

Energy transition & climate change

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Sustainability Research

Toil for oil spells danger for majors

Unsustainable dynamics mean oil majors need to become “energy majors”



Sustainability Research

Oil and stranded assets: gauging the risk from higher long-term prices

Until now, concern over new high-cost oil projects potentially becoming stranded in future has focused on the downside risk to oil prices, a concern that will only increase if oil prices – already down by nearly USD20/bbl since June on demand worries – fall further near term. However, there is another dimension to stranded-asset risk, largely ignored in this debate so far, namely the risk posed by a scenario of sustained *higher* oil prices over the longer term. And when looking at the risk of stranded assets it is the long term – i.e. beyond 2025 – that counts.

Dynamics of oil majors’ upstream capex increasingly unsustainable

Despite oil prices averaging close to USD110/bbl since mid-2011, the majors have seen their capital productivity decline sharply in recent years, prompting them to announce cuts to future capex in Q1 of this year. This is a clear sign they need higher prices for their higher-cost new projects. For this and many other reasons, we think that whatever happens in the near term, sustained higher prices will ultimately be necessary to bring on the supply projected in the IEA’s base-case scenario out to 2035. But with our Energy Return on Capital Invested (EROCI) analysis suggesting that renewables are already surprisingly competitive with marginal new oil projects, and with renewables set to see further cost reductions over the next two decades, higher long-term oil prices will be no guarantee against asset-stranding beyond 2025 for marginal new projects.

EVs are a risk to long-term oil demand growth, with China the key

The IEA sees global oil demand 14mbd higher in 2035, with c.4mbd of this for light vehicles in Asia. If the improving economics of renewables versus oil spurs a faster take-up of EVs in China than the IEA is assuming, this could threaten the viability of the marginal barrels beyond 2025. Higher long-term oil prices could thus create asset-stranding risk for new projects undertaken today at the higher end of the cost curve, a risk the majors should take seriously. Indeed, we think the oil majors now need to re-think their business model and become energy majors.

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Executive summary

Toil for oil: market's structural changes entail higher long-term prices

The global oil market has undergone profound structural changes in the last decade that have now culminated in a capex crisis for the industry, particularly the oil majors.

The structural changes that have precipitated this crisis are as follows:

- The fact that conventional crude-oil output has fallen since 2005, with overall supply ever more dependent since on (i) unconventional crude (more expensive and capital intensive than conventional crude), and (ii) natural-gas liquids and bio-fuels (of lower quality and less versatile than conventional crude);
- The fact that net global exports of crude oil have been declining since 2005 owing to sharply higher consumption in exporting countries – especially the OPEC countries with their very rapid population growth and highly subsidized domestic oil prices;
- The fact that the upstream oil industry's capital intensity has increased astronomically over the last decade owing to the massive annual investments now required in order (i) to replace declining output in ageing conventional fields, (ii) to counter the phenomenally high decline rates in US shale-oil plays, and (iii) to add supply over and above replacement levels so as to meet growing global demand;
- The fact that record recent levels of upstream capex since 2005 have fed through into only very modest increases in the total oil supply (and have not been able to prevent a decline in the supply of conventional crude oil);
- The fact that the rising costs associated with the industry's increasing capital intensity have run ahead of prices since 2011, and thus led to a fall in the oil majors' capital productivity and hence to cuts in their capex budgets since the beginning of this year;
- The fact that the always troubling geo-politics of oil seem to have become even more complicated recently, especially with regard to Iraq, Russia, and Libya.

Moreover, the base-case scenario of the International Energy Agency (IEA) over 2013-35 (known as the New Policies Scenario, or NPS) projects a further decline in the annual output of conventional crude oil over the next two decades and hence an accentuation of the increasing dependence on unconventional crude oil and other petroleum liquids observable since 2005. Despite this, the IEA projects only a modest increase in real oil prices out to 2035, although in our view some of its key assumptions look very optimistic. In this respect, we would highlight the following:

- The fact that the IEA projects that such growth as there will be in the supply of conventional crude oil will come from three countries – Iraq, Brazil, and Kazakhstan – whose ability to deliver on expectations is open to serious question. This means that the fall in conventional crude output over the next two decades could be much steeper than the IEA is projecting.
- The fact that the IEA's projections for growth in the aggregate supply of crude oil (i.e. conventional and unconventional combined) are highly dependent on continuing rapid growth in US unconventional oil, known as shale oil or light-tight oil (LTO).

Again, this means that if the IEA's projections for growth in US LTO output prove to be too optimistic, the increase in overall crude oil-production will be significantly lower over the next two decades than the IEA is projecting.

- The fact that the IEA is actually projecting an increase in net exports of crude oil out to 2035, even though net crude exports have been falling since 2005. Again, however, this increase in crude exports depends overwhelmingly on Iraq, Brazil, and Kazakhstan (with higher Canadian oil-sands production also boosting exports of unconventional crude). This means that if any or all of these countries sees slippage against the IEA's projections, global exports of crude oil could fall much more precipitously over the next two decades than they have over the last decade.
- The fact that the IEA sees a broadly flat annual capex requirement for the upstream oil industry over the next two decades despite the sharp year-on-year increases experienced over the last decade, and despite the increasing importance of unconventional crude oil – with its much higher capital intensity – in the IEA's projections out to 2035.

Significantly, though, the IEA does acknowledge that its base-case projections for the future oil supply depend on timely investments being made across the forecast period in order to bring on new supply to compensate for the ongoing decline in ageing oilfields. And in this respect, the main risk highlighted by the IEA to its future supply projections is that the increases in investment in the Middle East OPEC countries necessary to raise their output through the 2020s and beyond might not be forthcoming in a timely manner towards the end of this decade and the beginning of the next.

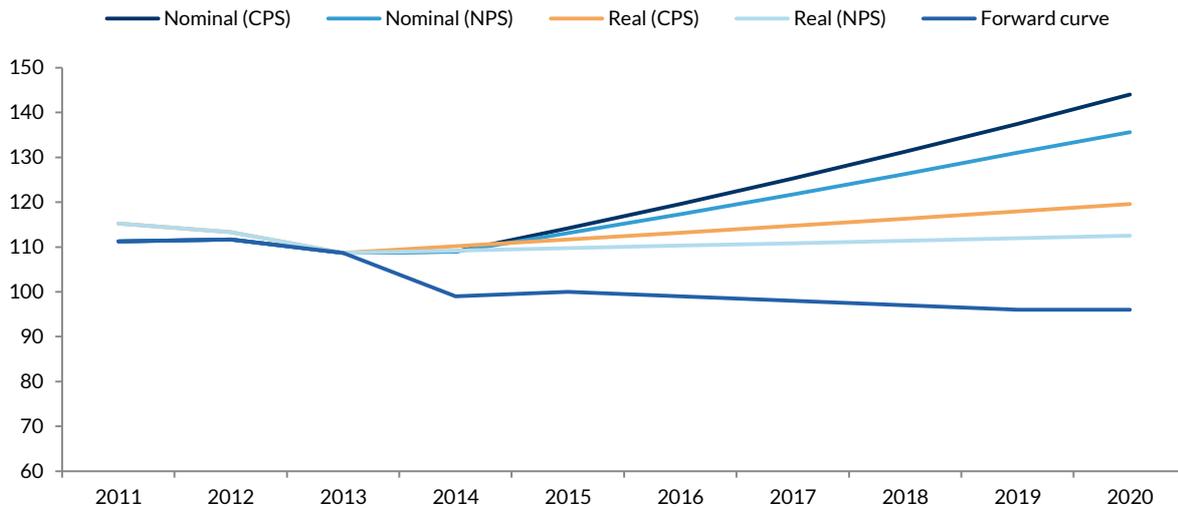
However, we think that the capex crisis of the oil majors – as signalled by their announcements earlier this year that they will reduce their upstream investments over their updated capital-budgeting horizons – means that the risk of insufficient investment is already here today. In turn, this means that the impact on supply is likely to be felt long before the early 2020s.

In particular, as the producers of the marginal barrels at the higher end of the industry cost curve, the majors are now signalling reduced investment in high-cost, high-carbon projects unless prices return to the levels required to remunerate the vast capital outlays such projects entail. As a result, we conclude that rising and sustained higher oil prices will be necessary over the next two decades to keep the oil supply growing, and think that prices will likely have to be some USD15-20/bbl higher across the forward curve than the IEA is projecting in its base-case scenario if its base-case supply projections are to be met.

Chart 1 shows a linear interpolation of the IEA's projections for oil prices out to 2020 under both its base-case scenario (known as the New Policies scenario, or NPS) and its business-as-usual scenario (known as the Current Policies Scenario, or CPS). It also shows the current forward curve out to 2020. Owing to what we think are over-optimistic supply projections in the IEA's NPS, we think future oil prices will in reality have to be much closer to those projected in the agency's CPS if the NPS supply projections are to hold good.¹

¹ Given that the IEA itself has signalled the risk that prices would have to rise by c.USD15/bbl versus its NPS projections if investments in future supply were to be delayed, our view on prices simply acknowledges the fact that future investments are already beginning to be scaled back in that all the oil majors have signalled capex cuts over their updated capital-budgeting horizons in Q1 of this year. We discuss this point in greater detail in both Section 1 and Section 3 of this report.

Chart 1: Potential oil-price trajectories out to 2020 (real and nominal USD/bbl, real in 2012 USD)



Source: BP, IEA

This means we would expect oil prices to reach USD120-125/bbl in real terms by 2020 (USD145-150/bbl in nominal terms), which is USD15-20/bbl higher than the IEA’s real and nominal projections under the NPS.²

Intuitively, our view on the need for sustained higher oil prices than those projected in the IEA’s base case would seem to be a positive scenario for the oil majors, allowing them to increase investment again at the upper end of the cost curve once prices return to a rising trajectory.

However, we think the traditional rules of the global energy system are now being upended as the world begins to transition away from fossil fuels towards a more sustainable future system based much more on renewable energy. And although this transition will take decades to be fully realised, the key point is that higher oil prices will only serve to accelerate it, not least because – in stark contrast to those of the oil industry – the costs of renewable-energy technologies will continue to fall over time.

This means that far from vouchsafing the future profitability of the higher-cost, high-carbon investments that the oil majors might make over the next decade, sustained high oil prices could actually lead to such investments becoming stranded beyond 2025 as the question of oil’s affordability relative to renewables comes into ever sharper focus.

² This view is strongly at odds with the forward curve at the moment, which, as can be seen, is currently in very mild backwardation out to 2020. We discuss the current shape of the forward curve relative to our view on the need for higher future prices – and the recent weakness in prompt prices since late June – in greater detail later in this Executive Summary under the subsection *Risks to our view*.

Oil and stranded assets: gauging the risks from higher long-term prices

Until now, the debate over the risk of stranded assets for the oil majors and other fossil-fuel companies has been conducted almost exclusively in terms of the threat from a potential tightening of global climate legislation designed to restrict the increase in the average global temperature to no more than two degrees C above pre-industrial levels.

This reflects the pioneering work in this field by [Carbon Tracker](#), whose seminal works [Unburnable Carbon](#) (2011) and the updated version [Unburnable Carbon 2013: Wasted Capital and Stranded Assets](#) have forced investors, fossil-fuel companies, and policymakers alike to engage much more seriously with the risks associated with future climate legislation.³

By the same token, however, this means that the debate over stranded assets has so far been focused almost exclusively on the premise of lower future demand for oil and other fossil fuels, and hence lower prices. This is fine as far as it goes, but as we argued in our report [Stranded Assets, Fossilised Revenues](#) earlier this year, it means that the potential for stranded assets arising under a business-as-usual scenario of continuing growth in oil demand and of *rising* oil prices has until now been almost completely ignored.⁴

And yet, in the absence of a meaningful binding global climate deal or a prolonged deflationary slump in the global economy, we think that continued rising demand for oil and hence rising real oil prices is much the more realistic scenario over the next two decades. Indeed, for the many reasons highlighted in this report, we see real oil prices rising more aggressively than the IEA's base case over the medium to long term.

But here's the catch: other things being equal, the steeper the upward trajectory for oil prices into the future, the greater will be the incentive to accelerate the deployment of renewable-energy technologies, especially as the cost trajectory for renewables is falling not rising. And as the producers of the marginal barrels in the global oil market who are making new investments today at the higher end of the cost curve to secure production beyond 2025, the oil majors will in our view be increasingly vulnerable to competition from the falling cost of renewable-energy technologies in that timeframe.

In this respect, we think the fact that up to 30% of the IEA's projected demand growth for oil out to 2035 is for cars and light commercial vehicles in China and India – both of which have a huge interest in reducing air pollution and minimising future oil imports – means that electric vehicles (EVs) have the potential to take a much larger share of projected oil-demand growth than either the IEA or the oil industry itself is currently assuming.

In particular, we think the single biggest risk posed to long-term demand outlook for oil is China's policy stance on EVs. As a result, if China decides to put in place a coherent strategic policy framework to accelerate the take-up of EVs, the IEA's current demand projections for 2035 would in our view have to be radically revised.

³ That said, we think the majors remain very complacent about the potential impact of future climate legislation, and almost completely oblivious to the risk to their business model posed by rising oil prices and the increasing competitiveness of renewables. It is the aim of this report to explain why the majors should be thinking much more seriously about the risk of stranded assets even under a scenario of rising and sustained high oil prices, and hence why they should be very cautious in particular about new investments in high-cost, high-carbon projects.

⁴ A notable exception is the recent very insightful piece by Chris Nelder for *SmartPlanet*, [Why the Potential for a Trillion-Dollar 'Carbon Bubble' Grows Bigger Every Day](#).

To illustrate the threat posed to future oil demand by the increasing competitiveness of renewable-generated electricity and the potential this has to revolutionise the market for light vehicles, we here develop the concept of the energy return on capital invested (EROCI) for a potential outlay today of USD100bn. How much energy would USD100bn purchase if invested in oil on the one hand, or in solar PV and wind energy on the other?

Table 1 below shows our calculations for the amount of gross and net energy that can be obtained from investing USD100bn in 2014 (i.e. based on current economics) in real 2012 USD (we use constant 2012 dollars so that we can compare EROCI estimates for 2014 with those we show later for 2020 and 2035). In all cases, our calculations are based on a one-off investment with no reinvestment taken into account.

We define gross energy as the amount of primary energy available before it is converted into useful energy in final consumption. We define net energy as the amount of energy available for final consumption after taking into account energy conversion and energy transmission losses. And in our analysis throughout this report, we define net energy more specifically to mean the useful energy available for final consumption in powering oil-fired cars and EVs. Accordingly, we use terawatt hours (TWh) as the unit of energy to compare the EROCI of oil versus renewables, using a conversion ratio of 1m barrels of oil equal to 1.7TWh.

For oil, we assume investment opportunities in new projects with full breakeven costs (all-in capital costs, operating costs, and any royalties payable) of USD75/bbl and USD 100/bbl, as these cover breakeven cost levels in the upper quartile of the industry cost curve and will account for a very significant share of the new investment opportunities available to the oil majors today and over the next decade. We assume two different potential lifetimes for new oil projects (ten and 20 years), as some projects (e.g. deep-water) have shorter lifetimes than others (e.g. conventional onshore and oil sands).⁵

For renewables, we assume capital costs of USD3bn/GW for solar PV, USD1.5bn for offshore wind, and USD 4.5bn/GW for offshore wind. In terms of operating costs, we assume that for solar projects operating costs account for 10% of total lifetime project costs, and for both onshore and offshore wind for 20%. We assume annual load factors of 13% for solar, 25% for onshore wind, and 40% for offshore wind. All renewables investments are assumed to have project lifetimes of 20 years.

As can be seen from Table 1, looking first at the numbers for gross EROCI, we see that on an annual basis over ten years oil at both USD75/bbl and USD100/bbl yields more gross energy than all the renewable sources. Even at USD100/bbl, oil has a gross EROCI of 169TWh per year over ten years, while onshore wind, the most productive of the renewable sources, yields only 117TWh. However, if we then look at the gross energy yield for oil projects with a 20-year lifetime, the relative economics of renewables improve, and onshore wind actually yields slightly more gross energy annually over 20 years than oil at a price of USD75/bbl (117TWh versus 113TWh), and nearly 40% more than oil at USD100/bbl (117TWh versus 85TWh).

⁵ Indeed, oil-sands projects can last beyond 20 years.

Table 1: Gross and net EROCI of oil and renewables for USD100bn (constant 2012 USD) invested in 2014 (TWh)

| | GROSS EROCI | | | NET EROCI | | |
|-------------------|----------------------|----------------------|--------------------------|----------------------|----------------------|--------------------------|
| | Annual over 10 years | Annual over 20 years | Cumulative over lifetime | Annual over 10 years | Annual over 20 years | Cumulative over lifetime |
| OIL | | | | | | |
| USD75/bbl | 225 | 113 | 2,250 | 56 | 28 | 563 |
| USD100/bbl | 169 | 85 | 1,694 | 42 | 21 | 424 |
| RENEWABLES | | | | | | |
| Solar PV | 35 | 35 | 704 | 24 | 24 | 475 |
| Wind | | | | | | |
| Onshore | 117 | 117 | 2,336 | 76 | 76 | 1,518 |
| Offshore | 62 | 62 | 1,246 | 39 | 39 | 779 |

Source: Kepler Cheuvreux

That said, oil at USD100/bbl still yields more gross energy annually over 20 years than either solar or offshore wind (85TWh versus 35TWh and 62TWh, respectively).

Given that we assume that all renewable projects have a 20-year lifetime, it follows that these same patterns for annual EROCI over 20 years also hold true for the gross cumulative energy yield, with onshore wind yielding slightly more gross energy over its full 20 years than oil at a price of USD75/bbl (2,336TWh versus 2,250TWh), and nearly 40% more than oil at USD100/bbl (2,336TWh versus 1,694TWh).

The first key conclusion we draw from this analysis is that in terms of the economics of gross energy yield, onshore wind is already very competitive with oil both on an annualised basis over 20 years and on a full 20-year lifecycle basis at prices of USD75/bbl and above. That said other renewable technologies are still a long way behind oil even at USD100/bbl.

However, is the gross energy yield the right way to be looking at the relative economics of oil and renewables or should we rather be looking at the net energy yield for powering cars and light commercial vehicles?

After all, the risk to the IEA's oil-demand growth forecasts is that its projections for the fuels used in road transportation out to 2035 assume a negligible take-up of EVs. And the point is that when we are looking at the relative economics of oil versus electricity for powering cars and light commercial vehicles, the key to competitiveness of each energy source is its net energy yield, not its gross energy yield.

In other words, we have to take into account the fact that for oil, the internal combustion engine loses 75-80% of the energy value of the oil input, while for EVs, converting electrical energy into battery-stored chemical energy and then back into electrical energy loses 25-30% of the original power input. We therefore assume a net energy yield from oil of 25%, and a net energy yield from renewable electricity for use in EVs of 70%.

However, in the case of renewables, we also then have to adjust for transmission losses. For our stylised purposes here, we assume 2.5% transmission losses for solar PV, 5% for onshore wind, and 7.5% for offshore wind. This means that the net energy yield for EVs powered by solar PV is here assumed to be 67.5%, for EVs powered by onshore wind 65%, and for EVs powered by offshore wind 62.5%.

This being the case, what does the EROCI look like for our various energy sources when we look at the net energy yield on an annualised ten-year and 20-year basis, and over the full lifetime of projects?

As can be seen from Table 1 again, on a net-energy basis the picture changes dramatically. Even on a ten-year basis, onshore wind at 76TWh has a net annual EROCI nearly 50% greater than that of oil at USD75/bbl (56TWh), and nearly twice that of oil at USD100/bbl (42TWh).

Even more strikingly, on a 20-year basis all renewable sources have a superior net EROCI to oil at USD100/bbl (solar is at 24TWh to oil's 21TWh), while onshore wind yields three times as much net energy as oil at USD100/bbl, and offshore wind nearly twice as much. Again, these same patterns hold on a full project-lifetime basis.

In short, what our analysis in this report shows is that looking at the *net* energy derived for powering cars from oil versus renewable-generated electricity on a full life-cycle basis, then already today USD100bn invested in wind would yield more energy than USD100bn invested in oil at USD75/bbl. Moreover, and already today, all renewable sources – including solar – have a superior net EROCI to oil at USD100/bbl.

More importantly, if we are right about oil prices then the relative competitiveness of renewables will only increase over time as oil costs increase in real terms and renewable costs continue to fall with technology improvements and economies of scale.

Table 2 shows our calculations for the net EROCI of oil and renewables in 2020 and 2035, again in real terms (constant 2012 USD). For oil, we assume new project opportunities for the majors at USD100/bbl and USD125/bbl in 2020, and at USD125/bbl and USD145/bbl in 2035. We think these are the right ranges in real terms for 2020 and 2035 for the upper quartile of the industry cost curve, and hence for the majors' new marginal investment opportunities by those dates.

Table 2: Net EROCI of oil and renewables for USD100bn (constant 2012 USD) invested in 2020 & 2035 (TWh)

| | 2020 | | | 2035 | | |
|-------------------|----------------------|----------------------|--------------------------|----------------------|----------------------|--------------------------|
| | Annual over 10 years | Annual over 20 years | Cumulative over lifetime | Annual over 10 years | Annual over 20 years | Cumulative over lifetime |
| Oil | | | | | | |
| USD100/bbl | 42 | 21 | 424 | | | |
| USD125/bbl | 34 | 17 | 339 | 34 | 17 | 339 |
| USD145/bbl | | | | 29 | 15 | 292 |
| Renewables | | | | | | |
| Solar PV | 28 | 28 | 559 | 33 | 33 | 657 |
| Wind | | | | | | |
| Onshore | 84 | 84 | 1,687 | 95 | 95 | 1,898 |
| Offshore | 46 | 46 | 916 | 54 | 54 | 1,078 |

Source: Kepler Cheuvreux

For renewables, we assume a 10% capital-cost cost reduction in real terms for onshore wind to 2020, and then a further 10% capital-cost reduction in real terms by 2035 versus 2020. For solar PV and offshore wind we assume slightly greater real-terms cost reductions of 15% to 2020 and a further 15% to 2035.

However, we make no changes to the assumptions on operating costs or load factors that we have assumed in our calculations for 2014, and this is in our view conservative given the further improvements in all renewable technologies that can be expected over the next two decades.

The numbers in Table 2 speak for themselves. By 2020 all renewable technologies have a significantly superior net EROCI to that of oil at both USD100/bbl and USD125/bbl, and it is almost impolite to compare the net EROCI of oil with that of renewables by 2035.

Of course, there remain huge infrastructure challenges to be overcome – and paid for – if EVs are to realise their potential over the next two decades, but our analysis of the net EROCI of oil versus renewables suggests that the balance of competitive advantage will shift decisively in favour of EVs over oil-powered cars over the next two decades.

In turn, this would suggest that by the late 2020s or early 2030s renewables could be competing much more aggressively with the oil market's marginal barrels for a share of Asia's fast-growing road-transportation market (and especially China's) than either the IEA or the oil industry itself is currently assuming.

If we are right, the implications would be momentous: it would mean that the oil industry faces the risk of stranded assets not only under a scenario of falling oil prices brought about by the structurally lower demand entailed by a future tightening of climate policy, but also under a scenario of rising oil prices brought about by increasingly constrained supply.

The structure of this report

This report is divided into three main sections.

In Section 1 (*The toil for oil: a much harder game since 2005*) we consider in detail the ongoing structural changes in the oil market since the middle of the last decade that have led to the huge increase in the capital intensity and cost base of the upstream oil industry, and hence to sustained higher prices.

In Section 2 (*Oil and IEA's New Policies Scenario: a critique*) we review the assumptions underlying the IEA's base-case projections for oil supply and oil prices out to 2035 as set out in the 2013 WEO. We also set out why we think the IEA's projections are optimistic, and hence why we think prices will have to go higher than the IEA is assuming in order to bring on the supply it is projecting.

In Section 3 (*Pricing scenarios and future capex risk*) we examine the relative economics of oil and renewable-energy technologies by comparing the EROCI of oil at different price levels with the EROCI of solar PV and onshore and offshore wind.

We find that in terms of *net* energy yield on a full life-cycle basis renewables – especially offshore wind – already look competitive with oil at USD100/bbl, and that all three renewable technologies will on this basis be much more competitive than high-cost oil by 2020 and 2035.

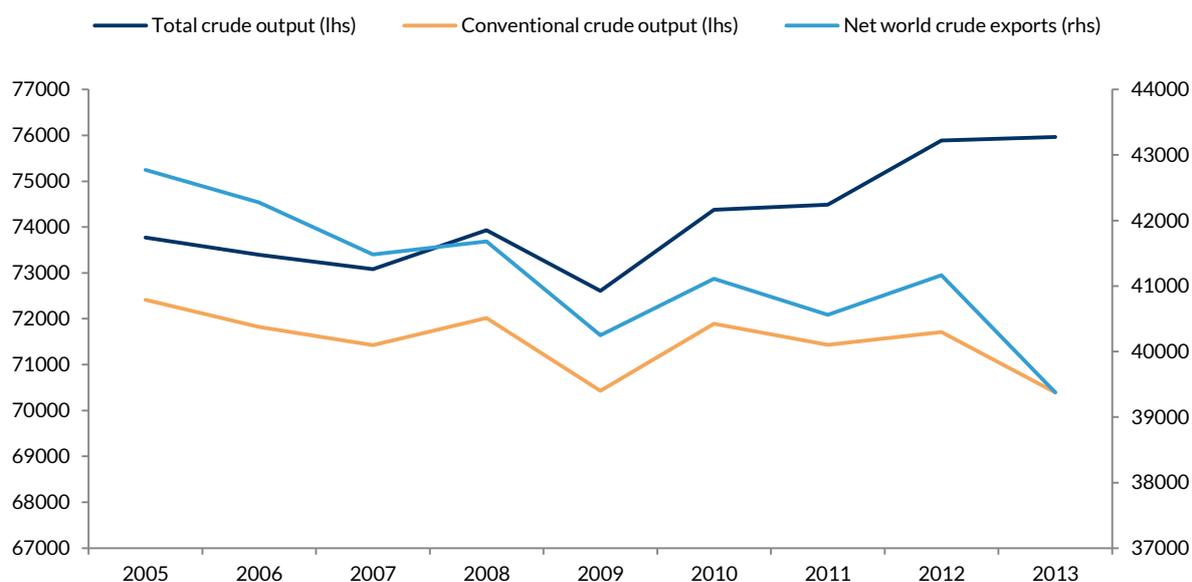
Below we offer a summary of the arguments developed in each of these three main sections

The toil for oil: a much harder game since 2005

Since 2005 conventional crude oil production has gone into decline and crude oil exports have also fallen from their 2005 peak, while crude oil prices have risen sharply before stabilising since 2011, averaging nearly USD110/bbl over the last three-and-a-half years (the longest period in history of such sustained high real oil prices).

Chart 2 shows the global trends in total crude oil (conventional and unconventional combined), conventional crude oil only, and net world crude oil exports since 2005.

Chart 2: Trends in world crude oil output (total and conventional) and in net world exports of crude oil, 2005-13 (kbd)



Source: Kepler-Cheuvreux estimates from EIA data

The fact that prices have risen so much since 2005 indicates that producers have had every incentive to raise conventional production in recent years, so the fact that they have been unable to do so points to rising decline rates in ageing conventional fields and a lack of sufficient new discoveries to make up for these declines.

At the same time, the falling share of crude oil in the overall supply mix means that the quality of the aggregate oil supply has been declining since 2005.

In contrast to the decline in conventional crude oil production, the trend in the output of unconventional crude in recent years has been sharply upwards, with the supply of US LTO surging since 2008, and Canadian oil sands steadily growing supply year after year. The surge of US LTO has prompted a growing narrative about a new age of global oil abundance in both academic and mainstream-media circles (see [here](#), [here](#), [here](#), and [here](#) for four examples of many such optimistic interpretations of what the US shale revolution means for the world), and production growth over 2008-13 has indeed been phenomenal.

Yet despite the extraordinary surge in North American unconventional crude production over the last few years, the global crude supply has increased by only 3% since 2005.

This means that without the surge in US LTO and Canadian oil-sands production the global supply of crude oil would actually have fallen by 2mbd over 2005-13. Moreover, both US shale oil and Canadian oil sands are extremely capital-intensive, with the US LTO plays characterised by very high decline rates and hence a drilling-treadmill effect that requires massive infusions of new capital each year.

Given that total crude oil production globally would have been in decline without the rise of US shale oil, the profile of future US LTO production is crucial to the outlook for global supply and global oil prices, so the stakes in this debate are very high.

Another key feature of the oil market in recent years has been the declining trend in exports of crude oil since 2005. This mainly reflects the very rapid increase in consumption in the main exporting countries, particularly OPEC, and with fast-growing populations and high levels of subsidisation on domestic consumption it is hard to see how this trend can be easily reversed. With global exports declining and demand for imports still increasing, this points to continuing upward pressure on prices.

Taken together, these trends have triggered a huge increase in the capital intensity of the upstream oil industry since 2005, and with prices flat since 2011 (albeit at or close to all-time highs), many of the world's major oil companies have recently announced cuts to their capex budgets. In our view, this raises serious questions over the outlook for both supply and prices over the medium to long term, as capex cuts today imply lower supply tomorrow (and, other things being equal, higher prices).

In short, our review of the oil market over the last decade leads us to conclude that the industry now faces unprecedented challenges. Accordingly, we think the oil majors will have to think very carefully about how they invest for the future.

Oil and the IEA's New Policies Scenario: a critique

This section looks at the IEA's modelling of the long-term outlook for oil markets as set out in the base-case scenario of the Agency's *2013 World Energy Outlook (2013 WEO)*. The IEA's demand projections largely reflect the changing pattern in global consumption underway since 2000, with the non-OECD countries in general, and Asia and the Middle East in particular, being the motor of growth over the next two decades.

Although this pattern of projected demand growth seems very reasonable, the IEA's projected GDP growth assumes very ambitious further improvements in oil intensity: the IEA expects global GDP to more than double out to 2035 while expecting the world to become 50% less oil-intensive. This represents a rate of improvement over the next two decades one-and-a-half times greater than that achieved over the last two decades.

On the supply side, the IEA projects an accentuation of the trends observed since 2005, with conventional crude oil production continuing to fall and the world therefore becoming ever more dependent on unconventional crude and other petroleum liquids. Moreover, such growth in conventional crude production as the IEA expects over 2013-35 – and without which its projections for the drop in conventional crude out to 2035 would be more severe – is focused on Iraq, Brazil and Kazakhstan.

The IEA expects Iraq to account for c.50% of total world oil-supply growth out to 2020 (or 2.8mbd out of a total 5.7mbd), and 45% out to 2035 (4.9mbd out of 11mbd), but we think

recent events there will make these expectations much harder to fulfil. As for Brazil (projected to supply an extra 1.9mbd by 2020, and an extra 3.8mbd by 2035), and Kazakhstan (projected to supply an extra 0.3mbd by 2020, and an extra 1.9mbd by 2035), both of these countries have failed in the last few years to meet both cost and supply targets, such that these projections look very optimistic to us.

Crucially, while fields already in production today account for 73% of conventional crude output over 2013-25, this falls to 43% over 2026-35, meaning that huge investments will be required in fields yet to be developed and yet to be found in order to meet demand over the second half of the IEA's projection period.

Yet while the IEA sees the oil supply becoming increasingly dependent on unconventional crude and other petroleum liquids, it expects the declining trend in net exports of crude oil witnessed since 2005 to be reversed over the next two decades. Indeed, in the NPS, net global exports of crude oil increase by 3mbd between 2012 and 2035, with Iraq, Brazil and Kazakhstan once again key to the realisation of this projection.

Again, we find these IEA projections for net exports of crude oil out to 2035 very optimistic. Similarly, despite sharp year-on-year increases in upstream capital outlays since 2005, the IEA expects the profile of annual investments to be broadly flat over the next two decades, even though US shale oil – with its relentless capex treadmill – is central to its supply-growth forecasts over the next decade. Again, this looks over-optimistic to us.

Finally, although the IEA projects rising prices in real terms over the next two decades, the upward trajectory is very gentle compared with the sharp increase seen since 2005: prices are projected to rise from USD109/bbl in 2012 to USD128/bbl by 2035 in real terms. This represents an increase of 17% compared with increase of 180% experienced over 2000-13.

In our view, however, the capex cuts announced by the oil majors in recent months suggest that prices will need to rise more aggressively than the IEA is assuming out to 2035 in order to stimulate the investments needed for its supply projections to hold good.

Pricing scenarios and future capex risk

In recent years the capital productivity of the oil majors has declined even more sharply than it has for the industry as a whole. It is for this reason that most of the oil majors have announced cuts to their capex budgets since the beginning of this year.

What is so striking about the recent capex cuts announced by most of the majors (and some of the national oil companies, or NOCs) is that they demonstrate that the IEA's warning about the risk of insufficient investment in the 2020s as recently flagged in its *World Energy Investment Outlook* this June is already obsolete. In other words, the risk of insufficient investment having an impact on future oil supply is not only about Middle Eastern OPEC countries delaying the ramp-up in their investments from 2020 onwards.

On the contrary, the scaling back of capex by the majors that is already taking place today indicates that the risk of insufficient investment is already here today, and hence that the impact on supply is likely to be felt long before the early 2020s.

Against this backdrop, what is the outlook for oil prices out to 2020 and beyond, and what are the prospects for the oil majors improving their capital-productivity ratio and avoiding the risk of stranded assets on new investments? We consider three pricing scenarios:

- **High-price scenario:** The logical conclusion of our analysis is that oil prices will need to go higher over the medium to long term in order to incentivise the investment needed to bring in the supply the IEA expects. In our view the IEA's trajectory of only modestly increasing prices is inconsistent with the supply growth it is forecasting.
- **Flat-price scenario:** This has been what has actually happened in the oil market since 2011, and in fact it is effectively what the IEA is assuming will happen all the way out to 2020 – after all, the IEA's 2020 real-terms price projection is USD113/bbl in 2020, which was the average price over 2011 and 2012.
- **Low-price scenario:** Although in our view a low-probability scenario, the risks that could bring about a prolonged period of depressed oil prices are a binding global climate deal to limit GHG-emissions (and hence demand for fossil fuels), and the threat of global deflation.

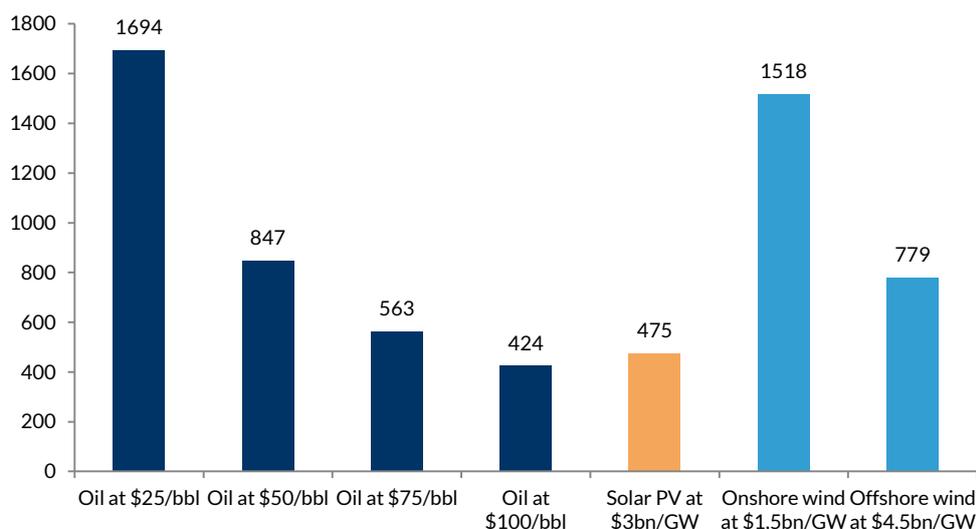
In our view, the most likely of these scenarios in practice is the high-price scenario, and in principle, this is the most positive scenario for the majors. Ultimately, however, even under a high-price scenario, we see asset-stranding risk for the oil industry. This is because if prices end up rising more sharply than the IEA's base-case trajectory this will likely raise serious questions about affordability and thereby only increase the incentive to invest in alternative energy sources, not least renewable technologies.

In particular, if we focus on the cumulative net energy derived for powering cars from oil versus renewable-generated electricity on a full project-lifetime basis (Chart 3), we find that already USD100bn invested in onshore wind would yield more than USD100bn invested in oil at USD50/bbl and above (indeed, at 1,518 TWh, onshore wind's net EROCI is almost as good as the 1,694TWh of oil at USD25/bbl). We also find that USD100bn invested today in offshore wind would yield more net energy than USD100bn invested in oil at USD75/bbl. And perhaps most striking of all, we find that USD100bn invested today in solar PV would yield more net energy than USD100bn invested in oil at USD100/bbl and above.

This means that already, in terms of net energy yielded on a project-lifetime basis, the EROCI for onshore wind is close to that of new oil projects at USD25/bbl, and significantly greater than that for new oil projects with full breakeven costs of USD50/bbl and above. It also means that already, in terms of net energy yielded on a project-lifetime basis, the EROCI for offshore wind is greater than that for new oil projects with full breakeven costs of USD75/bbl and above.

It also means that already, in terms of net energy yielded on a project-lifetime basis, the EROCI for solar PV is greater than that for new oil projects with full breakeven costs of USD100/bbl and above.

Given that we are projecting rising oil prices on the one hand, and falling renewables costs on the other, this means that by 2020 and 2035 our analysis shows that the relative energy yields move even further in favour of renewables by those dates.

Chart 3: Net cumulative EROCI over project lifetime from investing USD100bn in 2014 (TWh)


Source: Kepler Cheuvreux estimates

Of course, there remain huge infrastructure challenges to be overcome – and paid for – if EVs are to realise their potential over the next two decades, but our analysis suggests that as the net energy yield over the full life-cycle of renewables versus oil will only continue to improve over the next 20 years, the competitive advantage could shift decisively in favour of EVs over oil-powered cars in the next two decades.

And this is before we even begin to take account of the political tensions that are likely to make security of supply an increasingly important issue in future, adding further impetus to the deployment of renewable energy in import-dependent countries.

And if all of this sounds far-fetched, then the speed with which the competitive landscape of the European utility industry has been reshaped over the last decade by the rollout of wind and solar power – and the billions of euros of stranded fossil-fuel generation assets that this has given rise to – should be a flashing red light on the oil majors' dashboard.

Against this uncertain backdrop, and with up to USD200bn per year in potential upstream investment between them over the next decade,⁶ we think the majors should be asking themselves whether it makes sense to plan on replacing lost output from their existing projects on a barrel-for-barrel basis, or whether in fact they should be reducing their capital allocation to higher-cost new projects (i.e. those requiring >USD100/bbl), and looking instead to invest the money thus freed up in renewables.

⁶ See Carbon Tracker's recent report – [Oil & Gas Majors: Fact Sheets](#) – for more on the potential capex plans of the individual majors.

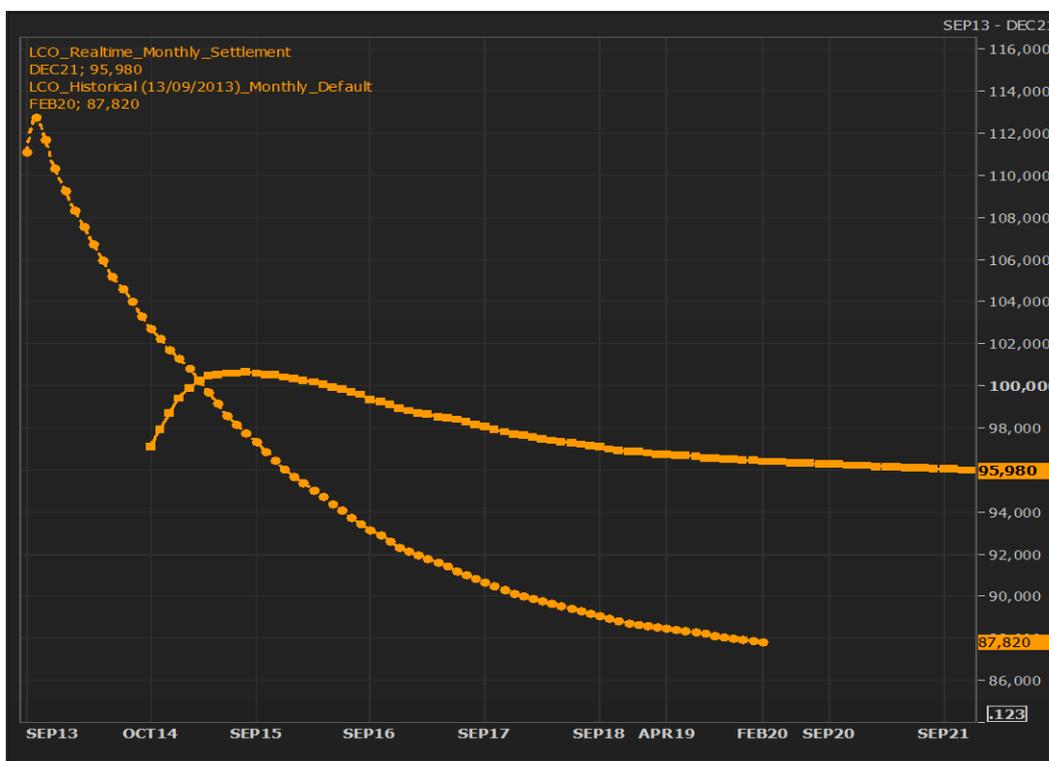
Risks to our view

Our thesis in this report is that the oil majors will face the risk of stranded assets beyond 2025 even under a scenario of rising and sustained high oil prices as renewable-energy technologies become increasingly competitive over time.

As a result, the main risks to our view relate to the outlook for oil prices on the one hand, and the outlook for cost improvements on the key renewable-energy technologies on the other.

As regards our view that oil prices will rise more steeply over 2013-35 than projected in the IEA’s base-case scenario, it is interesting to cross-check against the forward curve. Chart 4 shows the Brent futures strip as of today and as of one year ago in September 2013. Both curves are in backwardation, although today’s forward curve is only very mildly backwardated (indeed it is almost flat).

Chart 4: Forward curves for Brent crude oil as of September 2014 and September 2013 (USD/bbl)



Source: Eikon

The current curve shows a one-year forward price of USD100/bbl, but over time this trends down gradually and for delivery in December 2021 Brent crude is currently trading at USD96/bbl, exactly in line with today’s prompt price of USD96/bbl. The curve from one year ago in September 2013 shows prompt prices of USD113/bbl, with the contract for February 2020 12 months ago trading at USD87/bbl. What does this say about market expectations, and should we be concerned about our thesis – premised on higher future oil prices – when the market is projecting lower prices out to 2020?

The fact that the forward curve is currently in (mild) backwardation might be interpreted to mean that the market is more bearish on demand or more bullish on supply, or both, out to 2020 than either the IEA or we are.

However, the curve has flattened a lot over the last 12 months, with the front month some USD17/bbl lower than it was a year ago and the most far-dated month USD8/bbl higher. As a result, the degree of backwardation is much less marked than it was a year ago, which might be interpreted to mean that the market has either become more bullish on future demand, or more bearish on future supply, or both, than it was a year ago.

However, and interesting as it is to speculate on the signal the forward curve is sending at any given moment, the fact that it is in backwardation for the time being does not lead us to question the arguments we make in this report.

If we are right, the market will at some point start to worry about the discrepancy between the huge amounts of capital needed to bring future supply on-stream on the one hand, and the capex reductions announced by the majors since the beginning of this year on the other. As and when that happens, both the prompt price and the forward price will in our view move up, and the curve will ultimately move into a contango pattern, with longer-dated prices higher than shorter-dated ones, in order to incentivize future investment.

In terms of the fundamental risks to our view, If technology advances were to outpace decline rates aggressively in the US shale-oil plays in the next few years (and we think this is a very big if), then US shale-oil output could surprise on the upside, thereby helping to keep world prices lower for longer. Otherwise, the scope for positive supply surprises is in our view much more limited because the opportunities for big productivity gains in the more mature plays elsewhere in the world are far more restricted.⁷

On the oil-demand side, prices have fallen sharply in the last two months in response to slowing demand in China and other emerging markets, and prices could certainly fall further in the short term. Indeed, if recent signs of demand weakness were to worsen and be accompanied by further strong growth in US shale-oil production, we think prices could enter a trading range of USD85-90/bbl for the next six months or so.⁸

However, the real question in terms of the robustness of our thesis in this report is not whether prices drop into a lower trading range for a few months, but rather whether there is a realistic scenario under which they could not only fall sharply but also then remain at depressed levels for a prolonged period of time (say two to three years).

And in this respect we see the main risk as being a sustained period of global deflation, as this is what could lead to significantly weaker oil prices for a more prolonged period. That said, owing to the annual global production loss of 3-4mbd from the ongoing decline in

⁷ Indeed, [in comments to the Financial Times today](#), BP's former CEO Tony Hayward, concerned about the impact western sanctions on Russia will have on investment in Russia's upstream oil industry, asks the pointed question: "When US supply peaks, where will the new supply come from?" Hayward's interview in the FT is well worth reading as his comments also underline the relentless need for new investments to compensate for decline in ageing oil fields. Interestingly, he also says that without the recent surge in US shale-oil production, oil prices would already be trading at USD150/bbl, and that Iraq will struggle to meet the IEA's expectations of its supply growth out to 2020 (a point we ourselves make below in our review of the IEA's base-case scenario in Section 2 of this report).

⁸ If prices were to trade around USD85/bbl for six months, we would expect OPEC to take coordinated supply action.

ageing fields, the need for massive ongoing investment simply in order to maintain supply at existing levels means that even under a scenario of global deflation oil prices would probably not fall as far or for as long as some observers think.⁹

In terms of the risks to our forecasts regarding future declines in the cost of renewable-energy technologies, we have been deliberately conservative in our assumptions. As a result, we think the risk to our projections for the future energy productivity of solar PV and onshore and offshore wind is if anything to the upside rather than the downside.

Moreover, even if our view that oil prices will need to rise to and remain on a higher trajectory than that projected in the IEA's NPS turns out to be wrong, this would be of no comfort at all to the majors. For the ultimate conclusion of the argument we set out in this report is that the oil majors face increasing risks in the future under all pricing scenarios.

With a model in crisis oil majors must become “energy majors”

We have already explained the risk facing the oil majors under a scenario of lower demand and lower prices from a potential tightening of climate legislation globally (see our in-depth report from 24 April 2014, *Stranded Assets, Fossilised Revenues*). Meanwhile, the conclusion of our argument in this report is that they also face much bigger risks than previously imagined even under a scenario of sustained higher prices.

Moreover, and as we explain in Section 3 of this report, a scenario of sustained price stagnation would not help them either, as, after all, we have had stagnant oil prices at all-time average highs for the last three years, and the result is that the oil majors have been forced to cut back on capex.

From all of this we think the conclusion for the majors is clear: their business model is already being eroded by rising capital intensity and diminishing returns, while in future they will face much greater competition from renewable energy in the road-transportation market. At the same time, the threat of tighter environmental and climate legislation at a global, regional, and national level is always looming in the background and pressure for more concerted climate-policy coordination will in our view only increase in future.

As a result, we think they should already start directing much more of their future capital investments to renewable projects. This would enable them to become the energy majors of the future rather than ending up as the oil majors of the past.

Glossary of terms used throughout this report

bbbl: *barrel*, the standard volumetric measure for oil used in the market.

Bio-fuels: These are not petroleum-based fuels but rather fuels derived from organic matter. As such they do not count as petroleum liquids *per se*, but as they can be used as a substitute for oil-derived products in transportation and other uses they are included in both the EIA's and the IEA's annual tallies of total global petroleum and other liquids.

boe: *barrel-of-oil-equivalent*, a measure of energy value equivalent to the energy contained in a barrel of crude oil. In this report we take 6.3GJ as the energy value of a boe.

⁹ This point is also implicit in Tony Hayward's comments to the Financial Times cited in footnote 7 above.

Brent crude oil: A blend of sweet crude oil from the North Sea. Brent crude is the leading international price benchmark for global oil markets.

Conventional crude oil: For the purposes of this report we take the IEA's definition of conventional crude oil as used in its benchmark *World Energy Outlook* publication. This comprises all crude oil except US LTO (shale oil), Canadian oil sands, Venezuela's extra-heavy oil, and both coal-to-liquids and gas-to-liquids petroleum.

CPS: Current Policies Scenario, the IEA's business-as-usual scenario for energy markets over 2013-35.

Crude oil: Defined by the EIA as follows: "A mixture of hydrocarbons that exists in liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities." The EIA definition (and the one we use in this report) also includes "lease condensate recovered as a liquid from natural gas wells in lease or field separation facilities and later mixed into the crude stream is also included". Crude oil is the bedrock of the world petroleum market, as it has a higher energy density than other petroleum liquids and is the source for a wide range of oil products, such as heating oils, gasoline/petrol, diesel and jet fuels. Crude oil is classified according to whether it is heavy or light, and whether it is sweet or sour, and the precise energy content per barrel will vary across different grades. **EIA:** The *Energy Information Administration*, the US Government Agency responsible for compiling statistics on US and global energy markets, and for making short-, medium-, and long-term projections for trends in the US and global energy markets.

Energy density: A measure of the energy contained per unit of volume in a given energy source.

EROCI: *Energy Return on Capital Invested*, a term we have developed for the purposes of this report (as explained in Section 3 below). Our concept of EROCI can be measured on either a gross or a net basis, depending on whether the gross or net energy yield of a given investment is being considered (see also under *Gross energy* and *Net energy*).

GJ: Giga-joule, a measure of energy equivalent to one billion joules.

Gross energy: The amount of primary energy available in a given energy source before it is converted into useful energy in final consumption.

GW: *Giga-watt*, a measure of power-generation capacity equivalent to one billion watts.

IEA: The *International Energy Agency*. The IEA was founded in response to the first oil shock in 1973-74 in order to help founding countries (mainly western industrialised net oil importers) cope with disruptions in the global oil supply. It is today made up of 29 member countries, all of which are also OECD members. The IEA's current aim, as [it explains on its website](#) is "to ensure reliable, affordable and clean energy for its 29 member countries and beyond."

INOCs: *International national oil companies*. Defined by the IEA as "companies that are fully or majority-owned by their national governments, but have significant international operations alongside their domestic holdings". Examples would include Statoil and Petrobras.

IOCs: *International oil companies.* Publicly-quoted oil companies with an international reach comprising the majors and a number of other well-known companies.

kbd: *thousand barrels per day.*

kboe: *thousand barrels of oil equivalent*

LTO: *Light tight oil*, the technical term for what is more commonly known as shale oil. This is oil trapped in low permeability (“tight”) source rocks that requires hydraulic fracturing (“fracking”) to extract it. As explained in Section 1 of this report, the production of LTO in the United States has increased at a phenomenal rate since 2008 owing to the widespread application of fracking and horizontal-well drilling in the two main formations or “plays”, the Bakken in North Dakota, and the Eagle Ford in Texas.

Majors/Oil majors: The seven largest quoted IOCs: BP, Chevron, ConocoPhillips, ENI, ExxonMobil, Royal Dutch Shell, and Total.

mboe: *million barrels-of-oil-equivalent* (see boe above).

mbd: *million barrels per day.*

mtoe: *million tonnes-of-oil-equivalent* (see under tonne of oil equivalent below).

Net energy: The amount of energy available for final consumption after taking into account energy-conversion and energy-transmission losses. In our analysis throughout this report, we define net energy more specifically to mean the useful energy available for final consumption in powering oil-fired cars and EVs.

NGLs: *Natural gas liquids*, defined by the US EIA as follows: “*Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption, cooling in gas separators, gas processing, or gas cycling plants.*” NGLs are less valuable than crude oil as they contain less energy per barrel (in this report we assume an energy value for NGLs of 4.4GJ/bbl) and can only be used in transport to a limited extent.

NOCs: *National Oil Companies.* Defined by the IEA as “*companies that are fully or majority-owned by their national governments and concentrate their operations on domestic territory*”. Examples would include Saudi Aramco and the National Iranian Oil Company.

NPS: *New Policies Scenario*, the IEA’s base-case scenario for energy markets over 2013-35.

OECD: *The Organisation for Economic Co-operation and Development.*

Oil sands: The [Canadian Association of Petroleum Producers](#) defines oil sands as follows: “*Oil sands are a mixture of sand, water, clay and bitumen. Bitumen is oil that is too heavy or thick to flow or be pumped without being diluted or heated – at 11° Celsius bitumen is as hard as a hockey puck*”. As explained in Section 1 of this report, oil sands have become an increasingly important source of marginal supply in the global oil market, and the IEA expects production to increase by 2.5mbd over 2013-35. Oil sands are also known as tar sands.

OPEC: *The Organisation of Petroleum Exporting Countries*, comprising 12 of the most important oil-exporting countries (Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, Qatar, the UAE, and Venezuela).

Petroleum liquids: a term covering the petroleum-derived liquids that together comprise the world oil supply: crude oil (conventional and unconventional), and NGLs (see also under *bio-fuels*).

Prompt price: This refers to the market contract closest to expiration and is for delivery in the next calendar month.

ROW: *Rest of the world.*

Shale oil: The more common name for light tight oil (see under *LTO* above)

Specific energy: A measure of the energy contained per unit of mass in a given energy source.

Stranded assets: Throughout this report we use the term *stranded assets* in the sense defined by the [Stranded Assets Programme](#) of Oxford University's Smith School of Enterprise and the Environment: "*Stranded assets are assets that have suffered from unanticipated or premature write-downs, devaluations, or conversion to liabilities and they can be caused by a variety of risks. Increasingly risk factors related to the environment are stranding assets and this trend is accelerating, potentially representing a discontinuity able to profoundly alter asset values across a wide range of sectors.*"

toe: *tonne-of-oil equivalent*, a measure of energy value equivalent to the energy in one tonne of crude oil. In this report we take 45GJ as the amount of energy in a tonne of crude oil.

TWh: *Terawatt hour*, a measure of energy used in electricity and in our EROCI comparison of oil and renewables in Section 3 of this report. One TWh is equivalent to 0.6mboe.

Unconventional crude oil: For the purposes of this report, we take the IEA's definition of unconventional crude oil as set out in its 2013 WEO. This takes unconventional crude oil to be US LTO (shale oil), Canadian oil sands, Venezuela's extra-heavy oil, and both coal-to-liquids and gas-to-liquids petroleum.

WEO: *World Energy Outlook*, the IEA's annual reference work on the outlook for global energy markets over the following two decades. We analyse in depth the assumptions on oil markets set out in the 2013 WEO in Section 2 of this report.

WEIO: *World Energy Investment Outlook*, a special report published by the IEA in June 2014.

Toil for oil: a much harder game since 2005

Looking at the evolution of the global oil market since 2000, we think the broad dynamics observable can usefully be divided into two distinct phases:

- First, the 2001-05 period, during which demand for petroleum liquids increased strongly but so did production and exports of crude oil, with the result that the increase in crude oil prices over the period was orderly and manageable;
- Second, the period 2006 to date, during which demand has continued to rise but conventional crude oil production has gone into decline and exports fallen from their 2005 peak, with the result that crude oil prices have risen sharply in both nominal and real terms before stabilising over 2011-14 at levels in line with or close to average all-time highs.

In this section, we review what we see as the key trends in the evolution of global oil supply over 2000-13, beginning with a look at the declining share of conventional crude oil supply in the global supply mix since 2005 and the growing importance of unconventional crude oil and other petroleum liquids such as NGLs and biofuels. The decline in the supply of conventional crude oil since 2005 has occurred despite the very sharp increase in oil prices over 2006-13 relative to 2001-05. This indicates that producers have had every incentive to raise conventional production in recent years, so the fact that they have been unable to do so points to rising decline rates in ageing conventional fields and a lack of sufficient new discoveries to make up for these declines. At the same time, the falling share of crude oil in general (and conventional crude in particular) in the overall supply mix means that the quality of the aggregate oil supply has been declining since 2005.

In contrast to the decline in conventional crude oil production, the trend in the output of unconventional crude in recent years has been sharply upwards, with the supply of US LTO surging since 2008, and Canadian oil sands steadily growing supply year after year. However, both US shale oil and Canadian oil sands are extremely capital-intensive, with the US LTO plays characterised by very high decline rates and hence a drilling-treadmill effect that requires massive infusions of new capital each year. Given that total crude oil production globally would have been in decline without the rise of US shale oil, the profile of future US LTO production is crucial to the outlook for global supply and global oil prices, so the stakes in this debate are very high.

Another key feature of the oil market in recent years has been the declining trend in exports of crude oil since 2005. This mainly reflects the very rapid increase in consumption in the main exporting countries, particularly OPEC, and with fast-growing populations and high levels of subsidisation on domestic consumption it is hard to see how this trend can be easily reversed. With global exports declining and demand for imports still increasing, this points to continuing upward pressure on prices.

Taken together, these trends have triggered a huge increase in the capital intensity of the upstream oil industry since 2005, and with prices flat since 2011 (albeit at or close to all-time highs), many of the world's major oil companies have recently announced cuts to their capex budgets. In our view, this raises serious questions over the outlook for both supply and prices over the medium to long term, as capex cuts today imply lower supply tomorrow (and, other things being equal, higher prices).

In short, our review of the oil market over the last decade leads us to conclude that the industry now faces an unprecedented set of challenges. Accordingly, we think the oil majors will have to think very carefully about how they invest for the future.

Declining conventional crude output since 2005

A profound structural change has occurred in the global oil supply over the last decade, with the supply of conventional crude oil¹⁰ peaking in 2005 and starting to trend down since. As a result, the growth in the overall oil supply registered since 2005 has been in the form of: 1) other petroleum liquids such as NGLs, and biofuels; and 2) unconventional crude oil, specifically US shale oil and Canadian oil sands.

There are two main reasons why the declining share of conventional crude oil in the overall supply mix matters: 1) crude oil has a higher energy density than other petroleum liquids (i.e. contains more energy per barrel), so other things being equal a declining share of crude oil in the overall mix indicates declining quality in the aggregate supply; and 2) unconventional sources of production, although generally of equally high quality as conventional crude oil,¹¹ are typically much more capital-intensive – and hence more expensive to produce – than conventional sources.¹²

Other things being equal, we would expect the declining supply of a highly valuable commodity to prompt an increase in price, especially if demand for that commodity continues to increase over time and the best available alternatives are either: 1) liquids of lower quality that are not directly substitutable in many cases, or 2) liquids of similar quality but that are much more expensive to produce. Since this is exactly what has happened in the case of crude oil since 2005, it is hardly surprising that the price of crude oil has increased very sharply since 2005.

Growth in the supply of crude oil has slowed markedly since 2005

Table 3 and Chart 5 show the evolution of the total global oil supply in the broad sense – i.e. the supply of all liquids – over 2000-13. Over this period, the supply of total liquids has increased by 16% in headline terms, rising from 77.7mbd in 2000 to 90.1mbd in 2013.

As can be seen, nearly two-thirds of the growth in the total oil supply over 2000-13 was provided by crude oil, which increased by 7.4mbd over the period (to 76mbd in 2013 from 68.5mbd in 2000) and thereby accounted for 63% of the increase in aggregate supply (7.4mbd out of a total 12.4mbd).

¹⁰ As explained above, we are not including deepwater in our definition of unconventional crude here as we are following the categorisation of conventional and unconventional sources of crude oil used by the IEA in its *World Energy Outlook*.

¹¹ That said, and as explained above, there generally seems to be a higher average level of condensate produced per barrel of LTO than is the case for most conventional crude oil output and this means that US shale oil on average contains slightly less energy per barrel than heavier grades of crude oil.

¹² In addition, and as explained above, both LTO and oil sands entail higher environmental costs than conventional crude oil, but these externalities are not currently reflected in production costs. If these externalities were at some point to be priced in, the cost of both shale-oil and oil-sands production relative to conventional crude would rise even further.

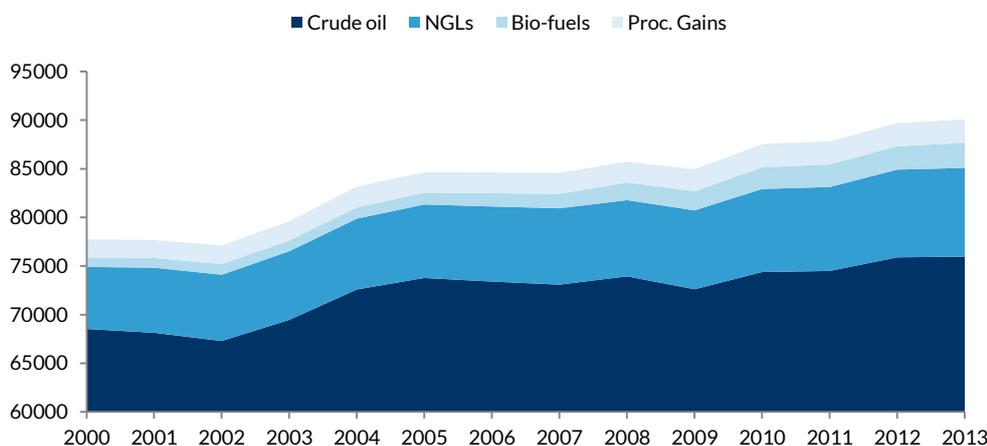
Table 3: Total world oil supply (all petroleum liquids and bio-fuels) on a volumetric basis (mbd)

| | 2000 | 2005 | 2013 | 2000-13 Δ (mbd) | 2000-13 Δ (%) | 2000-05 Δ (mbd) | 2000-05 Δ (%) | 2005-13 Δ (mbd) | 2005-13 Δ (%) |
|-------------------------|---------------|---------------|---------------|--------------------|------------------|--------------------|------------------|--------------------|------------------|
| Crude oil | 68,527 | 73,771 | 75,963 | 7,437 | 10,9% | 5,244 | 7.7% | 2,193 | 3.0% |
| NGLs | 6,376 | 7,552 | 9,125 | 2,749 | 43,1% | 1,176 | 18.4% | 1,573 | 20.8% |
| Biofuels | 978 | 1,220 | 2,578 | 1,600 | 163,5% | 241 | 24.7% | 1,359 | 111.4% |
| Processing gains | 1,844 | 2,104 | 2,414 | 570 | 30,9% | 260 | 14.1% | 310 | 14.7% |
| TOTAL LIQUIDS | 77,725 | 84,647 | 90,081 | 12,356 | 15,9% | 6,921 | 8,9% | 5,434 | 6,4% |
| Crude oil as % of total | 87.7% | 87.2% | 84.3% | 63% | n/a | 75.8% | n/a | 40.4% | n/a |

Source: United States Energy Information Administration (EIA)

However, growth was skewed towards the early part of this period (especially over 2002-05), as can be seen in Chart 5 (graph scaled from 60mbd). Of the total 12.4mbd output increase registered over 2000-13, 6.9mbd (56%) was added over 2000-05, and 5.4mbd (44%) over 2006-13.

Chart 5: Production of total petroleum liquids and bio-fuels, 2000-13 (kbd)



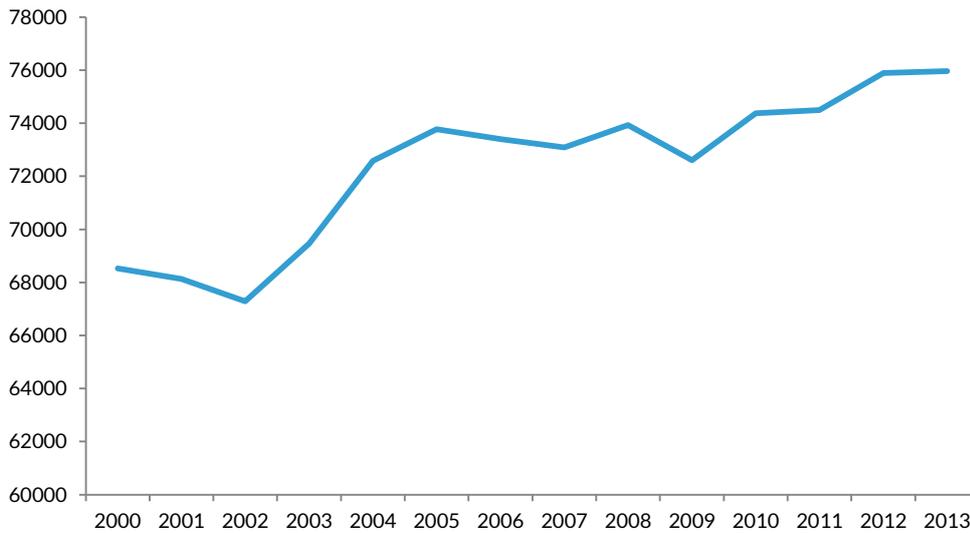
Source: Kepler Cheuvreux based on EIA data

And in the case of crude oil, this imbalance between the growth registered over 2000-05 versus 2006-13 was particularly marked: of the total 7.4mbd increase between 2000 and 2013, 5.2mbd occurred over 2000-05 (71%) and only a further 2.2mbd (29%) over 2006-13 (Chart 6).

So, while the rate of increase in the crude oil supply slowed sharply after 2005, the growth in the supply of the other liquids – especially biofuels – was greater over 2006-13 than over 2000-05.

Chart 7 then shows the annual increases in the global oil supply over 2001-13, and demonstrates how much greater the production increases were over 2003-05 than over 2006-13, both for the total supply of all liquids in general, and for the supply of crude oil in particular.

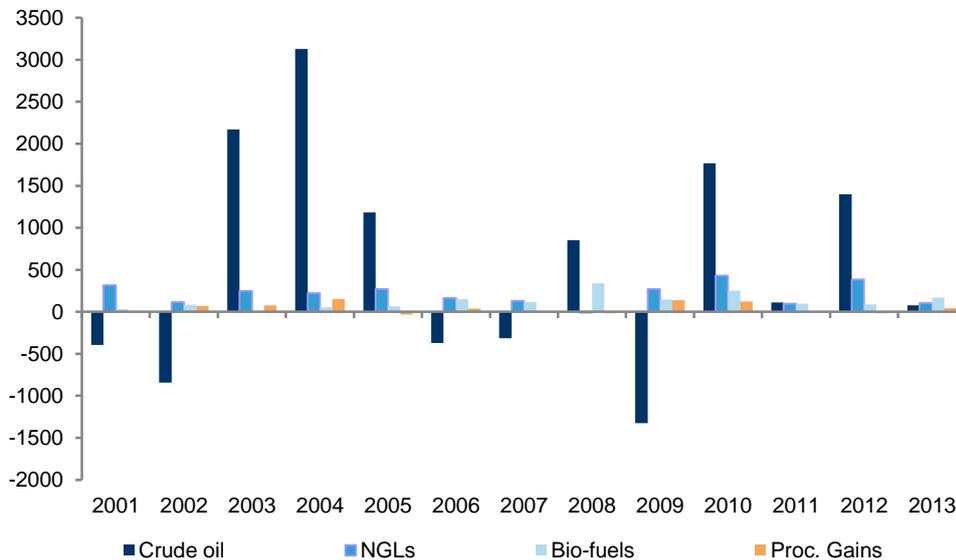
Chart 6: Production of crude oil (conventional and unconventional combined), 2000-13 (kbd)



Source: Kepler Cheuvreux based on EIA data

The structural pattern of slowing crude oil supply after 2005 is clear enough, although there is one temporary distortion over 2009-10, during which period the crude supply first fell back sharply in 2009, and then rebounded by virtually the same amount in 2010.

Chart 7: Annual change in the components of the global oil supply and bio-fuels, 2001-13 (kbd)



Source: Kepler Cheuvreux based on EIA data

This reflects OPEC's response to the worldwide economic slowdown that followed the global financial crisis of late 2008. As demand fell sharply in late 2008 and 2009, OPEC – and particularly Saudi Arabia – cut supply to try and maintain prices. Then, when demand rebounded in 2010, OPEC increased supply again. This swing over 2009-10 was therefore

cyclical rather than structural, with the OPEC cut and restoration of supply cancelling each other out in overall supply impact.

Apart from this cyclical oscillation, the fundamental structural story of slowing crude supply over 2006-13 is clearly laid bare in Charts 5-7: over the eight years 2006-13 the supply of crude increased by less than half the amount it did over the five years 2001-05. While crude oil accounted for 76% of the total increase in all liquids over 2000-05, it accounted for only 40% of the increase in total liquids over 2005-13. Crude oil's share in the overall supply mix thus fell from 88% in 2005 to 84% in 2013 (Table 3 above).

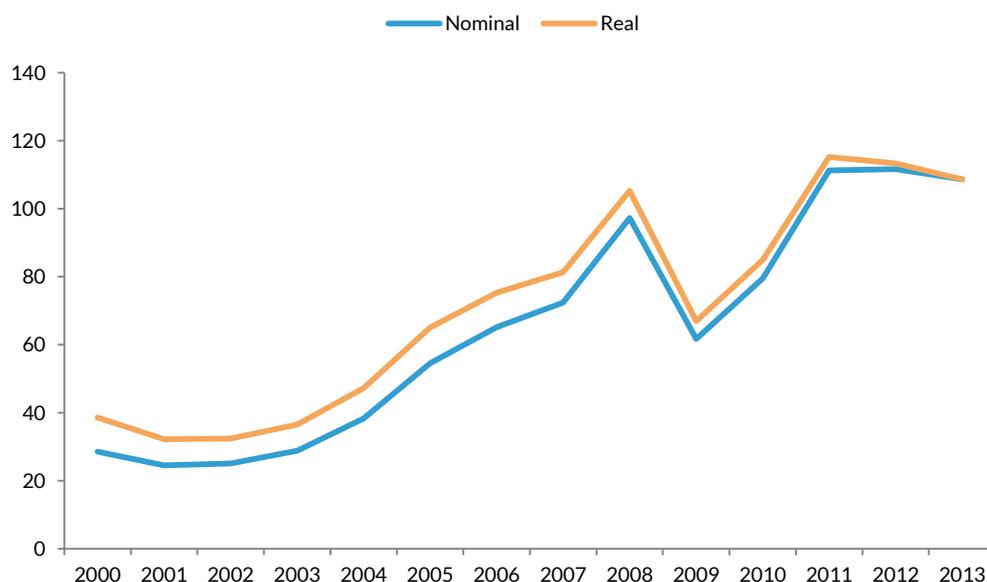
This slowing in the growth of the crude oil supply is all the more surprising when viewed against the backdrop of the trend in crude oil prices over the last decade.

Table 4: Average Brent average crude prices, nominal and real (2013 USD), USD/bbl

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | Δ 2013/ 2001 | Δ 2013/ 2005 |
|---------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|-----------------|-----------------|
| Nominal | 28 | 24 | 25 | 29 | 38 | 55 | 65 | 72 | 97 | 62 | 79 | 111 | 112 | 109 | 281% | 199% |
| Real | 39 | 32 | 32 | 37 | 47 | 65 | 75 | 81 | 105 | 67 | 85 | 115 | 113 | 109 | 182% | 167% |

Source: BP

Chart 8: Average Brent crude oil prices, 2000-13 (USD/bbl)



Source: Kepler Cheuvreux based on BP data

Table 4 and Chart 8 above show the evolution in the crude-oil price for the benchmark Brent contract over 2000-13 in both nominal and real terms (the real-terms price is shown in constant 2013 USD).

Over the entire period 2000-13 the crude oil price increased very dramatically, by 281% in nominal terms and 182% in real terms, with the majority of the price rise occurring over 2006-13 (prices rose by 199% in nominal terms and 167% in real terms over this period). And yet, as we have already seen, despite this staggering price increase over 2006-13, the

crude oil supply increased by only 3% over the same period.¹³ This price action suggests that the market has viewed the growing supply of other liquids since 2006 as an inadequate substitute for slowing crude oil output.

In the end, what counts is the energy value supplied, not the liquid volume

While the dramatic slowdown in the rate of growth in the global crude supply since 2005 has to some extent been offset by higher growth rates in the supply of other petroleum liquids, it is important to bear in mind that the volumetric presentation of the supply data in Table 3 does not adjust for the different energy densities of the different liquids: NGLs and biofuels are of lower quality than crude oil because they contain less energy per barrel.

This means that the supply data shown in Table 3 does not show the extent to which the growth in the supply of total liquids has translated into growth in the amount of energy supplied by these liquids.¹⁴

To make this adjustment we need to know the amount of gigajoules (GJ) contained in the same volume of liquid for each of these different sources. In other words, we need to convert barrel (bbl) measures of *liquid volume* into barrels-of-oil equivalent (boe) measures of *energy contained* in that volume.

Moreover, there is an extra qualification to be made about including biofuels and processing/refinery gains in oil-supply data, and this concerns the net energy they contribute to society compared with crude oil and energy-adjusted NGLs. As far as biofuels are concerned, the issue in this respect is that they are generally energy-intensive to produce as they entail the transformation of an organic energy source into a liquid one.

This means that the net energy they provide to society is much lower than that of crude oil (and in some cases barely positive at all).

As far as processing gains are concerned, these reflect the volumetric increase in liquid from breaking down large hydrocarbon molecules into smaller ones, and as such do not add any extra energy to that contained in the oil before it is processed in the refinery.

Taking all of this into account, Table 5 shows our estimate of the evolution of the world's petroleum and bio-fuels supply over 2000-13 on an energy-adjusted basis (we strip out

¹³ Moreover, and as we discuss below, the only reason the crude oil supply has increased at all since 2005 is the large increase in the supply of unconventional crude, and this – along with the need to offset declining conventional crude supply from ageing fields – has necessitated an astronomical increase in the capital intensity of the upstream industry, which itself has only been made possible by the equally huge increase in prices.

¹⁴ The energy per unit mass of a given energy source is known as its specific energy. In its simplest form under the International System of Units (SI), specific energy measures the number of joules (J) or megajoules (MJ) per kilogram (Kg) of a given energy source. While the specific energy value of crude will vary somewhat by region and by grade, if we use [the IEA's conversion factors](#) then we derive a specific-energy value for crude oil of 44MJ/kg, which means that one tonne of oil (1,000kg) contains 44 gigajoules (GJ) of energy. Energy can also be measured on a per-unit volume basis – i.e. in its simplest form on a MJ/litre basis – and the energy per unit volume of a given energy source is known as its energy density. Taking the barrel as the most common volumetric unit of measurement for crude oil, the IEA's specific-energy value of 44GJ/tonne gives an energy density for crude oil of 6.3GJ/bbl (again, this will vary slightly by grade of crude oil), whereas NGLs on average contain only about 4.4GJ/bbl (i.e. c.70% of the energy value of crude oil), and biofuels between 4GJ/bbl (ethanol) and 5.5GJ/bbl (vegetable oil). This means that ten barrels of NGLs equate to only seven barrels of crude oil in energy terms, i.e. 10bbls of NGLs = 7boe. Only if volumetric supply data is adjusted to take account of these varying energy densities will the true contribution of NGLs and bio-fuels to global supply be reflected.

processing gains completely and adjust the value of NGLs and biofuels using values of 4.4GJ/bbl and 4GJ/bbl respectively, using the value of ethanol for biofuels).¹⁵

Table 5: Total world oil supply (all liquids) on an energy-adjusted basis (mboe)

| | 2000 | 2005 | 2013 | 2000-13 Δ (mbd) | 2000-13 Δ (%) | 2000-05 Δ (mbd) | 2000-05 Δ (%) | 2005-13 Δ (mbd) | 2005-13 Δ (%) |
|-------------------------|---------------|---------------|---------------|--------------------|------------------|--------------------|------------------|--------------------|------------------|
| Crude oil | 68,527 | 73,771 | 75,963 | 7,437 | 10.9% | 5,244 | 7.7% | 2,193 | 3.0% |
| Natural gas liquids | 4,463 | 5,287 | 6,388 | 1,924 | 43.1% | 823 | 18.4% | 1,101 | 20.8% |
| Biofuels | 626 | 781 | 1,650 | 1,024 | 163.5% | 154 | 24.7% | 870 | 111.4% |
| TOTAL SUPPLY | 73,616 | 79,838 | 84,001 | 10,385 | 14.1% | 6,222 | 8.5% | 4,163 | 5.2% |
| Crude oil as % of total | 93.1% | 92.4% | 90.4% | 71.6% | n/a | 84.3% | n/a | 52.7% | n/a |

Source: Kepler Cheuvreux adjustments based on data from US Energy Information Administration (EIA)

As can be seen, the total increase in supply is lower on an energy-adjusted basis than on a purely volumetric basis, rising by only 10.4mboe over the period 2000-13 compared with the volumetric increase of 12.4mbd shown in Table 1.

This means that the increase in *energy* provided by all petroleum liquids and bio-fuels over the period 2000-13 is in fact 16% lower than might be inferred from a simplistic reading of the volumetric increase in the production of liquids.

That is to say, the increase in energy provided from petroleum liquids over 2000-13 was lower than the numbers in Table 3 above suggest by the equivalent of 2mbd of crude oil (i.e. the energy increase was 10.4mboe versus the 12.4mbd of volume increase shown in Table 1). Chart 9 below shows the trend in the production of crude oil and total liquids on an energy-adjusted basis (again scaled from 60mbd).

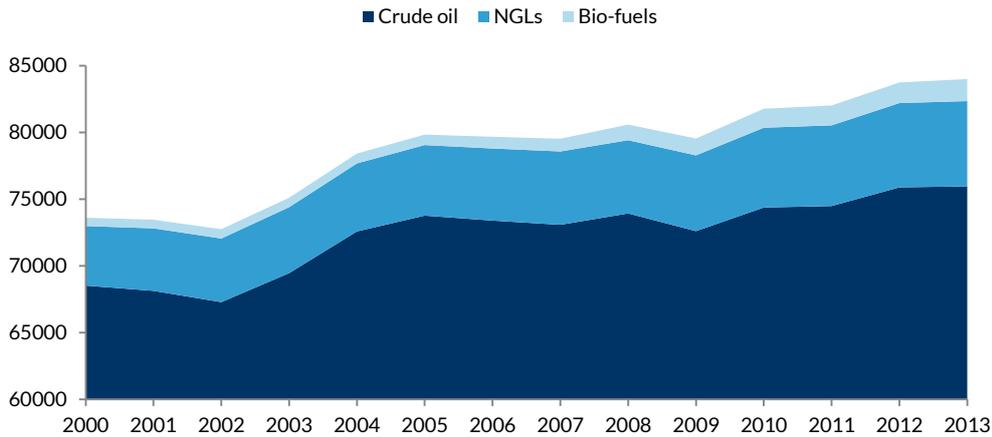
If we compare Chart 9 with Chart 5 above, it can be seen that the total-liquids line here starts from a lower base and hence finishes at a lower height than it does in Chart 5, reflecting the lower energy value per barrel of the NGLs and biofuels.

Otherwise, again, most of the increase in energy provided by petroleum liquids and bio-fuels over the period 2000-13 occurred in the first five years, with the balance in fact skewed even more to the 2000-05 period than is the case on a volumetric basis: 6.2mboe of the total 10.4mboe was added over 2000-05 (i.e. 60%), and 4.2mboe (40%) over 2005-13.

The imbalance is necessarily more skewed this time given the marked slowdown in the increase in the supply of crude oil (with its higher energy density) after 2005.

¹⁵ It should also be pointed out that the energy-adjusted numbers shown in Table 5 are shown on a gross rather than a net basis. In other words they show the amount of energy available in crude oil equivalent terms from the output of petroleum liquids and bio-fuels without showing how much energy was consumed in the production of that output. Calculating the net energy available from a given amount of gross energy is notoriously difficult and beyond the scope of this report, but what we can say here is that the net energy made available from a given source will tend to decline over time as the easy sources are extracted first. In this respect, it would be fair to say that as the world has come to rely more on oil that is highly energy-intensive to produce (in particular, unconventional crudes such as US shale oil and Canadian oil sands), the amount of net energy available to society per barrel produced will on average have declined since 2000, and especially since 2005, as production from these sources has increased.

Chart 9: Production of total liquids energy-adjusted), 2000-13 (kboe)



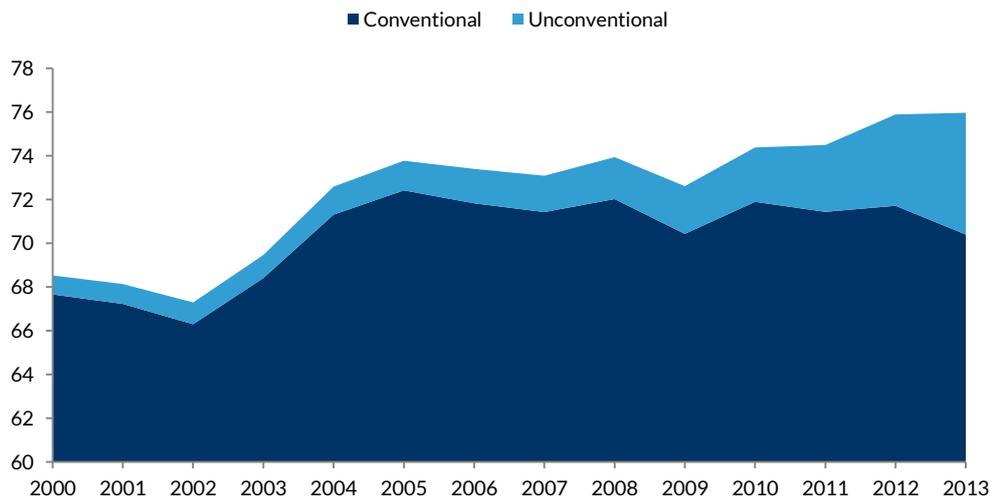
Source: Kepler Cheuvreux based on EIA data

In short, the slowing trend in the supply of crude oil since 2005 and the increasing importance of other liquids in filling the gap is a major structural change in the evolution of the global oil supply; and the slowdown in the overall supply of crude oil since 2005 would have been even more dramatic without the rise of US shale oil and Canadian oil sands.

Surging unconventional output disguises decline in conventional crude

Chart 10 shows the evolution in the global crude oil supply over 2000-13 broken down between conventional and unconventional sources.

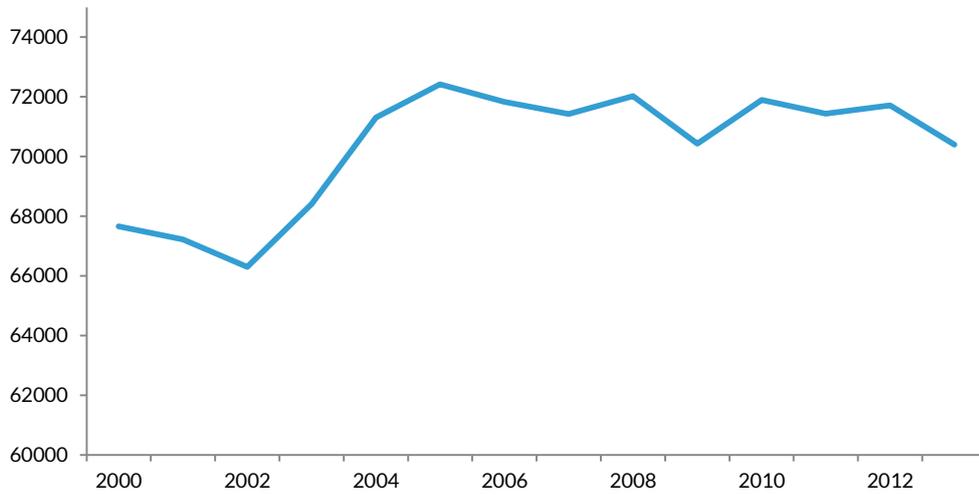
Chart 10: Production of conventional and unconventional crude oil, 2000-13 (mbd)



Source: Kepler Cheuvreux based on EIA data

Chart 11 then shows the evolution in output of conventional crude oil only.

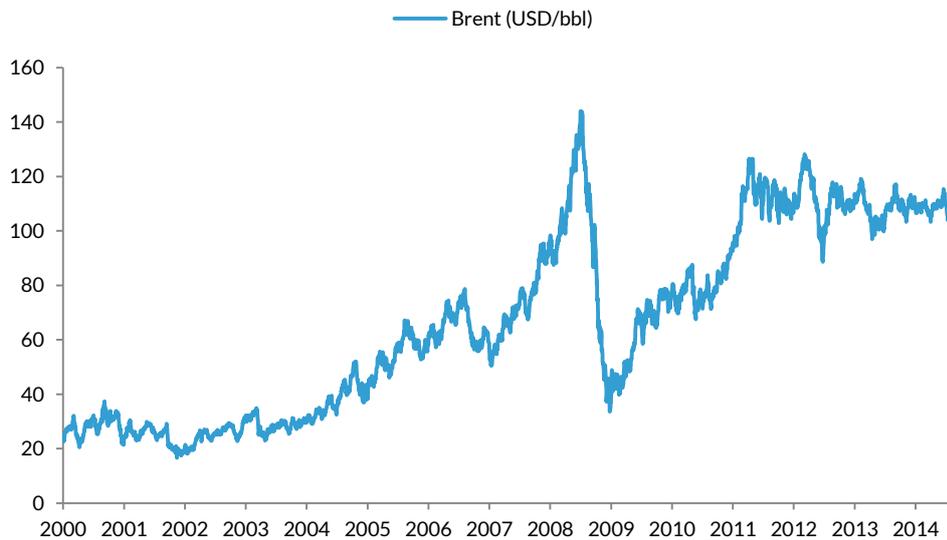
Chart 11: Production of conventional crude oil, 2000-13 (kbd)



Source: Kepler Cheuvreux based on EIA data

From these charts, it is clear that conventional crude peaked in 2005¹⁶ and has been trending down since while unconventional crude has surged in recent years, especially since 2010.

Chart 12: Brent crude oil prices, 2000-13 (mbd)



Source: Eikon

¹⁶ Note that if we classified deepwater production as unconventional, the downward trend in conventional crude production from 2005 would be much steeper.

What is particularly striking about the trend in conventional crude oil is that it failed to continue rising after 2005 – indeed it actually began to decline from then on – even though prices carried on rising at a spectacular rate from 2005 through to the summer of 2008 (Chart 12).

The most straightforward interpretation of the output and price data for crude oil since 2005 is that the peak and decline in conventional crude output over 2005-07 despite much higher prices over this period betrayed a lack of spare capacity among producers and a global system pumping every last barrel of conventional crude available. It also points to the impact of accelerating decline rates in ageing conventional fields and the lack of easy and cheap alternative sources of conventional crude.¹⁷ The output and price data shown in Charts 10 and 12 also imply that that the surge in unconventional crude oil was driven by the surge in prices and would not have happened without this.

Slowing crude/energy-supply growth since 2005 has led to much higher prices

The fact that the growth in the crude oil supply has slowed markedly since 2005 has led to a lower rate of growth in energy supplied from petroleum over 2006-13, in the process prompting much higher crude oil prices. Moreover, the global crude oil supply would actually have declined since 2005 without the rise of US shale oil and Canadian oil sands.

The rise of unconventional crude has therefore been a boon to a global economy thirsty for crude oil, but it has come at the cost of a big increase in the capital intensity of the industry, and has therefore been made possible only by the massive increase in prices since 2005. With this in mind, it is to a more detailed discussion of this increase in unconventional production that we now turn.

The rise of unconventional crude: intensive and expensive

One of the biggest stories in global oil markets over the last few years has been the surge in North American unconventional crude oil in the form of US LTO from the shale formations in North Dakota and Texas, and of Canadian oil sands from the vast bitumen deposits in Alberta.

In particular, the surge of US LTO (+3.2mbd over 2005-13)¹⁸ has prompted a growing narrative about a new age of global oil abundance, and production growth over 2008-13 was indeed phenomenal. Yet, as we know from Table 3 above, despite the extraordinary surge in North American unconventional crude production over the last few years, the global crude supply has increased by only 3% since 2005.

This means that without the surge in US LTO and Canadian oil-sands output, the global supply of crude oil would actually have fallen by 2mbd over 2005-13.

¹⁷ We discuss the impact of decline rates on crude oil output and capital-investment requirements in greater detail below.

¹⁸ Note that our numbers for US LTO production throughout this study are taken from the EIA, which has higher numbers for the LTO production from the Permian play in Texas than many market commentators and observers use (many others take most of the Permian's production as conventional crude). This means that our numbers for total US shale-oil production are also higher than those often cited outside the EIA's publications. However, since we are using EIA data throughout this section not only for US output but for numbers on global production and consumption, we think it is important to use the EIA data on shale oil in order to retain consistency throughout. What this means, though, is that as far as many commentators are concerned, the numbers we are using here overstate somewhat the current level of shale-oil production by c.0.5-1mbd. In the end, though, the crucial point in all of this is not so much the absolute numbers themselves as rather the trends the numbers display.

Moreover, the large-scale development of North America's unconventional crude has been made possible only by the increase in crude oil prices since 2005, as both US LTO and Canadian oil sands are extremely capital-intensive to extract and hence require high prices.

Shale-oil production is very capital-intensive because output from shale wells declines so quickly that a drilling-treadmill effect takes hold, with new wells constantly required to maintain and grow production in the face of ongoing declines from existing wells. The oil sands are capital-intensive because huge amounts of upfront investment are needed, although once these are made output can be maintained for a long time with only very low decline rates.

Of these two sources of unconventional production it is shale oil that looks set to be the much more important determinant of the world's supply-demand balance over the next decade. Both the EIA and the IEA (as well as industry players and many analysts and consultants) project a continuing increase in US LTO production until a peak around 2020 at just under 5mbd, with a plateau until the mid-2020s thereafter and a gentle decline to 3.7mbd by 2035 (still above current levels).

Other supply projections, not least from the renowned independent geologist David Hughes, are much less bullish, and foresee a peak in LTO production already within the 2016-17 timeframe, with a much shorter plateau and steeper decline thereafter.

In the end, whether the profile of LTO production is closer to the more bullish or more bearish supply projections will depend on the outcome of the battle between geology and technology. However, to the extent that this industry has a constant appetite for fresh capital, the real key to the industry's future production profile will be investors and their perception of whether the shale-oil revolution is sustainable, or whether it is just a bubble. If the capital stops flowing, so will the oil.

US LTO and Canadian oil sands: phenomenal growth since 2005

Table 6 shows North American oil supply over 2005-13 by conventional and unconventional sources.

Table 6: North American crude oil supply with and without US LTO production, 2005-13 (mbd)

| | 2005 | 2008 | 2013 | 2005-13 Δ (mbd) | 2005-13 Δ (%) | 2005-08 Δ (mbd) | 2005-08 Δ (%) | 2008-13 Δ (mbd) | 2008-13 Δ (%) |
|------------------------------------|--------------|--------------|---------------|--------------------|------------------|--------------------|------------------|--------------------|------------------|
| Total US crude oil | 5,181 | 5,000 | 7,443 | 2,262 | 43.7% | -182 | -1.9 | 2,444 | -1.1% |
| o/w US conv. crude oil | 4,891 | 4,390 | 3,963 | -928 | -19.0% | -502 | -10.3% | -426 | -9.7% |
| o/w US LTO | 290 | 610 | 3,480 | 3,190 | 1,100% | 320 | 110% | 2,870 | 471% |
| Total Canadian crude oil | 2,493 | 2,708 | 3,473 | 980 | 39.3% | 215 | 8.6% | 765 | 28.2% |
| o/w Canada conventional | 1,428 | 1,401 | 1,385 | -43 | -3.0% | -28 | -1.9% | -15 | -1.1% |
| o/w Canada oil sands | 1,065 | 1,307 | 2,087 | 1,022 | 96% | 243 | 22.8% | 780 | 59.7% |
| Total US and Canadian crude | 7,675 | 7,708 | 10,916 | 3,242 | 42.2% | 33 | -0.4% | 3,209 | 41.6% |
| o/w US & Canada conventional | 6,320 | 5,790 | 5,349 | -971 | -15.4% | -529 | -8.4% | -441 | -7.6% |
| o/w US LTO and oil sands | 1,355 | 1,917 | 5,567 | 4,212 | 96% | 563 | 41.5% | 3,650 | 190.4% |
| Unconventional as % of total | 18% | 25% | 51% | 130% | | n/a | | n/a | |

Source: Kepler Cheuvreux based on data from the EIA and the Canadian Association of Petroleum Producers; *i.e. excluding US LTO and Canadian oil sands

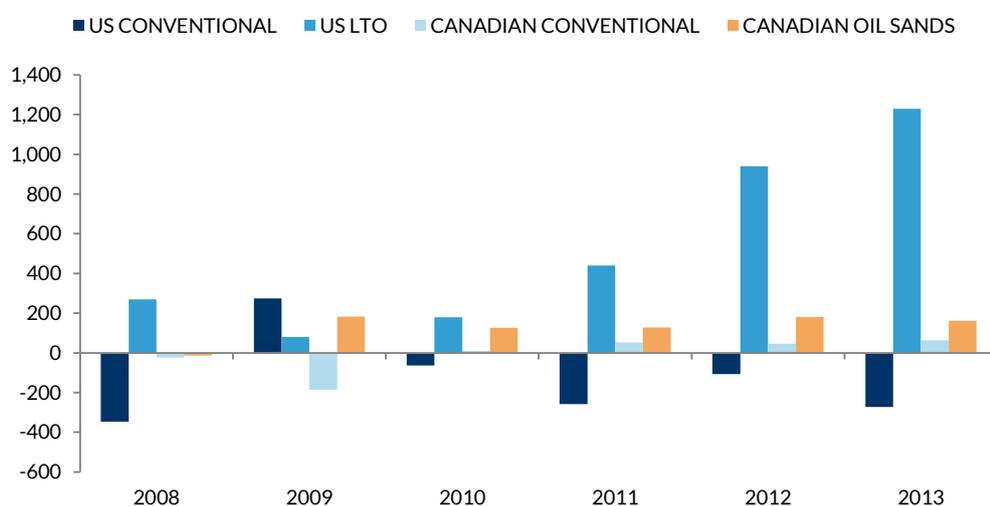
Over 2005-13, the combined US and Canadian crude oil supply increased by 3.2mbd, but this breaks down into a decline in conventional crude of 1mbd and an increase in unconventional of 4.2mbd.

Most of the increase in unconventional was from US LTO (+3.2mbd), although oil-sands growth was also very strong (+1mbd). In terms of the 1mbd decline in conventional crude production, all of this was attributable to the US, with conventional Canadian production basically flat over the period.

As can be seen, the overwhelming proportion of this increase in North American unconventional production occurred over 2008-13 (+3.7mbd), which broke down into +2.9mbd for US LTO and +0.8mbd for oil sands.

In short, and as can be seen from Chart 13, the rise of US LTO and Canadian oil sands has completely revolutionised the North American oil industry since 2005, and more especially since 2008, while the rise of US LTO has also reversed the structural decline in US crude output that had been ongoing since the mid-1980s.

Chart 13: Annual Δ in North American crude oil supply by source, 2008-13 (kbd)



Source: Kepler Cheuvreux based on data from the EIA and the Canadian Association of Petroleum Producers

The impact of rising US and Canadian unconventional production has been so great as to have a very significant impact not only on North American supply but also on the global crude oil supply.

As we already know from Table 3 above, total world crude oil supply increased by 2.2mbd over 2005-13, rising to 76mbd from 73.8mbd. However, and as can be seen in Table 7, if we strip out the impact of rising production from US LTO and Canadian oil sands, the global crude oil supply actually declined by 2mbd over this period, from 72.4mbd to 70.4mbd.

Table 7: World crude oil supply with and without North American unconventional production, 2005-13 (mbd)

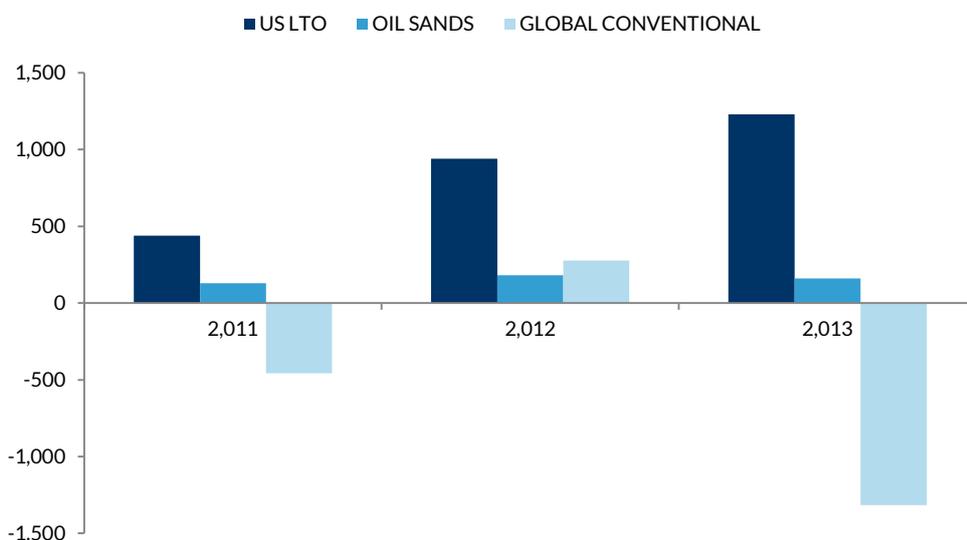
| | 2005 | 2008 | 2013 | 2005-13 Δ (mbd) | 2005-13 Δ (%) | 2005-08 Δ (mbd) | 2005-08 Δ (%) | 2008-13 Δ (mbd) | 2008-13 Δ (%) |
|----------------------------------|---------------|---------------|---------------|--------------------|------------------|--------------------|------------------|--------------------|------------------|
| Total world crude oil | 73,771 | 73,935 | 75,963 | 2,193 | 3.0% | 164 | 0.2% | 2,029 | 2.7% |
| o/w US LTO | 290 | 610 | 3,480 | 3,190 | 1,100% | 320 | 110% | 2,870 | 471% |
| o/w Canadian oil sands | 1,065 | 1,307 | 2,087 | 1,022 | 96% | 243 | 22.8% | 780 | 59.7% |
| Total conventional crude* | 72,416 | 72,017 | 70,396 | -2,020 | -2.8% | -398 | -0.6% | -1,621 | -2.3% |
| US LTO and oil sands % total | 1.8% | 2.6% | 7.3% | 192% | | 343% | | 180% | |

Source: Kepler Cheuvreux based on data from the EIA and the Canadian Association of Petroleum Producers; *i.e. excluding US LTO and Canadian oil sands.

This means that surging US LTO and Canadian oil-sands production has actually outweighed the 2mbd reduction in the rest of the world and thereby enabled the global supply of crude oil to increase by 2mbd over the entire 2005-13 period.

Chart 14 then shows the annual changes in production for US LTO, Canadian oil sands and the residual global crude oil supply over the last three years only.

Chart 14: Annual Δ in crude oil supply with and without unconventional crude, 2008-13 (kbd)



Source: Kepler Cheuvreux based on EIA data

North American unconventional output increased by 0.6mbd in 2011, by 1.1mbd in 2012, and by 1.4mbd in 2013.

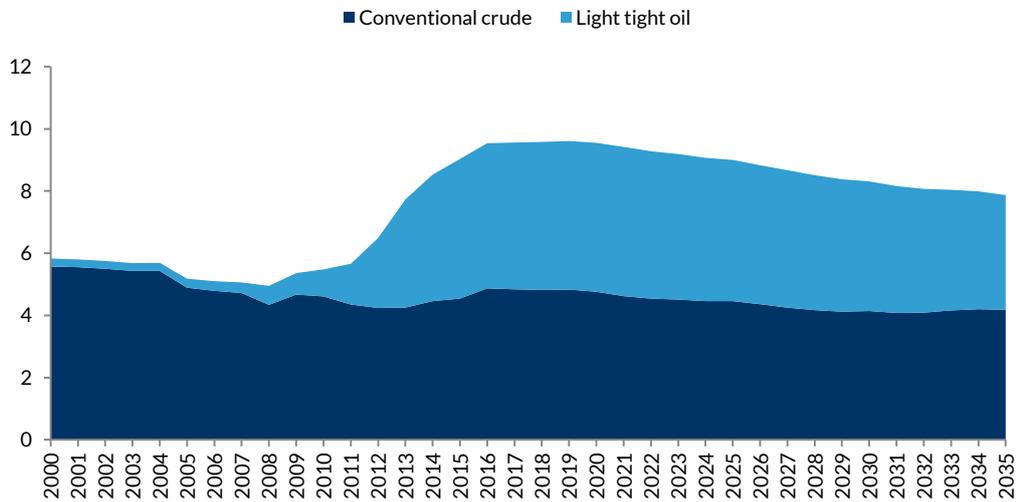
By contrast, in both 2011 and 2013, global crude production excluding US LTO and Canadian oil sands declined (by 0.5mbd and 1.1mbd respectively), while in 2012 it posted only modest growth (+0.3mbd).

This means that between 2010 and 2013 the increase in unconventional North American production of 3.1mbd allowed the global crude supply to increase by 1.6mbd, thereby disguising a fall in conventional crude production globally of 1.5mbd.

Chart 15 shows the EIA data on US crude oil production broken down between conventional and LTO, with the actual development to 2013 and the EIA's base-case

projections for supply out to 2035. The EIA expects LTO production to reach a peak of 4.8mbd over 2018-21 before gently declining to 3.7mbd by 2035 (which will still be some 0.5mbd higher than 2013 levels).¹⁹

Chart 15: US crude oil prod., con. plus LTO, 2000-13 historical, and 2013-35 projected (mbd)



Source: Kepler Cheuvreux based on EIA data

In short, and without any doubt, the surge in North American unconventional crude since 2008 has been a revolution. However, and like all revolutions, it has come with a very high price tag, namely a huge and growing capital-investment requirement.

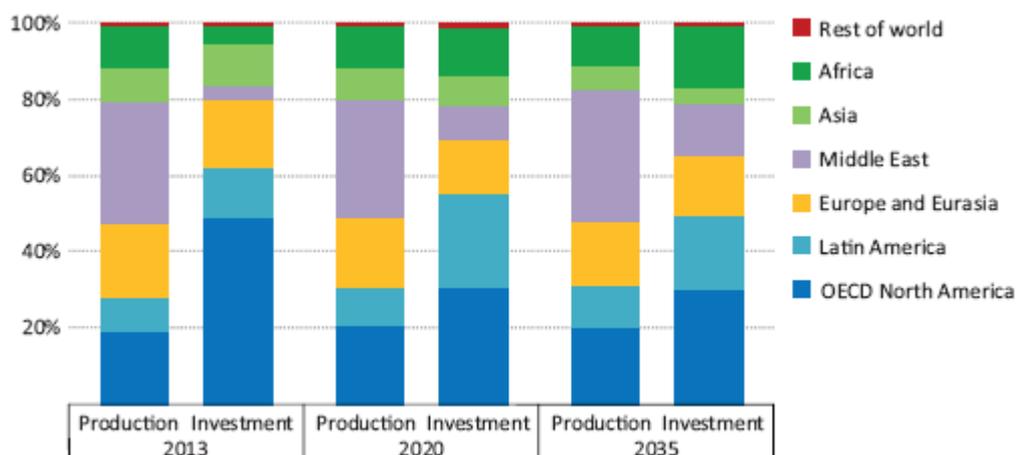
It is this capex price tag that some industry observers think will produce both an earlier and a lower peak in US LTO production, as well as a much steeper subsequent decline, than the profile assumed by the EIA.

But this growth has required massive and growing amounts of capital

Chart 16 shows the IEA’s estimate for the shares of global oil investment and production under its base-case scenario.

As can be seen, in 2013 the IEA estimates that the OECD North America countries (i.e. the US, Canada and Mexico) accounted for c.20% of world output but c.50% of global upstream investment.

¹⁹ As explained in our analysis of its supply projections below, the IEA numbers for US production over 2013-35 are identical to those of the EIA just shown in Chart 15.

Chart 16: Global share of oil production and upstream investment, IEA New Policies Scenario


Source: IEA, 2013 WEO (© OECD/IEA)

This is a staggering imbalance, yet the imbalance between US LTO's share in global production and global investment is even greater. A report from the Oxford Institute of Energy Studies ([US Shale Gas and Tight Oil Industry Performance: Challenges and Opportunities](#), by Ivan Sandrea) cites capex estimates for US shale-oil plays at USD80bn in 2013, which would imply that capital outlays for US LTO production alone accounted for c.20% of global upstream-oil capex in 2013.

This compares with US LTO production of 3.5mbd in 2013, which amounts to 4% of global production. That is to say, US LTO accounted for 4% of the industry's production in 2013 but c.20% of its upstream capex.

Adding the upstream capex of oil sands to this equation (c.USD20bn [according to one recent estimate](#)), we infer that North American unconventional crude accounted for 7% of global crude production in 2013, but for 24% of global upstream capex.

This raises two crucial questions on the industry's capital intensity:

1. Why is the upstream LTO industry in the US so capital-intensive?
2. Can this capital intensity be reduced over time with technology improvements, or will geology ultimately win out and prevent the US shale-oil industry from growing and maintaining LTO production in line with the EIA's and the IEA's assumptions?

Why is LTO production so capex-intensive and can the capex be reduced?

The short answer as to why the LTO industry is so capital-intensive is that decline rates for shale-oil wells are much higher than those for conventional oil wells, and this means that a large number of new wells must be drilled every year simply to offset the ongoing natural decline in existing wells. Logically, this means that as the overall output of a given shale-oil play grows over time, more new wells must be drilled each year just to offset the decline from the wells already producing.

The most comprehensive study of the production profiles of the US LTO plays, to our knowledge, remains the landmark study [Drill, Baby, Drill](#) by David Hughes, published February 2013.

In this study, Hughes analyses in exhaustive detail the production profiles of all the major US shale-gas and shale-oil-plays, and explains that the main reason for the extraordinary capital intensity of the shale industry is the very high decline rates of shale wells. Hughes' detailed analysis of the production profiles of wells in the Bakken play in North Dakota and the Eagle Ford play in Texas – by far the two largest US shale-oil plays currently accounting for about two-thirds of all US LTO production – revealed very steep average output declines in the first two years of production.

For the Bakken, Hughes' analysis concluded that the production from an average well declines by 69% over the first 12 months of its life and then by a further 39% over the second year, while for the Eagle Ford the average decline rates Hughes found were 60% in the first year and then a further 64% in the second. This means that after two years of production, the average shale-oil wells in these two plays are producing some 80-90% below their initial production levels. The conclusion of Hughes' analysis for the US shale-oil plays as a whole (p. 78 of *Drill, Baby, Drill*) is that “*overall field decline rates are such that 40% of production must be replaced annually to maintain production*”.

In short, the very high decline rates of shale-oil wells lead to a treadmill effect, whereby as overall production increases in the early years of a shale play more of the new wells being drilled every year are required simply to compensate for the very high decline rates of the wells already producing.

This requires a huge amount of capex every year just to maintain production at current levels, and then more on top to keep production growing. In other words, the mathematical logic of this production profile is that as more and more wells are added over time and a given play's aggregate production increases, the aggregate amount of supply lost each year via decline also increases, meaning, in turn, that the capex required simply to maintain flat production also has to increase.

As far as the limits of overall production are concerned, Hughes explains (*Drill, Baby, Drill*, p.85) that “*Future production growth is dependent on the number of wells drilled annually, new well performance, and the number of locations available to drill*”.

In other words, it all comes down to the performance of the new wells being drilled every year: if these are equal in quality to those already producing, and if there are enough locations left with many more such wells, production could carry on increasing for a long time, especially if the efficiency of the drilling process improves over time (as it has been doing).

However, this is where the key to understanding the inevitable production decline of an entire play is concerned, for as Hughes explains the US shale plays are not homogenous in terms of their geology, with some areas being much more productive than others.

As a result, producers will target the most productive areas within a given play first (the so-called “sweet spots”), where initial-production (IP) rates are highest.

Over time, though, as the sweet spots are exhausted, producers are forced to migrate to less productive areas of the play, and the rate of growth in production starts to slow down.

As Hughes says (*Drill, Baby, Drill*, p. 102), “*Application of 'better' technology, such as longer horizontal laterals with more hydraulic-fracturing stages, serves to maintain IPs even as drilling*

moves away from sweet spots to lower quality parts of a play”, but “eventually better technology cannot make up for lesser-quality geology, and IPs of new wells decline”. At this point, the number of new wells needed to offset declines from the sweet spots starts to increase even more sharply, and eventually output peaks and then goes into decline (Ibid): “As IPs decrease, more wells are required to offset overall field declines, and without massive amounts of new drilling the plays go into terminal decline”.

In short, the nature of these shale-oil plays is such that they allow for very rapid increases in production in the early phase of their development, and, as we have seen from the production data we reviewed above, this is borne out by the astonishing increase in US LTO output since 2008. At some point, however, the rate of growth will start to slow, and in time all these plays will inevitably peak and decline.

It is this drilling-treadmill effect that explains the capital intensity of the industry, then, and one way of getting a better appreciation of the treadmill effect is to look at the data published every month in the EIA's Drilling Productivity Report (DPR).

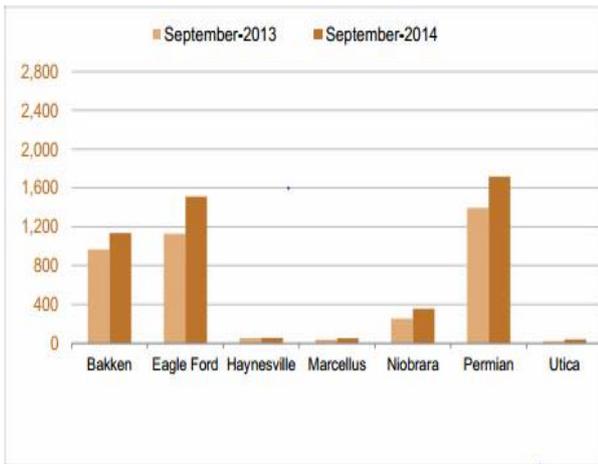
Charts 17-22 below illustrate the impact of this treadmill effect very clearly (all six of these charts are from the EIA's [Drilling Productivity Report](#) for August 2014).²⁰

Chart 17 shows that the production in all the major plays is still growing, with output in all of them projected to be higher in September 2014 than it was in September 2013. However, and as can be seen from Chart 18, the rate at which the Bakken is projected to grow in September 2014 is flat against September 2013.

Chart 18 shows that all the other major plays are expected to add more net new daily production in September 2014 than they did in September 2013, but the point hammered home in *Drill, Baby, Drill* is that owing to the treadmill effect this cannot carry on indefinitely. Indeed, Chart 18 shows that for both the Eagle Ford and the Permian the net new daily additional output expected in September of this year is only 10kbd and 15kbd higher respectively than it was in September 2013.

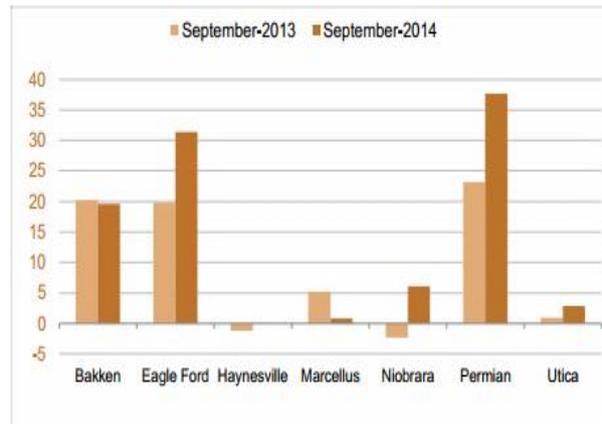
²⁰ We note here that some industry observers question the usefulness of the EIA's Drilling Productivity Report (DPR) in so far as: 1) the data for the following month (so, in the examples we are citing here for September 2014) are by definition speculative projections; and 2) even the data it gives for historic production are not the definitive numbers but also projections based on the trends observable in the actual data published at state level (the problem being that the actual data is published with a lag of a few months). This approach means of necessity that data in the DPR are subject to correction, but we nonetheless think that it can provide a good idea of the trend in production, and that the charts in the DPR are very useful for visualising the drilling-treadmill effect.

Chart 17: Production from the main US LTO plays (kbd)



Source: EIA

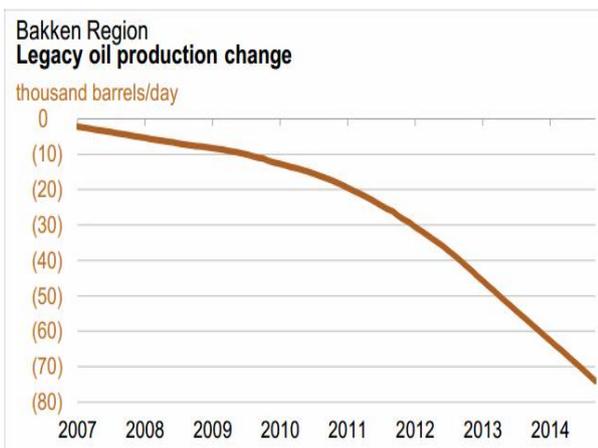
Chart 18: Indicated monthly Δ in oil production (kbd)



Source: EIA

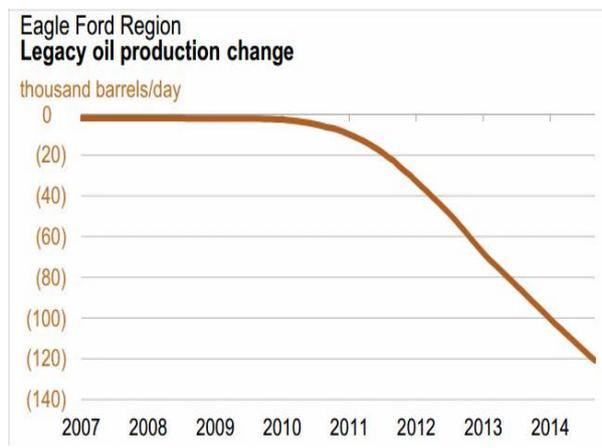
Looking next at Charts 19 and 20 we can see the increasing impact of decline rates over time. As can be seen from Chart 19, the Bakken was losing c.20kbd a day of legacy output per month at the start of 2011, but in September 2014 it is expected to lose c.75kbd. Meanwhile, in the case of the Eagle Ford, the impact of natural decline rates on legacy production has accelerated even more quickly than it has in the Bakken: as can be seen from Chart 20, at the beginning of 2011 the Eagle Ford was losing less than 10kbd of output to natural decline, but in September 2014 it is expected to lose 120kbd.

Chart 19: Legacy production Δ in Bakken, 2007-14 (kbd)



Source: EIA

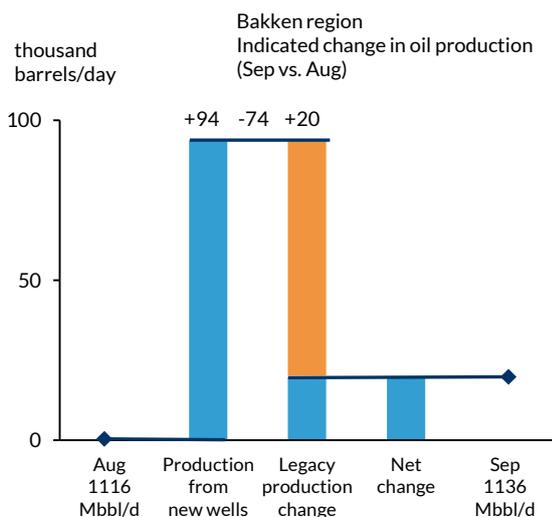
Chart 20: Legacy prod. Δ in Eagle Ford, 2007-14 (kbd)



Source: EIA

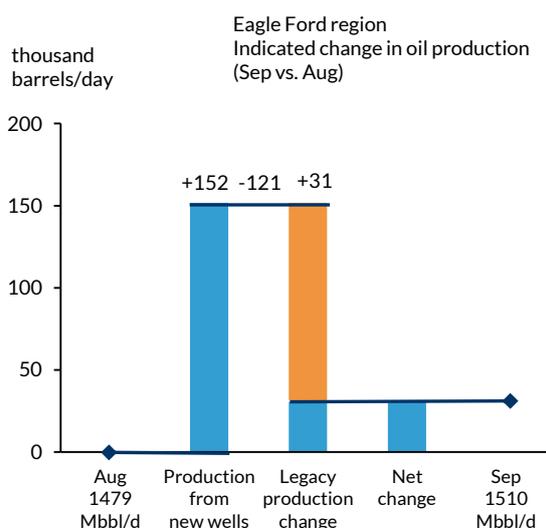
Charts 21 and 22 then synthesise the information shown in Charts 17-20 above for the Bakken and the Eagle Ford respectively.

Chart 21: Indicated MOM Δ in oil prod in Bakken (kbd)



Source: EIA

Chart 22: Indicated. MOM Δ in oil prod. in Eagle Ford (kbd)



Source: EIA

Chart 21 shows that the Bakken is expected to add net new output of only 20kbd, and Chart 22 shows the Eagle Ford net new output in September 2014 at only 31kbd.

In short, the two key distinguishing features of shale-oil plays as set out by David Hughes in *Drill, Baby, Drill* – their sharp decline rates and the drilling-treadmill effect this gives rise to – are not in dispute and are the underlying cause of the astronomically high capex that characterises the upstream shale-oil industry in the US.

Indeed, this much is acknowledged by some leading figures in the industry. For example, the CEO of EOG Resources (Bill Thomas), one of the largest producers in the Bakken, [recently said](#) that “over a fairly short period of time we really believe that the US will be in kind of a very low growth mode”. He went on to say that “oil is not going to just go on forever because there is not really another Eagle Ford or Bakken out there”.²¹

Owing to their very high capital intensity, the most marginal parts of these plays come at a cost that puts them up towards the high end of the global cost curve for oil.²² Over time, in keeping with the logic of the drilling-treadmill effect, as the sweet spots are progressively exhausted the average cost of these plays can be expected to rise because the capital intensity will only increase.

However, if the drilling-treadmill effect itself and its associated capex costs are not in serious dispute, what is much disputed in the market is the time it will take for the shale-oil plays in the US to reach their peak, how long they can remain on a plateau at or near the peak, and how fast they will decline after coming off that plateau.

²¹ At the same time, this does not mean that Thomas expects production in the Bakken or the Eagle Ford to start declining any time soon. On the contrary, in a recent [investor presentation](#), EOG stated that it had 8 years’ worth of drilling inventory in the Bakken and 12 in the Eagle Ford even assuming no further improvements in technology.

²² We put the cost of the US shale-oil plays into the context of the global cost curve for oil in the next main section of this report when looking at the IEA’s projections for supply and prices out to 2035.

On the one hand, there are the companies active in these plays, the EIA and the IEA, and many market analysts and industry consultants, who see aggregate LTO production continuing to rise until the end of this decade before peaking at 4.8mbd and then trending only very gently down thereafter with US LTO output still above current levels by 2035.

The EIA does not disclose the capex assumptions that underlie its base-case projections for US shale-oil production out to 2035 shown in Chart 15 above, but from Chart 16 above it is clear that the IEA – which takes the EIA’s production data for its supply projections in the World Energy Outlook – is assuming that the capital intensity of the shale industry will fall dramatically over time. This must be the case, as Chart 16 shows that the IEA expects OECD North America to hold its share of global production constant at 20% all the way out to 2035, but to reduce its share of upstream investment from c.50% in 2013 to c.30% in 2020, and then hold it at that level to 2035.

Similarly, there are [market analysts](#) and [consultants](#) who think that ongoing technology improvements such as multi-well pad drilling (which allows for tighter well spacing) and production from deeper zones will enable the Bakken in particular to continue growing at rates that ultimately see it surpass even the levels assumed by the EIA. Such technology advances have led a senior executive at Continental Resources (one of the Bakken’s largest producers) to say that [it will not go into decline within “the next 10 to 15 years”](#).

On the other hand, some industry observers take a much more pessimistic view, positing an earlier and much shorter peak followed by a much steeper and quicker decline thereafter. In *Drill, Baby, Drill*, David Hughes stated that the Bakken and Eagle Ford were both likely to peak in the 2016-17 timeframe, and reiterated the point in a presentation given in December 2013, available [here](#), in which he posited 2016 as the most likely date of peak production for both of these plays. Hughes projects a rapid decline thereafter, with US LTO output back at 0.7mbd by 2025.

Using a different methodology from David Hughes’ comprehensive fieldwork approach, [David Archibald](#) recently published [an article](#) with an even more aggressive view of the timeframe within which US shale oil will peak, and the rate at which it will decline thereafter. Archibald used the linearisation methodology originally made famous by M. King Hubbert to conclude that US shale-oil production will peak in 2015 at 3.9mbd, and thereafter go into a decline as rapid as was its ascent.

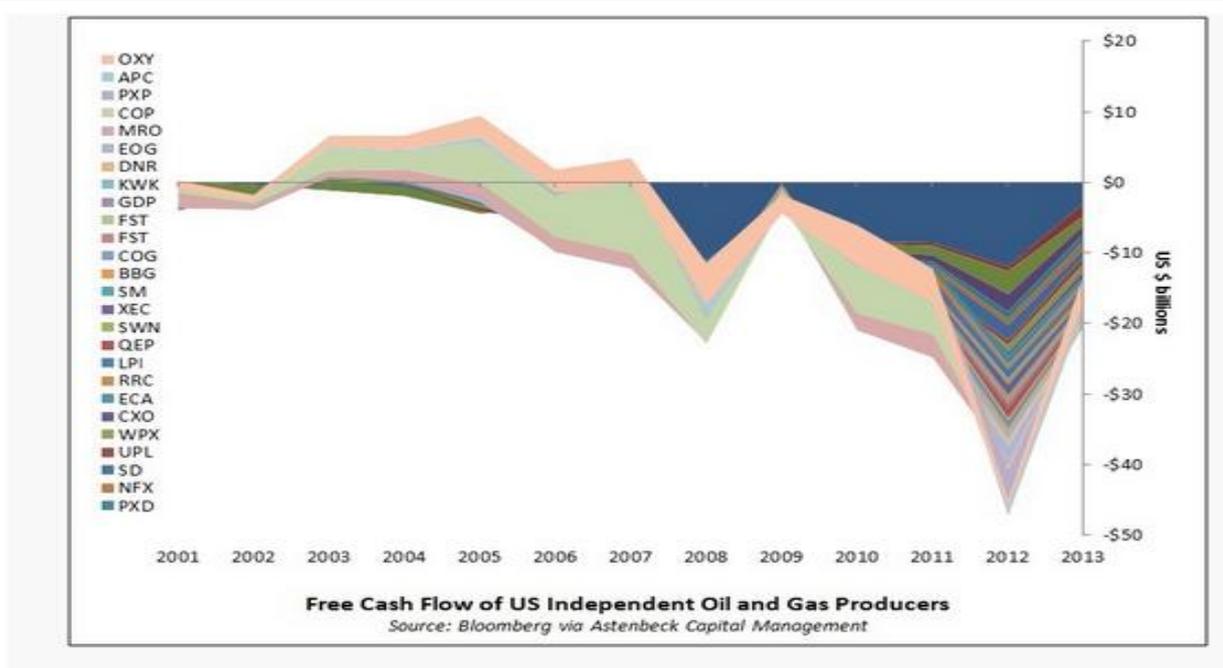
In the end, then, the debate over the profile of future US LTO production comes down to differing views on the relative strengths of geology and technology. Ultimately, the fight between geology and technology will be adjudicated by the industry’s providers of capital. In other words, the question is not just for how long and to what extent improving technology can stem the relentless ravages of the natural geological process of decline, but for how long debt and equity investors will be willing to continue funding the insatiable appetite for capital of the drilling-treadmill process.

This is nicely summarised by Ivan Sandrea in [the study](#) from the Oxford Institute for Energy Studies that we cited earlier (p. 3): *“In order to keep these plays going, build a scalable industry and ultimately meet expectations for future long-term US supply increase, exploitation must be viable commercially for industrial investors to stay in the business and rational investors to keep funding the activity beyond the initial excitement.”*

The question of investors' appetite to keep funding the shale-oil capex treadmill is an increasingly pressing one, because as explained by leading industry consultant and commentator Steve Kopits [in a recent article on oil-industry economics](#), the US shale industry in aggregate (oil and gas combined) has been free-cash-flow-negative since 2006 (Chart 23 below). Both Kopits and Sandra make the point that the current negative cash-flow dynamics of the shale-oil industry are not in themselves proof that the economics are unsustainable, with Sandra (p.7) explaining investors' rationale in the face of the cash burn shown in Chart 23 thus:

"From an industry point of view, these trends are not necessarily problematic, assuming that there will be a positive inflection point for cash flow and a full-cycle risk-adjusted return. Some major players see this economic inflection coming in another five years from now, since it is a fledgling industry."

Chart 23: Free cash flow of US Independent oil and gas producers, 2001-13 (USDbn)



Source: Bloomberg via Astenbeck Capital Management, as cited in [Steve Kopits' article of 30 July](#)

On the other hand, as Kopits points out, this means that it all comes down to how long investors will have faith in the growth dimension of the shale story: *"It is not clear that the US independents are profitable. An industry can see a boom irrespective of profits or free cash flow if banks and investors are willing to underwrite the promises of future profits. The internet bubble showed us that."*

Kopits' comment strikes at the heart of the issue, for the risk must now be that if the drilling-treadmill process in the Bakken and Eagle Ford results in a marked deceleration of production growth in these plays over the next 12-18 months, then investors could start to become increasingly concerned about the sustainability of the shale-oil growth story and come to think of it as a bubble instead.

In short, the shale-oil industry and its technological ingenuity are in a race against time with regard to both geology and investor patience, with investor patience now crucially dependent, in our view, on the trend and speed of the legacy-decline ratio in the two major plays over the next 12-18 months.

Indeed, as Sandra says (p.7), there may already be signs that traditional investors' willingness to fund further growth is waning: *"The funding machine is undergoing rapid changes. Sources of funding are now led by private equity, high-yield debt, capital release from the sale of mid-stream assets into master-limited partnerships (MLPs) and the sale of more non-core assets. There are fewer JVs with foreign-capital providers, certainly from outside China, and less reserve-based lending, hedging, and equity issuances."*

A final consideration in all of this is the outlook for US interest-rate policy, since as an April 2014 [Bloomberg article pointed out](#), much of the financing of the US shale-oil expansion has been in the form of junk-rated debt.

That said, whether a tightening of interest rates by the Federal Reserve at some point in the next 12-18 months (should that materialise) would actually have much of an impact on the industry's ability to fund further expansion was disputed in [a more recent Wall Street Journal article](#) (August 2014), which cited research claiming that 90% of the US E&P sector's outstanding debt was at fixed interest rates and that 60% of the total outstanding USD346bn did not mature until after 2020.

Nonetheless, to the extent that historically low interest rates have undoubtedly helped fuel the shale-oil boom, there can be no doubt that any tightening of rates by the Federal Reserve would have a net negative impact on the future financing prospects of the E&P companies that have driven the shale-oil boom.

Conclusion: future profile of LTO output pits geology against technology

As explained above, the global supply of crude oil would have registered a decline since 2005 without the extraordinary increase in unconventional North American crude, and especially US shale oil, seen in recent years.

This means that the near-to-medium term outlook for the global supply of crude oil, and hence for crude oil prices, will depend to a critical extent on the profile of US LTO production over the next decade.

As we have seen, the very high decline rates of the US shale-oil plays are not in dispute, but where there are very big differences of opinion is over the extent to which technology can mitigate geology.

On the one hand, there are those like the EIA, IEA and many market analysts and consultants who see growth continuing to the end of this decade, with a peak in production of nearly 5mbd and then an extended plateau and gentle decline back to 3.7mbd by 2035.

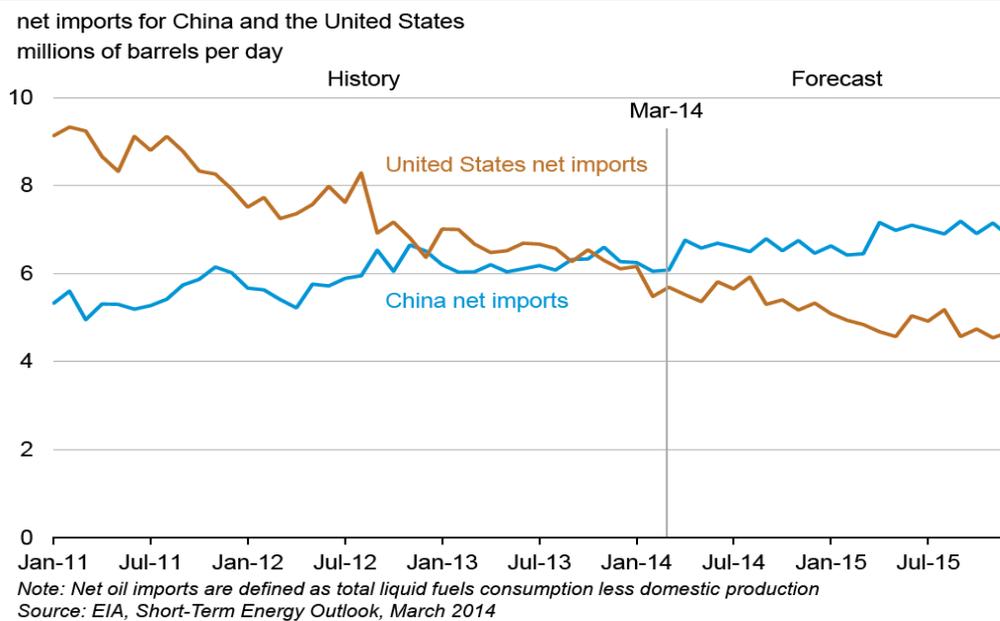
On the other hand, there are those like David Hughes and David Archibald who, though using different methodologies, see US shale-oil production peaking within a 2015-17 timeframe and thereafter declining to levels well below current production by the early 2020s.

In the end, much will depend on the industry’s need for continuing large infusions of capital to keep the drilling treadmill going, and hence on investors’ perception of the extent to which growth can be maintained at levels consistent with the expectation of higher future profitability and cash flows.

This makes the LTO industry more vulnerable than most to potential changes in investor sentiment, such as might be triggered not only by perceptions of the industry’s own dynamics, but also by exogenous factors (for example, a tightening of the Federal Reserve’s monetary policy).

Finally, the impact of rising US LTO production has been felt not only in terms of the global supply of crude oil *per se*, but also in terms of its impact on global trade in crude oil. Rising output of US LTO has reduced US crude imports by c.2.4mbd since 2008 and thereby freed up this volume of exports for other countries. Nonetheless, the US remains the world’s second largest importer of crude oil after China (Chart 24).

Chart 24: Historical/proj. trend in net oil imports (total pet. liquids) for US, China, 2011-15 (mbd)



Source: EIA

As a result, the outlook for US LTO output matters hugely in determining the competition that will exist for the pool of global crude exports over the next two decades, especially if this pool of exports continues to decline as it has been doing since 2007.

With this in mind, we will now make a closer examination of the trend in global exports of crude oil since 2000.

Global exports of crude oil in decline since 2005

With the EIA having stopped providing numbers for global exports of crude oil after 2010, and JODI (Joint Oil Database Initiative) suffering from many gaps and delays in its reporting, we think OPEC's dataset for gross global crude oil exports since 2000 is the best starting point for trying to understand what has been happening with global crude exports over the last decade or so, even though what we are ultimately interested in here is the trend in *net* global exports of crude oil.²³

The OPEC data indicate a declining trend in gross global exports of crude oil since 2007, with 2013 gross crude exports 2mbd lower than in 2005, and 3mbd lower than their peak in 2007.

Analysing the EIA data on production and consumption since 2005 in both the net exporters and the net importers of crude oil in an attempt to ascertain what has happened to *net* global exports of crude oil since 2005, we find the same trend as that shown for gross exports in OPEC's data, but with an earlier peak in 2005.

Our analysis indicates that net global exports of crude oil were some 3.4mbd lower in 2013 than in 2005, and is thus consistent with the trend shown in OPEC's data for gross exports from 2007, although the magnitude of the decline is greater in our analysis.²⁴

With the crude oil output of OPEC and the other net exporters on a plateau since 2005 (despite much higher average prices over 2006-13), the main reason for the decline in net crude exports over 2005-12 has been the huge increase in oil consumption in these countries over the last decade or so, especially in the OPEC countries.

In the face of this decline in net global exports of crude oil – and despite the surge in unconventional crude oil production in the US – net-importing countries have been forced to bid ever more aggressively in the market for the supplies made available by net exporters, and the result has been a dramatic redistribution of the global pie of net crude exports.

Our analysis indicates that non-OECD net-importing countries as a group (led by China and India) were by 2013 consuming c.5.5mbd of crude exports, which in 2005 were consumed by the OECD net-importing countries.

In other words, in the face of declining net crude exports, the fast-growing non-OECD net importers have increasingly eaten into the share of the global export pie traditionally consumed by the OECD net importers.

With very high population growth and high subsidies on domestic oil consumption, the outlook is for continuing strong growth in OPEC's domestic demand. This means that if the

²³ Owing to mismatches between the OPEC export and import data we do not think it is possible to get a clear view of the trend in net exports from the OPEC numbers. As a result, our approach here is to begin with a look at OPEC's figures for gross global exports of crude oil and then compare this with EIA data on production and consumption in the exporting and importing countries in order to impute what we think is a reasonable estimate of the underlying trend in net exports.

²⁴ The leading analyst on the trend in global exports of crude oil is the independent geologist Jeffrey J. Brown, who developed the [Export-Land Model](#) setting out the long-term implications of declining global exports and has published voluminously on this topic in recent years. Brown has recently refined his ideas further, developing the concept of the [Export Capacity Index](#).

declining trend in net global exports of crude oil is to be reversed (as the IEA assumes it will be over the next two decades), it will likely depend more on the production side of the equation.

This will require, among other things, a return to normality in Libya and Iran, an increase in Venezuela’s output of extra-heavy oil, and above all the fulfilment of Iraq’s undoubtedly huge potential. Outside OPEC, future export growth will above all depend on Canada, Kazakhstan and Brazil.

OPEC data shows a global peak in gross exports of crude oil in 2007

Table 8 shows gross global crude exports over 2000-13 broken down between OPEC on the one hand, and the rest of the world (ROW) on the other (the data is from [OPEC’s 2014 Annual Statistical Bulletin](#)).

Table 8: Global crude oil exports, 2000-13 (kbd)

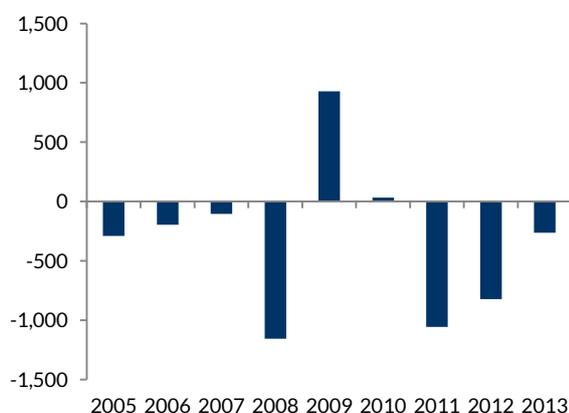
| | 2000 | 2005 | 2013 | 2000-13 Δ (mbd) | 2000-13 Δ (%) | 2000-05 Δ (mbd) | 2000-05 Δ (%) | 2005-13 Δ (mbd) | 2005-13 Δ (%) |
|----------------------|--------|--------|--------|--------------------|------------------|--------------------|------------------|--------------------|------------------|
| Total global exports | 38,371 | 41,715 | 39,830 | 1,459 | 3.8% | 3,344 | 8.7% | -1,885 | -4.5% |
| o/w OPEC exports | 20,894 | 23,297 | 24,054 | 3,160 | 15.1% | 2,403 | 11.5% | 757 | 3.2% |
| o/w ROW exports | 17,477 | 18,418 | 15,776 | -1,701 | -9.7% | 941 | 5.4% | -2,642 | -14.3% |
| OPEC % of total | 54.5% | 55.8% | 60.4% | 217% | | 71.8% | | n/a | |

Source: OPEC (calculations by Kepler-Cheuvreux)

On this data, gross global crude oil exports were 1.5mbd higher in 2013 than in 2000, with OPEC’s increase of 3.2mbd masking a decline in the ROW of 1.7mbd. However, between 2013 and 2005 global exports fell by 1.9mbd, with OPEC’s increase of 0.8mbd only partly offsetting the decline of 2.6mbd in the ROW.

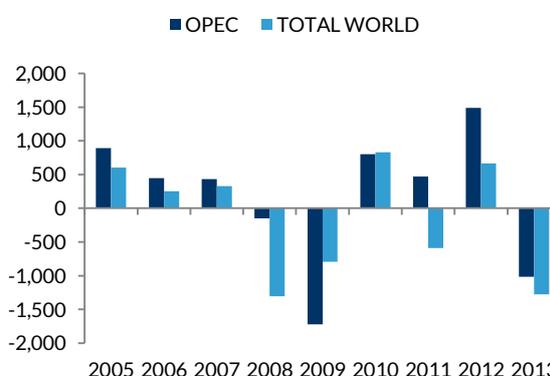
OPEC’s numbers show a peak for gross global exports in 2007 at 42.3mbd, but the ROW peaked already in 2004 at 18.7mbd and at 15.8mbd last year the ROW’s exports reached their lowest level since 2004. Chart 25 shows the annual changes in gross crude exports since 2005 for the ROW excluding OPEC, and Chart 26 the annual changes for OPEC and total world exports.

Chart 25: Ann. chg crude oil exp. ROW ex. OPEC, 2005-13



Source: Kepler Cheuvreux from OPEC data

Chart 26: Ann. chg OPEC, total world exp. of crude oil, 2005-13

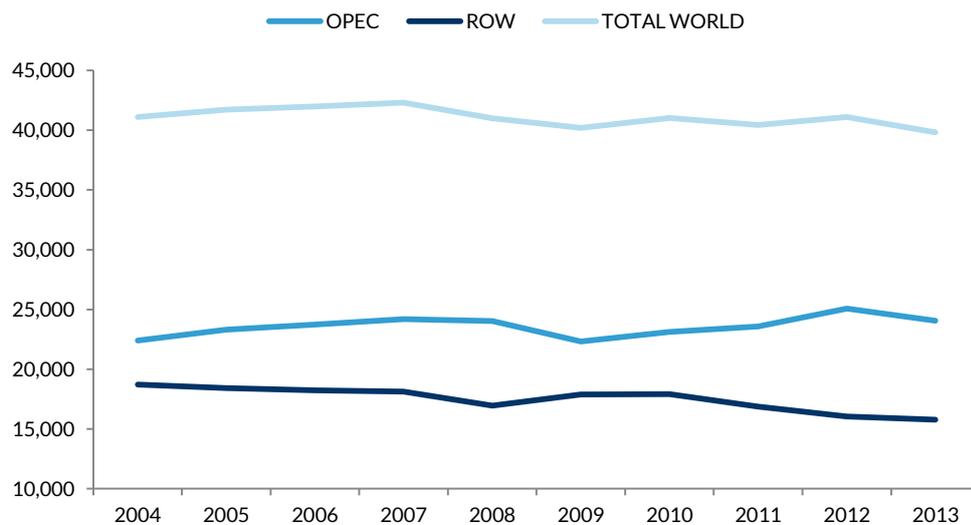


Source: Kepler Cheuvreux from OPEC data

Chart 27 then shows the trend in gross global exports since 2000 broken down between OPEC and the ROW.

We think the three clear trends shown in these numbers and visible from the charts are: declining ROW exports since 2004; OPEC exports flat since 2005 but generally on a slightly lower plateau over 2009-13 than over 2005-08; declining global exports of crude oil since 2007, albeit on an apparently fairly stable plateau since 2009.

Chart 27: Global exports of crude oil by source since 2000 (kbd)



Source: Kepler Cheuvreux from OPEC data

The question is, does this matter and should we be concerned about this trend of lower global exports of crude oil since 2007? The answer to this question depends on the reasons underlying this fall in crude oil exports.

Ultimately, what importers of crude oil want to consume is not crude oil *per se*, but the products derived from crude oil (gasoline, diesel, jet fuel, fuel oil and so forth). As a result, what really matters to countries that are net importers is not the net supply of global crude exports *per se*, but the net supply of global exports of crude oil and crude-derived refined products (not all countries have their own refineries so while the bigger net-importing countries will import crude and refine it for their own and other markets, some countries will simply directly import all the refined products they need).

As a result, if global exports of crude oil fall, what matters to the net importers is whether this reflects malign or benign underlying causes that will lead them to incur an economic loss or benefit.

Perhaps most obviously in terms of malign underlying causes, net exports of crude oil could decline over time simply because the output of crude oil in the major exporters declined. In this case, and other things being equal, declining net global exports of crude oil would by definition mean a decline in the sum of net global exports of crude and of crude-derived products, and would thus constitute an economic loss for net importers.

Alternatively, if crude oil output were simply to remain flat in crude-exporting countries but their consumption of crude and crude-derived products were to increase over time, then this too, other things being equal, would by definition result in a decline in the sum of net exports of crude oil and crude-derived products, and hence a net economic loss for net importers.

On the other hand, it is also possible to imagine more benign underlying causes for declining global exports.

For example, what if the major producers and exporters of crude oil were to increase both their output of crude oil *and* the amount of crude they refine themselves in order to produce exports of refined products? Under such a scenario, while net importers of crude and crude products might see a decline in the amount of *crude oil* available for them to import, they would nonetheless see an increase in the sum of crude oil plus crude products available to import, and other things being equal this would constitute an economic benefit for net importers.

Similarly, it is possible to imagine a scenario whereby countries that are net importers of crude oil but have their own crude production increase their own crude output over time and hence reduce their need for imports of crude and/or crude products. Other things being equal, this would reduce the need for net crude oil exports at global level, but without any net economic loss to importers (and in fact with a gain in terms of their balance of payments).

Alternatively, net importers might increase their energy efficiency over time. Other things being equal this would reduce their need for imports of crude and/or crude-derived products, thereby reducing net crude and/or crude-product exports at the global level while nonetheless providing an economic gain to the net importers.

In short, while any fall in global exports of crude oil ultimately and by definition occurs owing to a change in either the level of output or consumption (or both) of crude oil in net-exporting countries, what matters from an economic point of view is the underlying cause of these changes.

In other words, are exporters exporting less because they simply have less to export (i.e. owing to a non-discretionary fall in their output, or a rise in their consumption)? Or are they exporting less crude owing to a strategic decision to increase their exports of crude-derived products? Or are they exporting less crude owing to lower demand in the net-importing countries for crude imports (i.e. are they reducing exports on a discretionary basis in response to lower external demand)?

To understand the drivers of lower global exports of crude oil since the middle of the last decade – and to evaluate whether this trend is malign or benign for net importers – we need to analyse production and consumption patterns in the two categories of countries that are relevant here: 1) net exporters of crude oil; and 2) net importers of crude oil.

As a further aid to evaluating the underlying causes of the decline in global exports, we need to bear in mind what price signal the market has been sending while this decline has been happening.

From Chart 8 above we already know that the global trends in production and consumption since 2005 have played out against a backdrop of rising prices over most of the period 2005-11 followed by an undulating price plateau at or near all-time record highs since 2011. This means that for most of the period since 2005 net-exporting countries have had every incentive to maximise their production and hence their exports of crude oil.

Turning to a closer look at the EIA numbers, then, let us first consider the trends in production and consumption for the exporting countries since 2005, and then for the crude-importing countries.

Trends in output and consumption in exporting countries since 2005

Looking at the EIA crude-production data for countries that were net crude exporters in 2005 we find that production was basically flat in 2013 versus 2005 (57.8mbd versus 57.6mbd). As shown in Table 9, OPEC production was actually 0.4mbd higher, whereas output from net exporters in the ROW was -0.15mbd lower.

Table 9: Crude oil production of countries that were net crude exporters, 2005 & 2013 (kbd)

| | 2005 | 2013 | 2005-13 Δ (kbd) | 2005-13 Δ (%) |
|--|---------------|---------------|--------------------|------------------|
| OPEC | 31,897 | 32,280 | 382 | 1.2% |
| ROW | 25,682 | 25,535 | -147 | -0.6% |
| o/w countries with higher output in 2013 | 14,662 | 18,030 | 3,368 | 23.0% |
| o/w countries with lower output by 2013 | 11,020 | 7,505 | -3,516 | -31.9% |
| Total | 57,579 | 57,814 | 235 | 0.4% |

Source: EIA

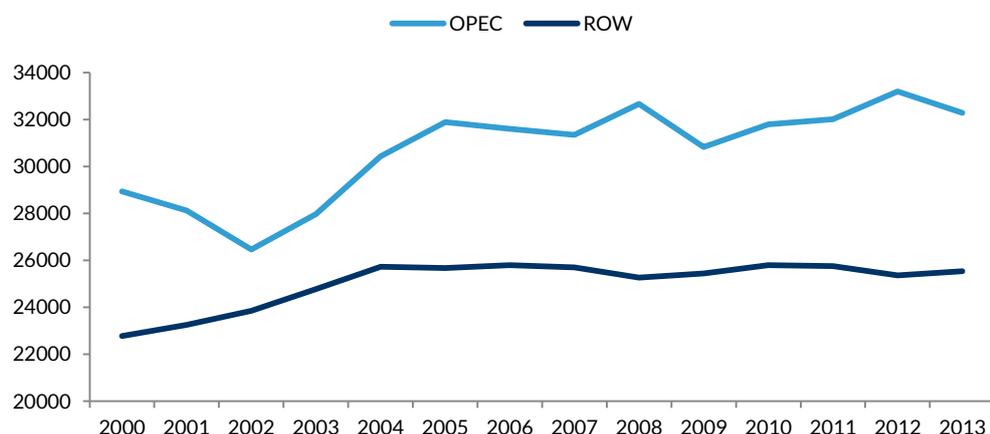
In addition to OPEC, 20 countries that were meaningful net exporters in 2005 (Azerbaijan, Argentina, Brunei, Canada, Colombia, Congo, Denmark, Equatorial Guinea, Gabon, Kazakhstan, Malaysia, Mexico, Norway, Oman, Russia, pre-partition Sudan, Syria, Trinidad & Tobago, and Vietnam), and for our purposes here we also include Indonesia in this list.²⁵ Of these, seven grew their production by a combined 3.4mbd between 2005 and 2013, and in order of magnitude these were Russia (+1mbd), Canada (+1.mbd), Colombia (+0.5mbd), Azerbaijan (+0.4mbd), Kazakhstan (+0.3mbd), Oman (+0.2mbd), and Congo (less than 0.1mbd). Among the other 13 countries, Norway (-1.2mbd), Mexico (-0.9mbd), Syria (-0.4mbd), and Indonesia (-0.2mbd) accounted for most of their combined 3.5mbd decline between 2005 and 2013.

OPEC's output has remained flat versus 2005 despite Iran and Libya seeing large drops in their production over the last two years as a result of the sanctions imposed on Iran over its nuclear aspirations on the one hand, and the chaos wrought by ongoing civil war in Libya on the other. Iran's 2013 output was down by 0.9mbd versus 2005 (3.1mbd and 4mbd respectively), and Libya's by 0.7mbd (0.9mbd and 1.6mbd respectively).

²⁵ Note that we include Indonesia here among net exporters because it is something of a special case. It was a member of OPEC until as late as 2008 even though it ceased to be a net oil exporter in 2005. We nonetheless include it among net oil exporters for our purposes here, as over the period 2005-08 its net imports were still very small and because the fact that it remained in OPEC over this period indicates that it was clearly hoping to be able to boost its production and thereby regain net-export status. However, the decision to leave OPEC in 2008 was recognition that it had lost its net-export status for good.

Chart 28 shows the evolution of crude output in these countries over 2000-13 broken down between OPEC and the ROW. After rising sharply between 2001 and 2005, the output of both groups has been flat since 2005, although OPEC's output has oscillated within a range of ± 1 mbd around the 2005 figure of 31.9mbd.

Chart 28: Evolution in crude oil output of countries that were net exporters in 2005, 2000-13 (kbd)



Source: Kepler Cheuvreux from OPEC data

The optimistic interpretation of this crude oil production pattern amongst net exporters since 2005 would be that OPEC is not yet experiencing *structural* issues in terms of its output, and that if anything it has scope to increase its exports by up to 1.5mbd from current levels over the next 18-24 months if: 1) negotiations between Iran and the west over the nuclear issue are ultimately successful and so lead to a lifting of sanctions at some point in the relatively near future, and 2) order can be restored in Libya in the near future (at least in terms of oil production), and hence output lifted back towards the 1.4mbd level achieved as recently as 2012.

An optimistic reading of the trend in OPEC production would also emphasize the rise in Iraq's production over the last decade (up by 1.2mbd between 2005 and 2013), and emphasize the potential for even bigger output and export increases from Iraq in future.

However, an alternative, less positive reading, would emphasize that geo-political issues are endemic to OPEC and therefore always pose a risk to the output of the bloc as a whole. Accordingly, even if the obstacles currently impinging on Iranian and Libyan output could be resolved in the relatively near future, there is always the risk that new problems would arise in another one or more OPEC country or countries. Indeed, in this respect the recent upsurge in violence in Iraq is the best example of an OPEC country that could see its output and exports negatively affected in the near term owing to endemic geo-political problems.²⁶

²⁶ Given the importance of Iraq to the IEA's supply-growth assumptions over the next two decades – Iraq accounts for 50% of the Agency's assumed global oil-supply growth out to 2020 and 45% out to 2035 – the political, ethnic, and religious divisions in Iraq and the potential these have for destabilizing the country is one of the biggest clouds hanging over the medium-to-long-term outlook for oil markets.

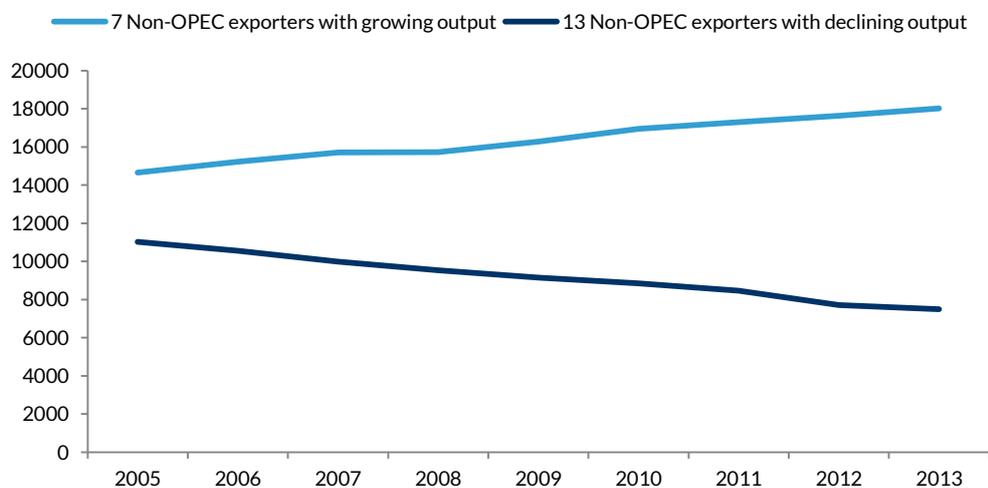
Moreover, it cannot be emphasized enough that, whatever the mitigating factors in Iran and Libya, OPEC as a group has not been able to grow its production meaningfully since 2005 despite sharply higher average crude oil prices over 2006-13. As can be seen from Chart 10 above, this is in stark contrast to the strong output growth OPEC registered over 2002-05 (when oil prices rose less sharply).

This is very telling, as against this backdrop of sharply higher average crude prices over 2006-13, OPEC producers would surely have had every incentive to maximize their output and thereby maximize their export earnings.

The fact that as a group they could not manage to increase production meaningfully suggests that – with the exceptions of Iran and Libya in the last couple of years – OPEC has been pumping at or close to its maximum capacity for most of the last decade (as already explained above, the violent oscillation in production over 2008-09 was an exception to the production pattern over rest of the period since 2005 induced by the global financial crisis, and hence falling global demand, at that time).

If we then look at the evolution in crude production of the non-OPEC exporters (Chart 29), we can observe a stark difference between the trend in the seven countries that managed to increase their output over 2005-13 on the one hand, and the 13 that experienced a reduction in their output on the other (the respective countries and the main changes in their production are listed above on page 49).

Chart 29: Evolution of crude oil output of non-OPEC net exporters, 2000-13 (kbd)



Source: Kepler Cheuvreux from OPEC data

As can be seen, the production changes in the two groups almost exactly cancel each other out, and this is why, as shown above in Chart 28, the crude production of non-OPEC exporters has been on an almost perfectly stable plateau since 2005.

Nonetheless, the cause for concern in this trend is that the growth within this group since 2005 has been concentrated on a small number of countries, especially Canada and Russia.

Moreover, the IEA is pinning a lot of hope on Kazakhstan as a major source of growth for both production and exports over the next two decades.²⁷

Yet as we have seen, Canada's production growth is attributable entirely to oil sands, and while this is expected to grow significantly over years to come the rate of growth is expected to be only 0.1-0.2mbd per year. At the same time, [Russia has recently warned that its output is set to fall by 6% in 2015 versus 2014 levels](#), while Kazakhstan has experienced a host of major problems with its giant Kashagan oil field, which is now expected to be out of action for the whole of this year and next, raising the question as to whether it will ever reach the production levels originally expected of it.²⁸

In short, while crude oil production from both OPEC and non-OPEC net crude exporters since 2005 has been flat, there are grounds for concern over these countries' collective ability not only to grow production over the medium-to-long term, but even to maintain it at current levels.²⁹

Table 10 then shows the increase in the production of NGLs in the net crude oil-exporting countries between 2005 and 2013 (we need this data in order to impute crude oil export numbers from the consumption data).

Table 10: NGL production of countries that were net crude exporters in 2005, 2005 and 2013 (kbd)

| | 2005 | 2013 | 2005-13 Δ (kbd) | 2005-13 Δ (%) |
|--------------|--------------|--------------|--------------------|------------------|
| OPEC | 2,844 | 3,456 | 612 | 21.5% |
| ROW | 2,129 | 2,150 | 21 | 1.0% |
| Total | 4,974 | 5,606 | 633 | 12.7% |

Source: EIA

Turning to the consumption of the net-crude exporting countries since 2005, the first thing to note is that the EIA does not show the consumption of crude oil on a disaggregated basis. As a result, we have to begin with the consumption of all petroleum liquids and work back from there.

Table 11 shows the total consumption of all petroleum liquids in the countries that were net crude exporters in 2005, again broken down between OPEC and the ROW. As can be seen, the increase in the consumption of all liquids of all these countries combined between 2005 and 2013 was 4.2mbd, which breaks down as +2.6mbd for OPEC and +1.6mbd for the ROW.

²⁷ As we discuss in the next main section of this report, when looking at the IEA's projections for global oil markets over 2013-35, the three countries after Iraq from which the IEA expects big increases in net exports over the next two decades are Brazil, Canada, and Kazakhstan (as of 2013, Brazil is still a net importer). By contrast, the IEA expects Russia's production and exports to remain flat until 2020 and then fall until 2035.

²⁸ Kashagan is meant to be the main driver of Kazakhstan's future supply growth, but has suffered from huge delays and cost overruns since its inception.

Table 11: Total oil consumption of 2005 net-crude exporters, 2005 and 2013 (kbd)

| | 2005 | 2013 | 2005-13 Δ (kbd) | 2005-13 Δ (%) |
|------------------------------|--------|--------|--------------------|------------------|
| World consumption | 84,150 | 90,326 | 6,175 | 7.3% |
| o/w 2005 net crude exporters | 17,713 | 21,884 | 4,171 | 23.5% |
| o/w OPEC | 6,475 | 9,051 | 2,576 | 39.8% |
| o/w ROW | 11,238 | 12,833 | 1,595 | 14.2% |

Source: EIA

We think there are two points worth emphasizing regarding this consumption data:

1. The growth rate of these 2005 net crude exporters' consumption over 2005-12 was more than three times higher than that of the world as a whole (23.5% versus 7.3%), and together they accounted for two thirds of the global increase in demand over 2005-13 (4.2mbd out of 6.2mbd). OPEC's consumption in particular grew extremely quickly, rising at more than five times the rate of the world as a whole over this period (39.8% versus 7.3%);
2. OPEC and other major net exporters of crude oil consume hardly any biofuels and account for only a tiny proportion of the global processing gains that are included in the EIA data for global consumption of all petroleum liquids. As a result, nearly all of this consumption will be in the form of crude oil and NGLs.

On the basis of the EIA's production and consumption numbers, we can both (i) derive numbers for total net exports of all liquids for these net oil-exporting countries, and (ii) impute numbers for these countries' net crude oil exports.

In imputing the net-export numbers for crude oil, our approach is to assume that OPEC and the other net exporters consume all of their bio-fuels and processing gains at home (only 0.4mbd and 0.3mbd in 2013 in any case), and that they consume 50% of the NGLs they produce at home and export the other 50%. This gives us a residual number for crude oil consumption in the domestic markets of the net crude oil-exporting countries, and hence allows us to impute a number for net global crude oil exports.

Table 12 and Chart 30 show the numbers and the trends in net global exports of all liquids and crude oil over 2000-13 that we derive using this methodology.

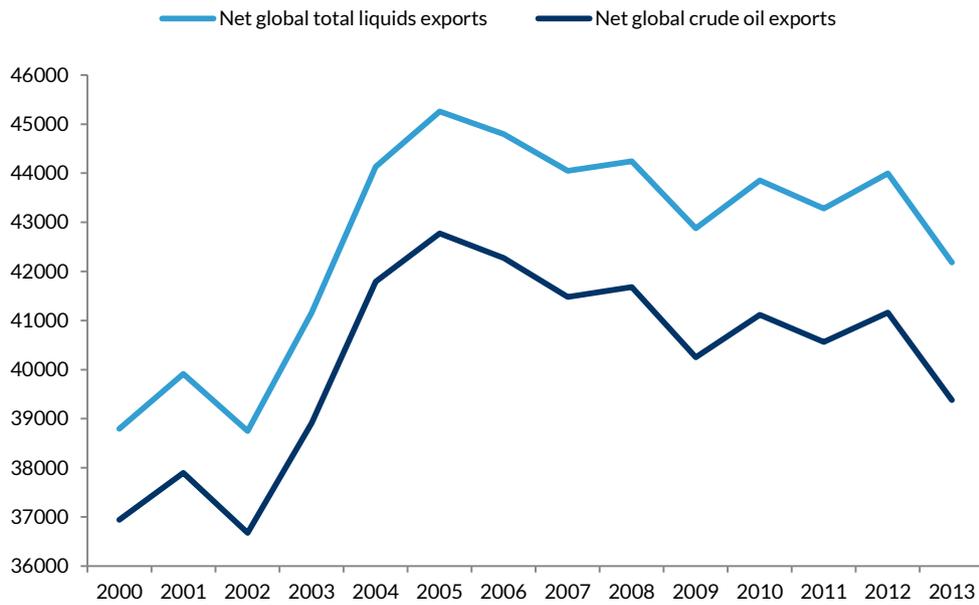
Table 12: Net global oil exports* (total petroleum liquids and crude oil), 2000-13 (kbd)

| | 2000 | 2005 | 2013 | 2000-13 Δ (mbd) | 2000-13 Δ (%) | 2000-05 Δ (mbd) | 2000-05 Δ (%) | 2005-13 Δ (mbd) | 2005-13 Δ (%) |
|--|---------------|---------------|---------------|--------------------|------------------|--------------------|------------------|--------------------|------------------|
| Oil production, all liquids | 55,809 | 62,973 | 64,065 | 6,085 | 11.8% | 5,850 | 11.3% | 1,092 | 1.7% |
| Oil consumption, all liquids | 17,015 | 17,713 | 21,884 | 4,869 | 28.6% | 698 | 4.1% | 4,171 | 23.5% |
| Net oil exports, all liquids | 38,794 | 45,260 | 42,181 | 3,387 | 8.7% | 6,465 | 16.7% | -3,079 | -6.8% |
| Net crude oil exports (imputed) | 36,939 | 42,773 | 39,378 | 2,439 | 6.6% | 5,834 | 14.8% | -3,395 | -7.9% |

Source: Kepler Cheuvreux estimates based on EIA data; *all numbers here are for the 32 countries named above

As can be seen, our numbers show that after rising very sharply over 2000-05 (net exports of all liquids and of crude oil rose by 6.5mbd and 5.8mbd respectively over this period), net global exports of total liquids and crude oil have fallen by 3.1mbd and 3.4mbd respectively between 2005 and 2013.

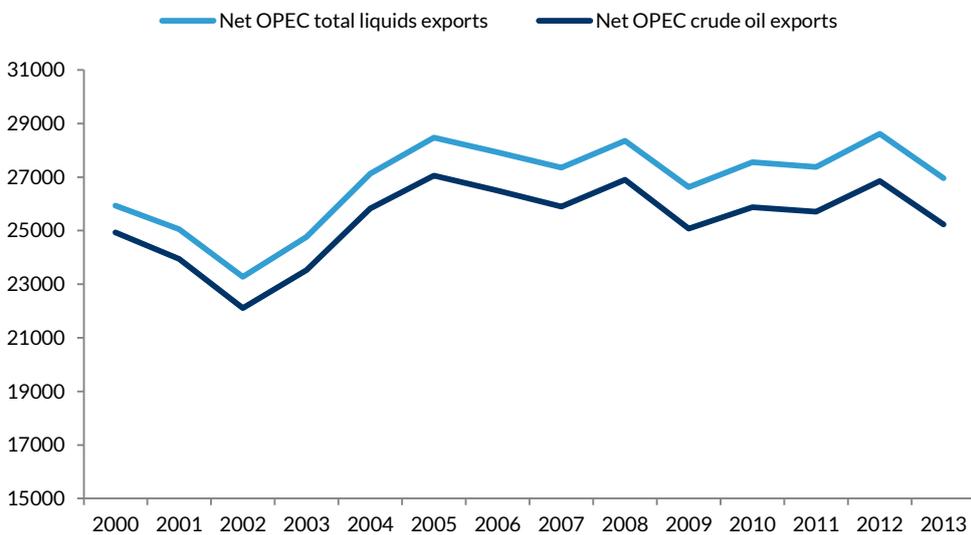
Chart 30: Net global exports of total liquids and crude oil, 2000-13 (kbd)



Source: Kepler Cheuvreux estimates from EIA data

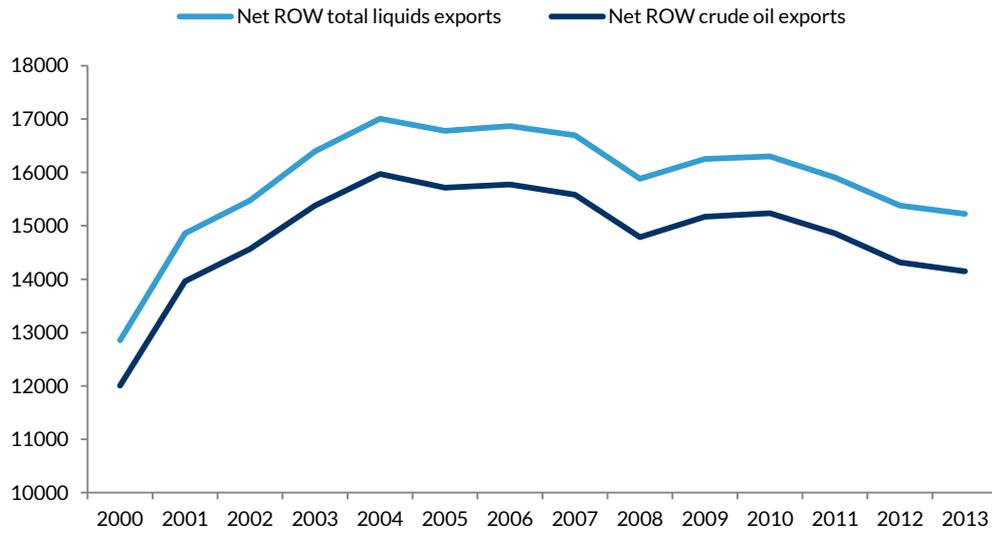
Charts 31 and 32 then break the aggregate change in net exports down between OPEC and the net-exporting countries in the ROW.

Chart 31: Net OPEC exports of total liquids and crude oil, 2000-13 (kbd)



Source: Kepler Cheuvreux estimates from EIA data

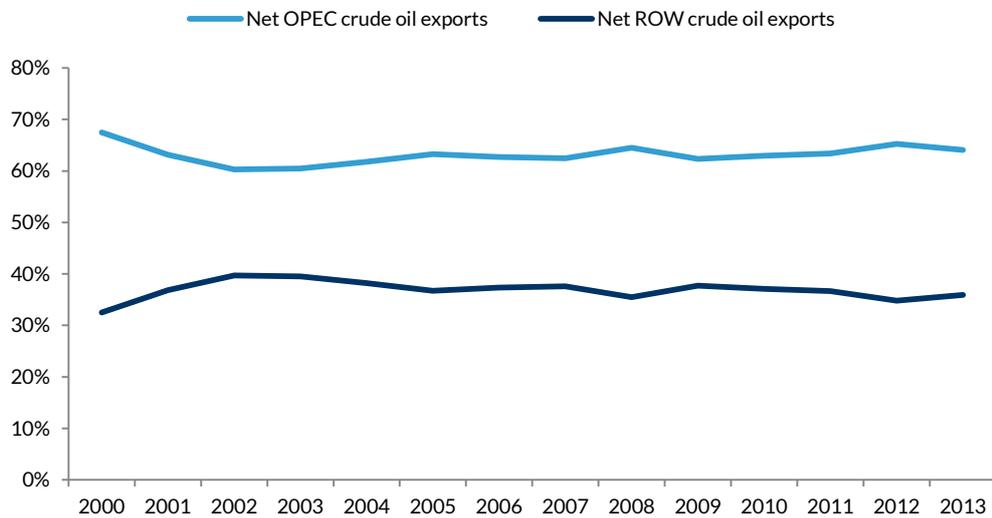
Chart 32: Net ROW exports of total liquids and crude oil, 2000-13 (kbd)



Source: Kepler Cheuvreux estimates from EIA data

Our numbers show the ROW's exports peaking in 2004 and global exports peaking in 2005 (slightly earlier than the 2007 peak shown in the OPEC data for gross exports that we reviewed above).

Chart 33: Share of total net global exports of crude oil 2000-13, OPEC and ROW



Source: Kepler Cheuvreux estimates from EIA data

The downward trend is clearer for the ROW net exporters than for OPEC, as OPEC's output can vary more in accordance with unplanned outages and re-starts (for example, Libya dropped sharply in 2011, surged back in 2012, and then dropped again in 2013).

Overall, though, the trend is clearly down in both since 2005, with rapidly rising consumption the main driver so far of declining exports in both OPEC and the ROW.

Chart 33 shows our estimates for the share of net global exports in crude oil broken down between OPEC and the rest of the world. Despite the changes in absolute volumes, the relative shares have so far remained broadly stable since 2005, with OPEC accounting for just over 60%, and the ROW just under 40%

So much, then, for the trends in production and consumption in the crude-exporting countries. What about the production and consumption trends in crude-importing countries?

Trends in output and consumption in importing countries since 2005

When looking at the 150 or so countries that are net importers of crude oil, it is important first of all to remember that about 50 of them have their own sources of crude oil production.

Of course, because all are net importers then many of these countries have only small amounts of production, and as a result it is easy to forget that in addition to being the world's two largest importers of crude oil, the United States and China are also the third and fourth-largest crude oil producers respectively (based on 2013 EIA data).

As shown in Table 13, the output of these 50 or so net-importing countries with their own crude oil production increased by 2mbd (18%) between 2005 and 2013, reaching 18.2mbd from 16.2mbd.

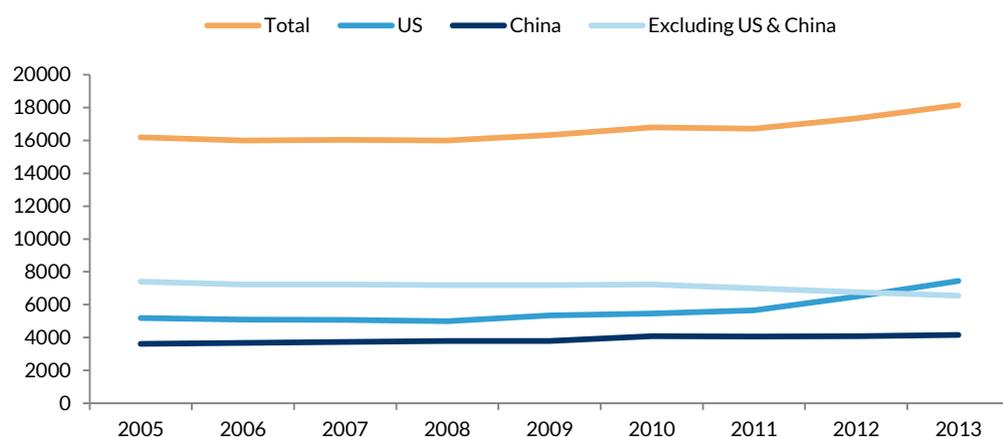
Table 13: Crude oil production of net crude oil importers, 2005-12 (kbd)

| | 2005 | 2013 | 2005-13 Δ (kbd) | 2005-13 Δ (%) |
|--------------|---------------|---------------|--------------------|------------------|
| Total | 16,191 | 18,149 | 1,958 | 17.7% |
| o/w US | 5,181 | 7,443 | 2,262 | 44.5% |
| o/w China | 3,609 | 4,164 | 555 | 15.1% |
| o/w others | 7,401 | 6,542 | -860 | -11.9% |

Source: EIA

As can also be seen, however, the US and China grew their production by 2.3mbd and 0.6mbd respectively over this period, such that the production of all the others combined fell by 0.9mbd. Chart 34 below shows the evolution of production in these countries over 2005-13.

Nonetheless, the fact that this group of countries increased their production by 2mbd in aggregate over the period is an impressive achievement.

Chart 34: Evolution in crude oil output of net importers with own crude production, 2005-13 (kbd)

Source: Kepler Cheuvreux from EIA data x

The next question is, what happened with regard to the consumption of oil in countries that were net importers of crude over this period?

Again, we must begin with the EIA figures for total liquids consumed and work back from there. Table 14 shows the breakdown of the consumption of net oil-importing countries between 2005 and 2013 broken down between OECD and non-OECD countries.

Table 14: Total world oil consumption broken down by net crude oil exporters and importers, 2005-13 (kbd)

| | 2005 | 2013 | 2005-13 Δ (kbd) | 2005-13 Δ (%) |
|-------------------------------|---------------|---------------|--------------------|------------------|
| World consumption | 84,150 | 90,326 | 6,175 | 7.3% |
| o/w OECD net importers | 44,962 | 40,543 | -4,419 | -9.8% |
| o/w US | 20,802 | 18,887 | -1,915 | -9.2% |
| o/w ROW net importers | 21,475 | 27,899 | 6,424 | 29.9% |
| o/w China | 6,695 | 10,117 | 3,421 | 51.1% |
| o/w India | 2,512 | 3,509 | 997 | 39.7% |

Source: EIA

As can be seen, US consumption of all liquids fell by 9% and that of all OECD net importers by 10%, but demand in non-OECD net importing countries increased by 30%. In total, demand amongst OECD net importers fell by 4.4mbd, whereas demand amongst non-OECD net importers increased by 6.4mbd. This means that for every one barrel of reduced oil demand in the OECD net importers in 2012 versus 2005, the non-OECD oil importers – led by China and India – increased theirs by nearly 1.5 barrels, or by 50% more.

Adding to this the increased consumption of OPEC and the other net exporters between 2005 and 2013 (+4.2mbd), it can be said that for every barrel of reduced demand in the OECD net importers, the rest of the world has been willing to increase its consumption by 2.4 barrels, or by more than 100% more than the OECD net importers' reduction.

In sum, net importers of crude oil as a group have increased their crude oil production by 2mbd between 2005 and 2013, and have increased their consumption of all petroleum

liquids by 2mbd (which breaks down as reduced consumption of 4.4mbd amongst OECD net importers, and increased consumption of 6.4mbd amongst non-OECD net importers).

Putting all of this production and consumption data together, then, what can we conclude about the underlying drivers of the fall in global exports of crude oil since 2007?

Conclusion: frustrated demand has bid up crude prices

Our review of the EIA data for the production of crude oil and the consumption of all petroleum liquids over 2005-13 data leads us to infer that net global exports of crude oil fell by 3.4mbd between 2005 and 13, greater than the decline shown in the OPEC in Table 8 above.

As far as explaining the declining trend in global crude exports over this period is concerned, then based on the EIA data we think by far the single most important factor has been sharply higher consumption in both OPEC and the other crude-exporting countries over this period. As we have seen, OPEC's own consumption of oil has risen more than four times as fast as that of the world as a whole since 2005, and in other net crude oil exporting countries nearly twice as fast as that of the world as a whole.

Can it nonetheless be argued that net exporters have in any way had an incentive to reduce their output (and hence exports) of crude oil over this period, either: 1) as a result of higher production in those net-importing countries with their own production (as we have seen, the world's two largest net importers of crude oil, the US and China, both increased their crude output over this period)?; or 2) as a result of lower consumption in some of the net importers (specifically, OECD net importers)?

To answer this question, the price action of this period is a crucial indicator, and as we know from Chart 8 above, global trends in production and consumption since 2005 have played out against a backdrop of rising prices over most of the period 2005-11 followed by an undulating price plateau at or near all-time record highs since 2011.

Against this backdrop, net-exporting countries have had every incentive to maximize their production and hence their exports of crude oil. Despite this fact, we estimate that net exports of crude were 3.4mbd lower in 2013 than in 2005.

Such price action is clearly more consistent with a market under pressure in which exporters have been struggling to keep up with demand than it is with a market in which exporters have been voluntarily reducing exports in response to waning external demand.

As a result, it is simply not plausible in our view to argue that the fall in global exports in recent years has in any way been a voluntary reaction on the part of net exporters to lower global demand for imports, especially as the non-OECD net crude-importing countries have almost absorbed on their own both the drop in consumption of the OECD net importers *and* the rise in crude production of the United States.

And this is before we add in the increased consumption of OPEC and the other net exporters over this period (+4.2mbd).

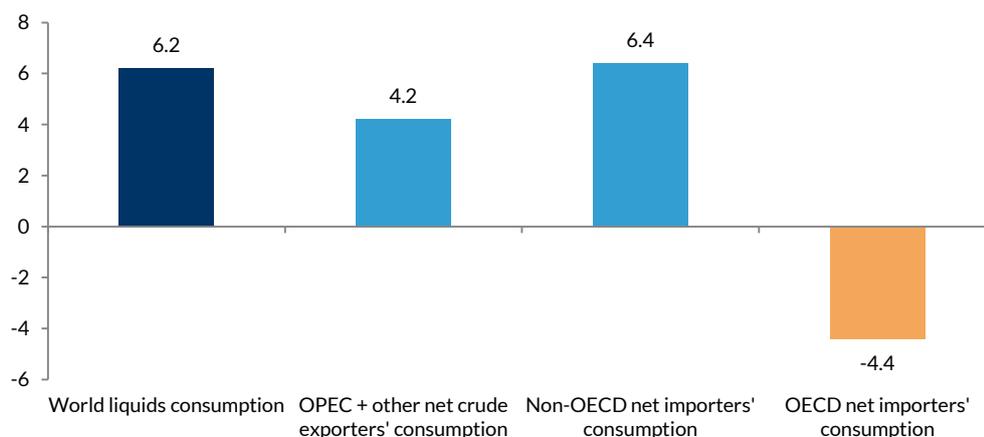
In short, our interpretation of the trends in crude oil production, petroleum consumption, and crude oil prices over 2005-13 is that together they reflect frustrated demand for crude oil and crude-derived products amongst importers, as 1) production in OPEC and other

net-exporting countries has failed to respond to higher prices since 2005 to anything like the same extent as it did over 2003-05; and 2) domestic consumption in these countries has risen dramatically.

As a result, net-importing countries have been forced to bid increasingly frantically in the market for a share of the declining pool of crude oil and crude oil derived product exports.

Chart 35 depicts the changes in consumption between net crude oil exporters on the one hand, and net OECD and net non-OECD crude oil importers on the other, between 2005 and 2013.

Chart 35: Changes in oil consumption by country category between 2005 and 2013 (mbd)



Source: Kepler Cheuvreux from EIA data.

So, what does the chart tell us? We think the main point it illustrates is that to a large extent the decline in OECD petroleum consumption since 2005 has been the result of the industrialized countries' being outbid by the much faster-growing emerging economies of the Asia-Pacific region – led by China and India – for the declining pool of net exports of crude oil.

Total world oil consumption (all liquids) increased by 6.2mbd between 2005 and 2013, but this broke down as an increase of 10.6mbd for net-exporters (+4.2mbd) and non-OECD net importing countries (+6.4mbd) on the one hand, and a 4.4mbd decline for OECD net importing countries on the other.

With OPEC and other net crude exporters consuming more of their own output of crude (+3.6mbd on our imputed estimate) and thereby reducing the size of the net global crude export pie, the only way for non-OECD importers to satisfy their increasing appetite for crude has been to outbid the OECD importers in the ongoing auction for a share of this shrinking pie.

In other words, the upshot of rising OPEC and other net-exporters' consumption of their own production has been not only to reduce global exports of crude over 2005-13 by 3.4mbd (again, our imputed estimated from above), but also to re-distribute the shrinking pie of global exports: non-OECD net importers like China and India have increasingly had

to source their crude and crude-derived products from that portion of the pie previously consumed by OECD net importers.

As can be seen, this re-distribution has been dramatic, with OECD net importers' consumption of all liquids falling by 4.4mbd between 2005 and 2013. Bearing in mind that these countries' consumption of NGLs plus biofuels has increased by over 1mbd over this period, this implies that OECD net importers' consumption of crude oil has actually declined by some 5.5mbd since 2005. All of this forgone consumption has been absorbed by the non-OECD net importers, as in the face of declining global exports this is the only way they have been able to increase their consumption.

Overall, then, the increase in oil consumption in crude-exporting countries in general and in OPEC in particular, since 2005 has had very far-reaching consequences on the global consumption patterns of crude oil, as well as on crude oil prices. In turn, this raises two very important questions: why has OPEC's consumption increased so much since 2005, and what is the outlook for the bloc's consumption over the medium-to-long term?

Why has OPEC's consumption risen so much since 2000? Where will it go from here?

As explained above, the net fall in global exports of crude oil since 2005 is largely attributable to flat output in OPEC and other net exporters and rapidly rising consumption in these countries, especially OPEC. Table 15 shows the scale of the problem: OPEC's oil consumption over 2000-13 has increased at nearly five times the rate of that of the world as a whole (74% and 16% respectively).

Table 15: Global oil consumption, 2000-13 (kbd)

| | 2000 | 2005 | 2013 | 2000-13 Δ (mbd) | 2000-13 Δ (%) | 2000-05 Δ (mbd) | 2000-05 Δ (%) | 2005-13 Δ (mbd) | 2005-13 Δ (%) |
|-------------------------|--------|--------|--------|--------------------|------------------|--------------------|------------------|--------------------|------------------|
| Total world consumption | 76,788 | 84,150 | 90,326 | 13,538 | 15.7% | 7,363 | 9.6% | 6,175 | 7.3% |
| o/w OPEC | 5,212 | 6,475 | 9,051 | 3,839 | 73.6% | 1,262 | 24.2% | 2,576 | 39.8% |
| o/w China | 4,796 | 6,437 | 10,117 | 5,321 | 111% | 1,900 | 39.6% | 3,421 | 51.1% |
| o/w India | 2,127 | 2,512 | 3,509 | 1,382 | 64.9% | 385 | 18.1% | 997 | 39.7% |
| o/w Saudi Arabia | 1,537 | 1,964 | 2,925 | 1,388 | 90.3% | 427 | 27.8% | 961 | 49.0% |
| OPEC % of total | 6.8% | 7.7% | 10.0% | 28.4% | | 17.1% | | 41.7% | |

Source: EIA

At 3.8mbd, OPEC's increase in consumption over 2000-13 was 28% of the global total (13.5mbd), with only China posting a larger increase in absolute terms (+5.3mbd) and OPEC's increase being more than twice as great as India's (+1.4mbd).

Indeed, Saudi Arabia alone increased its consumption by +1.4mbd (the same amount as India), and as such was the country in the world with the joint second-highest absolute increase in oil consumption.

These are staggering numbers when the relative populations are considered: in 2000, OPEC accounted for 5.3% of the world's population, China for 21% and India for 17%. And even more staggering is the fact that over 2005-13 OPEC accounted for 42% of the global increase in consumption (+2.6mbd out of +6.2mbd).

The underlying reasons for this astonishing growth in OPEC's demand are 1) its very high population growth rate (currently running at nearly twice the global average); and 2) the very high subsidies on domestic oil consumption in many OPEC countries.

Table 16 shows the growth in OPEC's population between 2000 and 2013 compared with the world as a whole.

Table 16: OPEC population growth, 2000-13 (000s)

| | 2000 | 2005 | 2013 | 2013 v 2000 Δ | 2012 v 2000 Δ (%) |
|--------------------|------------------|------------------|------------------|------------------|----------------------|
| Algeria | 31,719 | 33,961 | 39,208 | 7,489 | 23.6% |
| Angola | 13,925 | 16,544 | 21,472 | 7,547 | 54.2% |
| Libya | 5,176 | 5,594 | 6,202 | 1,025 | 19.8% |
| Nigeria | 122,877 | 139,586 | 173,615 | 50,739 | 41.3% |
| Ecuador | 12,533 | 13,777 | 15,738 | 3,205 | 25.6% |
| Venezuela | 24,408 | 26,726 | 30,405 | 5,998 | 24.6% |
| Kuwait | 1,906 | 2,296 | 3,369 | 1,462 | 76.7% |
| Iran | 65,911 | 70,152 | 77,447 | 11,536 | 17.5% |
| Iraq | 23,801 | 27,377 | 33,765 | 9,964 | 41.9% |
| Qatar | 30,962 | 31,837 | 32,778 | 1,575 | 265.3% |
| Saudi Arabia | 20,145 | 24,690 | 28,829 | 8,684 | 43.1% |
| UAE | 3,026 | 4,149 | 9,346 | 6,320 | 208.8% |
| TOTAL OPEC | 326,021 | 365,675 | 441,564 | 115,543 | 35.4% |
| TOTAL WORLD | 6,127,700 | 6,514,095 | 7,162,119 | 1,034,419 | 16.9% |
| OPEC as % of total | 5.3% | 5.6% | 6.2% | 11.2% | |

Source: United Nations

As can be seen, OPEC's population grew by 35% between 2000 and 2013, which was just over twice as fast as the world as a whole (17%). As a result, OPEC accounted for 11% of the total growth in the world's population over this period (116m out of 1.03bn).

The smaller Gulf states (Qatar and the UAE) had the highest growth rates of all, while Nigeria had by far the largest increase in absolute terms at 50m. We note also that the two OPEC countries of greatest importance to the total future oil supply in the IEA's projections, Saudi Arabia and Iraq, both experienced population growth in excess of 40% over this period.

Table 17 then shows OPEC's subsidies on oil consumption over the period 2010-12 as shown in [the IEA fossil-fuel subsidy database](#).³⁰

OPEC's direct subsidies for oil were USD149bn in 2010, USD160bn in 2011, and USD156bn in 2012.

Moreover, if we added to this number the subsidies on oil-fired electricity generation (principally in Saudi Arabia), we estimate that the total figure of direct and indirect subsidies on oil in 2012 for OPEC would come to about USD180bn.

³⁰ As far as the total subsidies for fossil-fuel consumption are concerned, the IEA estimates that these came to USD544bn in 2013, of which USD277bn were on oil. The remainder breaks down as USD124bn for gas, USD7bn for coal, and USD135bn for electricity generated from fossil fuels.

Table 17: OPEC subsidies on oil, 2010-12 (USD bn)

| | 2010 | 2011 | 2012 | 2012 vs. 2010 Δ | 2012 vs. 2010 Δ (%) |
|--------------|--------------|--------------|--------------|--------------------|------------------------|
| Saudi Arabia | 35.7 | 45.2 | 47.1 | 11.4 | 31.9% |
| Iran | 49.6 | 38.7 | 35.8 | -13.8 | -27.8% |
| Venezuela | 14.6 | 21 | 20 | 5.4 | 37.0% |
| Iraq | 10.4 | 14.5 | 14.6 | 4.2 | 40.4% |
| Algeria | 11.1 | 10.5 | 12.6 | 1.5 | 13.5% |
| Ecuador | 4 | 5.5 | 5.3 | 1.3 | 32.5% |
| Kuwait | 3.9 | 4.3 | 5.0 | 1.1 | 28.2% |
| UAE | 3.9 | 5.5 | 4.9 | 1 | 25.6% |
| Nigeria | 3.9 | 5.2 | 3.4 | -0.5 | -12.8% |
| Qatar | 2.7 | 3.7 | 3.4 | 0.7 | 25.9% |
| Libya | 7.4 | 5 | 2.5 | -4.9 | -66.2% |
| Angola | 1.3 | 1.2 | 1.5 | 0.2 | 15.4% |
| TOTAL | 148.5 | 160.3 | 156.1 | 7.6 | 5.1% |

Source: IEA

And aggregating the subsidies on domestic consumption in non-OPEC oil exporters such as Azerbaijan, Colombia, Kazakhstan, Mexico, and Malaysia would add another USD25bn on top of the OPEC numbers (Mexico and Malaysia had the biggest subsidies of this group in 2012 at USD16bn and USD6bn respectively).

In short, the IEA data indicate that direct and indirect subsidies on domestic oil consumption in OPEC and other net-exporting countries came to slightly more than USD200bn in 2012. And the point is that these subsidies in net-exporting countries create two problems beyond the borders of the countries concerned.

First, as we have already seen in our analysis above, to the extent that they encourage higher levels of domestic consumption than would otherwise be the case they reduce the amount of oil available for export to world markets, thereby pushing up international prices.

Second, to the extent that they impose a fiscal cost on the governments concerned (in terms of forgone export revenue), they push up the price of oil required by net-exporting countries to balance their budgets. This has become a growing issue in recent years both: 1) because following the Arab Spring many OPEC governments have increased social-expenditure programmes in order to maintain domestic political and social stability; and 2) in the case of Libya and Iran the lower output forced on them by civil conflict and sanctions respectively has increased the price they require to balance their budgets.³¹

[The Arab Petroleum Investment Corporation estimates](#) that the average fiscal breakeven oil price for OPEC increased to USD105/bbl in 2013 from USD99/bbl in 2012, and Table 18 shows APIC's estimated breakeven prices for 2012 and 2013 for OPEC countries.

³¹ [The IMF estimates that](#) over the period 2008-13 Iraq was the only OPEC country to see a fall in its breakeven oil price (owing to rising production volumes). The rest have seen increases ranging from USD15/bbl (Qatar and Kuwait) to USD60/bbl (Iran), with Saudi Arabia's breakeven price increasing by USD40/bbl over this period.

Table 18: OPEC breakeven oil prices, 2012 and 2013 (USD/bbl)

| | 2013 | 2012 | YOY change (USD) | YOY change (%) |
|---------------------|-----------|-----------|------------------|----------------|
| Iran | 144 | 127 | 17 | 11.8% |
| Algeria | 124 | 117 | 7 | 5.6% |
| Nigeria | 124 | 117 | 7 | 5.6% |
| Iraq | 122 | 111 | 11 | 9.0% |
| Ecuador | 121 | 112 | 9 | 7.4% |
| Venezuela | 113 | 102 | 11 | 9.7% |
| Libya | 112 | 108 | 4 | 3.6% |
| Saudi Arabia | 98 | 95 | 3 | 3.1% |
| UAE | 98 | 89 | 9 | 9.2% |
| Angola | 94 | 82 | 12 | 12.8% |
| Kuwait | 66 | 72 | -6 | -9.1% |
| Qatar | 58 | 55 | 3 | 5.2% |

Source: APIC

Iran had the highest breakeven price in 2013 (USD144/bbl versus USD127/bbl in 2012), and Qatar the lowest (USD58/bbl versus USD55/bbl). As the world's largest and only real swing producer, Saudi Arabia's breakeven price is a key indicator, and APIC estimates that this also increased in 2013, to USD98/bbl from USD95/bbl.

This means that the economic cost of oil production for OPEC countries does not give the full picture: there are social and political externalities at play that also need to be factored in to these countries' production costs when we are thinking about the global cost curve for oil.³²

In short, rapid population growth and high levels of subsidy on domestic oil consumption have led to a very dramatic increase in OPEC's demand for oil in the last few years, and this has been the single most important factor in explaining the downward trend in net global exports of crude and crude-derived products since the middle of the last decade.

Since reducing the rate of population growth is by definition something that can only be done over a long period of time, while removing subsidies is very complicated from a political point of view, this means that the short to medium-term options for slowing demand growth in the OPEC countries look very limited.

As a result, OPEC's ability to boost its net exports over the next decade and beyond would seem to depend much more on the production side of the equation, and in particular on three main factors: 1) restoring stability in Libya; 2) successfully resolving the long-standing diplomatic stand-off between Iraq and the West over Iran's nuclear aspirations; and (iii) on Iraq being able to continue growing its output and exports over the next few years (as the IEA and many other official bodies and commentators expect it to).³³

³² As we discuss in the next main section of this report, adjusting for the social and political externalities in the OPEC countries gives a very different profile to the IEA's global cost curve from the one produced by the IEA, which is based purely on the economic costs.

³³ It is always possible that Saudi Arabia could seek to increase its long-term capacity from the current declared level of 12.5mbd, but it does not appear inclined to do so at the moment. Indeed, ever since [Saudi Arabia first announced that it was targeting a level of USD100/bbl for oil prices in early 2012](#), it has largely refrained from commenting about increasing its long-term capacity. This suggests it remains content with its current level of capacity, a level after all which already gives it huge market power as the world's only real swing producer. As discussed below, the IEA assumes that total Saudi oil production (crude plus NGLs) increases to 12.2mbd by 2035, but that all of this is absorbed by increasing domestic demand.

It is possible, of course, that events in all three of these countries could develop in a positive way in the near-to-medium term, and if this were to happen it would certainly assuage a lot of the pressure that has built up in global oil markets over the last few years.

At the same time, however, it is equally possible to imagine a continuation or even deterioration of the situation in Libya, and a continuing stand-off between Iran and the West with no diplomatic breakthrough on a 12-24 month view.

Most worrying of all, though, is the recent upsurge in sectarian violence and political instability in Iraq and the risk of an even more serious deterioration in the situation there that might lead to disruption and long-term production outages.

Even assuming there is no disruption to Iraq's production, recent events have damaged the investment climate there, and Iraq will need huge amounts of investment if it is to achieve the production increases to 2020 and beyond that the IEA and the market are counting on.

In short, with the options for reducing consumption in OPEC in the near to medium term very limited, the outlook for global exports of crude oil over the next two decades will depend to a crucial extent on Iraq, Brazil, and Kazakhstan for conventional crude, and Canada and Venezuela for unconventional crude. If these countries suffer serious slippage in delivering on output expansions, then net global exports of crude oil could fall very precipitously over the next decade.³⁴

Conclusion: toil for oil triggers rising capital intensity

We take the trends in the production, exports, and prices of crude oil since 2005 reviewed above to be strong *prima facie* evidence of: 1) involuntary cuts in the production of conventional crude oil by producers; and 2) frustrated demand for crude oil amongst importers.

In other words, the fact that sharply higher prices since 2005 have prompted surging unconventional crude production but have not been able to stem the decline in conventional output and net crude exports points to a fundamental structural change in the oil market that crystallized in 2005.

We say that the fall in conventional crude output since 2005 has been involuntary because prices have been significantly higher on average in real terms over 2006-13 than they were over 2003-05, and yet while conventional crude oil production surged by 6.6mbd over 2002-05, it has been declining since 2005 (Charts 10 and 11 above).

According to the most fundamental law of economics, so long as there is sufficient spare capacity to meet increased demand surging prices would normally lead to surging production. Yet while this happened over 2003-05, it has not happened since, and the failure of production to respond to much higher prices over 2006-13 to anything like the extent that it did over 2003-05 is particularly telling in this respect.

We say that there has been frustrated demand for crude oil amongst importers since 2005 precisely because production has failed to respond to higher prices since 2005 to anything like the same extent as it did over 2003-05, with the result that importers have been forced

³⁴ We discuss this point in greater detail below when looking at the IEA's projections for net crude exports out to 2035.

to increase their consumption of other liquids while all the time bidding in an increasingly frantic auction for the declining pool of global crude exports.

At the same time, of course, and as we have seen, surging prices in recent years have prompted a surge in unconventional crude oil production in North America. But then again, as we have also seen, this surge in LTO and oil-sands production will require continuing high prices because it is so capital intensive.

The very fact that the world has come to rely so much on unconventional production such as US LTO and Canadian oil sands in the last five years or so is itself very revealing as it would indicate that the cheap and easy sources of conventional crude oil are now largely gone, with what remains primarily to be found in the OPEC countries of the Middle East.³⁵

Moreover, rising capital intensity has been a defining feature of the upstream oil industry since 2005 not only owing to the rise of US LTO and its drilling-treadmill effect, but also owing to the need to stem decline rates in conventional crude oil fields. With large mature conventional fields across the world ageing, the industry now has to invest much more every year than it did even a decade ago in order to mitigate the natural process of decline that ultimately affects all oil fields.³⁶ Without rising investment to slow natural decline in ageing fields, conventional crude output would have suffered a much more precipitous drop than the decline it has so far exhibited since 2005.

So what has been the trend in capital intensity across the industry since 2005 and what does this imply for the outlook for the oil supply and for oil prices over the next two decades?

Global oil industry in midst of major capex crisis

Chart 36 shows the trend in upstream capex for the oil-and-gas industry over 2000-13, as well as the evolution of Brent-crude oil prices.

As can be seen, since 2000 annual upstream investment for oil and gas combined has increased by 180% in real terms (i.e. in constant 2012 USD), rising from USD250bn in 2000 to c.USD700bn in 2012 (about two thirds of this combined total capex amount is for oil and one third for gas).

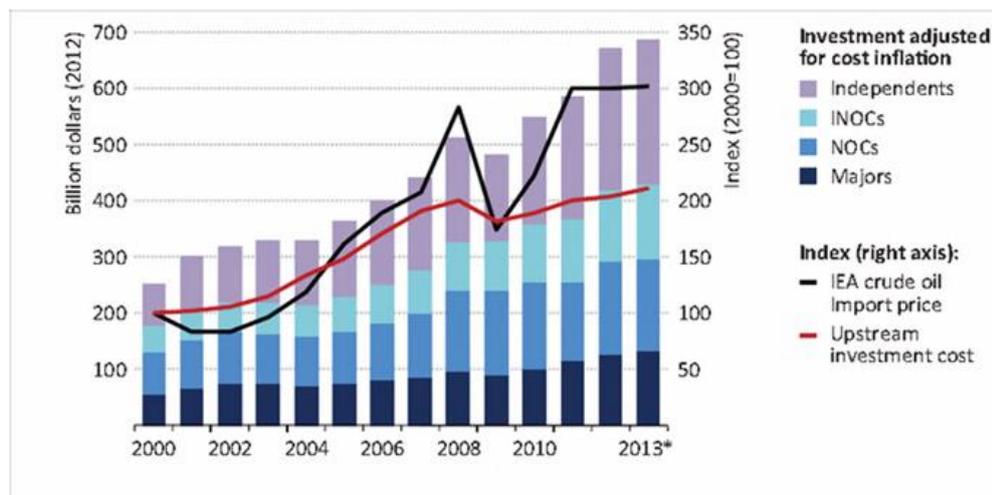
We think that the most straightforward interpretation of the supply trends, analysed above, vis-a-vis the astronomical increase in industry capex (Chart 36) and the extraordinarily capital-intensive nature of US LTO (Chart 16), is that the economics of oil have broken entirely with their historical norms since 2005. As a result, the industry is investing at ever higher rates for increasingly small incremental yields of energy.

Industry capex has increased almost threefold since 2000, but the supply of petroleum liquids and bio-fuels has increased by only 16% (or by 12.4mbd, Table 3 above) over the same period, and the supply of crude oil by only 11% (or by 7.4mbd, Table 3 above).

³⁵ Moreover, as our analysis above showed, the rapid population growth and high levels of domestic subsidization in these countries mean that their economic cost of production does not tell the whole story. Political and social externalities also need to be factored in, and when this is done the OPEC cost curve looks very different (see our more detailed discussion of this point below).

³⁶ We look at decline rates in conventional oil fields in greater detail in the next main section below when reviewing the IEA's projections out to 2035.

Chart 36: Global upstream oil and gas investment, 2000-13



* Budgeted spending. Notes: 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.

Source: IEA, 2013 WEO (© OECD/IEA)

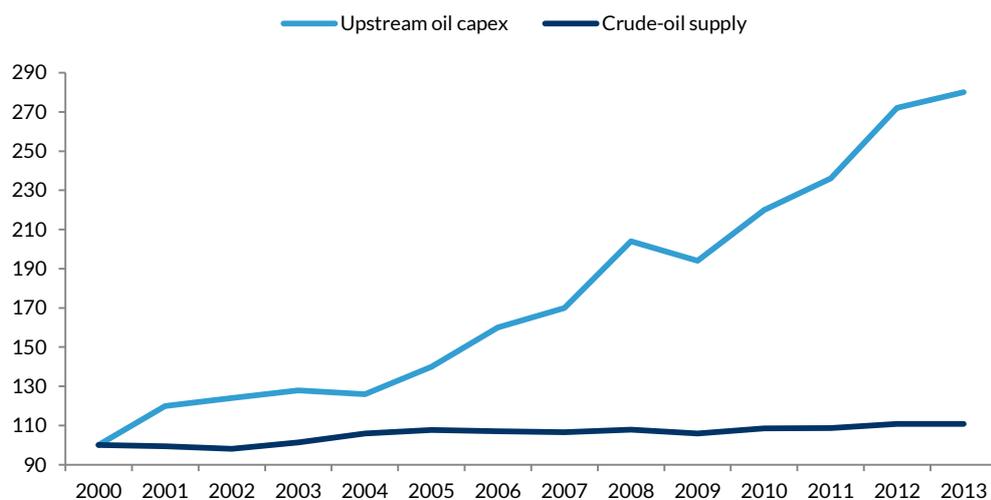
If we compare upstream capex with supply growth since 2005, the ratios are even worse. We estimate that since 2005 upstream oil capex has increased by 100% (from USD220bn to USD440bn), but the supply of all liquids has increased by only 6% (or by 5.4mbd, as per Table 3 above), and the supply of crude oil by only 3% (or by 2.2mbd, Table 3 above), while the supply of conventional crude oil has actually declined by 2mbd (Table 7).

Chart 37 shows the trend in the oil industry’s upstream capex and the crude oil supply since 2000 on an indexed basis, (base 100 starting in 2000).

This chart very clearly shows the diminishing returns of upstream capex in terms of incremental supply generated since 2005. The industry has been able and willing to finance such a dramatic increase in capex since 2000, owing to the similarly dramatic increase in prices.

Based on the historical BP pricing data reviewed above, the average price of Brent crude in real terms (constant 2013 dollars) increased from USD39/bbl in 2000 to USD113 in 2012. This represents a 190% increase, slightly greater in fact than the increase in industry capex over the same period (Chart 36).

However, looking only at the period since 2005 (Chart 36 again), capital outlays have risen faster than prices (90% and 75%, respectively), while in the past two years capex has risen by a further 20%, while Brent prices have actually averaged about USD4 a barrel less since the beginning of 2013 than they averaged over 2011.

Chart 37: Change in upstream oil capex and crude oil supply since 2000, with 2000 indexed to 100


Source: Kepler Cheuvreux based on EIA and IEA data

It is this misalignment since the beginning of 2011 between rising costs and flat-lining production and prices that explains why many international oil companies (IOCs) [have announced cutbacks to their capex](#) in their recently updated forward-budgeting plans.³⁷

With prices failing to keep pace with investments since 2011, companies such as [Exxon](#), [Shell](#), [BP](#), and [Total](#) – as well as NOCs such as [Statoil](#) and [Petrobras](#) – have announced reductions to their capital budgets. This would not be surprising if demand and oil prices had been falling in the last three years, but demand has continued to increase and prices have been broadly stable in an average range of USD105-112/bbl since 2011.

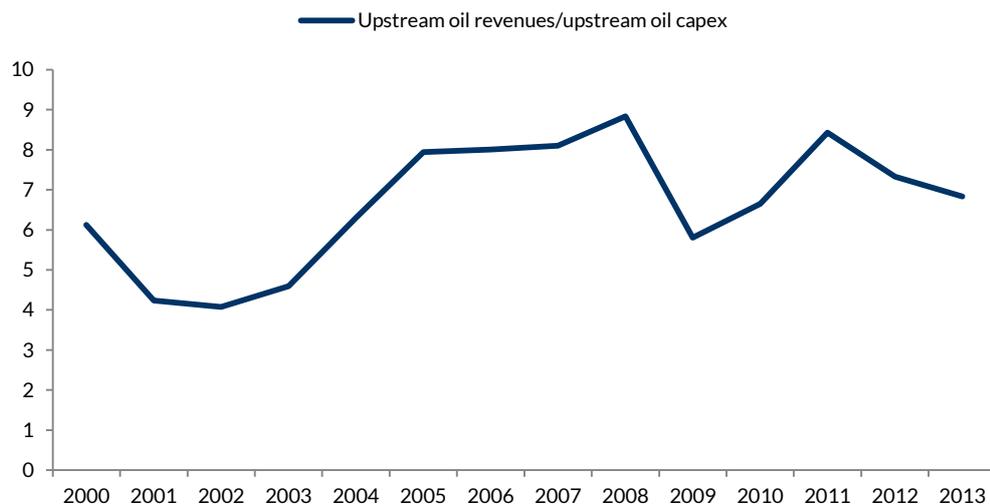
Moreover, these price levels represent all-time highs in both nominal and real terms. This means that companies are cutting back on their capex plans at a time when demand is still increasing and prices have never before been higher. So, why are they doing this?

Chart 38 plots the trend in the ratio of upstream oil revenues to upstream oil capex since 2000.

What Chart 38 shows is that over the last three years the capital productivity of the upstream oil industry has been declining sharply. It is this declining capital productivity since 2011 that explains why the upstream industry is now cutting back on capex.

With the exception of 2009, the industry enjoyed rising or flat capital productivity since 2003, as the sharp increase in prices over most of this period made up for only very modest annual increases in supply from ever higher levels of industry capex.

³⁷ As we discuss in greater detail below, this reflects the fact that the deterioration in the capex/supply-growth ratio has been even worse for the major IOCs than it has for the industry as a whole.

Chart 38: Evolution of upstream revenues from crude oil versus upstream oil capex

Source: Kepler Cheuvreux estimates based on EIA and IEA data

Since 2011, however, a further sharp increase in capex against a backdrop of flat prices has led to a falling capital productivity ratio and thus forced the industry to cut back on capex. Yet cutting capex cannot be a sustainable response, as what seems inevitable from the trends shown in Chart 36 is that reductions in capex today will translate into lower supply tomorrow.

Conclusion: rising capital intensity is the key risk to future supply

Our analysis of the key trends in the global oil supply since 2000 leads us to the conclusion that a fundamental structural change occurred in 2005 when conventional crude oil production went into decline.

It is this fact, above all others, that lies at the root of the capex crisis that has been building ever since, for despite surging unconventional output in North America and prices stable at or near all-time highs since 2011, the total supply of crude oil has grown by only 3% since 2005, while capex outlays have grown by 100% over the same period.

With capex now being cut at most IOCs and some national oil companies (NOCs), the risk must now be that supply will be lower than projected in future years unless prices rise further in the near future to incentivise investment. After all, as the IEA itself says (2013 *World Energy Outlook*: p. 459), “the main threat to future oil-supply security is insufficient investment.”

Indeed, to the extent that the IEA’s base-case scenario for growth in the oil supply out to 2035 foresees a continuation of the trends observed since 2005 – i.e. declining conventional crude oil production and hence an ever increasing dependence on unconventional crude, NFLs, and bio-fuels to fill the gap – the risk that supply will not come through as projected without higher prices must be all the greater.

With all of this in mind, we now turn to a more detailed examination of the IEA’s base-case projections for oil markets out to 2035, as set out in the 2013 *World Energy Outlook*.

Oil and the IEA's NPS: A Critique

In this section we look at the IEA's modelling of the long-term outlook for both the oil supply and oil prices, as set out in the base-case scenario of the Agency's *2013 World Energy Outlook (2013 WEO)* published last November.

The IEA's base case is known as the New Policies Scenario (NPS), and as explained in the 2013 WEO (p. 33) this scenario models *"the evolution of energy markets based on the continuation of existing policies and measures as well as cautious implementation of policies that have been announced by governments but are yet to be given effect"*.

Before looking at the IEA's outlook for supply and prices, though, we begin with a brief review of the Agency's macro assumptions as set out in the *2013 WEO*, and how these assumptions translate into its demand forecasts for oil. The IEA's demand projections largely reflect the changing pattern in global consumption underway since 2000, with non-OECD countries in general, and Asia and the Middle East in particular, as the motor of growth over the next two decades.

This pattern of projected demand growth seems very reasonable to us, but the GDP growth rates assumed by the IEA assume very ambitious further improvements in oil intensity: the IEA sees the world economy more than doubling in size over the next two decades while reducing its oil intensity by 50%. This represents a rate of improvement in oil intensity over the next two decades one-and-a-half times greater than that achieved over the last two decades, and looks very ambitious to us.

On the supply side, the IEA projects an accentuation of the trends observed since 2005, with conventional crude oil production continuing to fall and the world therefore becoming ever more dependent on unconventional crude and other petroleum liquids.

Moreover, such growth in conventional crude production as the IEA expects over 2013-35 – and without which its projections for the drop in conventional crude out to 2035 would be more severe – is focused on Iraq, Brazil, and Kazakhstan.

Crucially, while fields already in production today account for 73% of conventional crude output over 2013-25, this falls to 43% over 2026-35, meaning that huge investments will be required in fields yet to be developed and yet to be found in order to meet demand over the second half of the IEA's projection period.

However, while the IEA sees oil supply becoming increasingly dependent on unconventional crude and other petroleum liquids, it expects the declining trend in net exports of crude oil witnessed since 2005 to be reversed over the next two decades. Indeed, in the NPS, net global exports of crude oil increase by 3mbd between 2012 and 2035, with Iraq, Brazil, and Kazakhstan once again key to this projection.

Similarly, despite sharp year-on-year increases in upstream capital outlays since 2005, the IEA expects the profile of annual investments to be broadly flat over the next two decades, even though US shale oil – with its relentless drilling and capex treadmill – is central to its supply-growth forecasts over the next decade.

Finally, although the IEA projects rising prices in real terms over the next two decades, the upward trajectory is a very gentle one compared with the sharp increase seen since 2005: prices are projected to rise from USD109/bbl in 2012 to USD128/bbl by 2035 in real terms. This represents an increase of 17%, compared with the real-terms increase of 180% experienced over 2000-13.

In our view, however, the capex cuts announced by many of the oil majors in recent months suggest that prices will need to rise more aggressively than the Agency is assuming over the next two decades in order to stimulate the investments needed for its supply projections to hold good. In turn, this raises questions about future GDP growth and by extension – given the feedback loops between GDP and oil demand – whether sharply higher oil prices are necessarily a good thing for the oil majors.

The key macro assumptions underlying the NPS

Table 19 sets out the main assumptions underlying the NPS from a macro level, covering the policies assumed, GDP growth rate, population growth, energy prices, subsidies, CO₂-pricing, and technological developments.

Table 19: Overview of key assumptions in the IEA New Policies Scenario

| | Assumptions |
|-------------------------------|--|
| Policies | Continuation of policies that had been legally enacted as of mid-2013 plus cautious implementation of announced commitments and plans. |
| GDP growth | Global GDP increases at an average rate of 3.6% per year over 2011-35 (based on GDP expressed in year-2012 dollars in purchasing-power-parity terms). |
| Population growth | World population rises at an average rate of 0.9% per year, to 8.7 billion in 2035; The proportion of people living in urban areas rises from 52% in 2011 to 62% in 2035. |
| Energy pricing | Average IEA crude oil import price reaches USD128/bbl (in 2012 USD) in 2035. A degree of convergence in natural-gas prices occurs between the three major regional markets of North America, Asia-Pacific and Europe. Coal prices remain much lower than oil and gas prices on an energy-equivalent basis. |
| Fossil-fuel subsidies | Phased out in all net-importing regions within ten years (at the latest) and in net-exporting regions where specific legislation has already been adopted. |
| CO₂ pricing | New schemes that put a price on carbon are gradually introduced, with price levels gradually increasing. |
| Technology | Energy technologies – both on the demand and supply sides – that are in use today or are approaching the commercialisation phase achieve ongoing cost reductions. |

Source: IEA, 2013 WEO (© OECD/IEA)

In our view, the three key assumptions about oil demand at a macro level are the rate of increase in world population, global GDP growth, and the projected evolution of oil prices. As we look at the IEA's oil-price assumptions in greater detail below (see the sub-section *What will this future supply cost to bring in?*), we here look only at the IEA's assumptions on future population and GDP growth.

The IEA's assumptions on population and GDP growth

As far as the rate of growth in world population is concerned, the IEA's NPS assumes the medium-fertility scenario of the United Nations Population Division (UNPD), as set out in the UNPD's 2012 Revision of [World Population Prospects](#). This shows the world population as a whole rising to 8.7bn by 2035 from 7bn in 2011, an increase of 25% (Table 20).

Table 20: World population growth assumed in the New Policies Scenario, 2011-35 (000s)

| Region | 2011 | 2020 | 2035 | Delta over 2011-35 | % Delta 2011-35 |
|-----------------|------------------|------------------|------------------|--------------------|-----------------|
| Africa | 1,056,985 | 1,312,142 | 1,811,640 | 754,655 | 71.4% |
| Asia | 4,210,008 | 4,581,523 | 4,997,305 | 787,297 | 18.7% |
| Europe | 741,276 | 743,569 | 730,431 | -10,845 | -1.5% |
| Latin America | 602,974 | 661,724 | 738,780 | 135,806 | 22.5% |
| North America | 349,527 | 375,724 | 415,480 | 65,953 | 18.9% |
| Oceania | 37,229 | 42,066 | 49,812 | 12,583 | 33.8% |
| WORLD | 6,997,999 | 7,716,749 | 8,743,447 | 1,745,448 | 24.9% |
| OECD | 1,250,085 | 1,312,416 | 1,386,878 | 136,793 | 10.9% |
| Non-OECD | 5,747,913 | 6,404,333 | 7,356,569 | 1,608,656 | 28.0% |

Source: United Nations Population Division

The rate of growth is very different between the OECD and non-OECD countries: the combined population of the OECD countries increases by 11% over the period (137m people) whereas the combined population of the non-OECD countries increases by 28% (1.61bn people). Asia and Africa make the largest contribution to the world's population increase over the next two decades, with each of these regions growing by more than 750m people, thereby providing almost 90% of the total projected increase between them. Interestingly, the UN's medium-fertility projections also have the combined population of OPEC countries increasing very rapidly over the next two decades (by 263m people, or 64%). This means OPEC countries will account for 37% of the total increase in the world's population until 2035 (Table 21).

Table 21: World and OPEC population growth assumed in the New Policies Scenario, 2011-35 (000s)

| Region | 2011 | 2020 | 2035 | Delta over 2011-35 | % Delta 2011-35 |
|--------------|------------------|------------------|------------------|--------------------|-----------------|
| WORLD | 6,997,999 | 7,716,749 | 8,743,447 | 1,745,448 | 24.9% |
| OPEC | 412,271 | 512,411 | 675,469 | 263,198 | 63.8% |

Source: United Nations Population Division

Table 22 sets out the IEA's assumptions for global GDP growth until 2035, with the world growing at a CAGR of 3.6% over 2011-35, with the non-OECD countries again growing much faster than the OECD countries (5% and 2.1%, respectively).

Table 22: Real GDP growth assumptions by region under the New Policies Scenario

| Region | 1990-2011 | 2011-15 | 2011-20 | CAGR, 2011-35 |
|------------------|-------------|-------------|-------------|---------------|
| OECD | 2.2% | 1.9% | 2.2% | 2.1% |
| Americas | 2.5% | 2.7% | 2.9% | 2.5% |
| Europe | 2.0% | 0.9% | 1.5% | 1.7% |
| Asia & Oceania | 1.9% | 2.1% | 2.1% | 1.8% |
| Non-OECD | 5.0% | 5.0% | 5.0% | 5.0% |
| E.Europe/Eurasia | 0.7% | 3.3% | 3.5% | 3.3% |
| Asia | 7.5% | 6.8% | 7.1% | 5.6% |
| China | 10.0% | 8.0% | 8.1% | 5.7% |
| India | 6.5% | 5.7% | 6.5% | 6.3% |
| Middle East | 4.6% | 3.2% | 3.7% | 3.7% |
| Africa | 3.8% | 5.1% | 5.0% | 4.0% |
| Latin America | 3.4% | 3.4% | 3.7% | 3.3% |
| WORLD | 3.3% | 3.6% | 4.0% | 3.6% |

Source: IEA, 2013 WEOx

Asia is the fastest-growing region at 5.6% per year over the period, driven by China (5.7%) and India (6.3%).

Non-OECD countries drive increase in oil demand out to 2035

Oil has been the most widely used source of primary energy globally for at least the last 40 years, but its share of total energy supplied has been declining over that period. In 1973, oil accounted for 46% of total global primary energy supply (2,815mtoe out of 6,107mtoe), but by 1990 this had fallen to 36% (3,664mtoe out of 10,071mtoe). This pattern of absolute growth but relative decline is set to continue out to 2035.

Demand for oil is projected to grow by 14% out to 2035

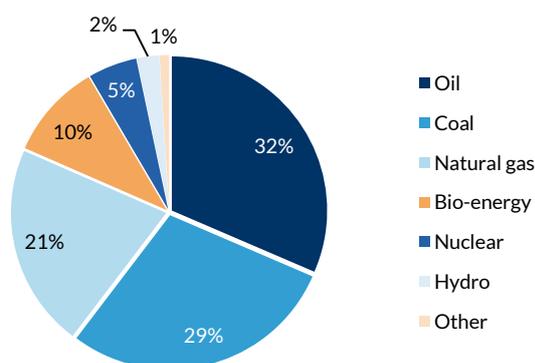
Table 23 and Charts 39 and 40 show the NPS's projections of primary energy demand to 2035.

Table 23: Global primary energy demand (mtoe) under the IEA's NPS

| | 2000 | 2011 | NPS | | Change by 2035 versus 2011 | |
|---------------------|---------------|---------------|---------------|---------------|----------------------------|--------------|
| | | | 2020 | 2035 | (mtoe) | % |
| Oil | 3,664 | 4,108 | 4,470 | 4,661 | 553 | 13.5% |
| Gas | 2,073 | 2,787 | 3,273 | 4,119 | 1332 | 47.8% |
| Coal | 2,357 | 3,773 | 4,202 | 4428 | 655 | 17.4% |
| Fossil fuels | 8,094 | 10,668 | 11,945 | 13,208 | 2540 | 23.8% |
| Nuclear | 676 | 674 | 886 | 1119 | 445 | 66.0% |
| Hydro | 225 | 300 | 392 | 501 | 201 | 67.0% |
| Bio-energy | 1,016 | 1,300 | 1,493 | 1,847 | 547 | 42.1% |
| Other renewables | 60 | 127 | 309 | 711 | 584 | 459.8% |
| Renewables | 1,301 | 1,727 | 2,194 | 3,059 | 1332 | 77.1% |
| WORLD (mtoe) | 10,071 | 13,069 | 15,025 | 17,386 | 4317 | 33.0% |

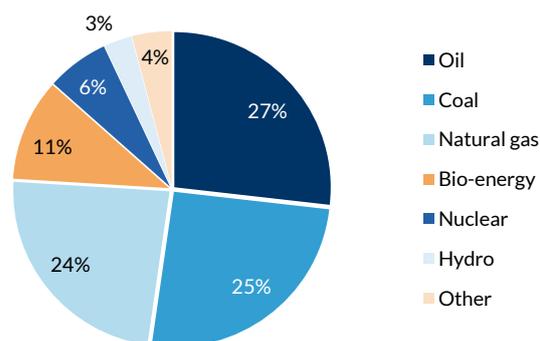
Source: IEA, 2013 WEO

Chart 39: Global primary energy demand, 2011



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Chart 40: Primary energy demand under the NPS, 2035



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

As measured in terms of millions of tonnes of oil equivalent (mtoe), the demand for oil is projected to increase by a further 14% over the next two decades, reaching 4,661mtoe in 2035 compared with 4,108mtoe in 2011.

As can be seen, however, the demand for other energy sources – especially gas and renewables – is projected to increase much more quickly, such that oil's share in the total energy mix declines further over the next two decades. As shown in Charts 39 and 40, oil's share in demand is projected to fall from 32% in 2011 to 27% in 2035.

Main drivers of demand non-OECD countries, especially Asia, Middle East

Looking in greater detail at the breakdown of oil demand (Table 24 below), it can be seen that the volume of all petroleum liquids consumed increases by 17mbd over the period, reaching 105.5mbd in 2035 versus 87.4mbd in 2012 (at 19%, this is a greater increase than the 14% shown in table 24).³⁸

Table 24: Global oil demand by region under the New Policies Scenario (mbd)

| Region | 2000 | 2012 | 2020 | 2035 | Delta, 2012-35 (mbd) | CAGR, 2012-35 |
|----------------------------|------|------|------|-------|-------------------------|---------------|
| OECD | 44.6 | 40.8 | 39.4 | 32.8 | -8.0 | -0.9% |
| o/w Americas | 22.7 | 21.3 | 21.9 | 18.4 | -2.9 | -0.6% |
| o/w Europe | 13.7 | 11.7 | 10.9 | 8.9 | -2.9 | -1.2% |
| o/w Asia & Oceania | 8.2 | 7.8 | 6.7 | 5.5 | -2.2 | -1.5% |
| Non-OECD | 26.5 | 39.6 | 48.3 | 59.2 | 19.6 | 1.8% |
| o/w E. Europe | 4.2 | 4.7 | 5.1 | 5.4 | 0.7 | 0.6% |
| o/w Asia | 11.5 | 19.3 | 24.8 | 32.5 | 13.2 | 2.3% |
| o/w Middle East | 4.3 | 6.9 | 8.2 | 9.9 | 2.9 | 1.6% |
| o/w Africa | 2.2 | 3.4 | 4.0 | 4.6 | 1.2 | 1.3% |
| o/w Latin America | 4.2 | 5.3 | 6.2 | 6.9 | 1.5 | 1.1% |
| Bunkers* | 5.2 | 7.0 | 7.8 | 9.3 | 2.4 | 1.3% |
| WORLD DEMAND | 76.3 | 87.4 | 95.4 | 101.4 | 14.0 | 0.6% |
| World biofuels** | 0.2 | 1.3 | 2.1 | 4.1 | 2.8 | 5.0% |
| World total liquids | 76.5 | 88.7 | 97.6 | 105.5 | 16.8 | 0.8% |

Source: IEA, 2013 WEO (© OECD/IEA); *Includes international marine and aviation fuel; **Expressed in energy-equivalent volumes of gasoline and diesel

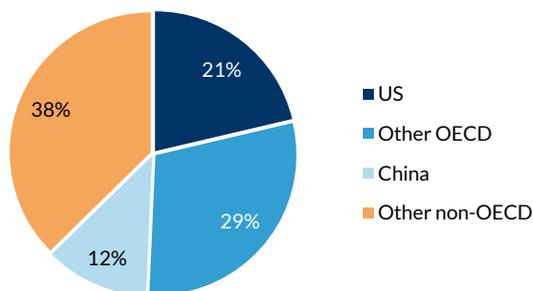
As can be seen, demand is driven by non-OECD countries, whose consumption increases at a compound rate of 1.8% per year over the projection period, while that of the OECD decreases at a compound rate of 0.9% per year.

As a result, non-OECD demand is 20mbd higher in 2035 than in 2012 (59.2mbd versus 39.6mbd), while that of the OECD is 8mbd lower (33mbd in 2035 versus 41mbd in 2012). Although this represents a significant increase in oil demand over the next two decades, it also represents a slowdown in the growth rate versus the last decade or so: the implied compound annual-growth rate (CAGR) out to 2035 is 0.8%, compared with the 1.2% achieved over 2000-13.

Looking at the change in the profile of demand over the next two decades (Charts 41 and 42), it can be seen that while OECD countries accounted for 51% of total petroleum consumption in 2012 (of which the share of the US alone was 21%), by 2035 the OECD is projected to account for only 36% of global demand (with the US at 15%).

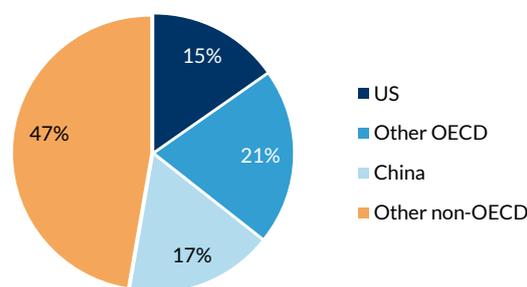
³⁸ The demand growth in Table 24 is higher than that shown in Table 23 because Table 23 measures the growth in oil demand on a purely volumetric basis (barrels), whereas Table 20 measures demand on an energy-adjusted basis according to the energy density of the different petroleum liquids.

Chart 41: Global oil demand by region, 2012



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Chart 42: Global oil demand by region, 2035



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Correspondingly, the non-OECD share increases from 49% in 2012 to 64% in 2035, with China being a bigger consumer than the US by 2035, at 17% of global demand.

Clearly, then, it is the non-OECD countries that drive demand over the next two decades. As can be seen in Table 21, Asia, in particular, is the motor of demand growth, accounting for 13mbd of the extra 20mbd consumed by non-OECD countries by 2035.

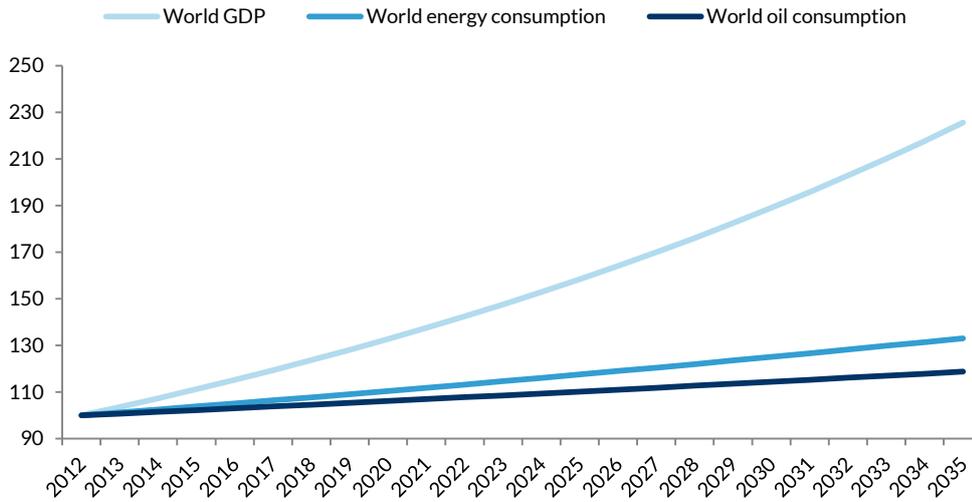
Unsurprisingly, it is China and India that account for most of this increase, with consumption in these two countries rising by 6mbd and 4.5mbd, respectively, over the forecast period (China’s demand reaches 15.6mbd in 2035 and India’s 8.1mbd).

IEA assumes huge improvement in energy and oil intensity

As we have just seen, the IEA’s NPS assumes that global GDP will rise at a CAGR of 3.6% over 2012-35, but that global demand for energy and for oil (all liquids) will increase at a CAGR of just 1.3% and 0.8%, respectively, over the same period.

Indexing these three variables to 100 in 2012, Chart 43 shows their projected changes until 2035 under the NPS: world GDP grows by 125% over the period, and world energy and oil consumption by 33% and 19%, respectively.

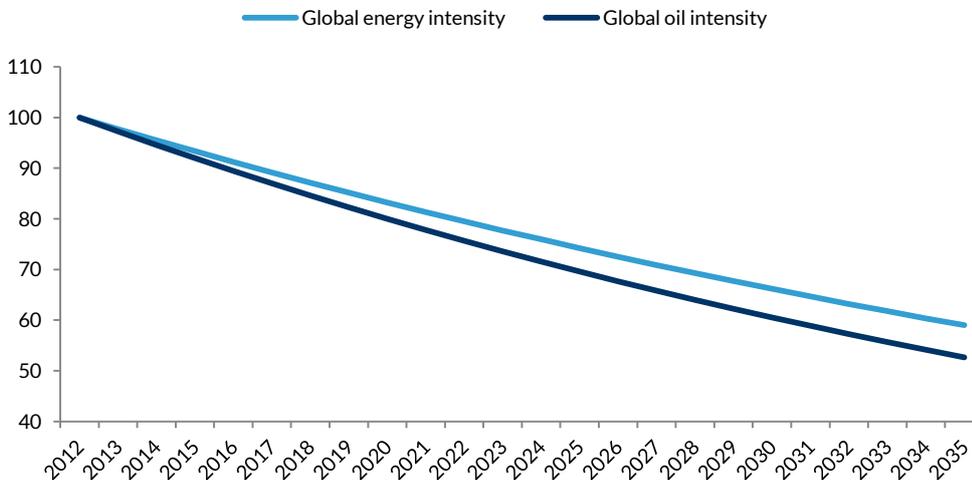
Chart 43: Growth in world GDP, energy consumption, and oil consumption under IEA's NPS



Source: Kepler Cheuvreux based on IEA data from 2013 WEO

In other words, the IEA is assuming that the world economy will more than double in size over the next two decades, while becoming 67% more efficient in its use of overall energy and 100% more efficient in its use of oil (Chart 44).³⁹

Chart 44: Implied reduction in world energy and oil intensity under IEA's NPS, 2012-35



Source: Kepler Cheuvreux based on IEA data from 2013 WEO

³⁹ If the world reduces its energy intensity by 40% over a given period this means that it is producing 1.67 units of output per unit of energy input compared with 1 unit of output per unit of energy input previously, and thus that it is 67% more efficient in using energy by the end of the period than it was previously. Similarly, if the world reduces its oil intensity by 50%, this means that it is producing two units of output per unit of oil input compared with one unit of output previously, and hence that it is 100% more efficient in using oil at the end of the period than it was previously.

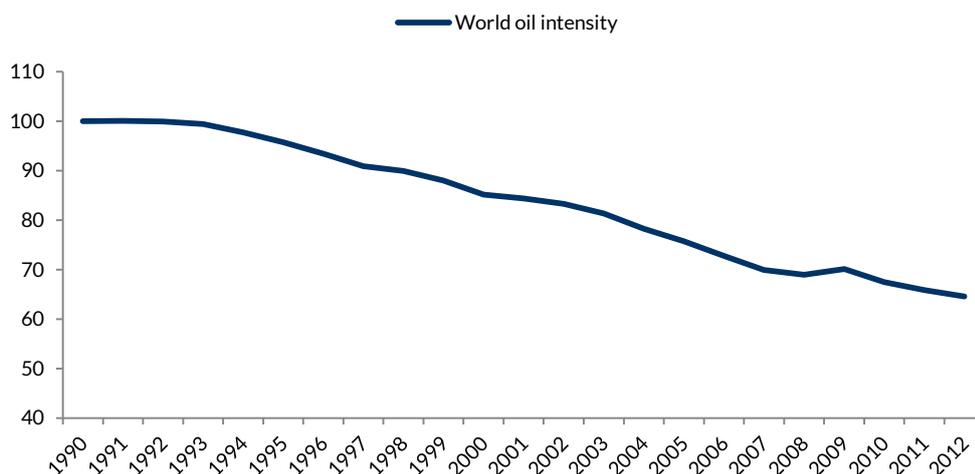
These are very ambitious projections, as becomes apparent if we put them into historical perspective.

First, regarding energy intensity, the IEA says in the 2013 WEO (p. 37) that “Global energy intensity – defined as the amount of energy used to produce a unit of GDP at market exchange rates – fell by 32% between 1971 and 2012”.

This means that while global energy intensity has improved by 32% over the last four decades, the IEA is assuming a further reduction of 40% over the next two decades, which represents a rate of reduction 20% greater (40%, 32%) in only half the time.

Second, with regard more specifically to oil intensity, Chart 45 shows the reduction in world oil intensity achieved over 1990-2012. Using IEA numbers for oil consumption and World Bank data for GDP at purchasing power parity in real terms, we calculate that between 1990 and 2012 the world reduced its oil intensity by 35%, meaning that in 2012 the world used 35% less oil per unit of GDP generated than it did in 1990.

Chart 45: Historical reduction in world oil intensity 1990-2012



Source: Kepler Cheuvreux based on IEA data from 2013 WEO and World Bank data for global GDP

This means that while world oil intensity has fallen by 35% over the last 22 years, the IEA is assuming a *further* reduction of 50% over the next 22 years (2013-35), or a rate of reduction nearly one-and-a-half times greater over the next two decades than has been achieved over the last two (i.e. 50%/35%).

This is not to say that these projections are unachievable, but simply to emphasise the ambitions built into these assumptions.⁴⁰

⁴⁰ In this respect, it is also worth pointing out that the IEA says in the 2013 WEO (p. 37) that the rate of improvement in global energy intensity has slowed since 2000: “The average rate of improvement [in energy intensity] was much lower in 2000-11 than in 1980-2000 (and energy intensity actually increased in 2009 and 2010), due to a shift in the balance of global economic activity to countries in developing Asia, which have relatively high energy intensities.” That said, and as can be seen from Chart 45, the rate of improvement in oil intensity does not seem to have slowed since 2000, probably because oil prices have risen very sharply and thereby given a greater incentive for savings with regard to oil than for other energy sources.

Finally, it cannot be emphasised enough that despite the huge improvements in energy and oil intensity registered over the last 40 years, global GDP growth and energy and oil, remain very closely intertwined. Accordingly, the IEA for its part chooses to highlight the extent to which the demand for energy - and by extension for oil - will in large measure be a function of the trend in GDP (2013 WEO, p. 37-38): *“Despite this partial decoupling of energy demand and economic growth (...) the two still remain closely tied. It follows that the projections in this outlook are highly sensitive to assumptions about the rates and patterns of GDP growth.”*

However, by the same token, we would emphasise that the inverse also applies. In other words, the rate and pattern of GDP growth over time will in large measure be a function of the supply of energy and oil. This means that even if the IEA's very ambitious assumptions regarding further reductions in energy and oil intensity over 2013-35 can be achieved, global GDP growth over the next two decades will not attain the levels projected in its NPS if energy and oil supplies do not materialise as envisaged.⁴¹

Conclusion: no margin for error on supply if demand is to be met

The IEA's demand projections for oil largely reflect the changing pattern in global consumption since 2000, with non-OECD countries in general, and Asia and the Middle East in particular, driving demand over the next two decades. This pattern of projected demand growth seems very reasonable to us, but the GDP growth rates assumed by the IEA in its demand-driven modelling assume both: 1) very ambitious further improvements in oil intensity, and 2) that the supply to satisfy this demand will be readily forthcoming.

Precisely because the IEA's projected oil-intensity reduction over 2013-35 is so ambitious this means that there is no margin for error in its supply projections. Accordingly, we now turn to take a more detailed look at its supply projections.

Where will the supply to satisfy this demand come from?

Bearing in mind the trends in the global oil supply observed over 2000-13 above, we see five key questions to consider when looking at the IEA's supply projections over 2013-35:

1. **How much future petroleum production will come from crude oil versus other liquids?** As explained above, this question matters because crude oil has a higher energy density than other petroleum liquids, and also because other petroleum liquids can only be used for transportation fuels to a limited extent. For both of these reasons, crude oil is more valuable than other petroleum liquids.

As a result, the projected trend in the share of crude in the overall supply mix over the next two decades is a useful indicator of its expected relative abundance or scarcity (and hence of its future value).

The IEA projects that crude oil will account for a diminishing share of supply over the next two decades (falling from 82% in 2012 to 76% in 2035), with NGLs and biofuels continuing to increase their share in the supply mix (from 18% to 24%).

2. **How much future crude supply will come from conventional and unconventional sources?**

⁴¹ We discuss this point further in the concluding section of this report, as it is key to our pricing scenarios.

3. As explained above, this question matters because unconventional sources of crude oil are generally much more capital intensive and hence more expensive to develop than conventional sources.

As a result, and other things being equal, the higher the level of unconventional production in the future supply mix, the higher the price required in future to meet a given level of demand will be.

The IEA projects that the share of conventional crude in total oil production will fall in both absolute and relative terms out to 2035, from 69mbd in 2012 to 65mbd in 2035, and from 77% in 2012 to only 62% in 2035. Although the rise in unconventional supply is forecast to more than offset this in absolute terms, the IEA's assumptions rest on: 1) continuing dynamic growth in US LTO, and 2) strong conventional supply growth from Iraq, Brazil, and Kazakhstan (without which conventional crude production would indeed fall very sharply over the next two decades).

3. **How much future crude supply will come from fields already in production versus fields either yet to be developed or yet to be found?** This question matters because the more new sources of production have to be developed and found over time to replace declining production from existing fields, the greater the investment cost will be.

As a result, and other things being equal, the higher the rate of decline from existing sources of production, the higher the cost of satisfying a given level of demand in the future will be (and hence the higher the oil price will need to be).

The IEA projects that 58% of total conventional crude production over the entire 2013-35 period will come from fields already producing today, but only 43% in the second half of the same period (i.e. 2026-35). With decline rates for certain unconventional sources of production being much higher than for conventional sources, this implies huge capital investments in the upstream oil industry out to 2035.

4. **How will future petroleum supply break down between OPEC and non-OPEC countries?** This question matters because oil from OPEC countries is on average – and in theory at least – generally still much cheaper to produce than oil from non-OPEC countries, owing to the much greater proportion of cheap conventional crude oil in OPEC's supply mix versus that of non-OPEC countries.

However, we say "in theory" because as we explained above, there are growing political and social externalities that in practice need to be factored into the price OPEC needs. As a result, we think in practice that the amount of OPEC production in the overall supply mix will not have a material impact on prices.

The IEA expects OPEC's share in the overall supply mix to decline to 2020 (from 43% in 2012 to 41% in 2020), as US LTO continues to grow, but then to rise again from 2020 onwards, reaching 46% by 2035. And with consumption in OPEC countries projected to remain on a strong upward trajectory out to 2035, this raises questions about where the exports of crude oil will come from for the world's net importers.

5. **Where will crude oil exports come from over 2013-35?** The IEA expects global exports of crude oil to increase by 3mbd by 2035 versus 2012, but this growth is very heavily dependent on four countries: Iraq, Brazil, Kazakhstan, and Canada.

We think the IEA's assumptions regarding growth in Canada's oil-sands production and exports are reasonable,⁴² but given the recent and ongoing flare-up in violence and political instability in Iraq, and the track record to date of both Brazil and Kazakhstan in delivering on large-scale projects, there is much more scope for scepticism regarding the large increases in exports envisaged for these countries.

IEA projects ongoing decline in crude as proportion of total oil supply by 2035

Table 25 shows the IEA's base-case projection for global oil supply out to 2035, with the total supply of petroleum liquids here matching the demand numbers shown in Table 24.

Table 25: World oil production by type under the New Policies Scenario (mbd)

| | 2000 | 2012 | 2020 | 2035 | Delta, 2012-35 (mbd) | % change, 2012-35 |
|----------------------------------|-------------|-------------|-------------|--------------|-------------------------|----------------------|
| Conventional crude oil | 66.0 | 69.4 | 67.7 | 65.4 | -4.0 | -5.8% |
| Unconventional crude oil | 1.4 | 5.0 | 10.4 | 15.0 | 10.0 | 200% |
| TOTAL CRUDE OIL | 67.4 | 74.4 | 78.1 | 80.4 | 6.0 | 8.1% |
| Natural gas liquids | 7.8 | 12.7 | 14.8 | 17.7 | 5.0 | 39.4% |
| WORLD OIL PRODUCTION | 75.2 | 87.1 | 92.8 | 98.1 | 11.0 | 12.6% |
| Processing gains | 1.1 | 2.1 | 2.6 | 3.3 | 2.2 | 4.8% |
| Biofuels | 0.2 | 1.3 | 2.1 | 4.1 | 2.8 | 215% |
| WORLD TOTAL LIQUIDS | 76.5 | 90.5 | 97.6 | 105.5 | 15.0 | 16.6% |
| Crude oil as % of total | 88.1% | 82.2% | 80.0% | 76.2% | n.a. | n.a. |
| Conventional crude as % of total | 86.3% | 76.7% | 69.4% | 62.0% | n.a. | n.a. |

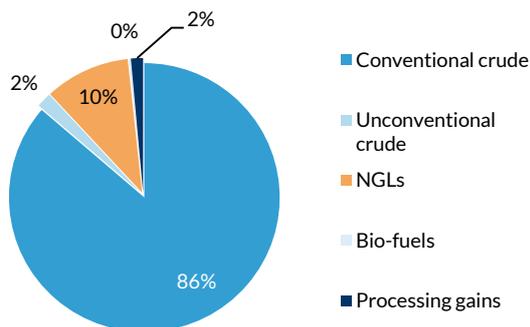
Source: IEA, 2013 WEO (© OECD/IEA)

In our view, the most striking feature of these projections is the declining share of crude oil in general, and of conventional crude in particular, in the total supply of petroleum liquids out to 2035.

Over the next two decades, the IEA forecasts that crude oil will fall from 82% of the total in 2012 to 76% in 2035, and that conventional crude will fall from 77% in 2012 to 62% in 2035. And as shown in Charts 46 and 47 below, the decline in the shares of crude and conventional crude between 2000 and 2035 are even more dramatic: in 2000, crude and conventional crude covered 88% and 86% respectively of total petroleum supply, but by 2035 the IEA sees these numbers falling to 76% and 62% respectively.

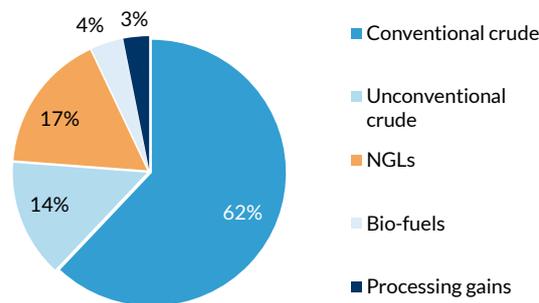
⁴² That said, there is always the regulatory/environmental risk to future oil-sands production, as we discussed in our report *Stranded Assets, Fossilised Revenues*.

Chart 46: Petroleum supply by source, 2000



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Chart 47: Petroleum supply by source, 2035



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

As already explained above, the reason this matters is that crude oil has a higher energy density than other petroleum liquids. Thus, to the extent that the IEA projects a declining share for crude oil over the next two decades this indicates a lower-quality supply mix over the same time horizon. Moreover, we think that the increasing relative scarcity of crude oil in the supply mix suggests an increasing premium for crude oil relative to other liquids in terms of price over the next two decades.

Conventional versus unconventional sources of production

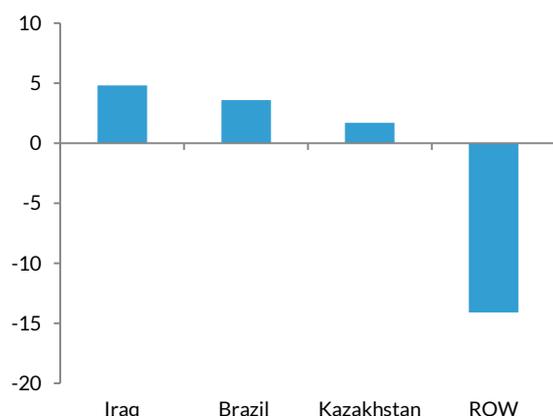
Table 25 above also shows the proportion of supply that the IEA expects to come from conventional versus unconventional sources over 2013-35 (as explained above, though, note that the IEA does not include ultra-deepwater as an unconventional source, only LTO and extra-heavy oils such as Canadian oil sands and Venezuelan extra-heavy oil).

As can be seen from Table 25, conventional crude oil falls over the period, from 69.4mbd in 2012 to 65.4mbd in 2035, and as shown in Chart 48, only three countries see a meaningful increase in production over the period: Iraq (+4.8mbd), Brazil (+3.6mbd), and Kazakhstan (+1.7mbd).

This means that the combined output of all other conventional crude oil producers in the rest of the world is projected to drop by 14.1mbd by 2035 versus 2012, with nearly all other countries projected to have lower output by 2035 than in 2012.

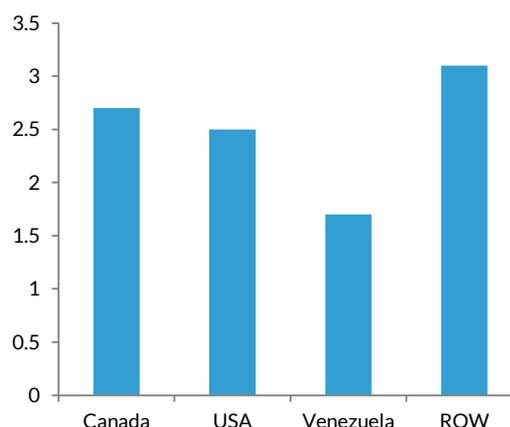
In short, if the world is to avoid a more precipitous drop in conventional crude oil production out to 2035 than the 4mbd assumed by the IEA, then there is no margin for error: Iraq, Brazil, and Kazakhstan must deliver.

Chart 48: Chge in convent. crude oil output, 2035 vs. 2012 (mbd)



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Chart 49: Chge in unconvent. crude oil output, 2035 vs. 2012 (mbd)



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Meanwhile, unconventional output is expected to increase by 10mbd over the forecast period, reaching 15mbd by 2035 versus 5mbd in 2012 (Table 25 and Chart 49 above).

This mainly reflects the IEA's expectation of continuing growth in US unconventional production (+2.5mbd by 2035 versus 2012) and a significant ramp-up in the production of extra-heavy oil and bitumen (EHOB) of +4.3mbd, principally from Canada (+2.5mbd from oil sands and 0.2mbd from shale oil) and Venezuela (+1.7mbd). The remaining increase of 3.1mbd is made up of coal-to-liquids, gas-to-liquids, additives and kerogen.

All of which means that the proportion of unconventional output in the supply mix is likely to rise dramatically over the next two decades, from 7% in 2012 to 14% in 2035 (up from an even lower 2% in 2000, Charts 46 and 47 above).

(In turn, and as explained in greater detail below, this means that as far as the outlook for reversing the trend in net exports since 2005 and growing net exports of crude oil is concerned, the IEA is counting almost exclusively on only five countries: Iraq, Brazil, and Kazakhstan for conventional crude, and Canada and Venezuela for unconventional crude. (The US remains a net importer in the IEA's projections over the entire 2013-35 period).

Existing production versus yet to be developed or found: decline is key

Table 26 shows the breakdown of the IEA's assumptions for total crude oil supply out to 2035 and shows the proportion of supply that will come from existing fields already producing today versus those that have yet to be developed or found over the next two decades.

We would note that the breakdown of production between existing and future sources of production is available only for conventional crude oil. This does not matter so much at the moment, as out of total crude oil production in 2012 of 74.4mbd, 69.4mbd (93%) was from conventional sources.

Over time, however, as can be seen in Table 26, the IEA has unconventional production increasing sharply while conventional supply declines gradually, such that unconventional production is projected to account for nearly 20% of total crude output by 2035.

Table 26: World oil production by type under the New Policies Scenario (mbd)

| | 2000 | 2012 | 2020 | 2035 | Delta, 2012-35 | CAGR, 2012-35 |
|---------------------------------|-------------|-------------|-------------|-------------|----------------|---------------|
| | (mbd) | | | | | |
| Conventional crude oil | 66.0 | 69.4 | 67.7 | 65.4 | -4.0 | -0.3% |
| Existing fields* | 64.5 | 68.0 | 50.9 | 27.1 | -41.0 | -3.9% |
| Yet to be developed | n.a. | n.a. | 13.9 | 19.8 | 19.8 | n.a. |
| Yet to be found | n.a. | n.a. | 1.4 | 15.9 | 15.9 | n.a. |
| Enhanced oil recovery | 1.5 | 1.3 | 1.5 | 2.7 | 1.4 | 3.1% |
| Unconventional crude oil | 1.4 | 5.0 | 10.4 | 15.0 | 10.0 | 4.9% |
| Light tight oil | 0.0 | 2.0 | 4.7 | 5.6 | 3.6 | 4.7% |
| TOTAL CRUDE OIL | 67.4 | 74.4 | 78.1 | 80.4 | 6.0 | 0.3% |
| Unconventional as % of total | 2.0 | 6.7 | 13.3 | 18.7 | n.a. | n.a. |

Source: IEA, 2013 WEO (© OECD/IEA)

This means that the rate of decline of unconventional production will become a much more significant factor in total crude production over the next two decades, and given that the average decline rates for LTO production are much higher than they are for conventional production, this has significant implications for future investment costs and hence prices.

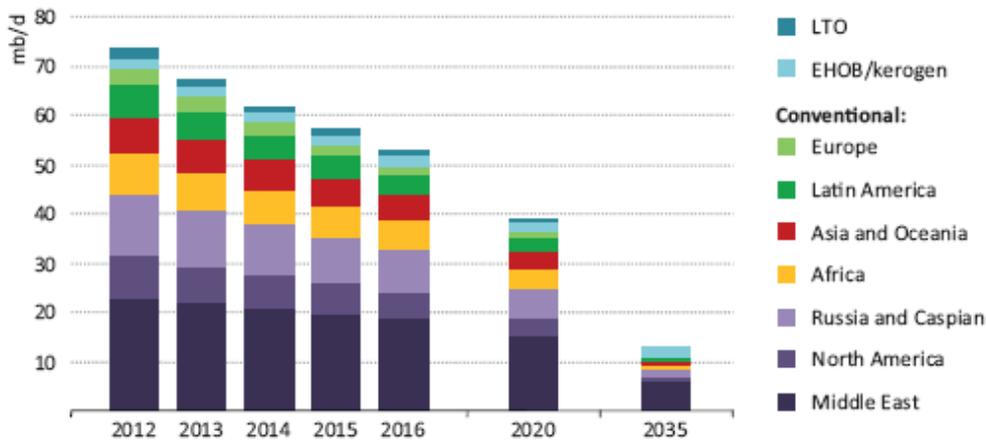
Looking at the numbers in Table 26, we can see that the output from existing fields falls sharply over the projection period, from 68mbd in 2012 to 27.1mbd in 2035. This is quite natural, as all conventional oil fields have a natural life in which production ramps up in the early years, then peaks, plateaus (defined by the IEA as a level of production at or above 85% of peak production) for a period, and then declines more sharply in the post-plateau period (which starts below 85% of peak production), as pressure in the field starts to fall more quickly.

The decline rate can be slowed via capex designed to maintain pressure but after a time this becomes uneconomic and the field's wells will be shut in.

Indeed, without this maintenance capex to stem the rate of decline, output from existing fields would fall even more dramatically. The IEA estimates that if all currently producing fields were simply left to decline naturally without any maintenance capex, total crude production would fall from 74mbd in 2012 to 13mbd in 2035 (Chart 50).

Overall, the IEA estimates the natural rate of decline for existing crude oil fields that have passed their peak level of production at 9% (the natural decline rate is that which would prevail without ongoing maintenance capex), while the observed decline rate after allowing for this maintenance capex is 6.2%.

Chart 50: Decline of crude oil production without ongoing maintenance capex

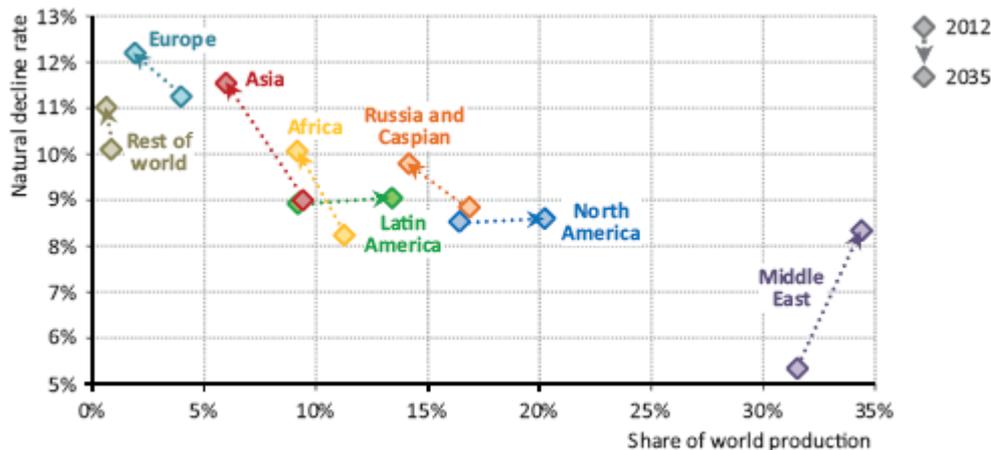


Note: EHOB = extra-heavy oil and bitumen.

Source: IEA, 2013 WEO (© OECD/IEA)

Moreover, while these decline rates vary greatly by region, the IEA expects the natural rate of decline to increase in nearly all regions globally over the next two decades, with only Latin America and North America holding decline rates steady out to 2035 (Chart 51).

Chart 51: Projected evolution of natural decline rates by region, 2012-35



Source: IEA, 2013 WEO (© OECD/IEA)

The reason the decline rate is expected to increase over time in most regions is that, outside the Middle East, an increasing proportion of production will be from smaller fields (which have intrinsically higher decline rates), while in the Middle East some of the largest giant and super-giant fields will be in more advanced stages of decline than they are today.

The decline rates in Latin America and North America remain stable over the projection period because the IEA expects large fields in Brazil and oil-sands projects in Canada to

offset increasing decline rates elsewhere in their respective regions. However, we think this is an overly optimistic projection.

Putting all of this together using a simple linear interpolation of the IEA's data, Table 27 shows our estimate of the total amount of crude oil that will be supplied over 2013-35 by source, based on the numbers already shown in Table 26.

Table 27: World oil production by type under the New Policies Scenario (Gb), 2013-35

| | 2013-25 | % of total | 2026-35 | % of total | 2013-35 | % of total |
|---------------------------------|--------------|--------------|--------------|--------------|--------------|--------------|
| Conventional crude oil | 322.6 | 88,7% | 240.9 | 82,8% | 563.6 | 86,1% |
| Existing fields* | 258.4 | 71,0% | 124.1 | 42,6% | 382.5 | 58,4% |
| Yet to be developed | 39.4 | 10,8% | 66.4 | 22,8% | 105.8 | 16,2% |
| Yet to be found | 17.1 | 4,7% | 42.2 | 14,5% | 59.2 | 9,0% |
| Enhanced oil recovery | 7.4 | 2,0% | 8.2 | 2,8% | 15.6 | 2,4% |
| Unconventional crude oil | 41.5 | 11,4% | 50.2 | 17,2% | 91.7 | 14,0% |
| TOTAL CRUDE OIL | 363.7 | | 291.1 | | 654.8 | |

Source: Kepler Cheuvreux estimates based on IEA data; *The numbers from existing fields are calculated after taking into account maintenance capex

As can be seen, we calculate total crude oil supplied of 655bn barrels out to 2035 (640bn excluding enhanced oil recovery), of which 584bn (86%) is conventional, and 92bn (14%) is unconventional.

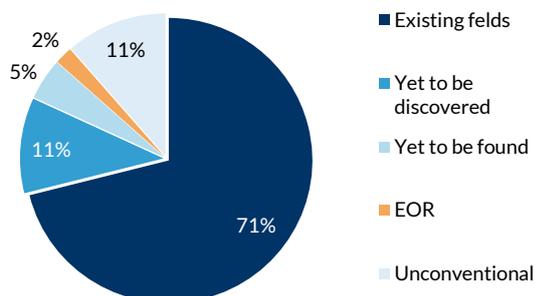
Looking more closely at the breakdown of supply from conventional sources, we find that 383bn (58%) is from existing fields, 106bn (16%) from fields yet to be developed, and 59bn (11%) from fields yet to be found. In other words, over the entire 2013-35 period, over half of total crude production is expected to come from fields already in production.

This reflects the fact that many of the fields producing today are still in the ramp-up phase, and others in the plateau phase before the more severe decline sets in, such that the average annual decline rate for all existing fields taken in aggregate – i.e. those in ramp-up, at peak, on the plateau, and post plateau – is only 3.9% (Table 26), and hence well below not only the natural post-peak decline rate of 9%, but also the observed post-peak decline rate of 6.2%.

However, looking more closely at the breakdown between the two halves of the forecast period, it can be seen that the contribution from existing fields is much lower over 2026-35 than it is over 2013-25.

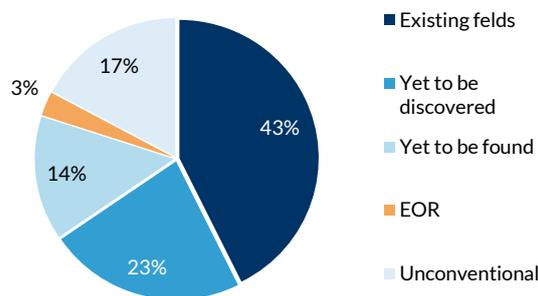
Whereas fields already in production in 2012 account for 71% of total crude oil production over 2013-25, the fact that a significantly larger proportion of these fields will be in the post-peak and post-plateau phases of their lives by 2025 means that they account for a much lower 43% of total crude oil production over 2026-35. This is shown graphically in Charts 52 and 53 below.

Chart 52: World crude production by source, 2013-25



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Chart 53: World crude production by source, 2026-35



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

These IEA figures suggest that on average over 2013-35 the world will lose about 2.5mbd per year of conventional crude output from existing fields, owing to natural decline, with maintenance capex reducing this to about 1.8mbd per year.

On top of this, we would estimate the loss of unconventional output, as defined by the IEA, from natural decline to be around 0.75-1mbd per year. As a result, we estimate that prior to maintenance capex aimed at stemming natural decline rates, the world loses around 3.25-3.5mbd per year of crude oil production. After adding in lost NGL output, we estimate that the world loses c. 4mbd per year of petroleum liquids to natural decline.

Owing to this very severe impact of natural decline rates on global oil supply over time, and the consequent need to invest very large amounts of capital to maintain production at levels commensurate with demand, the IEA states that *“the main threat to future oil-supply security is insufficient investment”* (2013 WEO, p. 459).

OPEC versus non-OPEC production

Table 28 shows the breakdown of global oil production (crude oil plus NGLs), broken down between OPEC and non-OPEC sources.

Table 28: World oil production, OPEC and non-OPEC, under the New Policies Scenario (mbd), 2013-35

| Region | 1990 | 2012 | 2020 | 2035 | Delta, 2035/12 (mbd) | CAGR, 2012-35 |
|-----------------------------|-------------|-------------|-------------|-------------|----------------------|---------------|
| Non-OPEC | 41.7 | 49.4 | 55.0 | 52.9 | 3.5 | 0.3% |
| OPEC | 23.9 | 37.6 | 37.8 | 45.2 | 7.6 | 0.8% |
| WORLD OIL PRODUCTION | 65.6 | 87.1 | 92.8 | 98.1 | 11 | 0.5% |
| OPEC share of total | 36.4% | 43.2% | 40.7% | 46.0% | 69.0% | n.a. |

Source: IEA, 2013 WEO

After raising its share of total world production over 1990-2012 from 36% to 43%, OPEC’s share is projected to fall back to 40% by the end of this decade, as US LTO production in particular ramps up, before rising again over 2020-35 to reach 46% by 2035.

If we then look at the breakdown of OPEC and non-OPEC production by source (Table 29), we can see that the IEA sees the share of conventional crude in non-OPEC output falling sharply, from 78% in 2012 to 61% in 2035.

Table 29: OPEC and non-OPEC oil production by type under the New Policies Scenario (mbd), 2013-35

| | 1990 | 2012 | 2020 | 2035 Delta, 2035/12 (mbd) | CAGR, 2012-35 |
|--------------------------------------|-------------|-------------|-------------|------------------------------|---------------|
| Non-OPEC | | | | | |
| Conventional crude | 37.6 | 38.4 | 38.3 | 32.3 | -6.1 |
| NGLS | 3.6 | 6.6 | 8.0 | 8.3 | 1.7 |
| Unconventional | 0.4 | 4.4 | 8.8 | 12.3 | 7.9 |
| Total Non-OPEC OIL SUPPLY | 41.7 | 49.4 | 55.0 | 52.9 | 3.5 |
| Conventional crude share of non-OPEC | 90.2% | 77.7% | 69.6% | 61.1% | n.a. |
| OPEC | | | | | |
| Conventional crude | 21.9 | 30.9 | 29.4 | 33.0 | 2.1 |
| NGLS | 2.0 | 6.1 | 6.8 | 9.3 | 3.2 |
| Unconventional | 0.0 | 0.6 | 1.6 | 2.8 | 2.2 |
| Total OPEC OIL SUPPLY | 23.9 | 37.6 | 37.8 | 45.2 | 7.6 |
| Conventional crude share of OPEC | 91.6% | 82.2% | 77.8% | 73.0% | n.a. |

Source: IEA, 2013 WEO

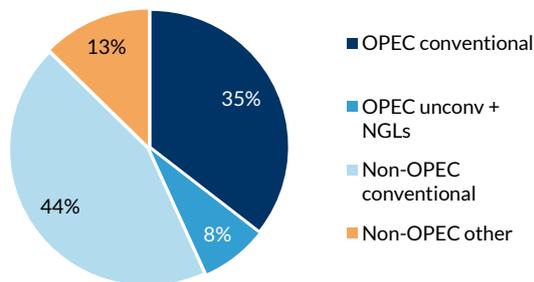
This reflects the fact that: 1) non-OPEC conventional output is projected to decline in absolute terms over 2013-35 (it is stable until 2020 but then falls by 6.1mbd between 2020 and 2035); and that 2) non-OPEC unconventional and NGL output both increase over 2013-35 (especially unconventional, which rises by 8mbd in 2035 compared with 2012).

By contrast, the IEA's projections show that while the share of conventional crude in OPEC's total output also declines over the next two decades, the fall is much less dramatic, with conventional crude still representing 73% of the bloc's output in 2035 compared with 82% in 2012.

Moreover, OPEC's conventional output actually increases in absolute terms over 2013-35 (+2.1mbd higher in 2035 versus 2012), it is just that the bloc's output of unconventional crude and NGLs increases more quickly over the period (combined they are 5.4mbd higher in 2035 than in 2012).

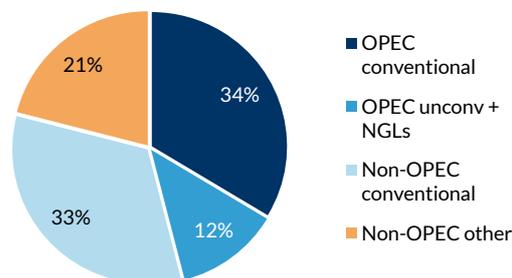
The change in the composition of OPEC and non-OPEC output as a proportion of total world oil supply is shown graphically in Charts 54 and 55. As can be seen by comparing Chart 55 with Chart 54, the reduction in non-OPEC production of conventional crude out to 2035 is very striking.

Chart 54: World oil output OPEC and non-OPEC, 2012



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

Chart 55: World oil output, OPEC and non-OPEC, 2035



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

As already explained in our discussion regarding the IEA’s projections for the breakdown between conventional and unconventional crude production over 2013-35, growth in the world oil supply over 2013-35 is overwhelmingly dependent on only six countries, two of which are OPEC members (Iraq and Venezuela) and four of which are non-OPEC members (Brazil, Canada, Kazakhstan, and the US).

As the figures in Table 29 and Chart 56 below show, growth in oil supply (crude plus NGLs) over the first part of the IEA’s projection period (2013-20) is driven overwhelmingly by non-OPEC countries, namely the US (+2.4mbd), Brazil (+1.9mbd), and Canada (+1.2mbd).

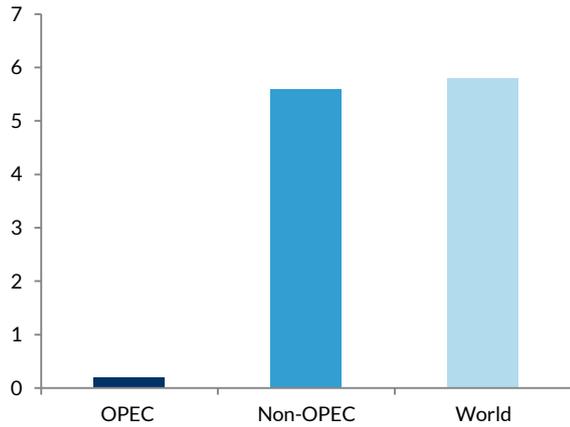
Within OPEC, Iraq posts strong growth up to 2020 (+2.8mbd), but this is offset by projected declines in the output of Saudi Arabia (-1.1mbd), Kuwait (-0.6mbd), and Angola and Nigeria (-0.5mbd between them).

However, the IEA assumes that the drop in Saudi and Kuwaiti production to 2020 is a temporary response to rising supply from the US and Iraq, as over the second part of the projection period (2021-35), the growth in output is dominated by OPEC (Tables 28 and 29 and Chart 57 below).

Iraq increases its output by 2.1mbd over this period, Saudi Arabia by 1.6mbd, Iran by 0.9mbd, Venezuela by 0.6mbd, and Kuwait by 0.5mbd. Overall, OPEC’s output increases by 7.4mbd over 2021-35, while non-OPEC countries see a decline of 2.1mbd as strong growth in Brazil (+1.9mbd), Kazakhstan (+1.8mbd), and Canada (+1.1mbd) is outweighed by the combined decline in other non-OPEC output (-6.9mbd).

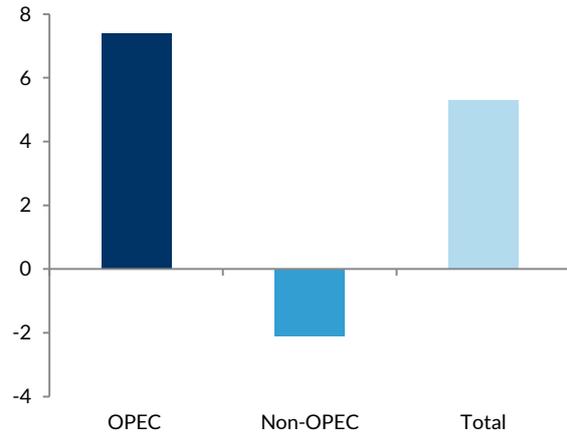
The biggest falls in non-OPEC production over 2021-35 are registered by OECD Europe (-1.1mbd), Russia (-1mbd), China (-1mbd), and non-OPEC Africa (-0.8mbd), the US (-0.7mbd), and non-OECD Latin America excluding Brazil (-0.7mbd).

Chart 56: Chge in world oil* out., OPEC & non-OPEC, 2012-20 (mbd)



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO; *Crude oil plus NGLs

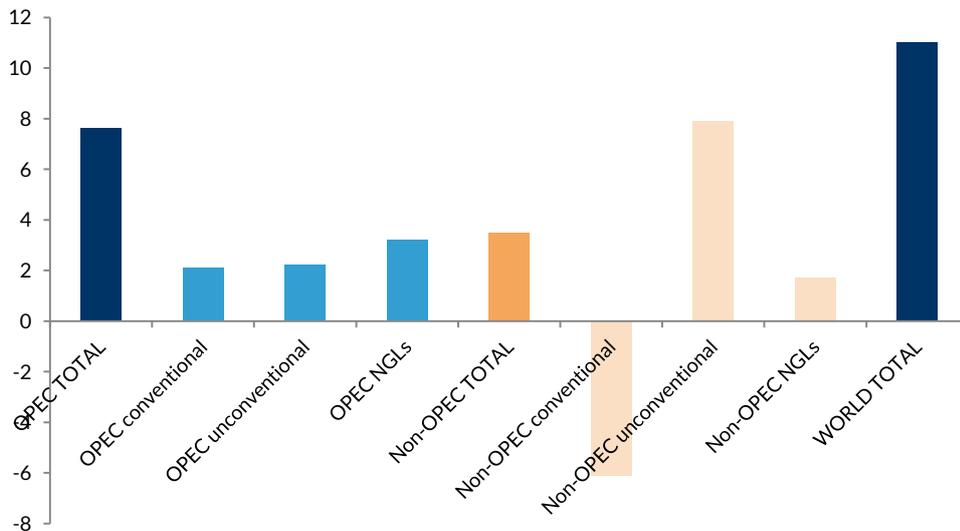
Chart 57: Chge in world oil* out., OPEC & non-OPEC, 2021-35 (mbd)



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO; *Crude oil plus NGLs

Chart 58 then summarises the change in the profile of world oil production between OPEC and non-OPEC countries over the entire 2013-35 period.

Chart 58: Change in world oil* output by source, OPEC and non-OPEC, 2013-35 (mbd)



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO; *Oil Crude oil plus NGLs

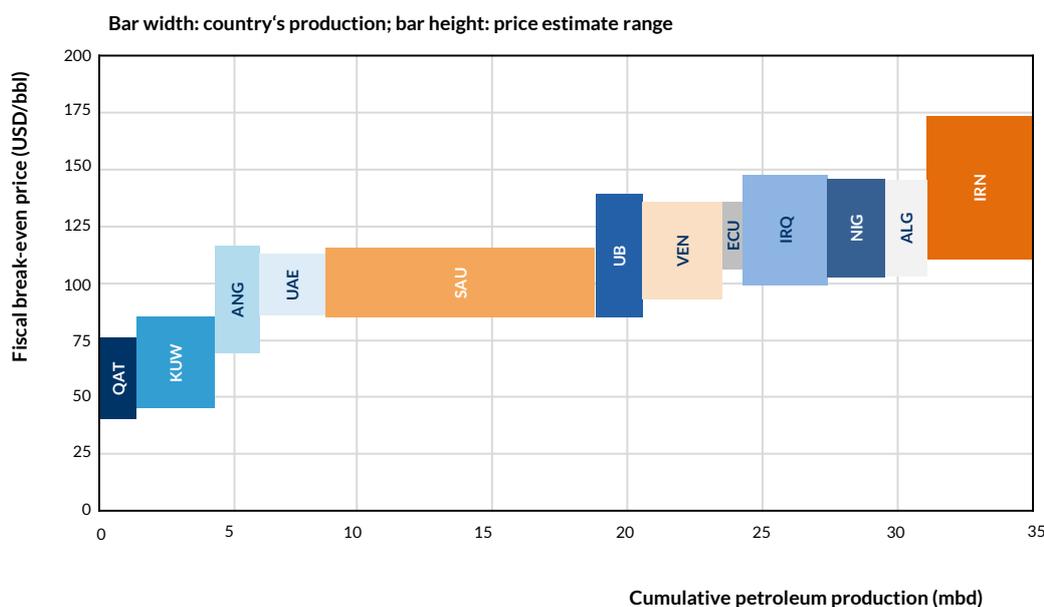
OPEC’s production is 7.6mbd higher by 2035 than today, and that of non-OPEC countries 3.5mbd. As is clear from Table 29 and Chart 58, though, whereas OPEC’s increase is fairly evenly split between conventional and unconventional crude and NGLs, non-OPEC output sees a 6mbd drop in conventional and a 7.9mbd increase in unconventional.

This means that the production of the world’s cheap conventional crude oil will be even more concentrated in OPEC by 2035 than it is today.

However, and as already explained, OPEC’s costs can no longer be measured in terms of the economics of production alone. Rather, we have to price in the political and social externalities that determine the oil price required by OPEC countries to balance their budgets.

On the basis of its estimates for the fiscal breakeven costs of OPEC members (Table 18 above), the Arab Petroleum Investment Corporation has developed a fiscal breakeven cost curve for OPEC members showing the price at which their output balances their 2013 budgets (Chart 59).

Chart 59: Fiscal breakeven cost-curve for OPEC, 2013



Source: APIC

APIC’s analysis gives a very different profile for OPEC costs than the IEA’s cost curve (Chart 63 below), reflecting the externalities associated with fast-growing populations and high levels of domestic subsidisation. In addition, these factors have caused rapid rises in domestic consumption in OPEC countries. It is for this reason that Iraq is the only OPEC country that the IEA expects to see increase its exports of crude oil substantially between 2013 and 2035.

This being the case, where exactly does the IEA expect the growth in global exports of crude oil to come from over the next two decades?

The outlook for crude oil exports: Iraq, Brazil, and Kazakhstan are key

Table 30 underlines the point about the phenomenal and ongoing growth in OPEC’s population, with the UN expecting it to rise at almost three times the global rate over the next two decades (64% versus 25%).

The UN’s base-case projections have the combined population of OPEC countries increasing by 263m people and thereby accounting for 15% of the total increase in the

world's population out to 2035. It is this population growth, combined with high subsidisation rates, which will make it hard for most OPEC countries to increase their exports over 2013-35.

Table 30: World and OPEC population growth assumed in the New Policies Scenario, 2011-35 (000s)

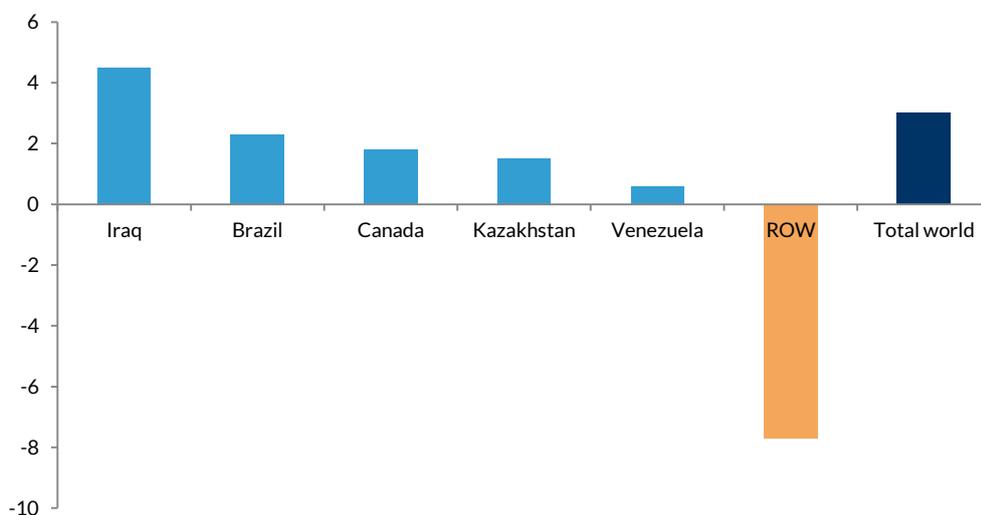
| Region | 2011 | 2020 | 2035 | Delta over 2011-35 | % Delta 2011-35 |
|--------------------|-----------|-----------|-----------|--------------------|-----------------|
| WORLD | 6,997,999 | 7,716,749 | 8,743,447 | 1,745,448 | 24.9% |
| OPEC | 421,970 | 512,411 | 675,469 | 263,198 | 63.7% |
| OPEC as % of world | 6.0% | 6.6% | 7.7% | 15.1% | |

Source: United Nations Population Division

That said, there is one OPEC country that is absolutely key to the IEA's projections for global exports of crude oil out to 2035, and that is Iraq. The IEA sees Iraq's exports of crude increasing by 4.5mbd between 2012 and 2035, with Brazil (+2.3mbd), Canada (+1.8mbd), Kazakhstan (+1.5mbd), and Venezuela (+0.6mbd) as the other main contributors to rising exports of crude oil (as shown in Chart 49 above, Venezuela sees an increase in its unconventional crude oil production of 1.7mbd between 2012 and 2035, but its conventional crude output declines by 1.1mbd over the same period).

Overall, the IEA sees net global exports of crude increasing by 3mbd between 2012 and 2035, which means that outside the countries just mentioned the IEA is projecting a combined decline in net exports among other net exporting countries of 7.7mbd between 2012 and 2035 (Chart 60).

Chart 60: Projected change in net exports of crude oil between 2012 and 2035 in IEA's NPS (mbd)



Source: Kepler Cheuvreux estimates from IEA data in 2013 WEO

In short, the IEA projects a 3mbd increase in net exports of crude oil by 2035, while in our analysis the world has in fact experienced a *decline* in net crude exports of 3.4mbd since 2005.

Summary of the IEA's projections for global oil supply over 2013-35

As our summary has shown, the IEA sees the world oil supply becoming increasingly dependent on NGLs and unconventional crude over 2012-35, and, from 2020 onwards, increasingly dependent on OPEC as well (in both relative and absolute terms). Crucially, while fields already in production today account for 73% of conventional crude output over 2013-25, this falls to 43% over 2026-35, meaning that huge investments will be required in fields yet to be developed and yet to be found in order to meet demand over the second half of the IEA's projection period.

Moreover, the IEA's projections for both crude oil supply and crude oil export growth over 2013-35 depend to a great extent on three countries whose ability to deliver on expectations is in our view very much open to question, namely Iraq, Brazil, and Kazakhstan.

So, given that: 1) the IEA sees a continuation of the trends observed in the structure of the world's oil supply since 2005 (albeit with a very optimistic projection for future crude oil exports that goes against the grain of the decline experienced since 2005); and that 2) these trends have led to a steeply rising trend in the capital intensity of the upstream oil industry since 2005, what are the IEA's assumptions for capex over 2013-35?

Outlook for upstream oil capex to 2035

In the NPS, as set out in the 2013 WEO, the IEA was projecting total upstream oil capex over 2013-35 of USD9.4trn, but these numbers have recently been updated in the [World Energy Investment Outlook \(WEIO 2014\)](#) published in June of this year.

Table 31 compares the IEA's upstream capex assumptions for oil by region over 2013-35 as published in the 2013 WEO with the Agency's updated estimates as published in the WEIO 2014. As can be seen, the updated estimate for cumulative investment out to 2035 is USD11.3trn (in constant 2012 USD), which is USD1.9trn (20%) higher than the USD9.4trn the Agency was projecting in the 2013 WEO last November.

Table 31: IEA's estimate of cumulative upstream oil capex necessary out to 2035 (constant 2012 USD)

| | WEIO 2014* | 2013 WEO* | Change (USDbn) | Change (%) |
|-------------------|---------------|--------------|----------------|-------------|
| OECD | 4,087 | 3,354 | 733 | 21.8 |
| Americas | 3,488 | 2,826 | 662 | 23.5 |
| o/w US | 2,021 | 2,060 | -39 | -1.9 |
| Europe | 500 | 450 | 50 | 11.1 |
| Asia/Oceania | 98 | 77 | 21 | 27.3 |
| Non-OECD | 7,197 | 6,041 | 1,156 | 19.1 |
| E. Europe/Eurasia | 1,345 | 1,180 | 165 | 13.9 |
| Asia | 1,079 | 664 | 415 | 62.5 |
| Middle East | 1,578 | 872 | 706 | 81.0 |
| Africa | 1,291 | 1,507 | -216 | -14.3 |
| Latin America | 1,905 | 1,818 | 87 | 4.8 |
| TOTAL | 11,284 | 9,394 | 1,890 | 20.1 |

Source: *IEA, 203 WEO, and IEA World energy Investment Outlook, June 2014

The IEA emphasises that most of this upstream investment is required to replace lost production from depletion at existing fields (WEIO 2014, pp-59-60):

“From an estimated USD700bn in 2013, global upstream oil and gas expenditure rises steadily throughout the projection period, reaching an average of more than USD850bn annually by the 2030s. More than 80% of this spending is required just to keep production at today’s levels, that is, to compensate for the effects of decline at existing fields. The figure is higher in the case of oil (at close to 90% of total capital expenditure).”⁴³

The IEA then says that the profile of this capex will remain fairly constant in terms of the annual amount, but that the geographical distribution of the spending will change over time (Ibid, p. 60):

“Although total spending on upstream oil projects remains fairly constant, at an average of just over USD500bn per year, there is a noticeable shift in the location of this investment over the coming decades. Average annual investment levels start to tail off in North America, largely in the United States, where investment and then production start to fall from the mid-2020s. Investment levels also fall in China and in some other mature basins, but they rise considerably in three regions: the Middle East, Brazil and the Caspian region.”

While it is reasonable to posit that the geographical distribution of global upstream capex will change over the next two decades, we find two points regarding the IEA’s assumptions highly questionable.

First, as far as the geographical split is concerned, and based on the drilling-treadmill effect in the shale-oil plays that we reviewed above, we find it counterintuitive that the projections for US capex fall sharply over time, while US production falls only gradually over 2025-35 (see our discussion of this point above regarding Chart 16). Second, the relatively flat annual profile for upstream capex that the IEA is projecting of just over USD500bn is very different from the profile of sharp year-on-year increases that the industry has in actuality experienced since 2005.

Moreover, although the IEA raised its upstream capex projections by 20% in the *WEIO 2014* it left its price projections over 2013-35 unchanged.

Despite higher capex estimates, WEIO 2014 maintains 2013 WEO price projections

On the outlook for oil prices, the *WEIO 2014* (p. 51) says the following:

“Gradual depletion of the most accessible reserves forces companies to move to develop more challenging fields; although offset in part by technology learning, this puts pressure on upstream costs and underpins an oil price that rises to reach USD128/bbl in real terms by 2035”. It then adds (WEIO 2014, p. 59): “In our modelling, the price trajectories for the various fuels are derived so that these investments yield reasonable rates of return, so it is also reasonable to expect that the required investment will be forthcoming”.

However, the IEA was already assuming that prices would rise to USD128/bbl in real terms by 2035 in the *WEO 2013* when its cumulative capex estimates for the upstream oil industry over the next two decades were USD1.9trn lower.

⁴³ It is because most of the upstream oil capex is to replace declining output at existing fields that the IEA does not see much risk of stranded assets arising for the oil industry from tighter climate legislation over the next decade or so (always assuming a global climate deal were to be reached in the first place), although it does see a higher risk thereafter.

We find this counterintuitive and remain puzzled that the IEA did not raise its price assumptions in the WEIO 2014 at the same time as it raised its assumptions for cumulative upstream capex by 20%.

With this in mind, let us now turn to a closer look at the IEA’s price projections.

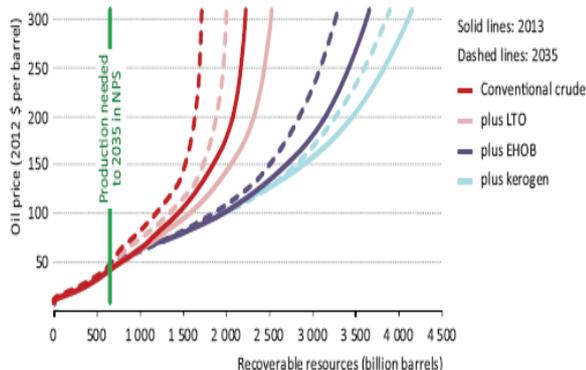
What will the IEA’s oil-supply projections cost to bring in?

The IEA’s price projections see crude oil rising from USD109/bbl in 2012 to USD128/bbl by 2035 in real terms, but the capex cuts announced by many of the majors in recent months suggest to us that prices may need to rise more aggressively than the Agency is assuming. In turn, this raises questions about future GDP growth and hence – given the feedback loops between GDP and oil demand – whether sharply higher oil prices would in fact be a good thing for the oil majors.

IEA sees modest real-term increase in oil prices out to 2035

In our calculations, based on the IEA data (see Table 27 above), total cumulative crude oil production (conventional and unconventional excluding enhanced oil recovery) over 2013-35 comes to 640bn barrels, and looking at the IEA’s global supply cost curves for 2013 and 2035 (Chart 61), we see that, in theory, there is enough supply out there to meet this level of cumulative demand at cost levels of USD50-60/bbl in constant 2012 USD.

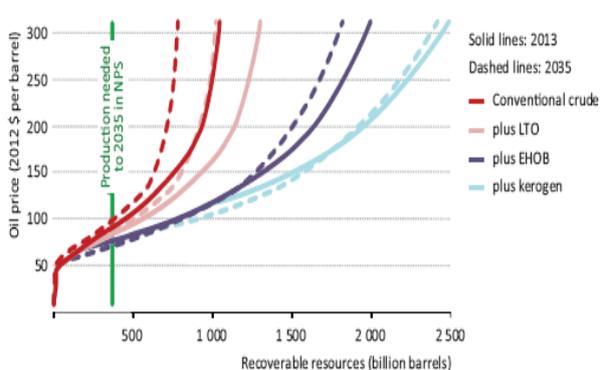
Chart 61: NPS global oil-supply curves, 2013 & 2035



Notes: The supply curves are cumulative, i.e. the “plus LTO” line includes conventional crude and LTO; the “plus EHOB” includes conventional crude, LTO and EHOB, and so on. The vertical green line indicates the amount of production required between 2013 and 2035 in the New Policies Scenario (NPS).

Source: IEA, 2013 WEIO (© OECD/IEA)

Chart 62: NPS non-OPEC oil-supply curves, 2013 & 2035



Note: The vertical green line indicates the amount of production required between 2013 and 2035 in the New Policies Scenario (NPS).

Source: IEA, 2013 WEIO (© OECD/IEA)

However, nearly all of the oil available at these levels is from OPEC sources, and there are at two obvious reasons why OPEC is not going to supply the world’s oil needs at these prices.

First, whatever the size of OPEC’s reserves (and it should be remembered that these have not been subject to independent verification for decades), there is simply not the capacity in place in OPEC countries currently to produce oil at a flow rate equivalent to the world’s demand – not nearly enough. OPEC currently produces c.30mbd of crude oil, and the world currently consumes c. 76mbd.

Even allowing for the restoration of Iranian and Libyan output to full capacity and taking a generous view of Saudi spare capacity would not take OPEC's maximum supply capability above 35mbd, and this would still be less than half of the world's current consumption.

This means that monumental levels of investment would be required to make OPEC's reserves available at the kind of flow rates required to meet 100% of global demand, and, in our view, investments on the kind of scale required could not be adequately remunerated at a subsequent selling price of USD50-60/bbl in constant 2012 USD.

Accordingly, we think Chart 61 is best viewed as a theoretical representation of the price at which OPEC could produce its reserves at *current* flow rates into the future, but not the price at which it could ever meet global demand on its own.

Second, and as already explained above, the cost of production on its own is in any case an inadequate yardstick for analysing the economics of oil in OPEC countries, as it fails to take into account the political and social externalities that OPEC countries have to worry about.

The current arrangement in world oil markets suits OPEC very well: the majority of OPEC'S production is low cost and low risk, which means that other producers (the majors, other IOCs, independents, and non-OPEC NOCs and INOCs) are taking most of the risk in terms of new exploration and thereby ensuring that prices remain at the high levels OPEC needs to cover its political and social externalities.

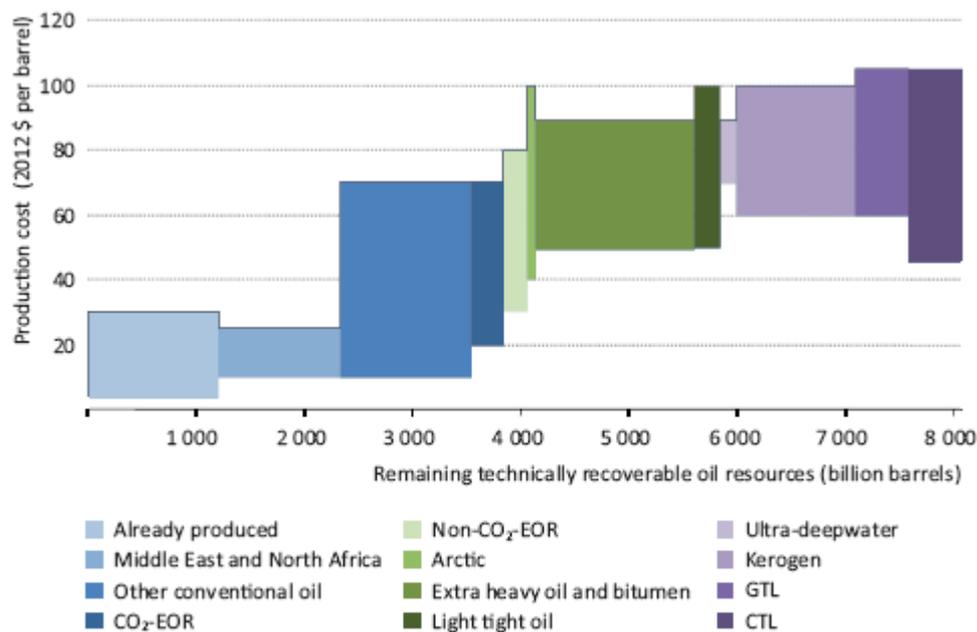
In short, there is no way that OPEC either could or would want to meet the world's demand for crude oil at USD50-60/bbl. As a result, the IEA assumes that of the 640bn barrels of cumulative production needed out 2035, only 260bn will come from OPEC, with the remaining 380bn coming from non-OPEC sources.

And as shown in Chart 62, this changes the economics dramatically, with cumulative demand for 640bn barrels here intersecting the supply curve at USD90/bbl (again, in constant 2012 USD) rather than USD50-60/bbl. As explained above, over the next two decades non-OPEC supply will become increasingly reliant on unconventional sources with higher long-run marginal costs (LRMCs) than conventional oil.

As shown in Chart 63 (again, constant 2012 USD), the IEA's long-run cost curve has conventional crude in a range of USD10-USD70/bbl, whereas for unconventional crude the ranges are higher: USD50-USD90/bbl for oil sands, USD50-USD100/bbl for light tight oil, USD70-USD90/bbl for ultra-deep water, and reaching up to USD105/bbl for gas-to-liquids and coal-to-liquids.

For this reason and based on Chart 62, the IEA estimates that the marginal barrel from non-OPEC sources out to 2035 can in theory be supplied at a cost of up to USD90/bbl. However, USD90/bbl is not the long-run price assumed in the NPS, because according to the 2013 WEO (p. 456), *"the ability of the industry to develop new resources quickly is limited (in large part by the availability of skilled personnel, as well as the long timescale s of new large projects)"*.

Chart 63: IEA estimate of LRMC of petroleum liquids (constant 2012 USD)



Source: *Resources to Reserves* (IEA, 2013).

Source: IEA, 2013 WEO (© OECD/IEA)

As a result, the 2013 WEO goes on to say (again, p.456) that “the oil-price trajectory, at a level above marginal cost per barrel, serves the purpose of limiting demand to a level that can reasonably be expected to be supplied, given expected limitations in both OPEC and non-OPEC countries”.

For all of these reasons, the NPS assumes that oil prices will rise in real terms (i.e. in constant 2012 USD), from USD109/bbl in 2012 to USD113/bbl in 2020 and USD128/bbl in 2035 (which, for reference, implies nominal prices of USD136/bbl in 2020 and USD216/bbl in 2035). These projections would be a real and nominal price increases of 17% and 98%, respectively, over 2012-35, as shown in Table 32.

Table 32: Brent crude prices under the New Policies Scenario in real terms (constant 2012 USD) and nominal terms

| Fuel | Unit | 2012 | 2020 | 2035 | % change, 2012-35 |
|-------------------------|------|------|------|------|-------------------|
| Real crude oil price | bbl | 109 | 113 | 128 | 17.4% |
| Nominal crude oil price | bbl | 109 | 136 | 216 | 98.2% |

Source: IEA, 2013 WEO

At this stage, it is worth pointing out that these projected price increases over 2012-35 are *much* lower than the actual increases recorded over 2000-13. As seen in Table 33, Brent prices increased by 180% and 276% in real and nominal terms, respectively, over 2000-13.

Table 33: Brent crude prices, 2000-13 in real terms (constant 2012 USD per unit) and nominal terms

| Fuel | Unit | 2000 | 2006 | 2013 | % change, 2000-13 |
|-------------------------|------|------|------|------|-------------------|
| Real crude oil price | bbl | 39 | 75 | 109 | 180% |
| Nominal crude oil price | bbl | 29 | 65 | 109 | 276% |

Source: BP, Statistical Review of World Energy 2014

That said, the IEA does acknowledge upside risk to its base-case oil-price assumptions.

... although WEIO 2014 acknowledges upside risk to its oil-price forecasts

On page 59 of the WEIO 2014 the IEA enters the following crucial caveat to its unchanged assumptions on oil prices:

“In our modelling, the price trajectories for the various fuels are derived so that these investments yield reasonable rates of return, so it is also reasonable to expect that the required investment will be forthcoming. In practice, good foresight will be required as to future regulatory and market conditions. Investor and company investment decisions are determined by their judgements as to the nature of regulatory and other risks, and their perceptions of future market opportunities. There is always the risk that investment will turn out to have been insufficient, driving energy prices higher or even creating energy shortages and thereby stimulating a new cycle of investment.” (emphasis ours).

It then goes on to highlight the risk that investment in the Middle East in particular might not be up to the level assumed in its updated base-case scenario (this investment will be crucial, as the WEIO 2014 assumes that Middle East oil production increases from 28mbd in the early 2020s to more than 34mbd by 2035).

The IEA’s analysis of the risks to investment in the Middle East’s upstream capacity occurring in a timely manner is solid (and pages 67-70 of the WEIO 2014 are well worth reading in this respect). However, we think there is a much more immediate and telling example of stalling investment in the upstream oil industry, which is the capex cutbacks that most of the international majors have announced since the beginning of this year.

Majors now cutting capex, underlining upside price risk

As explained above, over the last two months, most of the world’s major international oil companies have announced cutbacks to their capex plans [as costs have begun to outstrip prices](#). This is despite the fact that oil prices have been stable at record-high real levels for the last three years.

A very good recent example of the pressure that high costs are putting on upstream investments, despite historically high prices is [the recent decision announced by Total](#) to shelve its USD11bn Joslyn oil-sands mine in Canada. The head of Total’s Canadian division is quoted in the article linked above, as saying, “*Joslyn is facing the same challenge most of the industry worldwide [is], in the sense that costs are continuing to inflate when the oil price and specifically the netbacks for the oil sands are remaining stable at best – squeezing the margins.*”

All of which indicates to us that the upstream oil industry is already struggling to make the returns that shareholders require for the kind of upstream risks that are now being taken and that the industry therefore needs higher prices to provide it with the necessary incentive to continue investing. In other words, the IEA’s caveat that “*there is always the risk*

that investment will turn out to have been insufficient” is not some hypothetical future risk: it is already a reality.

In short, it is clear from the capex reductions announced by many of the world’s largest oil companies in recent months that if they are struggling to justify marginal new investments with prices at USD108/bbl (the average price in Q1 of this year when most of these capex cuts were announced), then it is very hard to see how the oil supply can grow in future with prices below USD100/bbl.

To the extent that it is projecting higher real oil prices into the future the IEA seems to acknowledge this reality, but we think there are nonetheless two big questions raised by the IEA’s projections out to 2035.

The first relates to the IEA’s oil-price assumptions. Given that capex cuts are already being announced, are the IEA’s price assumptions high enough? Or will the industry in general, and the majors in particular, need prices to rise more steeply than the IEA is assuming in order to stimulate the investment required to meet the Agency’s future supply projections?

The second relates to the IEA’s macro projections for GDP growth and oil intensity. As we saw above, the IEA’s NPS already assumes a huge improvement in world oil intensity out to 2035, and projects that it will fall at a much faster rate over the next two decades than was achieved over the last two.

As a result, if it turns out that higher oil prices will indeed be necessary to meet the IEA’s future supply projections, this would imply that global oil intensity will have to fall even faster if the Agency’s projections for GDP growth out to 2035 are to hold.

Given that the IEA’s base-case projections for the trend in oil intensity over the next two decades are already extremely ambitious, we are very sceptical that oil intensity could fall even more quickly in a manner consistent with the IEA’s assumptions on future global GDP growth if oil prices were indeed to turn out higher than the IEA is assuming.

As a result, we think that if higher oil prices than the IEA is projecting will indeed be needed to bring in the supply assumed in the NPS, then the growth rate in global GDP will likely be lower than the IEA is assuming. And given the feedback loops between GDP and oil demand, this means that there are also risks to the majors from higher oil prices as well as lower ones, especially given the extra stimulus that higher oil prices would give to renewables (whose costs are falling rather than rising).

In short, we think the risk of stranded assets with regard to future oil investments is not limited to a scenario of falling oil prices and that investors should also be alive to the risk of new high-cost oil projects becoming stranded under a scenario of rising oil prices.

We discuss these considerations in greater detail in the final section of this report below when looking at potential future oil-price scenarios.

Conclusion: higher oil prices needed, but can the world afford it?

As our review has highlighted, the IEA's base-case scenario projects the continuation and indeed accentuation over the next two decades of the ongoing structural changes in the global oil supply observable since 2005, namely declining output of conventional crude oil and hence an ever greater reliance on unconventional crude and NGLs.

Moreover, such growth, as the IEA is assuming in conventional crude oil production out to 2035, is concentrated in three countries that in our view will face significant challenges in meeting expectations, namely Iraq, Brazil, and Kazakhstan. A further feature of the IEA's projections is that OPEC becomes increasingly important to meeting global demand over the second half of the forecast period, as output from non-OPEC fields declines sharply from 2025 onwards.

Against this backdrop, and given the trends in exports, capital intensity, and prices that have accompanied the change in the structure of the global oil supply since 2005, we find the IEA's assumptions on the outlook for crude oil exports, upstream capex, and future prices to be extremely optimistic.

As our review has shown, net crude oil exports have declined by over 3mbd since 2005, but the IEA expects this trend to reverse going forward, projecting they will actually increase by 3mbd between 2012 and 2035 (with much faith being placed, again, in Iraq, Brazil, and Kazakhstan).

Similarly, despite sharp year-on-year increases in upstream capital outlays since 2005, the IEA expects the profile of annual investments to be broadly flat over the next two decades, even though US shale oil – with its relentless drilling and capex treadmill – is central to its supply-growth forecasts over the next decade.

Finally, although the IEA projects rising prices in real terms over the next two decades, the upward trajectory is a very gentle one compared with the sharp ascent seen since 2005.

This, together with the fact that many of the world's largest oil companies have recently announced capex cutbacks even with prices at around USD110/bbl, suggests that prices may need to go higher – perhaps much higher – than the IEA is assuming.

However, whether the world economy could withstand higher price levels than those projected by the IEA without global GDP suffering is another question, especially as the Agency is already assuming a very aggressive reduction in global oil intensity in its base-case scenario.

All of which means, in our view, that there are numerous broad outcomes imaginable for oil prices and oil markets over the next two decades, with oil companies by no means assured a smooth ride even under a scenario of sharply higher prices.

With this in mind, we will now take a more detailed look at potential future price scenarios, and the implications of these scenarios with regard to oil companies' investments.

Pricing scenarios and future capex risk

As we saw above the upstream oil industry's capital-productivity ratio has been falling for the last three years, and looking more closely at the majors, it can be seen that in recent times their capital productivity has been declining even more sharply than that of the industry as a whole. This is why most of them have announced cuts to their capex budgets since the beginning of the year.

If all of this were not evidence enough of the severe capital-productivity crisis now gripping the industry, then the world's largest oil-producing company of all, Saudi Aramco, has recently provided further confirmation. The CEO of Saudi Aramco, Khalid A. Al-Falih, recently stated that rising costs and geo-political risks are threatening timely investment in new upstream developments, and that this could lead to a future supply shock given the need to replace declining output from ageing conventional fields over the next two decades.

What is so striking about the recent capex cuts announced by most of the majors and some of the NOCs, and now this recent intervention by the CEO of Saudi Aramco, is that they demonstrate that the IEA's warning about the risk of insufficient investment in the 2020s as flagged in its *World Energy Investment Outlook* in June is already obsolete. In other words, the risk of insufficient investment having an impact on future oil supply is not only about Middle Eastern OPEC countries delaying the ramp-up in their investments from 2020 onwards.

On the contrary, the scaling back of capex by the majors indicates that the risk of insufficient investment is already here, and hence the impact on supply is likely to be felt long before the early 2020s.

Against this backdrop, what is the likely outlook for oil prices over the medium-to-long term, and what are the prospects for the oil majors regarding improving their capital-productivity ratio and avoiding the risk of stranded assets on new investments? In this concluding section, we outline three broad scenarios for future oil prices and briefly consider the prospects for the oil majors as a group under each of these scenarios. Our aim here is not to look at the prospects for individual companies, but rather to suggest how best they might respond strategically to the unprecedented challenges they now face as a group.

Informing our pricing scenarios is the paradox at the heart of the IEA's macro assumptions we reviewed above. On the one hand, the world's major industrialised economies are still clearly struggling to return to the kind of sustainable growth trajectories they were on for most of the post-war period, despite the best efforts of policy-makers and central bankers. With oil prices averaging over USD100/bbl for the last four years, we think this must, in part at least, be attributable to high oil prices. The world, and especially the industrialised world, is finding it hard to grow with oil prices above USD100/bbl.

On the other hand, it is clear from the capex reductions announced by many of the world's largest oil companies in recent months that if they are struggling to justify marginal new investments with prices at USD108/bbl (the average price in Q1 of this year, when most of these capex cuts were announced), then it is hard to see how the oil supply can grow with prices below USD100/bbl.

This paradox means that there are many conceivable future pricing scenarios, and that the majors need to prepare for all eventualities and plan their new investments accordingly.

We limit ourselves here to looking at three broad scenarios:

- **High-price scenario:** The logical conclusion of our analysis is that oil prices will need to go higher over the mid-to-long term in order to incentivise the investment needed to bring in the supply the IEA expects. In our view, the IEA's trajectory of only modestly increasing prices is inconsistent with the supply growth it is forecasting.
- **Flat-price scenario:** This has been what has actually happened in the oil market since 2011, and, in fact, it is effectively what the IEA is assuming will happen all the way out to 2020. After all, the IEA's 2020 real-terms price projection is USD113/bbl in 2020, which was the average price over 2011 and 2012.
- **Low-price scenario:** Although in our view a low-probability scenario, the risks that could bring about a prolonged period of depressed oil prices are a binding global climate deal to limit GHG-emissions (and hence demand for fossil fuels), and the threat of global deflation.

In our view, the most likely of these scenarios in practice is the high-price scenario, and in principle, this is the most positive scenario for the majors. Ultimately, however, even under a high-price scenario, we see asset-stranding risk for the oil industry. This is because if prices end up rising more sharply than the IEA's base-case trajectory, this will likely raise serious questions about affordability and thereby only increase the incentive to invest in alternative energy sources, not least renewable technologies.

In particular, we think the single biggest risk to the oil majors is posed by the potential for electric vehicles taking a much larger share of the global transport market than the IEA and the oil industry itself are currently assuming. In this respect, China is the key, as: 1) the single largest source of demand growth in the NPS over 2013-35 is the Chinese transportation sector; and 2) China has two very big incentives to accelerate the take-up of EVs over the next two decades: first, in order to minimise its dependence on oil imports, and second in order to address rising concerns over air pollution. As a result, if China decides to put in place a coherent strategic policy framework to accelerate the take-up of EVs, the IEA's current demand projections for 2035 will likely have to be revised sharply downwards.

To illustrate the threat posed to future oil demand by the increasing competitiveness of renewable-generated electricity and the potential this has to revolutionise the market for private vehicles, we here consider the Energy Return on Capital Invested (EROCI) for a potential outlay today of USD100bn. How much energy would USD100bn purchase if invested in oil on the one hand, or in solar PV and wind energy on the other?

The answer to this question depends greatly on the oil price assumed, but what is striking is that even using today's economics for oil and renewables we think a compelling case for a much more rapid commercialisation of EVs over the next two decades can be made than either the IEA or the oil industry is assuming. In particular, if we focus on the net energy derived for powering cars from oil versus renewable-generated electricity on a life-cycle basis, we find that already USD100bn invested in wind would yield more energy than

USD100bn invested in oil at USD75/bbl and above, with solar competitive against oil already on this basis at prices of USD100/bbl and above.

Of course, there remain huge infrastructure challenges to be overcome – and paid for – if EVs are to realise their potential over the next two decades. However, our analysis suggests that, as the net energy yield over the full life-cycle of renewables versus oil will only continue to improve over the next 20 years, the competitive advantage could shift decisively in favour of EVs over oil-powered cars in the next two decades.

This is even before we begin to take account of the political tensions that are likely to make security of supply an increasingly important issue going forward, so adding further impetus to the deployment of renewable energy in import-dependent countries.

If we are right, the implications would be momentous, as it would mean that the oil industry faces the risk of stranded assets not only under a scenario of falling oil prices brought about by the structurally lower demand entailed by a future tightening of climate policy, but also under a scenario of rising oil prices brought about by increasingly constrained supply conditions.

And if this sounds far-fetched, then the speed with which the competitive landscape of the European utility industry has been reshaped by the rollout of wind and solar power – and the billions of euros of stranded generation assets that this has given rise to – should be a flashing red light on the oil majors' dashboard.

Against this uncertain backdrop, and with up to USD200bn per year in potential upstream investment among them over the next decade,⁴⁴ we think the majors should be asking themselves whether it makes sense to plan on replacing lost output from their existing projects on a barrel-for-barrel basis, or whether in fact they should be reducing their capital allocation to higher-cost new projects (i.e. those requiring >USD100/bbl), and looking instead to invest the money thus freed up in renewables (we also note that the higher-cost new projects are almost by definition the most carbon-intensive ones).

This would enable them to become the Energy Majors of the future rather than ending up as the Oil Majors of the past.

The high-price scenario: not a panacea for the majors

We have long held the view that, other things being equal, oil prices higher than those assumed by the IEA will be necessary to bring on the new supply that the Agency projects will be needed over the next two decades, and the oil industry is obviously counting on this as well.

However, we do not think that higher prices will necessarily protect the oil industry from the risk of future asset stranding. This is because higher oil prices raise the question of affordability and also increase the incentive to switch to alternative energy sources, not least renewables, particularly as renewable-energy costs are falling rather than rising.

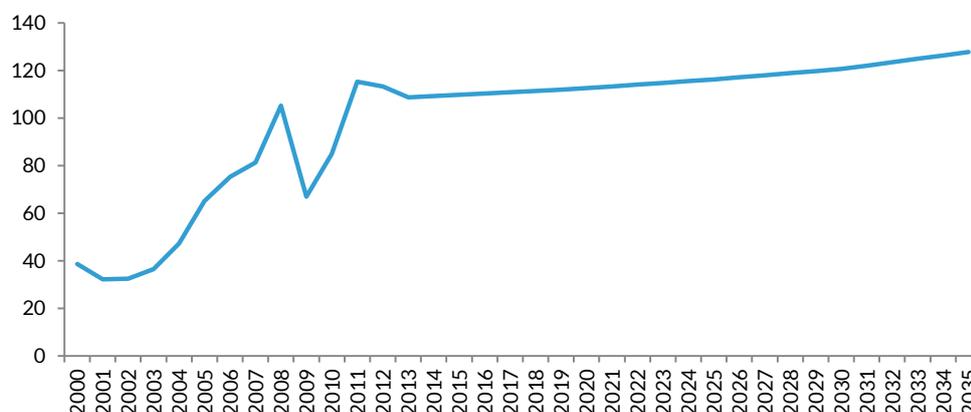
⁴⁴ See Carbon Tracker's recent report – [Oil & Gas Majors: Fact Sheets](#) – for more on the potential capex plans of the individual majors.

We think IEA's demand and supply projections are too optimistic

Chart 64 shows the actual evolution of the Brent crude oil price over 2000-13, together with our linear interpolation of the IEA's base-case price projections over 2013-35 as per the NPS in the 2013 WEO. The striking feature of Chart 64 is how much flatter the shape of the price curve is over the next two decades than it has been in actuality since 2000.

This would be understandable if there were strong grounds for believing that the IEA's projected growth in the oil supply are likely to be easily achieved. However, and as explained in our detailed analysis of those projections above, we think that if anything the opposite is the case. Indeed, we think there are numerous reasons for supposing that the IEA's projections for both demand and supply at the price levels it assumes over 2013-35 are too optimistic.

Chart 64: Brent crude oil price, act. 2000-13, IEA projections 2014-35 under NPS in 2013 WEO (USD/bbl)*



Source: BP (2000-13), and Kepler Cheuvreux estimates based on IEA data from the 2013 WEO (© OECD/IEA), 2014-35; *Historic prices shown are in constant 2013USD, IEA projections are in constant 2012USD.

The first reason relates to the demand side of the equation. As we discussed above, the IEA's assumptions with regard to the efficiency improvements that can be achieved over the next two decades are very aggressive.

As we saw, the IEA assumes a reduction in oil intensity over 2013-35 of 50%, which is some one-and-a-half times greater than the reduction achieved over the comparable timeframe of 1990-2012. The IEA explains its assumption thus (2013 WEO, p.509):

"The increase in vehicle ownership, industrial activity and number of dwellings would imply, other things being equal, a growth in oil demand over the level in 2012 of 46mbd. But anticipated efficiency improvements, resulting from both policy interventions and technological improvements, curb 45% of this consumption growth while delivering the same level of service. Fuel switching also plays an important role, displacing almost 12mbd of oil consumption."

We do not say that this will not be possible to achieve, simply that it is a very ambitious projection.

This means that if the world cannot achieve such a reduction in oil intensity then prices will have to rise by more than the IEA is assuming in its base case in order to stimulate the extra supply necessary.

And yet even assuming this huge reduction in oil intensity can be achieved, the IEA's base-case projection for growth in the oil supply still looks very optimistic to us. There are four main reasons for this in our opinion.

First, there is the fact that the IEA's supply-growth projections depend overwhelmingly on five countries, three of which we think warrant scepticism about their ability to deliver on the IEA's expectations of them. As we saw above, the five countries in question and in order of projected supply growth are Iraq (+4.9mbd), Brazil (+3.8mbd), Canada (+2.3mbd), Kazakhstan (+2.1mbd), and the United States (+1.7mbd).

Of these five, we think Iraq, Brazil, and Kazakhstan represent big questions about their ability to deliver the full extent of these supply increases (in the case of Iraq the obvious problem is the current political turmoil and sectarian violence, while in the cases of Brazil and Kazakhstan it is the consistent failure to deliver on production targets in recent years).

Second, and as we discussed above, the IEA's projections for the US rest on the surge in US shale-oil production continuing until 2021 with output trending down only very gently thereafter.

The IEA's projections mirror those of the US EIA and many industry players, market analysts, and consultants. However, there is also, as we saw above, a much less optimistic view that holds that US shale-oil production will peak in the 2015-17 timeframe at a lower level, and decline much more rapidly thereafter than the IEA is assuming.

We do not judge between these two views here, but there is no dispute over the exceptionally high decline rates of shale-oil wells and the drilling-treadmill effect this gives rise to, and this is why we questioned the IEA's projected trend for North American upstream capex in Chart 16 above. For the oil to keep flowing there will have to be relentless drilling and this means relentless capex. In short, we think the IEA is underestimating the capex requirements associated with its US oil-supply growth projections.

Third, we find the IEA's projections for net exports of crude oil out to 2035 even more optimistic than their projections for production. This is because, as we saw above, the Agency's export projections rely even more heavily on Iraq, Brazil, and Kazakhstan than do their projections for supply (remember that the US is projected to remain a net importer out to 2035 so its assumed increase in supply out to 2035 does nothing to increase exports).

Finally, the upstream capex profile assumed by the IEA over 2013-35 is much flatter than the profile of the last few years, which, as we saw above, have been characterised by sharp year-on-year increases since 2005.

In our view, these optimistic assumptions on both the demand and the supply side mean that there is absolutely no room for slippage on any of the IEA's key assumptions over 2013-35 if prices are indeed to be contained the way the IEA projects in its base-case forecasts (Chart 64).

And yet, as we have seen, there is already slippage occurring vis-a-vis one of the IEA's key assumptions, namely industry capex, and in our view these cuts in industry capex are bullish for future oil prices for two main reasons: 1) lower capex today implies a slower rate of future replacement for current production lost to ongoing decline, and hence greater difficulty in meeting the IEA's future demand-growth forecasts; and 2) if so many of the world's major oil companies do not feel confident about maintaining their capex levels with prices still at all-time record highs, this suggests that prices will have to rise further in future for investment to revert to a track consistent with meeting the IEA's forecasts.

Oil industry counting on higher future oil prices to bail it out

Saudi Aramco's CEO, Khalid A. Al-Falih, warned recently about the huge amount of investment that will be required to bring in new oil supply over the next two decades (a full transcript of Al-Falih's comments is available [on the Saudi Aramco website here](#)).

As Saudi Aramco is the world's largest oil company by both output and exports of crude oil, we think Al-Falih has a unique vantage point and that his comments are therefore worth paying close attention to. His message is very clear: massive upstream oil investments will be needed to meet future supply requirements, and this entails a need for higher prices.

Al-Falih said that *"rising costs and cost overruns are dragging many projects—and no one knows this better than those of you in the offshore industry, with project price tags in the tens of billions of dollars, and with significant financial and technical risks"*.

He also said that *"even at Saudi Aramco, project costs have roughly doubled over the last decade despite deploying cutting-edge technologies and applying our robust project-management systems to mitigate cost escalation."*

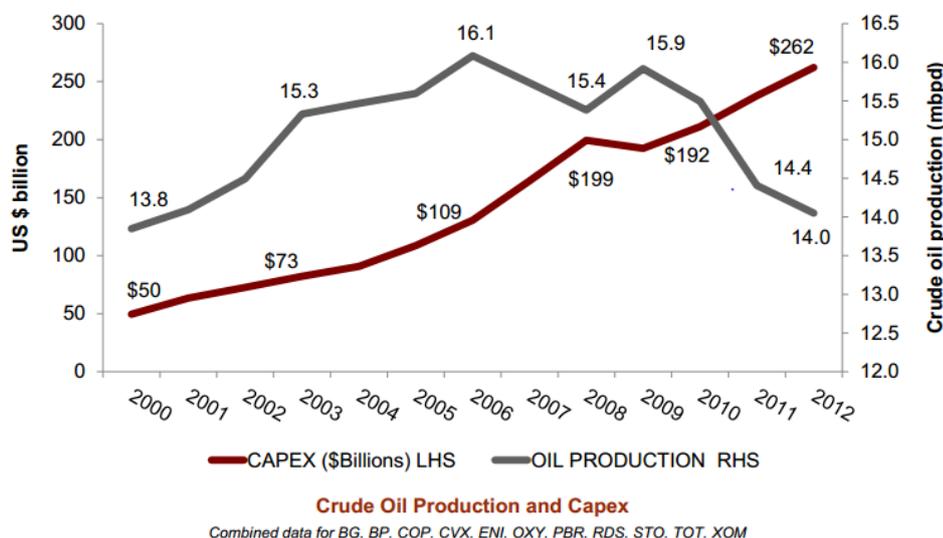
However, while acknowledging that the industry's rising cost base and capital intensity have led to recent capex cuts, Al-Falih also emphasised that massive investments would continue to be necessary to grow the supply needed to meet future demand projections, and concluded that this would underpin long-term prices:

"Many developed fields around the world are becoming increasingly mature, and offsetting their observed decline is not a trivial challenge. To meet forecast demand growth and offset this decline, our industry will need to add close to 40mbd of new capacity in the next two decades. [...] To tap these increasingly expensive oil resources, oil prices will need to be healthy enough to attract needed investments. The other side of the same coin is that long-term prices will be underpinned by more expensive marginal barrels."

In our view, Al-Falih's comments underline again the dilemma now facing the oil majors. On the one hand, their declining capital productivity over the last few years has led them to cut capex. On the other hand, if the oil majors want to remain key players in the industry, cutting capex can only be a short-term solution. After all, the IEA actually raised its projections for the upstream capex required out to 2035 in June.

The sheer scale of the crisis that the oil majors face in terms of their capital productivity is well illustrated by Chart 65, which was used by Steve Kopits in a very informative presentation at Columbia University earlier this year.⁴⁵

Chart 65: Selected listed IOCs' upstream capex and crude oil production



Source: Douglas Westwood from Bloomberg via Phibro Trading LLC

The chart shows the upstream capital investment and the crude oil production of 11 major international oil companies (the seven oil majors plus BG, Occidental Petroleum, Petrobras, and Statoil) over 2000-12.

As can be seen, the combined crude oil production of these 11 companies has been on a downward trend since 2006, falling from 16.1mmbd that year to 14mmbd in 2012, while their combined upstream capex has continued to rise relentlessly over the same period.

So long as prices were rising fast enough, rising capex could be justified even in the face of declining production, but with prices flat-lining since 2011 the majors have come under increasing pressure to return more cash to shareholders, and that is precisely why the majors are now cutting back on capex over their updated capital-budgeting horizons.

All of which means that Al-Falih is surely right, when he says that higher oil prices will be necessary to incentivise the investments in new supply needed to replace the declining production from ageing fields.

Notwithstanding his comments on supply, though, Al-Falih's view on oil markets is ultimately anchored in his bullish view of long-term demand prospects:

⁴⁵ It is well worth taking the time to study Kopits's [full presentation](#), and to watch the [detailed exposition of this presentation](#) that he gave to Columbia University's Center on Global Energy Policy.

“Despite some marvellous advancement by various hybrids and pure electrics, petroleum-based liquids will remain the fuels of choice, holding between 80 and 90 percent of transport market share in 2050 depending on the scenario considered. And while the bulk of demand will be concentrated in transport, petrochemicals will also contribute more, by growing at rates faster than GDP.”

Ultimately, it is this bullish view on demand that makes Al-Falih confident that the industry – driven by market forces pushing up prices – can overcome the “significant hurdles” he acknowledges it currently faces, and to sign off by saying that “rather than storm clouds, I look forward to even brighter days ahead.”

As we saw above in our review of the assumptions in its New Policies Scenario (2013 WEO), this demand-driven view is also very much the approach adopted by the IEA in its modelling of future energy and oil markets.

Moreover, we think that many in the oil industry and among the oil majors share the view of demand-led growth pushing up prices to the level needed to ensure the necessary investments in commensurate supply.

As a result, it is not surprising to find that the published projections for energy and oil markets by the majors are generally quite well aligned with those of the IEA’s NPS.

For example, ExxonMobil in its publication [The Outlook for Energy: A View to 2040](#) projects growth in oil demand of 0.7% per year over 2010-40, which is very close to the 0.6% assumed by the IEA over 2013-35 in its NPS. And like that of the IEA, ExxonMobil’s methodology for modelling future energy trends starts from GDP-derived demand-side projections, which then assume both the availability and affordability of the supply to meet the demand projected.

This methodological approach is clear from its report [Energy and Carbon – Managing the risks](#) (p. 3):

*“The global economy will grow as the world’s population increases, and it is our belief that GDP gains will outpace population gains over the outlook period, resulting in higher living standards. **Assuming sufficient, reliable and affordable energy is available**, we see world GDP growing at a rate that exceeds population growth through the outlook period, almost tripling in size from what it was in 2000” (emphasis ours).⁴⁶*

Shell’s alignment with the IEA methodology and the IEA’s NPS projections is even more explicit, as is clear from its [open letter on stranded-asset risk](#) published in May (p. 4):

“Shell regularly publishes its view on the future energy landscape. In our major publications and in our shareholder material, we show a single projection of future energy demand by production/energy technology. This view takes into account energy-efficiency gains, declining costs for early-stage technology, and is not a ‘static’ view of the world. (...)

⁴⁶The reason for our emphasis here is that we think the assumptions regarding both the availability and affordability of the future oil-supply growth posited by the IEA in its NPS (which, as just mentioned, is very close to ExxonMobil’s own projections) are open to serious question. We have already explained above the reasons why we think the IEA’s supply forecasts are optimistic, and we discuss below the question of affordability if prices do ultimately need to rise above the IEA’s base-case trajectory in order to bring on the supply required to meet its demand projections.

It is important to note that this aligns closely with various third-party viewpoints such as the IEA's New Policies Scenario (emphasis ours).

In short, the IEA and the key players in the oil industry itself – whether it be NOCs like Saudi Aramco, or the majors like ExxonMobil and Shell – all adopt a demand-driven view of the future and assume that for a given level of demand and a given level of energy-efficiency improvements over time supply will always come through (the only question is at what price).

We have already explained why we think the IEA's base-case price projections are too low to incentivise the supply growth assumed in the NPS, and the words of Saudi Aramco's CEO and actions by the majors since the beginning of this year in the form of their capex cutbacks indicate that they take the same view.

However, we think the kind of prices that might ultimately prove necessary to incentivise the supply assumed by the IEA under the NPS could raise serious questions about affordability.

As a result, the question is not so much whether higher oil prices will be necessary to incentivise future supply growth – as explained, we completely agree with this view – but rather at what point higher prices will drive the substitution of oil in the global energy mix.

Of course, it is very difficult to know on an *a priori* basis what the “right” trajectory for prices is to meet the IEA's base-case supply projections, but one way of looking at this is to take the delayed-investment scenario set out by the IEA in its *World Energy Investment Outlook* published in June.

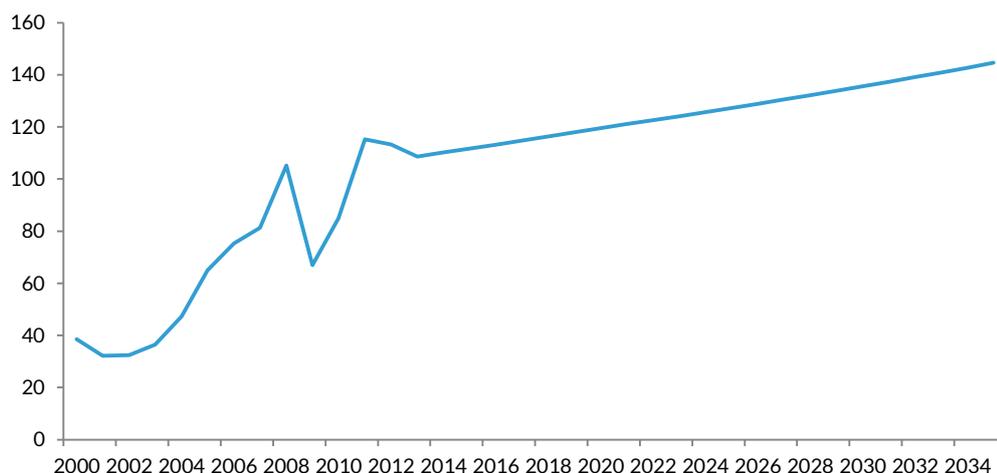
As explained above, in the *WEIO* the IEA does make reference to the risk that investment might not come through in line with the NPS assumptions. Specifically it sees the main risk being “*uncertainty over the right moment for Middle East producers to boost investment in anticipation of a plateau and eventual fall in non-OPEC supply*”. And if Middle-East OPEC countries do delay investments too long, the IEA sees prices being some USD15/bbl higher than under the NPS (*WEIO*, p.69):

“The oil price in the Delayed Case is pushed higher as the implications of the investment shortfall are felt in the market, with the price peaking at USD130/bbl in real terms in 2025 – some USD15/barrel higher than in the New Policies Scenario.”

Yet with the majors already cutting capex and thereby delaying investment, it seems reasonable to us to assume that in order to stimulate the necessary investment to meet the IEA's base-case supply projections prices might in reality need to be at least USD15/bbl higher in real terms not only in the 2020s but across the entire forward curve.

Coincidentally, this would produce a forward curve very similar to that which a linear interpolation of the IEA's price projections under its CPS gives.⁴⁷ Under this scenario, the oil price reaches USD120/bbl in real terms by 2020, and USD145/bbl by 2035 (Chart 66).

⁴⁷ Unlike the NPS, the Current Policies Scenario as set out in the 2013 WEO assumes no further changes in energy policy beyond those already implemented. This results in significantly higher demand for oil under the CPS than under the NPS, with projected 2035 oil consumption of 111mbd compared with 101mbd under the NPS. However, we think the oil majors' capex cuts indicate that the price trajectory in the CPS is actually more consistent with the supply projections in the NPS.

Chart 66: Brent crude oil price, act. 2000-13, IEA projections 2014-35 under CPS in 2013 WEO (USD/bbl)*


Source: BP (2000-13), and Kepler Cheuvreux estimates based on IEA data from the 2013 WEO (© OECD/IEA), 2014-35; *Historic prices shown are in constant 2013 USD, IEA projections are in constant 2012 USD.

This price trajectory seems more consistent to us with the kind of levels needed for the majors to justify the higher-cost investments they are now cutting back on.

However, if and when prices were to move higher and follow the kind of trajectory shown in Chart 66, we think this would simply present another challenge to the industry: could the world afford the extra expense entailed by such a price trajectory?

Affordability, falling cost of renewables threaten long-term oil demand growth

The paradox at the heart of the oil market is the tension between the oil price required by the world economy to grow healthily on the one hand, and the oil price needed by the industry to grow the oil supply on the other.

Despite the unprecedented efforts of central banks since 2009, the world's major industrialised economies are still struggling to return to the kind of sustainable growth trajectories they were on for most of the post-war period. With oil prices having averaged over USD100/bbl for the last four years, we think this must, in part at least, be attributable to high oil prices. On the other hand, it is clear from the majors' capex reductions in recent months – and from Al-Falih's recent comments quoted above – that the industry will struggle to grow the oil supply unless prices are at least above USD100/bbl.

As we saw above, the IEA justifies the difference between its rising trajectory for real oil prices out to 2035 on the one hand, and its robust CAGR for global GDP of 3.6% over 2013-35 on the other, by assuming that the oil intensity of the world economy will fall by 50% over this period.

We have already indicated that this looks a very ambitious assumption to us, as do the IEA's assumptions on oil-supply growth out to 2035. However, if, as we think, this means that prices are likely to rise by more over time than the IEA is assuming, what does this mean in terms of affordability?

In other words, will the world economy be able to cope with oil prices on the kind of trajectory shown in Chart 66, or will this lead to lower GDP growth than the IEA is projecting in its base case, and hence to lower demand, as the way of squaring the circle?

One of the most interesting discussions of this very complicated question is to be found in [an IMF working paper from 2012](#) entitled *The Future of Oil: Geology versus Technology*. This paper looks in detail at the relationship between GDP, oil prices, and the oil supply over time with a view to developing a predictive model out to 2020 for all three variables.

As with our own analysis above, the IMF paper emphasises the change in the structure of the oil supply since 2005, and the fact that despite the very sharp increase in oil prices since 2005 the growth in the overall supply has been very modest by historical standards. It therefore concludes that prices will have to go much higher in order to stimulate continuing growth in supply.

Interestingly, the IMF paper's central case for oil-supply growth out to 2020 is very similar to that of the IEA's NPS, with output of 93.4mbd by 2020 versus the IEA's 92.8mbd. Meanwhile, its assumed CAGR in world GDP until 2020 is exactly in line with that of the IEA's NPS (4%). However, in order to grow the oil supply to 93.4mbd by 2020, the IMF paper projects a need for much higher oil prices than those projected by the IEA's NPS (*IMF Working Paper*, p. 15):

*"Our empirical results also indicate that, if the model's predictions continue to be as accurate as they have been over the last decade, the future will not be easy... **Our prediction of small further increases in world oil production comes at the expense of a near doubling, permanently, of real oil prices over the coming decade.**"*

On the face of it, this would suggest that while the IMF paper is much more bullish on prices than the IEA, it nonetheless sees the world economy coping well with this price shock. After all, the model developed in the IMF paper projects the same 4% compound growth rate world GDP to 2020 as the IEA's NPS.

However, the IMF paper comes with a very serious reservation as far as the future affordability of oil is concerned (*Ibid*, p. 14):

*"This negative GDP effect of higher oil prices is present in the model's forecasts for GDP growth, but (...) it is modest. This raises the question of whether future versions of the model should include nonlinearities in the output response similar to the nonlinearities in our oil-demand equation. **There is likely to be a critical range of oil prices where the GDP effects of any further increases become much larger than at lower levels, if only because they start to threaten the viability of entire industries such as airlines and long-distance tourism. If this is correct, the effect of real oil prices on GDP should be modelled as convex**"* (emphasis ours).

It then goes on to conclude (*Ibid*, p.16):

"We suspect that there must be a pain barrier, a level of oil prices above which the effects on GDP becomes nonlinear, convex. We also suspect that (...) a lack of availability of oil may have aspects of a negative technology shock. In that case the macroeconomic effects of binding resource constraints could be much larger, more persistent, and they would extend well beyond the oil sector" (emphasis ours).

Now as we explained above, we are not arguing that the rise in oil prices over the next decade will be anything as dramatic as the near doubling in real terms out to 2020 projected in the IMF working paper. But, then, nor do we think prices would have to rise that sharply in order to raise affordability issues either.

This is for two main reasons.

First, the IMF paper leaves open the question regarding the actual price level at which what it calls the “pain barrier” is reached in different sectors of the economy. As it says, though, some sectors such as the airline industry and long-distance tourism are clearly much more sensitive than others, and will therefore reach the “pain barrier” at lower prices than less oil-intensive sectors, thereby precipitating a knock-on effect on other sectors of the economy and hence on GDP.

Second, the impact of high oil prices is no longer simply a question of *absolute* affordability. In other words, whereas oil demand has in the past been relatively inelastic owing to the lack of substitutes (especially in transport), the rapid improvements in electric-vehicle (EV) technology and falling costs of renewable-electricity technologies means that in future the competitive threat to oil in transportation will increase. In other words, the question will in future also be more and more one of relative affordability, especially as – in contrast to that for oil – the cost curve for EVs and renewables will continue to fall.

And in this respect, the news that China is planning to ramp up its investment in EV infrastructure should be a flashing red warning light on the dashboard of the oil majors. We discuss this further below, when looking at the majors’ future capex and stranded-asset risks.

Conclusion on the high-price scenario

For all the reasons laid out above we think that oil prices will ultimately have to rise to higher levels than those envisaged by the IEA in order to encourage the investment needed for supply to meet the IEA’s base-case projections. We also think that if and when this happens, the question of both the absolute and relative affordability of oil will rise in importance.

And it is the question of oil’s future affordability relative to renewable-energy technologies – and the implications this has for the future competitiveness of EVs – that in our view means that oil companies will face a risk of assets becoming stranded even under a scenario of rising prices.

We discuss this further below when looking at future capex and stranded-asset risk by comparing the Energy Return on Capital Invested (EROI) of oil relative to solar and wind.

The flat-price scenario: what if prices remain stagnant?

As we have seen, after rising very sharply over 2005-11, oil prices have been flat in the last few years, albeit it at or close to all-time average highs. Is it possible, therefore, that the world economy has reached a new equilibrium, and that prices could remain in the range of USD100-USD120/bbl that we have seen over the last three years for the next two decades? And if so, what would be the implications for the oil majors?

In this context, the first point we would make is that to all intents and purposes the IEA's base-case trajectory for prices out to 2035 as set out in the NPS falls into this category. After all, as we saw above, in the NPS, prices are still only at USD113/bbl in real terms (2012 USD), which is exactly the level they have averaged for the last three years.

The second point to make is that for all the reasons explained above we think the IEA's base-case price trajectory is too low given how optimistic we find its supply projections, and that our view is supported by the majors' reducing their capex budgets in recent months. This suggests to us that as well as being an unlikely scenario, it is not one that the majors would welcome either: a prolonged period of stagnant prices over the next decade is clearly not what they are hoping for.

However, while in our view an unlikely scenario, it is possible to imagine circumstances in which the pricing dynamics of the last three years continue until 2020 and beyond. In this respect, the most likely factor supporting such a scenario would, in our view, be a positive surprise in the US shale-oil plays.

If technology advances were to outpace decline rates aggressively in the next few years then either: 1) shale-oil output might surpass the IEA's expectations; or 2) capex in these plays might be kept in check in line with the IEA's NPS forecasts (as explained above, we find the IEA's shale-oil capex forecasts too low to be consistent with its shale-oil supply forecasts).

Otherwise, the scope for a positive surprise elsewhere that might bring the IEA's price forecasts into line with its supply forecasts is in our view much more limited because we think the opportunities for rapid productivity gains in the more mature plays elsewhere in the world are much more restricted.

As far as the impact on the majors is concerned, they would not benefit greatly from a positive supply or capex surprise in the US shale plays in any case, as: 1) they have negligible exposure to US LTO themselves; and 2) to the extent that this might prolong the stagnation in prices over the rest of the decade it would also, other things being equal, prolong the low capital productivity they have been suffering from in recent years.

On the other hand (and perhaps the silver lining for the majors), it might be argued that this scenario would see a prolonged period of capital discipline during which the majors avoid investments in higher cost new projects and hence minimise their exposure to future stranded-asset risk.

The low-price scenario: the biggest risk for the oil majors

Even though we view this as the lowest-probability scenario of the three, there is nonetheless always scope for a major price shock to the downside. The real question, though, is not whether prices could fall sharply at some point in the next few years, but whether there is a realistic scenario under which they would both fall sharply and then stay at depressed levels for a prolonged period.

One such scenario would be that the world reaches a binding global climate deal to limit the increase in the average global temperature to no more than 2°C above pre-industrial levels. We have already analysed this scenario in depth in our previous report *Stranded Assets, Fossilised Revenues*, in which we concluded that under such a scenario the oil industry would

stand to lose USD19trn in revenues over the next two decades versus the IEA's base-case scenario.

Such a scenario would clearly imply a catastrophic outcome for the oil majors, but as we emphasised in our analysis in that report, we also think that at this stage such a deal is very unlikely to be forthcoming in the near future. This is because there are huge political challenges to be overcome to arrive at such a deal.⁴⁸

An alternative scenario that could lead to prolonged low oil prices would be global deflation. The experience of Japan in the last two decades illustrates that deflation has not yet been consigned to the economic-history textbooks, and concerns have periodically been raised about the threat of deflation for the world economy since the global financial crisis and ensuing recession in 2008-09.

To the extent that such a scenario would reduce economic activity and the demand for oil, prices would likely be at depressed levels for a long period, which we think would be very difficult for the majors to cope with.

Apart from these two scenarios, though, we do not see a big risk of prices falling below say USD85/bbl for more than six months. This is because of OPEC's need to keep prices closer to USD100/bbl, as well as the change in the industry's cost structure in recent decades, combined with the need for massive amounts of capital investment every year just to offset ongoing natural decline and thus maintain output at current levels.

As we saw in early 2009, when prices fell to USD35/bbl after having hit USD147/bbl only seven months earlier in the summer of 2008, prices corrected sharply very soon afterwards.

As a result, any demand shock would in our view either have to be of a prolonged deflationary nature or a long-term structural behavioural change induced by climate policy in order to keep prices at depressed – and what for the majors would be distressed – levels for a prolonged period.

Conclusion on pricing scenarios

We think the most likely scenario over the next two decades is that prices will ultimately have to rise and remain above the trajectory set out by the IEA in its base-case scenario, and intuitively this should be the most favourable scenario for the oil majors.

However, we think that a scenario of rising and sustained high oil prices over the next two decades would bring its own risks for the oil majors, and in concluding this report it is to an overview of this risk that we now turn.

⁴⁸ That said, and as we emphasized in *Stranded Assets, Fossilised Revenues*, the fact that a meaningful binding global climate deal will be very difficult to achieve within at least the next five years does not mean that the oil industry can afford to ignore the possibility of such a deal being reached beyond that timeframe. The direction of travel in global climate negotiations is now clearly established and the pressure for a binding deal will therefore only increase over time. This is why we think oil companies should already be very cautious about investments in new high-carbon projects, as these would be most at risk of stranding under a future binding climate deal.

Future capex at risk of stranding even with higher oil prices

As we explained in our report *Stranded Assets, Fossilised Revenues*, the risk of asset-stranding for the oil majors is not a near-term threat but rather one that looms over the investments they will make over the next decade and beyond to replace declining production from existing assets beyond 2025.

In our view, sustained higher oil prices will be no guarantee against asset-stranding beyond 2025, as the relative economics of oil and renewables are moving decisively in the latter's favour, with clear implications for the large-scale commercialisation potential of EVs.

A reminder: stranded-asset risk relates to the period beyond 2025

Whether we are considering the risk of stranded assets under a scenario of low or high oil prices, we would emphasise upfront that, as the vast majority of upstream oil capex is to replace declining output from existing fields, the real risk of stranding is not in the next decade, but thereafter. The IEA makes the point with specific regard to the risk of asset stranding from a potential future tightening of climate legislation in the *World Energy Investment Outlook* (p. 86):

"(...) investment in upstream projects is insulated, to a degree, against the risk of becoming stranded by climate policies, because output decline is a natural phenomenon for all oil and gas fields and these declines are steeper than any conceivable rate of policy-induced decline in demand. Nonetheless, once a credible path towards decarbonisation is in place, projects at the higher end of the supply cost curve, particularly those that feature both long lead times and relatively high carbon-intensity, face significantly higher commercial and regulatory hazards."

As explained in our report *Stranded Assets, Fossilised Revenues* (see p. 6-7, and p. 27-30), this is very much in line with our own reasoning on this point, but we would extend the logic to cover the risk of asset-stranding from *higher* oil prices as well. This is because we think it will take a decade or more for sufficient investment in EV infrastructure to be made in order for EVs to make the kind of inroads into oil demand that would threaten the viability of future output from the high-cost, high-carbon investments that the oil majors will make over the next decade.

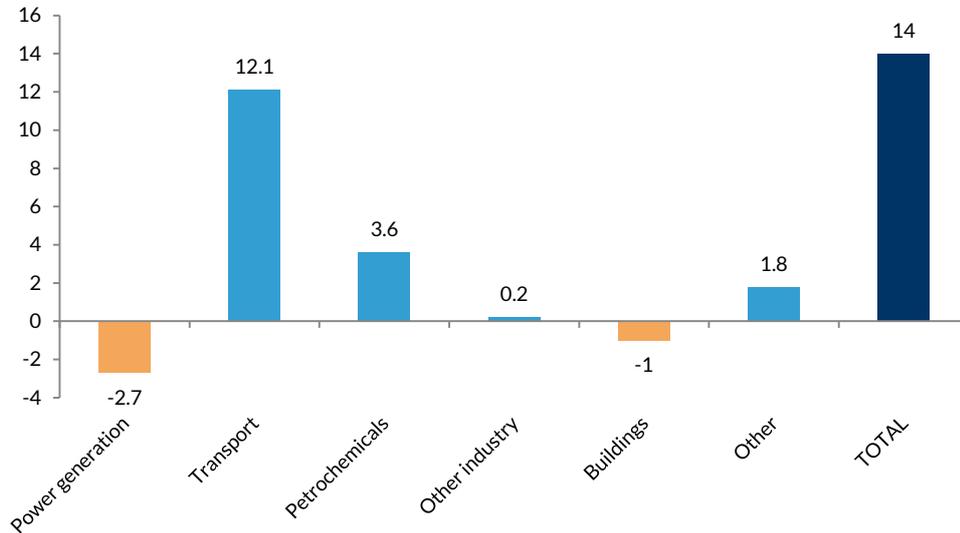
In short, when considering the risk of future asset-stranding for the majors, we are talking about the timeframe beyond 2025 and referring not to projects that are already producing but those resources already discovered by the majors but not yet developed.

With that in mind, we now consider the main drivers of oil demand over the next decade and how the growth they promise could be threatened by the improving economics of renewables relative to oil.

Transport and China are main drivers of future oil-demand growth

Chart 67 shows the breakdown of projected oil-demand growth in the IEA's NPS over 2013-35.

Chart 67: Projected changes in oil consumption by sector 2012-35 in IEA's NPS (mbd)

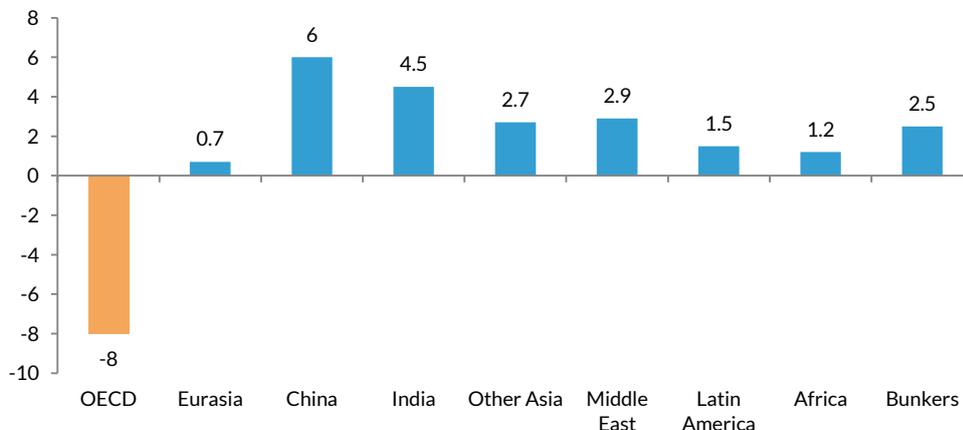


Source: Kepler Cheuvreux from IEA, 2013 WEO (© OECD/IEA)

Out of total growth of 14mbd, the IEA projects that 12mbd of this will be for transport, of which the majority would be road transport (3mbd for passenger vehicles and c. 5mbd for road freight, including light commercial vehicles).

Chart 68 then shows the breakdown of projected demand growth by region, and as can be seen China is the single largest driver on this basis, accounting for 6mbd out of the 14mbd total increase, with India close behind at 4.5mbd.

Chart 68: Projected changes in oil consumption by region 2012-35 in IEA's NPS (mbd)



Source: Kepler Cheuvreux from IEA, 2013 WEO (© OECD/IEA)

So, China on its own accounts for 43% of projected demand growth, and China and India together 75% (10.5mbd out of a total increase of 14mbd).

Taking Charts 67 and 68 together this means that rising Chinese appetite for oil for use in transportation is the single-largest source of demand growth for oil over 2013-35 (c. 4.8mbd out of 14mbd, or c.30%), and that the combined increase in Chinese and Indian oil demand for transportation accounts for c.60% of the IEA’s total projected growth in demand (c. 8mbd out of 14mbd).

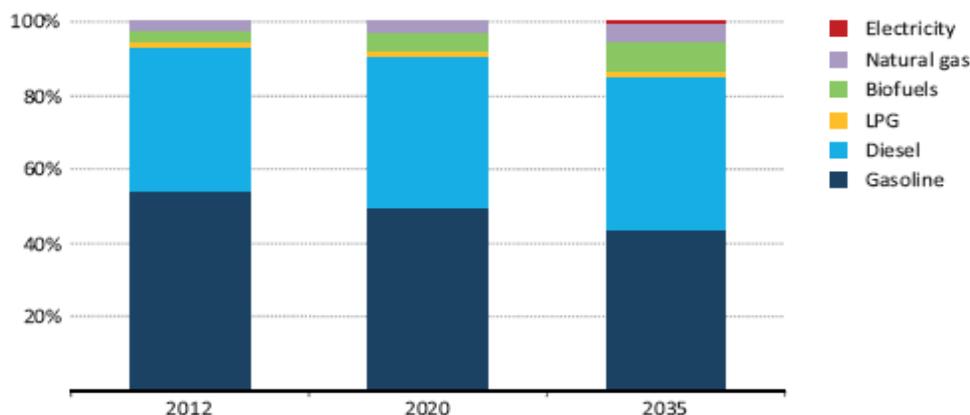
Of course, not all of the projected transportation-related growth in China and India will be in areas where electric-powered engines will be feasible or commercially viable even within the timeframe of the next two decades (for example, aviation and marine bunkers).

However, that still leaves a large amount of projected demand growth in China and India between 2013 and 2035 that would be vulnerable to a faster deployment of EV technology than currently envisaged by the IEA. We estimate that of the 8mbd of combined transport-related growth, 4mbd would be either for cars (passenger light-duty vehicles, or PLDVs as the IEA’s more specific term has it) or light commercial vehicles.

This is a very considerable chunk of the total 14mbd demand growth over the next two decades, so the question is whether this number already reflects a significant take-up of EVs (and therefore represents a robust projection), or whether it does not assume a meaningful take-up of EVs and is therefore vulnerable to downward revision in the event that EV costs come down much more quickly than expected.

Chart 69 shows the answer: the IEA sees only very negligible growth in EV deployment over the next two decades “in view of the continuing difficulties in bringing to market commercially attractive models” (2013 WEO, p. 520).

Chart 69: Projected fuel mix in road-transport energy demand out to 2035 in the NPS



Note: Shares for oil products are calculated on a volumetric basis; the contributions of other fuels are shown as equivalent volumes of the oil product that they displace.

Source: IEA, 2013 WEO (© OECD/IEA)

It then goes on to say (Ibid, p. 521) that “a large improvement in the performance of batteries and a big fall in their price could lead to a rapid take-off in demand; but without these advances, EVs are likely to remain a niche market”. As a result, the IEA sees EVs having only a very marginal impact on oil demand even by 2035 (Ibid):

*“In the NPS, global EV sales reach only about 500,000 vehicles in 2020 – far below the aggregate of targets of 7m around the world – and less than 4m in 2035. **The projected oil savings from EVs globally total around 35kdb in 2020 and about 235kdb in 2035 – far smaller than those from biofuels or natural gas**” (emphasis ours).*

In short, the IEA’s projections for transportation reflect the view that oil-derived fuels will remain dominant all the way out to 2035 (as shown in Chart 69, biofuels and natural gas take increasing market share after 2020 but diesel and gasoline still have over 80% by 2035), and that EVs will barely register as a threat to oil demand even in two decades’ time. This means that the IEA’s oil-demand forecasts are vulnerable to downward revision in the event that the global rollout of EV’s is quicker than it expects. And in this respect, China will be key.

China’s plans to invest in EV infrastructure are straw in the wind

[Bloomberg recently reported](#) that China is considering a USD16bn investment in EV charging stations to help boost demand for electric cars. This comes after the Chinese government has already put in place tax breaks for EVs, and mandated that Government ministries and departments purchase such cars for their official fleets. It also comes as China’s public policy more generally is now starting to engage much more seriously with the public-health issue of air pollution.

As a result, we think it is reasonable to expect further policy incentives for renewable energy, including EVs. Given that a major policy shift towards incentivizing EVs could have a significant impact on China’s future demand growth, we think this should at the very least be a on the radar screen of the oil majors in terms of scenario planning and future project appraisal.

Indeed, this is all the more the case given that the economics of solar PV and wind energy are already more competitive with oil than is apparent from looking only at the gross energy return on investment.

And the point is, when it comes to the economics of fuel for cars, what really matters is the net energy return on investment.

EROI of oil vs. renewables: how much energy does USD100bn of capex buy?

As our analysis of rising capital intensity above showed, one of the most striking features of the upstream oil industry in recent years has been the astronomical increase in upstream costs, and as explained, we expect costs for the oil industry to continue rising in real terms out to 2035.

Meanwhile, and in stark contrast, the renewable-energy industry has achieved tremendous cost reductions in recent years, and we think that this trend will also continue over the next two decades as further technological improvements occur and economies of scale are further exploited. Indeed, the relative economics of oil and renewables have already moved

to such an extent that comparing the amount of energy yielded for a given amount of capital invested offers some very interesting insights.

As a result to conclude our analysis in this report, we here consider the concept of energy return on capital invested (EROCI) for oil and renewable-electricity sources (solar PV as well as onshore and offshore wind). How much energy does an outlay of USD100bn buy if invested in oil or solar PV, or wind? And how much energy will USD100bn yield in 2020 and 2035 if our assumptions about the future trend in oil prices prove correct and if, as we expect, the cost of renewables continues to fall?

Below, we carry out some EROCI calculations for these different energy sources assuming that the USD100bn invested covers the full breakeven cost of new projects. For oil, this encompasses all capital and operating costs, plus any royalties payable. For renewables, this encompasses all capital and operating costs.⁴⁹

In each case, we analyse the gross energy yield and the net energy yield of investing USD100bn with no reinvestment taken into account. In order to calculate net energy yield, we assume that the energy is required for powering cars and light commercial vehicles, and this has a very big positive impact on the energy economics of renewables relative to oil.

We make this assumption for the reasons just explained above, namely that the biggest threat to oil demand in the IEA's base-case projections is greater EV penetration in China and India than either the Agency or the oil industry are currently assuming. As a result, it is crucial to understand how competitive renewable electricity is with oil already – and how much more competitive it might become in the future – when used to power EVs versus oil used to power conventional vehicles.

EROCI today: how much energy does USD100bn yield in 2014?

Looking at the EROCI of USD100bn in capital invested, we first consider the gross energy yielded. This is simply the total amount of primary energy before it is converted into useful energy in final consumption.

- **For crude oil:** we look at the amount of energy yielded from investing USD100bn at four different project breakeven levels: USD25/bbl, USD50/bbl, USD75/bbl, and USD100/bbl. We assume an energy value for crude of 6.3GJ/bbl. We assume two different lifetime profiles for oil projects: 1) that once a project is on-stream it has a production life of ten years (this would be the case for deepwater projects, for example); and 2) that once a project is on-stream it has a life of 20 years (this would be more realistic for a conventional project, and oil-sands projects could last even longer). We give the energy value for crude oil in TWh to be consistent with the solar and wind values, and our assumed energy value for crude oil means that 1m barrels of oil yield 1.7TWh of energy.

⁴⁹ Note that this is consistent with the way the IEA's industry cost curve for oil is constructed (Chart 63 above), in that for each source of oil shown in Chart 63 the supply cost represents "capital and operating costs, plus government take" (2013 WEO, p. 454). In this respect, while royalties are not an economic cost in the strict sense (rather they represent a transfer of value from consumers to governments, as project developers ultimately pass this on in their end selling price), for the majors developing new projects royalties are unavoidable and hence for all intents and purposes the same as an economic cost (oil cannot be produced without paying them). In other words, in our EROCI analysis here, we assume that for oil the USD100bn has to cover all economic costs (capital and operating) plus royalties, but for renewables just the pure economic costs (capital and operating).

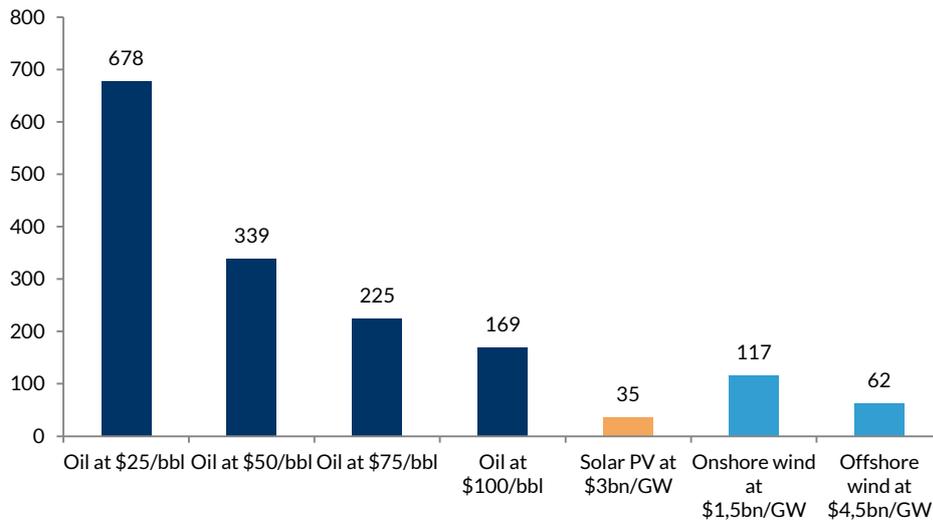
- **For solar PV:** we look at the amount of energy yielded assuming an upfront capital cost of USD3bn/GW. This reflects the average cost of the 39GW installed worldwide in 2013 according to the data provided by [Bloomberg New Energy Finance](#). We assume an average load factor for solar PV of 13%, which was the average figure worldwide for 2012. We assume a project lifetime for solar PV of 20 years. We assume only a modest level of operating costs over the lifetime of solar PV projects, which means that in our calculations 90% of the USD100bn invested is spent on capacity, and only 10% on operating costs.
- **For wind:** we here consider both onshore and offshore wind with respective capital costs of USD1.5bn/GW and USD4.5bn/GW. These assumptions reflect blended averages from a wide range of industry and academic sources. We assume average load factors for onshore and offshore wind of 25% and 40%, respectively. We assume a project lifetime for both onshore and offshore wind of 20 years. Again, we assume that the USD100bn is invested to cover the full breakeven costs of new projects, with operating costs assumed to be 20% of the total lifetime project cost. On this basis, we assume that USD80bn of the USD100bn is spent on capacity, with the remaining USD20bn covering operating costs.

Chart 70 shows a first glance at the EROCI of these different energy sources, and shows the gross amount of energy yielded annually over ten years from investing USD100bn. As such, this could be seen as representing a comparison between deepwater oil projects on the one hand, and solar PV and wind on the other.

Investing USD100bn at a cost of USD25/bbl would yield by far the most energy, with a gross annual return of 680TWh per year over ten years. This is not surprising, but as we saw above, only OPEC countries in the Middle East still have the luxury of being able to invest in such attractive projects.

That said, even looking at cost levels that are more realistic for the oil majors' current investment opportunities – especially those in the higher cost plays at USD75/bbl and USD100/bbl – we find that oil yields a higher annual gross energy return than either solar or wind. At USD75/bbl, USD100bn invested in oil yields USD225TWh per year over the ten years, and at USD100/bbl it yields 169TWh per year. This compares with 35TWh per year for solar, 117TWh for onshore wind, and 62TWh for offshore wind.

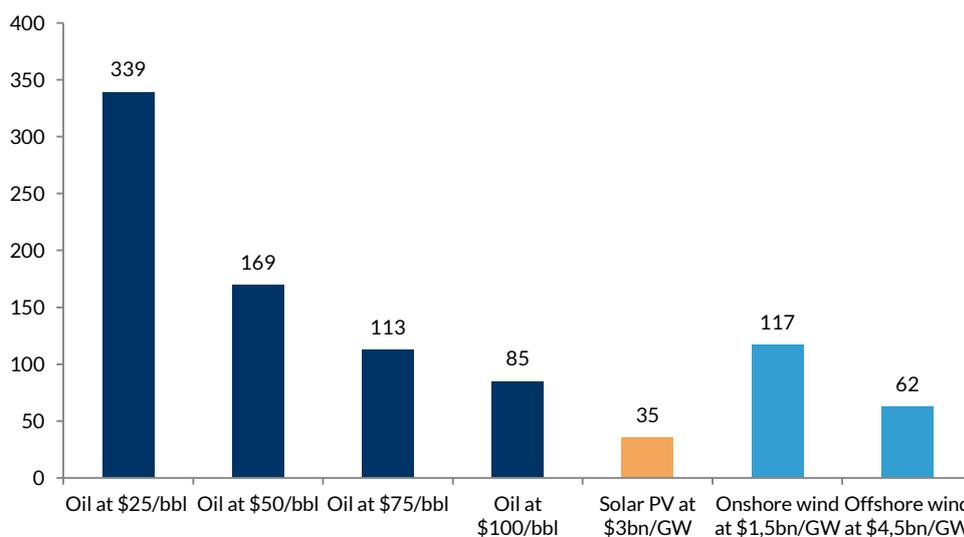
Chart 70: Estimated gross annual EROCI over 10 years from investing USD100bn in 2014 (TWh)



Source: Kepler Cheuvreux estimates

Chart 71, then takes the gross annual energy yield on a 20-year basis. This would be more representative of conventional oil projects (while oil-sands projects would have even longer lifetimes). Thus, on this basis, the relative economics of renewables improve, and onshore wind actually yields slightly more gross energy annually over the 20 years than oil at a price of USD75/bbl (117TWh versus 113TWh), and nearly 40% more than oil at USD100/bbl (117TWh versus 85TWh). That said, oil at USD100/bbl still yields more gross energy annually over 20 years than either solar or offshore wind (85TWh versus 35TWh and 62TWh, respectively).

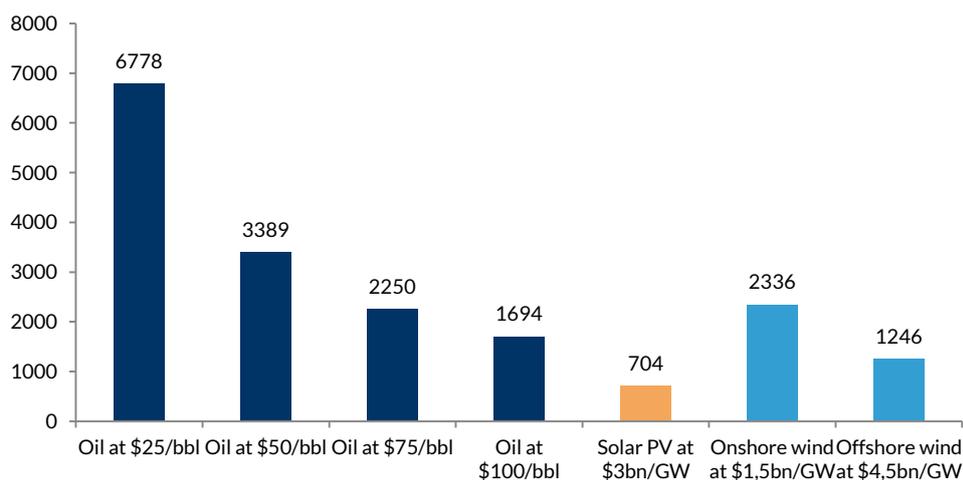
Chart 71: Estimated gross annual EROCI over 20 years from investing USD100bn in 2014 (TWh)



Source: Kepler Cheuvreux estimates

Chart 72 then shows the gross cumulative energy yield over the full project lifetime. Here we see the same pattern as in Chart 70: onshore wind actually yields slightly more gross energy over its full 20 years than oil at a price of USD75/bbl (2,336TWh versus 2,250TWh), and nearly 40% more than oil at USD100/bbl (2,336TWh versus 1,694TWh). That said, oil at USD100/bbl still yields more gross energy on a cumulative project-lifetime basis than either solar or offshore wind (1,694TWh versus 704TWh and 1,246TWh).

Chart 72: Estimated gross cumulative EROCI over project lifetime from investing USD100bn in 2014 (TWh)



Source: Kepler Cheuvreux estimates

The first key conclusion we draw from this analysis is that in terms of the economics of gross energy yielded, onshore wind is already very competitive with oil both on an annualised basis over 20 years and on a full 20-year lifecycle basis at prices of USD75/bbl and above. That said the other renewable technologies are still a long way behind oil even at USD100/bbl.

However, is the gross energy yield the right way to be looking at the relative economics of oil and renewables or should we rather be looking at the net energy yield for powering cars and light commercial vehicles?

After all, the risk to the IEA's oil-demand growth forecasts is that its projections for the fuels used in road transportation out to 2035 assume negligible take-up of EVs. And the point is that when we are looking at the relative economics of oil versus electricity for powering cars and light commercial vehicles, the key to competitiveness of each energy source is their net energy yield, not their gross energy yield.

In other words, we have to take into account the fact that for oil, the internal combustion engine loses 75-80% of the energy value of the oil input, while for EVs, converting electrical energy into battery-stored chemical energy and then back into electrical energy loses 25-30% of the original power input. This being the case, what does the EROCI look like for our various energy sources when we look at the net energy yield on an annualised ten-year and 20-year basis, and over the full lifetime of projects?

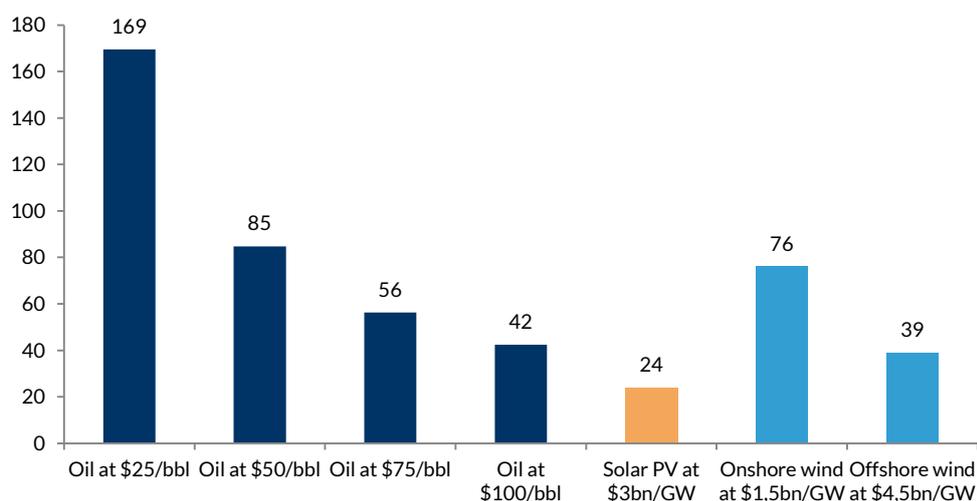
Charts 73, 74, and 75 compare the net energy yielded from an investment of USD100bn, assuming all the energy is used to power cars and light commercial vehicles, again on an annual 10-year basis (Chart 73), 20-year basis (Chart 74), and a full project life-cycle (Chart 75) basis.

We assume a net energy yield from oil of 25%, and a net energy yield for EVs of 70%. However, in the case of renewables, we also then have to adjust for the transmission losses.

For our stylised purposes here, we assume 2.5% transmission losses for solar PV, 5% for onshore wind, and 7.5% for offshore wind. This means that the net energy yield for EV cars powered by solar PV is here assumed to be 67.5%, for EVs powered by onshore wind 65%, and for EVs powered by offshore wind 62.5%.

Again, we take two cases for oil, projects with lifetimes of 10 years, and projects with lifetimes of 20 years. Chart 73, shows the annual net energy yield over 10 years for USD100bn invested in oil and renewables.

Chart 73: Estimated net annual EROCI over 10 years from investing USD100bn in 2014 (TWh)



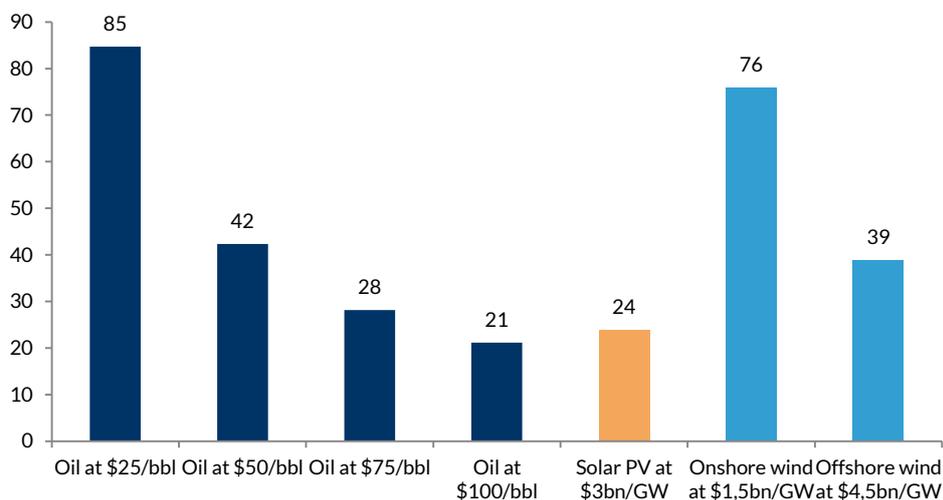
Source: Kepler Cheuvreux estimates

As can be seen, on this basis, onshore wind is becoming competitive with oil at USD50/bbl, (76TWh per year over ten years versus 85TWh per year for oil at USD50/bbl), and is well ahead of oil at both USD75/bbl and USD100/bbl. The other point to note is that offshore wind is close to being competitive with oil at USD100/bbl, yielding 39TWh per year over ten years versus 42TWh per year for oil at USD100/bbl.

Chart 74 then looks at the net annual energy yield on a 20-year basis. As can be seen, on this basis the relative economics of all renewables improve dramatically, and onshore wind actually yields much more net energy annually over the 20 years than oil at a price of USD50/bbl (76TWh versus 42TWh), and is not far away from oil at USD100/bbl (85TWh per year over 20 years). As such, onshore wind yields almost three times more net energy per year than oil at USD75/bbl (28TWh per year over 20 years), and almost four times as much per year as oil at USD100/bbl (21TWh per year over 20 years).

Moreover, and for the first time in any of our scenarios so far, offshore wind with an annual net energy yield of 39TWh beats oil at both USD/75bbl and USD100/bbl, and even solar, with its net annual energy yield over 20 years of 24TWh, beats oil at USD100/bbl, and is very close to oil at USD75/bbl.

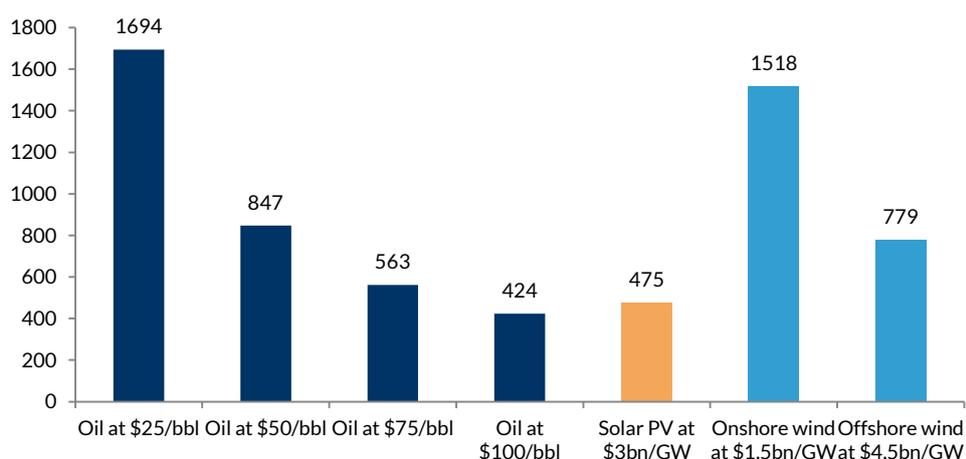
Chart 74: Estimated net annual EROCI over 20 years from investing USD100bn in 2014 (TWh)



Source: Kepler Cheuvreux estimates

Finally, Chart 75 looks at the cumulative net energy yield of USD100bn invested on a full project-lifetime basis. Here we see the same pattern as in Chart 74: onshore wind yields 80% more net energy on a cumulative project-lifetime basis than oil even at USD50/bbl (1,518TWh versus 847TWh), and is not far away from being competitive with oil at USD25/bbl (1,518TWh versus 1,694TWh).

And again, offshore wind with a cumulative project-lifetime yield of 779TWh beats oil at both USD/75bbl and USD100/bbl, and is not far away from being competitive with oil at USD50/bbl. And solar, with its net cumulative energy yield of 475TWh, beats oil at USD100/bbl, and is not far away from oil at USD75/bbl.

Chart 75: Estimated net cumulative EROCI over project lifetime from investing USD100bn in 2014 (TWh)


Source: Kepler Cheuvreux estimates

Other issues determining the attractiveness of EVs versus oil-powered cars

Beyond the question of the energy yielded from a given level of investment, there are other issues that will be key in determining how quickly EVs can become a large-scale commercial competitor to conventional oil-fired cars. Some of these issues favour oil, while others favour EVs.

For oil, there are two significant advantages that it will continue to enjoy over renewables for some time yet that are not captured in our stylised analysis here.

First, the oil industry's distribution infrastructure is huge, global, and a sunk cost. By contrast, existing EV infrastructure is miniscule by comparison, and will therefore require massive investments in order to persuade consumers that, beyond the merits of EVs in and of themselves, there is a sufficient critical mass of infrastructure in place able to service their requirements wherever they might want to drive. This infrastructure will take time and huge amounts of capital to build.

Second, whatever the respective full-lifecycle energy yields, oil has an advantage over renewables from a financing perspective in that the payback period on the upfront investment is shorter than it is for renewables. This is self-evidently the case in the example of the oil projects with a ten-year lifetime that we considered above, but even for projects with 20-year lifetimes, oil will not flow at an even uniform rate over 20 years, as we have assumed in our stylised analysis above.

Rather, a greater proportion of the total oil produced over the full 20 years will be extracted in the first ten years, meaning that investment calculations on a net-present value basis will look more favourable for oil than for renewables even when the project lifetimes are all ostensibly 20 years.

On the other hand, renewables have their own advantages that are not captured in our stylised analysis and that are likely to become more and more important over time.

First, whether one believes a binding global climate deal is ever likely to happen or not, the risk of some form of carbon pricing being imposed on oil in countries like China and India is a very real one over the next decade. This would only further improve the economics of renewables relative to oil.

Second, the infrastructure advantage of the oil industry is much greater in western industrialised countries than it is in the fast-growing oil markets of China and India. And China and India are precisely where the risk to the IEA's oil-demand forecasts are, in terms of the competitive threat from EVs. All other things being equal, this would suggest that EV-infrastructure build-out could happen much more quickly in China and India than in western industrialised countries, as the sunk-cost advantage of oil infrastructure is much lower in China and India (in other words, the economic write-down would be smaller).

Third, as battery technology improves over time, the flexibility of EVs versus oil-powered cars will become an increasingly important advantage. Oil-powered cars are idle most of the time and provide no value other than mobility. An EV will ultimately become a two-way mobile battery, enabling consumers to charge their cars when they are not driving them but also, whenever it makes sense, to sell stored power back to the grid from their cars.

And it is also worth emphasising that as the cost of renewable-generated electricity itself falls, so too the economic incentive to improve battery technology only increases. Indeed, ultimately this is why we think the IEA's projections on EVs are too pessimistic: with rising oil prices and falling renewables costs the incentive to improve all the other aspects around renewable-powered vehicles beyond the question of the energy yield will only continue to increase.

Finally, our stylised analysis above does not take into account the tax advantages of EVs relative to oil-powered cars and other light vehicles. This is already a big factor boosting EV demand in certain countries (for example, in Scandinavia), and such policy incentives are only like to increase over time if oil does indeed become increasingly expensive. In this respect, it is interesting to note that even in the US, where retail taxes on gasoline are very low, it can make a significant difference to the retail economics at the margin.

As a result, although oil will undoubtedly continue to benefit from all the advantages of incumbency (at least in western industrialised countries), such as a fully amortised infrastructure, a financial system geared to short-term paybacks, and the sheer weight of human apathy for some time to come, we think the speed and scale of EV take-up over the next two decades could be significantly greater than the IEA's NPS assumes, especially in China and India.

In turn, we think this means that the commercial viability of the higher-cost, high-carbon investments that the majors might undertake already and over the next decade in order to replace lost output beyond 2025 will be at risk. And the point is that the risk attached to new high-cost, high-carbon investments will only become greater over time.

Accordingly, let us conclude this report with a look at how the EROCI of new investments in oil might compare with renewables in 2020 and in 2035, assuming higher real oil prices and lower real renewables costs by these dates.

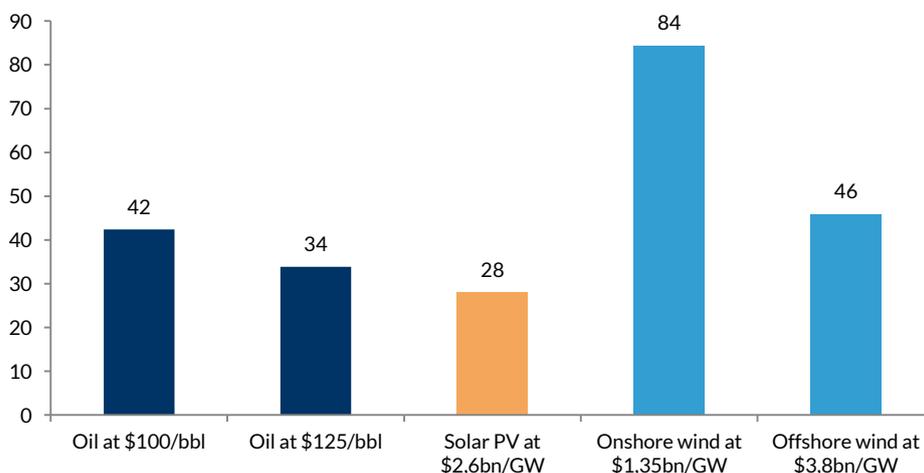
EROCI tomorrow: what will USD100bn buy in 2020 and 2035?

Charts 76,77, and 78 show a stylised analysis of the net annual energy yield over 10 years, 20 years, and on a cumulative project-lifetime basis, respectively, for new investments undertaken in 2020 on the basis of the following assumptions:

- **For oil:** investment opportunities at USD100/bbl and USD125/bbl in real terms (i.e. constant 2012 USD). On the basis of our pricing analysis above, these seem to us to be the right levels for the marginal new investment opportunities that the oil majors will face in 2020.
- **For solar PV:** a capital cost of USD2.55bn/GW (15% lower in real terms than the USD3bn/GW for 2014 assumed above), but the same average load factor of 13% that we assumed above (this is conservative, as this could also improve further over time as the technology improves)
- **For wind:** a capital cost of 1.35bn/GW (10% lower in real terms than the USD1.5bn assumed for 2014 above), and for offshore wind of USD3.825bn/GW (15% lower in real terms than the USD4.5bn/GW assumed for 2014 above). Again, though, we assume the same average load factors of 25% and 40% respectively (and again, we think this is conservative).

As can be seen from Chart 76, even on an annualised basis over ten years, oil at both USD100/bbl and USD125/bbl is totally uncompetitive with onshore wind, while offshore wind is also more competitive than oil at both USD100/bbl and USD125/bbl. Oil at both USD100/bbl and USD125/bbl beats solar on this basis, but solar is not far behind oil at USD125/bbl (28TWh per year and 34TWh per year respectively).

Chart 76: Estimated net annual EROCI over ten years from investing USD100bn in 2020 (TWh)

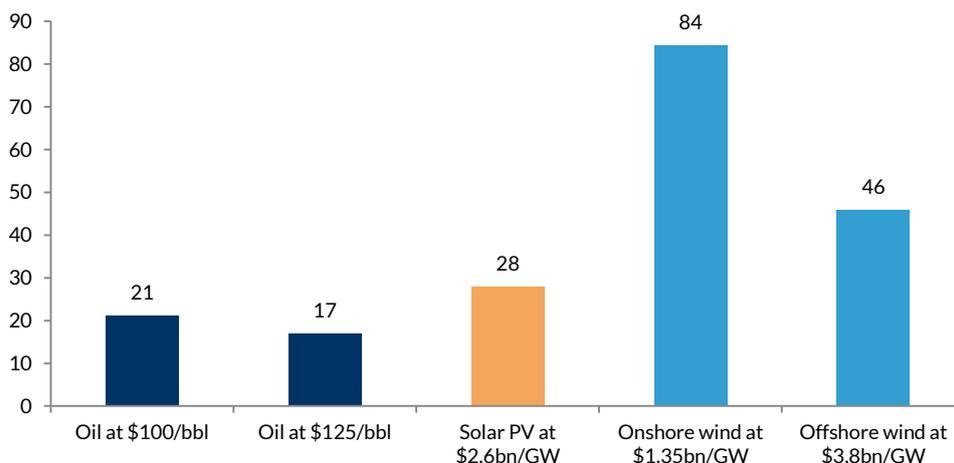


Source: Kepler Cheuvreux estimates

Chart 77 then shows the annual EROCI over 20 years for USD100bn invested in 2020.

As can be seen, on this basis the relative economics of all renewables improve dramatically, with all three technologies yielding more net energy annually over 20 years than oil at both USD100/bbl and USD125/bbl.

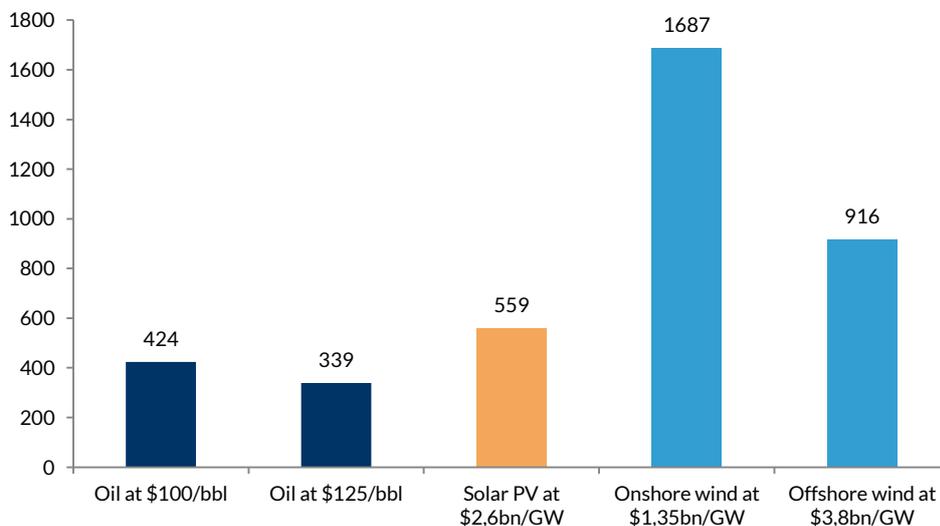
Chart 77: Estimated net annual EROCI over 20 years from investing USD100bn in 2020 (TWh)



Source: Kepler Cheuvreux estimates

Chart 78 then shows the EROCI in 2020 on a cumulative project-lifetime basis. Here we see the same pattern as in Chart 74: all three renewable technologies yielding more net energy annually over 20 years than oil at both USD100/bbl and USD125/bbl.

Chart 78: Estimated net cumulative EROCI over project lifetime from investing USD100bn in 2020 (TWh)



Source: Kepler Cheuvreux estimates

At this stage it seems almost impolite to labour the point further, but for the sake of completeness, Charts 79,80, and 81 then show a stylised analysis of the net annual energy yield over ten years, 20 years, and on a cumulative project-lifetime basis, respectively, for new investments undertaken in 2020 on the basis of the following assumptions:

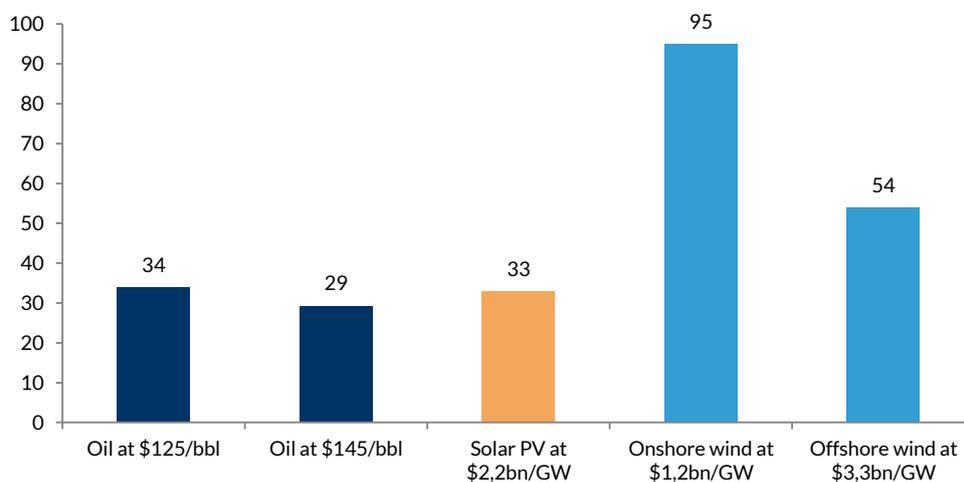
- **For oil:** investment opportunities at USD125/bbl and USD145/bbl in real terms (2012 USD). On the basis of our pricing analysis above, these seem to be the right levels to us for the marginal new investment opportunities for the oil majors by 2035.
- **For solar PV:** a capital cost of USD2.17 bn/GW (a further 15% lower in real terms than the USD2.55bn/GW assumed for 2020 above), but the same average load factor of 13% that we assumed above (this is conservative, as this could improve further over time as the technology improves)
- **For wind:** a capital cost of 1.2bn/GW (a further 10% lower in real terms than the USD1.35bn assumed above for 2020), and for offshore wind of USD3.15bn/GW (a further 15% lower in real terms than the USD3.825bn/GW assumed for 2020 above). Again, though, we assume the same average load factors of 20% and 35% respectively (and again, we think this is conservative).

Commentary on these charts seems almost superfluous, as the graphics speak for themselves.

What can clearly be said, however, is that these potential future net energy-yield numbers for renewables for both 2020 and 2035 – made, as we emphasise, on the basis of conservative assumptions for technological improvements – should terrify the oil majors.

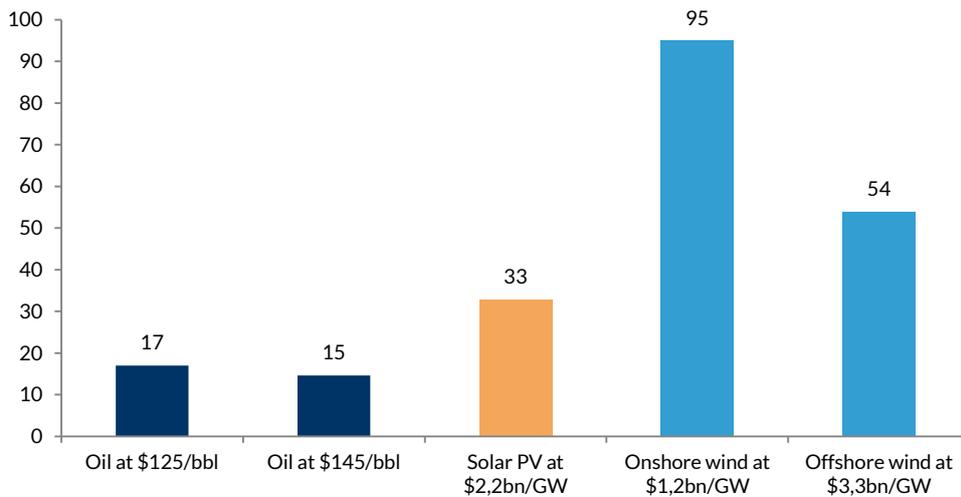
Indeed, the threat they should be focused on is the rising shape of their own industry cost curve (where they are the marginal suppliers) on the one hand, and the falling shape of the renewable technologies’ cost curves on the other.

Chart 79: Estimated net annual EROCI over ten years from investing USD100bn in 2035 (TWh)



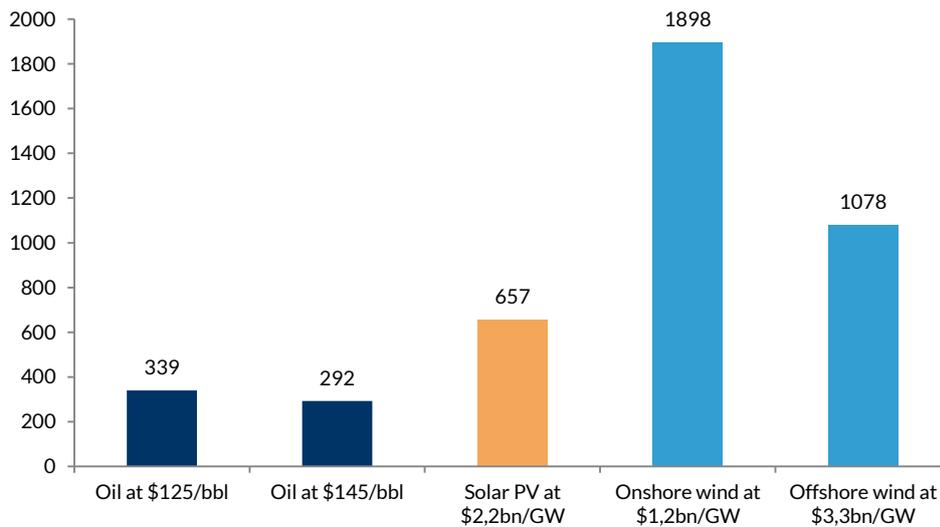
Source: Kepler Cheuvreux estimates

Chart 80: Estimated net annual EROCI over 20 years from investing USD100bn in 2035 (TWh)



Source: Kepler Cheuvreux estimates

Chart 81: Estimated net cumulative EROCI over project lifetime from investing USD100bn in 2035 (TWh)



Source: Kepler Cheuvreux estimates

Conclusion on relative EROCI of oil and renewables out to 2035

Other things being equal, the steeper the upward trajectory for oil prices and the steeper the downward trajectory for renewables costs, the greater the incentive to accelerate the deployment of renewable-energy technologies will be in the future.

This should be emblazoned on the wall of every oil major’s boardroom, and should inform every major investment decision they now make for projects at or above USD100/bbl.

Conclusion: oil majors need to become “energy majors”

Whilst we agree that higher oil prices will be necessary to grow the oil supply in future, we think the oil industry in general, and the oil majors in particular, face an increasingly uncertain future, not least owing to the questions of affordability and the increasing competitiveness of renewable-energy technologies that higher oil prices will inevitably raise.

If we are right, the implications are momentous, as it would mean that the oil industry faces the risk of stranded assets not only under a scenario of falling oil prices brought about by the structurally lower demand entailed by a future tightening of climate policy, but also under a scenario of rising oil prices brought about by increasingly constrained supply conditions.

Against this uncertain backdrop, we think the majors should be asking themselves whether it makes sense to replace lost output from their existing producing assets on a barrel-for-barrel basis, or whether in fact they should be reducing their capital allocation to higher-cost new projects (i.e. those requiring USD100/bbl or more), and looking instead to invest the money thus freed up in renewables (note also that the higher-cost new projects are almost by definition the most carbon-intensive ones).

This would enable them to become the energy majors of the future rather than ending up as the oil majors of the past.

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| BP | GB0007980591 | nothing to disclose | GBP | 471.60 |
| Chevron | US1667641005 | nothing to disclose | USD | 124.28 |
| Conocophillips | US20825C1045 | nothing to disclose | USD | 78.99 |
| ENI | IT0003132476 | 14, 16, 18 | EUR | 19.07 |
| Exxon Mobil | US30231G1022 | nothing to disclose | USD | 96.81 |
| Royal Dutch Shell | GB00B03MLX29 | nothing to disclose | EUR | 30.29 |
| Total | FR0000120271 | nothing to disclose | EUR | 50.29 |
| BG | GB0008762899 | nothing to disclose | GBP | 1,178.50 |
| Petrobras | BRPETRACNPR6 | nothing to disclose | BRL | 20.14 |
| Statoil | NO0010096985 | nothing to disclose | NOK | 176.40 |
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Source: Factset closing prices of 10/09/2014

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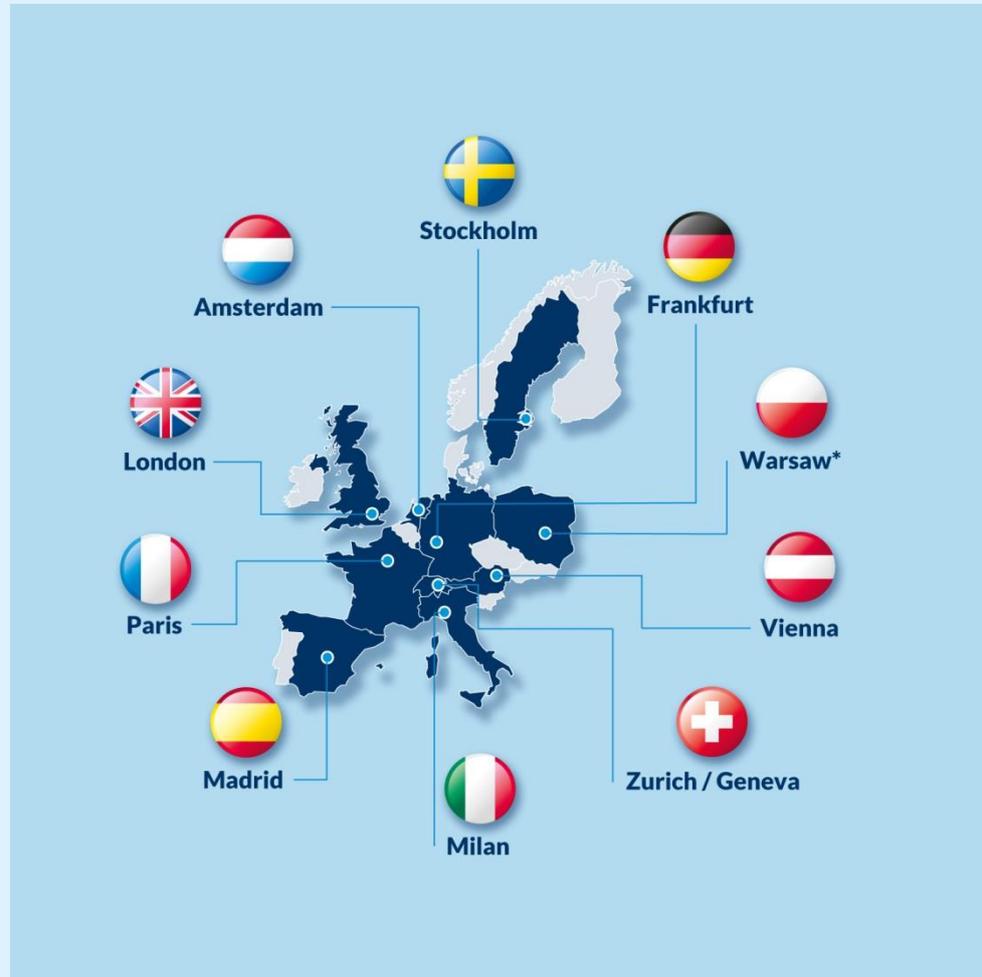
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