

OIL PRICE DRIVERS BOTTOM OF THE BARREL?

AN INDEPENDENT RESEARCH PAPER
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FOREWORD

Over recent years, the fundamentals governing the global price of oil have altered significantly. On the supply side, production from outside the Organisation of the Petroleum Exporting Countries (OPEC) has grown, driven by the deployment of new technologies such as hydraulic fracturing. On the demand side, a slow-down in economic growth from emerging economies, particularly China, has dampened demand. The decision by OPEC not to cut production to balance the market has caused a sustained downshift in the oil price, with major implications for the global economy.

Recognising the far reaching economic impacts of such a downshift, FTI Consulting EMEA has commissioned Dr Stuart Amor, an internationally-respected oil and gas analyst, to prepare this independent research paper. Therefore this paper does not represent an FTI Consulting 'house view' but is rather a contribution, via Dr Amor, to stimulate debate among industry players and policymakers.

The paper offers an analysis of how the drivers of the oil market have changed and assesses potential future price paths for what continues to be a key global commodity.

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By Dr. Stuart Amor

Independent Oil & Gas Analyst

EXECUTIVE SUMMARY

The oil price has moved from under US\$30/bbl (barrel of oil) in January 2016 to around US\$50/bbl today. I think this rally will prove to be another false dawn. Global crude inventory levels are still at all-time highs, and one of the main factors that has spurred prices in recent weeks, Canadian wildfires causing up to 1.5MMbpd (million barrels per day) of production to be halted, will be only a temporary supply shock. I forecast a mild seasonal inventory draw in H2 2016, followed by a larger seasonal build in H1 2017. Given this dynamic, I would expect Brent to trade in a rough US\$30/bbl to US\$50/bbl range until the middle of next year.

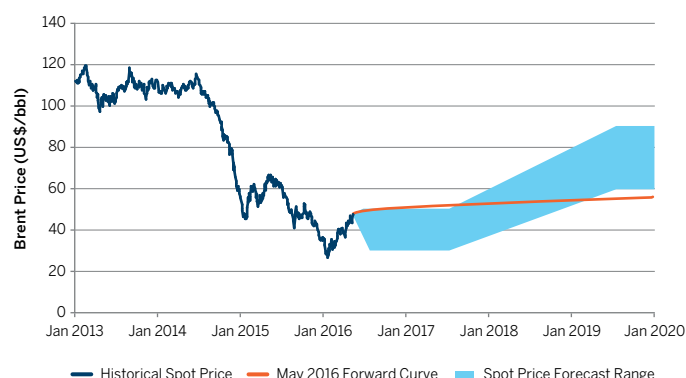
LONGER-TERM I BELIEVE THE OIL PRICE WILL TRADE WELL ABOVE CURRENT FORWARD CURVE PRICES

Longer-term I am much more bullish and believe that the oil price forward curve is underestimating the oil price three to five years from now. Brent forward contracts currently trade at around US\$58/bbl in 2020 and US\$62/bbl in 2023. In this time frame, the forward price should reflect the industry's marginal full cost of supply. The marginal full cost of supply is the full cost of supplying the last needed (i.e. most expensive) barrel of demand, which I think is closer to US\$70/bbl to US\$80/bbl. If this analysis proves correct, in the medium term Brent should trade in roughly a US\$60/bbl to US\$90/bbl range. This is presented in Figure 1. This forecast range is composed of a US\$75/bbl marginal full cost of supply and a US\$15/bbl spot premium/discount cyclical range.

I estimate that the 2015 non-OPEC marginal full cost of supply was US\$95/bbl. This is based on my analysis of the supplementary oil and gas data presented in the accounts of 81 of the world's largest public companies. The 2015 crude and natural gas liquid (NGL) production of these companies represented some 56% of non-OPEC supply.

While industry costs are likely to continue to fall, and 2015's large negative oil and gas reserve revisions are unlikely to be repeated, I think that the marginal full supply cost will not fall from last year's levels to US\$60/bbl, as the forward curve currently suggests. Many of the large deep water projects, currently on hold, are unlikely to be sanctioned unless the oil price remains much higher than US\$62/bbl on a sustained basis. Furthermore, unlike gas, conventional oil exploration success has proved challenging over the last five years, and there does not appear to be any major technological innovation ready to be adopted at scale that will allow a step change in exploration effectiveness.

Figure 1: Brent Spot Price, Forward Curve and Forecast Range



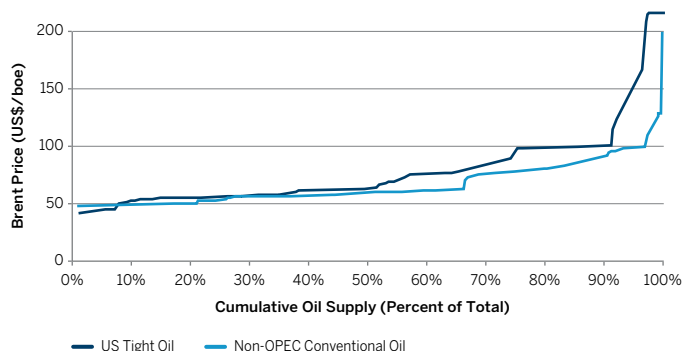
Source: Bloomberg, Analyst estimates

OPEC remains a cartel, albeit one operating in a more challenging market context. I believe it (or, in reality, Saudi Arabia and other Gulf Cooperation Council states) will continue to alter its short-term production to stabilise prices in the face of future temporary supply and demand shocks. However, the US tight oil industry, with its vast undeveloped resources, represented a structural supply shift rather than a temporary one. OPEC would not have been able to maintain crude prices in the face of fast growing US tight oil supply without ceding ever-greater market share year after year. My forecasts assume that OPEC does not act to restrain production over the next few years, as I assume that there are no large temporary supply/demand shocks in this timeframe.

US TIGHT OIL PRODUCTION IS A 'GAME CHANGER'

It is clear that the oil market has undergone an historic shift over the last few years: the US tight oil and shale gas revolution is a 'game changer'. It is the rapid production growth from this source that was the main initial cause of oversupply in the physical market. North America's vast tight oil resources (including natural gas liquids) meant further large increases in supply were likely, should the oil price have stayed at over US\$100/bbl. OPEC's reluctance to lower its quotas to support prices, in November 2014, put the onus back on higher-cost non-OPEC production to balance the market. US tight oil production, with its unusually short lead times and rapid decline rates, has taken the lead in this role. US tight oil production is already 0.4MMbpd below its peak in April 2015. I forecast that US tight oil production will continue to fall throughout 2016 and 2017.

Figure 2: 2015 Non-OPEC Conventional Oil & Tight Oil Supply Curves



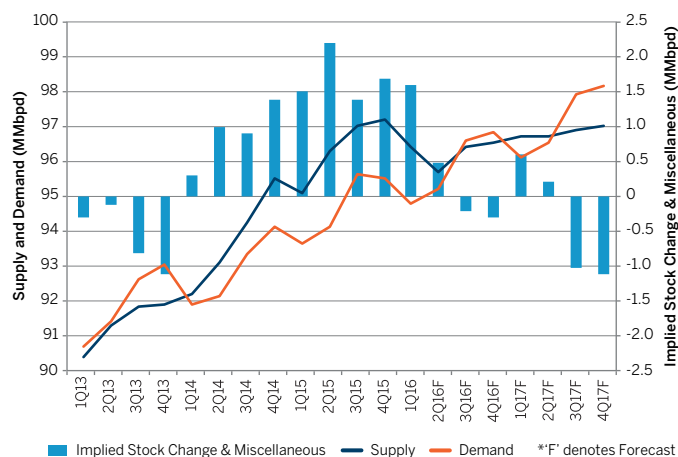
Source: Company data, Analyst estimates

US tight oil supply is often thought of as being relatively high-cost. In fact, US tight oil supply has a range and distribution of full costs that is very similar to conventional non-OPEC oil production. Figure 2 above compares the 2015 conventional and US tight oil supply curves. Some 50% of US tight oil supply in 2015 had a reported full cost of less than US\$64/bbl. This will slow the speed of the oil price recovery that I foresee. As the oil price moves above US\$60/bbl, some shale players will decide to invest in drilling wells targeting oil and NGL production from the lower cost US tight oil supply curve. New liquid production from this source will come on stream within a few months of the decision to invest, slowing down any crude inventory draw or adding to any seasonal stock build. As current high inventories will fall to normal levels more slowly than would be the case without US tight oil supply, the spot oil price discount to long-dated (3+ years) contracts will shrink more slowly.

I FORECAST THAT CURRENT HIGH GLOBAL PETROLEUM STOCKS WILL START TO FALL SUSTAINABLY TOWARDS MORE NORMAL LEVELS IN H2 2017

I forecast a mild seasonal petroleum stock draw in H2 2016, followed by a normal seasonal stock build in H1 2017. It is not until H2 2017 that I expect global petroleum stocks to start to fall sustainably towards more normal levels. In Figure 3, I chart my forecasts of global supply and demand. The forecasts take into account my modelling of US tight oil supply and the impact of recent Canadian wildfires. They also assume that Q2 2016 OPEC crude oil production is 32.3MMbpd down from 32.6MMbpd in Q1 2016 due to social unrest in Nigeria and Venezuela. H2 2016 OPEC production is assumed to return to Q1 2016 levels, while increased Iranian production leads to a 33.0MMbpd forecast for 2017.

Figure 3: Global Oil Supply/Demand Balance



Source: IEA, Oil Market Report, 14 April 2016, Analyst estimates

It is important note here that my oil price forecasts could be influenced down or up by a range of factors. Short-term changes to my supply and demand views would affect near-term oil price forecasts. Unforeseen new technology might lower supply costs, and thus lower my longer-term oil price forecasts.

Moreover, lower demand could cause global oil stocks to continue to build and lead to lower spot prices. Conversely, higher-than-forecast demand could lead to higher inventory draws and higher oil prices than I currently predict. Generally, demand risks are asymmetric, with risks to the downside due to global or regional recessions which are larger than unforeseen demand uplifts. Should there be a major recession in China, this would clearly present a negative outlook for oil prices.

Higher-than-forecast oil supply could weigh on oil prices, while lower-than-forecast production would support prices. Supply risks are also asymmetric, with risks to the downside due to civil war or social unrest generally larger and more common than unforeseen supply uplifts. Long unplanned disruptions to supply from politically unstable oil-producing countries could lead to significantly higher prices. According to the International Energy Agency (IEA), Libyan supply was down to 0.4MMbpd in Q1 2016 from 1.4MMbpd in 2012. Iraqi supply has grown over the last few years and averaged 4.3MMbpd in Q1 2016. Indeed, civil unrest in the Niger Delta has unexpectedly cut Nigerian supply this year, supporting the recent oil price rally.

US TIGHT OIL PRODUCTION WILL SLOW THE SPEED OF THE OIL PRICE RECOVERY

GLOBAL OIL SUPPLY, DEMAND AND STOCKS

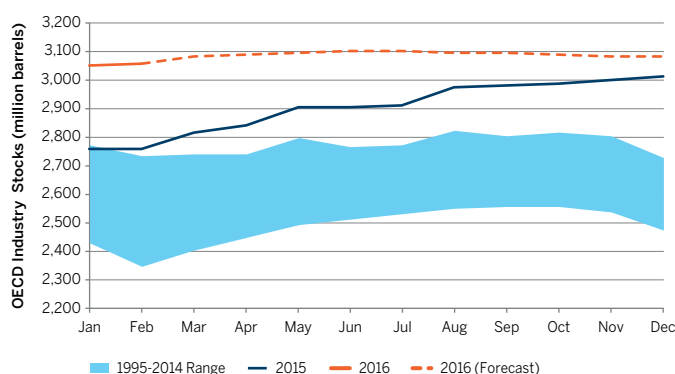
GLOBAL OIL STOCKS

I believe global oil supply will continue to outstrip demand over the next 12 months, leading to unprecedented levels of oil stocks and continued pressure on spot oil prices. I forecast Organisation for Economic Co-operation and Development (OECD) inventory stocks rising to over 3,100MMbbl at the end of June 2016. Interestingly, in the last 20 years, petroleum stocks have never been this high. The highest they have been previously was in August 1998, when they reached 2,820MMbbl.

CURRENT GLOBAL PETROLEUM STOCK LEVELS ARE AT ALL TIME HIGHS

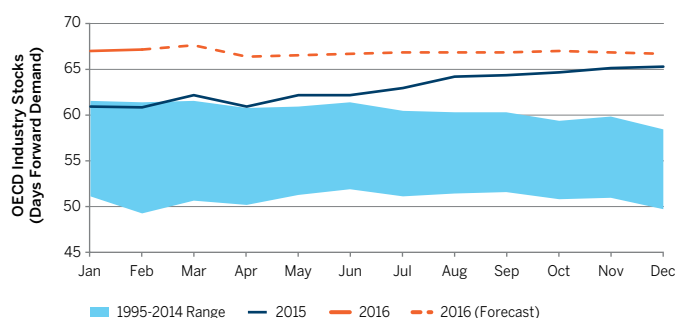
I also forecast supply to outstrip demand by some margin over H1 2016, leading to a significant increase in crude and product inventories. Below I have forecast 2016 OECD industry oil stocks (in total barrels in Figure 4, and in days of forward quarter demand in Figure 5).

Figure 4: 1995-2016 (Forecast) OECD Industry Stocks



Source: IEA, Analyst estimates

Figure 5: 1995-2016 (Forecast) OECD Industry Stocks



Source: IEA, Analyst estimates

Figure 4 plots the total industry oil stocks (crude and product) in OECD countries by month, from January 1995 to December 2014. I do not take account of government-controlled stocks (such as

the US Strategic Petroleum Reserve), which are generally static and released/built up based on political decisions, rather than for economic reasons. The chart gives the industry stock level range for each month over this 20-year period. I have forecast the 2016 monthly stock levels by taking the previous month's level and adding my estimate of the excess/deficit of global oil supply vs. demand, multiplied by the proportion of OECD demand in global demand (roughly 50%). Thus, I have assumed around 50% of global excess supply ends up in OECD industry stocks. I forecast OECD industry stocks to rise above 3,100MMbbl by the end of June 2016.

OECD oil demand is seasonal because the main centres of demand (North America and Europe) are in the Northern Hemisphere and demand tends to peak in the summer/autumn months for both areas. I believe, as the IEA does, that viewing stocks as a ratio of next quarter oil demand allows stock levels to be seasonally adjusted. Figure 5, plots the same stock data from Figure 4 in terms of days of next quarter demand using the IEA's estimate of historic and forecast OECD demand levels. I forecast 2016 stock levels to be 66 to 68 days of demand, well above their 20-year historic range (49-62 days of demand).

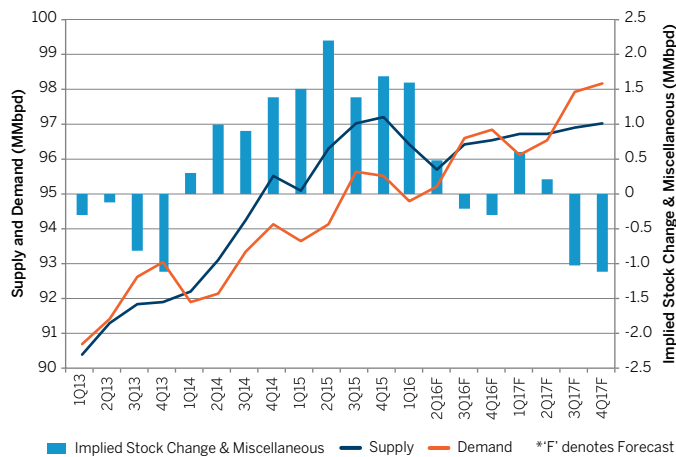
GLOBAL OIL SUPPLY AND DEMAND

In its April 2016 Oil Market Report, the IEA forecast global oil demand of 95.2MMbpd for Q2 2016. Total non-OPEC supply was forecast to be 56.9MMbpd that quarter. Adding OPEC crude supply of 32.6MMbpd (its Q1 2016 level) and forecast NGL supply of 6.8MMbpd gives total supply of 96.3MMbpd in Q2 2016. These levels would have led to global inventory builds of 1.1MMbpd in Q2 2016, or around 100MMbbl over the quarter (of which just under 50% should end up in OECD industry stock numbers). However, since the IEA made their forecast, Canadian wildfires during May have caused the shutdown of plant producing over 1MMbpd of heavy oil and syncrude. My forecast therefore assumes 30MM barrels less Canadian production for 2Q16 than the IEA's earlier forecast. I estimate that Q2 2016 OPEC production will be 0.3MMbpd below Q1 2016 levels because of social unrest in Nigeria and Venezuela.

I forecast supply and demand coming back into balance in H2 2016 (assuming flat OPEC crude production at Q1 2016 levels), as low prices stimulate demand and US tight oil production continues to fall. This should result in a slight draw in global oil stocks during H2 2016, although they will remain at very high levels in an historical context. Normally at this time of year oil inventories are significantly drawn down.

Figure 6 overleaf charts my forecast of global supply and demand, assuming H2 2016 OPEC production at Q1 2016 levels. I forecast a 0.4MMbpd increase in 2017 OPEC production, as Iran ramps up production towards pre-sanction levels. New non-OPEC production, from projects sanctioned before the oil price fell, will continue to come on stream in 2017, offsetting the decline in production from mature fields. My analysis of US tight oil production leads me to forecast a continued decline in total US production during H1 2017. However, the seasonal fall in demand will lead to a further global stock build during these six months. I forecast that it is not until H2 2017 that petroleum inventories start to fall back sustainably to more 'normal' levels.

Figure 6: Global Oil Supply/Demand Balance



Source: IEA, Oil Market Report, 14 April 2016, Analyst estimates

THE US TIGHT OIL AND SHALE GAS REVOLUTION

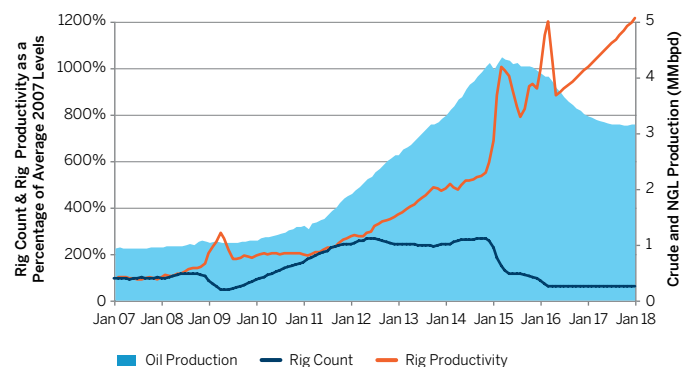
The main cause of the recent global oversupply of crude and petroleum liquids has been the rapid growth in US tight oil supply (shale oil, tight oil and NGL). According to the IEA, total US oil supply grew from 8.1MMbpd (9.2% global market share) in 2011 to 12.9MMbpd in 2015 (13.4% global market share). The vast majority of this growth has come from US tight oil and NGL production. To put this in perspective, global demand growth from 2011 to 2015 was only 5.2MMbpd. In other words, growth in US supply met over 90% of global demand growth over this five-year period.

US TIGHT OIL PRODUCTION IS MORE RESPONSIVE TO PRICE SIGNALS THAN CONVENTIONAL OIL PRODUCTION

US tight oil production is much more responsive to price signals than conventional oil production. Conventional oil supply shows a limited short-term response to oil price movements because of the long lag between investment decisions and production, and because variable cash costs are generally a small part of the full cost of production. It often takes several years from the decision to invest in a particular oil field before the field starts to produce. Once the oil is flowing, it will often last for many years. The responsiveness of tight oil is quite different. The time between the decision to drill and complete a well and that well's production is generally just a couple of months, rather than a few years. In addition, shale oil wells have decline rates that are far steeper than conventional oil wells, producing the vast majority of their reserves within the first couple of years.

The relatively quick response of US tight oil players to changes in oil prices will tend to smooth out the sharp swings in oil price that we have seen historically. US tight oil production is now seeing a much faster decline than conventional oil production, helping to support oil prices. In March 2015, the seven main tight oil and shale gas regions (the Permian, Eagle Ford, Bakken, Niobrara, Marcellus, Utica and Haynesville regions) produced some 5.5MMbpd of petroleum liquids. The active rig count in these seven shale regions is now down 78% from that time. Despite continued efficiency gains, March 2016 US tight oil production is down some 440,000bpd (or 8.1%) from its peak level a year ago. By contrast, the international active rig count is down just 29%, according to drilling company Baker Hughes. Non-OPEC production outside of the US is down just 2.7% over the same time period.

Figure 7: Permian, Eagle Ford & Bakken Regions' Oil Production



Source: EIA, Analyst estimates

The short lead times for US tight oil and NGL production will mean that as the spot oil prices start to rise from their current low levels towards the marginal full cost of supply, lower cost tight oil and NGL production will start to ramp up production long before new similarly-low-cost conventional oil production can come on stream. This will cause global oil inventories to fall more slowly than they would have in the past, and will cause the spot oil price to rise more slowly than it otherwise would.

I have modelled US tight oil production out to January 2018, assuming that:

- the active rig count remains at the March 2016 level throughout the forecast period.
- monthly rig productivity gains are the same as their average of the last six months.

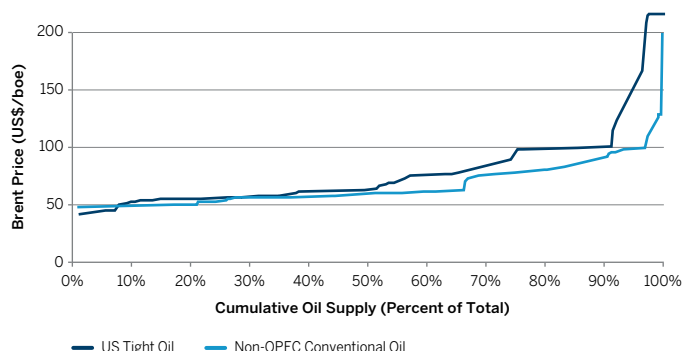
My model suggests that liquid production from the main US tight oil regions will fall from roughly 4.7MMbpd today to around 4.0MMbpd in August 2017. Production will then remain roughly flat until the beginning of 2018. In Figure 7 above, I have plotted the total tight oil production from the US's three main tight oil production regions.

The actual number of tight oil active rigs over the next few years will depend crucially on the oil price trajectory and where different shale plays, and parts of shale plays, lie on the supply curve. There is a misperception in the market that US tight oil supply is

GLOBAL OIL SUPPLY, DEMAND AND STOCKS

generally high-cost. This is not supported by the facts. Roughly 75% has lower full costs than my US\$95/bbl estimate of the global marginal full cost of oil supply. The current US tight oil full cost supply curve has a similar cost range and distribution to that of the non-OPEC conventional oil supply curve. Figure 8 compares the 2015 full cost supply curve of around 37 large conventional oil companies (combined 2015 global liquid production of 28.1MMbpd) against that of 44 US tight oil and shale gas companies (combined 2015 US liquid production of 3.2MMbpd).

Figure 8: 2015 Non-OPEC Conventional Oil & Tight Oil Supply Curves



Source: EIA, Analyst estimates

Over the lower-cost half of their supply curves, the conventional and tight oil curves track each other quite closely. Within the set of US tight oil and gas companies used for this analysis, just over 0.2MMbpd of 2015 tight oil production (8% of the total) had a full supply cost under US\$50/bbl, while around 1.1MMbpd had a full supply cost under US\$60/bbl (35% of the total). Roughly 50% of 2015 US tight oil supply had a full cost that was less than US\$64/bbl. The same is true for 2015 global conventional oil supply costs. Roughly 50% of 2015 global conventional oil supply had a full cost that was less than US\$60/bbl.

ROUGHLY 50% OF 2015 US TIGHT OIL SUPPLY HAD A FULL COST THAT WAS LESS THAN US\$64/BBL

US tight oil supply will slow the recovery of the spot oil price towards the marginal full cost of supply. As the oil price moves above US\$60/bbl, some shale players will decide to invest in more active rigs, targeting oil and NGL production from the lower cost third of the US tight oil supply curve. New liquid production from this source will then come on stream within a few months of the decision to invest, slowing down any crude inventory draw or adding to a seasonal stock build. As current high inventories will fall to normal levels more slowly than would be the case without US tight oil supply, the spot oil price discount to long-dated contracts will shrink more slowly.

The 2015 marginal full cost of US tight oil supply (US\$100/bbl) was significantly higher than the marginal full cost of conventional oil supply (US\$83/bbl). The main cause of this is higher-calculated finding and development costs of several US tight oil players, as a result of significant downward revisions to their proven undeveloped oil and gas reserves. The 81 companies in my database had negative net oil and gas reserve revisions totalling ~14.0bn boe. Shale players made up around 55% of this total, despite representing less than 15% of beginning year reserves.

The US tight oil supply curve is likely to continue to shift downwards, and faster than the global conventional oil supply curve. Certainly, US tight oil productivity gains over the last several years have been far greater than any seen in conventional oil production. For example, the average new production per rig per month for a Bakken rig was 112bpd in January 2007. By January 2015 it was 489bpd. In March 2016, the figure was 746bpd. Each year, the number of wells drilled by an average rig in a month has increased, as has the production per new well.

The US industry structure has contributed to this learning process: scores of relatively small production and oil service firms have continued to experiment with new drilling and completion techniques, leading to continued improvements to best practice. More efficient new A/C powered walking rigs, multi-well pad drilling, microseismic fracture monitoring, increasingly precise well architecture, and next generation completion methods have yielded productivity improvements in recent years. I believe that these improvements in efficiency will have been maximised by the time the US rig count begins to recover. For example, the days to drill a well are reaching the practical limits of efficiency in the major US tight oil plays.

As different tight oil and shale plays have matured, the industry's understanding (now using big data analytics) of the 'sweet spots' has improved. More recently, as companies have reduced the number of wells they are drilling, they have focussed their drilling on core acreage, improving the average production per well. The high-grading of crews, rigs and pressure pumping spreads has also contributed to efficiency gains in the shale plays during the downturn. Once companies start to increase the number of wells they are drilling, productivity gains from high-grading will likely reverse as the active rig count increases. Moreover, the destruction of parts of the US oil field services supply chain due to financial distress and permanent losses of field employees may impair the speed at which the industry can rebuild its new production capacity.

OPEC REMAINS A CARTEL

By deciding not to cut quotas in November 2014 OPEC made a rational choice. OPEC would not have been able to maintain crude prices in the face of fast-growing US tight oil supply without ceding ever-greater market share year after year. My view is that Saudi Arabia, OPEC's main actor, with around 75% of current spare capacity, realised the futility of trying to maintain prices in the face of this structural supply change. My base case is that OPEC continues to produce 32.6 to 33.0MMbpd of crude over the next couple of years. However, I believe that there is a small chance that in 2017 OPEC cuts its crude production towards its current group 30.0MMbpd quota level.

Over the past 20 years, OPEC has stabilised oil prices in the face of temporary demand and supply shocks. Following the demand shock from the East Asian financial crisis, OPEC cut its production quotas to support prices. Similarly, during the global financial crisis of 2008/9, as oil prices plunged from US\$140/bbl to US\$40/bbl, OPEC cut its production by nearly 3MMbpd to stabilise prices. On the supply side, as the Arab Spring disrupted oil supply from North Africa; Saudi Arabia and other GCC (Gulf Cooperation Council) members stepped in to partially offset the supply shortfall.

I BELIEVE OPEC WILL ACT TO STABILISE PRICES IF THERE ARE TEMPORARY FUTURE DEMAND/SUPPLY SHOCKS

However, OPEC is not able to sustain prices in the face of long-term structural supply and demand changes. Saudi Arabia attempted this in the early 1980s, but was unsuccessful. The oil price rose dramatically during the 1970s, due to two supply shocks: the 1973 Arab Oil Embargo and the Iranian Revolution, in 1979. Oil prices rose from under US\$2/bbl in 1970 to over US\$35/bbl in 1980. These high oil prices encouraged innovation and stimulated non-OPEC oil production in higher-cost locations such as the North Sea. From 1979 to 1984 non-OPEC oil supply rose by 5.1MMbpd. During the early 1980s Saudi Arabia tried to maintain the oil price in the face of this structural change to non-OPEC supply. It slashed crude production from 10.3MMbpd in 1980 to 3.6MMbpd in 1985, but prices fell throughout the period as it was not enough to offset increased non-OPEC supply and the demand contraction caused by the high prices of the late 1970s. From 1979 to 1984, global demand for crude dropped by some 5.0MMbpd as consumer countries put in place policies to lower demand.

Today's oil price decline is similar to that seen in the early 1980s, as its main cause has been the rapid growth in non-OPEC supply. While 2016 global oil demand growth is sluggish, fundamentally the problem has been that US tight oil supply (encouraged by a large backwardation¹ in the oil market over

several years) grew from less than 2MMbpd in 2011 to over 5MMbpd in 2015. Given the vast size of North America's tight oil resources, US tight oil production represents a structural supply change, rather than a temporary supply shock.

I believe that many Saudi Arabian policymakers are also starting to factor in a structural change in oil demand that lies just over the horizon. In my view, oil demand is likely to peak long before supplies start to run out, due to increased engine efficiency, consumer country policies to address climate change, and technological improvements that lower the cost of substitute products (e.g. electric cars). With an oil reserves to production ratio of over 60 years, according to British Petroleum's Statistical Review of World Energy, Saudi Arabian policymakers may be questioning whether it makes sense to hold back its production and risk more of its reserves becoming stranded. There are also signs that the Saudi Government is preparing to embark on a radical overhaul of the economy that aims to reduce the Kingdom's reliance on oil.

Much is made in the media of the oil price that various OPEC members need in order to balance their fiscal budgets; however, OPEC cannot just remove production from current supply and sustainably set any price it wants. If OPEC cuts enough production so that the oil market is put into too much backwardation, some oil demand is destroyed and increased investment in non-OPEC, high-cost supply occurs. This leads to more non-OPEC supply, and lower demand over time. Growing non-OPEC supply would then mean that OPEC would have to give up progressive amounts of market share in subsequent years to maintain spot prices.

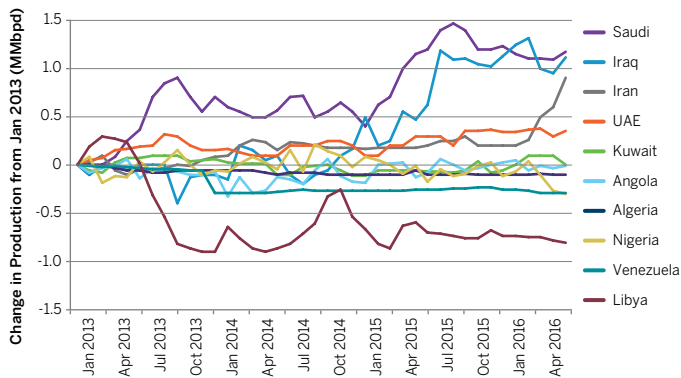
OPEC's *raison d'être* is to maximise oil cashflows for its members over time, and that has not changed. I believe that the best way of achieving this goal is for OPEC to control its near-term production so that the oil market is normally in slight backwardation. The backwardation should neither be enough to destroy too much demand nor be enough to encourage substantial growth in high-cost non-OPEC supply. Making temporary changes to its production to help stabilise oil prices in the face of temporary supply/demand shocks encourages oil usage and helps expand the overall market.

I believe Saudi Arabian policymakers understand this, and have recognised that US tight oil supply is a structural change, rather than a temporary shock, to global supply. Therefore the only logical response to this structural supply change is to maintain its market share and allow prices to fall, thus forcing some higher-cost producers to shut production and discouraging others from future investment in high-cost supply. Saudi Arabia needs some high-cost oil supply in the non-OPEC supply curve, as this sets the long-term oil price at levels that allow it to generate healthy profits from its own low-cost production. However, the debt-funded fast production growth rate from the vast US shale oil reserves was threatening Saudi Arabia's ability to maintain its own production volumes over the next few years.

¹ Backwardation – a term used to describe the situation in which the spot or cash price of a commodity is higher than the forward price

GLOBAL OIL SUPPLY, DEMAND AND STOCKS

Figure 9: OPEC Crude Production Changes



Source: Bloomberg, Analyst estimates

THERE IS NO SIGN OF OPEC CURTAILING PRODUCTION AT PRESENT

OPEC has not just maintained its market share since it confirmed its 30.0MMbpd group quota level in November 2014; it has increased its market share. Currently, Saudi Arabia, Iraq and Iran are each producing over 0.5MMbpd more than they did in November 2014. In April 2016, the group as whole was producing 2.0MMbpd more (a combined 32.5MMbpd), according to the IEA. I believe that there is only a very small chance that OPEC is able to reduce production back to its official 30.0MMbpd quota level some time in 2017. The obstacles to this are large.

For a start, in order to be able to allocate and monitor production cuts amongst its members, OPEC would have to resume cascading the group quota level down to individual country quotas. The internal negotiation of individual country quotas has proved problematic in the past, and OPEC abandoned them in favour of a group quota in December 2011. Also, the internal negotiation of deciding on production quotas within OPEC has been complicated by the removal of sanctions on Iran earlier in 2016.

With Saudi Arabia reportedly also wanting Iran to participate in a proposed production freeze, this year's Doha meeting with Russia may have been destined to fail before it started. Iran had clearly signalled that it should be allowed to raise its production to pre-sanction levels, and would not freeze its production at January's level. I think Iranian crude production will need either to plateau or to approach its pre-sanction level before Iran will be able to negotiate within OPEC on production restraint. While this is unlikely to occur this year, I believe Iran will approach its pre-sanction production levels next year.

The regional rivalry between Saudi Arabia and Iran will make any negotiation of OPEC production quotas challenging. So until a deal is concluded, its coming into force will remain highly uncertain. Indeed, even should a deal be agreed, it is not certain that all of OPEC's members will keep to their commitments. It appears to me that, after a long period of oil price pain, OPEC discipline will be effective initially, but could start to wane over time.

FACTORS AFFECTING THE OIL PRICE

1. Marginal Full Cost of Oil Production

The marginal full cost of oil production generally sets the long-dated oil price. Given the long lead times (three to five years) and long project lives (normally several or more years) of conventional oil and gas projects, it is long-dated oil prices that companies should use when forecasting conventional oil and gas project economics. The long-dated oil price required to incentivise investment in an upstream project must be at least as high as that project's full cost of supply (including its cost of capital). The long-dated oil price required to incentivise production of the marginal barrel (last needed and most expensive barrel) is the marginal barrel's full cost of supply. Thus, the price of long-dated oil price contracts represents the market's view of the marginal full cost of oil supply.

2. Global Crude Oil Supply and Demand

My view is that short-term forecasts of global supply and demand largely determine the spread (both contango² and backwardation) between spot and long-dated oil prices.

Long-term supply and demand forecasts generally do not affect either spot or long-dated oil prices. This is true providing that expected long lead times to build new oil production capacity outside OPEC do not constrain long-term supply so that it cannot match expected long-term demand. Should the market start to believe that long-term supply cannot keep up with long-term demand, long-dated prices can rise to well above the marginal full costs of supply in order to balance long-term supply and demand through demand destruction. I believe that OPEC production restraints led to such a period from 1973 to 1980.

3. Perceived OPEC Objectives

OPEC cannot generally affect long-dated oil prices substantially in my opinion. This is because these prices generally reflect the long-term marginal full costs of oil production, and the large majority of OPEC oil production is low-cost (especially that of its main swing producer Saudi Arabia).

Since 1973, OPEC has had varying amounts of spare oil production capacity that have allowed it to affect significantly the short-term supply of oil. OPEC's influence over the short-term supply/demand balance (and hence global levels of crude inventory) gives it substantial control over the spread between spot oil prices and long-dated future contracts. Thus, although I believe OPEC cannot influence long-dated prices by much, it can and does affect the spot price through the degree of contango/backwardation in the forward price curve.

4. Strength/Weakness of the US\$

Although it might be expected that a weaker US dollar would push up oil prices, I have been unable to find any convincing long-term correlation between US\$ exchange rates and oil prices over the last 20 years. A weaker US\$ decreases the oil price in other currencies, which might be expected to spur additional short-term global oil demand, thus pushing up the US\$ spot oil price. However, short-term demand inelasticity means that this effect is small and is probably offset by the much higher volatility of oil prices rather than exchange rates. A weaker US\$ increases the US\$ cost of local inputs (e.g. salaries), which ought to increase the marginal full cost of oil production. However, the vast majority

of finding and development capex (drilling rigs, pipe, cement, etc.) and a significant portion of variable lifting costs (e.g. energy) are priced in US\$, mitigating against much of an effect.

5. New Technology

Given the generally long time frames to implement new technology, it has little influence over the short-term supply/demand balance for oil. However, new technology can affect both long-term supply and demand for crude oil.

On the supply side, new technology generally lowers the full cost of oil production or substitute product production. In the case of deep water oil production (i.e. production from water depths >300m), lower costs have made previously unprofitable fields commercially viable. For example, the introduction of semi-submersible, tension-levied or compliant tower platforms, and more recently the use of Floating Production, Storage and Offloading (FPSO) vessels, have meant that production can now be commercially viable at sea depths of a few thousand meters (in the early 1990s, production was commercially viable only up to a couple of hundred meters).

New technology can increase demand for crude by creating new uses, or can decrease demand through efficiency gains. Back in the early 19th century, the main use for crude oil was lighting (e.g. kerosene lamps) and most transport was by foot, horse or steam engine (powered by coal). The invention and development of the internal combustion engine in the late 19th century led to the first automobiles and a huge increase in demand for refined crude. Today, crude oil's main end use is to provide energy for transportation. The high oil prices seen in the late 1970s/early 1980s, and regulation such as the Corporate Average Fuel Economy (CAFE) standards in the US encouraged car manufacturers to develop more efficient engines.

6. Substitute Products

Today, conventional crude oil, tar sands and shale oil are largely refined/converted to gasoline/diesel/aviation fuel and used as an energy source for transport. There are few direct substitute products for this end use, as these products have unusually high energy content per unit weight and volume. The main substitute products convert other hydrocarbons to similar high energy per unit weight liquids. These include biofuels, coal-to-liquid (CTL) technology and gas-to-liquid technology (GTL).

Although the US reserves of oil shale are vast, the poor economics and high environmental impact of their production have continually delayed commercial production. Both CTL and GTL technology have been around for decades (Germany used CTL to produce synthetic fuel in WWII), but high capital requirements make the economics of large-scale commercialisation uncertain, and these technologies, combined, still account for less than 1% of total road transport fuel demand.

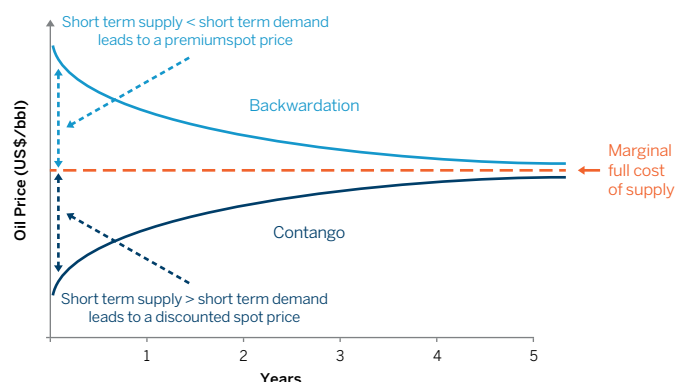
In my view, an increasing proportion of hybrid, electric, compressed natural gas (CNG) and fuel cell vehicles sold in developed countries is likely to slow oil demand growth in these countries. The effect over the next few years, however, is small, since hybrid, electric, CNG and fuel cell vehicles are all growing from a very low base. I believe that solar power may become the main threat to continued rises in oil demand over the next decades, as continued advances in solar cell efficiency and battery technology may eventually make electric vehicles a compelling substitute for vehicles using an internal combustion engine.

² Contango – a term used to describe the situation in which the spot or cash price of a commodity is lower than the forward price

FRAMEWORK FOR ANALYSING OIL PRICES

I think that much market commentary about oil prices puts the cart before the horse. It talks about where OPEC wants or needs the spot price to be, and then works out where the forward curve should go. I believe that oil price formation works the other way round. The long-dated forward price is the market's best guess at the marginal full cost of oil supply. As most OPEC oil production is low-cost, it has limited influence on this long-dated price. However, by heavily influencing short-term supply, OPEC can control the spot price premium or discount to this long-dated price (i.e. whether the market is in contango, as it is now, or backwardation, as is more normal).

Figure 10: Oil Price Formation: Spot Price and the Forward Curve



Source: Analyst representation

I believe that the spot oil price is best considered as being made up of two items: a long-term structural component set by the perceived long-term marginal full cost of oil (or oil substitute) supply, and a short-term cyclical component set by short-term supply/demand dynamics. The long-term structural component drives the price of long-dated oil futures. The spot oil price represents the addition of the long-term component and the discount or premium determined by short-term supply and demand. To illustrate this, I have plotted two stylised oil price forward curves (one in contango and one in backwardation) using the same long-term marginal total cost of oil production as shown in Figure 10 above.

I BELIEVE THAT THE SPOT OIL PRICE IS BEST CONSIDERED AS BEING MADE UP OF TWO ITEMS: A LONG-TERM STRUCTURAL COMPONENT AND A SHORT-TERM CYCLICAL COMPONENT

When short-term demand outstrips supply, inventories are generally low, the spot price trades at a premium to the long-dated future contracts and the market is said to be in backwardation. In such a tight market, this premium for prompt delivery reflects the scarcity of oil for immediate delivery.

When short-term supply outstrips demand, inventories are generally high, the spot price trades at a discount to the long-dated future contracts and the market is said to be in contango. In such a soft market, this discount reflects the cost of carrying inventory (the cost of the oil inventory, the cost of storage, and the cost of borrowing to fund these). Thus, the spot price is set by the arbitrage of buying and storing crude for sale at a future date. This arbitrage sets the structure for the forward curve.

The main constraint on the downside for the spot price is that it cannot sustainably fall below the marginal variable cash cost of oil production, as marginal oil producers will eventually stop producing if their variable cash costs are not met. I estimate that the marginal variable cost of oil production is currently at about US\$20/bbl Brent. There is no such constraint on the upside for the spot oil price. Should short-term supply not meet short-term demand, the price rises and more marginal uses of oil are reduced or stopped (i.e. demand destruction would take place).

THE MARGINAL FULL COST OF OIL SUPPLY REFLECTS THE PRICE REQUIRED TO STIMULATE INVESTMENT IN THE LAST NEEDED BARREL OF OIL PRODUCTION CAPACITY

As the lead time from the decision to invest to when conventional oil production actually occurs is generally several years, the long-dated future contract is the benchmark oil price companies should use in their financial models when taking any decision to invest in conventional projects, in my view. To stimulate investment, the long-dated futures price must cover the company's full cost of oil production. To encourage the last needed barrel of oil production the long-dated futures price must cover the marginal (barrel) full cost of production.

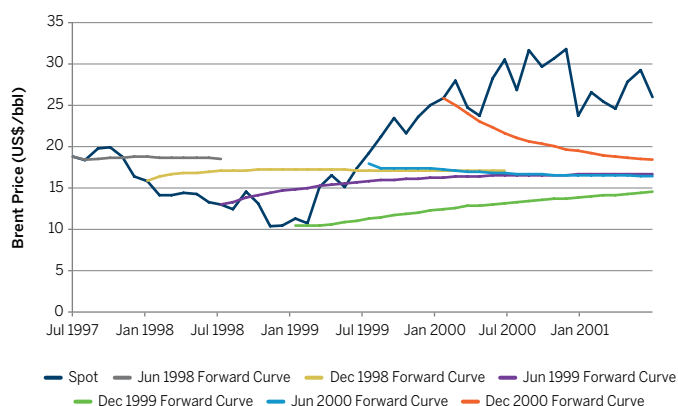
CYCLICAL COMPONENT

In Figure 11 overleaf, I have presented the Brent spot price and forward curves from 1997 to 2001, when the structural component was relatively stable. The spot price fell during 1998 as the East Asian financial crisis caused demand to fall below expectations. OPEC was slow to react, inventories built up, and the market was put into a sharp contango: Brent spot prices fell from US\$20/bbl to US\$10/bbl.

The long end of the curve also fell, but not by nearly as much as the spot price. It traded down to around US\$15/bbl (from US\$19/bbl) as the market priced in lower oil service costs and delays to high-cost projects.

By the beginning of 2000, OPEC had acted and the spot price was above US\$25/bbl and the long-dated price had moved back to US\$19/bbl. The market had gone full circle and was again assuming a US\$19/bbl long-term marginal cost of supply, as it had in 1997.

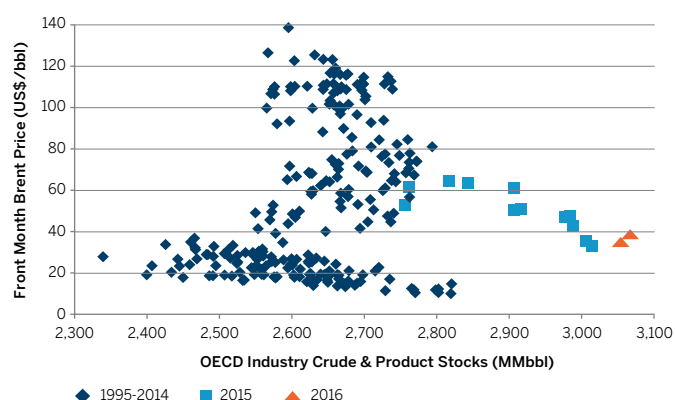
Figure 11: Brent Prices 1997-2001: Spot and Forward Curves



Source: Bloomberg

A graph of the spot Brent oil price vs. global crude and product stocks from 1998 to 2016 shows little correlation (Figure 12). To obtain a reasonable correlation between spot prices and inventory over the period an adjustment is needed for the rise in long-dated futures prices that occurred after 2003 by looking at the spread between spot prices and long-dated prices vs. inventory.

Figure 12: 1998-2016 Spot Oil Price vs. Global Inventories

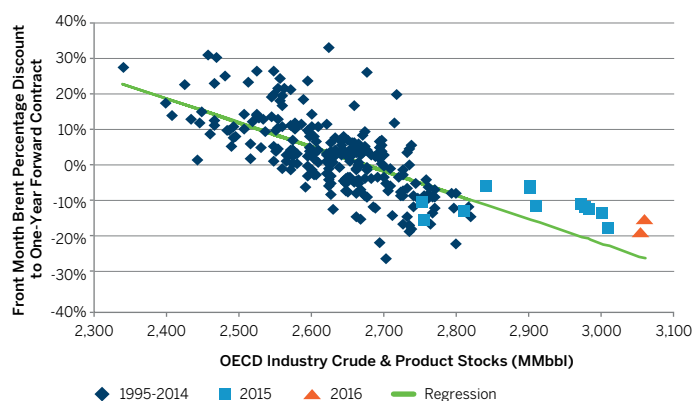


Source: IEA, Analyst estimates

In Figure 13, I have plotted the oil price spread (in this case the one-month Brent premium/discount to the 12-month forward price as a percentage of the 12-month forward price) against global industry crude and product inventories. Although not a perfect relationship, I believe this supports my view on oil price formation.

THE OIL PRICE SPREAD AGAINST GLOBAL INDUSTRY CRUDE AND PRODUCT INVENTORIES SHOWS A REASONABLE CORRELATION

Figure 13: 1998-2016 Oil Price Spread vs. Global Inventories



Source: IEA, Analyst estimates

STRUCTURAL COMPONENT

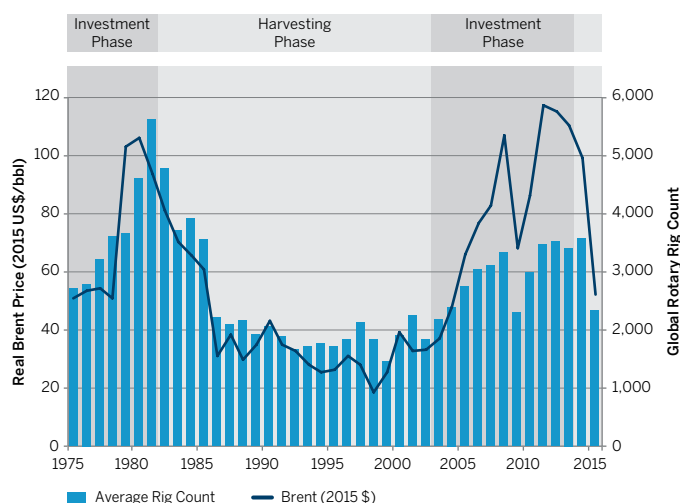
The long-term structural component of oil prices is subject to long (many years) cyclical changes in the industry's underlying costs, which I believe can be split broadly into two phases: an 'investment phase' and a 'harvesting phase'. During the investment phase, a scarcity of oil production inputs (oil rigs, service crews, geologists, etc.) causes a rapid rise in the cost of oil production, and consequently a rapid rise in the structural component of oil prices.

THE STRUCTURAL COMPONENT OF OIL PRICES IS SUBJECT TO LONG CYCLICAL CHANGES IN THE INDUSTRY'S UNDERLYING COSTS

This phase is typically associated with a considerable increase in oil production input capacity, brought about by the resulting high oil prices. This happened in the late 1970s and from 2003 to 2014. Eventually an oil price fall leads oil production input capacity to outstrip demand. During this 'harvesting phase', production input costs fall and the structural component of oil prices declines at first and then remains roughly flat while the excess input capacity is gradually worked off. This happened from the mid 1980s through to 2002. I believe the industry has just entered the next 'harvesting phase'. In Figure 14 overleaf, I show the real oil prices and active rotary rig count over the last 40 years split between 'investment' and 'harvesting' phases.

FRAMEWORK FOR ANALYSING OIL PRICES

Figure 14: Real Oil Prices and Global Rig Count

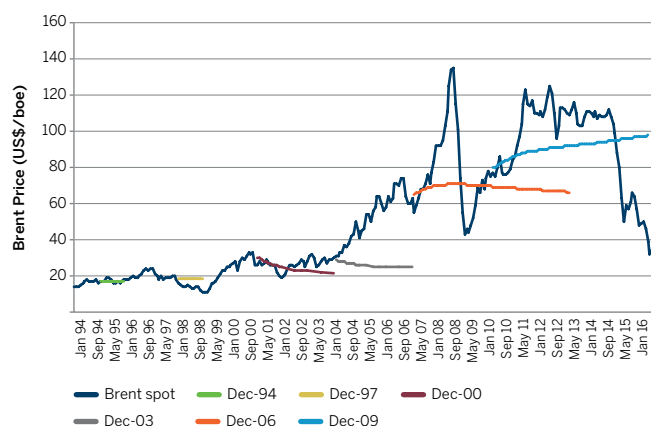


Source: BP Statistical Review of World Energy, June 2014, Baker Hughes, Analyst estimates

During the 1970s, geopolitical supply shocks (e.g. the Arab Oil Embargo and the Iranian Revolution) led to a substantial increase in oil prices. This encouraged a rapid expansion in non-OPEC production and the associated oil service inputs. For example, active global rotary rigs increased from under 3,000 to over 6,000. From 1980 to 1985, Saudi Arabia tried unsuccessfully to maintain a high oil price by cutting its production. In 1986, having cut production by over 50% from its peak level, Saudi Arabia ceased trying to support oil prices.

From 1986 until 2003 the structural component of the oil price (represented by the long-dated oil price) remained in a relatively tight range (US\$15-23/bbl). I believe the long-dated oil price stayed stable in nominal terms throughout this period due to the ample capacity prevalent in oil industry inputs (drilling rigs, etc.). Excess capacity in these oil production inputs had been built up during the investment phase in the 1970s, when oil prices were much higher.

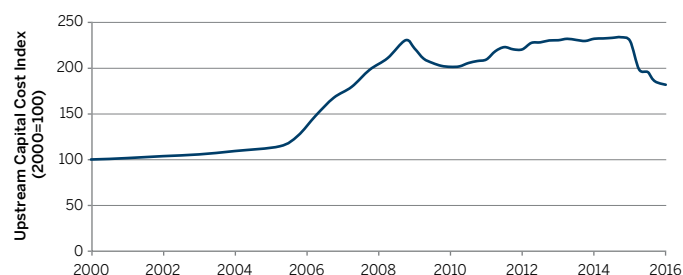
Figure 15: Brent Prices 1994-2016 — Spot and Forward Curves



Source: Bloomberg

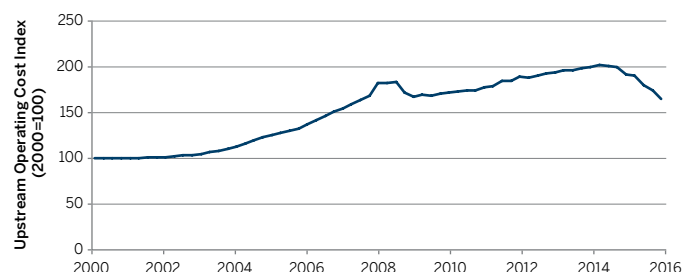
By 2004, I believe that 15+ years of global growth in oil demand had used up most of the spare capacity in supply industry inputs, such as oil rigs. Thus, oil industry input prices started to surge. Not only did day rates on rigs increase, but also prices of steel pipe and geologists' salaries rose dramatically. Below I show the Upstream Capital Cost Index (UCCI) and Upstream Operating Cost Index (UOCI) produced by IHS CERA, which clearly show the substantial capital and operating cost inflation in the industry from 2004 until 2008. All this was reflected in long-dated oil prices. By the end of 2009, just after the global financial crisis, the five-year forward price of Brent was over US\$90/bbl.

Figure 16: Upstream Capital Cost Index



Source: IHS CERA

Figure 17: Upstream Operation Cost Index



Source: IHS CERA

I BELIEVE THAT THE INDUSTRY HAS ENTERED A NEW HARVESTING PHASE

Given the high oil prices (well above the marginal full cost of supply) we have generally had from 2008 to 2014, I believe that the industry has just entered a new 'harvesting phase'. Once the current short-term cycle has turned and the oil market has returned to backardation, there will continue to be substantial excess capacity in industry inputs (oil rigs, etc.) keeping industry costs below the levels they reached from 2008 to 2014. This might be viewed as positive for the industry, but lower input costs will also feed through into a lower marginal full cost of supply, and thus lower long-dated oil prices, about which spot prices should fluctuate.

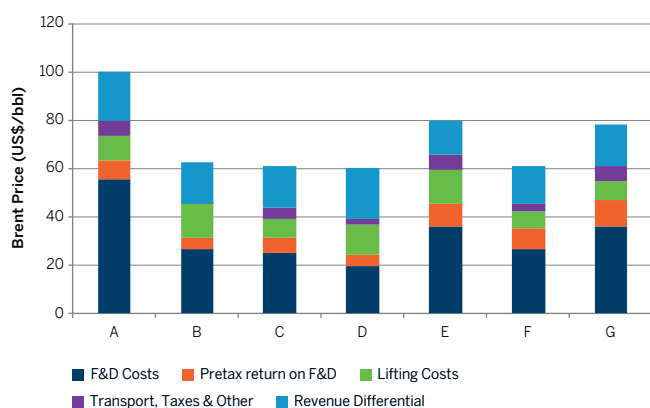
ESTIMATING THE MARGINAL FULL COST OF OIL SUPPLY

COMPANY FULL COST OF OIL SUPPLY ELEMENTS

I have used the ASC 932 (Supplemental Oil & Gas) data attached to the US GAAP (United States Generally Accepted Accounting Principles) accounts of over 80 of the world's largest publicly-traded companies to estimate the Crude Oil Full Cost Supply Curve. The crude oil and NGL production of these companies totalled 32.4MMbpd in 2015, or around 56% of non-OPEC production. Their 2013 upstream oil and gas revenue was over one trillion dollars (it was roughly US\$590bn in 2015). The ASC 932 data includes proven oil and gas reserve levels and movements, upstream results of operations, upstream exploration, development and acquisition costs incurred, and capitalised costs. This allows me to estimate the full cost of crude supply for each company. This then allows a supply curve to be constructed company by company. Each company's full cost of oil production is made up of the following elements (with data for seven anonymised oil & gas majors presented in Figure 18 below):

- Revenue differential
- Lifting costs
- Production taxes
- Finding & development costs
- Cost of capital

Figure 18: Oil & Gas majors' 2015 Full Cost of Oil Supply



Source: Company data (anonymised), Analyst estimates

Revenue Differential

The actual oil and gas revenue per barrel of oil equivalent reported by companies depends on the crude quality, the proportion of gas produced, and the location of production. The quality of oil affects the price it can be sold for. The lighter the crude (shorter chain hydrocarbons) and the sweeter the crude (less sulphur), the higher the price it can achieve.

As gas is generally produced at the same time as oil, companies report combined oil and gas revenues and costs. It is not normally possible to split the revenues and costs of oil production from those of gas production. I convert gas reserves and production to boe on a rough energy equivalence basis. In my calculations I have used 6,000 cubic feet of gas equals one barrel of oil (6Mcf = 1bbl).

Over the last few years, both US and European gas prices have been considerably lower than oil prices when converted in this way to a boe basis. For example, in 2013, when Brent averaged US\$108.68/bbl, Henry Hub averaged US\$3.83/Mcf of gas, or just US\$23.00/boe. Thus, all else being equal, the greater the percentage of production that is gas, the wider the discount to benchmark oil prices a company will report.

As revenue is measured 'at the well-head', location and the final destination market also affect the price received. For example, Russian companies report wide discounts to benchmark oil prices. Lukoil's 2013 upstream revenue was just US\$53.85/boe, or US\$54.83/boe below the average Brent price. This reflects the long distance from well-head to refinery or export port, the low Russian domestic crude oil price, and that revenue is reported net of the export tax paid on Russian crude exports.

To calculate the revenue differential, I take the reported oil and gas revenue (from the results of operations) and divide by the oil and gas production (from the reserve movements) to arrive at the revenue per boe. Subtracting this revenue per boe from the average Brent price for the year gives the revenue differential per boe.

Lifting Costs

The lifting costs (or production costs) represent the ongoing variable and fixed cash cost required to produce the oil and gas. Lifting cost levels are mainly determined by location and geology. The main lifting costs are usually energy (pumps are often used to transport oil up from the reservoir or to maintain reservoir pressure through water flood or gas injection), maintenance, and staff costs.

To calculate the lifting cost per boe, I take the reported oil and gas production costs (from the results of operations) and divide by the oil and gas production (from the reserve movements) to give the lifting cost per boe.

Production Taxes

Oil companies pay 'windfall' taxes of various sorts to host governments. These include royalty payments, production taxes, export duties, and increased levels of profit (corporation) tax. Revenue is often reported after royalty payments and export duties, and thus is included in the revenue differential above.

To calculate the production taxes per boe, I take the reported production taxes (from the results of operations) and divide by the oil and gas production (from the reserve movements) to give the production taxes per boe.

ESTIMATING THE MARGINAL FULL COST OF OIL SUPPLY

Finding & Development Costs

Finding costs include the cost of exploration to find the oil in the first place, and also include the cost of appraisal to firm up the resources to justify a commercial development. The main finding costs are drilling, seismic surveys, and geological surveys. Development costs are the capital cost required to build the infrastructure to allow the oil to be produced. These are generally several times larger than finding costs. Development cost levels are mainly determined by location and geology. The main development costs are usually drilling, gathering pipelines, separation/treatment plant and platform costs (if the oil is offshore).

I estimated each company's finding and development cost by summing its exploration and development expenditure over the last five years (from the incurred costs) and dividing the result by total changes in proven oil and gas reserves from extensions and discoveries, improved recovery, and revisions (from the reserve movements) over the same time period. I have used a five-year period because this matches the Securities and Exchange Commission (SEC) rule that undeveloped proven reserves should only be booked if there is a sanctioned plan to develop them within the next five years.

Cost of Capital

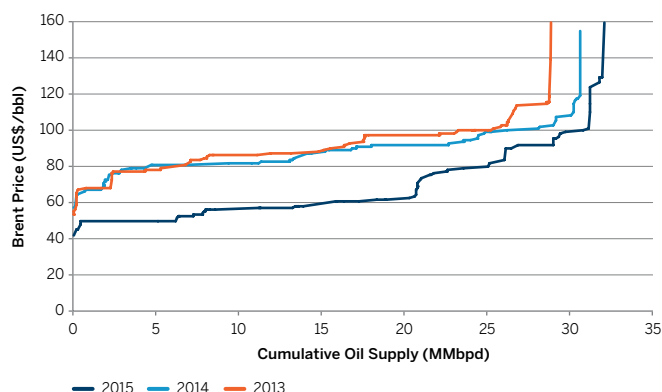
The cost of capital can easily be forgotten by oil and gas executives — and indeed oil and gas analysts. In order for a project to be sanctioned, companies need to foresee a reasonable return on their investment to compensate for the risks involved.

I have estimated the per boe cost of capital by multiplying each company's finding and development cost per boe by an after tax illustrative 10% return, grossed up for the corporate profit tax rate. For example, if the corporation tax is 33%, I would multiply the finding and development cost by 15% ($0.1/(1-0.33) = 15\%$).

REPORTED FULL COST OF OIL SUPPLY

In Figure 19, I have built up a large part of the non-OPEC supply curves for the last few years. I have used the liquid (crude oil, natural gas liquid and synthetic crude oil) production levels and the full supply cost of each of the 81 companies in my database. I estimated the 2015 marginal full cost of oil production by finding the full cost of the 9th decile (highest cost 10% of production), which was around US\$95/bbl. This is down only slightly from around US\$100/bbl in 2013 and 2014.

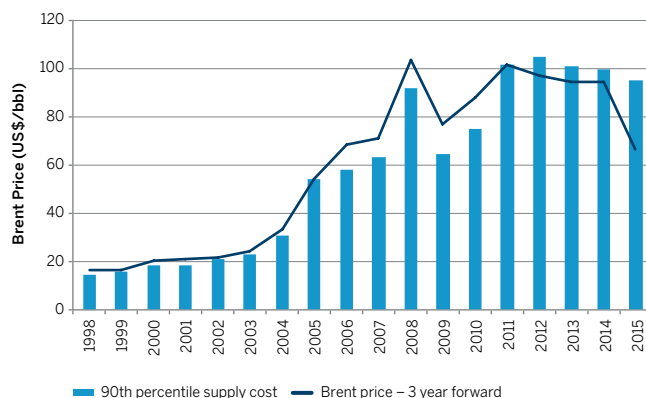
Figure 19: Non-OPEC Crude Oil Full Cost Supply Curves



Source: Analyst estimates

I believe the marginal full cost of supply calculated in this way gives a good first approximation of the real marginal cost of oil supply. In Figure 20, I have plotted the average annual 36-month Brent forward contract price against my estimate of the marginal full cost of oil production from 1998 to 2015. This Figure shows that the marginal full cost of supply barely changed from 1998 to 2003, before rising substantially from 2003 to 2008.

Figure 20: Marginal Full Cost of Supply & 36-month Forward Brent Prices



Source: Analyst estimates

My estimates of the reported marginal full cost of supply (US\$95/bbl) is much higher than long-dated Brent forward contracts, which currently trade at US\$58/bbl to US\$62/bbl. Part of the explanation for this is unusually high 2015 finding and development (F&D) costs, which in turn is due to unusually high net negative oil and gas reserve revisions that companies reported for that year (a relatively large percentage of 2014 reserves became non-commercial at the lower 2015 oil price). However, the industry's inability to control development costs and poor exploration record over the past five years have also made a major contribution.

I ESTIMATE THAT THE 2015
MARGINAL FULL COST OF
SUPPLY WAS US\$95/BBL

The marginal cost company in my selection had a 2015 full cost of supply of US\$95/bbl. Roughly US\$70/bbl of these costs were costs the company has control over (F&D costs, lifting costs, etc). The other US\$25/bbl was due to taxes and a revenue differential. The split of controllable costs to non-controllable costs is similar for adjacent companies in the full cost supply curve. If we assume that a 20% to 35% cost saving from 2015's level in its controllable costs can be achieved, then the marginal full cost of supply would fall to roughly between US\$70/bbl and US\$80/bbl.

ADJUSTED FULL COST OF OIL SUPPLY

When the average annual oil price is below the marginal full cost of production, that year's reported production taxes per barrel of oil equivalent (boe) and discount to benchmark prices per boe are lower than would have been the case had the oil price equalled the marginal full cost of production. We can adjust the full cost of supply for each company.

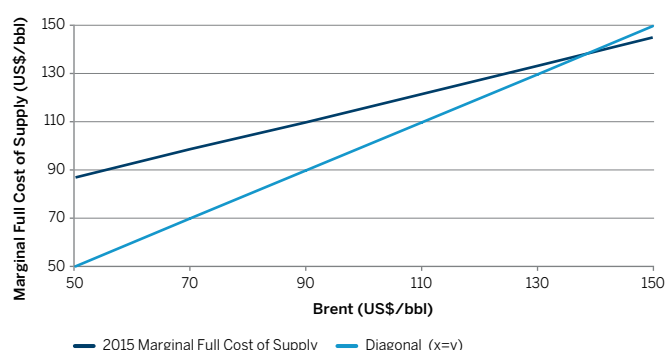
I ESTIMATE THAT THE 2015
ADJUSTED MARGINAL
FULL COST OF SUPPLY WAS
US\$135/BBL

One of the largest components of many companies' reported cost of oil supply is the revenue differential to the main oil benchmark I use — Brent. The main cause of this for the vast majority of companies is the significantly lower boe revenue achieved for gas sales (particularly in the US). For example, in 2015, when Brent averaged US\$53.60/bbl, Henry Hub averaged US\$2.63/Mcf of gas, or just US\$16.15/boe. The per boe revenue differential that we calculate will depend on the difference between that year's benchmark oil price and that year's gas price. When the average annual oil price is below the marginal full cost of production, reported discounts per boe to benchmark prices are lower than would have been the case had the oil price equalled the marginal full cost of production. Thus, each company's reported full cost of supply will be understated when the Brent price is below the marginal full supply cost (as was the case in 2015) and overstated when Brent is above the marginal full supply cost (as was the case in 2013 and 2014).

Similarly, reported production taxes are dependent on the average annual oil price. Fiscal regimes are set up so that higher oil prices lead to higher production taxes per boe for host governments. The per boe production tax in my cost of supply calculation will be understated when the benchmark price is below the marginal full supply cost. It will be overstated when the benchmark is above the marginal full supply cost.

To take account of these relationships, I ran a multiple regression for each company, to see how the per boe revenue differential and production tax varied with benchmark oil and gas prices. Using the coefficients from the results of these regressions (which generally had very strong r^2) allowed me to calculate new marginal full costs of supply at different benchmark oil and gas prices. In Figure 21, I have plotted calculated adjusted marginal full costs of supply against Brent (assuming a Henry Hub gas price of US\$3/Mcf). The point at which this line crosses the diagonal line (i.e. is equal to the Brent input price) represents the adjusted marginal full cost of supply. From this chart I estimate that the adjusted marginal full cost of supply in 2015 was around US\$135/bbl.

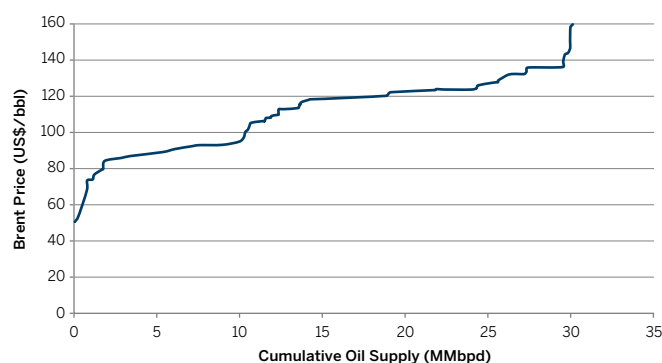
Figure 21: Marginal Full Cost of Supply vs. Brent Price



Source: Analyst estimates

In Figure 21, I have plotted the Adjusted Full Cost of Oil Supply Curve using Brent at US\$135/bbl and Henry Hub at US\$3/Mcf. With a 2015 adjusted marginal full cost of supply of around US\$135/bbl and an average Brent oil price of US\$54/bbl, most of the industry was making significant losses.

Figure 22: Adjusted Full Cost of Oil Supply Curve



Source: Analyst estimates

ESTIMATING THE MARGINAL FULL COST OF OIL SUPPLY

ADJUSTED CASH COST OF OIL SUPPLY

The marginal cash cost of supply represents the floor below which spot oil prices cannot sustainably fall. At prices below this level marginal supply generates negative operational cashflow, and companies will start to 'shut in' (i.e. halt) this production. Spot oil prices do not necessarily fall to this floor in a downturn.

AT PRICES BELOW THE MARGINAL CASH COST OF SUPPLY, MARGINAL SUPPLY GENERATES NEGATIVE OPERATIONAL CASHFLOW, AND COMPANIES START TO 'SHUT IN' THIS PRODUCTION

I have looked at how oil prices behaved in two previous down cycles, to assess how close they got to my estimate of the marginal cash costs. In Figure 23, I have plotted the spot Brent price as a multiple of the marginal cash cost at that time. The horizontal axis represents months from the peak in Brent spot prices. In 1998, oil prices fell very close to marginal cash costs, while in 2008 they stayed well above my estimate. I estimate that the current marginal cash cost of oil supply is just under US\$20/bbl.

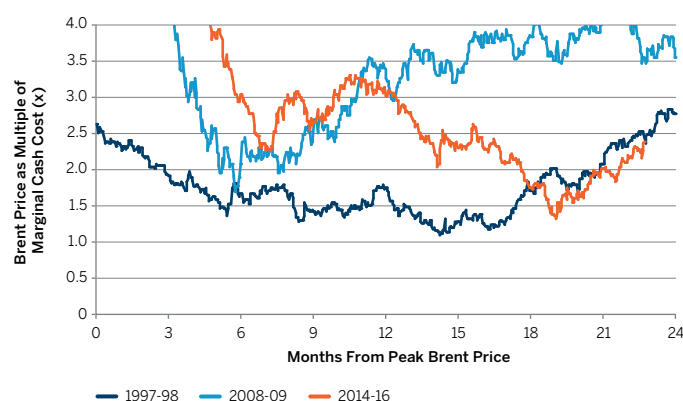
In the 1997-98 oil price fall, Brent got close to my estimate of the marginal cash costs at that time. I estimate, using the same methodology as for estimating 2015 marginal cash costs, that 1997 marginal cash costs were around US\$8.20/bbl (Brent). In December 1998 (14 months after the oil price peaked) the Brent price fell as low as US\$9.00/bbl, or within 10% of the marginal cash cost at that time.

In the 2008-09 oil price fall, Brent stayed above my estimate of the marginal cash costs at that time. I estimate that 2007 marginal cash costs were around US\$20/bbl (Brent). In December 2008 (six months after the oil price peaked), the Brent price fell as low as US\$34/bbl, or 70% above my estimate of the marginal cash cost at that time.

I ESTIMATE THAT THE ADJUSTED MARGINAL CASH COST OF SUPPLY WAS US\$20/BBL IN 2015

In January 2016, the Brent spot price fell briefly to US\$26/bbl, or 1.3x my estimate of marginal cash costs. Current spot Brent prices are just under US\$50/bbl, which is more than double my estimate of marginal cash costs. Should global oil stocks build to a level where the cost of arbitrage (buying and storing oil for future sale) would imply a discount to long-run full supply costs, which would put the spot price below US\$20/bbl, I would expect the marginal cash cost of supply to act as a floor.

Figure 23: The Oil Price as a Multiple Of Marginal Cash Costs



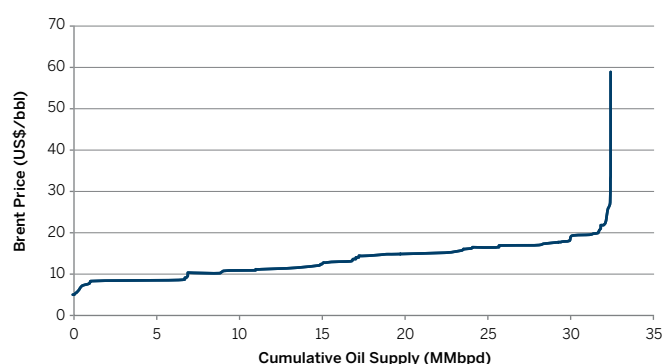
Source: Company data, Analyst estimates

Using the same ASC 932 data, I can calculate each reported company's cash cost of oil production, which is made up of the following elements:

- Revenue differential
- Lifting costs
- Production taxes

This therefore excludes the capital and cost of capital elements in the full cost of supply calculation. Adjusting for the dependence of the revenue differential and production taxes on benchmark oil prices using the same regression coefficients as above, this allows me to estimate the adjusted marginal cash cost of oil supply (defined as the price at which 10% of cumulative company production was cashflow negative at the operating level). In 2015, the adjusted marginal cash cost of oil supply was just under US\$20/bbl. I have plotted the adjusted cash cost of supply curve in Figure 24 below.

Figure 24: 2015 Adjusted Cash Cost of Supply Curve



Source: Analyst estimates



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