Supermajors’ cost index - measuring development cost efficiency of oil and gas companies

Muktadir Ur Rahman

apexconsultingltd.com

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Contact Details

W: apexconsultingltd.com

T: +44 (0)78 114 555 09

E: mrahman@apexconsultingltd.com

About the Author

Muktadir Ur Rahman is a highly experienced consultant with considerable experience in project economics, investment appraisal, economic evaluation, and modelling of upstream projects and portfolios. He has worked extensively with major oil and gas companies worldwide on a variety of projects, from undertaking independent reviews of economic models and modelling various fiscal regimes to leading investment appraisal, risk and sensitivity exercises to identify commercial value drivers for clients' commercial teams. Muktadir has also worked as a Commodities Economist in global commodities research providing analytical and research reports, price forecasts, and market updates to clients to convey the impact of economic data and policy developments on various commodities including oil and gas. As a subject expert, he provided regular commentaries to media agencies including Reuters, Bloomberg and the Wall Street Journal.

Contact Details

T: +44 (0)78 114 555 09

E: mrahman@apexconsultingltd.com

W: apexconsultingltd.com

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Abstract

The 'lower for longer' oil price environment has forced oil and gas companies to look hard at their cost structures. Despite development costs accounting for more than 50% of total costs, the industry currently lacks a widely accepted measure for assessing efficiency in this area. In this paper we present an index that measures how 'Supermajors' as a group have been performing over the years in developing their reserves. The index indicates that recent efforts by industry players to decrease their costs have had some impact in reducing the cost of their development activities. However, the index is still relatively high in the historic context even though it is around the levels seen in 2013. More actions are needed not only to reduce the cost of developing new assets and meet future demand but also to address the structural cost problem of the industry.

Table of Contents

1. Introduction - why we are looking at Development cost

The collapse in oil price since mid-2014 has affected the oil and gas industry more deeply than many industry participants anticipated originally. Corporate earnings have fallen sharply, investments in new projects have been cut significantly and the industry has experienced widespread job losses. This 'lower for longer' oil price environment has forced oil and gas companies to look hard at their cost structures that escalated dramatically in the years preceding the collapse of the oil price.

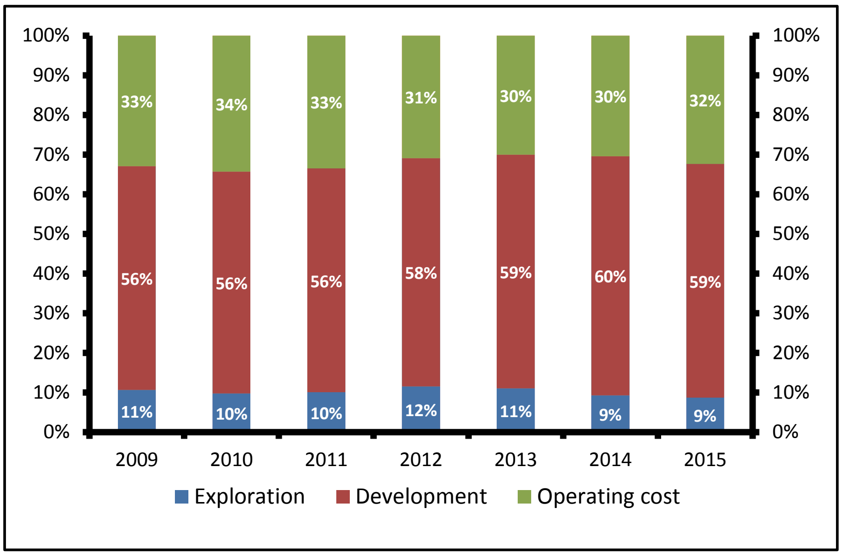
The industry has taken a number of steps to reduce costs and survive this prolonged slump in prices. These steps include cutting exploration investments, reducing operating costs through improved efficiency and productivity gains, standardising and simplifying processes and design to reduce the costs of developing assets. These steps have generated significant cost savings for the industry. For example, Statoil recently reported 20% reduction in the estimated development cost of its Johan Sverdrup oil field[1] and BP reported more than 50% reduction in the development cost estimate of its Mad Dog Phase 2 project in the Gulf of Mexico[2].

In spite of these cost savings, a recent study by Wood Mackenzie suggests that as much as 4 million barrels per day of production required to meet demand by 2025 would be unsustainable if Brent price remains below $85 per barrel.

Furthermore, there are concerns in the industry about the sustainability of the cost reductions achieved over the last couple of years. A significant part of the industry's cost reduction was achieved because oil services companies offered deep rate cuts in order to keep their businesses going during this downturn. There is a good chance that these rate cuts would be reversed when the market improves and operators begin to invest more. So many industry observers argue that most of the recent cost savings would be lost when investment activity in the industry picks up in line with improved market conditions.

More actions are clearly needed not only to reduce the cost of developing new assets and meet future demand but also to address the structural cost problem of the industry. Therefore, cost reduction will remain the focus of the industry over the coming months and years.

Chart 1: Cost distribution of 'Supermajors' as a group



Source: Apex Supermajors database.
Note: 'Supermajors' group consists of Shell, BP, Total, ENI,Chevron, ExxonMobil and ConocoPhillips.
Operating cost data do not include production tax.

[1] http://www.statoil.com/en/NewsAndMedia/News/2016/Pages/JSaug2016.aspx
[2] http://www.upstreamonline.com/live/1165872/mad-dog-2-for-under-usd-10bn

Of the three major cost categories (exploration, development and operating costs) reported by the oil and gas companies, development cost is the most significant, accounting for more than 55% of these costs on average between 2009 and 2015 (see chart 1).

Sustainable reduction in development cost is therefore crucial to achieving lower breakeven prices and ensuring that projects remain feasible during periods of adverse price swings. In turn, this not only ensures a stream of stable and sustainable cash flows in a low oil price environment but also allows the company to capitalise on price upswings[3].

Despite the importance of development cost on a company's bottom line, the industry currently lacks a widely accepted measure for tracking the efficiency of a company's development costs. Industry analysts and observers typically look at 'Finding and Development' (F&D) cost to measure how efficient a company is in replacing its reserves. F&D cost is typically measured as

$$\frac{exploration\ cost + development\ cost\ + cost\ of\ acquiring\ unproved\ properties}{changes\ in\ Proved\ reserves\ for\ the\ period\ due\ to\ extensions\ \&\ discoveries, revisions, imprved\ recovery\ excluding\ purchases\ for\ the\ period}$$

While this measure serves as a reasonable proxy to estimate the overall cost of replacing reserves, it does not provide a good picture of how efficient a company is in developing its assets and monetising its reserves. There are several reasons for this.

Development cost represents the amount that a company spends '*to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.*'[4] This includes cost of development wells to produce from proved reserves as wells as the cost of acquiring, constructing, and installing production facilities such as storage tanks, gas processing facilities, improved recovery systems and so on. Development cost enables a company to start producing its reserves and allows the company to reclassify its reserves from the 'Proved Undeveloped' (PUD) category to the 'Proved Developed' (PD) category. Therefore, to understand how efficient a company is in developing its reserves, one needs to compare the development costs incurred with the changes in 'Proved Developed' reserves.

F&D cost does not capture these changes adequately. As well as development cost, the numerator includes both exploration cost and acquisition cost associated with unproved properties. For a given amount of reserves, this would underestimate the development cost efficiency of a company.

Even if we exclude exploration and acquisition costs from the numerator, the denominator of F&D costs focuses on proved reserves, which is the sum of proved undeveloped and proved developed reserves. Since proved reserves volumes would be higher than proved developed volumes, F&D costs would overestimate the development cost efficiency of a company for a given amount of development cost.

[3] A lower breakeven price achieved through sustainable reduction in development costs has numerous benefits. For example, a low breakeven price ensures a stream of stable and sustainable cash flows for the company in periods of low oil prices. And in periods of high oil prices, it generates additional cash flows for the company that can be used for in a variety of ways, from paying down debts to strengthen the balance sheet, to preserving cash that can in turn be used to make profitable opportunistic acquisitions in a deteriorating market environment.

[4] Jennings, Dennis R., Feiten, Joseph B. and Brock, Horace R., 'Petroleum Accounting: Principles, Procedures and Issues', 5th edition, PricewaterhouseCoopers.

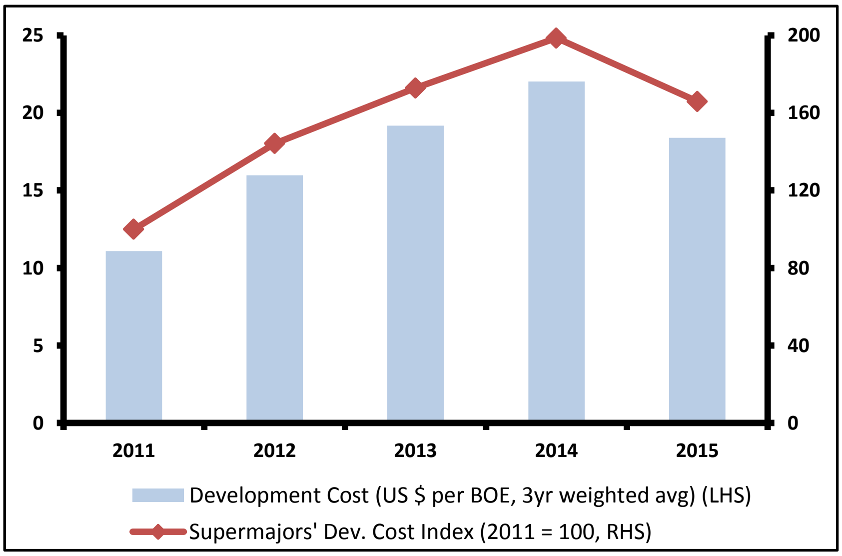
2. Supermajors’ Cost index

We, therefore, have developed our own proprietary method to address these limitations and measure the development cost efficiency of a company. Based on our method, we have developed a cost index for the industry’s ‘Supermajors’: BP, Shell, ENI, Chevron, Exxon Mobil, Total and ConocoPhillips.

As industry leaders, these companies often set the tone for the rest of industry in many key aspects, ranging from reducing the cost of major development projects via design and process simplifications to leading (or postponing) the exploration and development activities in challenging frontier basins. Therefore, movement in this ‘Supermajors’ Cost Index’ would provide us with valuable information about how efficient the key players in this industry are in developing and monetising their reserves. This in turn sets an important benchmark for the rest of the industry.

Furthermore, changes in this index would also give us crucial information about the underlying cost pressure that these firms and by extension the industry as a whole are facing. A rising index in this case would typically highlight increasing cost pressure across the industry and can be used to prompt industry-wide actions to prevent recurrence of runaway cost escalations, as has on occasion been seen in the past. On the other hand, a falling index would indicate easing of cost pressure and how successful various cost reduction measures have been in bringing costs down to a more sustainable level.

Chart 2: Supermajors’ Cost Index – evolution of development costs



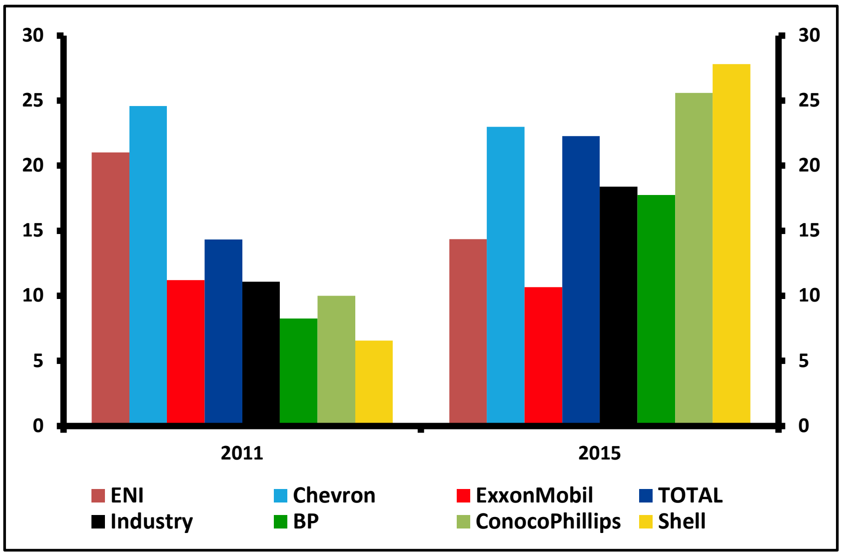
Source: Apex Supermajors database.
Note: ‘Supermajors’ group consists of Shell, BP, Total, ENI,Chevron, ExxonMobil and ConocoPhillips.

Our ‘Supermajors’ Cost Index’ suggests that development cost per BOE for ‘Supermajors’ as a group increased by a staggering 66% between 2011 and 2015. However, the index after reaching its peak in 2014, declined by around 17% in 2015 (see chart 2). This indicates that efforts by industry players to decrease their costs have had some impact in reducing the cost of their development activities.

The index is still relatively high in a historic context, though it is lower than the levels seen in 2013. Nevertheless, further actions are urgently needed, to bring costs down to more sustainable levels.

Considerable variations exist within this group. Among the seven companies analysed between 2011 and 2015, we found that ENI’s performance improved the most (see chart 3). We estimate that its development cost efficiency improved by 32% between 2011 and 2015. Although Chevron’s development cost efficiency improved by 6% during this period, at the end 2015, it was still 25% higher than its peer group average.

Chart 3: Supermajors' Development Cost per BOE – 2011 vs 2015



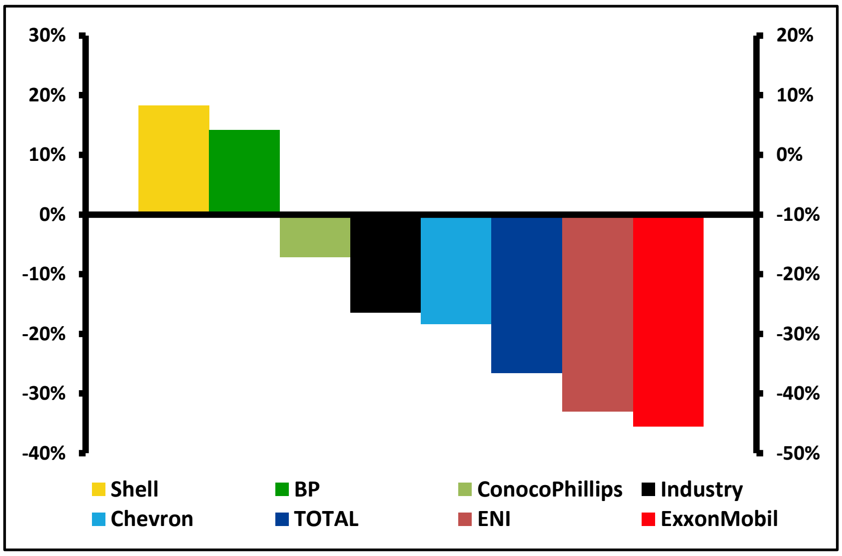
Source: Apex Supermajors database.
Note: 3 year weighted average Development Cost per BOE, measured in US $.

ExxonMobil's development cost also improved during this period. While the development cost per BOE for Supermajors as a group went up by 66% between 2011 and 2015, ExxonMobil's costs went down by 5%. As a result, by the end of 2015, ExxonMobil had the lowest development cost per BOE among its peers.

On the other hand, Shell's development cost efficiency deteriorated during this period. As a result, by the end of 2015, its development cost per BOE was more than 50% higher than the industry average. We estimate that Shell's development cost per BOE was $ 27.80 in 2015 while it was $18.39 for Supermajors as a group.

Development cost efficiency also declined between 2011 and 2015 for both Total and BP. Our estimates show that by the end of 2015, TOTAL's development cost per BOE was approximately 21% higher than its peer group average. However, although BP's development cost per BOE more than doubled during this period, it is still lower than its peer group average.

Chart 4: Changes in Development Cost between 2014 and 2015 (%)



Source: Apex Supermajors database.
Note: Negative % reflects reduction in development cost per BOE and therefore, improvement in cost efficiency.

ExxonMobil and ENI were the best performers again when we analysed how these companies performed between 2014 and 2015 (see chart 4). Compared to 2014, ExxonMobil and ENIs' development cost efficiency improved by more than 35% and 33% respectively in 2015. Total's development cost efficiency also improved during this period, while Shell and BP's development cost efficiency deteriorated.

Looking ahead, we expect the Supermajors' cost index to continue to drop in 2016 as development costs continue to drop further in 2016. This will be reflected in our next update once these companies have published their annual reports for 2016.

3. Making costs more sustainable

As our index has shown, various cost reduction measures that industry players have undertaken over the last year or so have undoubtedly reduced the cost of developing assets. While operators remain confident about further cost deflation in 2017 and beyond, oil services companies and many industry observers as well expect costs to go up as demand for services improves.

So, will costs inevitably escalate as predicted? The answer depends on a number of factors and the scenarios that will eventually materialise.

Oil supply from Non-OPEC countries has been falling steadily since the beginning of this year. However, recent reports suggest a pull-back in that trend. More importantly, Non- OPEC supply is actually predicted to grow in 2017[5].

OPEC also continued to produce at record levels before production cut agreement comes into effect in January 2017. According to the latest IEA report, the group produced around 33.83 million barrel per day (bbl/d) in October due to record production in Iraq and production recovery in Nigeria and Libya[6].

However, OPEC has recently agreed to cut production by 1.2 million bbl/d. Furthermore, latest reports suggest that OPEC has successfully convinced some of the Non-OPEC countries to cut their production by approximately 560,000 bbl/d[7]. Russia has agreed to cut output by around 300,000 bbl/d while other Non-OPEC countries such as Oman, Kazakhstan and Azerbaijan have also agreed to reduce their production. If both OPEC and Non-OPEC countries cut production by the declared / desired amounts then oil production could fall by as much as 1.7 million bbl/d in 2017.

We estimate that in the third quarter of this year, global oil output exceeded demand by between 0.3 to 0.5 million bbl/d on average, a significant improvement compared to 2016 Q1, when excess supply was estimated to be between 1 to 2 million bbl/d. The excess supply situation may have worsened since then due to the recent surge in both OPEC and Non-OPEC production. Despite this, we do not expect excess supply to be more than 0.7 to 1 million bbl/d on average in the fourth quarter of 2016. Therefore, even if both OPEC and Non OPEC only deliver half of the declared/desired cut, it would most likely eliminate the excess supply and reduce the bulging inventory level.

On the demand side, while global oil demand growth slowed considerably in the 3rd quarter of this year due to slowdown in OECD economies and China, return of more normal (colder) winter is likely to increase global oil demand in the 4th quarter and early 2017. Despite this, oil demand growth in 2016 is now forecasted to be a third lower than what it was in 2015.

Boosted by near 50% fall in average crude prices (see chart 5), oil demand in 2015 grew by 1.8 million bbl/d. On the other hand, after reaching the bottom in February, prices have recovered by more than 50% in 2016. This recovery in prices meant that crude prices in 2016 have not supported oil demand in the same way as they did in 2015. As result, both OPEC and the IEA expect oil demand to grow by around 1.2 million bbl/d in 2016.

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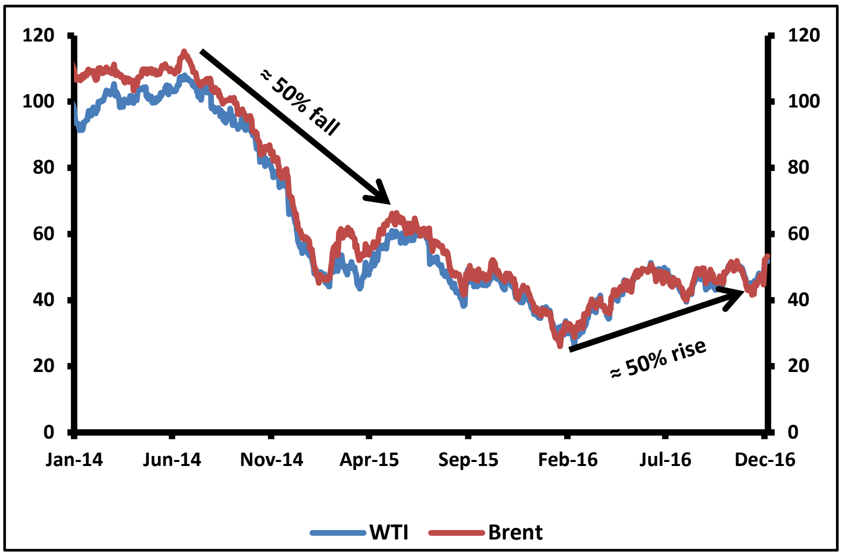
[5] International Energy Agency, 'Oil Market Report', November 2016.
[6] International Energy Agency, 'Oil Market Report', November 2016.
[7] Reuters, 'OPEC, non-OPEC agree first global oil pact since 2001', 10 December 2016.

Chart 5: Crude Oil Prices since January 2014 (US $ per Bbl)



Source: U.S. Energy Inormation Adminstration (EIA), Apex

Looking ahead, other than occasional fluctuations, prices are not expected to fall as sharply as they did between mid-2014 and early 2016. In addition, the recent OPEC and Non-OPEC agreement to limit production is likely to provide additional boost to prices. Therefore, as in 2016, oil demand is not likely to receive any additional support from oil prices in 2017.

The global economy continues to face considerable headwinds, including subdued baseline for growth in advanced economies, China's rebalancing, and macroeconomic and structural adjustment in oil and other commodity exporting emerging economies to lower revenues[8]. The uncertain global macroeconomic conditions, which has prompted the International Monetary fund (IMF) to revise down its global growth forecast for 2016 and 2017, will also weigh on oil demand.

Consequently, IEA now expects oil demand to grow by the same amount as 2016, by 1.2 million bbl/d in 2017, according to its latest report.

However, considerable uncertainties exist about OPEC's ability to implement the deal given the long history of OPEC members not adhering to assigned OPEC quotas. In addition, the elevated stock level and possibility of higher production response from US shale producers will cap any potential upward trend in oil prices in 2017.

As a result, we expect oil prices to move between the $55-65 over the next year or so. In fact, latest futures data from NYMEX and CME support our view. By the end of Friday 9th December, WTI futures were trading around $54 on average for calendar 2017 and $55 for calendar 2018. Similarly, Brent futures were trading around $56 on average for calendar 2017 and $57 for calendar 2018.

Oil and gas companies' appetite for new investment are likely to remain weak given that prices are expected to remain around $60 over the next year or so. In addition, the continuation of the current low-price environment in 2017 means that cost reduction will remain a key priority for the industry.

At the same time, some of the subsectors, such as offshore oil rigs are suffering from both low utilisation and oversupply of rigs. As a result, the demand for services is unlikely to go up significantly in 2017 and the rates offered by services companies are likely to remain at current suppressed levels.

However, looking beyond 2017, operators will eventually have to increase their investment activities (both in terms of developing assets and finding new reserves) in order to replace their depleting reserves. This would invariably increase the demand for services, putting upward pressure on rates

[8] International Monetary Fund (IMF), 'World Economic Outlook: Subdued Demand – Symptoms and Remedies', October 2016.

and consequently on costs. Given that a significant part of the cost savings achieved in recent years came from the fall in suppliers' rates, there is a genuine concern among industry participants regarding the sustainability of these cost reductions.

To be clear, not all cost savings would be lost if suppliers' rates go up. A number of cost savings measures such as optimising logistics and production operations, simplifying processes, adopting lower cost drilling techniques and so on are not dependent on third party rates. Cheaper costs of raw materials such as steel have also helped the industry in its drive to cut costs. These measures will continue to help the industry keep a check on costs.

Nevertheless, as the era of 'peak supply' gets replaced by 'peak demand', it is clear that too many projects are still unsustainable at prices below $60 per barrel. And there is very little room left (if any) to drive third-party rates even lower to improve the commercial viability of these projects. A new approach is therefore needed in order to make the industry truly sustainable around the $60 price mark.

We believe that the industry needs to take a more long term view in order to address its structural cost problems and make cost savings more sustainable. Not only do we need greater collaboration between operators and service providers, but we also need oil services companies to be incentivised appropriately to find innovative ways to cut costs.

This type of approach is quite common in the construction and car industries. In these industries, the customers work with their preferred supplier from an early stage to find innovative ways to reduce project costs. Suppliers are incentivised to find innovative cost saving solutions because they receive a share of the cost savings as 'bonuses'. There are plenty of examples of how this kind of collaborative and incentivised agreements has resulted in significant cost savings for these industries.

Of course, by sharing the some of the cost savings with the contractors, operators won't be able to internalise 100% of the achieved cost savings. This may seem somewhat counterintuitive to many. But this is where the industry needs to take a longer term view beyond the current quarter or year in order to fully appreciate the benefits of this kind of approach.

In the short term operators may be able to achieve more cost savings by driving down already suppressed third-party rates even further. In such instances, rates would invariably go up when activities pick up and the cost savings achieved during this period would be lost. On the other hand, cost reductions achieved through appropriate incentive mechanisms and collaborative working agreements would be more sustainable and less susceptible to upticks in investment activities.

In this low oil price environment where further cost savings are necessary to make many of the projects commercially viable, we believe that the industry stands to gain more from collaborative and incentivised working agreements rather than focusing on short term cost savings and fluctuating between periods of cost deflation and escalation.

Some oil and gas players have already taken steps towards this approach and started to involve their preferred suppliers from an early stage. For example, BP, Rosneft and Schlumberger have recently reached an agreement to collaborate on seismic research to improve '*the efficiency of exploration, appraisal and field development*'[9] activities.

Whatever form it takes, collaboration with appropriate incentive structure would be the key to prevent the recurrence of the runaway cost escalations of the past and to make the industry's activities more resilient to adverse price movements.

[9] BP Press release, 'Roseneft, BP and Schlumberger sign technology agreements' , 2nd September 2016, http://www.bp.com/en/global/corporate/press/press-releases/rosneft-bp-and-schlumberger-sign-technology-agreements.html