Global oil supply: the decline rate problem

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About the authors

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Charles has extensive experience in both industry and fund management. Before joining Investec Asset Management two years ago, Charles worked at Newton Investment Management (BNY Mellon) for 12 years, where he led oil and gas research and was the number one rated buy-side oil and gas analyst in the Thomson Extel Survey for 2012.

Charles spent nearly 20 years in the oil and gas industry before coming to the City, much of this time was spent in reservoir engineering roles, with responsibility for optimising recovery and understanding decline from oil and gas fields. Charles has been responsible for field development plans for oil and gas fields and for several field studies looking at increasing recovery from fields using primary, secondary and tertiary recovery mechanisms. At BNOC/Britoil Charles was responsible for reservoir studies that enabled economic production from the tight lower reservoirs of the Beatrice field; he also worked on reducing depletion for the Thistle field by more efficient use of water injection, and ran simulation for tertiary recovery using polymer injection. At ARCO Charles was responsible for the field development plans for the Blenheim oil field, the Thames field compression, and the Welland and Trent and Tyne fields. Charles led industry and joint venture initiatives to open up the shale dominated carboniferous area of the UK southern gas basin for development and worked reservoir studies for the Viking Graben, Central Graben, Hampshire Basin in the UK and Prudhoe Bay in Alaska. Charles has expert knowledge in reservoir characterisation, simulation, special core analysis, relative permeability and well testing – all of which are critical for understanding oilfield recovery and decline. Charles maintains a strong interest in leading-edge oilfield technologies, visiting research and technology centres for the oil and service companies. Charles has recently returned from visiting companies in the W Texas Permian basin, and has visited fields and operations in North and South America, Europe, Russia, Africa, Asia and Australia in the last 5 years.

Tom Nelson, Co-Portfolio Manager of Investec Global Energy

Tom Nelson’s experience is principally on the investment side where he has been part of two very successful energy investment teams since 2005. Before joining Investec Asset Management two years ago Tom worked at Guinness Asset Management where he was Co-Portfolio Manager of the Guinness Global Energy Fund with a specific focus on Exploration & Production companies. He was previously part of the team that managed the outsourced Investec Global Energy Fund from 2005-2008.

He has gained first-hand exposure to the leading geoscience and exploration teams from all of the major oil and gas companies, and has also engaged consistently with consultants and industry leaders on the topic of oilfield depletion and production decline rates.


The views expressed in this document are those of the authors and may not reflect the views of all the investment professionals at Investec Asset Management.
Introduction

We believe the market has been complacent about oil supplies for too long. Despite a very poor decade of exploration drilling and very limited production growth even allowing for sharply rising industry capital expenditure, commentators continue to talk about comfortable oil supplies and long-term oil price weakness. We think that there are fundamental industry and geological trends that are being misunderstood and which will lead to a tightening oil market, and it is our intention to address and explain them in this paper. We will also cover the significant investment opportunities that derive from this analysis later in the paper.

Background

At Investec Asset Management we have a clearly defined investment process for all of our Commodities & Resources strategies. As can be seen from the diagram below, the investment process begins with commodity supply and demand analysis. Given our significant industry experience (Britoil, ARCO, BP, British Steel, Commodities Research Unit, BHP Billiton, Xstrata), we believe we are well-equipped to undertake this analysis ourselves.

Figure 1: Investment process

A thorough understanding of commodity price fundamentals forms the basis of successful investment in resource equities. When we analyse the global oil market we focus on four main drivers: supply (OPEC and Non-OPEC), demand (OECD and Non-OECD), marginal cost and inventory levels. Projections of supply growth are based on two main drivers: incremental production from new projects, offset by decline rates from existing production. We will go into further detail on the fundamentals of reservoir properties and production declines in the next section. What is clear from our analysis is that the decline rates from existing production are being underestimated and are likely to increase in future with new development trends – and this is what has compelled us to write the paper.
Consistent optimism about new supply growth

The International Energy Agency (IEA) was set up in 1974, following the 1973/1974 oil crisis. One of its founding mission statements was to operate a permanent information system on the international oil market. Forty years on the IEA’s oil supply and demand analysis is considered authoritative. Given its history, access to data, and experience in the sector (its 2008 World Energy Outlook contains a global decline rate study based on the 800 largest oil fields in the world) it is surprising that its forecasts for Non-OPEC production growth have been consistently too high throughout the last decade: in 7 of the last 10 years the IEA has overestimated Non-OPEC production growth for the following year. Given its role to ensure adequate supply, it is concerning that it has been so consistently optimistic and wrong. It is increasingly clear that in making production growth estimates the IEA and others are repeatedly making the same mistake. They rightly spend a lot of time considering project delays and production disruption, which are relevant ‘above ground’ risks, but they are consistently miscalculating reservoir depletion and production decline rates which are the all-important ‘below ground’ factors. Hence in making production forecasts they are modelling incremental supply but underestimating the underlying losses from declines. Moreover, as we shall examine later, these underlying decline rates are rising as the industry becomes more reliant on deepwater fields, unconventional fields, and overall smaller field sizes. We think the IEA’s forecast for 2014 Non-OPEC supply growth which started at 2 million barrels/day will continue to be revised lower.

In our last White Paper “US Energy Independence: Fact or Fiction” (January 2013) we published our extensive analysis of US tight oil plays in which we detailed our bottom-up work on the Bakken, Eagle Ford and Permian basins in the US, as well as the lesser and less prolific plays. It is clear from our work that some of these plays will deliver strong growth, but some will disappoint. What the market is overlooking is how weak the production profile has been in the rest of the Non-OPEC world. In the chart below we illustrate annual production growth from the Non-OPEC ex-US, and the result is startling: if we strip out biofuels and US growth, Non-OPEC production is flat since 2004.

Figure 2: Annual oil production from the Non-OPEC ex-US, ex biofuels

Source: IEA
“Every two years the oil industry needs to build a new Saudi Arabia”
Peter Voser, CEO Royal Dutch Shell, 1 October 2013

In making his statement Voser encapsulates the corrosive effects of decline rates on the global oil industry as seen by the CEO of the world’s second-largest listed oil company. A new Saudi Arabia represents 9 million barrels per day of production, hence a new Saudi Arabia every two years equates to 4.5 million barrels per day per year out of global production of 90 million per day. This 5% is broadly consistent with the findings of our decline rate studies, which we will analyse later. The greatest challenge for the industry is offsetting decline rates.

Investment opportunities

If supply growth continues to be hindered by underlying oilfield decline rates as we expect, the implications for the oil price are structurally positive. We believe that when the extent of the production challenge is understood, energy equities will be re-rated.

This will present a strong operating environment for the whole sector, but selected areas and companies will be particular beneficiaries. Resource-rich companies with deep asset bases, differentiated service and drilling companies, and prolific explorers will lead the sector and we believe that through our greater understanding of the industry challenges we are well placed to identify tomorrow’s winners.

Later in the paper we look in more detail at the relative valuation of the sector after five years of underperformance, and examine where the investment opportunities lie. First we take a quick trip through the fundamentals of oil recovery using our own first-hand experience.

Fundamentals of reservoir behaviour and oil extraction

In order to produce oil from the rock, or reservoir, it is necessary to move the crude oil from within the pores of that rock (where it has been trapped for millions of years) towards and into the wellbore and then to the surface. This requires energy. However, crude oil, unlike natural gas, has limited compressibility so there is limited energy in the system to drive the fluid to the surface. Also crude is much denser than gas, so needs more energy to lift the fluid from the reservoir to surface. The combination of these factors means the Primary (unassisted) recovery from oilfields will generally be less than 20% of the oil in the reservoir.

Primary recovery is increased with artificial lift, which reduces the pressure at the bottom of the well that is needed to lift the oil to surface. Artificial lift might involve a downhole Electrical Submersible Pump (ESP), a rod pump (nodding donkey) or gas injection at the bottom of the wellbore. Incremental recoveries of 10% might be achieved with artificial lift. So black oil reservoirs may recover 25% of the oil-in-place through assisted primary recovery; whilst gas reservoirs will commonly recover 90%+ of gas-in-place with the help of compression.

Incremental Oil Recovery (IOR) or Secondary recovery improves recovery, generally to around 40%, though potentially 50% where the permeability profile and reservoir continuity are good. The focus for secondary recovery is the maintenance of the pressure in the reservoir. This is achieved by pumping water or natural gas back into the reservoir. In addition to re-energising the reservoir, the injecting fluid will also act as a piston, pushing the oil towards the production well; this works better with less viscous oils.
Enhanced Oil Recovery (EOR) or Tertiary recovery can take recovery to 60-70%. This enhanced recovery stage aims to increase the mobility of the oil within the reservoir, or reduce the bonds between reservoir rock and the fluid. Indeed, if you were to bring the rock to surface and flush with high pressure water, there would be a residual saturation of oil bound in the rock of around 30%. Tertiary recovery involves processes like polymer or steam injection, surfactants or even microbacteria – these processes are very capital intensive.

Recovery factors, or percentage oil recovery, will vary depending on the quality of the reservoir, the composition of the crude and the type of development. We demonstrate this later.

Depletion rates and production decline

Unlike a normal manufacturing process, it is a frustrating fact that an oilfield’s capacity to produce diminishes through time as the volume of oil available for production decreases and the deliverability of the production system reduces.

Although depletion and decline are often used interchangeably, there is a difference. In simple terms depletion refers to the proportion of recoverable oil that has been taken out of the reservoir. Decline refers to the reduction in production rate from the field. So depletion rate refers to the rate that the oil reserves are reducing, and the decline rate is the rate that production is declining. Generally oil field decline rates are much greater than other extractive industries. The reasons for this are numerous, the two most important being:

1) The hydrocarbon is under significant pressure; this energy is needed to drive the hydrocarbon out of the reservoir rock and up the well. As hydrocarbons are extracted pressure falls.

2) The effective permeability of the rock generally reduces as the hydrocarbon is produced, as the hydrocarbon saturation reduces and water saturation increases.

The diagram below demonstrates a typical production profile for a large conventional oil or gas development. As can be envisaged from this diagram, reserves are being produced from the start of production, so the field reserves (recoverable oil) are depleting. However, during the build-up phase, as wells are drilled, production is actually building (causing a reduction in a company’s overall decline rate). During the production plateau phase depletion rates are high and steady, whereas decline rates are zero. In the production decline phase decline rates are initially very high, whilst depletion rates are decreasing. As this phase matures decline and depletion rates reduce.

Figure 3: Typical production profile for a large conventional oil or gas development

Source: Höök, 2009
It is important to note:

Decline rates at a well level and at a field level will vary, mainly because incremental wells are added through time. This explains the difference between natural or underlying decline rates and observed decline rates.

Depletion rates may be defined as either a function of initial or remaining reserves.

**Are high depletion and decline rates a good or a bad thing?**

The design of an oilfield development is often a compromise. The oil company wants to maximise the investment return, whilst the host government generally wants to maximise recovery of reserves and the fiscal return. From the oil company’s perspective accelerated production is a positive. However, from the government’s perspective this is often not the case if it involves incremental capital expenditure which is set off against tax, and under many contracts, cost recoverable from initial production revenues. Some of the delay for new projects is explained by the time governments take to ensure the contract strategy is in-line with their objectives of local content and non-proliferation of infrastructure.

The reality is that as field sizes reduce (because we are not finding enough giant fields), there are faster ramp-up and shorter plateau periods for new fields, as the production is less likely to be constrained by the field’s process facilities. Though there are still notable exceptions, these tend to be the larger fields at the higher end of the technology curve (Guara Lula in Brazil and Kashagan in Kazakhstan being the obvious examples), where the ramp-ups have been delayed through either equipment failures or delays.

**Case studies**

Two fields, where the Investec team has first-hand operating experience, are reviewed.

**Thistle Field, UK Sector, Northern North Sea**

The Thistle field (see picture below) was developed using a single offshore platform installed in 1976. The platform is very large, approximately 75,000 tonnes of steel supporting two full size drilling rigs for the development phase (the tall structure in the photograph is the flare tower).

Figure 4: Thistle field

Source: Oil Rig photos
Production is from the Middle Jurassic Brent Formation (approximately 11,000 feet below sea level, which had been deposited around 168 million years ago). The production profile shown in the figure below is typical of fields of this era in the North Sea (first production in February 1978). There was limited drilling before the platform was installed, as the Xmas tree valve block for each well is located at the platform level (unlike today’s deepwater fields, which have subsea trees on the ocean floor, which allows more pre-drilling). There was an extended period of production build-up as wells were drilled and brought on production. As well as 43 production wells, there were 15 water injection wells. Water injection is necessary to maintain reservoir pressure, to stop gas breakout and to sweep the reservoir. Unfortunately, as in most of the Brent sandstone reservoirs, the water injection did not behave as envisaged in the initial reservoir simulation models. The contrasts in reservoir permeability, particularly the Etive and Ness sands of the B-R-E-N-T formation, caused the water to channel preferentially through the high permeability streaks, forming water highways between injection wells and production wells. This is the main reason why Thistle does not exhibit a plateau phase, because the water production grew quickly. So rather than oil process and export capacity, it was water separation and injection capacity that limited production (as is also evident in Figure 5).

Figure 5: Thistle oil and water production

The Thistle platform very quickly became a water treatment facility, as much greater volumes of water have needed to be recycled through the reservoir to achieve the same ultimate recovery from the field. Estimates for ultimate recovery for most giant and super giant fields have increased through time, as better technologies, and particularly the availability of greater computer processing capacity, have allowed more efficient reservoir management. Thistle’s reserve estimates went up initially as the early well productivity was encouraging, however this reversed as the impact on water production was understood. Several field extension projects later, the ultimate recovery for Thistle is up marginally on the original estimates, but this has taken many more years and much greater volumes of water. As with most northern North Sea offshore fields, the principal recovery mechanism for Thistle is water injection (secondary recovery), with most technical work focused on optimising the sweep pattern for the waterflood. The offshore location makes large scale tertiary recovery difficult, although some polymer injection has been used. From peak production, compound average decline rates (CADR) averaged 14.9% p.a. over the first 5 years and 16.7% p.a. over 10 years.

Whilst these numbers seem high relative to perceptions of decline, the data for the North Sea actually shows otherwise. We analysed the UK field database, and the overall total UK production decline from peak averages 24.3% CADR over the first 5 years, and 25.6% CADR over 10 years. Fields producing less than 5,000 barrels per day, which decline faster, were removed from the dataset. Fortunately the UK North Sea has several development areas so, although production peaked in 1999, the phasing of developments ensured that there were new fields coming on production offsetting decline, and many of the largest fields were past their high decline periods. The UK production as a whole has a CADR of 6.7% for the first 5 years after the 1999 peak and 6.6% CADR for the first 10 years.
Global oil supply: the decline rate problem

Prudhoe Bay, Alaska

Prudhoe Bay Field was the largest producing field in North America, producing over 1.5 million barrels per day at its peak. We chose Prudhoe Bay as an example of a super-giant onshore field. The size and the location onshore mean that it is viable to use a series of technologies to optimise recovery.

Figure 6: Prudhoe Bay, Alaska

Source: Northern Alaska Environmental Center

The field, or more accurately the series of reservoir structures, benefit from having a gas cap i.e. a cushion of gas sitting on top of the oil, which acts as an accumulator. Reinjection of produced gas into the gas cap gives another mechanism for field pressure maintenance. Indeed, rather than concentrating on secondary recovery through water injection, Prudhoe Bay has used most of the tricks in the book: horizontal wells, stimulation, artificial lift, in-fill drilling, waterflood, gas cap expansion/gravity drainage, miscible flood, polymer injection and gas stripping. The combination of these technologies and the modular nature of the field, as well as the constraints on peak production, mean that the decline profile is much less severe than a waterflood-dominated field.

Figure 7: Prudhoe Bay oil and water production

Source: Investec Asset Management
Prudhoe Bay came on stream in June of 1977, ramping up production until the field’s maximum allowable rate was reached in 1979 at 1.5 million barrels per day. This plateau rate, constrained by State approvals and transportation capacity, was maintained for a decade. Given the excess deliverability of the field, only produced gas reinjection was used initially to maintain pressure. Miscible gas flood commenced in 1983, and waterflood in 1984. The timing was critical, as the production from initial wells had declined by 40%. Over the field life, the well spacing has been cut down from the initial 320 acre plan to 80 acre spacing. The combination of 30 years of production optimisation and enhancement has yielded a 40% increase in reserves, taking the Prudhoe Bay field recovery factor to 60%, which is extremely impressive given the complex geology of the field.

It was extremely fortunate that the Prudhoe Bay fields and the North Sea came on production at the same time as the Iranian revolution took oil off the market. As can be seen from the Prudhoe Bay example, technology has increased recovery factors (from 43% to 60% in this case); incremental recovery from oil fields has provided a significant proportion of the major oil companies’ reserve replacement. Unfortunately, for current fields, the baseline has moved significantly higher, so there is limited potential to add incremental reserves.

Also evident from this work is the reduced flexibility that offshore facilities have compared with onshore when it comes to production enhancement. We confirmed this was not entirely a North Sea factor by looking at the Gulf of Mexico. Interestingly 5 and 10 year CADRs for the shallow water gulf were 11.6% and 10.7%, whilst the deepwater fields had CADRs of 19.6% over 5 years and 15.9% over 10 years. This confirms our expectation that deepwater fields, where the cost of intervention is high, will decline faster.

### Tight oil in North America

The tight oil revolution in North America also has had a significant impact since 2011, dampening oil price volatility during a period of significant political upheaval in the Middle East and North Africa following the Arab Spring. The fact that the maximum rate of additional production increases from US tight oil are behind us is apparently lost on an oil market that still prices in a significant backwardation in forward oil prices. This complacency was the main catalyst for us undertaking a full review of depletion rates and the underlying fundamentals for oil supply and demand.

### Why are new fields likely to decline faster?

The reality of oil exploration and development is that the largest fields are easiest to find and the first to be developed. As can be seen from the diagram later in the paper, discoveries of large fields peaked in the 1960s, most were developed by the 1980s and are now fully mature (increased recovery factors on these fields have fuelled reserve replacements for the majors for many years).

We believe that the majority of supply and demand projection is based on extrapolation and normalisation, with too little focus on changing trends in the industry. The industry this century is changing structurally, as the shortage of new opportunities drives the major western oil companies to new frontiers in order to replace reserves. From 2000-2010 exploration focus also changed from liquids to more natural gas, particularly for liquefied natural gas, and unconventional gas. With more than 50% of discoveries in recent years being in the deepwater, this decade we are seeing a further push into ultra-deepwater development, and a major push into unconventional oil in the United States. This structural change of increasing unconventional oil, deeper water and reducing field size will increase decline rates as outlined on the following page.
**Unconventional fields** are producing from very tight rock. Hydraulic fracturing introduces high permeability highways from the tight rock to the well. Initial production comes from this fracturing system and the rock that lines the fracture system. After this production the tight rock has to feed the fracture system, which requires more pressure drawdown, leading to slower and slower rates. This recharge works better with natural gas than crude oil due to the significantly greater mobility of the gas molecule. In unconventional oil reservoirs it is very difficult to use secondary and tertiary recovery mechanisms to help maintain pressure and to sweep the rock, as the rock system is too tight to accept the fluids. Unconventional oil production wells have a short period of clean-up (producing back the fracturing fluids); once the frac fluid is reversed out of the well, the maximum production rate is achieved, followed by a rapid decline (commonly 50% of well rate is lost in the first 30 days). The flow performance during the initial flow is dominated by the main fracture system, the rubbleised zone surrounding it, and any natural fracturing intersected. This will transition into a flow period where the rock matrix itself contributes; the steepness of the decline therefore depends on many factors. Rock with over-pressure, or high permeability sections will decline slower than tight rock, where the classical hyperbolic type curve (that requires flow into the well drainage area) will become significantly truncated, leading to reduced ultimate recovery.

**Deepwater fields** demonstrate different problems. Firstly these fields are produced from floating production systems, which do not have drilling rigs onboard, and are usually leased (on a high day-rate). With subsea well completions, access into the wells is significantly more difficult. The economics of a deepwater development differs from a conventional development which can be produced for longer with much lower operating costs, and the wells worked-over cheaply. The economic cut-off production rate for abandonment of deepwater fields is therefore significantly higher than conventional fields. In this scenario, the ultimate recovery is reduced; therefore the initial depletion rate is increased. The lack of tail production has a negative impact on portfolio decline rates. The impact of the deepwater is evident both in our research and in the IEA (WEO-2013) report, where post-peak decline rates are 12.7% for the deepwater (approximately 70% higher than the shallow water and 135% higher than onshore).

The development hopper is now full of **smaller fields**; these tend to see faster depletion because the initial production is not constrained by process and offtake capacity, so the natural and observed decline rates are similar with little in-fill drilling potential. Various studies analyse the impact of decline rates on smaller fields, and are in agreement directionally with our findings. Hook (2009) finds depletion-at-peak to average approximately 9% for giant fields and 17% for small fields. IEA (WEO-2013) has decline rates (post-peak) of 8% for giant fields and 11.9% for small.

**Oil field contract and fiscal terms also play a role in depletion**

Outside the US and Europe the majority of major oil projects developed by the listed companies are now under contract terms called Production-Sharing Agreements or PSA. Under this agreement the government or its agency, such as the national oil company (NOC), contracts the foreign or international oil company (IOC) to explore and develop the licence in return for an entitlement to a proportion of the production from the field. The proportion of production comes in two phases; firstly, during the initial phase of production (cost recovery) the IOC takes a high proportion of production until costs (or an agreed portion of costs) have been recovered. During the second phase (profit oil), the IOC takes a considerably smaller proportion of production, which can reduce further after certain returns thresholds have been reached, and will generally be subject to local taxes. Under this contract structure the NOC usually has to approve contracting strategies and major project awards, so is likely to push for a capital-light option (for example leased rather than purchased vessels). The IOC wants to bolster early production. The difficulty comes later in field life when there is little incentive for the IOC to invest incremental capex, and, as in the deepwater scenario above, unit operating costs are high – leading to early abandonment. Again, the ultimate recovery is reduced, therefore the initial depletion rate is increased as are future portfolio decline rates, as there are fewer projects with low-decline tail production.
What do the decline rate studies tell us?

Given the importance of the subject it is surprising that so few comprehensive decline rate studies have been undertaken. The most authoritative studies have come from the International Energy Agency as part of their World Energy Outlook, first in 2008 (Chapter 10: Field by field analysis of oil production) and recently in November 2013 (Chapter 14: Prospects for oil supply). Detailed statistical analysis has also been done by the Department of Earth Sciences at Uppsala University, most recently in December 2013 (Decline and depletion rates of oil production: a comprehensive investigation). We at Investec Asset Management built our own bottom-up global oil supply model in July 2013 incorporating country-by-country and field-by-field decline rates. We will also reference the Cambridge Energy Research Associates (CERA) paper from 2007 (Finding the Critical Numbers: What are the real decline rates for Global Oil Production?).

The studies draw on different datasets, and there are varying definitions and weighting methods within their analysis. In the table below we set out the published global decline rate numbers from the three main studies:

<table>
<thead>
<tr>
<th>Source</th>
<th>Decline Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>International Energy Agency</td>
<td>6.2%</td>
</tr>
<tr>
<td>Cambridge Energy Research Associates</td>
<td>5.8%</td>
</tr>
<tr>
<td>Uppsala University</td>
<td>5.5%</td>
</tr>
<tr>
<td>Average</td>
<td>5.8%</td>
</tr>
</tbody>
</table>

It is very striking that three non-competing organisations with independent data sets doing the analysis over a seven year period reach such similar numbers. The work we have undertaken internally at Investec Asset Management through our own global oil supply modelling also supports a decline rate of 6% but suggests that decline rates will move higher.

The three main studies analyse decline rates by different types of oilfield, for example OPEC vs Non-OPEC, onshore vs offshore, large vs small. The conclusions they reach are extremely consistent. Smaller fields tend to decline faster than larger fields. Offshore fields decline more quickly than onshore fields. And unconventional fields, such as US light tight oil, decline fastest of all. There are two principal conclusions to draw from this: first, that OPEC fields, which are predominantly onshore and very large, exhibit lower decline rates than Non-OPEC fields, and second, that decline rates are increasing. The reason for this is relatively simple: the industry outside OPEC is increasingly reliant on smaller fields, offshore fields and unconventional fields. The twin engines of Non-OPEC supply growth in 2014 are expected to be onshore US (unconventional) and Brazilian deepwater – both notably high decline areas.

The one outlier in all of this is the 2012 paper from Harvard Kennedy School which appears to ignore the mathematical effect of decline rates and paints a uniquely optimistic picture for global oil production growth (Oil: The next revolution). Maugeri, an economist, argues that it is impossible to predict the precise future production profile of an oilfield. He disagrees with the findings of the IEA and CERA decline rate studies, asserting that “throughout recent history there is empirical evidence of depletion overestimation.” He concludes that 2-3% is the actual global oilfield decline rate figure.

It is quite clear that Maugeri’s analysis is less detailed than the others – he does not have access to the full IEA, CERA and Wood Mackenzie databases – and his expectations for global oil supply growth are way above any others in the market. He arrives at a figure of 29 million barrels/day for risked new oil production coming onto the market by 2020 – an uplift of 31% on 2013 levels – which is bordering on the fantastical, in our view. His optimism on global oil production growth is summed up in this statement: “Contrary to what most people believe, oil supply capacity is growing worldwide at such an unprecedented level that it might outpace consumption. This could lead to a glut of overproduction and a steep dip in oil prices.” Yet even Maugeri concedes that smaller fields decline faster than giant fields, which is increasingly significant when we consider that the giant fields discovered in the 1950-1970 period will make up less of overall global oil production in the future.
What are the implications for the oil industry?

We believe Peter Voser is right. With global decline rates running at 5-6%, the global oil industry does indeed need to bring on 4.5-5.5 million barrels/day of new production each year to stem the losses from decline rates. Worryingly, because of the move towards unconventional fields (such as US tight oil), smaller fields (we are not discovering enough giant structures), and offshore fields (West Africa, US Gulf of Mexico and Brazil), this decline rate is rising rather than falling. There are two charts that capture concisely the challenges faced by the oil industry. In the first chart, we can see quite clearly how the exploration record of the oil industry has deteriorated since the ‘golden’ era of the 1950-1970 period, both in terms of number of discoveries but also size of discoveries. Indeed, more oil has been consumed each year than has been discovered every year since the early 1980s. Today, we consume 33 billion barrels of oil per year and are discovering 10-20 billion barrels at most. It appears that the biggest single oil discovery in 2013 was less than 1 billion barrels in size.

Figure 9: Deteriorating exploration record of the oil industry

Source: Investec Asset Management

This trend is alarming, particularly when we consider the huge growth in oil industry capital expenditure over the last twenty years. In the chart below we show the oil industry spending on exploration and production from 1985 to 2013:

Figure 10: Capex on exploration and production from 1985 to 2013

Source: Investec Asset Management
From 1992-2013, exploration capex (light blue line in Figure 10) increased by 540%, or 10% per year. This rise was in lockstep with the rise in the Brent oil price (black line), which moved from $19 to $110, or 9% annualised. Yet despite a huge increase in spending, global oil production grew by only 1.3% annualised from 1999-2013. So the industry has been discovering approximately 5% per year of what it did fifty years ago and has grown production at 1% per year over the last twenty years, despite the enormous ramp-up in spending. Current analysis expectations for capex growth in 2014 are in the 5-9% range; while this marginal slowdown may appease shareholders in the short term it will only exacerbate the supply shortage in the future.

At Investec Asset Management we built a bottom-up, country-by-country oil supply and demand model in 2013 to understand better the challenges the industry faces (Figure 11). On the supply side we used industry data on individual fields and projects combined with decline rate analysis from the studies referenced earlier. For demand, we looked at GDP forecasts from the IMF and World Bank for each country and looked at the historic correlation between GDP growth and oil demand growth to derive annual oil demand in the future. The outcome of the analysis is shown in the graph below:

Figure 11: World oil demand likely to outstrip supply by 2016 at current rates

Source: IEA, Investec Asset Management

If global oil demand continues to grow at 1-1.5% per year, which is not an aggressive assumption, total global demand will reach 105 million barrels/day within ten years. We currently have 2 million barrels/day of spare capacity: there is a lot of ground that needs to be made up in the coming decade if we are going to satisfy this new demand. Indeed, we can see in the graph that current spare capacity is exhausted by 2016. It is clear from this analysis that oil prices will have to move higher, both to stimulate increased supply, and to curb demand.

The greater technical challenges faced by the industry today are one of the main reasons why returns on investment have fallen for the super-major oil companies as the oil price has risen. The marginal cost of supply for many of the unconventional, deepwater and the oil sands plays have converged to around $80-90 per barrel.

A significant proportion of the unconventional oil drilling in the US has not been economic on a stand-alone basis; drilling has been necessary to retain licences. With the majority of initial licence commitments now satisfied, future drilling is much more sensitive to oil pricing. We anticipate a slowing in activity if US crude differentials widen to international crude markets, particularly if local prices fall below $90 per barrel.
Can technology save the day?

The underlying decline rate problem for new fields has been masked by improvement in recovery from the large producing developments. The website for oil company ENI states that recovery factors (the proportion of oil initially in place) have increased by over 10% since 1980, with each percentage increase in production potentially yielding two years of incremental reserves. The greatest technology breakthrough for the oil field was the ready access to computing capacity from the mid-1980s. This allowed for much more detailed interpretation and simulation of the geology and reservoir performance. Progress in seismic capture and interpretation, geological modelling, reservoir simulation, downhole logging and measurement, and directional drilling all benefited hugely from greater processing capacity.

Whilst there have been further step-changes in technology, for example the combining of horizontal drilling and multi-stage fracturing for the unconventional plays, it is difficult to envisage a step forward in conventional mature field recovery without a significant increase in the oil price. Strong oil prices since the turn of the century, and poor exploration results, have ensured that the international oil and service companies have focused on improving recoveries, so the easy steps have been achieved. Recovery factors, now anticipated to be around 50% in the North Sea (and as high as 70%) are now expected, where these would have been 35-40% 25 years ago.

Another reason why technology is unlikely to provide a further step-change to recovery factors is demonstrated by the performance of recent new-field start-ups. Historically fields were developed with lower anticipated recovery factors, so, as technology improved, there has been significant potential for improved recovery. Today’s fields are designed with more technology, with significantly higher baseline production expectations and therefore less potential for optimisation. However, worryingly, a study by one of our consultants, Kessler Energy, demonstrates that average field production for the peak year of production is averaging less than 70% of design capacity, reflecting the complexity and heady expectations for new field production.

With conventional and tight reservoirs the oil has migrated from a source rock to a reservoir rock, albeit over millions of years, demonstrating that the pore space (holes in the rock) have been connected. Many unconventional developments are targeted at the source rock, where the hydrocarbon has been trapped since generation, and has not been able to move. The actual fracturing of a rock from a wellbore will introduce high permeability flow paths, but only to a small production of the rock. Given that rock porosity might average around 5% (proportion of holes, where the oil sits), there is significant uncertainty as to the amount of the hydrocarbon pore space that is connected, and then has a route to the wellbore. We had an opportunity to inspect core samples taken from the Wolfcamp B formation in the Midland (Permian) Basin. This rock is a black shale, apparently very homogeneous (linear), small grained, well cemented, calcareous, and very competent (hard). With these properties it is not surprising that the rock propagates fractures well, and therefore high initial rates should be anticipated. However, once the hydrocarbon is produced from the fracture system and the immediate rock interface, the decline rates evident from current well data are very high. All forecasts that we have seen show this initial decline rate moderating to give hyperbolic decline curves, similar to conventional wells, where the drainage area from the well is fed by flows from the deeper reservoir, across the drainage boundary (unlikely in tighter rock). We anticipate a steeper decline path, as the low quality rock is unable to contribute flow. It is still early days, however our review of initial production from Permian unconventional wells (Midland and Delaware Basins) is even worse than anticipated (first year average decline rates of 64.8% -71.9% from peak).
Figure 12: Permian well decline rates

<table>
<thead>
<tr>
<th></th>
<th>Midland</th>
<th>Delaware</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 month</td>
<td>-25.0%</td>
<td>-30.9%</td>
</tr>
<tr>
<td>3 months</td>
<td>-39.9%</td>
<td>-51.2%</td>
</tr>
<tr>
<td>12 months</td>
<td>-64.8%</td>
<td>-71.9%</td>
</tr>
</tbody>
</table>

Source: Kessler Energy, as at 31.01.14

Further technology improvements for unconventionals can bring many of the marginal plays towards profitability. One such technology is Baker Hughes’ FLEX series downhole electrical submersible pump (ESP). Previously it had been difficult running ESPs in unconventional wells because the well rates declined so fast. This new pump, with a wider operating range, accelerates production and reduces the need for well workovers.

The rush for investment in unconventionals, and the associated oil price uncertainty, has taken investment and research dollars away from enhancing conventional production. The impact of this, combined with the failure of new frontier oil exploration and delays in new developments, is captured in our supply modelling. It is clear from this work that further production and reduced demand must be stimulated, which means that oil prices need to rise, in our view.

**Investment opportunities**

Decline rates are the greatest challenge faced by the global oil industry today but at the same time give rise to a considerable investment opportunity. They are likely to have more bearing on long-term oil production than any geopolitical factors, and create more demand for new oil supply than any emerging market growth forces. The industry needs to do a better job of understanding and reacting to them. The work we have done at Investec Asset Management and the analysis we have done of other people’s work gives us greater than ever conviction in our higher oil price forecast. We anticipate that, just as 2013 improved confidence that oil prices could not retrench to $80/barrel, 2014 will illustrate that oil prices need to increase as the global economy improves. We expect an average Brent oil price for the year of $112.50.

If our expectations for the oil price over this decade prove to be accurate this will provide a strong tailwind for energy equities. Energy equities have underperformed the broad market meaningfully over 1, 3 and 5 years, as shown in the chart below. The underperformance since the equity market trough in March 2009 stood at 60% at 31 January 2014; over the same period Brent crude has moved from $44 to $110.

Figure 13: Energy stocks have underperformed for past 5 years

![Energy stocks have underperformed for past 5 years](chart.png)

Source: MSCI, Bloomberg, Investec Asset Management

**Decline rates are the greatest challenge faced by the global oil industry today but at the same time give rise to a considerable investment opportunity**
The sector continues to be rated on a significant discount to the broad market (MSCI All-Country Energy on 11.4x 2014 earnings vs MSCI All-Country World on 14.4x), and we expect this gap to close when the market gains confidence in the sustainability of the oil price. At the same time, a rising oil price would create a headwind for the broad equity market, which would provide a further relative boost to energy equities. In the table below we outline a range of valuation multiples which illustrate the opportunity.

**Figure 14: Valuation multiples highlight investment opportunity**

<table>
<thead>
<tr>
<th>Source: MSCI, as at 31.01.14</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy screens as the cheapest sector on both P/E and EV/EBITDA, and one of the cheapest on Price/Book, as well as being the third-largest dividend payer.</td>
</tr>
<tr>
<td>In terms of specific sectors and themes, we would highlight companies with deep resource bases and some EM oil majors, such as Canadian oil sands companies, and some emerging market oil majors, such as Petrobras, CNOOC and Lukoil. These companies have huge resource positions and long-life assets, with the ability to grow production over the long term with reduced exploration risk. Of course, for as long as there continues to be complacency around supply security the true long-term value of these companies will not be fully understood, which presents a very attractive entry point for investors like us with a long-term horizon.</td>
</tr>
<tr>
<td>The LNG market is an attractive investment area. Almost all LNG contracts are oil price-linked, so our commodity price view is immediately supportive of this sector. The supply/demand balance in the global LNG market is tight; demand is growing significantly quicker than new supply, led by the Asia-Pacific region (Korea, Japan, China), but also some emerging regions of demand growth, Latin America and the Middle East. Most of the new supply megaprojects (Australia, Russia, East Africa) are taking longer to reach first gas than was initially expected and our modelling indicates that the market will remain structurally tight for the next five years. We continue to find BG a compelling way to gain investment exposure to this trend.</td>
</tr>
<tr>
<td>E&amp;P companies with sustainable production growth should attract a premium multiple to reflect their leverage to an increasing oil price and their earnings growth. In our last White Paper “US Energy Independence: Fact or Fiction” (January 2013) we published our extensive analysis of US tight oil plays in which we detailed our bottom-up work on the Bakken, Eagle Ford and Permain basins in the US, as well as the lesser and less prolific plays. It is clear from our work that some of these plays will deliver strong growth, but some will disappoint. Anadarko Petroleum and Noble Energy, both US companies, are our preferred large-cap names in this subsector, though we are beginning to find value in selected European names with international assets after a period of noted underperformance.</td>
</tr>
<tr>
<td>Service and Drilling companies should trade at a premium as long-term rising capital expenditure from the National Oil Companies, Integrateds and Explorers will drive revenue growth and margin expansion. We see notable value in the offshore drilling companies, such as Ensco Petroleum.</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>P/E</th>
<th>EV/EBITDA</th>
<th>P/B</th>
<th>Dividend yield (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>MSCI ACWI Energy</td>
<td>11.4</td>
<td>5.4</td>
<td>1.5</td>
</tr>
<tr>
<td>MSCI AC Financials</td>
<td>12.2</td>
<td>-</td>
<td>1.3</td>
</tr>
<tr>
<td>MSCI AC Materials</td>
<td>14.1</td>
<td>7.8</td>
<td>1.8</td>
</tr>
<tr>
<td>MSCI AC Utilities</td>
<td>14.4</td>
<td>8.3</td>
<td>1.4</td>
</tr>
<tr>
<td>MSCI AC Information Technology</td>
<td>14.5</td>
<td>7.9</td>
<td>3.0</td>
</tr>
<tr>
<td>MSCI AC Telecommunication Services</td>
<td>14.7</td>
<td>6.3</td>
<td>2.2</td>
</tr>
<tr>
<td>MSCI AC Industrials</td>
<td>15.9</td>
<td>9.5</td>
<td>2.5</td>
</tr>
<tr>
<td>MSCI AC Consumers Discretionary</td>
<td>16.4</td>
<td>9.4</td>
<td>2.8</td>
</tr>
<tr>
<td>MSCI AC Healthcare</td>
<td>16.7</td>
<td>10.8</td>
<td>3.6</td>
</tr>
<tr>
<td>MSCI AC Consumers Staples</td>
<td>17.4</td>
<td>10.5</td>
<td>3.5</td>
</tr>
</tbody>
</table>
In the graph below we look at how the Price/Book ratio of the Global Integrated oil and gas companies has moved over time. We can see that today’s valuation is at a twenty year low, on a market relative basis. The sector has derated significantly as the return on capital of these companies has been dragged down by rising costs, escalating capex, and anaemic earnings growth.

Figure 15: Global integrated oil and gas companies derate significantly

Source: MSCI, Bloomberg, Investec Asset Management

We expect Integrated Oils to rerate initially to a market multiple and potentially higher if they can improve their Return on Capital. Within the group we see the best value within the European names, particularly Total and StatOil. But our view remains that this group of companies is structurally impaired: shareholders are baying for lower spending and higher dividends/share buybacks but the companies need to spend on exploration and development to retain any chance of future growth.

It is worth mentioning that at Investec Asset Management we approach the Energy sector from a truly global perspective. The market has become very US-focussed and this has led to significant valuation and performance dislocation. We will continue to look to take advantage of this.

There are tremendous investment opportunities that arise from a tightening of the world’s oil supply brought about by rising oilfield decline rates. Through a better understanding of the decline rate problem we believe we can find exciting investment opportunities.
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