiated between two parties to purchase and sell gas and power at a specified price, with delivery and settlement at a future date. Typically, the contracts specify delivery terms for the underlying commodity. Some of these transactions are not settled physically as they can be achieved by transacting offsetting sale or purchase contracts for the same location and delivery period that are offset during the scheduling of delivery or dispatch. The contracts contain standard terms such as delivery point, pricing mechanism, settlement terms and specification of the commodity. Typically, volume, price and term (e.g. daily, monthly and balance of month) are the main variable contract terms.

Swaps are often contractual obligations to exchange cash flows between two parties. A typical swap transaction usually references a floating price and a fixed price with the net difference of the cash flows being settled. Options give the holder the right, but not the obligation, to buy or sell crude, oil products, natural gas or power at a specified price on or before a specific future date. Amounts under these derivative financial instruments are settled at expiry. Typically, netting agreements are used to limit credit exposure and support liquidity.

Spot and term contracts

Spot contracts are contracts to purchase or sell a commodity at the market price prevailing on or around the delivery date when title to the inventory is taken. Term contracts are contracts to purchase or sell a commodity at regular intervals over an agreed term. Though spot and term contracts may have a standard form, there is no offsetting mechanism in place. These transactions result in physical delivery with operational and price risk. Spot and term contracts typically relate to purchases of crude for a refinery, products for marketing, or third-party natural gas, or sales of the group s oil production, oil products or gas production to third parties. For accounting purposes, spot and term sales are included in sales and other operating revenues when title passes. Similarly, spot and term purchases are included in purchases for accounting purposes.

Dividend yield

Sum of the four quarterly dividends declared in the year as a percentage of the year-end share price on the respective exchange.

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

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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.

Free cash flow

Operating cash flow less net cash used in investing activities, as presented in the condensed group cash flow statement.

Gearing

See Net debt and net debt ratio definition.

Hydrocarbons

Liquids and natural gas. Natural gas is converted to oil equivalent at 5.8 billion cubic feet = 1 million barrels.

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 control

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

Joint operation

A joint 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.

Major projects

Have a BP net investment of at least $250 million, or are considered to be of strategic importance to BP or of a high degree of complexity.

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 Financial statements Note 25 for information on gross debt, which is the nearest equivalent measure to net debt on an IFRS basis.

Net wind generation capacity

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 gross data is the equivalent capacity on a gross-JV basis, which includes 100% of the capacity of equity-accounted entities where BP has partial ownership.

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.

Operating capital employed

Non-GAAP measure. Total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation.

Operating cash flow and operating cash

Net cash provided by (used in) operating activities as stated in the condensed group cash flow statement. When used in the context of a segment rather than the group, the terms refer to the segment s share thereof.

Operating management system (OMS)

BP s OMS helps us manage risks in our operating activities by setting out BP s principles for good operating practice. It brings together BP requirements on health, safety, security, the environment, social responsibility and operational reliability, as well as related issues, such as maintenance, contractor relations and organizational learning, into a common management system.

Organic capital expenditure

Excludes acquisitions, asset exchanges, and other inorganic capital expenditure. An analysis of capital expenditure by segment and region is shown in Financial statements Note 4.

Plant efficiency

Plant efficiency is calculated taking 100% less the ratio of total plant deferrals divided by installed production capacity. Plant deferrals include planned and unplanned deferrals associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoir). Plant deferrals include breakdowns, planned events, turnarounds, and weather.

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.

Proved reserves replacement ratio

The extent to which production is replaced by proved reserves additions. This ratio is expressed in oil equivalent terms and includes changes resulting from revisions to previous estimates, improved recovery, and extensions and discoveries.

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.

Refining marker margin (RMM)

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.

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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 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.

Tier 1 process safety events

Losses of primary containment from a process of greatest consequence causing harm to a member of the workforce or costly damage to equipment or exceeding defined quantities.

Tight gas

Natural gas reservoirs locked in hard sandstone rocks with low permeability, making the underground formation extremely tight.

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 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.

Unit cash margin

Net cash provided by operating activities for relevant projects in the Upstream segment, divided by the total number of barrels of oil and gas equivalent produced for the relevant projects. It excludes dividends and production for TNK-BP and Rosneft.

Trade marks

Trade marks of the BP group appear throughout this Annual Report and Form 20-F in italics.

They include:	
Aral	*Titanium Fluid Strength Technology*
	SaaBre
ARCO	*Wild Bean Cafe*
BP	
	Permasense is a trade mark of Permasense
Castrol	Limited.
	M&S Simply Food is a registered trade mark of Marks & Spencer plc.
EDGE	
Field of the Future	
Fluid Strength Technology	

The Directors report on pages 51-71, 90, 167-196 and 207-255 was approved by the board and signed on its behalf by David J Jackson, company secretary on 3 March 2015.

BP p.l.c.

Registered in England and Wales No. 102498

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Signatures

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

BP p.l.c.

(Registrant)

/s/ David J Jackson

Company secretary

3 March 2015

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