Oil & Gas Majors: Fact Sheets
BP
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About Carbon Tracker
The Carbon Tracker Initiative (CTI) is a team of financial specialists making climate risk visible in today’s financial markets.
Our research to date on unburnable carbon and stranded assets has started a new debate on how to align the financial system with the energy transition to a low carbon future.

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1. BP emphasises its intended capital discipline, and expects capex to only rise marginally to 2018.  

2. The company has further focussed on disposals, with some of the cash being returned to shareholders rather than re-invested in new projects.  

3. BP’s portfolio is notable amongst the majors for having relatively limited exposure to high break-even projects, and particularly a near-absence of expensive mega-projects in development.  

4. This focus on quality over quantity is well-received, and we note that it has continued with the recent sale of 50% of Liberty (amongst other Alaska projects) to Hilcorp in April.  

5. However we note BP’s farm-in (announced in July 2013) to a 40% interest in the block containing Pitu, an ultra-deep water discovery in Brazil, which investors may want to look at given the relatively high break-even and technical risks.  

6. Two oil sands projects also seem to stand out, being the Sunrise and Terre de Grace projects in Canada. They both require a market oil price in excess of $120/bbl for sanction and account for an aggregate $6.1bn in potential capex to 2025 (of which Sunrise, BP’s largest high-cost project, represents $4.3bn). Although Sunrise is due to begin production later on this year, given its high-cost nature and earlier stage Terre de Glace could be a candidate to not pursue further.  

Introduction  
CTI has demonstrated in its research the mismatch between continuing growth in oil demand and reducing carbon emissions to limit global warming. Our most recent research with ETA to produce the carbon cost supply curve for oil indicates that there is significant potential production that could be considered both high cost and in excess of a carbon budget. We have focused our research on undeveloped projects that, allowing for a $15/bbl contingency, would need a $95/bbl market price or above to be sanctioned (i.e. a market price required for sanction of $95/bbl is equivalent to a project breakeven price of $80/bbl), as they are the marginal barrels that could be exposed to a lower demand and price scenario in the future. This note examines BP’s potential future project portfolio looking at production and capex using Rystad Energy’s UCube Upstream database (as at July 2014). “Capex” and “production” in this note (amongst other terms) are thus based on Rystad’s analysis and expectations of the company’s potential projects. BP’s planned or realised capex and production may differ from these projections. Where possible we have sought to verify the status of the projects at the time of writing.

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Potential future oil production

- BP’s potential future project portfolio (2014-2050 production) is of an unusually low-cost nature, with 40% requiring a market oil price above $75/bbl for sanction and 21% (5.1bn bbls) above $95/bbl, the second-lowest breakeven profile amongst majors.
- BP’s portfolio stands out as having a remarkable amount of very low cost potential production, with 9.4bn bbls (38% of total potential production) requiring a market price of $35/bbl or less.
- In the medium term, over the next decade, only 10% of BP’s production will need oil prices over $95/bbl for a commercial return (10% IRR).
- But by the end of 2025, projects requiring $95/bbl or more will have risen to 27% of the company’s potential future production.

Capex

- Turning to capital spend in the nearer term, on Rystad’s data, BP has potential capex of $247bn earmarked for oil projects during 2014-2025.
- Potential capex rises steadily through to 2022 at a CAGR of 11.9%, before falling off over the following years.
- $61bn (25% of the total potential capital budget) is on potential projects requiring market prices of $95/bbl or more, and 62% requiring at least $75/bbl.
BP

- Focusing on currently undeveloped future projects, of the $61bn of capex for projects requiring a market price of $95/bbl or higher, $49bn (80%) is on projects that are yet to be developed.
- “Undeveloped” in this sense comprises fields where a discovery has been made (“discovery” in the chart opposite) and where no discovery has been made (“undiscovered”)
- As high-cost, undeveloped projects, these could represent a focus for investors demanding cost savings from the company, either to be cancelled or deferred.

BP’s capex on high-cost projects is heavily biased towards high technical risk deep water projects; 41% of capex with market price requirements of at least $95/bbl is on ultra-deep water projects and 36% on deep water projects, in aggregate the most amongst majors.
- Just 4% of potential high-cost capex is on conventional projects (onshore and continental shelf).
- Oil sands (in-situ) and arctic projects account for 12% and 5% respectively of the potential budget.
BP’s potential capex is spread over a large number of projects, with only 38% of the $49bn potential capex on higher-cost new development attributable to the 10 largest discovery stage projects. These top 10 have individual capex requirements ranging from c.$1.0bn to c.$4.3bn. The market oil prices required for sanction of these projects are shown below.

BP states that it uses a benchmark of $80/bbl in its decision making; some of the projects in the below table are presumably therefore likely to be deferred, and we would welcome declarations that this is the case.

### Questions Arising

1. What is the process for reviewing the 35% of potential production which requires more than the company’s benchmark price of $80/bbl – is this the right proportion of options to have above this level?

2. How will the company ensure cost control and risk management across such a large number of projects?

3. Does the emphasis on ultra-deep water and deep water projects leave the company more exposed to technical risk and cost inflation?
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