Energy Transition Advisors
ETA

Carbon Tracker Initiative

Executive Summary

- **A 2°C carbon budget context**: As Carbon Tracker has pointed out in its previous research, staying within a 2 degree Celsius (2°C) global "carbon budget" will require a significant reduction in future oil demand.[1] Measures necessary to achieve this reduction include stronger climate policies, heightened energy efficiency, and broader deployment of renewable energy sources. In this new study we examine the supply and demand for oil at the global level through 2050. As a reference point, we find that the oil-related portion of a 2°C carbon budget (360 billion tons of carbon dioxide, or $GTCO_2$, which is 40% of the global 900 $GTC0_2$ that CTI has calculated) can be exhausted entirely through potential production with a break-even oil price (BEOP) below $60/bbl (i.e. production that, after adding a $15/bbl contingency, requires a minimum market oil price of $75/bbl). The focus of our document is a risk analysis of oil project economics in this context.

- **Through 2050 the private sector will play a pivotal role in developing new oil resources:** In our analysis of Rystad Energy's UCube Upstream database, we find over half of potential production in total is set to come from the private sector (as opposed to entities with any state ownership). As a result, economic or policy constraints on future oil production will have major implications for investors.

- **Stress-testing the logic of rising upstream oil capital expenditure:** To bring online their full potential supplies through 2050, private oil companies will need to invest $25.5 trillion in upstream oil production with a BEOP above the $60/bbl threshold - or an average of $0.7 trillion per year. In this study we provide information for investors to evaluate capital expenditures of oil companies under different demand scenarios that include constraints to CO_2 emissions, varying rates of economic growth, and other key drivers. The goal of this is to stress-test the demand and oil price assumptions that drive corporate decision-making on future reserve and production growth. Investors can use such analysis as a starting point to engage with companies on

[1] The target to limit global warming to 2°C was formalized in the UNFCCC Cancun Accord. Organizations including NASA, the IEA and the World Bank have warned of catastrophic impacts that will result from warmer temperatures.

Carbon Supply Cost Curves – Evaluating Financial Risk to Oil Capital Expenditures

Key Takeaways

- *A 2°C carbon budget context*
- *Through 2050 the private sector will play a pivotal role in developing new oil resources*
- *Stress-testing the logic of rising upstream oil capital expenditure*
- *Introducing the Carbon Supply Cost Curve*
- *Projects needing a $95/bbl+ market price are most vulnerable in a low-carbon demand scenario*
- *Significant exposure for private companies, including Majors*
- *Focus on Estimated Ultimate Recovery (EUR)*

Given that over the next decade private-sector oil companies will invest $1.1 trillion in new upstream capex, controlling carbon asset risk ought to be a priority for stewards of capital. With falling returns and rising capital intensity (capex/barrel of production capacity), investors should scrutinize company investment plans more thoroughly than they have in the past.

To assess potential future oil production, we use Rystad Energy's UCube upstream oil and gas database numbers for expected remaining recoverable volumes, referred to as Estimated Ultimate Recovery (EUR).

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capital allocation, i.e. how much should be devoted to new capital expenditures or returned to shareholders via buybacks and dividends.

- **Introducing the Carbon Supply Cost Curve:** We have previously emphasized the importance of a 2°C "global carbon budget". We analyze how this budget interacts with the economics of oil production via Carbon Supply Cost Curves; these curves show potential oil supply in terms of cumulative oil production (million barrels per day, or MBPD) and lifecycle CO_2 emissions (billion tons of carbon dioxide, or $GTCO_2$). This bridges the gap between decisions on capital and climate change. We analyze the economics of oil projects using the breakeven oil price (BEOP), the price at which an asset yields a net present value of zero (assuming a 10% internal rate of return).[2] On top of that we add a $15/bbl contingency to arrive at a market price.

- **Projects needing a $95/bbl+ market price are most vulnerable in a low-carbon demand scenario:** Through 2050, 20 MBPD of oil production (20% of total potential production and CO_2 emissions) will potentially come from private-sector projects with BEOPs over $80/bbl (i.e. that require a market price above $95/bbl); financing such projects will require $21 trillion of new investment. Many such projects involve significant technical challenges (ultra-deepwater, oil sands, Arctic), or are in geo-politically sensitive locations (Russia, East Africa, Nigeria, Venezuela) or both. To help investors understand their exposure to these risks we examine in detail the technological/categories and location break-down of high-cost projects.

- **Significant exposure for private companies, including Majors:** Though the bulk of potential production from the seven global "Majors"[3] is projected to have a BEOP below $80/bbl, these companies also have notable exposure to higher-priced locations/oil types. Avoiding expenditure at the high end of the cost curve in order to return cash to shareholders is a valid capital management strategy. Engaging with the Majors over these higher priced projects within their overall portfolio could catalyze an industry-wide pullback on new capital expenditures. Note that many independent smaller companies have significant exposure to high-cost projects that is not compensated for by a strong position in lower-cost resources.

- **Focus on Estimated Ultimate Recovery (EUR):** To assess potential future oil production, we use Rystad Energy's UCube upstream oil and gas database numbers for expected remaining recoverable volumes, referred to as Estimated Ultimate Recovery (EUR). Rystad generates EUR by combining reported numbers on P90 (proven) and P50 (probable) reserves with empirical case studies and its own case-by-case judgment.[4]

[2] Following industry practice, we add a $15/bbl "contingency" on top of a project's BEOP to determine the minimum market oil price necessary for the project to be sanctioned.
[3] These are BP, Chevron, ExxonMobil, Shell, Total, ConocoPhillips, and ENI.
[4] For more discussion, see detailed results in Section 6 of this report.

Key details – High-cost projects: BEOP above $80/bbl (i.e. needing market prices above $95/bbl)

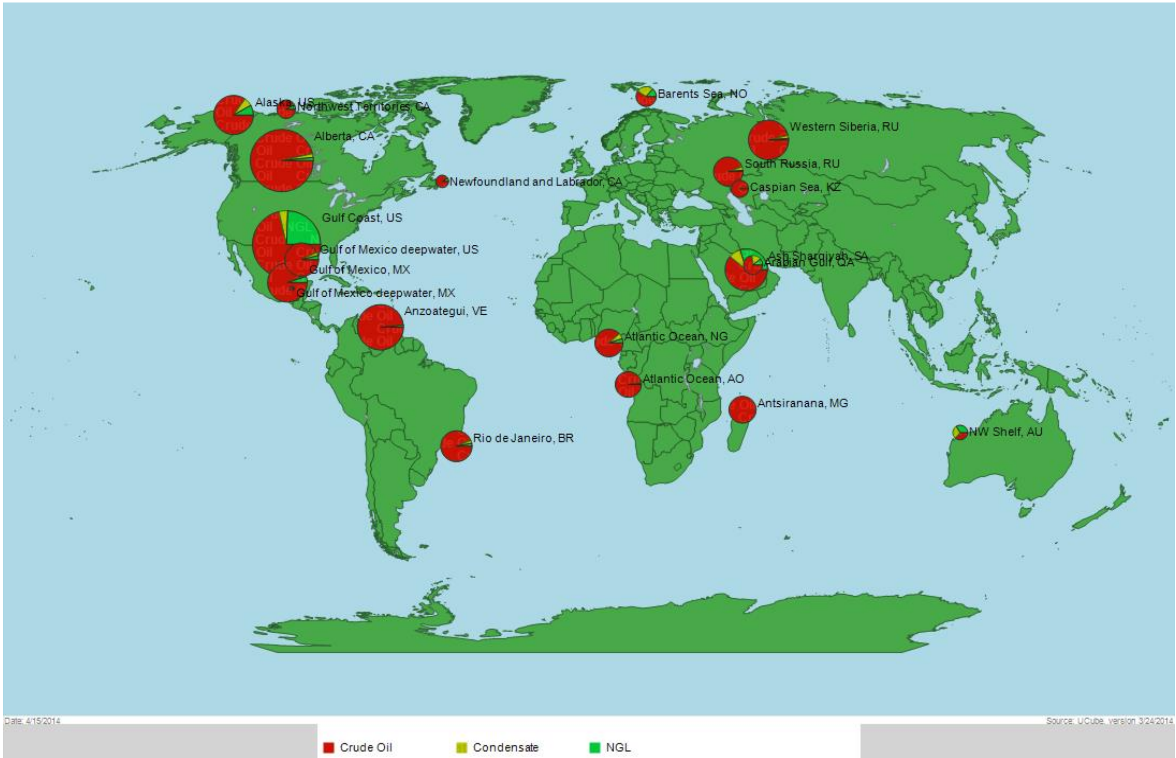
- High-cost projects make up 29 MBPD or 185GT of CO_2 2014-50 of total global potential oil production from 2014-50.
- The private sector has potential oil production of 22 MBPD or 135GT of CO_2 2014-50 within the high-cost bands.[5]
- Private-sector capital expenditure to develop potential conventional production of $18.1 trillion 2014-50 in real terms.
- Private-sector capital expenditure to develop potential unconventional production of $2.8trillion 2014-50 in real terms.
- Private-sector deepwater and ultra-deepwater potential oil production of 4 MBPD or 26.4GT of CO_2 costing $7 trillion capital expenditure 2014-50 with 50% (or more) of each of these totals relating to projects with $120+ BEOP.
- Private-sector Arctic potential oil production of 1.4MBPD or 9GT of CO_2 costing $2.8 trillion 2014-50 with 80% of this relating to projects with $150/bbl BEOP.
- Private-sector oil sands potential oil production of 2.2MBPD or 16GT of CO_2 costing $1.2trillion 2014-50 with 90% of oil production/CO_2 and 50% of capex relating to $100/bbl BEOP projects.
- The 7 global oil Majors have potential high-cost ($80/bbl plus) oil production of 2.5MBPD or 17GT of CO_2 costing $1.3 trillion 2014-50.
- Across our eight different categories of oil resource type,[6] focusing in on the Top 5 geographic locations (in terms of province[7]) within each category, the combined potential oil production from these provinces will require capex of $1.1trillion during the 2014-2025 timeframe; these medium-term planned expenditures should be a critical topic for engagement between investors and companies.
- Aggregating 2014-2025 capex for the Top 5 provinces (in terms of CO_2 production) within each oil resource type category, we find 10 such provinces to account for 90%+ of total capex. Capex related to Alberta's oil sands comprises nearly 40% of the combined 2014-

[5] For more discussion of the company-level implications of our analysis, see our companion note to this report - Carbon Tracker Initiative, *Carbon cost curves: evaluating risk to oil projects*, May 2014.
[6] The categories for conventional production are conventional (not including arctic or deepwater), arctic, deepwater (not including ultra-deepwater or arctic), and ultra-deepwater (not including Arctic); the categories for unconventional production are shale oil (including kerogen), oil sands, extra heavy oil, and tight liquids.
[7] i.e. Caspian Sea, Kazakhstan; Gulf Coast, US; Alberta, CA; etc.

2025 total, with the other Top 5 provinces relating to unconventional oil on the US Gulf Coast and deepwater/ultra-deepwater production in the US Gulf of Mexico, the Atlantic Ocean off the coasts of Rio de Janeiro and Angola, and Madagascar.[8]

Figure 1 The High-Carbon – Capital Expenditures Radar Map

Key high-carbon (>1GTCO$_2$) and high-cost (>$80/bbl BEOP) locations for potential oil production



Source: Rystad Energy, CTI/ETA analysis 2014

Recommendations for Investors

Given $1.1trillion of upstream capex at stake for the private oil sector over the next decade, controlling carbon asset risk ought to be a priority for stewards of capital. With falling returns and rising capital intensity (capex/barrel of production capacity), investors should scrutinize company investment plans more thoroughly than they have in the past. Unfolding low-return disasters such as the Kashagan oil field in the northern Caspian Sea and various LNG projects demonstrate that management of oil Majors are not subjecting their investments sufficiently to "stress" scenarios. As a result, over the past few years the financial performance of oil companies has suffered due to volatility in capital costs, fiscal terms and commodity prices (CO_2 costs have not had a material impact on returns - so far).

[8] Capex in Madagascar relates only to ultra-deepwater production; the other three provinces have both deepwater and ultra-deepwater production.

To promote better monitoring and avoidance of carbon asset risk, we propose the following recommendations for asset owners and fund managers to consider:

1. Understand the exposure of your portfolio/fund to the upper-end of the cost curve, both in terms of volume of embedded carbon and projected profitability of production returns (as in the future the two may become linked). Understand how company management are assessing and managing these risks and how projects are "tested" against them.

2. Identify the companies with the majority of capex earmarked for high-cost projects, especially high-cost, capital-intensive projects (since capital-intensive projects take longer to pay out and so are exposed to a longer period of risk).

3. As a starting point, focus engagement on projects requiring $95/bbl+ market prices. This includes a wide range of projects with BEOPs of around $80/bbl which includes oil sands, some ultra-deep water plays and heavy oil. Most oil companies use $80-100/bbl as an economic test and investors ought to know the percentage of a company's projects that are within (or above) this high-cost band.

4. Set thresholds for portfolio companies with respect to exposure to projects at the high end of the cost curve (i.e. $80-100/bbl or more).

5. Make it known to company management that you seek *value* over *volumes*, even if that means reducing the size of the company's asset base. Also, emphasize that strategies to create shareholder value must be robust even under scenarios of higher project costs and/or lower oil prices.

6. Ensure that company remuneration policies are consistent with long-term shareholder return objectives, rather than just rewarding reserves replacement or capital investment.

7. Require improved disclosure of the demand and price assumptions/scenarios underpinning capex strategy.

8. Support transparency of company exposure to the cost curve and impairment trigger points, for example through annual publication of sensitivity analyses/stress tests to different oil price scenarios.

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Contents

1. Introduction - carbon asset risk

- In April 2013 Carbon Tracker Initiative (CTI) published *Unburnable Carbon 2013: Unburnable Carbon and Stranded Assets*.[9] This study defined a global "carbon budget" compatible with limiting the atmospheric concentration of carbon dioxide (CO_2) to 450 parts per million (ppm) and future temperature increases to 2 degrees Celsius (2°C) or up to 3°C. CTI compared its carbon budgets against the quantity of carbon attributed to fossil fuel reserves of listed companies.[10] This analysis provided a snapshot in time of company exposure to existing fossil fuel reserves as well as of aggregate capital expenditures (capex) to develop new fossil fuel reserves ($674 billion in 2012 for the 200 largest listed oil, gas, and mining companies).[11]

- CTI's 2013 study concluded that "if listed companies are allocated their proportion of the carbon budget relative to total reserves (a quarter), they are already around three times their share of the budget" to give a reasonable chance of achieving a 2°C outcome.[12] The question then becomes, if society demands a 2°C pathway, and considering the many other fossil-based energy demand drivers, how will these reserves work out?

- Will there be stranded assets? In effect, will capital be wasted developing reserves in coming years before climate constraints becomes more binding and/or alternatives combined with efficiency and changes to economic growth lead to a material fall in demand?

- This leads to questions from investors as to which are the most likely assets to be at risk of becoming non-economic and who the winners and losers are likely to be as a result.

Markets allocate the carbon "budget" - focus on oil

- Since the publication of *Unburnable Carbon 2013*, CTI and its research partner, Energy Transition Advisors (ETA), have moved on to analyze carbon outcomes on the basis that *markets* will be the determining forces in allocating any global "carbon budget."

- The demand and supply interaction of fossil fuel markets setting commodity prices will in economic terms determine the viability of fossil fuels down to the project or asset level

- In this study we focus in particular on *oil* - the source of 36% of current global CO_2 emissions,[13] 48% of the carbon reserves held by the 200 largest listed owners of fossil fuel

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[9] Carbon Tracker Initiative (CTI) and the Grantham Research Institute, *Unburnable Carbon 2013: Wasted capital and stranded assets*, 2013, http://carbontracker.live.kiln.it/Unburnable-Carbon-2-Web-Version.pdf
[10] The 2012 CTI study considered both the "proven" (defined as P1 or P90) and "potential" (defined as P2 or P50) reserves of listed companies. As explained in our methodology section and in Appendix B, this study used a related approach.
[11] CTI and the Grantham Research Institute, *Unburnable Carbon 2013*, 34.
[12] CTI and the Grantham Research Institute, *Unburnable Carbon 2013*, 22. The 2013 study also found existing reserves of listed companies to exceed their pro-rata share of a carbon budget for a 3°C future.
[13] IEA, *WEO 2013*, 2013, Annex A - Tables for Scenario Projections, 574.

reserves,[14] and (considering capex on "oil and gas" as one item) close to 90% of 2012 capex by listed companies to develop new fossil fuel reserves.[15]

- Future demand for oil will be affected by climate-related policies and other environmental policies, such as those related to air and water, as well as other measures such as potential curtailment of subsidies for oil consumption (estimated at $200+ billion for 2012).[16] Additionally, supply constraints are also possible.

- Demand will also be affected by competition from alternative sources of energy – renewable energy being the most obvious.

- Demand will be heavily affected by efficiency measures, including improved efficiency in processes or products demanding fossil fuels, especially for oil in motor vehicles.

- The shape of world economic growth will affect demand – with the developing and emerging world dominant at the margin.

- Demand then has to interact with the supply stack or curve; the supply curve being based on production volumes at different economic breakeven prices. We express our Breakeven Oil Prices (BEOPs) in terms of a Brent price-equivalent (in real terms assuming 2.5% world inflation).

- So if demand were to prove weaker than expected due to environmental policy or other factors, how much exposure is there to risky investments at the higher BEOP end of the supply curve?

- Is there significant capital expenditure planned in fossil fuels that looks uneconomic without significantly higher prices?

- At the macro level, how will these supply curves (and associated break even prices) tie into a global carbon budget?

- We address these questions by completing an analysis of carbon asset development risk, based on comprehensive market-based demand and cost driver scenarios. Ultimately, this analysis of oil projects will demonstrate how investors can incorporate scenarios other than "business as usual" into both company and project risk. It will also enable them to assess the risk and viability of corporates investing in production with high breakeven price requirements while incurring significant capital expenditure outlays.

[14] CTI and the Grantham Research Institute, *Unburnable Carbon 2013*, 14.
[15] CTI and the Grantham Research Institute, *Unburnable Carbon 2013*, 14. Considering current capex just related to oil (as we do below) would reduce the share of overall fossil fuel capex below 90% but still above 50%.
[16] International Energy Agency (IEA). *World Energy Outlook 2013*, (Paris: OECD/IEA, 2012), 94. For reference, the IEA estimates 2012 global subsidies to renewable energy to have been $101 billion.

Breakeven oil prices (BEOPs) and the market contingency risk premium

- The starting point for any new oil project development is the Breakeven Oil Price (BEOP), which can be thought of as the per-barrel marginal cost of developing an asset.

- In the project analysis model of our data provider, Rystad Energy, a project's BEOP is the Brent oil price that - considering all future cash flows (i.e. costs, revenues, government take - are needed to deliver an asset-level net present value (NPV) of zero assuming a 10% discount rate.[17]

- Prior to sanctioning a project, however, most oil companies add on top of a project's BEOP a "contingency" or "risk premium," which Rystad estimates to be $15/bbl. Hence, when considering what level of contingency (or spread between market price and BEOP) might be necessary for a project to be sanctioned, we assume that companies will use a $15/bbl contingency.

- As of April 2013, one analysis suggested that most publicly-listed oil companies (including several Majors and large International Oil Companies) needed oil prices in the $100-120/bbl area to be cash-flow neutral in 2013-14 assuming current capex and dividends.[18] Though over the medium-term declines in capex and increases in cash flow from new production will for some companies lower the required cash-flow-neutral oil price, in the short term a high required price still leaves them vulnerable to unexpected volatility in oil prices or capital costs.

- **Most of our analysis in this study is in terms of BEOP. The key point is that companies and investors need to allow for a contingency when analyzing projects. This means that corporates will need a market oil price up to $15/bbl higher than the BEOP before a final decision can be made.**

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[17] Rystad Energy, "Breakeven prices in UCube - breakeven price calculated at an asset level," *UCube Technical Presentation 2014*, 2014, 23. For more discussion, see Appendix B of this report.
Rystad Energy, *Petroleum Production under the 2 degree scenario (2DS)*, July 2013, 26.
[18] Goldman Sachs, *Top 380 Global Oil Price Update - Higher long-term prices required by a troubled industry*, April 12, 2013, 5. Note that this estimate is for a particular moment in time. As production from new projects comes online and capex for many companies decelerates, the level of cash-flow neutral oil price will decline.

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Bridging the carbon and economic analysis gap: carbon supply cost curves

- We introduce a new concept, *Carbon Supply Cost Curves*. Traditionally potential supply or production levels are expressed in terms of oil production (normally in terms of million barrels per day, MBPD) against supply cost (in terms of Breakeven Oil Price, BEOP). These potential production supply curves are commonly used by financial analysts and corporates. By converting potential production of oil (in terms of MBPD) into potential production of carbon (in terms of billion tons of carbon dioxide, or $GTCO_2$) we relate the economic market to the carbon outcome.

- In order to analyze the carbon content of future production, we take as inputs Rystad Energy estimates of (1) expected total recoverable economical resources (termed Estimated Ultimate Recovery, or EUR[19]); and (2) the BEOP levels associated with these resources. Converting oil resources from MBPD to $GTCO_2$ enables us to determine the cost of marginal supply under a carbon-constrained scenario (i.e. how far up the BEOP cost curve we can move before exceeding the carbon budget for a particular climate outcome). To demonstrate our approach we use as a reference point the global carbon budgets (for fossil fuels in general and oil in particular) consistent with limiting future warming to 2°C.

- This, combined with different demand-price scenarios, allows us to determine:

    - Investment risk to higher-cost, higher-carbon assets;

    - The capital expenditure associated with the assets; and

    - The challenge to meeting a 2°C outcome and the risk that may bring to longer-term investment in fossil fuels

Comprehensive models of oil supply and demand

- The most comprehensive approach is a broad economic model that incorporates all global demand and supply for all energy markets and solves the outcome at a very granular project level. The leader in this kind of energy analysis at the global level is the International Energy Agency (IEA), whose annual *World Energy Outlook* (WEO) projects future energy trends under both business-as-usual and carbon-constrained scenarios.[20] Moreover, the IEA's modeling of oil and gas reserves and supply costs draws on data from Rystad Energy, the same source as we use for this study.

- Relative to an economy-wide model such as that used in the IEA's WEO publications, our approach is more focused on exploring the supply curve for oil in detail and comparing estimated supply costs with potential future demand conditions. It is more of a partial or "bottom-up" approach, but does still draw from and fit into a more comprehensive

[19] Rystad Energy, "Reserves and resources forecasting," *UCube Technical Presentation 2014*, 2014, 19. For more discussion, see Appendix B.
[20] IEA, *WEO 2013*, Annex B - "Policies and Measures by Scenario," 645.

framework. Indeed, we use two scenarios from the IEA's WEO 2013 study - the New Policies Scenario and the 450 Scenario[21] - as two overall key reference points and important sources for analysis of oil-related supply and demand trends.

Focus on Upstream Capital Expenditure (capex)

- From the perspective of carbon asset risk, the fundamental issue that investors and financial intermediaries face is the risk to future capital expenditures (capex) - in other words, under what conditions will this investment be rewarded? This can be split into capex on *existing fields* and capex on fields that are *not-yet-producing*. Though we show both of these sub-totals we focus chiefly on the overall total (i.e. including both existing and *not-yet-producing* fields).

- While the economic viability of some existing oil assets could be threatened by lower commodity prices, we believe that future capital expenditures is the key to mitigating carbon and that this is where the key risks for investor lie.

- Starting with identifying the highest-cost potential production, we then drill down by location and assess how much capex is associated with bringing that production on line. Importantly, we look at the split between public and private ownership: for CTI, the focus has been on future capex from listed companies in the private sector, rather than on capex of fully state-owned companies.

- To support current investor engagement activities, we explore in particular carbon asset risk implications for the seven oil "Majors."[22] **A companion note to this study explores company exposure to carbon asset risk in more detail;[23] that analysis concludes that many non-major private companies (i.e. "Independents") have significant exposure to high-cost projects and are vulnerable to carbon asset risk. Indeed, arguably Independents carry more risk relative to their overall portfolios than do the Majors.**

[21] IEA, *WEO 2013*, Annex B - "Policies and Measures by Scenario," 645.
[22] These are BP, Chevron, ExxonMobil, Royal Dutch Shell, Total, ConocoPhillips, and ENI.
[23] Carbon Tracker Initiative, *Carbon cost curves: evaluating risk to oil projects*, May 2014, http://www.carbontracker.org. Section 6 of this report reproduces key conclusions on company-level exposure to carbon asset risk.

2. Oil demand: comparing projections and examining key risks (see companion report)[24]

We initially survey the following projections for future oil demand:

- IEA scenarios to 2035: the New Policies Scenario[25] and 450 Scenario[26]
- IEA scenarios to 2050: the 2°C Scenario (2DS)[27], which is consistent with the 450 Scenario through 2035
- Scenarios from global oil Majors – BP[28], Shell[29], ExxonMobil[30]

- We also examine in more detail several downside risks to future oil demand and oil prices that have the potential to create a demand trajectory more aligned with the IEA 450 and 2DS scenarios
    - Lower-than-expected economic growth in China and other developing nations
    - Rapid increases in energy efficiency
    - Greater-than-expected penetration of electric vehicles
    - Adoption of aggressive measures to reduce vehicular air pollution by China and other emerging economies
    - Curtailment of oil consumption subsidies

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[24] Energy Transition Advisors and Carbon Tracker Initiative, *Oil demand: Comparing projections and examining key risks*, May 2014. http://www.carbontracker.org/

[25] IEA, *WEO 2013*, Annex B - "Policies and Measures by Scenario," 645, notes that the New Policies Scenario "takes into account broad policy commitments and plans that have already been implemented to address energy-related challenges as well as those that have been announced, even where the specific measures to implement these commitments have yet to be introduced. It assumes only cautious implementation of current commitments and plans."

[26] IEA, *WEO 2013*, Annex B - "Policies and Measures by Scenario," 645, notes that the 450 Scenario "sets out an energy pathway that is consistent with a 50% chance of meeting the goal of limiting the increase in average global temperature to 2°C compared with pre-industrial levels. For the period to 2020, the 450 Scenario assumes more vigorous policy action to implement fully the Cancun Agreements than is assumed in the New Policies Scenario. After 2020, OECD countries and other major economies are assumed to set economy-wide emissions targets for 2035 and beyond to collectively ensure an emissions trajectory consistent with stabilization of the greenhouse-gas concentration at 450 parts per million."

[27] IEA, *Energy Technology Perspectives 2012: Pathways to a Clean Energy System*, (Paris: OECD/IEA, 2012), 8, 31, http://www.iea.org/Textbase/npsum/ETP2012SUM.pdf

[28] BP, *BP Energy Outlook 2035*, January 2014, http://www.bp.com/content/dam/bp/pdf/Energy-economics/Energy-Outlook/Energy_Outlook_2035_booklet.pdf

[29] Shell, *New Lens Scenarios: A shift in perspective for a world in transition*, March 2013, http://s01.static-shell.com/content/dam/shell-new/local/corporate/Scenarios/Downloads/Scenarios_newdoc.pdf

[30] ExxonMobil, *The Outlook for Energy: A View to 2040*, 2014, http://www.bp.com/content/dam/bp/pdf/Energy-economics/Energy-Outlook/Energy_Outlook_2035_booklet.pdf

- These scenarios must account for the influence of the Organization of Petroleum Exporting Countries (OPEC). The source of 73% of current proven oil reserves[31] and 38% of projected production through 2050 (including 55% of projected production below $60/bbl),[32] OPEC exerts significant influence on pricing.

- We do not explicitly look at upside demand/price scenarios, as we believe these are adequately captured by the scenarios of the some of the global oil Majors we survey. Some scenarios do call for an oil price surge but leading to further substitution with a lag and thus a more volatile path to a lower price eventually.

IEA scenarios for future oil demand

We consider scenarios for long-term oil demand from the IEA[33] and industry sources

- In *IEA New Policies Scenario* post-2020 demand growth flat (2020-35 CAGR of 0.4%, vs. 1.4% for 2000-2013)

- In *IEA 450 Scenario out to 2035* demand growth peaks in 2020 and then begins declining at a -1% CAGR)

- Cumulative required production through 2035 is 790 billion barrels in the New Policies Scenario versus 720 billion barrels in the 450 Scenario.

    - Excluding natural gas liquids and a variety of ancillary oil sources (i.e. gas-to-liquids, coal-to-liquids, and additives), Cumulative required production through 2035 in the New Policies Scenario is 640 billion barrels

- Looking out to 2050, the IEA 4DS Scenario (which resembles the New Policies Scenario through 2035) sees oil use at roughly 95 MBPD (i.e. halfway between current demand and projected 2035 demand in the New Policies Scenario). This reflects the cumulative impact of higher transport fuel-efficiency across all major economies.

- The IEA 2DS Scenario (which resembles the 450 Scenario through 2035), however, sees oil demand decline to roughly 50 MBPD (i.e. ~40% lower than current global demand)

    - The 2DS sees substantial increases in fuel efficiency (as described above) but also major penetration of electric vehicles, hydrogen-powered vehicles, and biofuels. Realizing these levels of penetration will require substantial technical advances.

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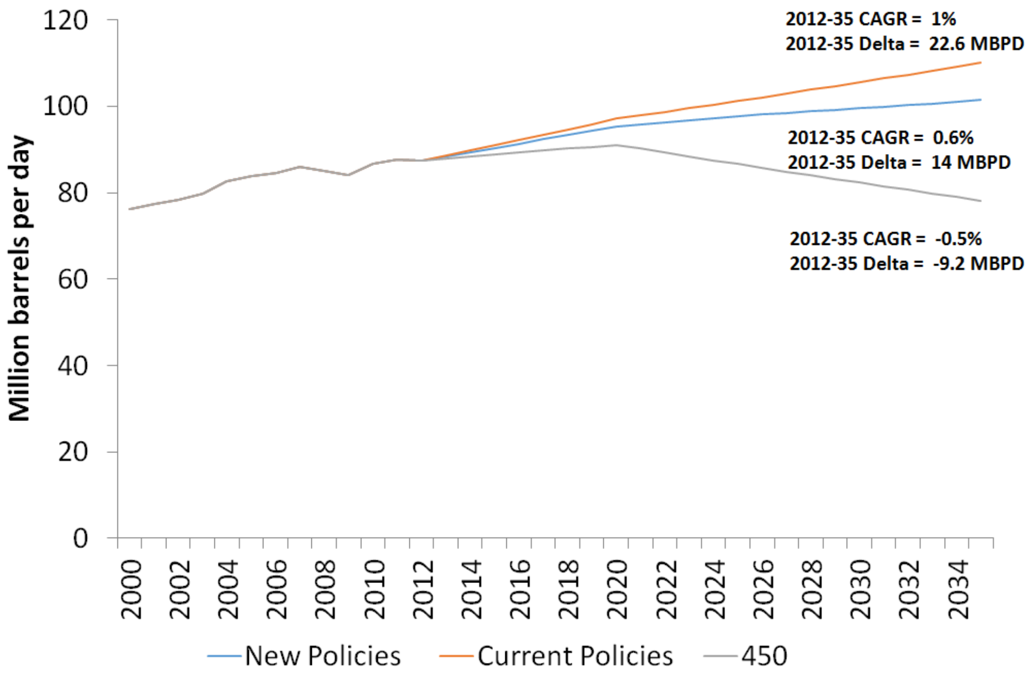
[31] BP, *BP Statistical Review of World Energy*, June 2013, p. 6. Includes gas condensate and natural gas liquids (NGLs) as well as crude oil. BP defines proved reserves of oil as "generally taken to be those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions."
[32] Based on analysis of data from Rystad Energy, as presented in Figure 15 below.
[33] References throughout this section are taken from IEA, *WEO 2013*, 2013 "Chapter 15: Prospects for oil demand - Growth in a narrowing set of markets," 501-534.

Figure 2 IEA oil demand scenarios – 2035 demand of 101 MBPD (New Policies Scenario) vs. 78 MBPD (450 Scenario)



Source: IEA, CTI/ETA analysis 2014

Comparing IEA and industry projections of future oil demand

On average, the *oil Majors* (Shell, BP, ExxonMobil) project 2012-35 demand growth to be 5.5 MBPD higher than in IEA New Policies Scenario and 28.7 MBPD higher than in the IEA 450 Scenario

Table 1 Change in oil demand under different scenarios, 2012-2035

	Delta (MBPD)*	CAGR**
IEA - New Policies	14.0	0.6%
IEA - 450	-9.2	-0.5%
BP	18.1	0.8%
ExxonMobil	20.2	0.8%
Shell - Mountains scenario	13.7	0.6%
Shell - Oceans scenario	26.1	1.1%
OPEC	19.6	0.9%

Source: IEA, BP, Shell, ExxonMobil, OPEC, CTI/ETA analysis 2014

* Data for oil Majors converted from million tons of oil equivalent to million barrels per day assuming the IEA's mix of product specific conversion factors.

** Compound Average Annual Growth Rate. Source: IEA, BP, ExxonMobil, Shell, OPEC

Role of CO_2 prices in oil demand projections

- Both the New Policies and 450 Scenarios assume adoption of CO_2 prices in multiple regions, particularly in the 2020-2035 timeframe[34]

    - Estimated coverage of oil demand by CO_2 prices across the two scenarios ranges from ~20% (assuming adoption of CO_2 prices in China) to under 10% (assuming no adoption of CO_2 prices in China)

    - The effective coverage of oil demand by carbon prices is restricted as CO_2 prices are assumed to apply predominantly to industrial and power sectors (currently less than 15% of global oil demand) but only weakly to the transport sector (currently 55% of global oil demand)

    - Even with comparable coverage, however, assumed CO_2 prices are significantly higher in the 450 Scenario

        - From 2020-2035, estimates of CO_2 prices range from \$8-40/tCO_2 in the New Policies Scenario to \$10-125/ tCO_2 in the 450 Scenario (all figures in 2012 dollars)

Table 2 Implications of carbon price assumptions for oil markets in selected regions of IEA New Policies and 450 scenarios

	Share of world oil demand covered by CO_2 price, 2020-2035* (%)		**Weighted average CO_2 price (2012\$/ton CO_2)**		**Potential impact on price of oil (\$/bbl)****	
	with China	*w/o China*	*2020*	*2035*	*2020*	*2035*
New Policies	18.5	4.0	12.0	32.0	5.7	15.1
450	22	7.0	17.0	107	7.5	5.03

*Includes only selected CO_2 price regimes as detailed in Table 1.5 of the IEA's 2013 WEO. **Assumes lifecycle CO_2 emissions of 0.47 tons/bbl. In practice the impact of a carbon price on the actual market price of oil will depend on the relative price-elasticity of supply and demand. **Source**: IEA, ETA analysis 2014

- Oil demand projections of some oil Majors explicitly incorporate future CO_2 prices, whereas others merely indicate CO_2 prices as a key area of uncertainty

    - By 2040, ExxonMobil assumes a "CO_2 proxy cost" (in 2012 dollars) of \$0-20/tCO_2 for Africa and the Middle East (as well as parts of Asia), \$20-40/tCO_2 for most of Latin America and Asia, and above \$40/tCO_2 for the US, Europe, and Australia (with prices in some scenarios reaching \$80/tCO_2)[35]

[34] IEA, *WEO 2013*, 2013, Table 1.5.
[35] ExxonMobil, *MEnergy and Carbon - Managing the Risks, 2014,* 18, http://cdn.exxonmobil.com/~/media/Files/Other/2014/Report%20-%20Energy%20and%20Carbon%20-%20Managing%20the%20Risks.pdf

Combining demand projections with global supply curves to estimate key BEOP levels

As we discuss below, we assess how future demand and supply for oil will interact by comparing different BEOP levels (which we term "price bands") against the oil prices expected to prevail under different demand scenarios discussed above

- The bands therefore represent potentially critical levels for both companies and investors in terms of economic risk i.e. the minimum price needed to make the marginal barrel economic. .

- Also, as demand will determine future production and so CO_2 emissions, the bands can be used to determine the price at which a given level of CO_2 (oil demand) can be met economically

- Key breakeven price levels: We examine the supply cost (**or breakeven oil price, BEOP**) of the marginal barrel of oil **under different demand scenarios** as set out above and derive some key levels

Under $60/bbl

- below 60/bbl: $60/bbl is where the CTI reference oil-specific carbon budget *t* is covered and so in a sense is "climate robust," by which we mean all demand under this scenario can be met from oil projects with a supply cost (BEOP) below $60/bbl. OPEC is dominant in this band given its low-cost production

- $50/bbl: In IEA New Policies Scenario, world oil supply (inclusive of all OPEC production) satisfies global demand through 2035 with projects that have a marginal supply cost (i.e. BEOP) of $50/bbl or less.[36]

$60-$80/bbl

- This is the price range where most future non-OPEC production begins to become economic. This is consistent with the $72/bbl cost for marginal non-stranded new fields as calculated by Rystad Energy under the IEA 2DS 2050 demand forecast.[37]

- Significant falls in demand caused by more aggressive efficiency and policy measures such as higher carbon prices and lower economic growth in China would all be needed to see demand and prices fall to this level.

Above $80/bbl

- Above $80 up to $100: This is the area of pricing that most oil companies plan on and so can be seen as the true marginal area for private oil

    - $80-90/bbl: Cost of marginal non-OPEC supply necessary to meet demand through 2035 in IEA New Policies Scenario.[38] Barring unexpected growth in OPEC production

[36] IEA, *WEO 2013*, 2013, Figure 13.18.
[37] Rystad Energy, *Petroleum Production under the 2 degree scenario (2DS)*, July 2013, 26.
[38] IEA, *WEO 2013*, 2013, Figure 13.19.

(captured in the IEA's "low oil price" case), the New Policies Scenario has the actual market oil price rising above $80-90/bbl.

- $80-100/bbl: Cost of current marginal non-OPEC supply (chiefly from heavy oil projects) as calculated by Goldman Sachs[39]
- At time of writing, the NYMEX forward curve has the price of Brent crude declining from $107/bbl in December 2014 to $91/bbl in December 2019.[40]
- For planning and project analysis purposes, many oil Majors assume a price of $80-100/bbl.[41] Some companies, however, use a wider long-term pricing range for planning purposes. For example, as of Q42013, Shell tested the economic performance of long-term projects against price ranges of $70-110/bbl for Brent crude oil."[42]

- High demand future: $100-120/bbl. As this band is at or above the long-term price of oil, we consider projects in this band to be economically marginal. As the band is above most companies' planning assumptions, projects in this band are unlikely to be developed except for strategic reasons.
- High price: $120-150/bbl. This band is above most industry assumptions and forecasts and would only appear possible if demand growth proved to be extremely robust or, more likely, if we saw a supply shock such as the 1979 Iranian revolution or the 1973 OPEC oil embargo. Even if prices rose to these levels, we suspect that oil companies would be reluctant to commit to developments unless conditions were seen to be sustainable. As such, projects in this band are likely to be seen by companies themselves as uneconomic in our view.

- **I**n both the IEA & Rystad scenarios, the ***breakeven price (BEOP) of oil supply* is less than the *market oil price required for oil companies to take development approvals***

[39] Goldman Sachs, *Top 380 Global Oil Price Update - Higher long-term prices required by a troubled industry*, April 12, 2013, 2. Note that from the same analysis Goldman Sachs identifies 2.4 MBPD of future production that requires a BEOP over $100/bbl. Goldman Sachs, *380 Projects to Change the World From resource constraint to infrastructure constraint,* April 12, 2013, 11. A different analysis, from Citi, shows the BEOP of marginal new supply generally in the range of $70-90/bbl, with a small portion above $90/bbl. Citi, *Global Oil Vision: Stand and Deliver - Global Energy Enters a New Cycle*, March 11 2014, 16.
[40] "Commodity Futures Price Quotes for Brent Crude Oil (NYMEX)", http://quotes.tradingcharts.com/futures/quotes/SC.html, accessed May 2 2014.
[41] Industry consultant Douglas-Westwood observes that "absent a convincing oil price model, a number of oil companies are using a 'best guess' approach, which assumes that oil prices will remain around or above $100 / barrel on a Brent basis. This is not scientific, but many, if not most, oil company executives think this seems plausible and sufficiently conservative for investment decisions." Steven Kopits, "Oil and economic growth: a supply-constrained view," presentation to Columbia University Center on Global Energy Policy, 11 February 2014, 26, http://tinyurl.com/mhkju2k.
[42] Shell 2013 Annual Report, "Crude Oil and Natural Gas Prices," 16 http://reports.shell.com/annual-report/2013/servicepages/downloads/files/entire_shell_ar13.pdf

   - *Rystad adds $15/bbl "contingency" to account for risks[43] (so with $72/bbl marginal supply cost the required market oil price for a development decision would be $87/bbl)*

   - *IEA cites constraints on development of new supplies, risk, and impact of OPEC as reasons for why the IEA New Policies scenario has oil prices rising above $80-90/bbl[44]*

- **Therefore we express the key demand outcomes in terms of BEOP "hurdles" – which represent where different demand scenarios intersect the cost curves but with a $15/bbl market contingency**

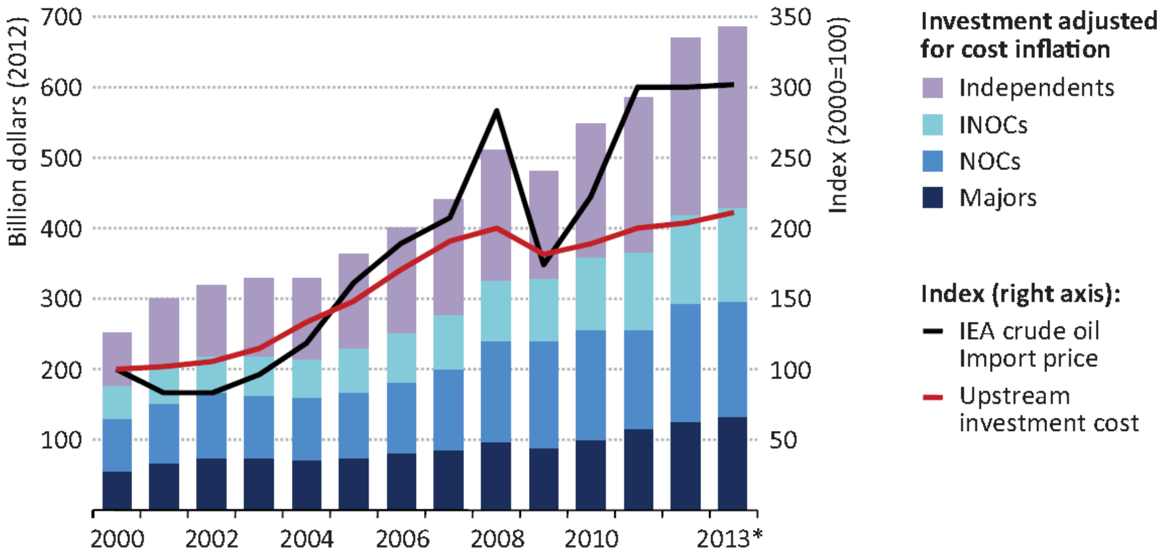
[43] Rystad Energy, *Petroleum Production under the 2 degree scenario (2DS)*, July 2013, 26.
[44] IEA, *WEO 2013*, 2013, 455-456.

3. From capex growth to capital discipline? - cost, risk, and return trends in the upstream oil industry (see companion report)[45]

Rising capex, falling capital productivity

In response to rising oil prices and technological advances, global upstream oil investment (capex) increased from roughly $250 billion in 2000 to nearly $700 billion in 2013 (both figures in 2012 dollars).[46]

Figure 3 Worldwide upstream oil and gas investment and the IEA Upstream Investment Cost Index



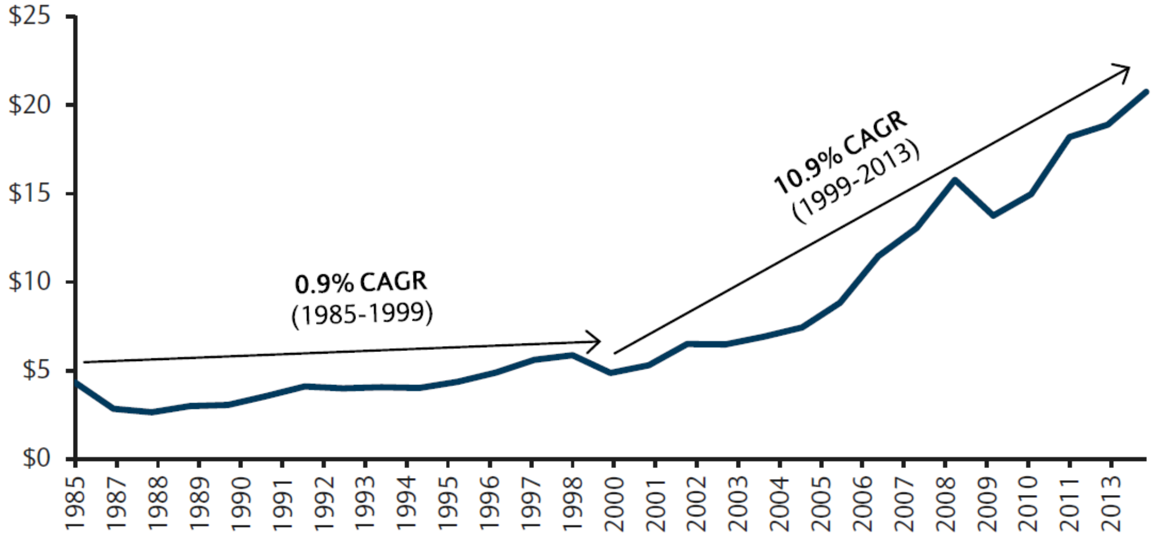
Source: IEA databases and analysis based on industry sources

*Budgeted spending. The IEA Upstream Investment Cost Index, set at 100 in 2000, measures the change in underlying capital costs for exploration and production. It uses weighted averages to remove the effects of spending on different types and locations of upstream projects.
**In this report INOCs and NOCs combined into one category that we term "National oil companies." "Independents" are a subset of the category that we label "Private."

Rising investment, however, has been yielding progressively smaller increases in the global oil supply; from 1999-2013 industry-wide exploration and production capex per barrel increased at a compound annual growth rate (CAGR) of 10.9% - or roughly 10X faster than during the period from 1985-1999 (0.9% CAGR).[47]

[45] Energy Transition Advisors and Carbon Tracker Initiative, *From capex growth to capital discipline? - Cost, risk, and return trends in the upstream oil industry*, May 2014. http://www.carbontracker.org/
[46] IEA, *WEO 2013*, 2013, Figure 14.20.
[47] IEA and Barclays Research data, cited in Kopits, 43..

Figure 4 E&P Capex per barrel



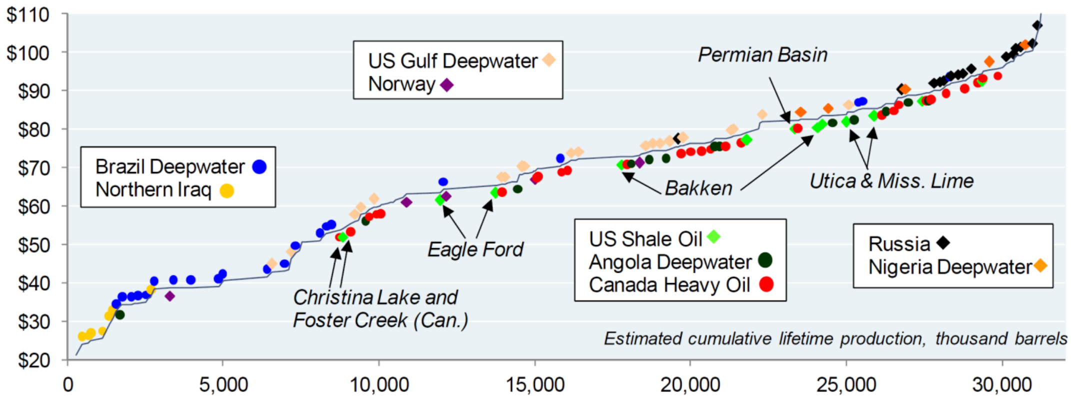
Source: Barclays Research based on IEA data

Increase in the cost of new resources

Declining capex productivity reflects in part the rise in production of "unconventional" oil (e.g. shale oil, tight liquids, oil sands), as well as a shift in production of "conventional" oil toward deepwater and ultra-deepwater projects. Through the late 1990s when the price of Brent crude (in 2012 dollars), dipped below $20/bbl, oil companies had been selecting new projects that had to be competitive in a world of $20-30/bbl oil.[48] The rise in oil prices since then has spurred a shift to develop higher-cost resources.[49] In the Goldman Sachs database of all 'new' (i.e. recently producing, under development, or pre-sanction) oil projects (April 2013) half of the combined total cumulative lifetime production was projected to come from projects with a BEOP above $70/bbl.[50] Moreover, most (though not all) projects added over the last two years have had BEOPs above $80/bbl.[51]

[48] Citi, 13.
[49] Note that a portion of the increase in E&P capex per barrel is also attributable to a move toward "mega-projects" (e.g. the Kashagan project in Kazahkstan or several Canadian oil sands projects) that have high capex-to-production ratios as a result of high costs and very long reserve lives.
[50] Goldman Sachs, *380 Projects,* 11.
[51] Note that high breakeven prices for Russian projects are chiefly due to heavy taxation.

Figure 5 Cost curve for new projects (recently producing, under development or pre-sanction), $/bbl



Source: JPM based on Goldman Sachs,"380 projects to change the world," April 2013.

Growth at the expense of ROI? - Inflation in upstream investment costs and recent declines in the quality of project execution

The surge in upstream activity since 2000 has seen inflation in industry costs (e.g. for drilling services), with the IEA's upstream investment cost index increasing by one-third from 2005 to 2013.[52] In turn, stretched supply chains have undermined the execution of many recent projects. Citi analysts note that costs overruns and delays have become more common in the past decade, a problem that they attribute in part to "the industry's focus on a land-grab of resources" and "targets and management incentives increasingly aligned around growth rather than return on investment."[53] Accordingly, improving the quality of project execution - and avoiding over-priced acquisitions[54] - has become a major industry focus.

Upstream returns compressing toward hurdle rates

Combined with a leveling off in oil price appreciation after 2008, the trend toward higher costs has pulled upstream returns back towards the industry's long-term hurdle rate. Average returns on upstream projects have declined from a peak of 21% in 2008 to just under 12% in 2013 (in line with the industry's estimated long-term hurdle rate of 12-13%).[55] Though in part this reflects a natural (and expected) dynamic in a competitive market, the magnitude and suddenness of the correction appears to exceeded industry expectations.

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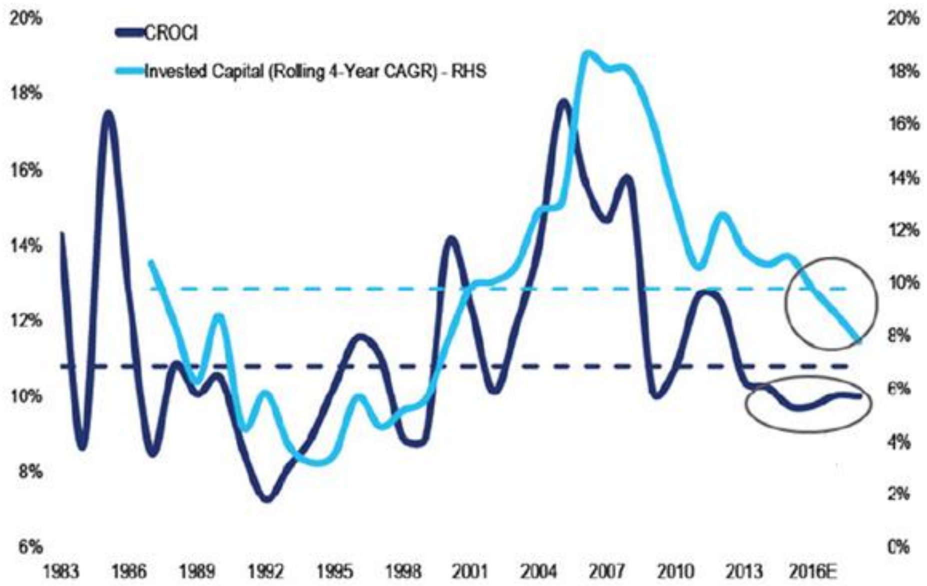
[52] IEA, *WEO 2013*, 2013, Figure 14.20.
[53] Citi, 13, 31.
[54] For 2008-2012 Citi analysts tally $360 billion acquisitions (equal to 17% of end-2007 upstream invested capital), many of which have begun to look highly questionable (examples including Total investments in Canadian oil sands and Royal Dutch Shell investments in North American tight liquids). Citi, 13.
[55] Citi, 11.

Current company-level cash returns below 30-year averages

Compression of upstream returns at the project level has led to an erosion of cash returns at the company level. Focusing on the metric of Cash Return on Capital Invested (CROCI),[56] returns have fallen below the 30-year industry average of ~11%, suggesting that "for most players that cash generation is not enough to support current investment and dividends needs."[57] Analysts project cash returns to remain flat through 2017-2018, after which there is the potential for them to increase as a result of decelerating capex growth, new production from recently sanctioned/developing projects, and better project execution.

Figure 6 Financial outlook for oil companies - returns below 30-year average, projected to remain that way through 2018



Source: Citi estimates based on company data (dashed lines show 30-year averages)

Company-level cash-flow neutral oil price

In April 2013, Goldman Sachs estimated almost half of the oil industry (including most global oil Majors) needed oil prices above $120/bbl to be cash-flow neutral after capex and dividends.[58] Note that this finding is for a particular point in time. Over the medium and longer-term, the bank suggested that this price will likely diminish as invested capital grows at a rate more slowly than it has over the past decade, and cash-flow from recently-producing projects increases. That

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[56] CROCI = EBITDA/Total Value of Equity, the measure is useful because it compares a company's cash return against its equity.

[57] Citi, 31.

[58] That this price is higher than the BEOP for many new projects reflects chiefly (1) an increase on maintenance capex for existing fields; and (2) declining cash-flow from non-E&P businesses. Goldman Sachs, *Top 380 Global Oil Price Update*, 5. Note that this estimate is for a particular moment in time. As production from new projects comes online and capex for many companies decelerates, the level of cash-flow neutral oil price could decline.

said, the finding still highlights the current economic incentive for companies to exercise cost-control and capital discipline.

Capex growth expected to continue

Despite a raft of recent project cancellations and delays - including the recent announcement of a new two-year delay at the $50 billion Kashagan oilfield in the northern Caspian Sea[59] -[60] some observers believe that upstream capex will remain robust for the next several years. [61] Investment for some Majors may come back from recent peaks but will still remain well above 10-year averages. Any cutbacks by the Majors will almost certainly be offset by other players in the oil industry (i.e. national, semi-national and independent companies). New projects are being added with a wide range of breakeven prices, and many analysts cite the potential for attractive economics[62], particularly in emerging deepwater and ultra-deepwater plays (with ultra-deepwater, among all resource types, set to see the largest relative increase in annual capex).[63]

The key issue that we point out to investors, however, is that projected economics of new project portfolios are increasingly uncertain due to (1) the demand projection uncertainties explored in this paper (2) rising levels of technical risk; and (3) a return, for some projects, of significant geopolitical risk.

Trends in technical and geopolitical risk

Technical risk increasing across multiple dimensions

Technical complexity can harm project economics by (1) necessitating repeated changes to initial design and engineering plans; and (2) increasing the time before project sanction and initial production. Goldman Sachs identify *five criteria for technical risk: water depth, environment/geography/climate, technology dependence, geological issues, and infrastructure dependence*.[64] Excluding (generally low-risk) projects related to tight liquids (i.e. shale) in North America as well as Caspian Sea projects, Goldman find technical risk in their global database of new projects to "rise to never-before-seen levels of risk, presenting a potential danger to delivery outside of the shale winzones."[65]

- Difficult risk dynamics of deepwater/ultra-deepwater projects: Low-cost projects (Brazil pre-salt, Gulf of Mexico) tend to have high technical risk, and lower-technical risk projects

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[59] Kepler Chevreux, *ESG Alert: Caspian Calamity Continues: FT Report Today Reinforces Our View that Kashagan Risks Becoming Giant Stranded Asset,* April 28 2014.
[60] Kopits, 49, cites capex cancellations or delays from BG, Shell, Statoil, ExxonMobil, Hess, and Chevron.
[61] As of January 2014, Morgan Stanley (*Analyzing Key Geographic and Operator Type E&P Capex Trends into 2014*, January 17 2014, 2) project global upstream oil and gas spending to grow ~$40 billion in 2014 and ~$50 billion in 2015 (i.e. significantly less than the annual growth of $120 billion in 2012) In their April 2013 *Top 380* report (page 87), Goldman Sachs projects for 2012-2018 total capex related to their Top 380 oil and gas projects to grow at an 8% CAGR (versus a 21% CAGR for 2006-2012).
[62] Across major oil and gas projects to 2020, Citi see " portfolios geared to deliver a weighted average IRR of 17%" (assuming flat a $90/bbl Brent price in real terms). Citi, 15.
[63]Goldman Sachs, *380 Projects to Change the World,* 87.
[64] Goldman Sachs, *380 Projects to Change the World,* 120.
[65] Goldman Sachs, *380 Projects to Change the World,* 123.

(Angola, Nigeria, Congo) tend to have higher costs and higher geopolitical risks (discussed below)

- Another key risk area is the dependence of Canadian oil sands production on development of widespread new transport infrastructure and upgrading capacity

- The next several years will indicate whether industry responses to greater technical risk (e.g. via more investment in front-end engineering, more risk-sharing with contractors[66]) can succeed in controlling vulnerability to cost increases

Table 3 Categories of Technical Risk for Oil Projects

Category	Description	Example fields
Water depth	Fields in greater water depths are assumed to have higher risk profiles	Jack, Stones, Lula
Environment, geography & climate	Fields subject to hostile operating conditions, e.g. Arctic operations, environmentally sensitive areas, planning permission, high civil unrest or other complex geographies, e.g. sub--salt or hostile weather patterns.	US GoM, Newfoundland
Technology dependence	Greater than average dependency on new or complex production technologies, e.g. subsea systems, early generation deepwater developments, heavy oil, unconventional production technologies	Kashagan
Geological issues	Risks regarding complex reservoirs, heavy oil, HPHT, sour liquids or unconventional reservoirs	Kristin Tyrihans, Kashagan
Infrastructure dependence	Infrastructure required to develop and monetize produced hydrocarbons	Uganda, Iraq, Caspian Sea

Source: Goldman Sachs, ETA analysis 2014

[66] Citi, 23, cites multiple elements that may lead to better future project execution (e.g. more front-end engineering).

Return of geopolitical risk

The recent surge of production in the US and Canada has diminished attention on how geopolitical risk can impede development of new oil supplies. Such risk, however, remains pervasive, and is poised to become more prominent as the next round of major capex projects ramps up over the rest of this decade. For example, at the time of writing the continuing diplomatic standoff over the status of Ukraine and recent economic sanctions against Russia has highlighted the risks facing BP, ExxonMobil, Royal Dutch Shell, and other foreign-based companies doing business there.[67]

In discussing our detailed results below, we draw on data from the Worldwide Governance Indicators (WGI) project to measure geopolitical risk in key oil-producing provinces listed in Tables 8 and 9 below (for results see Appendix A).[68]

- With respect to production of conventional oil (which includes deepwater and ultra-deepwater production), key countries with high geopolitical risk include Russia, Kazakhstan, Iraq, Nigeria, Angola, Madagascar, Congo, and Equatorial Guinea;
- with respect to production of unconventional oil, key high-risk countries include Venezuela and – given its recent history of expropriating foreign-owned oil assets - Argentina.[69]
- We find $300 billion+ of potential capex through 2025 in countries with significant geopolitical risk

How industry succeeds at managing technical and geopolitical risk will largely determine whether actual costs of future projects are in line with projections

[67] Andrew E. Kramer, "New Complications in Russia: Sanctions Over Ukraine Cause Headaches in the Energy Sector," *New York Times*, April 29, 2014, http://www.nytimes.com/2014/04/29/business/international/sanctions-over-ukraine-cause-headaches-in-the-energy-sector.html?_r=0

[68] Daniel Kaufmann, Aart Kraay, and Massimo Mastruzzi, "Worldwide Governance Indicators," The World Bank Group, 2013, http://info.worldbank.org/governance/wgi/index.aspx#home For 215 economies over the period 1996–2012, the WGI project assembles aggregate measures of six dimensions of governance. These aggregate indicators combine the views of a large number of enterprise, citizen and expert survey respondents in industrial and developing countries. They are based on 31 individual data sources produced by a variety of survey institutes, think tanks, non-governmental organizations, international organizations, and private sector firms.

[69] For detailed data on capex by country and province, see Tables 8 and 9 below.

4. Carbon Supply Cost Curves: Methodology for oil markets

In simple terms, estimated resources of various types of oil have different economic thresholds, i.e. different BEOPs. These can be used to produce a supply curve or stack.[70]

- We have taken crude oil, condensates and natural gas liquids (NGLs) – together collectively referred to as "liquids" – in our supply analysis. We emphasize **potential future Production through 2050.** Future Production for a given company is a function of for expected remaining recoverable volumes, or Estimated Ultimate Recovery (EUR). EUR numbers combined reported "proven" (P90) and "probable" (P50) reserves, as well as empirical studies and the case-by-case judgment of our data provider Rystad Energy as to "possible" (P10 reserves), contingent reserves, and the broader category of prospective Resources.[71]

- Potential production can then be converted in to carbon in terms of CO_2 in order to express this as carbon supply at different BEOPs.

- This potential CO_2 production in turn can be broken down into key categories of oil production – conventional such as deepwater, unconventional such as oil sands etc.

- Potential CO_2 production can then be tied to the amount of potential capital expenditure that is required to develop it.

- This can be further broken down to key locations or project areas.

- Finally, specific companies can be mapped to these break downs to look at their own exposure.

- All data comes from the Rystad UCube database, as of March 2014 (see Appendix B) .

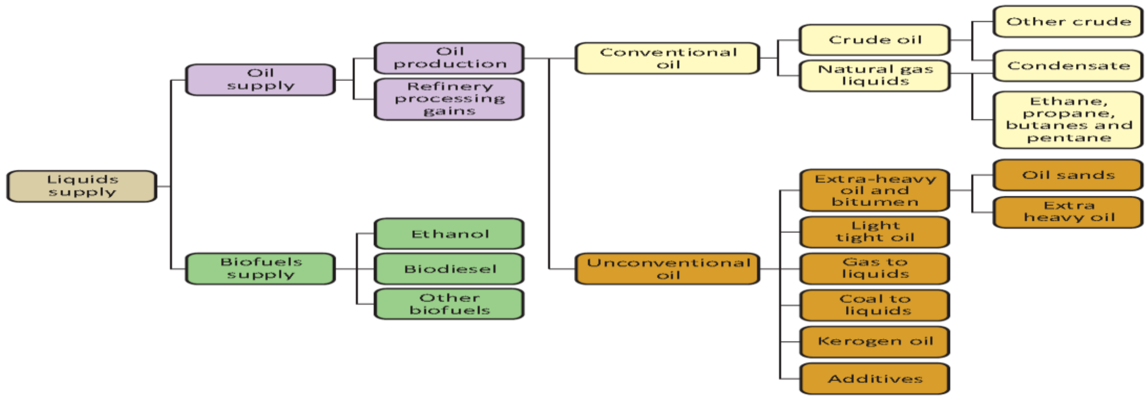
What is Oil?

- However when it comes to precisely carrying out the analysis there are a number of key assumptions that analysts have to make that can produce very different results. These need to be clearly understood by any reader and are often lost in studies.

- First, what type of "oil supply" is being analyzed? As shown in Appendix C there are many categories of oil supply. We have settled on crude oil plus condensates plus NGLs as a middle ground, wide enough to match many other studies but not the widest definition:

[70] For more detail on our methodology and data, see Appendix b.
[71] For more detail see discussion of "Resource Classification Proxy: P90, P50, and Pmean" and "Resource Classification Proxy: P90, P50, and Pmean" in Appendix b below.

Figure 7 IEA classification of liquid fuels



Source: IEA

How to calculate CO_2 emissions from oil production

- The conversion ratio to calculate carbon emissions from oil production is a crucial feature for estimating the use of the carbon budget and the concept of carbon emissions from oil supply. Simply put, the different categories of oil supply have to be converted to $C0_2$ emissions, using an oil to carbon conversion factor (or ratio). Combustion-only ratios can be calculated using empirical data and known chemical processes. For oil the calculations are as follows, as described by the EPA (http://www.epa.gov/cleanenergy/energy-resources/refs.html):

  - *Carbon dioxide emissions per barrel of crude oil are determined by multiplying heat content times the carbon coefficient times the fraction oxidized times the ratio of the molecular weight of carbon dioxide to that of carbon (44/12).*
  - *The average heat content of crude oil is 5.80 mmbtu per barrel (EPA 2013). The average carbon coefficient of crude oil is 20.31 kg carbon per mmbtu (EPA 2013). The fraction oxidized is 100 percent (IPCC 2006).*
  - *5.80 mmbtu/barrel × 20.31 kg C/mmbtu × 44 kg CO_2/12 kg C × 1 metric ton/1,000 kg = 0.43 metric tons CO_2/barrel*

- Because we are doing an analysis that just looks at oil supply outside of a general or comprehensive economic model, we use life cycle emission estimates (instead of combustion-only ratios) which take into account other factors, for example the energy used to produce the oil and gas, and how much of the oil and gas is not combusted. However, the estimates are more difficult to determine and will vary somewhat between locations, depending on extraction type and how the oil and natural gas liquids are used.

- Some studies therefore still use combustion only for conversion. That is generally taken to be 0.43 for Crude oil (EPA, 2012). Certainly this is uniform across different type of oil supply and region, which is a consideration when looking at a global supply curve. Indeed the IEA use this conversion factor production on carbon emissions in their oil work but capture production of oil emissions elsewhere in their modeling. The emissions factors we have applied are consistent with the range of regional lifecycle factors indicated by industry studies.[72]

- The life cycle conversion factors we use are as follows:

Table 4 Life-cycle CO2 conversion factors for different oil types

Conversion Factors	tCO_2/bbl
Crude Oil	0.5
Condensate	0.45
Natural Gas Liquids (NGLs)	0.3
Oil Sands	0.55

Source: Rystad, US State Department, Santos Energy Calculator, CTI/ETA analysis 2014

- Condensate: we took 0.92 tCO_2/bbl as the energy conversion factor (per estimate from Santos Energy Calculator, 2014) and multiplied it by our life cycle 0.5 tCO_2/bbl crude oil estimate, rounded down to give 0.45 tCO_2/bbl condensate.
- NGLs: we used Rystad Energy's conversion factor estimate of 0.3 tCO_2/bbl NGLs.
- Oil Sands: US State Dept. KXL conversion factor of 0.55 tCO_2/bbl.[73] Note that the oil sands conversion factor is used for the oil sands specific calculations in this report, and not for the global conversions in Table 1 and Table 2.

The CTI Oil Carbon "budget" – a reference point

To be consistent with a 2°C world, CTI has previously published analysis showing a global carbon "budget" of 900 $GTCO_2$.[74] At a particular sector level, this will be determined by supply and demand factors as we set out in our analysis. As a reference point for oil, however, a simple approach is to look at how much of that 900 $GTCO_2$ would be used up if oil continued with its current share of roughly 40% of global energy emissions.[75]

On that basis the oil-specific carbon budget through 2050 is approximately 360 $GTCO_2$; this is the value we use in our analysis.

Which oil price?

- Further, there is the question of which oil price – there are many oil price benchmarks, Brent, WTI, medium density (API gravity) oils such as Saudi Light and heavy oils including Maya and Saudi Heavy.

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[72] IHS CERA, "Oil Sands, Greenhouse Gases, and US Oil Supply: Getting the Numbers Right," December 2012, 16, http://www.api.org/aboutoilgas/oilsands/upload/cera_oil_sands_ghgs_us_oil_supply.pdf.
[73] United States Department of State Bureau of Oceans and International Environmental and Scientific Affairs, *Final Supplemental Environmental Impact Statement - Keystone XL Project*, "Chapter 4 Environmental Consequences," January 2014, Table 4.14-3, 4.14-29.
[74] CTI and the Grantham Research Institute, *Unburnable Carbon 2013*.
[75] IEA, *WEO 2013*, 2013, Annex A - Tables for Scenario Projections, 574.

- For our analysis using Rystad Energy's UCube database of upstream oil and gas assets,[76] the BEOPs are expressed in *Brent Price Equivalents* – the different types of oil with different specific gravities for instance (API) are equalized for comparison (most oil companies use Brent or WTI-based planning assumptions).

- The oil prices and capital expenditures and other economic data we use are real prices, as Rystad assume all prices rise at 2.5% which we assume to be world inflation

- We note, however. that transport costs are not always fully captured in this calculation – particularly for Canadian oil sands (as we set out in our March 2014 note *KXL – The Significance Trap*).[77] We adjusted for this when looking at oil sands in this study by adding $15/bbl to the BEOP (note that this is separate from the $15/bbl contingency discussed above).

Calculating upstream capital expenditure (capex)

- We use the term *capex* to describe the capital expenditure for exploration and production combined[78]

  - Capex includes investment costs incurred related to development of infrastructure, drilling and completion of wells, and modification and maintenance on installed infrastructures.

  - Exploration capex are costs incurred to find and prove hydrocarbons: seismic, wildcat and appraisal wells, general engineering costs, based on reports and budgets or modeled.

Reserves, Resources and Production

- Many investors question how a company's production cost curve relates to its actual reserves (and whether those reserves are or are not listed on corporate balance sheets). In the context of our dataset, Appendix C discusses the connection between reserves, resources, and production.

- Reserves, and the broader category of Resources, are generally taken at a point of time and broken down into key categories of probability of being produced. Rystad shows

  - "P90", which estimates the quantity of reserves that (with 90% confidence) are likely to be economically recovered;

[76] Rystad Energy, "UCube," describes UCube as a "complete and integrated field-by-field database, including reserves, production profiles, financial figures, ownership and other key parameters for all oil and gas fields, discoveries and exploration licenses globally. UCube includes 65,000 oil and gas fields and licenses, portfolios of 3,200 companies, and it covers the time span from 1900 to 2100." http://www.rystadenergy.com/Databases/UCube
[77] CTI, *Keystone XL Pipeline (KXL) - The "Significance" Trap*, March 3 2014, http://www.carbontracker.org/wp-content/uploads/2014/03/Kxl-The-Significance-Trap_FINAL_03_03_2014.pdf.
[78] Rystad Energy, UCube Technical Presentation 2014, 29-33.

- Incremental “P50”, which estimates the quantity of reserves that (with 50% confidence) are likely to be economically recovered (the “incremental” here refers to reserves that are part of P50 over and above what is included within P90).

- Incremental “Pmean”, which is an aggregate risk-weighted total of all three classes of reserves (P90, P50 and P10) together with an estimate of contingent and prospective resources. The “incremental” here refers to reserves and resources that are part of Pmean over and above that included in P90 and Incremental P50).

    - Incremental Pmean, when added to P90 and incremental P50, is an estimate of the "Expected Ultimate Recovery" (EUR)

        - PMean = EUR - P90 - incremental P50.

- EUR includes oil that is either currently non-commercial (Contingent Resources) or may not have been discovered yet (Prospective Resources). These two resource classifications carry a degree of risk.

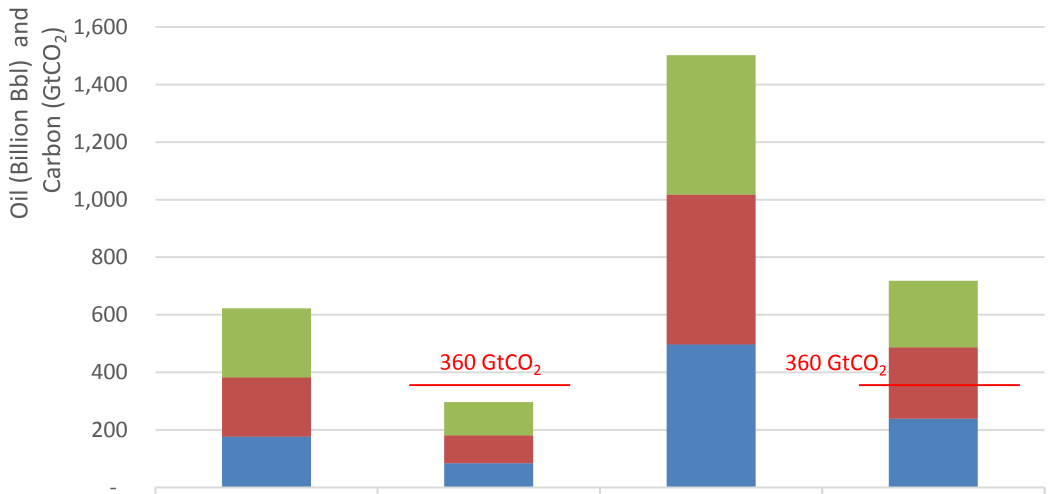
- Over time, some of the volumes in fields classified as prospective resources will become contingent resources and ultimately reserves. Rystad uses a probability weighted estimate of resources to calculate Production at various BEOP levels. It assumes that a portion of prospective and contingent resources will move in to the reserve category over the 2013-2050 analysis period. (see Appendix C for further details).

- Potential Production out to 2050 – our focus – makes the same assumption i.e. that oil currently classified as resource will – through seismic interpretation, exploration, appraisal, and field development – mature to P50 and P90 reserve status. It is only possible, however, to display these categories at a point in time (i.e. as Figure 10 does below), rather than in the aggregate over an extended period of time.

- Our analysis looks at all reserves and resources over 2014-2050: we do not distinguish between how these are treated in an accounting sense (i.e. whether they are on or off-balance sheet), as accounting treatment of oil reserves is not the focus of this study.

- As a starting point, however, we examine the Expected Ultimate Recovery (EUR) of oil resources as of March 2014 (decomposed into P90 reserves and incremental P50 and Pmean)

Figure 8 2014 estimate of global and private-sector oil resources (EUR, or Estimated Ultimate Recovery) in terms of both potential cumulative production (BBbl) potential carbon emissions ($GtCO_2$)



	Oil (Billion Bbl)	Carbon (GtCO2)	Oil (Billion Bbl)	Carbon (GtCO2)
	Private reserves (Billion bbl)		Global reserves (Billion bbl)	
Pmean (incremental)	240	116	484	231
P50 (incremental)	206	98	521	248
P90	176	84	497	239

Source: Rystad Energy, CTI/ETA analysis 2014

- We express these numbers in terms of both production (billion barrels of oil) and emissions ($GTCO_2$) using our CO_2 conversion factors for crude oil, condensates and NGLs. From the global totals, we separate out the share owned by private-sector companies[79]
- For reference, we compare this to the CTI 2050 CO_2 budget for oil (360 $GTCO_2$), discussed in more detail below
- Private companies' share of P90 reserves only accounts for 23% of the CO_2 reference budget for oil; including incremental P50 reserves would increase this share to 48%.

[79] Note that the term "Private" here refers to private ownership versus state ownership, rather than private ownership versus public ownership in the sense of being a publicly-listed company. Many of our "Private" companies are publicly-listed.

5. Detailed Results of Carbon Supply Cost Curves

Having explained our methodology, this section now surveys key findings from our analysis.

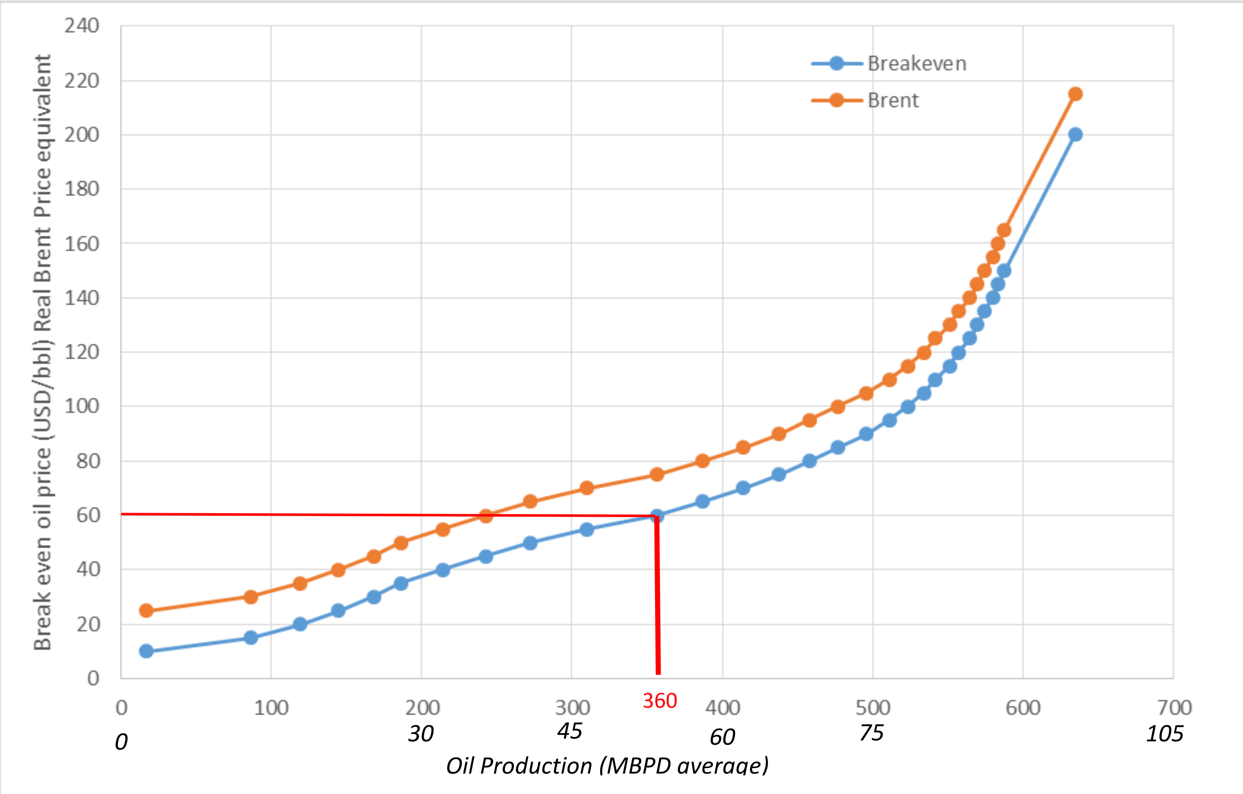
Global perspective: oil capable of supplying 75% of CTI's total 2050 carbon budget for fossil fuels

- We first examine potential CO_2 emissions from global production of oil between 2014 and 2050 (our key date for achieving a climate stable world).
- To set the context of a climate-constrained world, we calculate what fraction of existing oil reserves can be produced by 2050 within a 2°C global carbon budget.
- With respect to a 2°C global carbon budget, there are two relevant numbers:
    - 900 CO_2: The total 2050 carbon budget for all fossil fuels as defined by CTI
    - 360 $GTCO_2$: The implied 2050 carbon budget specifically for oil, assuming that (roughly consistent with its current share of global fossil fuel-related CO_2 emissions[80]) oil has a 40% share of the total 2050 carbon budget for all fossil fuels
- We compare the 2050 carbon budget for oil with cumulative emissions from potential global oil production through 2050
    - Instead of showing 2014-2050 oil production in terms of the cumulative total (i.e. Billion Barrels), we show daily averages of production over this period in terms of the more Million Barrels Per Day (MBPD).[81]
    - We show global oil supply curves in terms of BEOP, and also Brent price-equivalent BEOP (which adjusts for quality differences among different oil types).
- Assuming an average production level of 100 MBPD through 2050, oil would on its own be capable of supplying 75% of CTI's total 2050 carbon budget for fossil fuels (i.e. 675 of 900 $GTCO_2$)
    - *Put differently, at an average production level of 100 MBPD through 2050, CO_2 emissions from oil would be 1.8X the implied oil-specific carbon budget*

[80] IEA, *WEO 2013*, 2013, Annex A - Tables for Scenario Projections, 574.

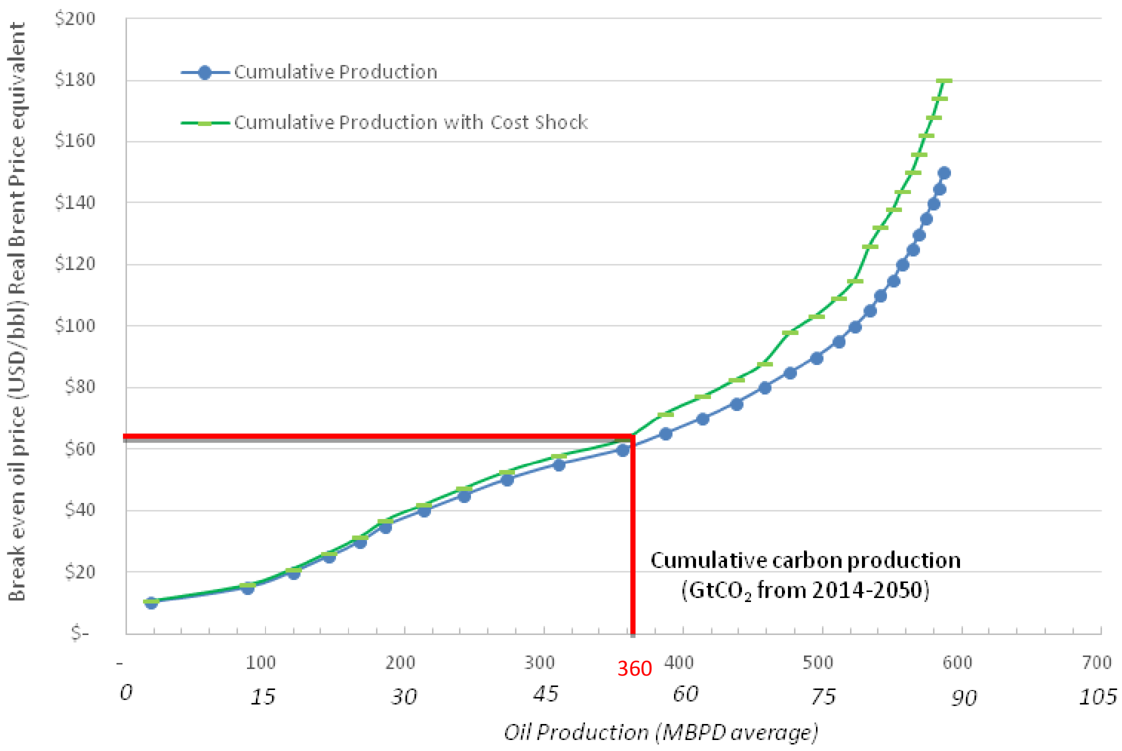
[81] For reference, global oil production in 2013 of roughly 90 million barrels per day equates to a cumulative annual total of 33 billion barrels.

Figure 9 2050 global carbon budget for oil (360 GTCO₂) compared against carbon (GTCO₂) from global oil production (MBPD) - global oil supply curves expressed in terms of BEOP ($/bbl) and Brent price-equivalent BEOP ($/bbl adjusted for resource quality differences), 2014-2050



- Above show potential cumulative production with the equivalent carbon content on the same horizontal axis (different scale)
- This shows the CTI carbon reference budget for oil is covered at $60/bbl BEOP, equivalent to $75/bbl Brent with a contingency applied
- Below we show how the supply curve might look if costs escalated

Figure 10 Cost shock to cumulative BEOP ($0-$59/bbl: +5%; $60-$79/bbl: +10%; $80-$99/bbl: +15%; $100+/bbl: +20%)



*Note that horizontal axis displays both GTCO$_2$ (on upper row of numbers) and MBPD of oil production (on bottom row). BEOP figures are expressed in real terms assuming world inflation of 2.5%. **Source**: Rystad Energy, CTI/ETA analysis 2014

Potential production by Public and Private sector: - combination of Private and partly-listed National oil companies control 65% of potential production through 2050

Company categories

- Across the 159 companies in our dataset[82], we separate companies into two main categories based on ownership structure
    - National oil companies: 39 companies with full or partial government ownership[83]
        - Partly-listed national oil companies: 10 companies with partial listing of shares on public exchanges (i.e. private-sector ownership)
            - CNOOC Ltd, Ecopetrol, MOL, ONGC (India), Petrobras, PetroChina, PTT PCL, Rosneft, Sinopec, and Statoil ASA.
    - Private oil companies: 120 companies with no degree of formal government ownership. Note that the term "private" here refers to the private sector, rather than being privately-held in the sense of not being listed on a public exchange (as many of these companies are indeed publicly-listed).
        - Majors: a subset of our "Private" category, this is a group of seven of the largest global oil companies
            - BP, Chevron, ExxonMobil, Shell, Total, ConocoPhillips, and ENI.

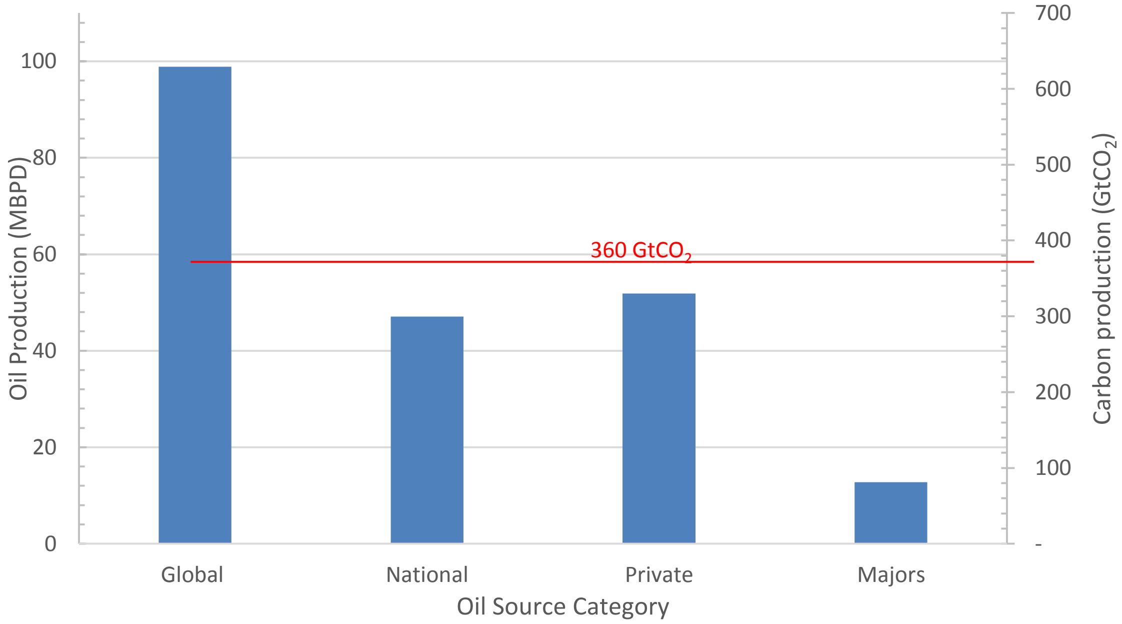
[82] For detailed company-level results, see Section 6 of this report, or our companion note CTI, *Carbon cost curves: evaluating risk to oil projects*. http://www.carbontracker.org/

[83] In grouping oil and gas companies, the IEA distinguishes National Oil Companies (NOCs) from International Oil Companies (NOCs). Both are majority of fully-owned by their national governments; whereas NOCs (e.g. Saudi Aramco, National Iranian Oil Company Rosneft, PDVSA) concentrate their operations on domestic territory, however, INOCs (e.g. Statoil, PetroChina, Petrobras) have significant international operations in addition to their domestic holdings. We combine both of these groups within the category we term "National oil companies." Note, however, that our sub-group of 10 party-listed "National oil companies" is composed mostly of companies that the IEA would label INOCs. IEA, *WEO 2013*, Box 13.3, 433.

Carbon and oil production by company category

- In terms of future oil and carbon production potential through 2050, National and Private oil companies are roughly equal in size
- Including in the "Private" total the 10 partly-listed National oil companies increases the Private share of potential production from 53% to 65% (i.e. to 65 MBPD of potential production and 413 $GTCO_2$ of emissions)[84]
    - These totals already exceed CTI's 2050 oil-specific carbon budget
- The seven Majors alone account for 23% of the CTI's 2050 oil-specific carbon budget

Figure 11 Carbon supply and oil production by sector and company category, 2014-2050



*Note that the "Majors" total is a subset of "Private" total. **Source**: Rystad Energy, CTI/ETA analysis 2014

[84] Note that this 65% share reflects the full production of the partly-listed National oil companies, rather than a pro-rata share of their production according to their degree of private ownership.

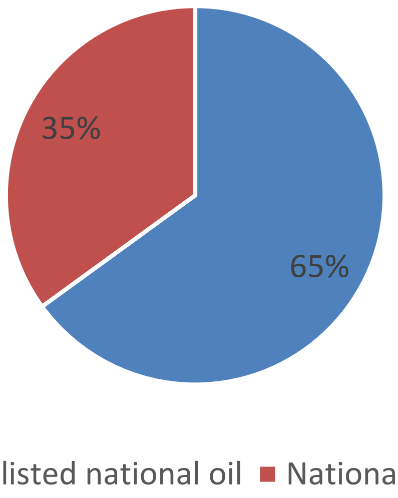
Table 5 Oil and carbon production by company category with comparisons to CTI 2050 carbon budget for all fossil fuels and for oil specifically, 2014-205

	Oil Production (MBPD)	Carbon Production ($GtCO_2$)	Proportion of 900 $GtCO_2$ Budget	Proportion of 360 $GtCO_2$ Budget
Global	99	635	71%	177%
National	47	304	34%	85%
Private	52	330	37%	92%
Majors	13	83	9%	23%

Source: Rystad Energy, CTI/ETA analysis 2014

*Note that the "Majors" total is a subset of "Private" total. The "Global" totals are a sum of the "National" and "Private" totals

Figure 12 Breakdown of total potential oil production - % controlled by National oil companies versus % controlled by Private and partly-listed National oil companies, 2014-2050



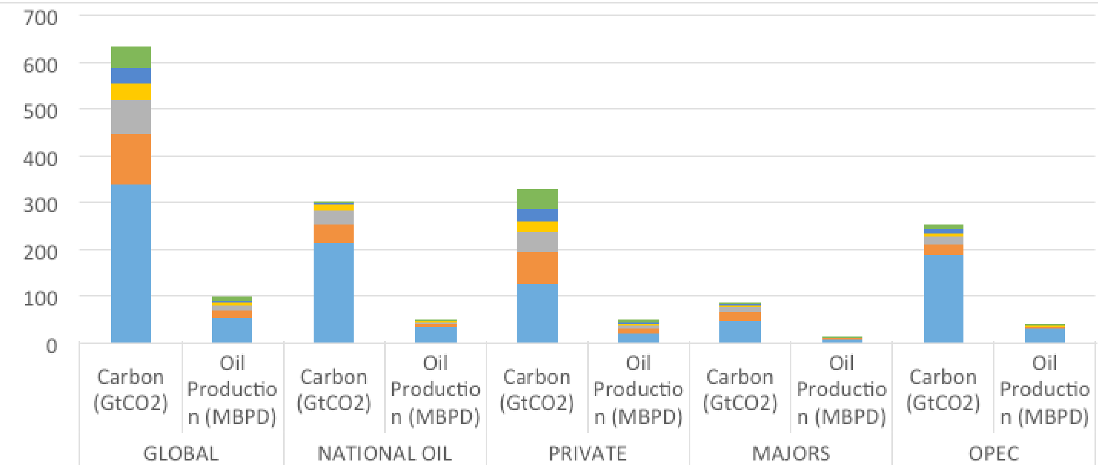
Source: Rystad Energy, CTI/ETA analysis 2014

Future production economics: analyzing BEOP levels by company category

Global perspective - $80+/bbl production equal to half of the oil-specific carbon budget, three-fourths of this production in the private sector

- The global oil supply curves in Figure 9 above illustrate that future oil production will come online at BEOP levels from below $20/bbl to above $100/bbl. Since in a climate-constrained world demand and price risks will be stronger for higher-cost producers, the figure below illustrates for different categories of producers the breakdown of future production by BEOP level.
    - Given their price-setting influence in world oil markets (and high degree of state control over oil resources), we separate out production from the 12 nations in the Organization for Petroleum Exporting Countries (OPEC).[85]

Figure 13 Carbon and oil production at different BEOP levels by company category, 2014-2050



	GLOBAL		NATIONAL OIL		PRIVATE		MAJORS		OPEC	
	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)
Above 150	47	7	5	1	42	7	1	0.2	8	1
120-150	31	5	4	1	27	4	2	0.2	9	1
100-120	37	6	12	2	24	4	4	0.5	7	1
80-100	70	11	28	4	42	7	10	1.6	17	3
60-80	109	17	39	6	70	11	21	3.2	22	3
0-60	340	53	215	33	125	19	46	7.0	189	29

Source: Rystad Energy, CTI/ETA analysis 2014

*Note that the "Majors" total is a subset of "Private" total.
**Totals within each row will not sum to the global total, as the OPEC totals are calculated separately from the company totals. As above, the "Global" total is a sum of the "National" and "Private" totals.
***Table above shows that carbon from global production with a BEOP below $60/bbl is equal to 95% of the CTI 2020 oil-specific reference carbon budget of 360GTCO$_2$, which is approximated at the $60 BEOP price.

[85] OPEC members include Saudi Arabia, Iran, Iraq, Kuwait, Qatar, the United Arab Emirates, Nigeria, Angola, Algeria, Libya, Venezuela, and Ecuador. For more discussion on the role of OPEC in world oil markets see Box 1.2 of our companion report

- OPEC nations dominate low-cost oil production, accounting for 55% of potential production below $60/bbl through 2050. The Majors also have reasonable exposure to low-cost production; though they control only 13% of potential production below $60/bbl, this low-cost band amounts to over half of their potential production through 2050.[86]

- Above the key economic level of $80/bbl, average oil production through 2050 of 29MBPD amounts to cumulative carbon production of 185 $GTCO_2$ (i.e. 50% of CTI's oil-specific carbon budget)
    - Within this range of $80-150+/bbl, nearly three-fourths of potential production comes from Private companies
        - Despite strong positioning lower down the cost curve, through the Majors still have 2.5 MBPD of potential production with a BEOP of $80/bbl or more

A more detailed look at the oil supply curve - BEOP levels by oil resource type

- To better understand the economics of different oil resource types, we decompose the global oil supply curve into two broad categories ("conventional" vs. "unconventional) that each contain four subcategories

- Conventional oil: The term "conventional" refers to conventional reservoirs (i.e. those with good permeability), conventional hydrocarbons (i.e. not extra heavy crude), or conventional recovery methods (i.e. not hydraulic fracturing).
    - Subcategories include Arctic, deepwater (125 - 1500 meter depth), ultra-deepwater (> 1500 meter depth), and a fourth category that encompasses all conventional oil production that is not in the Arctic, deepwater, or ultra-deepwater categories
    - We also include condensate and NGLs within our Conventional category

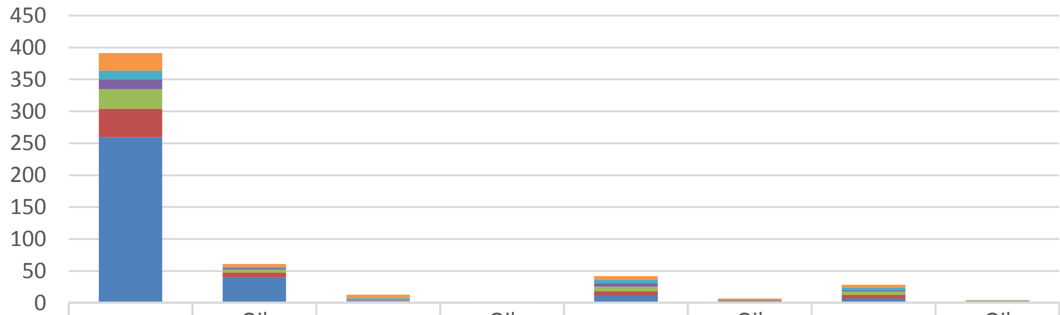
- Unconventional oil: Subcategories of this group oil shale (kerogen) and shale oil plays combined, oil sands (in-situ and mining), tight liquids, and extra heavy oil (for definitions of shale oil and tight liquids see Appendix B).

[86] Though, as discussed in our separate report on upstream supply trends, much of this future low-cost production faces significant technical and geopolitical risks.

Supply curves for conventional oil: deep/ultra-deepwater account for majority of production above $80/bbl

- Overall, "conventional" (i.e. non-Arctic/deepwater) oil dominates future production
    - ~3/4 of the 2050 oil-specific carbon budget could be taken up by "conventional"(i.e. non-Arctic or deep/ultra-deepwater) production with a BEOP below $60/bbl. Note, however, that 70%+ of this low-cost conventional oil held by OPEC countries
- Majority of production with a BEOP over $80/bbl to come from deepwater and ultra-deepwater sources (6.3 MBPD or 40 $GTCO_2$)
    - As discussed in our companion note,[87] many deepwater/ultra-deepwater plays face significant technical challenges (e.g. drilling in environmentally sensitive or hurricane-prone areas) and geopolitical risk (e.g. from burdensome fiscal regimes)
- Potential for 1.6 MBPD of Arctic production (10.2 $GTCO_2$) but half of this needs over $150/bbl to be commercial
    - Initial exploration activity in the Arctic has suffered numerous setbacks and delays due to both operational hazards and legal challenges[88]

Figure 14 Conventional oil categories: global carbon and oil production by BEOP level, 2014-2050



	Conventional (not inc. Arctic and Deep Water)		Arctic		Deep water conventional (not inc. Arctic)		Ultra Deep Water conventional (1500m+) (not inc. Arctic)	
	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)
Above 150	28	4	5.3	0.8	6	1.1	5	0.7
120-150	13	2	2.5	0.4	6	1.0	4	0.6
100-120	16	2	1.4	0.2	5	0.8	2	0.3
80-100	31	5	1.0	0.2	7	1.0	5	0.8
60-80	45	7	1.2	0.1	6	1.0	6	0.9
0-60	259	40	1.1	0.1	12	1.9	7	1.0

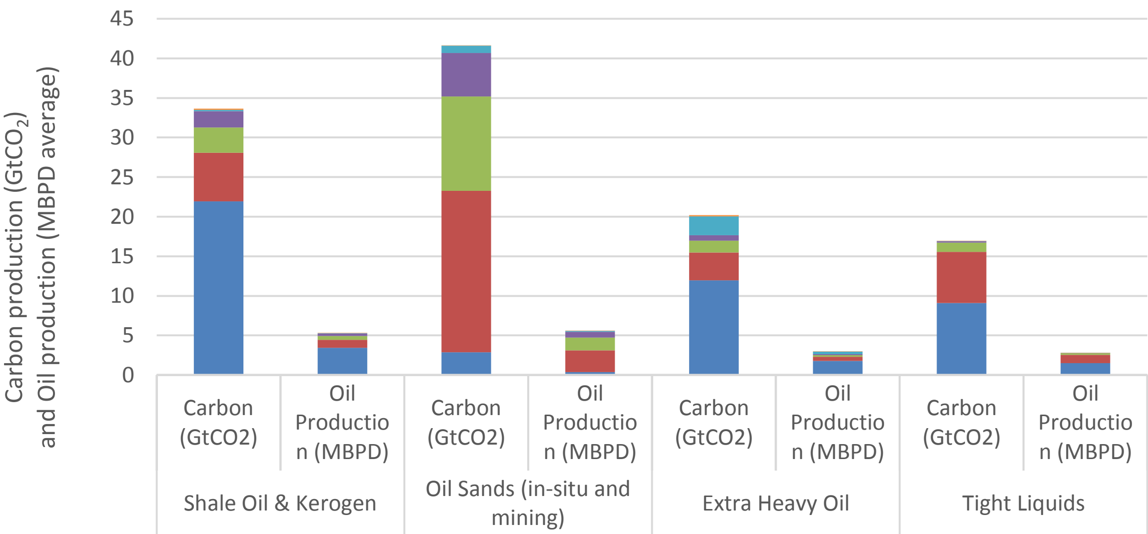
Source: Rystad Energy, CTI/ETA analysis 2014

[87] ETA/CITI, *From capex growth to capital discipline?* http://www.carbontracker.org/
[88] Matt Smith, "Shell's Arctic dreams postponed another year," CNN, January 30 2014,

Supply curves for unconventional oil: oil sands heavily concentrated above $80/bbl

- For oil sands, the share of production requiring a BEOP above $80/bbl is 44% (2.4 MBPD, 17 $GTCO_2$) - a higher share than for any other unconventional category
- Despite accounting for only one-third of total unconventional oil production through 2050, oil sands oil sands account for half of the carbon associated with $80+/bbl unconventional supplies
    - Reflects oil sands' relatively higher costs and greater carbon intensity of production
- Aside from oil sands, supply in other unconventional categories concentrated below $80/bbl
    - As discussed below, however, in several cases steep geopolitical complications involved in accessing these supplies (e.g. extra heavy oil in Venezuela, shale oil in Argentina)

Figure 15 Unconventional oil categories: global carbon & oil production by BEOP level, 2014-2050



	Shale Oil & Kerogen		Oil Sands (in-situ and mining)		Extra Heavy Oil		Tight Liquids	
	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)
Above 150	0.1	0.02	0.01	0.00	0.2	0.03	0.01	0.00
120-150	0.2	0.03	0.9	0.12	2.4	0.35	0.04	0.01
100-120	2.1	0.32	5.5	0.74	0.7	0.10	0.1	0.03
80-100	3.2	0.52	11.9	1.60	1.5	0.23	1.2	0.20
60-80	6.2	0.99	20.4	2.74	3.5	0.52	6.4	1.05
0-60	21.9	3.45	2.9	0.39	12.0	1.77	9.1	1.50

Source: Rystad Energy, CTI/ETA analysis 2014

Private-sector perspective

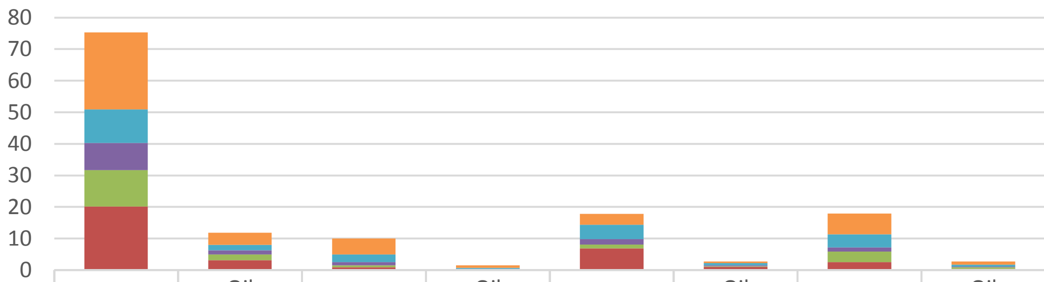
- Having examined supply curves by resource type at the global level, we now examine in particular the economics of supply from producers in our Private category - the issue most relevant to our focus on how asset owners and fund managers can assess carbon risk within their investment portfolios.

- Given their prevalence in mainstream investor portfolios, we highlight results for the seven global oil Majors; for reference we also show results for National oil companies.

Private-sector conventional production - Majors active in higher-cost Arctic and deep/ultra-deepwater plays

- Across all categories of conventional oil, 65% of potential production above $80/bbl (i.e. 90.6 $GTCO_2$) is projected to come from the private sector
    - nearly one-third of this higher-cost private-sector production is from deep/ultra-deepwater sources (4 MBPD or 26.4 $GTCO_2$)
    - Notable share as well for Arctic production (1.4 MBPD or 9 $GTCO_2$)
    - Significant presence of the Majors in both Arctic and deep/ultra-deepwater plays

Figure 16 Private conventional: total carbon & oil production by BEOP level, 2014-2050



	Conventional (not inc. Arctic and Total Deep Water)		Arctic		Deep water conventional (not inc. Arctic)		Ultra Deep Water conventional (1500m+) (not inc. Arctic)	
	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)	Carbon (GtCO2)	Oil Production (MBPD)
Above 150	24.4	3.89	5.1	0.80	3.4	0.52	6.6	1.06
120-150	10.6	1.68	2.3	0.36	4.6	0.72	4.2	0.63
100-120	8.6	1.35	1.0	0.17	1.7	0.27	1.3	0.20
80-100	11.6	1.80	0.7	0.10	1.2	0.20	3.4	0.51
60-80	20.1	3.17	0.9	0.09	6.9	1.04	2.5	0.38

Source: Rystad Energy, CTI/ETA analysis 2014

Table 6 Carbon from conventional oil production by BEOP level and company category, 2014-2050 ($GTCO_2$)

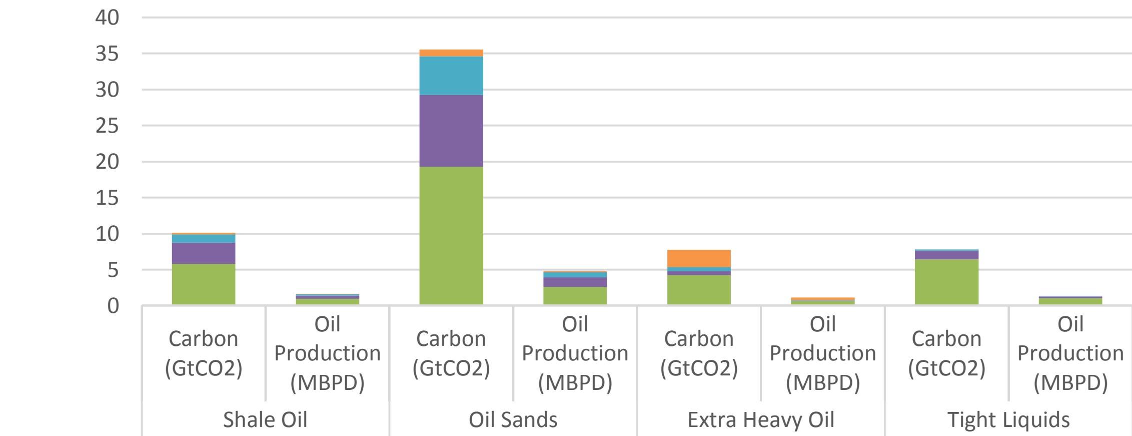
BEOP $	Conventional (not inc. Total Deep Water or Arctic)	Arctic	Deepwater only (not inc. Arctic)	Ultradeep water (not inc. Arctic)	Total Deepwater (Ultra deep water and deep water). Not inc. Arctic	Total Conventional
60-80 (Total)	44.5	1.2	13.0	5.8	18.8	64.6
National oil	24.4	0.4	6.0	3.3	9.4	34.2
Private	20.1	0.9	6.9	2.5	9.4	30.4
Majors	5.4	0.4	3.3	3.3	6.7	12.5
80-100 (Total)	30.9	1.0	7.0	5.1	12.0	43.9
National oil	19.3	0.3	5.7	1.7	7.4	27.1
Private	11.6	0.7	1.2	3.4	4.6	16.8
Majors	2.0	0.4	2.2	1.7	3.9	6.2
100-120 (Total)	15.6	1.4	5.2	1.9	7.1	24.1
National oil	7.0	0.4	3.4	0.6	4.0	11.4
Private	8.6	1.0	1.7	1.3	3.0	12.6
Majors	0.8	0.2	0.7	0.6	1.3	2.3
120-150 (Total)	13.3	2.5	6.0	4.3	10.3	26.1
National oil	2.7	0.2	1.4	0.1	1.5	4.4
Private	10.6	2.3	4.6	4.2	8.8	21.7
Majors	0.3	0.1	0.8	0.1	0.9	1.4
Above 150 (Tot	27.7	5.3	4.3	7.0	11.3	44.3
National oil	3.3	0.2	0.9	0.4	1.3	4.8
Private	24.4	5.1	3.4	6.6	9.9	39.5
Majors	0.3	0.2	0.1	0.5	0.6	1.0

Source: Rystad Energy, CTI/ETA analysis 2014

Private-sector unconventional production - near-monopoly on higher-cost supply, but Majors currently notable only in oil sands

- Across all categories of unconventional oil, 86% of potential production above $80/bbl (i.e. 25.4 $GTCO_2$) is projected to come from the private sector
    - Nearly two-thirds of this is from oil sands (2.2MBPD or 16 $GTCO_2$)

Figure 17 Private unconventional: total carbon & oil production by BEOP level, 2014-2050



	Shale Oil Carbon (GtCO2)	Shale Oil Oil Production (MBPD)	Oil Sands Carbon (GtCO2)	Oil Sands Oil Production (MBPD)	Extra Heavy Oil Carbon (GtCO2)	Extra Heavy Oil Oil Production (MBPD)	Tight Liquids Carbon (GtCO2)	Tight Liquids Oil Production (MBPD)
Above 150	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
120-150	0.20	0.03	0.91	0.12	2.39	0.35	0.00	0.00
100-120	1.15	0.18	5.40	0.73	0.58	0.09	0.15	0.03
80-100	2.96	0.48	9.94	1.34	0.51	0.08	1.19	0.20
60-80	5.79	0.93	19.29	2.60	4.26	0.63	6.44	1.05

Source: Rystad Energy, CTI/ETA analysis 2014

- The Majors have a one-quarter share of higher-cost oil sands production (4 $GTCO_2$), but (in the aggregate) do not at this time have a notable presence (at any BEOP level) in shale oil, extra heavy oil, or tight liquids
  - North American shale oil and tight liquids are dominated by mid-size "Independents," whereas the bulk of extra heavy oil reserves controlled by PDVSA, Venezuela's state-owned oil company

Table 7 Carbon from unconventional oil production by BEOP level and company category, 2014-2050 ($GTCO_2$)

BEOP $	Shale Oil	Oil Sands	Extra Heavy Oil	Tight Liquids	Total Unconventional
60-80 (Total)	6.2	20.4	6.3	6.4	39.3
National oil	0.4	1.1	2.0	0.0	3.5
Private	5.8	19.3	4.3	6.4	35.8
Majors	0.9	6.1	0.5	0.9	8.4
80-100 (Total)	3.2	11.9	1.5	1.2	17.8
National oil	0.1	2.0	1.0	0.0	3.1
Private	3.0	9.9	0.5	1.2	14.6
Majors	0.15	3.3	0.1	0.1	3.6
100-120 (Total)	2.0	5.5	0.7	0.1	8.3
National oil	0.9	0.1	0.1	0.0	1.1
Private	1.2	5.4	0.6	0.1	7.3
Majors	0.4	0.7	0.0	0.1	1.2
120-150 (Total)	0.2	0.9	2.4	<0.1	3.5
National oil	<0.1	<0.1	<0.1	<0.1	<0.1
Private	0.2	0.9	2.4	<0.1	3.5
Majors	<0.1	<0.1	<0.1	<0.1	<0.1

Source: Rystad Energy, CTI/ETA analysis 2014

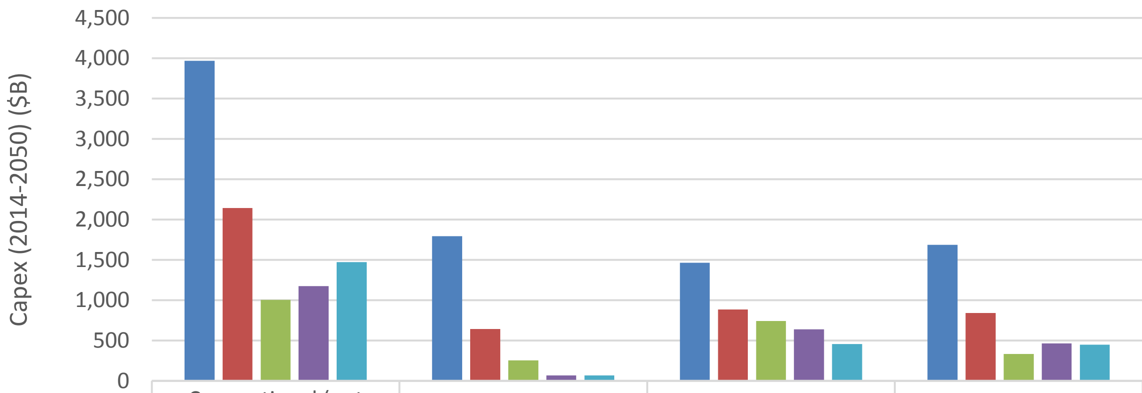
Private capital expenditures - $21 trillion of investment in higher-cost supply

- As discussed above, the past decade has seen tremendous growth in upstream capital expenditures (capex) related to oil production; the data reviewed above suggest that current investment trends exceed what is required in a 2°C world, creating demand and price risks for higher-cost projects.
- To assess such risk, we examine (for companies in our Private category) capex devoted to developing oil resources (and, therefore, carbon) that have a BEOP of $80/bbl or more

Private-sector capex on conventional production: going deep - one-third of private capex through 2050 on deep/ultra-deepwater production

- Through 2050, the amount of private capex required to develop all potential sources of $80-150+/bbl conventional oil is $18 trillion
    - Deepwater and ultra-deepwater projects account for $7 trillion of private capex - far more than any other oil type (whether conventional or unconventional)
    - $2.8 trillion of capex for Arctic projects

Figure 18 Private-sector capex for conventional oil production by BEOP level, 2014-2050 ($bn)



	Conventional (not inc. Deepwater or Arctic)	Arctic	Deep water only (not inc. Arctic)	Ultra deep water only (not inc. Arctic)
Above 150	3970	1793	1466	1685
120-150	2142	646	887	843
100-120	1004	255	743	336
80-100	1175	69	639	464
60-80	1472	67	456	451

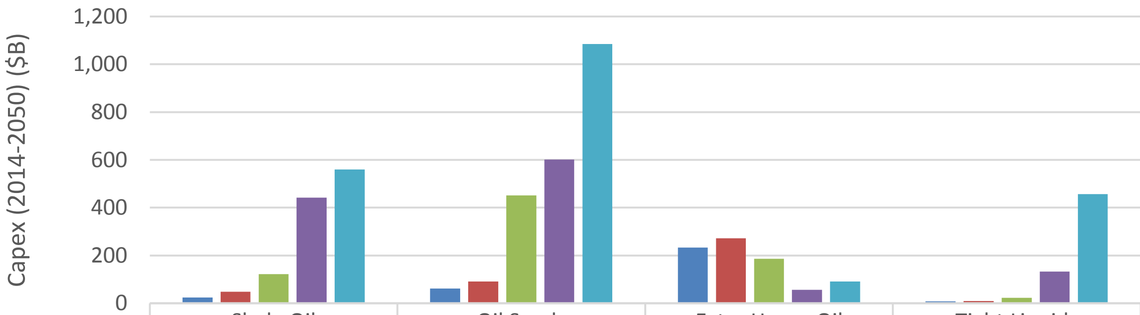
Source: Rystad Energy, CTI/ETA analysis 2014

*All capex totals expressed in real terms assuming 2.5% world inflation.

Private-sector capex on unconventional production: oil sands account for nearly half of high-cost capex

- Within unconventional production over $80/bbl, oil sands projects account for 43% of potential capex through 2050 ($1.2trillion)
- Significant capex also budgeted for $80-150+/bbl shale oil (~S600bn) and extra heavy crude ($840bn)

Figure 19 Private-sector capex for unconventional oil production by BEOP level, 2014-2050 ($bn)



	Shale Oil	Oil Sands	Extra Heavy Oil	Tight Liquids
Above 150	24	61	233	8
120-150	48	91	272	9
100-120	122	451	187	23
80-100	441	601	56	133
60-80	560	1084	91	456

Source: Rystad Energy, CTI/ETA analysis 2014

Capex geography - identifying the provinces where private capex will occur
Having broken down our capex and production numbers by company category, oil resource category, and BEOP level, we now identify *where* this capex and production is to occur. Following the convention of our data provider Rystad Energy, we sort capex by *province*, which Rystad defines as a "a geographic aggregation of assets or projects."

To focus on a timeframe relevant to investors and companies, we also shorten our period of analysis for capex to 2014-2025. To relate this medium-term capex to the carbon that is has the potential to produce over the long term, however, we show 2014-2025 provincial capex totals alongside potential carbon production from 2014-2050 (as we have been doing so far).

- Analyzing each oil resource category separately, we rank the Top 5 locations (by cumulative potential carbon production 2014-2050) within each BEOP level above $80/bbl
- Aggregating across all oil resource categories and BEOP levels above $80/bbl, we highlight any location with the potential to supply at least 1 $GTCO_2$

Top provinces for conventional capex: ramp-up of deep/ultra-deepwater spend in the Atlantic and Gulf of Mexico

- Key deep and ultra deep-water locations amount to $331 billion of medium-term capex and 18.1 $GTCO_2$ of potential long-term carbon production
    - Gulf of Mexico (mostly US), Brazil, Angola, Madagascar, Nigeria
- Key Arctic regions amount to $63 billion of medium-term capex and 5.3 $GTCO_2$ of potential long-term carbon production
    - Canada, Norway, US (potentially Russia in the future)
- $49 billion for conventional oil production in the northern Caspian Sea - may raise concerns for investors given challenging track record of the Kashagan oil field[89]

[89] Kepler Chevreux, *ESG Alert: Caspian Calamity Continues: FT Report Today Reinforces Our View that Kashagan Risks Becoming Giant Stranded Assetl,* April 28 2014.

Table 8 Key provinces for production across all conventional oil categories - carbon ($GTCO_2$, 2014-2050) and capex ($bn, 2014-2025) for the Top 5 provinces within each BEOP range above $80/bbl

Conventional (not inc. Arctic or Deep Water)		Arctic		Deepwater (excl. Ultra Deep Water)		Ultra Deep Water	
$80-$100		**$80-$100**		**$80-$100**		**$80-$100**	
1. Caspian Sea, KZ	1.6GT $49B	1. Northwest Territories, CA	0.2GT $10.7B	1. Gulf of Mexico deepwater, US	1.2GT $33.8B	1. Gulf of Mexico deepwater, US	1.2GT $44.2B
2. Western Siberia, RU	1.3GT $32.2B	2. Newfoundland and Labrador, CA	0.2GT $11.1B	2. Rio de Janeiro, BR	0.6GT $33.4B	2. Antsiranana, MG	0.8GT $<0.1B
3. Gulf Coast, US	0.6GT $15.2B	3. Nunavut Territory, CA	0.1GT $<0.1B	3. Atlantic Ocean, AO	0.6GT $34.6B	3. Rio de Janeiro, BR	0.7GT $13.2B
4. Arabian Gulf, QA	0.4GT $0B	4. Barents Sea, NO	0.1GT $3.6B	4. North Sea, NO	0.4GT $14.2B	4. Maranhao, BR	0.3GT $2.4B
5. Arbil (Kurdistan), IQ	0.4GT $9.1B	5. Alaska, US	0.1GT $4.4B	5. NW Shelf, AU	0.4GT $3.1B	5. Atlantic Ocean, BR	0.3GT $5B
$100-$120		**$100-$120**		**$100-$120**		**$100-$120**	
1. Western Siberia, RU	0.7GT $21.5B	1. Barents Sea, NO	0.5GT $11.8B	1. Atlantic Ocean, NG	0.5GT $2.5B	1. Rio de Janeiro, BR	0.7GT $14.6B
2. Toliara, MG	0.5GT $4.7B	2. Alaska, US	0.2GT $4.4B	2. Atlantic Ocean, GB	0.4GT $11.8B	2. Gulf of Mexico deepwater, US	0.6GT $12.2B
3. Gulf Coast, US	0.3GT $5.3B	3. Northwest Territories, CA	0.1GT $0.7B	3. NW Shelf, AU	0.3GT $2.6B	3. North Sea, DK	0.3GT $12.4B
4. Espirito Santo, BR	0.3GT $3.5B	4. Norwegian Sea, NO	0.1GT $0.6B	4. Timor Sea, AU	0.3GT $2.8B	4. Atlantic Ocean, CG	0.2GT $3.4B
5. Central North Sea, GB	0.3GT $5.4B	5. Alaska OCS, US	<0.1 GT $0.1B	5. Atlantic Ocean, AO	0.3GT $4.6B	5. Atlantic Ocean, NG	0.1GT $6.4B
$120-$150		**$120-$150**		**$120-$150**		**$120-$150**	
1. South Russia, RU	0.9GT $6.3B	1. Alaska, US	1.1GT $2.3B	1. Atlantic Ocean, NG	1.7GT $2.5B	1. Antsiranana, MG	2.1GT $33.6B
2. Ash Sharqiyah, SA	0.6GT $2.3B	2. Barents Sea, NO	0.6GT $5.9B	2. Atlantic Ocean, AO	0.7GT $11.8B	2. Atlantic Ocean, AO	1.1GT $6.7B
3. Western Siberia, RU	0.4GT $7B	3. Newfoundland and Labrador, CA	0.3GT $4.5B	3. Atlantic Ocean, GH	0.2GT $2.6B	3. Gulf of Mexico deepwater, US	0.4GT $10.3B
4. Atlantic Ocean, US	0.4GT $3.2B	4. Northwest Territories, CA	0.2GT $1.2B	4. Atlantic Ocean, GQ	0.2GT $2.8B	4. Bay of Bengal, IN	0.3GT $5.4B
5. Arabian Gulf, QA	0.3GT $1.3B	5. Norwegian Sea, NO	0.1GT $2B	5. Pacific Ocean, US	0.2GT $<0.1B	5. Atlantic Ocean, US	0.2GT $0B
Above $150		**Above $150**		**Above $150**		**Above $150**	
1. Ahmadi, KW	1GT $11.8B	1. Alaska, US	1.4GT $7.8B	1. Rio de Janeiro, BR	1.3GT $26.2B	1. Gulf of Mexico, MX	1GT $6.7B
2. South Russia, RU	1.2GT $9.1B	2. Barents Sea, RU	0.8GT $1.8B	2. Sabah, MY	0.4GT $2.5B	2. Atlantic Ocean, BR	0.9GT $12.1B
3. Western Siberia, RU	0.9GT $9.7B	3. East Siberian Sea, RU	0.7GT $1.2B	3. Gulf of Mexico, MX	0.4GT $1.1B	3. Gulf of Mexico deepwater, US	0.7GT $12.8B
4. Gulf of Mexico, MX	0.9GT $12B	4. Barents Sea, NO	0.6GT $4.2B	4. Gulf of Mexico deepwater, US	0.3GT $4.9B	4. Mozambique Channel, MZ	0.4GT $3.1B
5. Ash Sharqiyah, SA	0.5GT $6.4B	5. Newfoundland and Labrador, CA	0.3GT $2.9B	5. Sea of Okhotsk, RU	0.2GT $0.5B	5. Atlantic Ocean, AO	0.4GT $5.5B
Total of key provinces	**9.9GT $170.7B**	**5.3GT $62.9B**		**7.2GT $154.2B**		**10.9GT $176.9B**	

Source: Rystad Energy, CTI/ETA analysis 2014

*Note that locations in red, when aggregated across all resource categories and BEOP levels, have the potential to supply at least 1 $GTCO_2$ through 2050.

Top provinces for unconventional capex: largest overall spend is for Alberta's oil sands, with additional significant shares for US shale oil/tight liquids and heavy oil in Venezuela

- Provinces that produce oil sands, chiefly Alberta, amount to $383 billion of medium-term capex and potential long-term carbon production of 20 $GTCO_2$
- Key shale oil regions (mostly US Gulf Coast and the Vaca Muerta formation in Argentina's Neuquen basin) amount to $66 billion of capex and 2.1 $GTCO_2$ of potential carbon
- $45 billion of capex for tight liquids on the US Gulf Coast (e.g. Permian Basin plays), with potential carbon of 1 $GTCO_2$
- $25 billion of capex for extra heavy oil in Venezuela (Anzoategui), with potential carbon of 3 $GTCO_2$

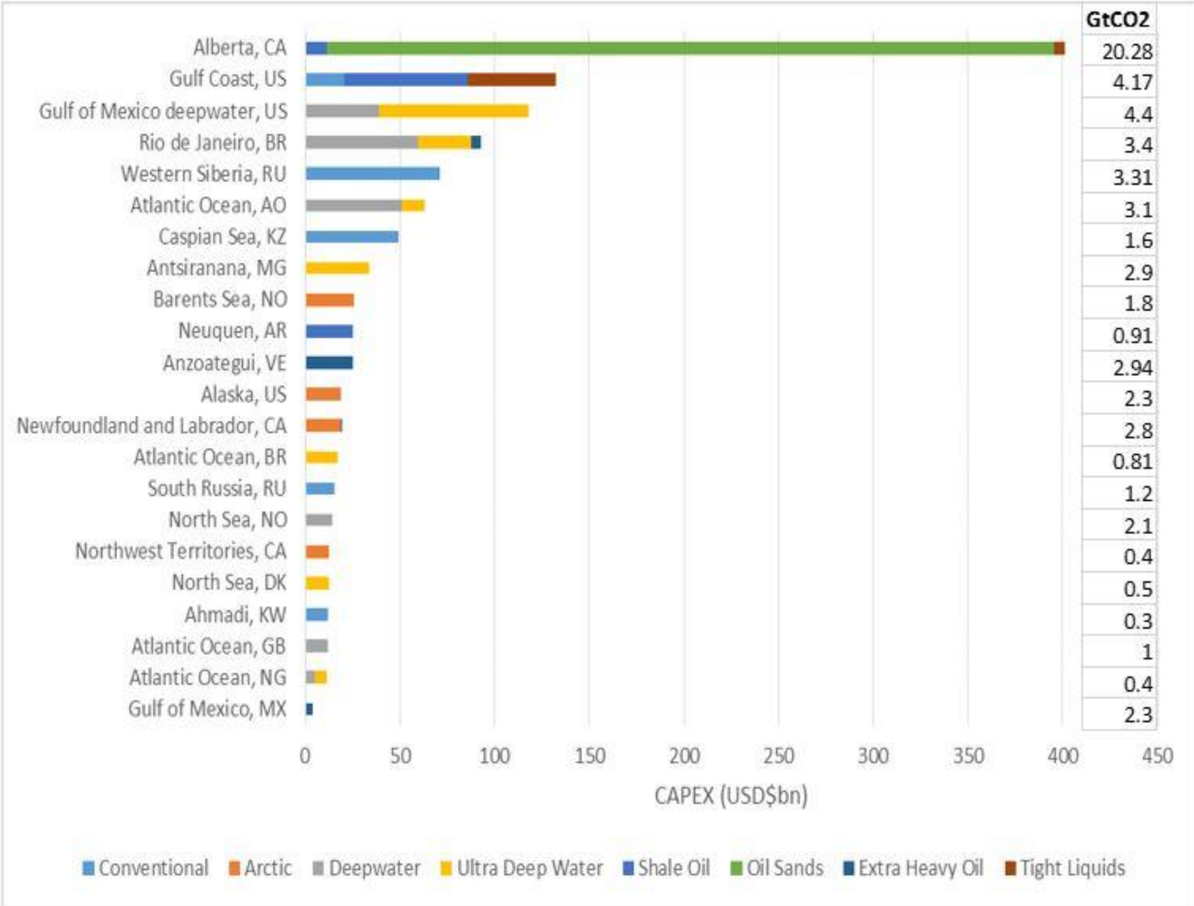
Table 9 Key provinces for production across all unconventional oil categories - carbon ($GTCO_2$, 2014-2050) and capex ($bn, 2014-2025) for the Top 5 provinces within each BEOP range above $80/bbl

Shale Oil		Oil Sands		Extra Heavy Oil		Tight Liquids	
$80-$100		**$80-$100**		**$80-$100**		**$80-$100**	
1. Gulf Coast, US	2.05GT $60.5B	1. Alberta, CA	9.9GT $167.9B	1. Guarico, VE	0.15GT $0.7B	1. Gulf Coast, US	0.98GT $39.8B
2. United States, US	0.28GT $3.1B	2. Ontario, CA	0.05GT $1.1B	2. Meta, CO	0.13GT $5.8B	2. Midcontinent, US	0.15GT $7.4B
3. Alberta, CA	0.21GT $11.2B	3. Saskatchewan, CA	<0.01 GT $<0.1B	3. Atlantic Ocean, SN	0.11GT $<0.1B	3. Alberta, CA	0.05GT $3.6B
4. Midwest, US	0.2GT $8.3B			4. Pastaza, EC	0.05GT $2.4B	4. British	0.02GT $1.1B
5. Rocky Mountain, US	0.15GT $4.7B			5. Northern North Sea, GB	0.03GT $1.2B		
$100-$120		**$100-$120**		**$100-$120**		**$100-$120**	
1. Neuquen, AR	0.75GT $20.5B	1. Alberta, CA	7.59GT $152.2B	1. Anzoategui, VE	0.38GT $<0.1B	1. Gulf Coast, US	0.14GT $4.9B
2. Central Jordan, JO	0.14GT $<0.1B			2. Rio de Janeiro, BR	0.1GT $5.5B	2. Alberta, CA	0.01GT $1B
3. North Jordan, JO	0.08GT $<0.1B			3. Meta, CO	0.05GT $1.9B		
4. South Jordan, JO	0.05GT $<0.1B			4. Thies, SN	0.02GT $<0.1B		
5. Gulf Coast, US	0.04GT $2.2B			5.	0.01GT $<0.1B		
$120-$150		**$120-$150**		**$120-$150**		**$120-$150**	
1. Neuquen, AR	0.16GT $4.6B	1. Alberta, CA	2.32GT $62.8B	1. Anzoategui, VE	2.56GT $24.9B	1. Gulf Coast, US	0.03GT $1.6B
2. Gulf Coast, US	0.02GT $0.9B			2. Thies, SN	0.02GT $<0.1B	2. Alberta, CA	<0.01 GT $0.2B
3. Midwest, US	0.01GT $0.6B			3. Pastaza, EC	0.02GT $0.2B	3. South Australia, AU	<0.01 GT $0.2B
4. Rocky Mountain, US	<0.01 GT $0.4B			4. Sicilia, IT	0.01GT $0.3B		
5. Champagne-Ardenne, FR	<0.01 GT $0.1B			5. Arauca, CO	0.01GT $0.6B		
Above $150		**Above $150**		**Above $150**		**Above $150**	
1. South Jordan, JO	0.08GT $2.6B	1. Alberta, CA	0.18GT $1.2B	1. Gulf of Mexico deepwater, MX	0.07GT $3.9B	1. Alberta, CA	0.01GT $0.8B
2. Rocky Mountain, US	0.02GT $2.1B	2. Kouilou, CG	<0.01 GT $<0.1B	2. Arctic Russia, RU	0.04GT $0.2B	2. Midcontinent, US	<0.01 GT $<0.1B
3. Gulf Coast, US	0.01GT $1.9B			3. Atlantic	0.02GT $<0.1B		
4. Western Siberia, RU	0.01GT $0.1B			4. Sicilia, IT	0.02GT $0.3B		
5. Boyaca, CO	<0.01 GT $0.2B			5. West Coast, US	<0.01 GT $0.1B		
Total of Key Provinces	**2.1GT $65.5B**	**19.8GT $383B**		**2.9GT $24.9B**		**1.1GT $46.4B**	

Source: Rystad Energy, CTI/ETA analysis 2014

*Note that locations in red, when aggregated across all resource categories and BEOP levels, have the potential to supply at least 1 $GTCO_2$ through 2050.

Figure 20 Most significant total (conventional + unconventional) key provinces broken down by oil type – carbon (2014 to 2050) and capex (2014-2025) for Top 5 provinces by oil category above $80/bbl



Source: Rystad Energy, CTI/ETA analysis 2014

Note: not all provinces shown.

Measuring geopolitical risk in key oil-producing provinces - $300 billion of potential capex subject to significant geopolitical risk

To measure geopolitical risk, we draw on data from the Worldwide Governance Indicators (WGI) project.[90] The four measures we focus on are:

- Control of corruption: the magnitude of public corruption, which can undermine the conditions necessary for international competitiveness

- Political stability and absence of violence/terrorism: the likelihood that the government "will be destabilized or overthrown by unconstitutional or violent means, including politically motivated violence and terrorism"

- Rule of law: extent to which individuals and businesses have confidence in and abide by the rules of society and in particular the quality of contract enforcement, property rights, the police, and the courts, as well as the likelihood of crime and violence

- Regulatory quality: "ability of the government to formulate and implement sound policies and regulations that permit and promote private sector development"

Drawing on our list of key provinces for future production and capex (Tables 8 and 9 above), we map the performance of key countries on the geopolitical risk indicators listed above (for results see Appendix A).

- With respect to production of conventional oil, key countries with high geopolitical risk include Russia, Kazakhstan, Iraq, Nigeria, Angola, Madagascar, Congo, and Equatorial Guinea;

- With respect to production of unconventional oil, key high-risk countries include Venezuela and – given its recent history of expropriating foreign-owned oil assets - Argentina.

- Specific risk-factors in key oil-producing countries include:

  - Political stability and absence of violence/terrorism: Iraq, Nigeria, Madagascar
  - Expropriation of foreign-owned assets: Argentina, Venezuela, possibly Russia
  - Corruption: Russia, Venezuela, Angola, Iraq, Nigeria
  - Legal risks to contracts with foreign oil companies: Venezuela, Argentina, Kazakhstan, Nigeria, Iraq, status of oil contracts with
  - High government take of oil company revenues: Russia, Nigeria, Angola, Venezuela

[90] Daniel Kaufmann, Aart Kraay, and Massimo Mastruzzi, "Worldwide Governance Indicators," The World Bank Group, 2013, http://info.worldbank.org/governance/wgi/index.aspx#home For 215 economies over the period 1996–2012, the WGI project assembles aggregate measures of six dimensions of governance. These aggregate indicators combine the views of a large number of enterprise, citizen and expert survey respondents in industrial and developing countries. They are based on 31 individual data sources produced by a variety of survey institutes, think tanks, non-governmental organizations, international organizations, and private sector firms.

  - Local content requirements for foreign oil companies: Kazakhstan, Angola, Brazil
- Using three of the four WGI categories that we outline above ("regulatory quality" is excluded), Goldman Sachs assign a geopolitical risk score and rating to each oil-producing country.[91]
  - Through 2025, oil companies have $147 billion of capex planned in countries that Goldman rate as “high risk” and $68 billion of capex planned in countries that Goldman rates as “very high risk.”[92]
  - Including $102 billion in capex planned for Angola (which Goldman rate as “medium risk,” but is in the bottom decline of 2012 World Governance Indicators rankings for corruption and rule of law) and Madagascar (which Goldman does not rate, but has recently experienced a period of political instability[93]), over the next 11 years oil companies have $317 billion of capex planned in countries with significant geopolitical risk.
- How industry succeeds at managing technical and geopolitical risk will largely determine whether actual costs of future projects are in line with projections

Looking ahead: $900 billion of capex on not-yet-producing-fields (i.e. a source of carbon asset risk over which companies have the most control)

Given the long project lead times in the oil industry, companies are now contemplating capex on resources that may not deliver their first oil for a decade or more. To characterize this, we examine capex (using the same criteria as above) specifically for "not-yet-producing" fields (i.e. those either "in discovery" or "not yet discovered").

- Across both conventional and unconventional oil nearly $900 billion of capex
- Regional/resource type breakdown similar to the findings above, with Canadian oil sands and Gulf of Mexico/Atlantic Ocean deep and ultra-deepwater production taking the largest share of future investment
- Note that, as many of the projects behind the aggregate numbers below are well in advance of a Final Investment Decision (FID), these are the projects that companies will find easies to cancel should economic or environmental risks become more relevant

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[91] Goldman Sachs, *380 Projects to Change the World,* 126. With the exception of “Regulatory Quality,” Goldman measures geopolitical risk using the same WGI risk indicators as we show in Appendix A.
[92] The “high risk” countries are Russia, Kazakhstan, Colombia, and Equatorial Guinea; the “very high risk” countries are Congo, Iraq, Nigeria, Argentina, and Venezuela.
[93] African Energy, "Madagascar: IOCs return following elections," Issue 275, 11 April 2014, "http://archive.crossborderinformation.com/Article/Madagascar+IOCs+return+following+elections.aspx?date=20140411#

Table 10 Key provinces for private capex on new (discovered and undiscovered) conventional oil resources - carbon ($GTCO_2$, 2014-2050) and capex ($bn, 2014-2025) for the Top 5 provinces within each BEOP range above $80/bbl

Conventional (not inc. Arctic or Deep Water)		Arctic		Deepwater (not inc. Ultra Deep Water), not inc. Arctic		Ultra Deep Water, not inc. Arctic	
80-100		**80-100**		**80-100**		**80-100**	
1. Western Siberia, RU	0.56GT $1B	1. Northwest Territories, CA	0.49GT $18.6B	1. Gulf of Mexico deepwater, US	1GT $24.1B	1. Rio de Janeiro, BR	1.1GT $20.3B
2. Zulia, VE	0.4GT $2B	2. Barents Sea, NO	0.14GT $3.5B	2. Atlantic Ocean, AO	0.9GT $38.6B	2. Antsiranana, MG	0.8GT $0B
3. Gulf Coast, US	0.32GT $3B	3. Alaska, US	0.1GT $6.9B	3. Rio de Janeiro, BR	0.49GT $29.1B	3. Gulf of Mexico deepwater, US	0.71GT $25.7B
4. Arbil (Kurdistan), IQ	0.32GT $4B	4. Newfoundland and Labrador, CA	0.09GT $7.1B	4. NW Shelf, AU	0.35GT $2.8B	4. Atlantic Ocean, AO	0.36GT $6.9B
5. Abu Dhabi, AE	0.26GT $5B	5. Norwegian Sea, NO	0.04GT $0.8B	5. North Sea, NO	0.38GT $7.3B	5. Maranhao, BR	0.31GT $2.4B
100-120		**100-120**		**100-120**		**100-120**	
1. Toliara, MG	0.47GT $1B	1. Alaska, US	0.47GT $0.1B (0.2)	1. Atlantic Ocean, NG	0.47GT $2.5B	1. Atlantic Ocean, AO	0.82GT $7.5B
2. Western Siberia, RU	0.27GT $2B	2. Barents Sea, NO	0.39GT $4.3B	2. Atlantic Ocean, GB	0.44GT $11.8B	2. Atlantic Ocean, CG	0.2GT $3.5B
3. Espirito Santo, BR	0.28GT $3B	3. Nunavut Territory, CA	0.09GT $0B	3. NW Shelf, AU	0.27GT $2.6B	3. Gulf of Mexico deepwater, US	0.12GT $5.6B
4. Baku, AZ	0.28GT $4B	4. Norwegian Sea, NO	0.06GT $0.4B	4. Timor Sea, AU	0.25GT $2.8B	4. Rio de Janeiro, BR	0.1GT $4.7B
5. Central North Sea, GB	0.26GT $5B	5. Gulf of Labrador, GL	0.04GT $0B	5. Atlantic Ocean, AO	0.28GT $4.6B	5. Atlantic Ocean, NJ	0.09GT $0B
120- 150		**120- 150**		**120- 150**		**120- 150**	
1. South Russia, RU	0.9GT $1B	1. Alaska, US	0.08GT $35.8B	1. Atlantic Ocean, NG	1.42GT $19.6B	1. Antsiranana, MG	2.06GT $33.6B
2. Ash Sharqiyah, SA	0.61GT $2B	2. Barents Sea, NO	0.03GT $1.7B	2. Rio de Janeiro, BR	0.89GT $13.4B	2. Atlantic Ocean, BR	0.43GT $2.3B
3. Western Siberia, RU	0.42GT $3B	3. Newfoundland and Labrador, CA	0.01GT $1.1B	3. Gulf of Mexico deepwater, US	0.51GT $10.3B	3. Atlantic Ocean, AO	0.42GT $5.3B
4. Atlantic Ocean, US	0.38GT $4B	4. Northwest Territories, CA	0.01GT $0.8B	4. Atlantic Ocean, AO	0.28GT $1.7B	4. Atlantic Ocean, US	0.2GT $0B
5. Arabian Gulf, QA	0.3GT $5B	5. Norwegian Sea, NO	0.01GT $1.9B	5. Atlantic Ocean, GH	0.21GT $1.8B	5. Bay of Bengal, IN	0.19GT $3.5B
Above 150		**Above 150**		**Above 150**		**Above 150**	
1. Ahmadi, KW	1.11GT $1B	1. Alaska, US	1.24GT $6.1B	1. Gulf of Mexico, MX	1.2GT $4.3B	1. Gulf of Mexico, MX	0.77GT $4.5B
2. South Russia, RU	1.07GT $2B	2. Barents Sea, RU	0.77GT $1.7B	2. Rio de Janeiro, BR	0.57GT $13.9B	2. Gulf of Mexico deepwater, US	0.56GT $9.6B
3. Gulf of Mexico, MX	1.06GT $3B	3. East Siberian Sea, RU	0.7GT $1.1B	3. Gulf of Mexico deepwater, US	0.57GT $10.8B	3. Mozambique Channel, MZ	0.43GT $3.1B
4. Western Siberia, RU	0.9GT $4B	4. Barents Sea, NO	0.61GT $3.9B	4. Sabah, MY	0.39GT $2.4B	4. Atlantic Ocean, BR	0.43GT $9.8B
5. Abu Dhabi, AE	0.63GT $5B	5. Kara Sea, RU	0.34GT $2.4B	5. Sea of Okhotsk, RU	0.25GT $0.5B	5. Hadhramaut, YE	0.32GT $3B
Total of key provinces	**7.2GT $85B**	**1.95GT $56.5B**		**8.9GT $173.7B**		**8.7GT $135.6B**	

Source: Rystad Energy, CTI/ETA analysis 2014

*Note that locations in red, when aggregated across all resource categories and BEOP levels, have the potential to supply at least 1 $GTCO_2$ through 2050.

Table 11 Key provinces for private capex on new (discovered and undiscovered) unconventional oil resources - carbon ($GTCO_2$, 2014-2050) and capex ($bn, 2014-2025) for the Top 5 provinces within each BEOP range above $80/bbl

Shale Oil inc. Kerogen		Oil Sands		Extra Heavy Oil		Tight Liquids	
80-100		**80-100**		**80-100**		**80-100**	
1. Alberta, CA	0.24GT $1B	1. Alberta, CA	6.71GT $58.6B	1. Guarico, VE	0.18GT $0.8B	1. Gulf Coast, US	0.62GT $20.2B
2. Rocky Mountain, US	0.1GT $2B			2. Pastaza, EC	0.05GT $2.4B	2. Midcontinent, US	0.04GT $1.1B
3. Gulf Coast, US	0.06GT $3B			3. Northern North Sea, GB	0.03GT $1.2B	3. Alberta, CA	0GT $0.1B
4. Tamaulipas, MX	0.05GT $4B			4. Dohuk (Kurdistan), IQ	0.02GT $0.5B		
5. Midwest, US	0.05GT $5B			5. Casanare, CO	0GT $0.6B		
100-120		**100-120**		**100-120**		**100-120**	
1. Central Jordan, JO	0.14GT $1B	1. Alberta, CA	5.97GT $120.9B	1. Anzoategui, VE	0.15GT $0B	1. Gulf Coast, US	0.13GT $3.7B
2. Neuquen, AR	0.11GT $2B			2. Atlantic Ocean, SN	0.11GT $0B	2. Alberta, CA	0.01GT $0.2B
3. North Jordan, JO	0.08GT $3B			3. Rio de Janeiro, BR	0.1GT $5.9B		
4. South Jordan, JO	0.05GT $4B			4. Thies, SN	0.02GT $0.1B		
5. Midcontinent, US	0.03GT $5B			5. Newfoundland and Labrador, CA	0GT $0B		
120- 150		**120- 150**		**120- 150**		**120- 150**	
1. Neuquen, AR	0.09GT $1B	1. Alberta, CA	2GT $50.1B	1. Anzoategui, VE	2.56GT $24.9B	1. Gulf Coast, US	0GT $1.2B
2. Gulf Coast, US	0.02GT $2B	2. Kouilou, CG	0.3GT $9.4B	2. Thies, SN	0.02GT $0B		
3. Champagne-Ardenne, FR	0.01GT $3B			3. Pastaza, EC	0.02GT $0.2B		
4. Alberta, CA	0.01GT $4B			4. Sicilia, IT	0.01GT $0.3B		
5. Queensland, AU	0.01GT $5B			5. Arauca, CO	0.01GT $0.6B		
Above 150		**Above 150**		**Above 150**		**Above 150**	
1. South Jordan, JO	0.08GT $1B	1. Alberta, CA	0GT $0.8B	1. Gulf of Mexico deepwater, MX	0.06GT $0.9B	1. Midcontinent, US	0.02GT $0B
2. Western Siberia, RU	0.02GT $2B			2. Arctic Russia, RU	0.04GT $0.2B		
3. Rocky Mountain, US	0.01GT $3B			3. Atlantic Ocean, MA	0.02GT $0B		
4. Boyaca, CO	0GT $4B			4. Sicilia, IT	0.02GT $0B		
5. Santander, CO	0GT $5B			5. West Coast, US	0GT $0B		
Total of key provinces	**0.24GT $0.3B**	**14.7GT $230.4B**		**2.7GT $24.9B**		**0.76GT $25.3B**	

Source: Rystad Energy, CTI/ETA analysis 2014

*Note that locations in red, when aggregated across all resource categories and BEOP levels, have the potential to supply at least 1 $GTCO_2$ through 2050.
** In Shale Oil and Tight Liquids categories, Alberta, CA is highlighted as a Key Province as it meets the criteria based on related carbon production from oil sands.

6. Detailed results on company exposure to higher-cost production

For the major provinces identified in Tables 8 and 9 above, the following tables show 2014-2025 potential company capex on oil resources with a BEOP above $80/bbl. To show exposure to particular resource types, the capex totals are sorted by oil resource category.[94]

Absolute exposure

Given all of the criteria and categories that we have outlined above to identify high-risk projects (a BEOP above $80/bbl within varies regional and oil type categories), Table 12 below shows the 20 companies with the largest *absolute* exposure to high-risk projects. The concentration of the seven oil Majors (BP, ConocoPhillips, Chevron, ENI, ExxonMobil, Statoil, Total) on this list is to be expected, as these companies have among the largest upstream capex budgets within the private-sector oil industry. Partly reflecting the strategy of Majors to build diversified portfolios that include every significant geography and resource type, the Majors are invested in opportunities throughout the cost curve, including ones at the upper end. Investors ought to monitor spending on such projects to ensure that desire to build a diversified portfolio does not result in capex being sanctioned on projects that do not make economic sense.

Note also the presence of partly-listed National Oil Companies such as Petrobras (through its interests in the deepwater "pre-salt" fields off the coast of Brazil) and Statoil (which has exposure to Arctic, deepwater and oil sands interests). The largest operators of Canadian oil sands (CNRL, Suncor Energy, Cenovus Energy, Athabasca Oil Sands) also make the list, reflecting the capital intensity of new projects in Alberta.

[94] For more discussion of the company-level implications of our analysis, see our companion note to this report - Carbon Tracker Initiative, *Carbon cost curves: evaluating risk to oil projects*, May 2014.

Table 12 Top 20 companies with the highest total capex exposure in the provinces and oil types above $80/bbl BEOP, 2014-2025

	Capex (2014-2025) US$million									
Company	Convent-ional	Arctic	Deep Water	Ultra Deep Water	Shale Oil	Oil Sands	Extra Heavy	Tight Liquids	High cost /risk total	Total company capex
Petrobras	26		79,336				4,089		83,452	454,317
ExxonMobil	1,736	3,944	22,307	20,066	2,286	18,075	5	4,927	73,346	290,012
Rosneft	69,009	456			129			92	69,686	264,661
Shell	49	152	20,254	15,869	1,169	25,898			63,392	314,551
Total	58	50	17,188	26,909		11,987			56,193	197,674
Chevron	3,062	4,942	20,095	12,857		7,435		7,384	55,774	247,093
BP	228	6,546	11,039	24,223		3,978	-	-	46,014	253,066
Gazprom	44,214	420	9		81				44,724	111,881
Statoil	2	22,432	8,329		22	7,848			38,634	218,578
CNRL		2	1			38,507		45	38,555	74,917
Eni	48	3,768	11,481	11,412	78	9,448			36,235	173,426
Saudi Aramco	35,582								35,582	402,509
Suncor Energy	114	3,142	20			31,402	2		34,679	70,995
Lukoil	28,997	9							29,006	132,497
Cenovus Energy	244					25,650	2,961		28,855	46,805
OGX Petroleo			21,117	2,340				4,681	28,138	30,839
ConocoPhillips	6,679	1,432	5,833		9,054	939		2,212	26,150	140,085
BG	5	115	2,001					23,147	25,267	55,775
Athabasca Oil Sands					23,634		65		23,698	26,498
Repsol	90	1,223	2,166					15,601	19,079	47,030

Source: Rystad Energy, CTI/ETA analysis 2014

Relative exposure

Having listed the 20 companies that have the highest absolute exposure to high-risk projects through 2025, Table 13 below shows the 20 companies that have the highest *relative* exposure (i.e. the largest share of higher-risk capex as a percentage of overall capex). Included in this table are the 20 companies with the with the largest capex totals which represented 50% or more of their total potential capex through 2025.

Note that for several smaller Independents (Teck Resources Limited, Queiroz Galvao E&P, Barra Energia, Rocksource, Famfa Oil) 100% of potential capex through 2025 meets our criteria for high risk (i.e. a BEOP above $80/bbl). This list brings highlights in particular the aggregation of risk around production from oil sands (10 companies with combined capex of $159 billion) and deepwater deposits (5 companies with combined capex of $22 billion). In particular, even aside from the 100% high-risk capex group noted above, a large number of Independents have a majority of their interests in projects with a BEOP above $80/bbl.

For the Majors (not included in Table 13 below), the "high-risk" share of overall capex ranges from 18% to 28% - suggesting that these companies retain significant exposure to the higher-end of the cost curve.

Table 13 Companies with the largest exposure where 50% or over of the total capex is in provinces and oil types above $80/bbl BEOP, 2014-2025

	Capex (2014-2025) US$million									
Company	**Convent-ional**	**Arctic**	**Deep Water**	**Ultra Deep Water**	**Shale Oil**	**Oil Sands**	**Extra Heavy**	**Tight Liquids**	**Total high cost / high risk**	**%capex**
CNRL	0	2	1			38,507		45	38,555	51%
Cenovus Energy	244	0				25,650	2,961		28,855	62%
OGX Petroleo e Gas			21,117	4,681			2,340		28,138	91%
Athabasca Oil Sands Corp						23,634		65	23,698	89%
Laricina Energy						14,428			14,428	97%
Teck Resources Limited						12,502			12,502	100%
MEG Energy						12,278			12,278	64%
OSUM						11,755			11,755	99%
Denbury Resources	9,656								9,656	57%
Queiroz Galvao E&P			182	5,625			1,755		7,562	100%
Sunshine Oil Sands						7,527			7,527	90%
Barra Energia				5,625			1,755		7,380	100%
Value Creation						7,308			7,308	99%
Reliance			375	6,700					7,075	85%
Rocksource		15		6,902					6,917	100%
Clayton Williams Energy	105				1,096			5,473	6,674	76%
Paramount Resources	42					5,490		8	5,541	91%
Famfa Oil				5,010					5,010	100%
Partex (Gulbenkian Fdn)			54	2,672					2,726	82%
Forest Oil					691			1,951	2,642	61%

Source: Rystad Energy, CTI/ETA analysis 2014

Company significance

To understand the significance of exposure to high-risk capex, investors should analyze the context of each company's potential capital expenditures. To begin, investors should ask:

• What is the timing of the planned expenditure?

• What is the expected time between project sanction and initial production ("first oil")?

• In the company's 10-year capex plan, what portion is for high-cost (i.e.$80/bbl+) projects?

• Is the capex concentrated in a particular region or oil type (e.g. oil sands, deepwater)?

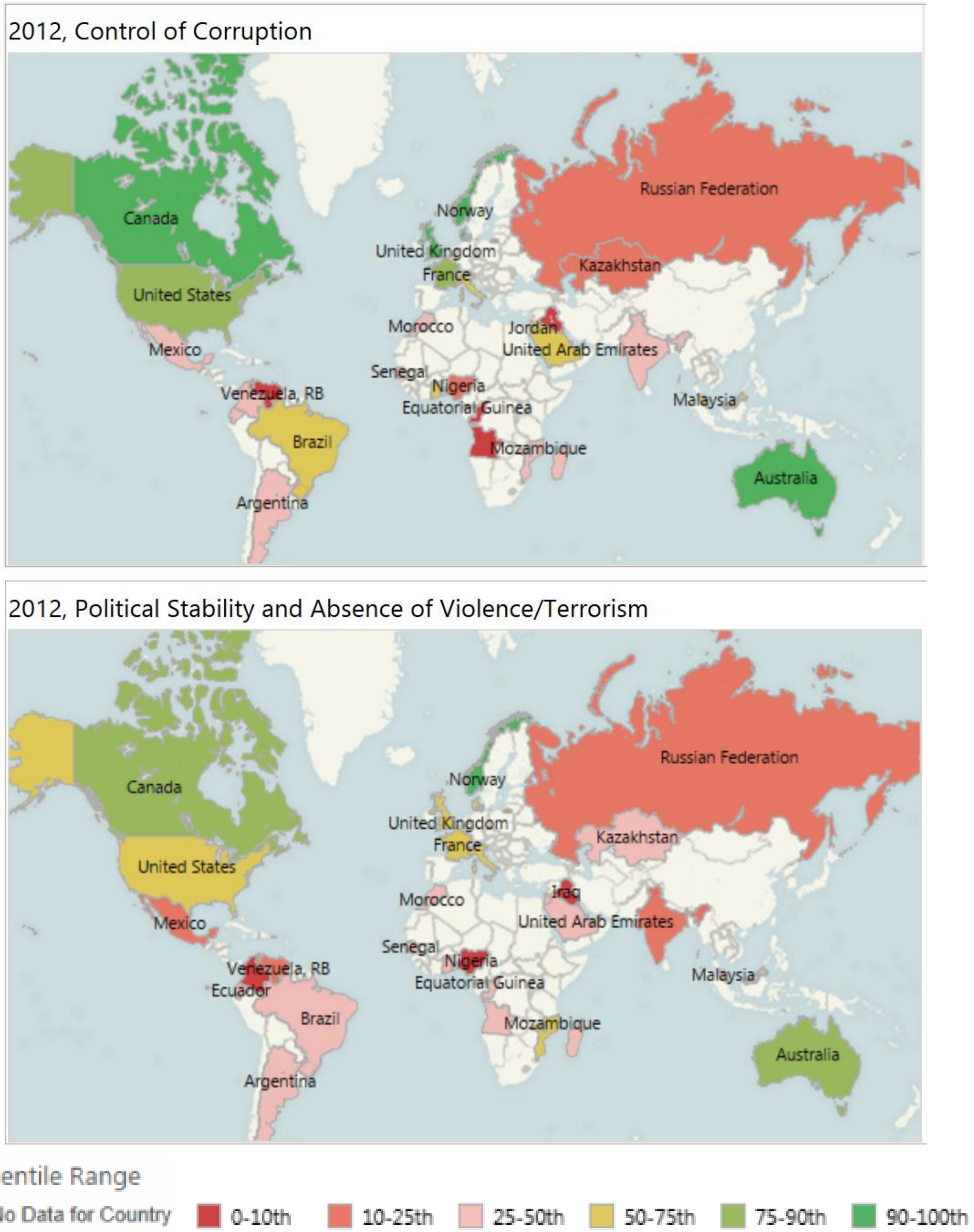
• What other significant cash commitments does the company have? How might volatility in capital costs or oil prices affect the ability to meet these commitments?

Reducing exposure to high-cost, high-risk projects does not mean that the oil Majors will go out of business. Indeed, in the past financial companies have rewarded companies that abandon excessively costly projects. Exercising greater capital discipline by reducing capex exposure to the higher end of the cost curve has the potential to be a positive process (for companies and investors alike) rather than a painful one. In the same vein, where Majors exit high-cost plays, this should be a signal to investors that any smaller operators still active in these regions are betting on high prices and low costs in order to generate profits for investors.

Appendix A – Geopolitical risks in key oil basins

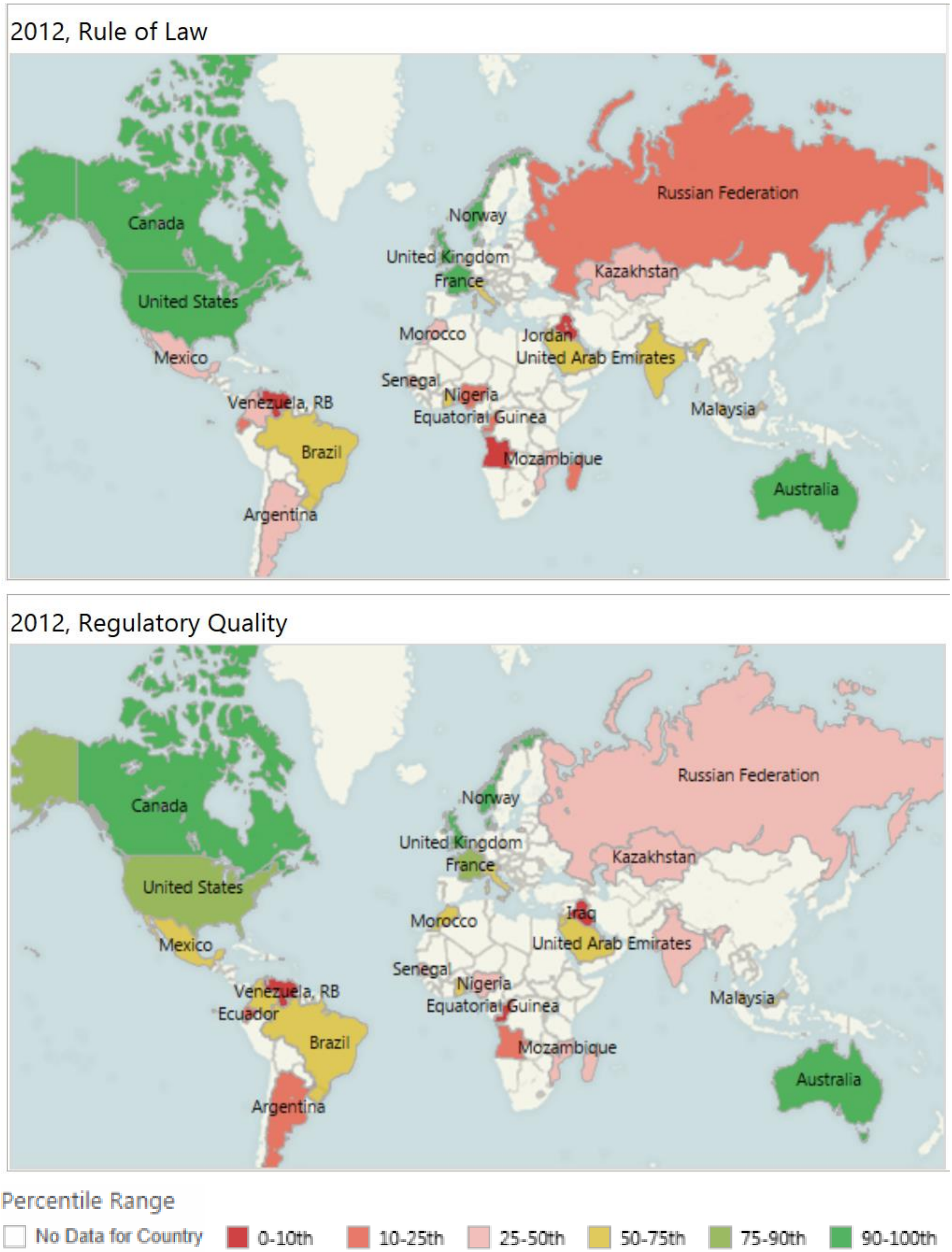
Countries in the figures below are taken from our lists of Top 5 provinces in Tables 8 and 9 above.

Figure 21 Corruption and political stability in countries containing key oil basins



Source: The Worldwide Governance Indicators, CTI/ETA analysis 2014

Figure 22 Rule of law and regulatory quality in countries containing key oil basins



Source: The Worldwide Governance Indicators, CTI/ETA analysis 2014

Appendix B – Oil supply methodology and data

Data Sources: Rystad Energy

The Rystad Energy (Rystad) UCube data (downloaded between January and April 2014) were used for the oil supply calculations. Unless specified otherwise, all of the definitions are quoted directly from Rystad.

Rystad UCube

UCube (Upstream Database) is an online, complete and integrated field-by-field database, including reserves, production profiles, financial figures, ownership and other key parameters for all oil and gas fields, discoveries and exploration licenses globally. UCube includes 65,000 oil and gas fields and licenses, portfolios of 3,200 companies, and it covers the time span from 1900 to 2100. Hence, UCube is a representation of the global E&P universe. UCube is an indispensable tool for anyone involved in strategy and business development work or investments within the global upstream oil and gas industry. UCube can be broken down along a number of dimensions like, hydrocarbons, life cycle, geography, water depth, field type, unconventional, companies and operators. Financial figures can be split among costs such as operational costs, exploration and investments, government take and free cash flow. All this make it possible to tailor-make queries in our database to get as precise data as possible. The data in UCube originates from primary sources such as company and government reports. Where information is not available we are doing in-house estimates to ensure that UCube is complete in all dimensions.

Oil: what is included

In this study we include crude oil, condensate and natural gas liquids (NGLs).

- Crude oil: Crude oil is oil excluding lease condensate.
- Condensate: Condensate is gaseous at reservoir conditions, but a liquid with spesific gravity below 0.8 at standard conditions. The UCube includes lease condensate, even when this is blended (spiked) with crude if such data are available, but excludes plant condensate sourced from several fields, which in UCube is considered as NGL.
- Natural gas liquids (NGLs): Natural Gas Liquids, ethane, propane, buthane sold separately from dry gas. Propane and buthane can be sold as Liquified Petroleum Gas, i.e. in pressurized bottles.

Conventional and Unconventional Oil Types

- Conventional refers to conventional reservoirs (ie good permeability), conventional hydrocarbons (ie not extra heavy crude) or conventional recovery methods (ie not hydraulic fracturing).
    - We include Arctic, Deep Water, Ultra-Deep Water and shelf and land conventional oil, condensate and NGLs in our Conventional grouping.
    - Water Depth Group disaggregates the Values from assets on land and offshore shelf (0-125 m depth) (that we combine) with assets in Deep Water (125 m - 1500 m depth) and Ultra Deep Water (deeper than 1500 m) that we refer to as Total Deep Water.

- Unconventional includes fields that are developed to extract unconventional resources, including oil sands (in-situ and mining combined), shale oils that we define as oil shale (kerogen) and shale oil plays combined, tight liquids, and extra heavy oil.

    - Oil shale and shale oil: Our "oil shale (kerogen) & shale oil" category combines the following:

        - - Oil shale is a petroleum source rock with a high content of immature hydrocarbons (kerogen), the rock is mined and can be burned like coal, or oil and gas but needs to be cooked out of the source rock by pyrolysis.

        - - Shale oil is crude or condensate produced from petroleum source rock by horizontal drilling and hydraulic fracturing. The associated gas may also have a high yield of NGL. Shale oil has recently become increasingly importance to US domestic oil supply thanks to breakthroughs on fracturing and drilling technologies

    - Tight liquids: The term "tight liquids" includes "all the new unconventional plays that cannot be classified as shale (examples: emerging unconventional plays in the Permian and Anadarko basins). The tight liquids plays in the Permian basin are either drilled vertically as in the northern Midland sub-basin where they target several very thick formations with the same well (e.g. Wolfcamp+Spraberry='Wolfberry'), in most other cases the unconventional wells are horizontal. All of these wells are accessed used hydraulic fracturing."

Company Segments
We split companies that produce oil, condensate and NGLs by the following segments: National, Private, and Majors.

- National companies include National Oil Companies (NOCs) such as Saudi Aramco, and International National Oil Companies (INOCs) that are NOCs with an international agenda such as Statoil, Petrobras, CNOOC, and Gazprom.

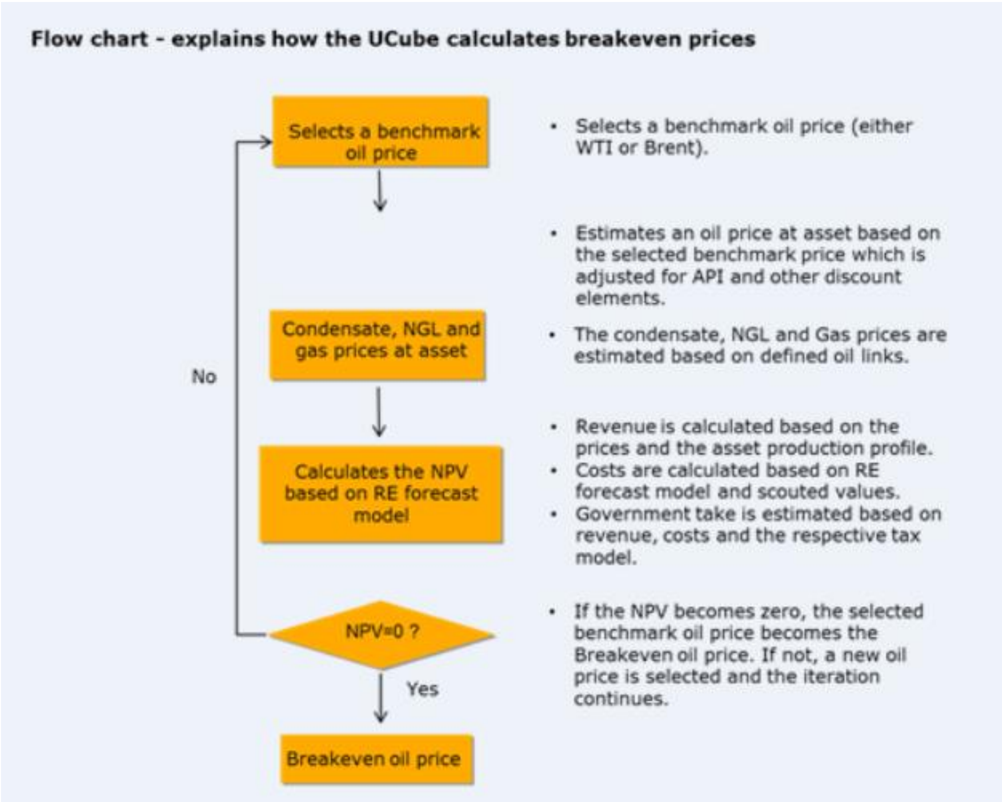
- Private companies are all companies that are not NOCs and not INOCs. Private includes operating companies, independents, investors, industrial companies, Majors, open acreage, unknown companies, suppliers etc.

    - The Major company segment includes the 7 largest E&P companies: ExxonMobil, BP, Shell, Chevron, Total, ConocoPhillips and ENI.

Breakeven Oil Price (BEOP)

Breakeven oil prices indicate at which oil prices the assets are commercial, i.e. oil price required for a net present value (NPV) of zero assuming a given discount rate. For gas fields it is the oil-equivalent breakeven price. The Breakeven Oil Price is the calculated breakeven price. Rystad uses by default a Brent Equivalent Oil Price and 10% discount rate.

Figure 23 Schematic of how Rystad calculates breakeven oil prices



Source: Rystad Energy

Breakeven Oil Price – Oil Sands

For the oil sands break even oil price in the separated unconventional figures (i.e. not higher level global figures) we assume transport costs of $15 in the analysis. For example, we report the production volume by using Rystad data for a break even oil price of $45 and under as production supplied at a (transport adjusted) break even oil price of $60 and under. Note that the Brent Equivalent Price takes into account oil quality factors (API, sulfur, etc.) that are already adjusted by Rystad in its equivalent price.

Capital Expenditure (CAPEX)

Unless otherwise noted we combine exploration capex and all other types of capex into our Capex definition. Capex includes investment costs incurred related to development of infrastructure, drilling and completion of wells, and modification and maintenance on installed infrastructures. It also includes all exploration costs to find and prove hydrocarbons: seismic, wildcat and appraisal wells, general engineering costs, based on reports and budgets or modeled.

Production and Forecasting

As recommended by Rystad, we used the Production 140 scenario to estimate future supply that are technically and economically recoverable.

Basis for Forecasting

Forecasting and modeling is used to obtain a complete data set. As UCube is a bottom-up database, all modeling is done on asset level. The value of applying qualified estimates for asset parameters appears when analyzing aggregated results. As an example, certainly no one knows how current exploration licenses will be developed in future. By assigning a development type to each license based on analogies to existing fields and industry trends, UCube provides insight into development trends.

Modeling in UCube is generally based on:

- Analogies - The industry is mainly going to continue as it has, thus analyses of industry practices are the starting point for modeling.
- Industry trends - Ongoing shifts in technology or practice are included in the modeling. As new trends usually enhance new business, trends are followed closely.
- Data - All known data points are included in the modeling in order to adapt models to field specifics and to limit the contribution from models.
- Simplicity - Conceptually, simple models are preferred; users prefer, accept, and trust simpler models they understand, despite possibly lower precision.
- Calibration - The bottom-up models are calibrated top-down against benchmarks on aggregated levels.

Forecasting Production

In UCube all assets - fields, awarded and unawarded acreage - have reserves and production profiles. The minimum parameters to provide a production profile are Reserves and Production start year. The resulting generic production profile will show a build-up, plateau, and decline phase, where production stops at economic cut-off. The more information available the more field specific the profile; reserve size, hydrocarbon type, development type, water depth, distance to shore, geography, and previous production all influence the resulting production profile. Licenses are risked with respect to volumes to take into account that not all licenses will result in successful discoveries and developments. Production (and economics) are forecasted on de-risked volumes and then risked to UCube values.

Forecasting Economics

Economic data on developments and operations at asset level are scarce, and Economics in UCube are mainly model-based. As for production the models are based on case studies and analogies. Size of reserves, development type, and water depth determine input parameters to decide development capex levels and timing as well as opex, well capex, and modification capex throughout field life. The models are extensively calibrated to known development cases and are calibrated "top-down", to benchmarks at aggregated levels. The fields stop producing when operational and well costs exceed revenue from production.
Economic modeling starts by allocating exploration, development, operational costs, and modification costs to the asset. When the asset starts producing the revenue is determined by multiplying production by prices. Oil prices depend on oil quality (API and total acids) and gas prices on local markets or known contracts. Knowing production, revenue, and costs, the government take is calculated and so is the profit (FCF- free cash flow). More than 600 different tax regimes are

included to calculate correct government take, comprising a variety of taxes, royalties, PSAs, sliding scales, and bonus schemes. In UCube the Economics variable is identical to the revenue, thus Economics = Revenue = Capex + Opex + Government take + FCF. From the economics time series the Net Present Value, not only of FCF but also of capex, opex, and government take, is calculated in the Economics Present Value (thus, to get the NPV use the Economics Present Value for 2010 with only FCF selected in Economy Type). For the purpose of analyzing economics effectively, the calculated fields.

Estimating Yet-to-find Resources

Two different approaches are used to estimate resources in open (unawarded) acreage and licensed (awarded) acreage. In both cases to-be-discovered volumes allocated to specific assets are risked to obtain overall expectancy correct results. When volumes are allocated, production and economics are calculated on de-risked volumes, and the resulting production profiles and economics are risked again before being entered into UCube. The interpretation of risked volumes is that all assets have a probability of becoming discoveries but many will not become so. Thus, it is expected that successful discoveries will show larger volumes than allocated. Since we do not know where discoveries will occur the YTF-volumes are generally low for each asset.

For open (unawarded) acreage volumes are mainly based on USGS surveys and basin estimates. However, resource estimates are reduced by roughly 50% as USGS is assumed to be too optimistic. In order to provide a realistic development of each basin, future licensing rounds are simulated to distribute discoveries and developments on time. As an example, for Tampen Spur in the North Sea there are 11 assets named "Open 2011 Tampen Spur Offshore North Sea, NO" for 2011, 2013, .. 2027, 2029. In practice, each of these assets (simulating rounds) represent a number of fields.

For licenses (awarded acreage) an industrial approach is applied:

- The best indication for the prospectivity of specific license blocks is given at "the moment of truth" when companies make their bids (work commitments and signature bonuses) for the blocks.

- Companies show different track records in finding costs. A company with a track record in finding costs of USD 2/bbl bidding MUSD 100 for a license will find 50 MMbbl; a company with track record USD 5/bbl will find 20 MMbbl. The best track record in the owner group applies.

- Volumes will be risked for probability of discovery, mainly depending on the maturity of a basin (e.g. ILX, frontier) and also taking into account the recent discoveries in a license or basin.

- Further, volumes will be risked by probability of drilling. In particular, this applies to offshore deepwater, where committed wells generally exceed exploration rig capacity. Confirmed wells get a pdrilling=1; for other wells pdrilling is reduced to ensure realistic drilling capacity.

- Exploration capex (expex) is based on simulating license commitments (e.g. seismics, number of wells).

When a discovery has been made in a license, a field asset is created and the remaining volumes of the license are reduced. The reserves of the discovery are determined by Rystad Energy's review board, estimating reserves based on published information, context, and industry insight.

Lifecycle classification

Life Cycle describes the current maturity status of the assets. Life Cycle is used to identify production from already producing fields, fields under development, discoveries and still to be discovered assets. We combine all lifecycles as part of our analysis unless otherwise noted. We call production from discovery and undiscovered assets "new production".

Resource Classification Proxy: P90, P50 and Pmean – Estimated Ultimate Recovery (EUR)

The Resource Classification Proxy gives an estimate for the volumetric uncertainty of remaining recoverable volumes in accordance with the SPE resource classification scheme: P90 for low estimate, P50 for best estimate, Pmean for expectance value.

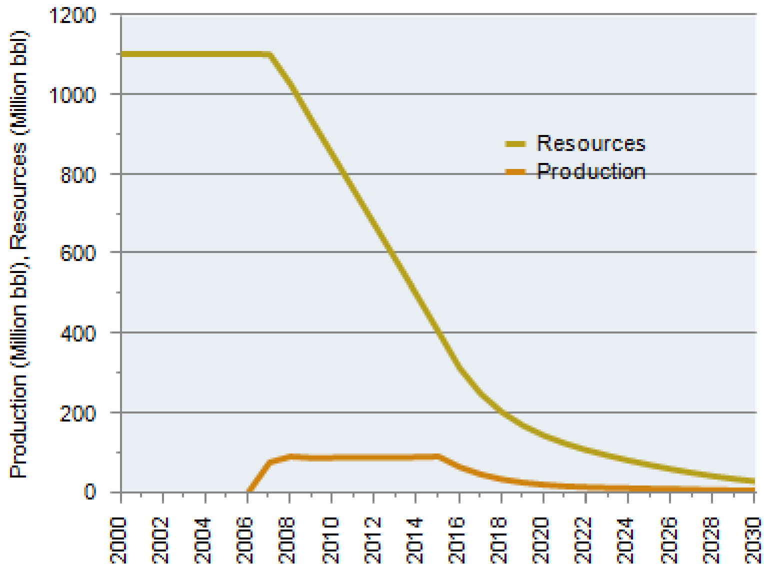
P90 is a low (high confidence) estimate of the remaining recoverable volumes. P50, when added to P90, is a best estimate of the remaining recoverable volumes. Pmean, when added to P90 and P50, is an estimate of the expected remaining recoverable volumes or Estimated Ultimate Recovery (EUR). Rystad uses the SPE resources and reserves classifications.

The Resources in UCube do not correspond directly with company reported 1P or 2P numbers. To reduce confusion Rystad uses the term Resources, not Reserves (Note that we use the term Reserves where the term is appropriate). The Resources in UCube correspond to the expected ultimate recovery (EUR) of the fields. The EUR number is based on reported 1P and 2P numbers, as well as empirical studies and case-by-case judgment. Whereas real fields may have both 1P, 2P, and 3P reserves, 1C, 2C, and 3C contingent reserves, as well as low, best and high estimate prospective resources, each UCube asset is assigned only the EUR, which is assumed to include all the above contributions. Similarly, UCube assets have only one lifecycle, whereas real fields may have resources of different maturity. Petroleum resources are best classified by the Petroleum Resources Management System, as described by SPE/AAPG/WPC/SPEE:

Resources and Production

The Resources variable in UCube is identical to the sum of future production, thus Resources and Production variables are internally consistent (with the exception that Other liquids are not included in Resources). For one asset the Resources value for a year is identical to the remaining reserves at January 1st that year, i.e. the sum of Production for this and the following years (see Figure 24 below).

Figure 24 Relationship between resources and production

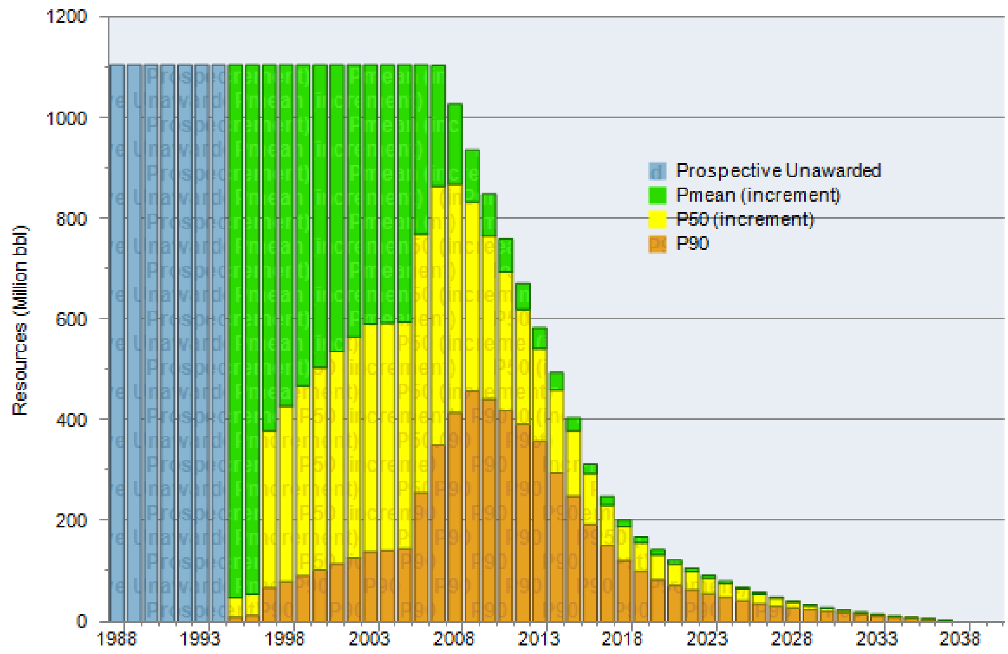


Source: Rystad Energy

Resource Classification Proxy

The Resources variable can be split by the Resource Classification Proxy. This split is modeled, and the purpose is to simulate the process of maturing the resources at asset level. This is shown for one asset in the figure below. Before the license is awarded the resources are "Prospective unawarded". Through seismics interpretation, exploration, appraisal, and field development the resources are gradually matured to P50 and P90 resources, and the remaining resources drop as resources are produced. Note that since P50 includes P90, and Pmean includes P50, we display the additive "P50 (increment)" and "Pmean (increment)". Thus P50=P90+P50 (increment). The Resource Classification Proxy can be used to analyze how companies mature their portfolios, and to estimate 1P and 2P-values at portfolio level.

Figure 25 Estimated ultimate recovery (EUR)



Source: Rystad Energy

Figure 26 Rystad production taxonomy

Estimate	Resources Classification Proxy	Lifecycle Category
1P	P90	Producing, Under development
2P	P90, P50 (increment)	Producing, Under development
Resource base	P90, P50 (increment), Pmean (increment)	All lifecycles except Undiscovered
Resource potential	no filtering	All lifecycles including Undiscovered

Source: Rystad Energy

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