Supplementary Information:
- to accompany 10-Dec-2014 Upstream 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.

Production – Crude oil, condensate, natural gas liquids (NGLs) and natural gas produced by subsidiaries and equity-accounted entities. 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.

Total Resources – Total resources are the estimated quantities of crude oil, condensate, natural gas liquids, bitumen 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 categorized within our proved reserves.

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

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

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

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

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

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

<u>Undeveloped oil and gas reserves</u> – 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.

<u>Developed oil and gas reserves</u> – Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

<u>Reserves / resources to production ratio (R/P)</u> – The amount of a remaining reserves (or resources) divided by the current rate of production of those reserves (or resources). The metric is typically represented in units of years, and is an indicator of the remaining life of the reserves (or resources).

<u>Operating cash / ops cash</u> – Operating cash (or ops cash) is net cash provided by operating activities for the BP Group, the Upstream segment, or the applicable share thereof.

<u>Operating cash margin</u> – Operating cash margin is operating cash divided by the applicable number of barrels of oil equivalent produced.

<u>Operating efficiency</u> – Operating efficiency (OE) is the amount of actual production expressed as a percentage of the installed production capacity (IPC). IPC is the agreed rate achievable (measured at the export end of the system) when the existing production system (reservoir, wells, plant and export) is operated at full rate with no planned or unplanned deferrals.

<u>Plant efficiency</u> – Plant efficiency is calculated as 100%, less the ratio of total plant deferrals divided by IPC. Plant deferrals include planned and unplanned deferrals associated with the topside plant and, where applicable, the subsea equipment (excluding wells and reservoir). Plant deferrals are the result of breakdowns, planned events, TARS, and/or the impact of adverse weather.