Supplementary Information – February 2011 Investor presentation

The information below has been provided to enhance understanding of the terminology and performance measures that have been used in the accompanying presentations.

Group Measures

Replacement cost profit and underlying replacement cost profit

Replacement cost profit or loss reflects the replacement cost of supplies. The replacement cost profit or loss for the period is arrived at by excluding from profit or loss inventory holding gains and losses and their associated tax effect. Replacement cost profit or loss for the group is not a recognized GAAP measure. Underlying replacement cost profit is replacement cost profit adjusted for non-operating items and fair value accounting effects.

Reconciliation of profit (loss) before interest and tax for the group to underlying replacement cost profit attributable to BP shareholders

$ million	2008	2009	2010
Profit (loss) before interest and tax	35,239	26,426	(3,702)
Inventory holding (gains) losses	6,488	(3,922)	(1,784)
Replacement cost profit (loss) before interest and tax	41,727	22,504	(5,486)
Less non-operating items:			
- Gulf of Mexico oil spill response	-	-	(40,858)
- Other non-operating items	(1,276)	(827)	3,629
	(1,276)	(827)	(37,229)
Less fair value accounting effects	229	658	39
Underlying replacement cost profit before interest and tax	42,774	22,673	31,704
Finance costs and net finance income or expense relating to pensions and other post-retirement benefits	(956)	(1,302)	(1,123)
Less Finance costs relating to Gulf of Mexico oil spill response	-	-	(77)
	(956)	(1,302)	(1,046)
Taxation on an underlying replacement cost basis	(15,066)	(6,613)	(9,741)
Minority interest	(509)	(181)	(395)
Underlying replacement cost profit attributable to BP shareholders	26,243	14,577	20,522

Reconciliation of replacement cost profit before interest and tax for segments to underlying replacement cost profit before interest and tax

$ million	2008	2009	2010
Exploration and Production			
Replacement cost profit before interest and tax	38,308	24,800	30,886
Less non-operating items	(990)	2,265	3,199
Less fair value accounting effects	(282)	919	(3)
Underlying replacement cost profit before interest and tax	39,580	21,616	27,690
Refining and Marketing			
Replacement cost profit before interest and tax	4,176	743	5,555
Less non-operating items	347	(2,603)	630
Less fair value accounting effects	511	(261)	42
Underlying replacement cost profit before interest and tax	3,318	3,607	4,883
Other businesses and corporate			
Replacement cost profit (loss) before interest and tax	(1,223)	(2,322)	(1,516)
Less non-operating items	(633)	(489)	(200)
Less fair value accounting effects	-	-	-
Underlying replacement cost profit before interest and tax	(590)	(1,833)	(1,316)
Consolidation adjustment	466	(717)	447
Underlying replacement cost profit before interest and tax	42,774	22,673	31,704

Inventory holding gains and losses

Inventory holding gains and losses represent the difference between the cost of sales calculated using the average cost to BP of supplies acquired during the period and the cost of sales calculated on the first-in first-out (FIFO) method after adjusting for any changes in provisions where the net realizable value of the inventory is lower than its cost. Under the FIFO method, which we use for IFRS reporting, the cost of inventory charged to the income statement is based on its historic cost of purchase, or manufacture, rather than its replacement cost. In volatile energy markets, this can have a significant distorting effect on reported income. The amounts disclosed represent the difference between the charge (to the income statement) for inventory on a FIFO basis (after adjusting for any related movements in net realizable value provisions) and the charge that would have arisen if an average cost of supplies was used for the period. For this purpose, the average cost of supplies during the period is principally calculated on a monthly basis by dividing the total cost of inventory acquired in the period by the number of barrels acquired. The amounts disclosed are not separately reflected in the financial statements as a gain or loss. No adjustment is made in respect of the cost of inventories held as part of a trading position and certain other temporary inventory positions.

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

Non-operating items

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

Fair value accounting effects

BP uses derivative instruments to manage the economic exposure relating to inventories above normal operating requirements of crude oil, natural gas and petroleum products as well as certain contracts to supply physical volumes at future dates. Under IFRS, these inventories and contracts are recorded at historic cost and on an accruals basis respectively. The related derivative instruments, however, are required to be recorded at fair value with gains and losses recognized in income because hedge accounting is either not permitted or not followed, principally due to the impracticality of effectiveness testing requirements. Therefore, measurement differences in relation to recognition of gains and losses occur. Gains and losses on these inventories and contracts 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.

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

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

The way that BP manages the economic exposures described above, and measures performance internally, differs from the way these activities are measured under IFRS. BP calculates this difference for consolidated entities by comparing the IFRS result with management's internal measure of performance, under which the inventory and the supply and capacity contracts in question are valued based on fair value using relevant forward prices prevailing at the end of the period. We believe that disclosing management's estimate of this difference provides useful information for investors because it enables investors to see the economic effect of these activities as a whole. The impacts of fair value accounting effects, relative to management's internal measure of performance, are shown in the table above. A reconciliation to GAAP information is set out below:

			$million
	2008	**2009**	**2010**
Exploration and Production			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	38,590	23,881	30,889
Impact of fair value accounting effects	(282)	919	(3)
Replacement cost profit before interest and tax	38,308	24,800	30,886
Refining and Marketing			
Replacement cost profit before interest and tax adjusted for fair value accounting effects	3,665	1,004	5,513
Impact of fair value accounting effects	511	(261)	42
Replacement cost profit before interest and tax	4,176	743	5,555

Net debt ratio – Ratio of net debt (finance debt, including the fair value of associated derivative financial instruments that are used to hedge foreign exchange and interest rate risks relating to finance debt, for which hedge accounting is claimed, less cash and cash equivalents) to net debt plus equity.

The table below presents BP's Debt to Debt plus Equity ratio on a gross basis as net debt is not a recognized GAAP measure:

			$million
	2008	**2009**	**2010**
Gross debt	33,204	34,627	45,336
Less: Fair value asset (liability) of hedges related to finance debt	(34)	127	916
	33,238	34,500	44,420
Less: Cash and cash equivalents	8,197	8,339	18,556
Net debt	25,041	26,161	25,864
Equity	92,109	102,113	95,891
Gross debt to gross debt-plus-equity ratio	26%	25%	32%
Net debt to net debt-plus-equity ratio	21%	20%	21%

Cash costs – Cash costs are a subset of production and manufacturing expenses plus distribution and administration expenses. They represent the substantial majority of the expenses in these line items but exclude associated non-operating items, and certain costs that are variable, primarily with volumes (such as freight costs). They are the principal operating and overhead costs that management considers to be most directly under their control although they include certain foreign exchange and commodity price effects.

Inorganic capital expenditure (capex) for the Group is equal to acquisitions and asset exchanges plus, for 2008, the capital expenditure relating to our transactions with Husky and Chesapeake and for 2010, the accounting for our transaction with Value Creation Inc. and for the purchase of additional interests in the Valhall and Hod fields in the North Sea.

Organic capital expenditure (Organic Capex) is equal to total capital expenditure and acquisitions less inorganic capital expenditure.

Operating capital employed – total assets (excluding goodwill) less total liabilities, excluding finance debt and current and deferred taxation. BP publishes segment results on a pre-tax basis and publishes operating capital employed for each segment.

Exploration and Production:

Production – Crude oil, natural gas liquids (NGL) and natural gas produced from consolidated operations, and BP's interest in joint ventures and associates. Converted to barrels of oil equivalent (boe) at 1 barrel of NGL = 1 boe and 5,800 standard cubic feet of natural gas = 1 boe. Historical volumes shown are as previously reported. Projections reflect indications, not targets. This is not an amount that can be targeted, nor is it a specific forecast for a year.

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

(i) The area of the reservoir considered as proved includes:

(a) The area identified by drilling and limited by fluid contacts, if any, and

(b) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(a) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(b) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The main marker prices used for 2010 were $79.02/bbl Brent (oil) and $4.37/mmBtu Henry Hub (natural gas).

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

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

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

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

Reserve replacement ratio – The ratio of reserves booked through discoveries, extensions, net revisions and improved recovery to production for the period. This measure excludes the effects of acquisitions and disposals. Unless stated otherwise, this ratio is based on a combined basis which includes both subsidiaries and equity-accounted entities, excluding acquisitions and disposals and is based on reserves estimated in accordance with the SEC rules and relevant guidance.

Total Resources – Total resources are the estimated quantities of crude oil, bitumen, natural gas liquids and natural gas likely to be produced in the fullness of time from fields in which BP has current entitlement. The estimation, categorization and progression of total resources is founded on a discrete deterministic base case informed by interpretation and integration of the relevant data.

Total resources are divided into reserves and contingent resources and are evaluated using existing economic conditions.

Non-proved resources – that portion of our total resources that has not yet been categorised within our proved reserves.

Resources replacement ratio: The ratio of resources booked through discoveries, extensions, net revisions and improved recovery to production for the period. This measure excludes the effects of acquisitions and disposals. Unless stated otherwise, this ratio is based on a combined basis which includes both subsidiaries and equity-accounted entities, excluding acquisitions and disposals.

Refining and Marketing:

Global Indicator Refining Margin (GIM) – The Global Indicator Refining Margin is the average of regional indicator margins weighted for BP's crude refining capacity in each region. Each regional indicator margin is based on a single representative crude with product yields characteristic of the typical level of upgrading complexity. 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. GIM data for comparative years has been restated for BP's 2010 portfolio.

Refining Marker Margin: – RMMs are simplified regional indicators based on product yields and a "marker" crude oil deemed appropriate for the region.

Competitive performance ranges – The R&M segment's measures for ROACE and underlying net income per barrel are compared with the nearest comparative measures of our super-major competitors, as calculated using published competitor data.

Performance improvement: The 'performance improvement' is the improvement in BP's R&M segment pre-tax underlying replacement cost profit for each year since 2007, after adjusting for the effects of the refining and petrochemical environment, foreign exchange impacts and price-lag effects for crude and product purchases.

Reconciliation of R&M underlying replacement cost profit before interest and tax to 'Performance improvement'

$billion

	2007	2008	2009	2010	Cum
Underlying replacement cost profit before interest and tax	3.9	3.3	3.6	4.9	
Year-on-year change in underlying replacement cost profit before interest and tax		(0.6)	0.3	1.3	1.0
Adjustment for refining and petrochemical environment, foreign exchange impacts and price-lag effects for crude and product purchases.		(3.3)	(1.8)	0.4	(4.7)
Underlying year-on-year performance improvement		2.7	2.1	0.9	5.7
		(0.6)	0.3	1.3	1.0

Net investment – R&M organic capital expenditure less proceeds from disposals, adjusted in 2005 to include proceeds of $8.3 billion for the sale of Innovene, which was not part of the R&M segment in 2005.

Pre-tax returns – R&M's underlying replacement cost profit before interest and tax, divided by R&M's operating capital employed (as defined for the group above).

Underlying Net Income / barrel – R&M's underlying net income/ barrel is calculated by taking R&M's underlying replacement cost profit before interest and tax, deducting tax at the group effective tax rate on replacement cost profit (excluding the impact of the Gulf of Mexico oil spill) and then dividing this notional post tax underlying replacement cost profit by the R&M segment's total refining capacity.

Underlying post-tax return on average capital employed (ROACE) for R&M segment

- *Numerator* – Replacement cost profit for the period, adjusted for non-operating items and fair value accounting effects. The numerator is tax effected using the BP group effective tax rate on replacement cost profit (excluding the impact of the Gulf of Mexico oil spill).
- *Denominator* – Average capital employed, which equals the average of the operating capital employed for the R&M segment (excluding goodwill) on 1 January and 31 December of each year, including liabilities for current and deferred taxation allocated on the basis of the segment's relative percentage of the group's operating capital employed (excluding the impact of the Gulf of Mexico oil spill).

Reconciliation of R&M replacement cost profit before interest and tax to ROACE and to Net Income / bbl

			$million
	2008	**2009**	**2010**
Numerator for ROACE and NI/bbl			
Replacement cost profit before interest and tax	4,176	743	5,555
Non-operating items	(347)	2,603	(630)
Fair value accounting effects	(511)	261	(42)
R&M underlying profit	3,318	3,607	4,883
Taxation*	(1,194)	(1,190)	(1,514)
R&M underlying profit after tax	**2,124**	**2,417**	**3,369**
Denominator for ROACE			
Operating Capital Employed (excluding goodwill)	41,199	46,501	48,422
Liabilities for current and deferred taxation**	(5,814)	(6,387)	(6,857)
Capital Employed for R&M (excluding goodwill)	35,385	40,114	41,565
Average capital employed	**37,823**	**37,750**	**40,839**
R&M Underlying ROACE	**6%**	**6%**	**8%**
Denominator for NI/bbl			
Capacity (mmbbls)	988	975	973
R&M Underlying Net Income ($) per bbl	**2.1**	**2.5**	**3.5**

*BP does not present post-tax segment results. For the purposes of comparison with competitors, tax has been applied using the BP group effective tax rate on replaceiment cost profit, excluding the impact of the Gulf of Mexico oil spill.

** Liabilities for current and deferred taxation have been allocated to R&M on the basis of the segment's relative percentage share of the group's operating capital employed.

Group effective tax rate on replacement cost profit (excluding the impact of the Gulf of Mexico oil spill)	36%	33%	31%

Reconciliation of operating capital employed to capital employed

			$million
	2008	**2009**	**2010**
E&P	92,757	101,154	106,272
R&M	41,199	46,501	48,422
OB&C	742	1,882	14,383
GOM	–	–	(23,277)
Consolidation adjustment	(298)	(1,016)	(564)
Total operating capital employed	134,400	148,521	145,236
Liabilities for current and deferred taxation	(18,965)	(20,401)	(12,607)
Goodwill	9,878	8,620	8,598
Capital employed	125,313	136,740	141,227
Net assets	92,109	102,113	95,891
Finance debt	33,204	34,627	45,336
Capital employed	125,313	136,740	141,227