Supplementary Information:
Upstream investor Day & Field Trip Oman December 2018

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

Resources and production

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.

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.

Developed oil and gas reserves – 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.

Production – Crude oil, condensate, natural gas liquids (NGLs), bitumen 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.

Financial and operating measures

Cash costs – Non-GAAP measure. Cash costs are a subset of production and manufacturing expenses plus distribution and administration expenses and exclude costs that are classified as non-operating items. They represent the substantial majority of the remaining expenses in these line items but exclude certain costs that are variable, primarily with volumes (such as freight costs). Management believes that the presentation of cash costs is a performance measure that provides investors with useful information regarding the company's financial condition because it considers these expenses to be the principal operating and overhead expenses that are most directly under their control although they also include certain foreign exchange and commodity price effects.

Development costs per barrel of oil equivalent (boe) – Development costs per boe equals development costs divided by the expected ultimate recovery in boe. Development costs are costs incurred after a decision has been taken to develop a reservoir area, including the costs of: (a) drilling, equipping and testing development wells; (b) production platforms, downhole and wellhead equipment, pipelines, production and initial treatment and storage facilities and utility and waste disposal systems; and (c) improved recovery systems and equipment.

Drilling efficiency – Drilling efficiency is the percentage of offshore wells delivered with top quartile performance based on calculated dry hole days per 10,000ft drilled. Dry hole days are the days spent drilling from spud (start of drilling) to total depth.

Operating efficiency – Operating efficiency (OE) is calculated as production for BP-operated sites, excluding US Lower 48 and adjusted for certain items including entitlement impacts in our production-sharing agreements divided by installed production capacity for BP-operated sites, excluding US Lower 48. Installed production capacity is the agreed rate achievable (measured at the export end of the system) when the installed production system (reservoir, wells, plant and export) is fully optimized and operated at full rate with no planned or unplanned deferrals.

Organic capital expenditure – Organic capital expenditure is a subset of capital expenditure and is a non-GAAP measure. Organic capital expenditure comprises capital expenditure less inorganic capital expenditure. BP believes that this measure provides useful information as it allows investors to understand how BP's management invests funds in developing and maintaining the group's assets.

Inorganic capital expenditure is a non-GAAP measure. It comprises consideration in business combinations and certain other significant investments made by the group. It is reported on a cash basis.

Plant reliability – Plant reliability (BP-operated) is calculated taking 100% less the ratio of total unplanned plant deferrals divided by installed production capacity. Unplanned plant deferrals are associated with the topside plant and where applicable the subsea equipment (excluding wells and reservoir). Unplanned plant deferrals include breakdowns, which does not include Gulf of Mexico weather related downtime.

Production costs per barrel of oil equivalent (boe) or unit production costs – Unit production cost is calculated as production cost divided by units of production. Production cost does not include ad valorem and severance taxes. Units of production are barrels for liquids and thousands of cubic feet for gas. Amounts disclosed are for BP subsidiaries only and do not include BP's share of equity-accounted entities.

Tier 1 process safety events – Losses of primary containment from a process of greatest consequence – causing harm to a member of the workforce, costly damage to equipment or exceeding defined quantities. This represents reported incidents occurring within BP's operational

HSSE reporting boundary. That boundary includes BP's own operated facilities and certain other locations or situations.

Tier 2 process safety events – Losses of primary containment from a process of lesser consequence.

TAR (Turnaround) - a major maintenance project.

Upstream break-even – Break even Brent oil price at which post-tax Upstream proxy free cash flow becomes positive. Post-tax Upstream proxy free cash flow is Upstream net income, adding back Upstream depreciation, depletion and amortization, and exploration write-offs, less Upstream organic capital expenditure.

Upstream net income – Non-GAAP measure. Upstream net income is calculated as Upstream underlying replacement cost profit before interest and tax, less notional tax calculated at 40 %.

Upstream pre-tax free cash flow – Non-GAAP measure. Upstream pre-tax free cash flow is Upstream pre-tax operating cash flow, less Upstream organic capital expenditure.

Upstream pre-tax operating cash flow – Non-GAAP measure. Upstream pre-tax operating cash flow is Upstream underlying replacement cost profit before interest and tax, adding back Upstream depreciation, depletion and amortization, and exploration write-offs.

Upstream unit cash flow – Non-GAAP measure. Upstream unit cash flow is calculated as Upstream net income, adding back Upstream depreciation, depletion and amortization, and exploration write-offs, divided by units of production.