



# Energy Journal – Oil & Gas

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*Perspectives on the Oil & Gas Industry 2017*

**Arthur D Little**

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# Foreword

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**Dr. Jaap Kalkman**

Managing Partner and Global Head  
of the Energy & Utilities Practice

Dear Reader,

The energy industry, from oil and gas to utilities, is going through an unprecedented change. It's a change similar to when the world moved from wood to coal, with the steam machine, or from coal to oil, when utilities centralized and the car industry took off early last century. Today, the shift is from hydrocarbons to alternative and renewable sources of energy. The change will be gradual from our perspective, but could be completed this century.

Historically, this is a revolution. It has huge implications on our businesses, on the way we organize and on the way we focus, from the R&D agenda to new business development focus and M&A. ADL's Energy & Utility Practice works in the center of that change, and aspires to be your advisor and business counsellor of choice. To that end, we continuously conduct research and push the envelope with new thinking and drawing implications of the trends we see around us. We trust you will enjoy the reading, and are, of course, open to comments and discussion.

You know where to find us!

Warm regards,

Dr. Jaap Kalkman



# Alternative paths for large IOCs

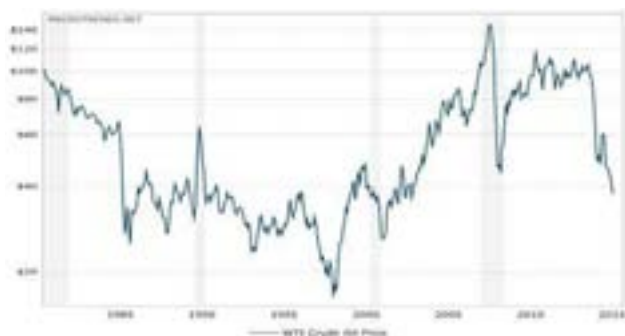
*Low oil prices may drive pervasive structural changes in upstream oil and gas*



The financial health of the oil and gas industry has always been set by oil and gas prices, with major price inflections often leading to significant structural changes in the sector. After the price drop of 1986, WTI oil prices remained low for nearly 20 years, at about \$30-\$40 in 2015 Real terms (as shown in the Figure below). This low price environment not only drove a wave of project deferrals but also triggered a series of consolidations among international oil companies, seeing the demise of Arco, Amoco, Mobil, Fina, Texaco and Phillips, among others. The much higher prices of the past 10 years have ushered in an era of greatly accelerated oil and gas exploitation in often much more technically complex, deep-water and remote settings, with many smaller, emergent players now pursuing unconventional hydrocarbons and playing a much more influential role in price setting. With oil prices again now at around \$40 per barrel, a price-level which increasingly looks as if it may be sustained for many months if not years into the future, it is appropriate to ask what alternative future structural trends might come to dominate the sector over the next few years.

## Oil price: Driving structural change in the sector

It is clear that many of the highest-cost and technically most complex oil and gas development projects, including remote and deep-water fields, are now being deferred or cancelled, as their economic outlook deteriorates.



This of course presents the International Oil Companies (the “majors”; or “IOCs”) with an increasing reserves replacement challenge, one that is not faced in the same way by many of the largest National Oil Companies (“NOCs”).

These NOCs not only control over 58% of the world’s current oil production but they also control around 90% of global oil reserves, the vast bulk of which comprises relatively low-risk, low-cost volumes, generally in brown-field settings. While some NOCs remain very dependent on external support, many of the more sophisticated NOCs are increasingly able to access their resources without needing IOC support and participation.

These more capable NOCs have increasing access to all the technologies required – they have been rapidly expanding their R&D budgets, and are building ever deeper, direct relationships with oil services companies, without a need for IOC intermediation. Indeed, an increasing trend over the past five to ten years involves services companies taking direct oil field equity positions from the NOCs. These more advanced NOCs are in fact acquiring ever more effective staff skills and competencies, often without needing to engage with IOCs at all. Further, many NOCs are also now able to raise funds in global capital markets in order to develop their resources.

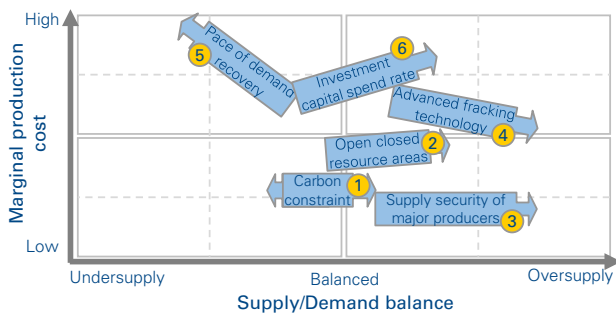
The IOCs have also recently been challenged by the rise of shale-oil and shale-gas, largely produced by a tier of relatively small, independent US oil and gas companies, having nimble operations and low-cost structures. These companies have changed the face of the industry, often leaving the IOCs stretching to catch up.

## Developing scenarios for IOC development

In consequence, future access to economically viable resources by the traditional IOCs is becoming increasingly challenging, especially in this relatively low oil price environment and uncertain market. This presents the IOCs with a growing strategic dilemma. What are potential future winning strategies for the IOCs? What directions are plausible and how can they either pursue growth or maintain earnings? Might some or all of them need to rethink their business models? What types of

future partnership or collaboration might be appropriate? The aim of this paper is to identify and evaluate a set of strategic options for the IOCs under each scenario formulated/considered. The first step toward identifying these futures is to examine the key drivers of change in the sector, considering both their likelihood and impact, and then develop coherent combinations of these changes that can be developed into scenarios. These are as follows:

**Key drivers of change in the sector**



Source: Arthur D. Little analysis

**Driver 1 – Carbon constraint**

Current pressures for limits on carbon emissions are likely to become more severe. Displacement in the short term of first coal (5-10 years) and then some oil by gas will initially lead to a preferential pursuit of gas opportunities by the IOCs, with the Shell/BG merger being only a first indication of such a transition. In the longer term (10-15 years) there will be continued growth in renewable energy production, driven by both technology breakthroughs and policy pressures. This will then progressively lead to a further shift of gas-fired power from base-load to peak, then to material levels of transport electrification, perhaps with CNG/LNG as a partial bridging solution. The resulting shift and drop in gas and liquids demand will drive prices down and eliminate high-cost supply sources. **Likely/High Impact**

**Driver 2 – Opening of closed resource areas**

The reform and opening up of E&P provinces which are currently closed to IOCs, particularly those involving the less developed NOCs, could generate very attractive prospects for the IOCs. Mexico is the most obvious current example, but others may also follow, in Latin America, the Middle East and elsewhere. **Uncertain/Moderate Impact**

**Driver 3 – Supply security of major producers**

Changes to either the political or security environment which impact a major oil or gas producer may have a critical impact on supply levels and pricing in the global market. Expanded disruption in the Middle East, blockades, the resolution and re-emergence of Iran or Libya, etc., could all have very significant effects, changing both prices and the extent of access opportunities for the IOCs. **Likely/High Impact**

**Driver 4 – Advances in fracking technology**

Some of the current shale-oil/shale-gas production companies will be driven out of business by the twin pressures of rising debt and falling prices. Nevertheless, break-even development costs for shale oil/gas production will continue to drop, as they have done in recent years, enabled by progressive technology improvements. This trend, if sufficiently pronounced, will enable the lowest cost and most flexible of the remaining US shale oil/gas companies to grow their unconventional production. The increasingly low-cost gas volumes that result will displace gas from conventional projects elsewhere in the world and set a cap to gas prices. Several IOCs may, as a result, attempt to re-establish a more significant position in the unconventional sector, either in the US or elsewhere. **Certain/High Impact**

**Driver 5 – Pace of demand recovery**

Given current production overcapacity in both oil and gas, and significant current levels of oil overstocking, it may be several years before demand growth leads to a re-balancing of supply and demand. While we assume that overall demand will continue to increase slowly, not peaking before at least 2040, the pace and timing of that increase is highly uncertain, with continued economic volatility and downturns likely in all key markets. When supply is more reliably balanced by growing future demand, thus tightening the existing gap, the resultant more stable oil price foundation will give IOCs greater opportunity to pursue the more challenging and complex plays that have formed much of their reserves growth over the past 10 years. **Uncertain/High Impact**

**Driver 6 – Investment capital spend rate**

The uncertain timing of a future tightening of supply and demand is also governed, to a significant degree, not only by the rate of natural production decline in existing fields but also by the depth and duration of the current slow-down in investment in new production capacity. This will be influenced to a large degree by the level of investor confidence in the sector. Though a full-scale “investor strike” is unlikely, the capital markets may increasingly view much of the oil and gas sector as the holders of “stranded assets” as the carbon agenda gains more traction. The result, in combination with heightened price volatility, may be a need for much higher project rates of return in the sector, to compensate the market for the higher equity risks being taken. In consequence, while companies will continue to cut costs, improving development and production economics, many plays and projects, and the companies that own them, may increasingly become unviable. In this event, with potential constraints on supply, prices would rise, presenting opportunities to those IOCs with the highest quality assets, at the same time that other companies see only shrinking potential. **Uncertain/Moderate Impact**

## Scenarios for IOC development

By combining potential outcomes from the above drivers, to form discrete and internally consistent scenarios for the sector's development, we form a series of alternative future visions for environments in which IOCs may come to live. These outcomes also describe the strategic responses that the IOCs may have to make. In its advice to clients, Arthur D. Little is often asked to produce industry scenarios which, though relatively extreme and highly challenging for the companies involved, are nevertheless recognizable, credible and requiring of a response. Illustrative current scenarios are as follows:

### Scenario 1 – “Carbon controlled”

This is a world in which effective policies to reduce worldwide carbon emissions are both put in place and enforced. There is continued rapid growth in renewable energy sources, driven by technology breakthroughs and progressive policy pressures, with an early and progressive displacement, by gas, of most current coal demand, except in India and China, where reduction will be rather less. In the longer term there will be continued and even greater growth in renewable energy production, together with a slow expansion of nuclear capacity. Progressive transport electrification and a shifting of gas-fired power from base-load towards mid-merit and peak will lead to an eventual erosion of both gas and liquids demand, but particularly of oil. This reduced oil and gas demand growth will suppress prices and eliminate high-cost supply sources.

The early increase in demand for gas, as coal is displaced over the next 10-15 years, will strengthen gas prices sufficiently to stimulate major new gas projects. These will mostly be pursued by the IOCs worldwide, together with expanded unconventional gas capacity in the US. This will be stimulated by continued fracking technology improvement, with the resulting associated gas liquids having the effect of dampening further any oil price rise.

Oil prices will be even further dampened by slower demand recovery, as energy efficiency is also significantly strengthened along the energy value chain. As a result, though the IOCs will see only very limited scope for oil resource replacement, there will be significant potential for the preferential pursuit of gas opportunities, some organic but also by M&A. While no new NOC oil provinces are opened up to the IOCs there are progressive but generally limited attempts by the major NOC producers to increase output. This further reduces oil prices and further weakens the financial robustness of many of the mid-sized IOCs and larger independents.

In consequence, though there will be some M&A activity among oil firms, it will be more common, as the availability of project finance becomes more difficult for major new developments, for the IOCs to shift towards being more strongly

gas-dominated, led by gas development projects and gas mid-stream infrastructure.

In addition, it is also likely that current firms will be progressively split up and disaggregated into separate, asset-cluster specific, individually owned and project-funded entities, sometimes linked to discrete demand hubs. The oil-dominated part of their portfolios may often be hived off into a separate business and a number of the major IOCs will invest heavily in renewable energy projects.

### Scenario 2 – “Open-house; return to easy oil”

This is a world in which there is only a relatively slow adoption of fossil-fuel constraints, though the gradual changes that are made will dampen coal demand in particular. Partly as a result, oil demand growth is restored by continued Asian economic strength, with that demand being met by reinstated additional supply from markets such as Iran, Iraq, Libya and Mexico. These markets may have undergone not only a political, and in some cases a security settlement, but will also start to undergo a major capacity overhaul.

In most of these cases the local NOCs will still lack the strengths and capabilities to perform this capacity overhaul themselves. The unlocking of the currently untapped, low-cost potential in these areas can therefore only be carried out by the active engagement of the IOCs and service companies. There will thus be significant growth in the opportunities open to these companies.

The widespread pursuit of such opportunities, many of which will involve the upgrading of large brownfield assets, will keep oil prices relatively low for many years, inhibiting, canceling or substantially delaying most of the more challenging, complex and costly development projects currently being pursued whilst also slowing the penetration of new renewable assets and technologies.

This will result in the IOCs being left with a number of “stranded,” uneconomic assets. It will also result in them being compelled to accept much lower rates of project return from their host NOCs on the relatively lower-risk opportunities provided. Some of the companies involved will also start to face challenges securing the capital required for this investment however, because of the low returns involved.

Partly as a result, this scenario could see the acquisition by IOCs of oil field services or facilities development or management companies, or the creation with such entities of much closer partnering styles, marking a shift from transactional to more closely collaborative relationships as the IOCs increasingly undertake projects which no longer reflect the return expectations of their current shareholders.

This should result in opportunities for the IOCs to strengthen their involvement with unconventional gas and shale oil, both in



North America and elsewhere, which will again provide a ceiling on oil prices in the \$50/bbl range and will cap for gas prices at about \$4.50/mmbtu.

### **Scenario 3 – “Return to mega-projects”**

A world in which there is an only very slow adoption of carbon constraints, with oil and gas demand growth only gradually being restored, particularly in Asian markets. This growth prompts a gradual strengthening of oil and gas prices over the next five years, at least partly the consequence of continuing security challenges or political instability in areas where this is currently an issue and the continued closure to IOCs of many NOC provinces.

The next few years of low prices however results in a cashflow crisis and low earnings which drives an extended and pervasive wave of M&A consolidation involving most IOCs, both majors and large independents (such as the recently mooted Anadarko/Apache tie-up, or the Shell/BG merger). Mergers, or fire-sales involving the debt-ridden smaller independents, are also very likely. As a result of these aggregations, the fewer, remaining, much larger entities are better able to take advantage of the slow oil price recovery.

The merged, stronger IOCs will have the greater technological and capital strengths needed to master the more complex, larger and deep-water play opportunities for major oil and gas projects at significantly lower overall costs. Some of these strengthened IOCs, delivering higher rates of return are also likely methodically to pursue unconventional oil and gas plays but only in the traditional US play areas, rolling up the shale-gas plays currently being exploited. They are likely to leave international shale-gas plays to other, smaller players.

### **Conclusions**

The scenarios outlined above are not necessarily mutually exclusive: aspects of each can perhaps coexist at the same time. Nor indeed is it intended that this outline should comprise an exhaustive review of all possible future worlds.

It is however intended that these outlines should provide a selection of alternative possible visions of the future against which companies might stress-test their own portfolios, with the intention of identifying the most viable and profitable strategies for long-term growth. In this uncertain energy world, the best approach would be to develop strategies that are resilient under most plausible scenarios and that can be relatively easily adapted depending on which direction the energy world takes.

Arthur D. Little is often asked by clients for its views on the future direction of the sector on this centrally important strategic issue, a structural perspective which is perhaps more important now than ever.

### **Authors**

Stephen Rogers and Ondrej Sanislo



# Unconventional hydrocarbons in Latin America

*From dreams to reality*



## Executive summary

Production of unconventional hydrocarbons became globally prominent in 2010, when the US, for the first time, reached a daily output of 1 million barrels of tight oil. In Latin America, where high unconventional hydrocarbon potential has been widely recognized, Governments noticed the need to attract experienced international operators, qualified suppliers and risk-prone investors to develop such resources. The current global low-prices and increasing social and environmental pressures raise questions about the timing of Latin America's unconventional take-off. This article anticipates that, notwithstanding the pitfalls, at least 1 mmboepd of new unconventional oil and gas production could come online in Latin America within the next 10 years.

There are enablers and challenges to be addressed to develop Latin American unconventional hydrocarbon resources efficiently:

- Benefit from the US's and Canada's development experience
- Encourage collective knowledge building and innovation
- De-risk reserves fast and efficiently
- Use advanced analytical tools selectively and fine-tune processes to attain outstanding results
- Assure sustainable operations and community support
- Secure market advantage

As conventional O&G production in Latin American countries such as Mexico, Colombia and Argentina approaches a decline phase, their unconventional O&G upside can be explored and developed, and serve to both increase overall hydrocarbon production and improve the trade balance. This is not only good news for their NOCs, but also offers ample opportunity for international E&P companies and service providers with appetites for and experience in unconventional production. However, the unconventional developments in the region will be subject to particular country level conditions and Argentina has taken the lead in developing large unconventional resources in Latin America, followed by Mexico and Chile, while Colombia still needs to overcome key challenges to relaunch exploration.

# 1. Introduction

Production of unconventional hydrocarbons became globally prominent in 2010, when the US, for the first time, reached a daily output of 1 million barrels of tight oil<sup>1</sup>, together with nearly 20 Bcfd of shale gas. From then on, massive development continued to take place, until US unconventional oil production peaked at 4.5 MMbld in 2014. In the interim, global oil prices averaged over USD 90 per barrel. High prices motivated companies to invest strongly in proving the productivity and reducing technical risks.

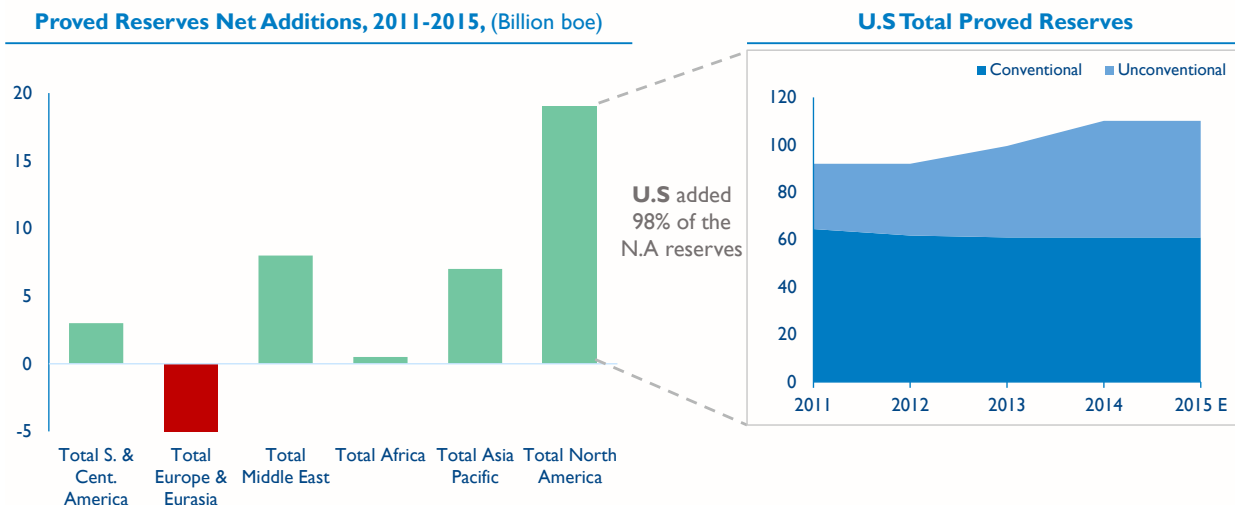
This US production ramp-up reshaped the global market with US unconventional reserve additions dominating the global industry over the last five years, as shown in Figure 1.

Ultimately, the expansion of the global oil supply caused oil prices to fall in late 2014. The price downturn challenged the economic feasibility of many unconventional development projects, but at the same time stimulated improvements in project competitiveness through innovation in development and production techniques, technologies, and management processes, as well as through industry consolidation. Today, the opportunities with superior productivity are profitable even at USD 40 per barrel, and the US industry continues to grow with the Permian Basin being in the vanguard.

Latin America’s high unconventional hydrocarbon potential has been widely recognized, especially in Argentina, Mexico, Colombia, and Chile. International researchers also estimate large unconventional resources in Brazil and Paraguay, too, but they are located in scarcely studied onshore basins. Shale oil potential in the Maracaibo Basin’s source rock has hardly been explored, eclipsed by Venezuela’s very large Miocene extra-heavy oil resources.

Governments in the region noticed the need to attract experienced international operators, qualified suppliers and risk-prone investors to develop unconventional resources, and some countries adopted policies to encourage such developments. But the pace has been slow and uneven region-wide. The current global low-prices and increasing social and environmental pressures raise questions about the timing of Latin America’s unconventional take-off. Notwithstanding the pitfalls, we believe that within the next 10 years at least 1 MMboed of new unconventional oil and gas production could come online in Latin America.

Figure 1: Global net proved reserves addition 2011–2015 (left), US oil and gas proved reserves (right) (EIA)



Source: Arthur D Little

<sup>1</sup> EIA defines tight oil as the oil embedded in low-permeable shale, sandstone, and carbonate rock formations.

## 2. Challenges for unconventional developments in Latin America

Figure 2: Fiscal and contractual incentives to promote unconventional hydrocarbon developments

Colombia	Argentina
<ul style="list-style-type: none"> <li>40% discount in royalties over the conventional rates</li> <li>Longer exploratory phase in E&amp;P contracts (up to 13 years)</li> <li>Longer E&amp;P contract duration up to 30 years (vs. 20 years for conventionals)</li> </ul>	<ul style="list-style-type: none"> <li>25% reduction in royalties (from 12% down to 8%) during 10 years, available till late 2017</li> <li>Longer exploratory phase: 8 years in 2 periods, plus a potential extension of up to 5 years (vs. 6 years + 5 for conventionals)</li> <li>Exploitation term = 35 years (vs. 25 for conventionals), including a pilot project period of up to 5 years</li> </ul>
Mexico	Chile
<ul style="list-style-type: none"> <li>Authorities still working on the unconventional regime</li> </ul>	<ul style="list-style-type: none"> <li>Preferential terms for unconventional projects can be included in current CEOP contracts, but the conversion process is not clear yet</li> </ul>

Source: Government websites. Arthur D. Little Analysis

Latin American countries have tried different approaches for promoting investments in unconventional resources. Governments and local players were aware that the first factor in attractiveness was the size and quality of the resource base. They also understood that in this context, "quality" meant not only richness, concentration, maturity or rock properties, but also the extent to which all those attributes were known and understood so that reliable conclusions about cost, productivity and commerciality could be reasonably drawn. Then some countries focused on improving technical knowledge and invested in exploration, while others prioritized the appeal of the contract terms and incentives offered to private investors.

For example, Colombia was the first country in the region to approve preferential fiscal terms for unconventional developments, and offered unconventional areas in its 2012 bidding rounds. Argentina relied on its world-class resource base, and its progress towards unconventional developments has been gradual, and somewhat contradictory, but so far encouraging. It combined promotional efforts, pioneering investments, unconventional-specific regulations, partnering strategies and a recent move to market liberalization mixed with regulated or negotiated price incentives. In Mexico, Pemex took the lead in exploring and confirming the unconventional potential, but energy reform has only recently opened the

Figure 3: Characterization of unconventional activity

	Argentina	Mexico	Colombia	Chile
Prospective area, Formation (Basin)	30,000 Km <sup>2</sup> , Vaca Muerta (Neuquina)	50,000 Km <sup>2</sup> , Tithonian / Turonian (Tampico-Misantla, Burgos, Sabina-Burro-Picachos)	30,000 Km <sup>2</sup> , La Luna (Valle Magdalena Medio)	10,000 Km <sup>2</sup> , Springfield (Magallanes)
Technically Recoverable Resources	~ 15 Bn boe ~300 Tcf	~ 30 Bn boe ~140 Tcf	~ 5 Bn boe ~ 20 Tcf	~ 48 Tcf including both shale and tight gas
Area awarded for exploration and/or exploitation	~ 70% of the prospective area in 28 unconventional blocks (19 pilot-project exploitation concessions and 9 exploration permits) + ~ 40 conventional blocks that can be re-converted	~ 8,200 km <sup>2</sup> (14 blocks)	~ 8,000 km <sup>2</sup> (8 blocks)	~ 60% of the prospective area in 11 CEOPs + 2 direct ENAP areas that may need re-negotiation if moving to unconventional activity
Main players	YPF + its subsidiary YSUR; major oil companies, IOCs, foreign NOCs, key Argentine and Regional players	100 % Pemex	Ecopetrol; Exxon Mobil; Patriot; Conoco; Canacol; Parex Resources	Enap; ConocoPhillips; GeoPark; PetroMagallanes
Shale/tight wells drilled	~ 800 since 2010	~ 25 since 2011	-	~ 75 since 2012
Investments completed	~ 8,000 MM USD	~ 500 MM USD	Less than 100 MM USD	~ 500 MM USD
Future announced investments	~ 5,000 MM USD 2016-2020 announced	55 MM USD for 2016-2018	Environmental regulation for development pending	1,000 MM USD estimated next 5 years

Source: Government and companies' websites. Arthur D. Little Analysis

discussion about contract models and special regulations for unconventional developments. Interest in Chile's unconventional potential gained momentum a bit later, but its contract models can adapt to the new initiatives.

The different strategies, efforts, timing and local conditions have resulted in varied rates of progress in unconventional resource developments, as shown in Figure 3.

There are enablers and challenges to be addressed to develop Latin American unconventional hydrocarbon resources efficiently:

- **Benefit from the US's and Canada's development experience.** Each individual play has unique characteristics and differential issues to be addressed. Though the North American experience may not be fully replicable, it provides visible best practices for Latin America's unconventional development programs. At the time of peak activity in the USA, the "factory-drilling" paradigm prioritized adding production and minimizing rig-setup time. The price downturn produced a paradigm shift to models such as Statoil's "perfect well"<sup>2</sup> or Argentina's "super pozo," which focus on attaining premium well productivity by means of optimal drilling, completion and reservoir engineering designs. Well-after-well cost reduction and time shortening are still targeted and measured, but priority attention is also now paid to keeping rig count and resource exposure controlled, as well as to lowering the costs per produced barrel.
- **Encourage collective knowledge building and innovation:** Openness and cross-fertilization of the knowledge base is the shared responsibility of government agencies, unconventional oil and gas (O&G) operators and service and equipment suppliers – engaging both experienced international companies and established local players. An innovative collaborative atmosphere is needed more than ever in the prolonged price downturn.
- **De-risk reserves fast and efficiently:** The window of opportunity in which US unconventional resources were commercially developed allowed a broad margin for trial-and-error overspending. That window is no longer open. In the low-price cycle, Latin American developers need to understand the plays, prove well productivity and reduce well cost at higher speeds and lower spending rates.
- **Use advanced analytical tools selectively and fine-tune processes to attain outstanding results:** A new generation of optimal wells demands knowledge-based decisions to define and locate sweet-spots, premium-well areas within sweet-spots, horizontally navigable intervals within the formation, and selectively frackable stages along the horizontal section in order to, in the end, devise the most appropriate drilling, completion and stimulation techniques. A broad spectrum of disciplines and new technologies support decisions related to the longitudinal or transverse orientation of the horizontal well section; its length, incline and trajectory; the completion type; the number, spacing and reach of fractures; the tuning of hydraulic pressures; and the selection of relevant chemicals and proppants. Powerful analytical tools are available, but they must be used selectively in a context in which "razor-thin"<sup>3</sup> economics do not allow unnecessary spending. Pilot projects are key for spatial clustering and drilling-campaign planning. To pursue wells that maximize recovery and production efficiency, feedback from operations needs to be made immediately available to the teams designing the next well.
- **Assure sustainable operations and community support:** A receptive natural environment and supportive communities are also threshold enablers, which constantly challenge all involved stakeholders to superior levels of responsibility. Governments must set both general and unconventional-specific environmental regulations - preferably upfront - , build a consensus, and become the key communicators of their countries' strategic decisions and the primary facilitators of stakeholder dialogue. Authorities at national, regional and municipal levels should align the information they convey to local communities, and mediate in order to enforce high social and environmental standards in operations on one side. On the other side they need to deter incidental coercion from less scrupulous pressure groups. Companies need to display strategies to proactively communicate their policies and create a strong link with local communities, not just as an image builder, but as an ethical end in itself. Non-governmental organizations (NGOs), unions, local representatives and social organizations need to play surveillance roles, but at the same time they should honestly seek solutions to let the activity progress in order to allow citizens to enjoy the benefits of an enlarged energy supply.
- **Secure market advantage:** Unconventionals flourished as an import substitution opportunity in the heart of world's largest energy-consuming market. Success in Latin America will also be tied to preferential access to domestic and neighboring markets, either due to *locational advantages* or because of *upstream-downstream integration forces* at NOC or country levels. The advent of shale oil will be a blessing for domestic refineries looking to replace region-wide light oil production decline. Conversely, in those countries that are more openly exposed to international competition, unconventional developments may be more vulnerable.

<sup>2</sup> Quoted by The Wall Street Journal on May 17, 2016.

<sup>3</sup> Halliburton's *dixit*, as used in its commercial materials.

### 3. Where will large unconventional developments flourish in Latin America?

#### Argentina

- So far, Argentina is the only Latin American country in which unconventional production has started commercially, though it is still small relative to its potential.
- The Vaca Muerta formation is a large, concentrated and broadly known play, with large shale oil, shale gas and tight gas potential. It is the main source rock in the mature Neuquen Basin, which still accounts for 40% and 54%, respectively, of Argentina's conventional oil and gas production. There is a significant upside in overlying and underlying plays, as well as additional unconventional resources in other Argentine producing basins.
- Argentina issued specific license terms for unconventional hydrocarbons, including tight gas, in July 2013. Consistently, the Congress modified the Hydrocarbons Law in late 2014. Wellhead crude oil prices – set by a collective agreement between producers and refiners – stood above import parity in the downturn, but this benefit did not make a big difference for unconventional investment decisions, as it was never believed that it would be long lasting.
- A large part of the Neuquen Basin's prospective acreage was already licensed under conventional terms. License holders can now apply for block reclassification, in full or in part, and obtain unconventional licenses in exchange for specific work commitments. YPF and other established players have sought international partners to exploit these opportunities. Provincial bidding rounds, direct negotiations, and an active secondary market of petroleum interests provide dynamic access vehicles.
- The new government administration that took over at the end of 2015 removed all export restrictions, taxes and foreign-exchange controls, further liberalizing the economy. In 2016, Argentina's financial situation improved significantly after an agreement on conflicting foreign-debt hold-outs was reached.
- Available capacity at the Neuquen Basin's infrastructure and surface facilities provides a sunk-cost advantage. A strong service and equipment-supplier market is already established. The knowledge base is broadly available, and an intellectually open, collaborative and innovation friendly atmosphere prevails. Prestigious, industry-wide organizations serve as active networking platforms, and there is a busy agenda of industry events.
- Local authorities and populations are familiar with and supportive of the oil and gas industry. The industry itself has taken the lead in clarifying the most sensitive environmental issues about unconvensionals. However, no specific regulation has been promulgated so far, and unconventional exploration and production (E&P) is still ruled by the same norms as conventional activities.
- Vaca Muerta's light crude oil production will rise to fill the gap left by the rapid decline of El Medaniito conventional light oil from the Neuquen Basin. As the Latin American country with the largest penetration of natural gas in its primary energy matrix (around 52–54%), Argentina is a major net gas importer, too. The unconventional natural gas price that Neuquen Basin's producers get at the production delivery point continues to be set by the Government, and is independent from the opportunity cost given by the import parity for natural gas (a mix of pipeline and liquified natural gas import prices). To promote unconventional developments, a fresh new regulation has placed such price at a level that is clearly above import parity today, and declines slowly along time.
- Argentina has taken the lead in developing large unconventional resources in Latin America, followed by Mexico and Chile, while Colombia still needs to overcome key challenges to relaunch exploration. With almost 20 unconventional pilot projects and further exploration plans under way, Argentina is firmly moving towards its next more substantial development stage. Apart from the NOC YPF and the Province-owned GyP Neuquen, many top-rated operators and investors are engaged in these activities: major oil companies and large international oil companies IOCs (e.g. Chevron, Exxon Mobil/XTO, Shell, BP, Total), key Argentinean regional players, large national oil companies, Canadian independents and others.

## Mexico

- Mexican resources are concentrated in three major basins: Sabina-Burro-Picachos (SBP), Burgos and Tampico-Misantla (TM). So far, the exploration and analysis of these unconventional plays have been conducted exclusively by Pemex. Geophysical conditions and productivity still need to be proved. After Round Zero, Pemex kept nine blocks with unconventional potential and is currently in the process of negotiating five other contracts under the service contract framework (CIEPs).
- Proximity to large unconventional developments in the US brings advantages in terms of knowledge and closeness to a specialized service market. Under the energy reform legislation, Mexican contract models are aligned with international standards. The 25% minimum national content required by 2025 is not deemed to be excessive if the domestic industry learns to leverage expertise from providers in neighboring US plays.
- The SBP basin is the geological continuity of Eagle Ford. Wells drilled by Pemex confirmed the presence of natural gas, but existence of liquids is still to be proved. For players with large acreage on the US flank and natural gas orientation, opportunities in SBP could represent a natural extension for their current operations. One key challenge will be to reach necessary cost-efficiency levels to compete with gas imports from the US, since Mexican prices are mainly indexed to Henry Hub. However, Mexico is still an LNG importer, and gas pipeline infrastructure expansion plans provide an opportunity to broaden the natural gas customer base.
- The hydrocarbons found in the Burgos basin consist mainly of wet gas and condensate, which offer attractive technical conditions for natural fracture flow. The area's remote location involves lower social risks. Burgos could be appealing to players interested in liquids and keen to accept higher technical risks in their search for material opportunities with high upside potential.
- Initial technical studies conducted by Pemex indicate high rock quality in terms of thickness and organic content, especially in the TM basin. These blocks are located in conventional oil producing areas, with easy access to oil facilities and infrastructure, as well as sufficient water availability. Potential investors in these opportunities should have expertise in enhanced liquid-recovery techniques, and

be capable of managing the social risks posed by proximity to communities.

- Declining crude oil production and growing natural gas demand provide key market incentives. As domestic petroleum production has fallen by about 30% in the last 10 years, Mexico urgently needs to add new barrels in the short and medium terms. Deepwater opportunities are highly prospective, but will not likely deliver significant production before 2022, so unconvensionals with shorter development periods could help mitigate the supply gap in the medium term.

## Colombia

- Colombia pioneered the promotion of unconventional resources in Latin America and, in 2012, adopted a special regime to improve the economies of these types of resources. Currently there are six unconventional blocks contracted by ANH to Exxon, ConocoPhillips and other companies, but plans have suffered the double set-back of the price downturn and environmental controversy. As a result, exploration activities were delayed and unconventional drilling has been very limited.
- The estimated unconventional resources of Colombia in the Middle Magdalena Valley (MMV) are 5 billion barrels and 20 Tcf<sup>4</sup>. Technical studies, such as the one conducted by EIA with the support of Colombian operators, have highlighted the rock quality of La Luna formation. The prospective areas are oil-prone with a lower wet gas potential. However, La Luna presents substantial vertical heterogeneity and needs to be drilled and studied in further detail.
- MMV is a mature conventional basin where the availability of oil surface infrastructure and water resources provide additional attractiveness. In spite of the government's fiscal incentives, diverging stakeholder interests have raised tensions in the debate about the environmental impact of unconventional activities and the standards to be enforced. As a result, specific regulation for unconvensionals has only been completed for exploration activities, but not for field development operations.
- Ecopetrol's medium-term strategy no longer considers investments in unconventional developments. This apparent side-step of the NOC might discourage some international players willing to find local partners with extensive knowledge of Colombian geology and topography, as well

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<sup>4</sup> EIA, May 2013



as those with the experience to deal with local communities and security issues.

- The constrained road infrastructure in Colombia is one key challenge for large-scale unconventional operations. The national hydrocarbon industry is used to working with large tanker-truck fleets for heavy oil operations; however, most rural roads are not built for traffic as heavy as that required during massive fracking operations, and this will demand extra investments from operators.
- In sum, with still-high geological uncertainty and significant operational, logistical and environmental barriers, as well as challenging economics, we believe the development of unconvensionals in Colombia over the next decade is far from secured. To speed up and implement the environmental regulation, as well as to attract the investments needed to confirm the potential of unconvensionals, a strong commitment from the government is required. Colombia's hydrocarbon sector has traditionally been open and friendly to international players, but additional efforts from the stakeholders are required to incorporate unconventional production into the country's supply portfolio.

## Chile

- Chile has recently joined the group of countries with recognized unconventional hydrocarbon prospectivity in the region. As early as 2005 ENAP, the Chilean NOC, coined the concept that very large volumes of gas had to be trapped all across the Magallanes Basin, which extends onshore across the South end of the continent and the Island of Tierra del Fuego, as well as offshore in the interjacent Magellan Strait. However, for several reasons, commercial conventional discoveries have not been declared. The idea was later revisited using unconventional approaches and technologies, and giving rise to further optimism.
- Significant unconventional gas potential has been identified in the Springhill Formation, the source-rock of Chile's Magallanes Basin, and its foreland continuation in Argentina, the Austral Basin. Additional gas potential is deemed to lie in tight Springfield reservoir rock. This potential has encouraged the Chilean government to promote the exploration of unconvensionals in Magallanes, led by ENAP.
- In the 1970s, Chile created the figure of the "Special Operating Agreement" (CEOP), by which private companies can hold contract rights on E&P blocks, risk capital investments and, if successful, earn in compensation the

right to be paid in cash or in the form of a freely marketable share in production.

- The Magallanes Basin lies in the XII Region in the South of Chile, and is an oil, gas and petrochemicals pillar of the regional economy. A developed supplier market provides related conventional services and materials. ENAP itself runs terminals, gas processing plants and major maintenance facilities. The XII Region is distant, but can be approached by ship and counts with good industrial harbors.
- Scale and locational advantages to attract international fracking and services companies may clearly emerge if Chile and Argentina cooperate to develop unconventional resources on both sides of the bi-national basin. On the Argentine side, unconventional hydrocarbon potential (mainly gas) has been identified in shales of the Springhill Formation and some of its upper and side members. Both countries are strongly linked in terms of industry culture, integrated land and marine logistics, presence of private players on both sides of the border, and cooperation and partnering between their NOCs.
- Local authorities, communities and unions are strongly supportive of the presence and expansion of the petroleum industry in the XII region. On the other hand, environmental organizations have made public their concerns about fracking in Central-Western Tierra del Fuego island, a natural land with sparse human settlements. The prevailing feeling of the population is favorable, but neither specific environmental regulations nor a management guide have been published in Chile yet, as they were for renewable energies and other industries.
- Substitution of hydrocarbon imports is a strong economic motivator for domestic production. Chile imports circa 96% of its refinery feedstock and 80% of the natural gas it consumes.
- The price downturn and poor exploration results have had an impact on conventional exploration activity. Investment plans have decelerated, and some blocks were either relinquished or taken over by ENAP. However, eleven CEOPs are still moving forward, with GeoPark and New Zealand's Greymouth as key players, together with several non-operating partners. Besides partnering in many of those CEOPs, ENAP is investing heavily in exploration in its own blocks, with a strong unconventional focus. In 2016, ConocoPhillips farmed in ENAP's Coiron block, targeting unconventional prospection and drilling.

# Conclusions

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As conventional O&G production in Latin American countries such as Mexico, Colombia and Argentina approaches a decline phase, their unconventional O&G upside can be explored and developed, and serve to both increase overall hydrocarbon production and improve the trade balance. This is not only good news for their NOCs, but also offers ample opportunity for international E&P companies and service providers with appetites for and experience in unconventional production. However, the unconventional developments in the region will be subject to particular regional conditions and specific country level challenges:

- Latin American unconventional resource holders are expected to operate in a scenario of intensified competition between different energy sources – including, but not limited to, all hydrocarbon and deposit types – with the perspective of a long-term, changing demand mix. Consequently, they should not keep waiting for a spectacular price rebound, but get ready to compete at flatter, slowly growing, acid-test prices.
  - The conditions are set for extensive development of unconventional resources in Argentina. Meanwhile Chile and Mexico still need to confirm the productivity and economic feasibility of their plays, while the prospects for Colombia remain uncertain.
  - Majors committed to unconvensionals, resilient North American E&P niche players, and Latin American independents with long histories of success in the region can be counted among the investors ready to join host NOCs with solid domestic positions in the Latin American unconventional adventure.
- We expect production to grow in Argentina over the next five years to reach a large scale in the early 2020s. We expect something similar to happen in Chile and Mexico over a longer period – for instance, the next 10 years, provided, in all cases, that oil prices do not drop below \$50/Bbl.
  - The four countries we analyzed are in great need of crude oil supply. Unconventional resources are positioned to become mid-term sources of light oil feedstock to their domestic refineries.
  - Natural gas has emerged as transition fuel for a low carbon future. The share of natural gas is expected to continue expanding into the world's primary energy matrix, and domestic markets in Latin America are following this trend. Large gas consuming countries as Argentina and Chile have a strong business case to develop unconventional gas soon, since LNG or natural gas imports have a strong negative impact in their foreign trade and foreign currency balances.

## Authors

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# The NOC technology & innovation management challenge

*Improving performance in technology management*



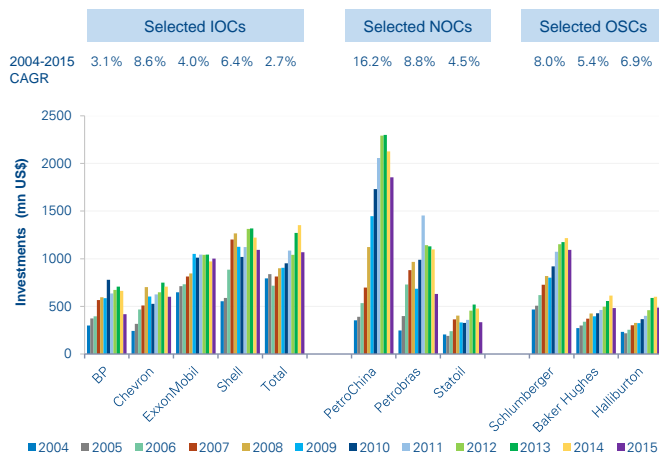
National Oil Companies (NOCs) are spending more and more on R&D. But this has not yet had much of an impact. With the oil price currently well below the break-even point of their nations' budgets, they are still behind Independent Oil Companies (IOCs) in terms of R&D effectiveness. IOCs have been shown to adjust faster to a new baseline price. Arthur D. Little (ADL)'s framework for E&P Technology management suggests that better focus on delivering the corporate strategy through active portfolio management, and an organizational form that links technology with projects or operations and embeds deployment in budgetary planning, can help.

## The continued rise of NOCs in technology development

Five years ago, ADL observed a shift, with some NOCs notably increasing their R&D expenditures.<sup>1</sup> With energy demand rising at home and resource nationalism increasing, NOCs began to realize the importance of mastering technology leadership in facing the challenges posed domestically and in their international operations. Since then, some NOCs have raised their technical capabilities and gained confidence in "going it alone" without IOC expertise, while often relying on support from Oil Field Service (OFS) companies. At the same time, IOCs pledged significant investments in new projects for the next five years, partly in an attempt to maintain their technical capabilities. However, the rate of growth for their R&D investment has averaged 5.0% since 2004, whilst leading NOCs have grown at 9.9% and that of leading service companies at 6.8%.

Over this time period, some NOCs (e.g. PetroChina, Petrobras, and Saudi Aramco<sup>2</sup>) invested more than IOCs and OFS companies in R&D. The technology lead of IOCs has been partially eroded. While some NOCs have established clear leadership in areas of particular significance to them (e.g. Petrobras in deep water and Statoil in arctic environment), others have partnered with peers for access to their resources (e.g. PetroChina with Petrobras).

## 2004-2015 R&D spending for selected IOCs, NOCs and OFS companies



Source: Arthur D. Little analysis, Companies' financial disclosures

R&D spending by NOCs has allowed them to become credible partners to other resource-holding NOCs. Leading NOCs have become more sophisticated buyers, understand better what IOCs and OFS companies can bring, and have developed strategies for technology development of their own.

## The case for technology management

More recently the entire industry has been under tremendous cost-cutting pressure, and we expect that R&D budgets will continue to be under pressure for the foreseeable future –

<sup>1</sup> Thuriaux-Aleman *et al.*, *Journal of Petroleum Technology*, Oct 2010

<sup>2</sup> Aramco does not publish R&D expenditures but these are thought to be higher than the IOCs

technology & innovation management (TIM) will become critical for NOCs wishing to improve their performance.

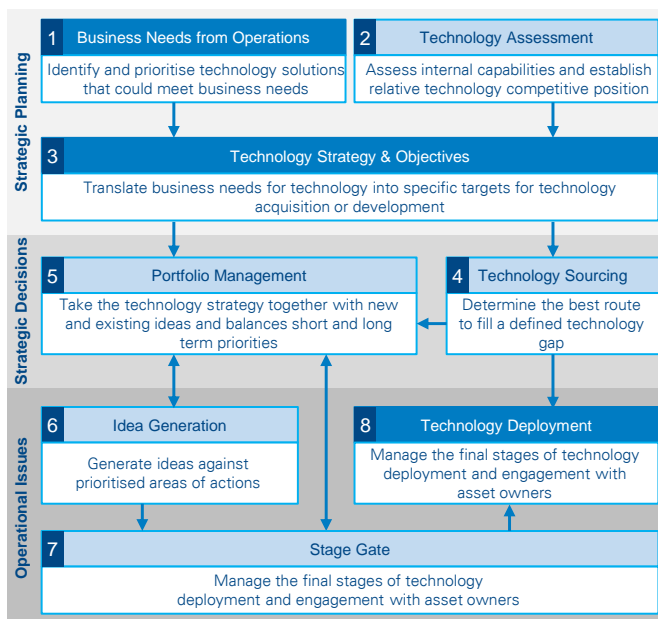
Despite the strong growth in R&D spending by leading NOCs, some have struggled to translate this into operational impact. And in the current context, increasing R&D spending is seen as the least likely area to improve innovation for O&G firms.<sup>3</sup>

IOCs have long experience of managing technology development to support both domestic and international operations. In contrast, some NOCs have found that operations in home markets and dependence on PSC partners or service companies may have hindered the development of strong technology management competencies. As a result, a number of NOCs need to develop better working practices and raise their technical capabilities.

### A framework for technology management

ADL has developed and deployed a framework for technology management (TIM) in E&P and in some cases we have developed specific TIM processes for companies. The framework consists of eight interlocking processes that operate at the level of strategic planning and formulation, which facilitate strategic decision-making and operationalize key aspects of technology and innovation management. These processes need to be tailored to the company’s organizational structure (i.e. centralized E&P, BU-driven E&P or integrated Project & Technology functions).

#### Technology & Innovation Management core processes



A key insight from integrating the different parts of these eight processes is that, in order to manage technology development effectively, it is critical to keep a strong link between the company overall strategy and its technology strategy. IOCs tend to keep a much stronger link between corporate strategy and technology and have more effective technology management processes. This allows them to achieve better focus – for example, by deciding what technology development they should focus on internally versus what technology they should collaborate on. This ability to focus and refocus has helped them deal with fundamental changes to the industry.

While some NOCs have had long-ranging technology strategies seamlessly aligned with their field development objectives (e.g. deep water for Petrobras, subsea operations for Statoil, heavy oil for Ecopetrol, and most recently shale oil & gas for YPF), others may be struggling to strike a balance between long-term R&D objectives and short-term focus in support of their operations.

Despite progress in alignment with strategy, we continue to see issues with effective prioritization of technological opportunities in terms of potential value creation and associated risks. Often this is driven by aggressive targeting of assets by technology vendors.

IOCs such as BP often have an excellent grip on the field deployment process of technology – including for technology they did not develop – through robust project management practices. In contrast, we know from experience that some NOCs struggle with deployment and find it difficult to leverage their efforts at this crucial step of the technology development, in part because of weaker integration of TIM processes, lack of experience in dealing with stage development across geographies and understanding of scale effects.

Sometimes technology assessment and deployment efforts are carried out in isolation by one single E&P asset and/or dedicated functional team, missing much broader opportunities for implementation across the company’s operations. This typically results in very low success ratios for deployment across operations.

### How can NOCs improve their technology management effectiveness?

In our experience NOCs improving efficiency in the management of technology is one of the most impactful ways to boost performance without increasing R&D budgets. The issues can be broken down into three main areas: **strategic issues, organizational issues and process issues**, and all need to be addressed to improve performance.

<sup>3</sup> Lloyds Register Energy, 2015, *Innovating in a new environment*

## Typical Technology Management issues along with opportunities for improvements

<p>Strategic alignment &amp; Portfolio rebalancing</p>	<ul style="list-style-type: none"> <li>■ The technology strategy must be regularly updated top down (by aligning with the corporate strategy and targeted resource play) and bottom up by identifying future needs from operating units. This requires strategic engagement with corporate planning and with operations.</li> <li>■ Launch a portfolio review of ongoing technology activities driven by the impact of recent changes (e.g., drop in oil price) and to drive fundamental strategic resource transfer in the portfolio. Our recent research shows that this requires a clear idea of how the technology portfolio should be balanced prior to carrying out the review.<sup>4)</sup></li> </ul>
<p>Organizational integration of R&amp;D with Projects or Operations</p>	<ul style="list-style-type: none"> <li>■ One option is to position technology so it is jointly integrated with a Projects &amp; Procurement division (as in Shell, Statoil and PETRONAS)<sup>5)</sup> to ensure that high Capex projects benefit from integration with technology deployment.</li> <li>■ Alternatively, re-organizing so that R&amp;D reports into business units (i.e. reporting directly into E&amp;P) and is funded by the relevant BU typically leads to increased relevance of technology to operations and this can increase the short-term impact of technology.</li> </ul>
<p>Process alignment with operations on deployment</p>	<ul style="list-style-type: none"> <li>■ Technology developments should be properly scoped from birth. Business owners must co-manage the technology road maps to deployment in articulation with their key business projects' critical paths. Knowledge and experience sharing platforms may help to further widespread the technology.</li> <li>■ Adopting stronger requirements for BU funding for technology deployment can help embed technology in asset plans. For example, the requirement to include BU budgetary provision for piloting technology (subject to success in scale-up and prototyping) forces early discussion of the value and relevance of technology.</li> </ul>

a) This is based on our R&D management best practice study: [Finding you balance: Insights into world class portfolio management](#)

b) See for example The Projects, Technology & Procurement Organization: The Emergence of a New Organization Form in E&P. [www.adl.com/emergence](http://www.adl.com/emergence)

### A. Strategic issues

Being a passive adopter of technology can lead to significant underperformance<sup>4</sup>, but that does not mean NOCs have to follow selective technology leadership strategies – we have shown that variants of the fast-follower strategy, such as the intelligent adopter (those with sufficient capability to integrate, adopt and improve supplier technology through dedicated investments), can be very successful.

However, this requires considerable focus and clarity of action, and some NOCs suffer from a lack of focus on defining how technology will support the corporate strategy and core focus of the organization. As an example, a few years ago one NOC with mature fields had one of its strongest research groups in engine development rather than in EOR.

This lack of a robust “top-down” technology strategy leads to a shortage of focus and prevents some NOCs from achieving critical mass in core areas. A related problem that can also contribute to lack of relevance is a poor definition of “bottom-up” technology needs from the operating units, and insufficient efforts to quantify the value of solving operational challenges in a way that allows prioritization of technology needs across different operating areas.

The technology portfolio management process is responsible for operationalizing the strategy, but in NOCs the portfolio of technology activity is not managed as aggressively as in IOCs

– some NOCs have never carried out full reviews of their R&D portfolios and lack the necessary data on the range of projects they fund to undertake such an exercise. This increases the likelihood that legacy projects will progress into large-scale investments despite the fact that the underlying economic rationale for their projects no longer makes sense. This leads to strategic drift, with technically good but irrelevant projects soaking up scarce technical resources. For example, the recent dramatic reduction in oil price should result in portfolio rebalancing, but this has not yet occurred for many NOCs.

### B. Organizational issues

An organization set-up that separates R&D from operations and isolates it from operational concerns typically results in few technologies being deployed to field operations. Operations tend to treat R&D as a tax and do not actively manage the R&D budget. As a result, R&D is allowed to focus on long-term projects which struggle to compete with readily available external technology solutions, or which become irrelevant when operational strategy changes, the technology under development is superseded, or it is not made available on time to match key projects' critical paths.

A number of NOCs attempt to broaden their R&D resources through different forms of cooperation with governmental science and technology promotional agencies – ranging from loans and contracts to co-sponsored entities with different degrees of autonomy. This provides access to funds, top-level scientists, technology development services and labs. However, it exposes technology development to fiscal policy fluctuations, as well as losing focus and control of projects and portfolio if intellectual interests rather than business interests become the key driver. The mission of such joint ventures sometimes includes the option to market technologies to third parties, but they often fail to accomplish said commercial purpose, since technology marketing is not at the core of the NOC's business and scientists are not usually sales oriented.

Conversely, if R&D is strongly linked to operations, we often see R&D staff drift into providing increasing levels of technical service functions. This is typically driven by the scarce technical resources available, which means that short-term fire-fighting of operational problems with required technical expertise takes priority over long-term development activities. This prevents R&D staff from delivering other projects on time.

Furthermore, there are opportunities to strengthen the managerial competences of teams involved in technology management, especially in the areas of business vision (e.g. understanding the entire value chain, identifying local and worldwide industry trends) and economic and financial analysis.

<sup>4</sup>Thuriaux and Rogers, 2012, *Technology Application in Mid-Sized Oil and Gas Companies*

### C. Process issues

Engagement with operating units on technology deployment is often problematic, with operating units sourcing their own solutions because technology roadmaps for acquired or developed technology are not fully shared with and maintained in coordination with the assets either, due to lack of communication among business units/assets. As a result, assets often lack budget provisions to pilot and deploy technology, and no one has had the difficult conversation about how deployment will be financed.

From our case experience and study of R&D management best practices, the starting point lies with a prioritized technology strategy. Having such a strategy strongly linked to their corporate development strategy and core strategic business projects, and mastering a process to maintain this link, allows companies to do more with less, with better use of available resources. Likewise, NOCs should be more aggressive in actively managing their technology portfolios and kill projects.

### Conclusion

Some NOCs have now caught up to IOCs in R&D spending, and in some cases overtaken them. But while some IOCs, and some leading NOCs have started to adjust to the new baseline for oil price, others have been slower to learn to manage technology & innovation more effectively.

IOCs are more effective at managing their R&D spending and adjusting to current conditions. One of the reasons is that they are able to maintain a tighter link between their corporate strategy and technology strategy than some of the NOCs. IOCs are also generally much better at deploying technology and controlling the costliest phase of technology development.

From our experience, NOCs face three types of challenges with technology & innovation management:

- Strategic – Technology strategy and associated roadmaps must be reviewed on a regular basis to ensure strong alignment with the corporate development strategy, and portfolio reviews must be conducted frequently.
- Organizational – NOCs can also benefit from tighter integration of the technology function with other operational ones to help it deliver more efficiently on expectations from the business.
- Process-driven – Deployment of technology is too often the stage at which the development of technology fails, and NOCs should heed the need for an ongoing dialog with operations on budgeting and planning for this crucial phase.

NOCs have to raise their levels of expertise in technology & innovation management if they want to convert their R&D spending into long-term technology leadership.

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# A perspective on the Iranian upstream oil & gas industry

*Can Iran achieve its full potential?*



## Executive summary

The global oil & gas market has begun to rebalance in the first half of 2017, following a period of suppressed prices that has stalled the US shale revolution and prompted OPEC<sup>1</sup> intervention, with an agreement to take 1.2 mmbbl/d off the market. Despite this rebalancing, it is likely that the market will remain uncertain in the short to medium term. In this context, and following two years of declining investment in exploration and production (E&P) with reserve replacement ratios falling dangerously low, many integrated energy companies and private investment funds are looking for the next big opportunity. The question is: could Iran be that compelling investment case?

The size of the Iran's hydrocarbon reserves presents indisputable significant potential, boasting the world's largest proven gas deposits and fourth-largest proven oil reserves. What's more is that the current political leadership has displayed progressive reform and begun to rebuild relationships with the west, following decades of sanctions. A major milestone was reached in January 2016, when the Joint Comprehensive Plan of Action (JCPOA) was implemented, removing nuclear-related sanctions. Since then, a number of bold steps have already been made to swiftly rejuvenate the country's economy and draw much-needed investment back to its primary industry – oil and gas.

Ambitious targets have been set across the upstream sector for the next four years, with plans to nearly double oil production volumes and increase those of gas by circa 50 percent. However, even to get close to these targets, companies must first find ways to address the financial, technical and capability gaps across the upstream industry. A possible roadmap has been constructed around five key pillars: urgently attracting foreign investment, optimizing existing resources, establishing a capability-building mechanism, prioritizing a fit-for-purpose gas-monetizing strategy, and improving global perception and access to new markets, including expanding the customer base in order to reach desired export targets. If Iran can agree on a strategic direction and deliver on its own targets, the only question that remains is how long it will be until Iran becomes the world's largest gas exporter.

<sup>1</sup> OPEC – The Organization of Petroleum Exporting Countries

# 1. Global hydrocarbon outlook

While projecting the future oil price is tricky business, a good starting point is to look back to understand what has happened historically.

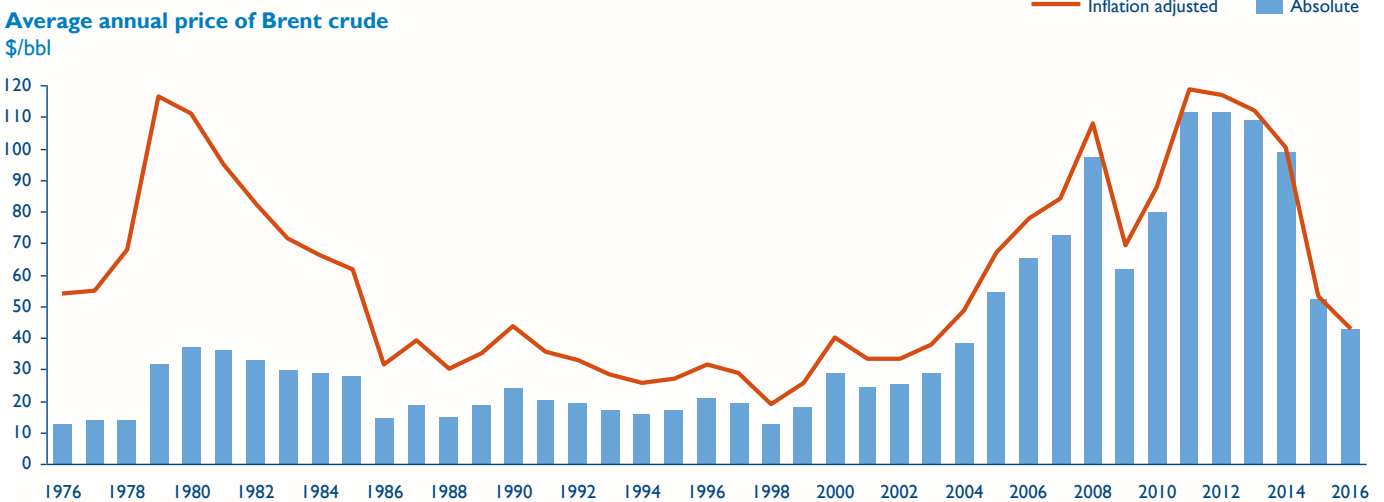
In which year did the oil price hit a peak of \$117/bbl, alongside the release of the Sony Walkman (available for \$200), the invention of the first snowboard, the election of the first female prime minister in the UK, and the formation of Iran into an Islamic Republic following the return of Ayatollah Ruhollah Khomeini? The answer is 1979. This year was significant; while it was the beginning of a revolution in Iran, it also marked the end of a period of high oil prices, which had unlocked huge supplies of oil and gas that were previously uneconomical. The market was flooded, over-supplied by as much as 14 mmbbl/d. OPEC tried its best to prop up prices, with Saudi Arabia alone taking 6mmbbl/d off the market in the early 1980s. However, the effect of this was to support non-OPEC members, which, at the time, were undertaking large capital investments, including the North Sea and Canada. In 1985 Saudi Arabia announced that it would no longer act as the swing producer, and what followed was a decade of low oil prices. (See Figure 1.)

In the early 2000s, due to growth from China and other developing nations, the demand for oil exceeded the supply and the price of a barrel rose quickly. After a momentary blip during

the financial crash of 2008, the spot price of a barrel recovered to over \$110/bbl. Shortly after this, the US shale revolution took hold and grew with unprecedented speed and resilience. This drove up US domestic production volumes, which more than tripled, from 3 mmbbl/d to 10 mmbbl/d. However, in 2014 global demand started to slow, the Eurozone appeared stagnant and Chinese growth forecasts were downgraded. The high US volumes, coupled with a period of stability across the Middle East, saw the market balance tip and oil prices tumble from July onwards. By January 2015, the price had reached \$47/bbl. What was then considered a low point would continue on a downward trajectory to a nadir of \$29/bbl in January 2016. The difference this time was that the market had only been oversupplied by 1–2 mmbbl/d, so production disruption in one oil-producing country or a well-orchestrated production cut by OPEC would rebalance the market relatively quickly, especially if the demand side was to pick up more quickly than expected.

The effect of the sustained low oil price through 2015 and into early 2016 saw many marginal producers squeezed, with over 200 E&P companies in the US filing for chapter 11 bankruptcy. US production began to decline, and the global market slowly rebalanced. In November 2016 OPEC members<sup>2</sup> agreed to cut production by 1.2 mmbbl/d. A number of non-OPEC members, including Russia, Mexico and Azerbaijan, among others<sup>3</sup>,

Figure 1: Following a spike in the late 1970s was a long period of suppressed prices; however, the situation today is somewhat different

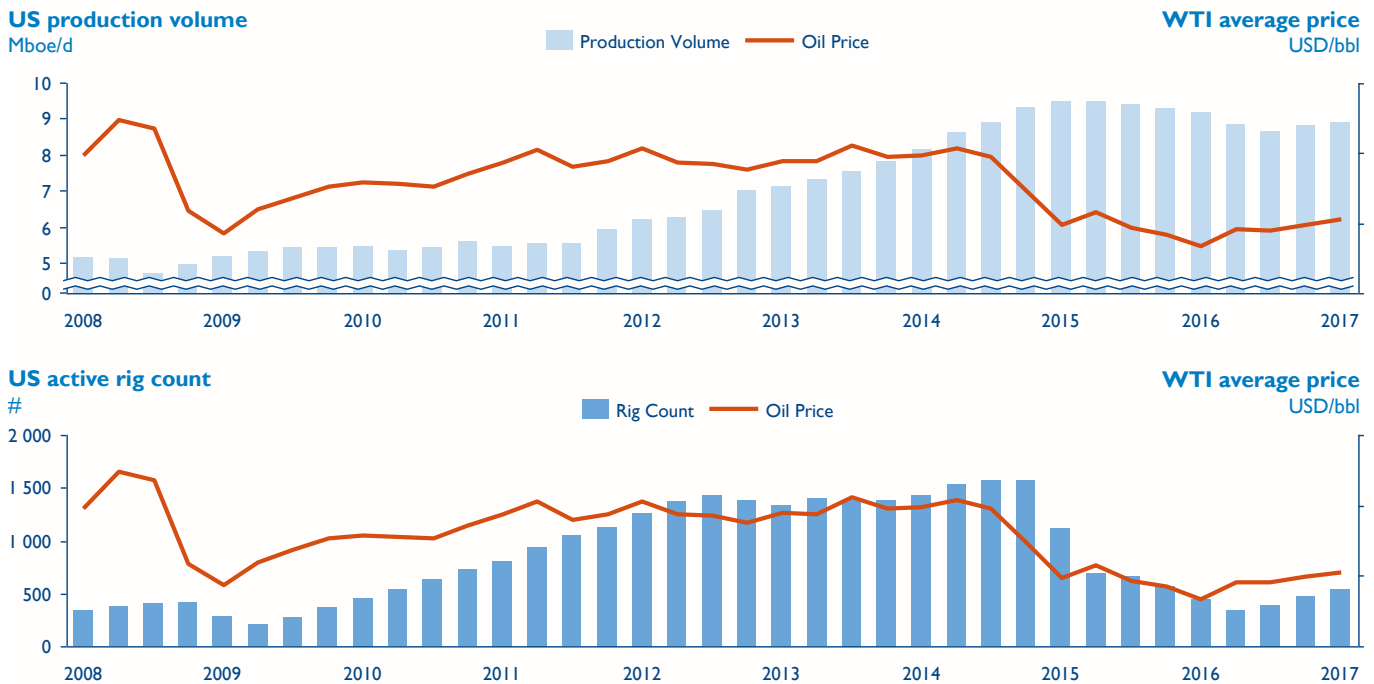


Source: EIA, Statista, Arthur D Little

<sup>2</sup> Countries that were exempt from cuts included Iran, Nigeria and Libya, which were struggling to maintain production volumes

<sup>3</sup> Other non-OPEC members included: Oman, Kazakhstan, Sudan, Malaysia, Bolivia, Brunei

Figure 2: As the oil price crept up and over \$50/bbl towards the end of 2016, the active US rig count began to rise again



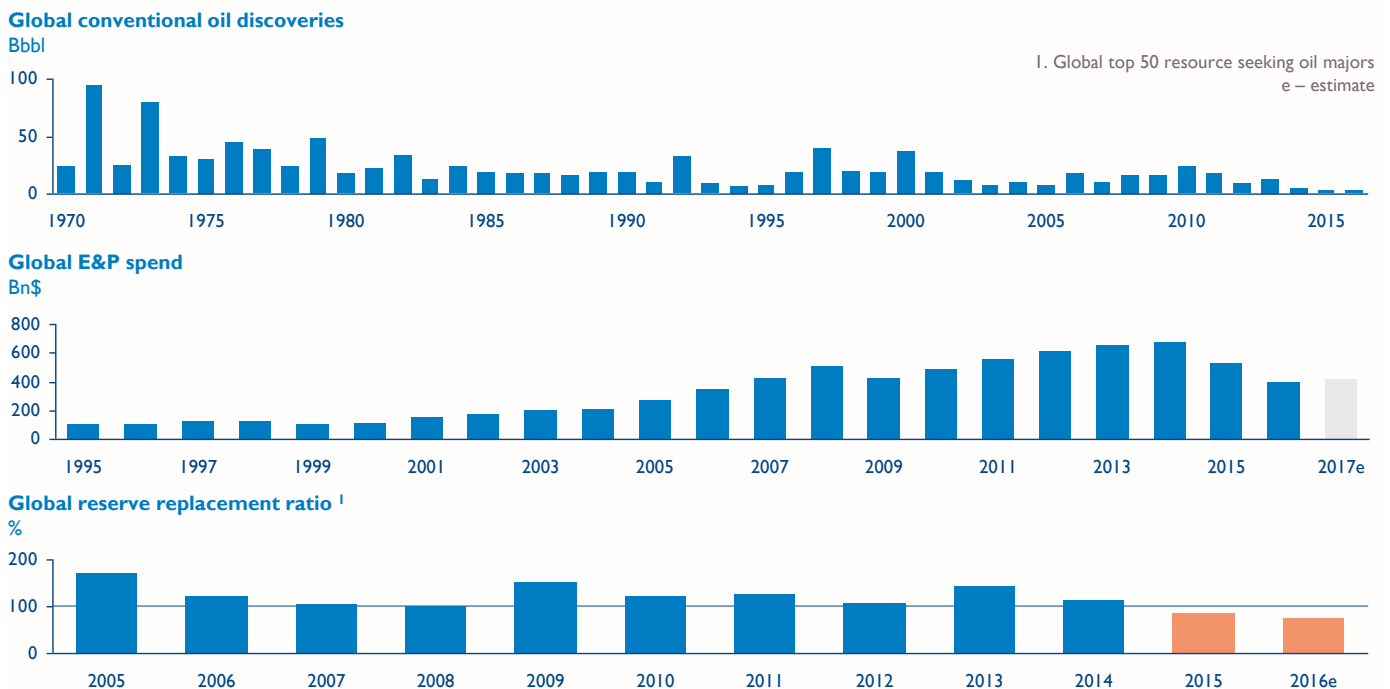
Source: Schlumberger, Barclays E&P Survey

agreed to cut a further 600 kbb/d. Historically compliance has been difficult to control, but early signs are that all parties are committed to their quotas. With oil prices hovering around the mid-\$50s, all eyes are on the US producers as rig count creeps up in the Permian Basin, where operators have healthier balance

sheets, greater access to capital, and vastly improved drilling and completion efficiency. (See Figure 2.)

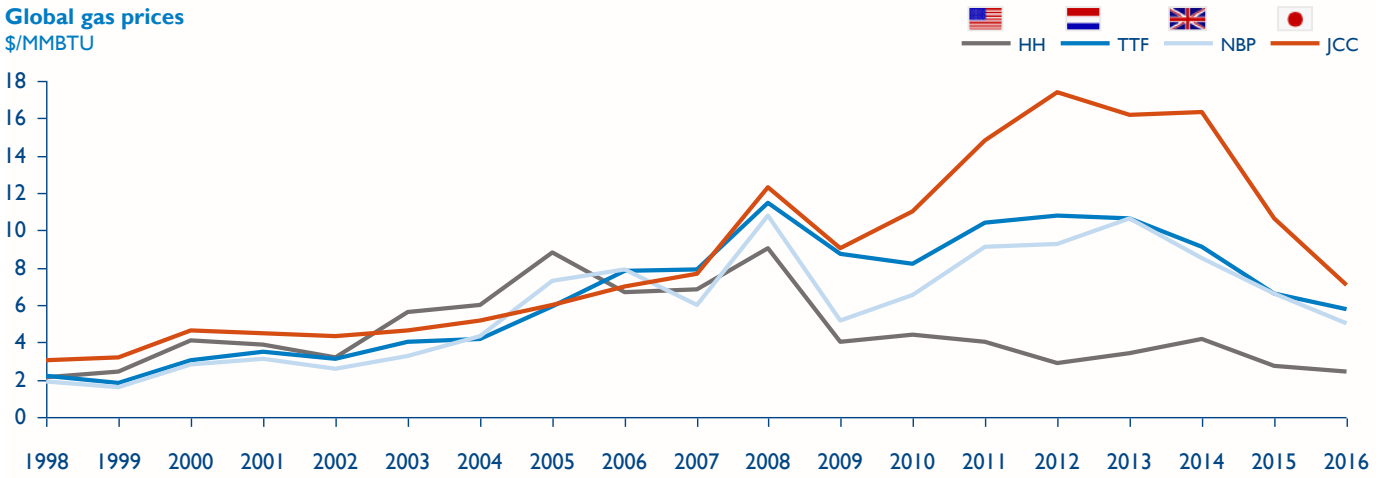
However, looking further ahead, with global peak demand not anticipated until sometime after 2040, a sustained drop in

Figure 3: Looking ahead further, it is possible that a supply squeeze will be experienced long before global demand for oil peaks



Source: Bloomberg, SEC Filings

Figure 4: As LNG volumes continue to flood the market, global gas prices show signs of convergence



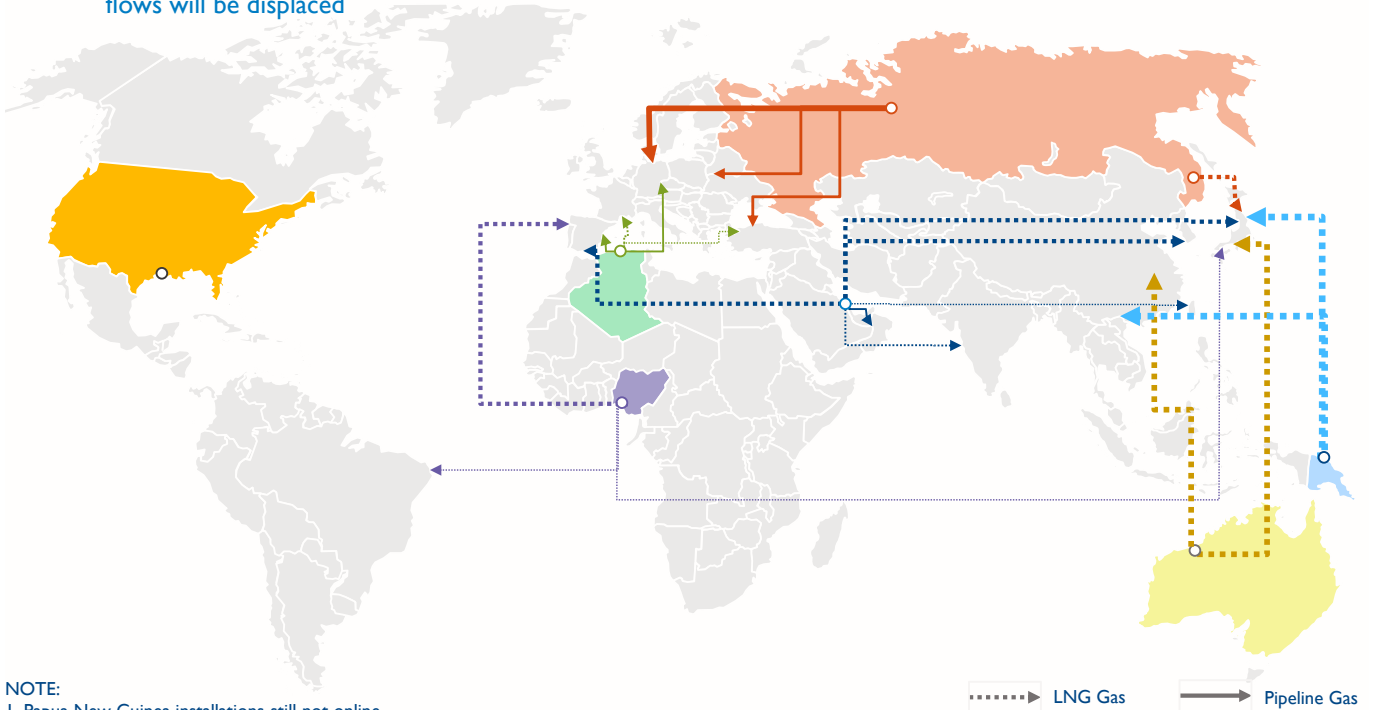
Source: BP Energy Outlook – Jun 2016, EIA Dec 2016

conventional discoveries and the year-on-year reduction of E&P over the last two years has led to the reserve replacement ratios of super majors dropping to below 100 percent for the first time. (See Figure 3.) It remains to be seen whether US shale producers respond quickly enough to fill the demand gap or there will be a supply squeeze in the medium to long term.

Turning now to the gas story, global gas prices rose in line with oil prices from 2000 to 2008, driven by increased demand from

emerging economies and a shift away from coal for power generation. Following the financial shocks in 2008 a divergence in global hub prices emerged. In 2011, following the Fukushima disaster, Japan's reliance on imported gas rocketed and the JCC hub price reached \$16–18 MMBTU in 2012. Meanwhile, in the US, market fundamentals drove down the Henry Hub price with an abundance of cheap, accessible gas to supply the domestic market, leaving the price hovering between \$2–4 MMBTU. (See Figure 4.)

Figure 5: As LNG continues to flood on to the global market from both the Asia-Pacific basin and the US, established trade flows will be displaced



NOTE:  
 1. Papua New Guinea installations still not online  
 2. Colours indicate the originating country for the gas export  
 Source: BP, Arthur D. Little Analysis

Recently, a number of large LNG projects<sup>4</sup> have come onstream in Australia and across the Pacific basin, providing an increased supply to Korea, Japan and other Asian markets. This has begun to displace Middle Eastern exports (mainly from Qatar) west into Europe. While the US begins to ramp up exports of its own, the market appears to be oversupplied until 2020. Going forwards, we are likely to see altered trade flows (see figure 5) and movements in regional pricing, with hub-price convergence already apparent. The impact on Iran is notable as it considers its position as a future supplier of gas across the Middle East and into Europe and Asia.

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<sup>4</sup> QCLNG, Donggi-Senorro, APLNG and Gorgon

# 2. Iran's oil & gas potential

## I. Geopolitical context

To understand the current situation in Iran it is helpful to reflect briefly on its history. In 1951 Iran voted to nationalize its oil industry, which, until then, had been dominated by the Anglo-Iranian Oil Company. Following a coup in 1953 the Shah returned, and the two decades that followed are seen as a time of prosperous growth for the oil and gas sector. In 1954 oil income was \$22.5 million, and by 1976 it was over \$19 billion. Peak production of 6.6 mmbbl/d was reached in 1976, and two years later, in 1978, Iran became the second-largest OPEC producer and exporter of crude oil.

Following the revolution in 1979, NIOC took absolute control over the oil and gas sector and abolished all international agreements. With US-imposed sanctions, production was curtailed and exports suspended. To follow was a war with Iraq in 1980, which lasted until 1988, when a ceasefire agreement was signed. Throughout the period no oil agreements were signed with foreign companies, and production levels were suppressed.

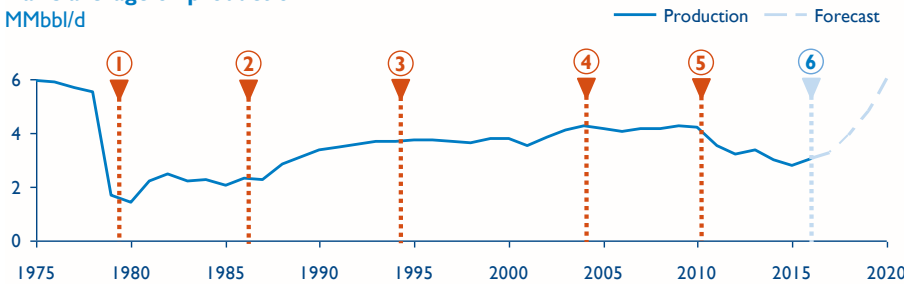
It was only in the mid-1990s that the Iranian government began to strengthen the sector, investing \$40 Bn between 1997 and 2005 in developing existing fields and exploring new ones. The projects were financed either directly by NIOC, through domestic contractors, or as joint ventures with foreign investment companies. In the case of joint-venture agreements, a buy-back scheme was put in place, in which NIOC reimbursed expenses but maintained complete ownership of the assets.

Major oil companies from France, Italy, the Netherlands, the UK, China and Russia had agreements with the ministry to develop the oil and gas sector during the early 2000s. However, under the leadership of Mr. Ahmadinejad<sup>5</sup>, relationships with the west deteriorated, and in 2006 sanctions were imposed and later renewed in 2012, hampering growth in the sector further. (See Figure 6.)

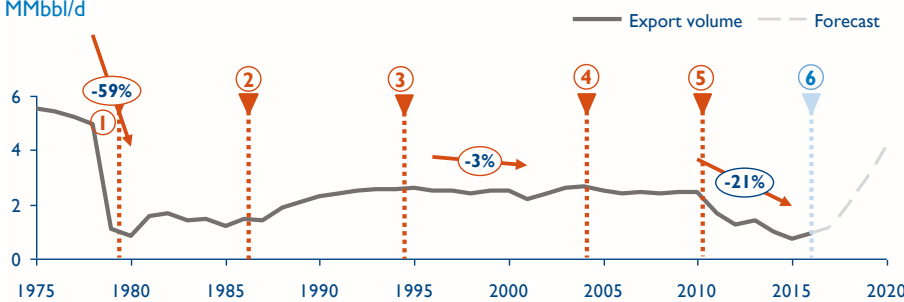
Despite sanctions, Iran's economy grew steadily from \$110 Bn (\$1,500 per capita) in 2000 to \$592 Bn (\$7,000 per capita) in 2011, although with a retraction of around 8 percent per year from 2011 until 2017, following the imposition of unilateral

Figure 6: Iran's produced and exported volumes of oil and gas have been below the historical levels of 1976 and can potentially grow with lifting of sanctions

### Iran's average oil production MMbbl/d



### Iran's average oil export volumes MMbbl/d



#### Main sanction changes:

- ① US imposes the first sanctions
- ② Iran listed as "state sponsor of terrorism" in US
- ③ Ban on US trade with and investment within Iran
- ④ New round of US and UN sanctions
- ⑤ Unilateral round of sanctions
- ⑥ Nuclear-related sanctions lifted under the JCPOA

Source: BP, EIA, OPEC Annual Statistical Bulletin

<sup>5</sup> Mr. Mahmoud Ahmadinejad was President of Iran from 2005 to 2013

sanctions. Despite this, Iran still has the second-largest economy in the MENA region after Saudi Arabia, with an estimated GDP of \$424 Bn in 2016. It also has the second-largest population in the region, swiftly approaching 80 million people. Further, a slowdown in GDP has not fully translated into unemployment-level terms, with a continued fall from 13 percent in 2011 to 11 percent in 2016.

**II. Impact of the JCPOA**

In January 2016, following a review by the International Atomic Energy Agency (IAEA), the JCPOA was implemented, releasing nuclear-related sanctions. Throughout 2016 Iran has been quick to reengage with foreign companies, offering improved contractual terms to attract them back to the negotiating table.

Following the JCPOA, signs of economic recovery have been strong, with growth forecasted at 5–6 percent for the next two years, based on the expectation that Iran will remain committed to the terms of the deal. However, the heavy dependence on oil and gas revenues means forecasts on economic activity and government proceeds remain volatile. The budget deficit grew by 4.3 percent to reach \$14.3Bn in 2016, and Iran hopes that the anticipated new deals in the oil and gas sector will help rebalance the books in the coming years.

With regards to exports, the successive rounds of sanctions have previously closed doors to the western world, limiting both

Iran’s available markets and its access to foreign funds. In 2016 Iran exported approximately \$100bn in commodities, of which 80 percent was oil and gas related (including both feedstock and refined petroleum products), and the remaining 20 percent included chemical and petrochemical products, fruit and nuts, carpets, and cement and ore. Nearly all of it went east to Asia; its largest export partners are China (27 percent), India (12 percent), Turkey (11 percent), Japan (8 percent) and South Korea (6 percent). (See Figure 7.) Iran will now be looking to expand its export partners to higher-priced markets across Europe, as well as further afield, as relationships continue to thaw.

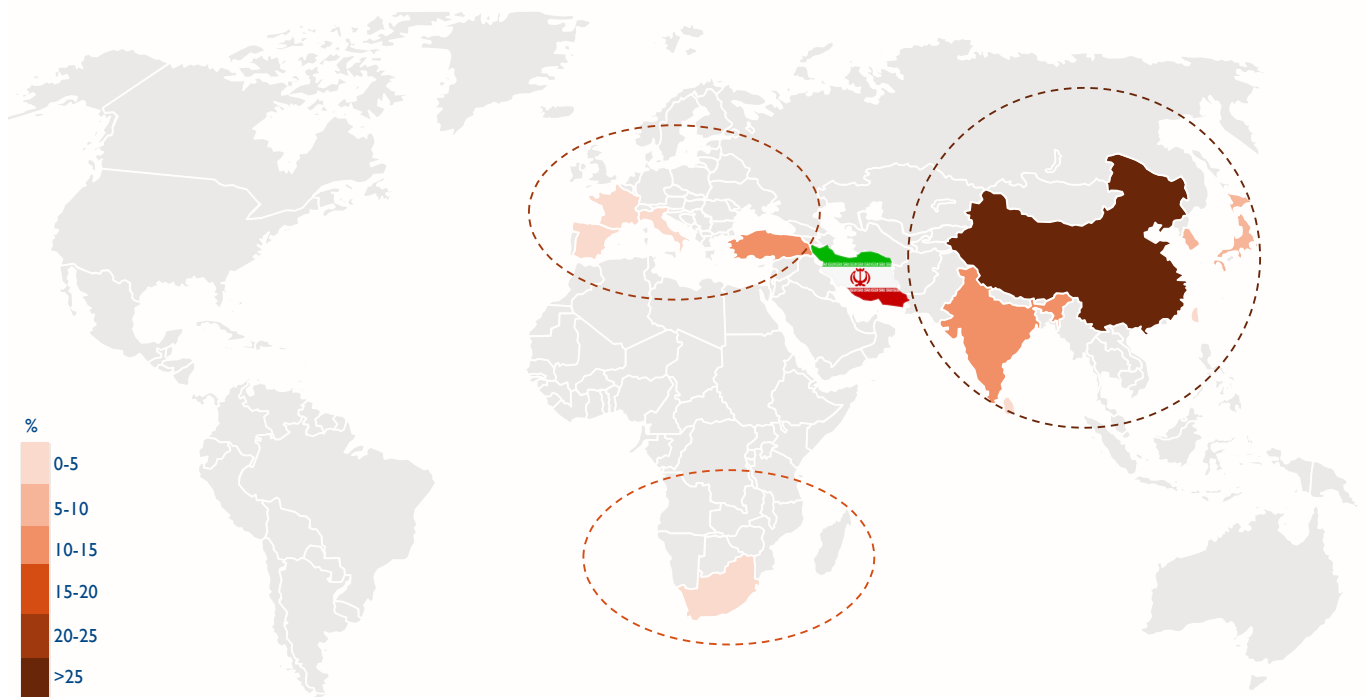
**III. Hydrocarbon reserves**

Iran’s reliance on the oil & gas industry is evident and likely to continue, given the size of its proven reserves. Proven gas reserves stand at 34 trillion cubic meters, making it the largest known source of gas in the world<sup>6</sup>.

The South pars field is the largest gas field in the world, and makes up 50 percent of Iran’s gas reserves. Shared with Qatar and only separated by a maritime border, the giant field was discovered in 1971 but only commenced production in Iran in 1989, after the war.

Interestingly, unlike oil production, which has been largely constrained and disrupted by political interruptions, gas production has continued to rise consistently (at around 10

Figure 7: Iran’s main export customers have historically been in east Asia, leaving plenty of room for diversification



Source: OEC

<sup>6</sup> BP Statistical review 2016 (published numbers end of 2015) Russian federation is second with 32TCM proven gas reserves

Table 1

Field name	Formation	Reserve (tcm)	Condensate (mmbbl)	Discovery year	First Production
South Pars	Kangan & Upper Dalan	14	18,000	1971	1989
North Pars	Kangan & Upper Dalan	1.3	1,900	1967	Na
Kish	Kangan & Upper Dalan	1.3	400	2006	2015
Golshan	Kangan & Upper Dalan	0.8	Na	1993	Na
Tabnak	Kangan & Upper Dalan	0.6	Na	1967	1980
Kangan	Kangan & Upper Dalan	0.6	Na	1967	1980

percent a year) since the early 1980s (see Figure 8), driven by domestic demand and helped by government subsidies.

Focusing now on oil volumes, Iran also has one of the largest proven oil reserves in the world, with an estimate of 158 billion recoverable barrels<sup>8</sup>. These reserves are spread across 140 hydrocarbon fields, many of which contain both oil and gas. Two-thirds of these reserves are located onshore, with the remaining one-third in the Persian Gulf. These stated reserves are easily accessible and can be conventionally produced. At the current production rate, the country reserves can last more than 110 years.

Iran produced an average of 3 million bbl/d in 2016; more than 50 percent of this production comes from the four largest fields. (See Table 2.) However, the average age of those fields is 69

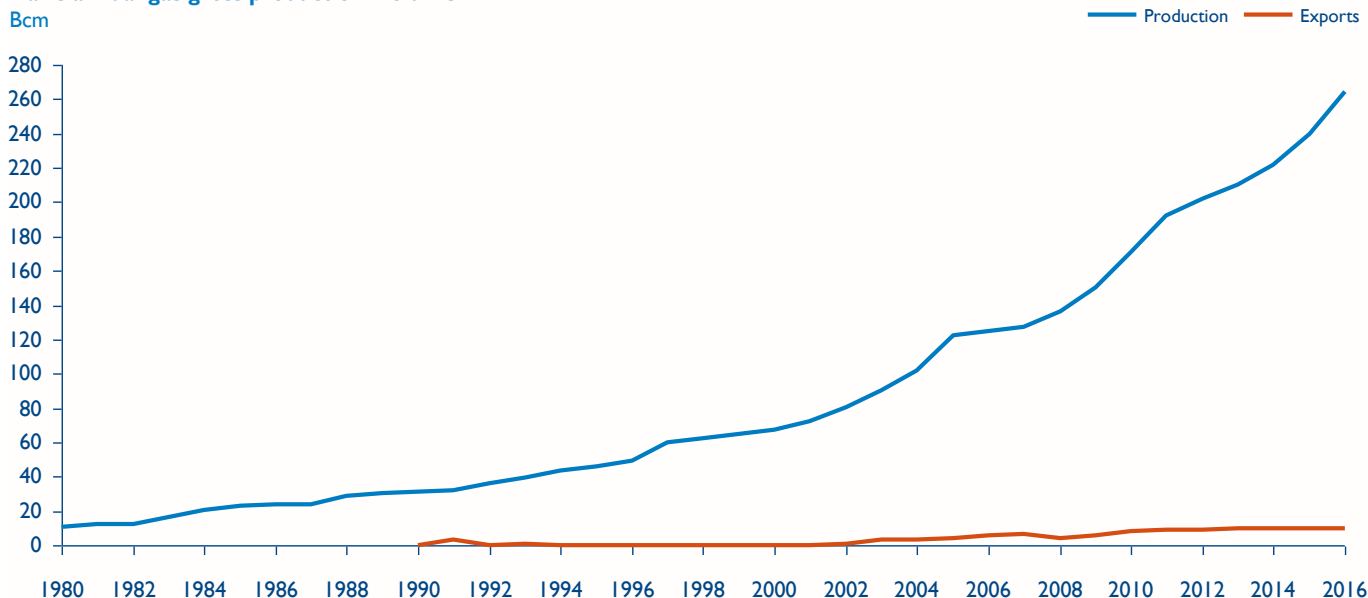
years, which highlights the need to invest in exploration to bring new fields online.

#### IV. Infrastructure and reservoir condition

During the 1970s, when oil prices were relatively high, large volumes of gas were re-injected into oil reservoirs to increase production volumes, which subsequently went from 2 mmbbl/d to 6 mmbbl/d. However, this led to rapid decline in some large reservoirs by the late 1970s. This was followed by a series of strikes by workers in the upstream sector, which led to deterioration of reservoir management, compounded further by the Iraq war in 1980.

Figure 8: While Iran's production of natural gas has ramped up, it has historically been used for internal consumption and exports have remained low

#### Iran's annual gas gross production<sup>1</sup> volume



1. Gross production is the total flow of natural gas from oil and gas reservoirs of associated-dissolved and non-associated gas

Source: OPEC 2016 report

<sup>8</sup>Wood Mackenzie 2015



Table 2

Field name	Formation	Initial oil in place (billion barrels)	Discovery year	First production
Ahvaz	Asmari & Bangestan	65.5	1953	1954
Gachsaran	Asmari & Bangestan	52.9	1928	1930
Marun	Asmari	46.7	1963	1966
Aghajari	Asmari & Bangestan	30.2	1938	1940
Karanj	Asmari & Bangestan	11.2	1963	1988

The aggressive production of the 1970s and the neglect in the 1980s have caused reservoir-pressure problems and water encroachment in a number of oil fields. This makes it a top priority for the country to develop a clear reservoir management strategy and introduce technologies that can quickly improve reservoir performance.

As in many other industries, Iran has proven ingenious in its approach to developing and manufacturing equipment locally to assist production. Nonetheless, despite admirable resourcefulness, and perhaps as a result of inconsistent investment and a short-term view of production, there are low recovery rates. The underlying problems lie in aging platforms that need rigorous maintenance plans and well stocks that require urgent remedial action.

### V. Recent changes

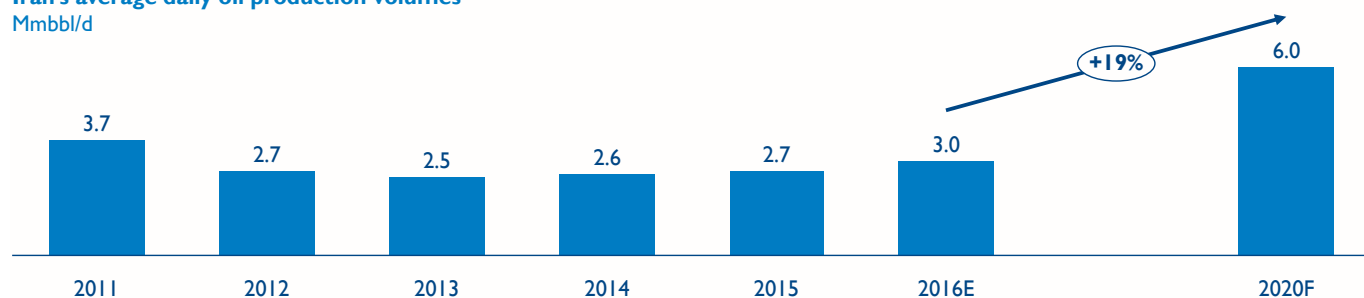
Following the JCPOA, Tehran has shown positive steps of putting a century of turbulent relations with the international oil industry behind it, and begun to focus on being commercial and competitive. In January 2016 new IPCs were issued as an alternative to the legacy buy-back contracts. The IPCs are similar to production-sharing deals, in which foreign companies win the rights to output and reserves, and risks are shared. The question remains whether these new contract terms are sufficiently attractive to reach the \$200bn desired target stated by Mr. Zanganeh in June 2016<sup>10</sup>.

These new IPCs enable foreign companies to set up joint ventures with NIOC or one of its subsidiaries, with duration terms of 20–30 years, replacing the previous period of six to

Figure 9: Iran sets ambitious target for oil and gas production by 2020

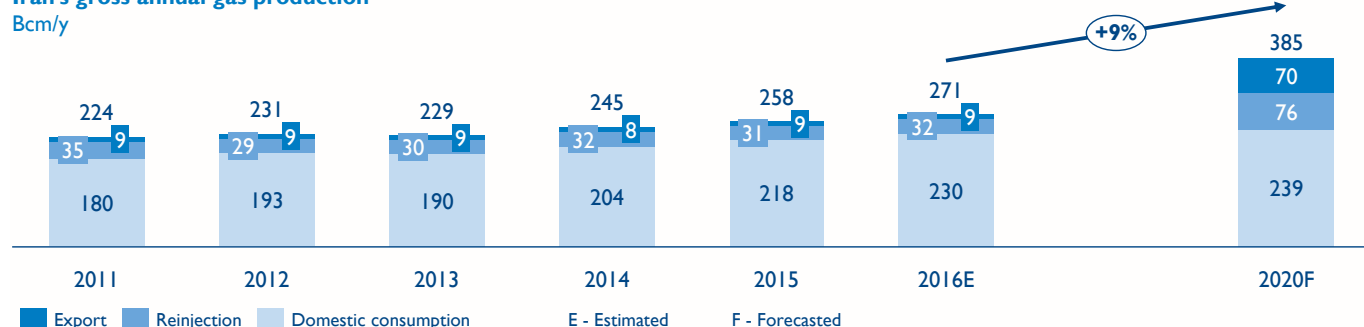
#### Iran's average daily oil production volumes

Mmbbl/d



#### Iran's gross annual gas production

Bcm/y



Source: Research Center of the IRI Parliament; Opec annual bulletin; ADL analysis

10 Mr. Bijan Namdar Zanganeh is the Iranian oil minister; this statement was made in an address to parliament on 15th June 2016

12 years. Moreover, remuneration is flexible instead of a fixed fee, and rates of return are negotiable on a sliding scale and proportionate to risks surrounding development. One significant change is that oil companies will now be able to book the value of reserves on their balance sheets, subject to strict conditions in line with Iranian law and its terms of reserve ownership. (Foreign companies cannot own Iranian reserves.)

With the intent of moving the Iranian oil & gas industry in the right direction, bold policies continue to be adopted. Towards the end of 2016, ambitious targets were set to raise oil production volumes to 6 mmbbl/d and gas production to 1,055 mcm/d (385 bcm/y) by 2020. (See Figure 9.) If met, these targets would have dramatic implications for both the industry and the country's wider economy. What remains to be seen is how and when they will be met, considering the existing gaps.

### 3. Iran’s oil & gas sector gaps

The Iranian government has demonstrated the motivation, aspiration and desire to balance its books and resurrect Iran as a global oil and gas superpower. In order to reach these ambitious targets, it will be necessary to address financial, technical and capability gaps across the country’s upstream industry.

The single most limiting factor to achieving targets in the sector is access to funds. As mentioned above, a target of \$200bn was stated in 2016 to fund projects across all parts of the value chain. (See Figure 10.) In the upstream sector, this includes developing the giant gas fields further and exploring and appraising new fields, while also upgrading production facilities and introducing new technology. Some of the funds could go towards finishing Iran’s first LNG terminal at Tombak Port, though this would likely require a deal with an oil major with access to technology and expertise.

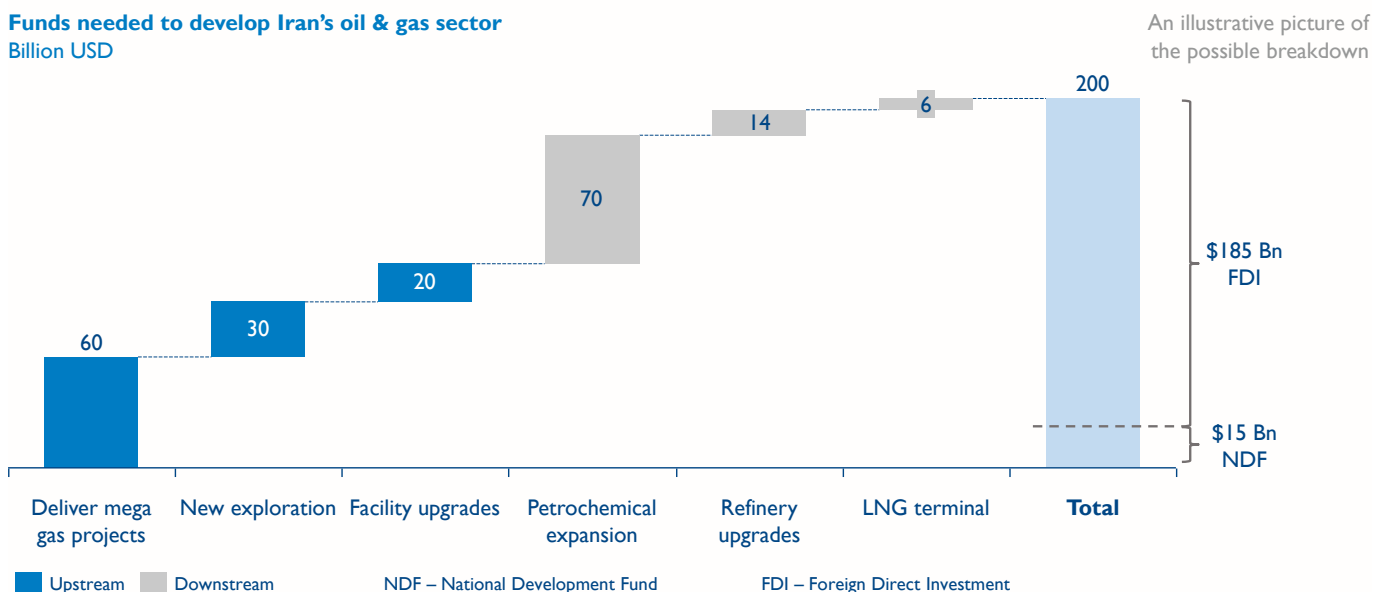
Historically banks and financial institutions have been very slow and hesitant to back large investments in Iran. Some level of institutional reform across the financial sector would help accelerate funding, as the current structure of the industry has

made it challenging for the Iranian banking system and private capital to engage in the oil and gas business.

Assuming that some financing continues to trickle through, ramping up oil production volumes will be a priority. Over the past five to six years the average daily oil production volume has been around 3 mmbbl/d, and export volumes have been around 1 mmbbl/d. (See Figure 9.) Following the JCPOA these volumes increased swiftly, to as high as 3.9 mmbbl/d and 1.8 mmbbl/d, respectively, through the second half of 2016. However, this increase was exclusively due to existing production capacity, opening wells that had been shut in, and exporting volumes that had been held in terminals and tankers. So with that in mind, and looking more closely at the target, achieving 6 mmbbl/d by 2020 does appear ambitious.

Given that Iran does have an exceptionally low recovery factor of around 20 percent compared to the 35 percent global average and best-in-class performers, such as the UK at 46 percent, there is clearly substantial room for improvement. By introducing modern IOR/EOR technologies and adopting the latest methods

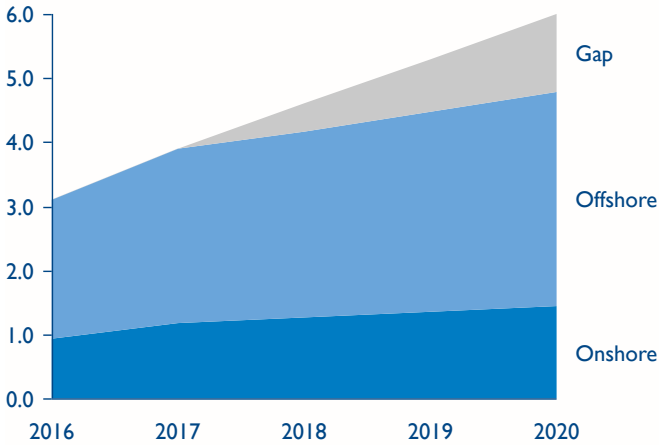
Figure 10: An injection of \$200B is part of the 5-year plan to revitalize both upstream and downstream arms of the sector



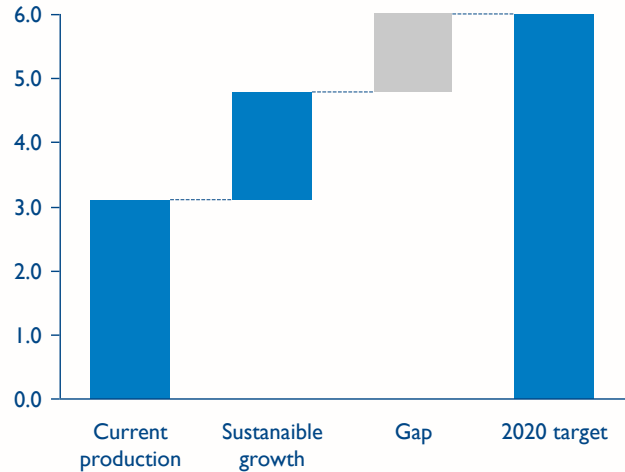
Source: Press releases including: Financial Times, MEI, Financial Tribune

Figure 11: In order to achieve the oil production targets set, it will be necessary to do more than just optimise existing capacity

**Iran forecasted oil production**  
Mmbbl/d



**Iran forecasted oil production**  
Mmbbl/d



Source: Opec, Forbes, Center for Strategic and International Studies, ADL analysis

of reservoir management and increased gas injection volumes, it has been suggested that the annual production volumes could be increased by 7% a year.

However, stripping out the inflated volumes of 2016 and applying the 7 percent annual production increases that are detailed for existing capacity increases, it becomes clear that there is still a gap of 1.2 mmbbl/d that would need to be filled through new fields and assets in order to achieve that 6 mmbbl/d target by 2020.

Looking now at the gas production volumes, there are already many large developments under way, including the South and North Pars and Kish, to name a few. Thus, it is perhaps quite feasible that Iran will achieve its gas production target of 385 bcm/y by 2020. Despite this, what will still be required is careful consideration for how that gas is utilized between supplying the growing domestic and industrial demand, addressing the power generation requirements, maintaining oil-reservoir pressures and meeting the stated export targets.

In 2016, Iran's gross<sup>11</sup> gas production volume was around 270 bcm. (See Figure 8.) Less than 10 bcm of this was exported, while around 80 percent was consumed domestically, primarily for residential and industrial use and power generation. The remainder was either flared, lost or re-injected. Domestic

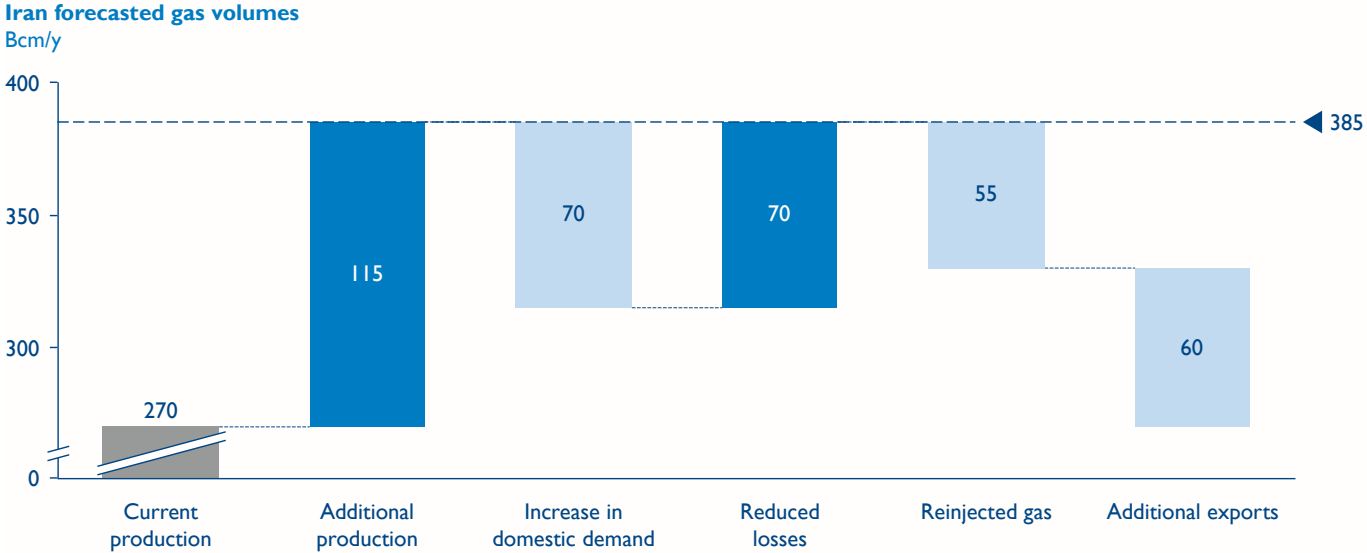
demand is contextualized by the fact that it is currently greater than the available supply, meaning that the country burns a lot of its oil just to keep the lights on.

If the target of 385 bcm/y is reached, it is hoped that 70 bcm/y will be exported. To do this, and as production volumes increase due to the aforementioned new developments being brought onstream, there will need to be a well-thought-through plan for gas utilization. As domestic and industrial use and power generation will be prioritized, the likely trade-off will be between the volume of gas that is reinjected into the oil reservoirs and the export volume.

An example of where process capabilities could be greatly improved is through waste management. As illustrated in Figure 12, a possible way the export target and the growing domestic demand could both be met is through increasing production efficiency and reducing losses in the current system, as well as reducing flaring of associated gas volumes. This could potentially offset the projected increases in domestic demand, freeing up the much-needed additional production volumes for reinjection and export.

<sup>11</sup> Gross production: the total flow of natural gas from oil and gas reservoirs of associated-dissolved and non-associated gas

Figure 12: Improving efficiency and reducing losses will offset domestic demand growth, leaving additional production volumes for reinjection and export



Source: OPEC, Press releases, ADL analysis

## 4. A way forward for Iran

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In order for Iran to reinstate itself as the fourth-largest oil and gas global player behind Saudi Arabia, Russia and the US, it must first establish a clear strategic vision. Iran has many advantages; not only does it pose the world's largest proven reserves of gas, but it is also well located between the European and Asian markets and has access to a large pool of local talent and resources.

What is required now is a well-detailed action plan built around five key pillars to support sustainable growth across the industry. These are:

1. Urgently attract foreign investment
2. Optimize existing resource management
3. Establish a mechanism for capability development
4. Prioritize the most effective gas monetization strategy
5. Improve global perception and customer base to realize export objectives

### 1. Urgently attract foreign Investment

Iran faces two main challenges here. Firstly, the relationship with the US and renewed sanctions will make some large companies wary. Secondly, there is a high level of competition from a range of other investment options for the scarce capital being deployed.

While the abundant investment opportunities are clear, Iran's challenge is to convince foreign investors that the risks are not too high. This includes persuading them to look beyond the geopolitical tensions across the region, as well as reassuring them that progress on reform will not be short lived and the governance of the country will work hard to avoid the reimposition of sanctions.

### 2. Optimize existing resource management

Iran has been producing oil for more than 100 years; however, it is essential that it manages these resources optimally. In order to do that, it is first necessary to fully understand the current state of the assets in terms of production potential, technical specification and structural integrity. Second, the country must identify the production chokes and bottlenecks, which could include reservoir-, well-, plant-, export- or market-related constraints. Third, there should be prioritization of projects to

address these bottlenecks, which could include the introduction of new reservoir management techniques, remedial well work (e.g. setting bridge plugs to reduce water cut), reviewing compressor uptime or increasing export-pipeline capacity.

### 3. Establish a mechanism for capability development

Perhaps the second-hardest challenge for Iran after raising the required capital will be attracting and retaining the required talent and skills to continue to grow and develop the sector. Many other countries have grappled with this challenge, adopting a number of well-known policies and procedures, both contractual and non-contractual, to address regional capability gaps. Contractual capability development models include setting terms for local training schemes and establishing formal mechanisms for knowledge sharing and transfer, as well as enforcing local procurement. Non-contractual capability development models tend to generate higher impact, as well as involve collaboration with education institutions and universities and include sponsorship, R&D funding and theoretical training. It could also include joint ventures with local manufacturers or even establishing apprentices. An example of best practice for capability development within the oil and gas sector can be seen in Malaysia, which has a dedicated institution known as the Malaysian Petroleum Resource Corporation (MPRC). This acts as an independent body to link government entities, international oil companies (IOCs), national oil companies (NOCs) and academic institutions together with one common goal of developing capabilities within the industry.

Critical in local capability development is the definition of a clear and centralized strategy on how companies should work with the government and one another to develop talent sustainably. Often, "local content" strategies fail because they become a clause in a contract that IOCs and independents see as a financial rather than strategic commitment.

### 4. Prioritize the most effective gas monetization strategy

Historically, the simplest way for Iran to monetize its gas reserves has been to use its gas as feedstock to petrochemical plants and sell the products that include methanol, ammonia, urea, etc. While the technology is well known and the processes simple, the margins are relatively low. As gas production

volumes increase and the market constraints reduce, Iran can begin to look at other ways to monetize its gas. Three possible ways are: LNG, GTL and pipelines.

The LNG process involves treating the gas and then cryogenically cooling it to -160 degrees centigrade. The technology has developed extensively over the last decade, with many mega-projects due online in the coming years. (See Figure 5.) However, it is still very expensive and only available to a limited number of western companies. While Iran may be able to learn a lot from its neighbor, Qatar, the expected oversupply to the market may prove a barrier to developing a greenfield LNG industry.

The second possibility is a process known as gas to liquid (GTL). Unlike LNG, which involves a change in state through cooling, GTL is a chemical transformation process to a different product, which typically supplies the transport and petrochemical markets. While this is also a very expensive technology, it may be a lucrative route for Iran to pursue as it allows producers to hedge between the oil and gas market.

The third option is the very traditional and well-established concept of transporting gas via pipeline. This appears an

extremely feasible option for Iran as all neighboring countries, bar Qatar, require gas. It is also possible to reach larger markets beyond these immediate neighboring countries. To do so, it will be necessary to look west to Europe and east to Asia.

Currently 90% of Iran's limited gas exports are to Turkey. Perhaps the most obvious export expansion route is to extend the pipeline through Turkey and into Europe once Iran and Turkey have resolved their pricing dispute<sup>12</sup>. This would provide access to the large European market. This proposed pipeline project is known as the "Persian"<sup>13</sup> pipeline.

The other route to Europe is through Iraq, Syria and Lebanon, and then across the Mediterranean, through a project known as the "Friendship"<sup>14</sup> pipeline. A \$6bn contract was due to be signed in 2011, which included supplying a potential refinery in Damascus. However, it is unclear if construction was ever started. The project is ambitious, with a delivery capacity of 110 mcm/day (40 bcm/yr), a length of 1,600 km and an investment cost of \$10 bn. While it could benefit all parties, it is unconfirmed where the required funding would come from. This is not to mention the significant instability of the regions through which the pipeline would run.

Figure 13: Since the current infrastructure cannot meet Iran's ambitious targets, significant development projects are under way to expand it



NOTE:  
 1. LNG terminal under development  
 2. Key export terminals: (Kharg island, Lavan Island, Sirri Island, Neka)  
 Source: Map of Iran

<sup>12</sup> Iran lost a case in the court of arbitration in January 2017 and must pay Turkey \$1.9Bn in compensation over a gas-price dispute from 2012  
<sup>13</sup> Also known as the Pars pipeline or Iran-Europe pipeline  
<sup>14</sup> Also known as the Islamic pipeline by some western countries  
<sup>15</sup> Shah Deniz is the largest natural-gas field in Azerbaijan, located in the South Caspian Sea

These options could be an alternative to the Nabucco West pipeline project. This pipeline, supplied predominantly from Azerbaijan's Shah Deniz<sup>15</sup> field, was designed to provide alternative natural gas supplies to Europe. However, the Shah Deniz consortium has stated a preference to supply the Trans-Adriatic pipeline, and it remains to be seen whether Nabucco West will go ahead. The proposed Iranian pipelines to supply Europe could thus supplant Nabucco if completed in time.

The second major export route is through Pakistan. The "Peace" pipeline should run directly from the South Pars field to Multan in Pakistan. It has been discussed since 1995 and was due to be complete in 2014, but has been subject to lengthy construction delays, with talks that it will be scrapped altogether if agreement between Pakistan and Iran cannot be reached soon. The real benefit for Iran would be to extend this pipeline to Delhi and provide access to the large Indian market. However, there are both competition and geopolitical tensions complicating the pipeline's progress. First, Russia is considering a \$25 Bn infrastructure project to construct a pipeline from Siberia to India, though it is believed that the transportation costs could be considerably greater from Siberia than from South Pars. Second, India and Pakistan may need to resolve long-standing tensions before the pipeline can get approval. One possible other option for Iran is to supply India from a pipeline via Oman and bypass Pakistan altogether.

## 5. Improve global perception and extend the customer base

Perception is perhaps the final key to the success of this plan. To achieve its desired growth, Iran must be perceived as both an attractive place for foreign investment and a reliable exporter of cargo. To achieve that, Iran must develop an investor-targeted marketing program as well as a customer-targeted marketing program.

The investor-targeted plan must highlight transparency, quality and ease of doing business.

By targeting larger, integrated oil majors with which Iran has historically well-developed relationships, the intended knock-on effect would be to establish the viability of the Iranian market

and thus attract smaller and mid-size players, expanding the scope of investment flowing into the country.

It will also be important for Iran to develop relationships with new customers in order to gain access to higher-value markets around the world and achieve higher market prices. To do this, it must diversify its customer portfolio so it is comprised of both neighboring (e.g., Turkey and Iraq), emerging (e.g., India and China) and mature countries across western Europe. This should help to secure the trade balance and limit the impact of regional demand fluctuations.

## Closing remarks

As global demand for gas is expected to rise for the next 20–30 years and shale producers are tightening competition, Iran has a golden opportunity to not only become a regional hub, but also establish its footprint as a world leader in the gas industry.

The question is whether Iran will be able to attract enough investment to develop greenfield projects while simultaneously rejuvenating brownfield sites and bringing recovery rates in line with regional players such as Kuwait and Saudi Arabia.

Crucial to answering this question is whether Iran can do the following three things: set the correct terms in its IPCs to convince international investors of the potential opportunity, conduct internal reforms to better facilitate project approval and delivery, and attract and retain the required knowledge and skill for the sustainable operational development of the industry. If so, it is quite feasible that one day Iran could become the world's largest exporter of gas.

## Authors

Jaap Kalkman, Nicholas Strange and Aida Mbaye





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### 1. Start early

While it may be better for parties to settle disputes amicably, we recognize that it can sometimes be impossible to resolve disputes, and for tactical reasons it may be necessary to launch legal or arbitral proceedings to ensure the other side engages seriously in negotiations.

One piece of advice we always share with our clients and their legal teams is to get our input sooner rather than later. We are increasingly asked to provide our input earlier in cases. We can support with the development of the economic theory of a case during the merits/liability phase, ensuring key common-sense economic and industry practice arguments are considered as the basis of the claim. We then offer support as the case strategy is being developed, and throughout the process, culminating in a claim, damages calculations and settlement calculations.

This early strategic support can help ensure that there is clarity and agreement about the nature of the claim before any detailed quantum evaluation takes place. Late-stage changes in the definition of the claim will generally lead to re-work and schedule pressures.

### 2. Getting early access to all the relevant data

We understand that sometimes it may be difficult to access all relevant documents and that some potentially critical data may become available only after our analysis is well underway. This may be because of a long translation backlog, changing priorities as to what data may be required, a new realisation as to what is available, or challenges with the disclosure and discovery processes. Such delayed information-flow can result not only in a significant late-stage change in perspective but also in substantial re-work, both of which should be avoided. We therefore always find it very valuable at the outset of any engagement to spend time discussing with the legal team all likely data needs, in great detail. This supports the legal team in their efforts to secure all relevant data as early as possible and helps ensure that the work can be completed in as efficient and timely manner as possible.

### 3. Remember that an initial view is just that – initial!

We have been asked many times to give a rough estimate of value based on only a few hours of review and analysis. This is then used to provide an initial assessment of the potential claim. We are happy to do this, though it must be borne in mind that this value is an early indication and is likely to change once we have spent several weeks analyzing a particular issue, perhaps

sifting through thousands of documents to support our final view. Our more considered judgement may turn out to be rather different from our initial quick calculation; in fact deviation to some degree should be expected. We are looking for the most robust analysis in our reports, and ultimately on the stand during hearings we must be able to defend every assumption we use and every figure we quote.

### 4. Two heads may be better than one

In our experience, it can be very hard to find a single expert who can cover the depth of detail required across all disciplines. On several occasions we have been asked to team up with other consultancies which offer niche services, such as forensic accountancy, or specific engineering or other technical experience. We bring the commercial, valuation and industry expertise, and can work with the other Expert to produce a jointly authored Expert Report. Pooled knowledge is often more valuable on the witness stand. We have experience of working with many Counsel, Arbitrators and Experts, and can share our experiences of them to assist in identifying how to deal with counterparts most effectively.

### 5. Working together

We prefer to work closely with clients and their Counsel throughout the case, to ensure timely input to work schedules, clarity of deadlines and responsibilities of the team. A good working relationship is especially important as we prepare ourselves for hearings. Some legal teams invite us to provide technical inputs to their opening statements, closing arguments and post hearing briefs. Multi-disciplinary case teams with the legal counsel, client representatives and industry experts working together ensure every aspect of the case can be addressed appropriately.

### 6. Meeting the counterpart's expert witness

As part of the process, we are often asked to meet with the counterpart's expert with the objective of setting out any areas of agreement or disagreement to the Tribunal or judge. At this stage, within the confines set by the legal case, we do our best to serve Counsel and our client, while maintaining and defending our independent view. We need clear instructions as to what we can and cannot discuss in these meetings.

### 7. Maintaining the expert's integrity and independence

We are bound by our ethics and company values to retain our integrity and independence, to ensure our lasting credibility as an independent Expert able to assist a Tribunal or a judge. Within that context, we need to focus on the most robust arguments we can find to support our position, and keep the analysis and commentary simple for all non-technical readers.



## Examples of our work in Dispute Resolution – Upstream oil and gas

- Expert Witness support on behalf of a National Oil Company in a dispute arising from the delay of a producer contractually obliged to develop an upstream gas project and an associated liquefaction plant.
- Expert Witness testimony concerning the valuation of an oil field in Azerbaijan following a dispute between the owner and an investment bank which had allegedly undersold the asset.
- Expert Witness testimony, valuation and business plan assessment of a newly patented Ultrasound Technology to improve production from mature oil fields.
- Expert Witness testimony in a dispute heard at the High Court in London, valuing oil fields in Kurdistan, both during the exploration and the development phase.
- Expert economic and valuation support in a dispute concerning Asian coal bed methane potential.
- Expert support in a dispute concerning the value impact of seismic survey data in large areas of undrilled deep-water offshore exploration acreage in South East Asia.

## Examples of our work in Dispute Resolution – Midstream oil and gas

- Expert Witness testimony on behalf of a National Oil Company disputing the value of over-lifted gas volumes via a gas export pipeline to Europe.
- Expert Witness testimony in a dispute regarding the unreliability of gas supplies in a long term gas contract, and quantifying a potential price discount.

- Expert Witness support in a dispute following a cancelled gas pipeline import contract in the Eastern Mediterranean.
- Expert Witness testimony in a dispute involving two parties who had invested in infrastructure to supply LNG to the US, which had then been impacted by US shale production.

## Examples of our work – Tax

- Expert economic support valuing oil and gas assets, for tax purposes.
- Negotiating upstream taxation regimes in countries such as Angola, Mozambique, Norway, the UK, and many others.
- Expert Witness testimony in a dispute regarding a new upstream windfall profits tax.
- Expert Witness support in a dispute regarding the fiscal regime and competitiveness of natural gas in the Eastern Mediterranean.

## Examples of our work – Price reviews

- We have been involved in numerous price review processes and arbitrations involving gas delivered under long term contracts to European buyers from other locations in Europe, Africa, Russia and the Middle East.
- We undertake market value research and calculations, price and margin analyses, TDS cost and netback calculations, LNG market trend analysis, spark/dark spread analysis, reviews of traded market development, and of gas-to-gas competition.
- We use our understanding of custom and practice in the gas industry, experience derived from involvement in contract negotiations and knowledge of commercial terms, to support our clients.
- We have been involved throughout these processes, from negotiation support, interpretation of PR terms, evidence and justification for trigger decision, assessment of robustness and quantum of claim and proposals for adjustment, through to provision of expert reports and testimony. We have also acted as expert determinator on several occasions.

## Key team members

### Nick White

Nick White has over 35 years' experience in the upstream oil and gas industry and the European gas and power industries. He is heavily involved in dispute resolution work relating to gas price review arbitrations, building on his experience of negotiation of fiscal terms and negotiation of GSAs as well as studies of the market value of gas in various European markets and prefeasibility studies of new gas infrastructure, etc.

He has provided oral expert witness testimony on many occasions in a variety of locations (including London, Stockholm, Paris, Geneva and Lausanne), jurisdictions, and under various procedural arrangements (including ICC, SCC, ICSID and UNCITRAL).

### Stephen Rogers

Stephen is an exploration and development geologist by training, having spent 14 years with BP managing exploration development projects in various parts of the world, and a further 7 years managing the commercial aspects of producing assets for both Hess and TXU. He joined Arthur D. Little in 2004, and has focused on the provision of strategic, operational and contractual support to oil and gas exploration and production companies worldwide.

He has given oral expert witness testimony on various cases at the High Court in London, regarding upstream oil field disputes in Europe, Asia and the Middle East, in addition to appearing as an expert witness in several arbitrations.

### Kirsty Ingham

Kirsty Ingham is a Principal in Arthur D Little's UK Energy Practice, which she joined in September 2004. She has worked in the European energy markets for over fifteen years, including roles in industrial and commercial gas, electricity and oil procurement, risk management, contract valuation and optimization, and acquisition processes. At Arthur D. Little, Kirsty has supported clients on contractual disputes, price reviews, arbitrations and regulatory issues in the natural gas and power markets across Europe.

## Authors

Nick White and Stephen Rogers

### Yvonne Fuller

Yvonne Fuller is a Principal based in Arthur D. Little's Energy Practice in London. She has specialized in energy strategy and economics for both public and private sector clients since 1998. Her analyses have covered oil and gas market modeling throughout the value chain, including upstream, LNG, gas pipelines, trading and retail. Over the past decade, the majority of her dispute resolution work has focused on supporting clients involved in upstream and midstream arbitrations and litigations in North Africa, Asia and the Middle East.

### Katia Valtorta

Katia Valtorta is a Principal in Arthur D. Little's Milan office. She focuses on gas and power retail and wholesale markets, feasibility studies for gas transportation assets, energy efficiency and energy sourcing for large industrial users, distributed generation, cogeneration and renewable energy projects. She has acted as an Expert Witness in various arbitrations, focusing on the development of the Italian energy market, price reviews and commercial LNG matters.

### Salman Ali

Salman Ali is a Principal based in Arthur D. Little's Madrid office. He has worked in consulting for over 20 years, with experience across a range of energy segments including natural gas and power, as well as numerous low carbon technologies. He has supported utilities, E&P companies, financial investors, industry associations and regulators. In addition to his litigation work, he has worked on a range of topics from market modeling, technology development and sourcing, investment analysis and valuation, and regulatory model design.



# Detection and prevention of risk from third parties

*Better safe than sorry*

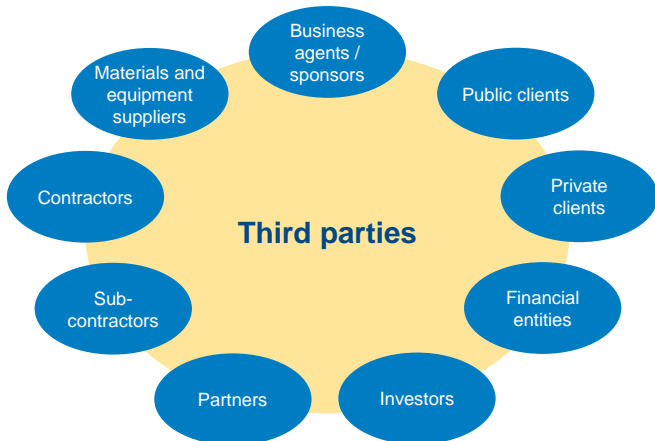


As companies' reliance on third parties (such as contractors, partners and suppliers) increases, the need to both detect and prevent risk from these third parties becomes ever more important. National legislation with broad international reach is increasing the acute risk of legal non-compliance and the associated impact on corporate reputation. A risk-based due diligence approach is required to detect and prevent these risks.

### Relevance and best practices in third-party due diligence

Companies in many sectors – particularly construction, infrastructure operation, energy and telecoms – interact with a large number of third parties, including their customers, partners, suppliers (from subcontractors to material suppliers, utility suppliers and even financial entities) and commercial agents. A company may have an economic relationship with thousands of third parties each year and potential relationships with more than three times those selected in the same period (such as business opportunities which are not secured, suppliers from which quotations are sought but that are ultimately not selected). A standard map of third-parties can be found below.

### Standard map of third parties



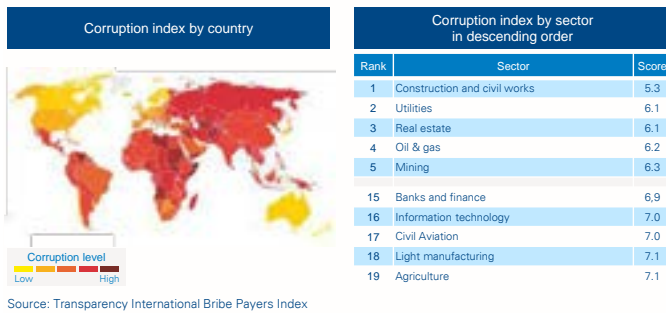
Source: Arthur D. Little

In some sectors – particularly construction – companies can critically depend on third parties. It is not unusual for over 90% of any given contract value to be passed on to these third parties. Some of the types of risk and potential impact that these third parties can bring include:

- If the third party has financial issues during the relationship, it can lead to delays in the work and overall contract delivery.
- If a third party behaves in an overly contractual or argumentative manner, it can lead to delivery delays, additional costs and often the need to dedicate more company resources to manage the third party.
- If a third party is involved in corruption cases (either real or alleged), legal liability may extend to the company and have reputational impact.

We predict that this situation will continue to increase in the coming years. For instance, major construction and infrastructure development companies are increasingly expanding their footprints into countries far from their “home markets”. Major infrastructure development in the coming years will be carried out in emerging markets with potential for higher rates of return and lower levels of national debt. The third parties in these emerging markets tend to be less well known and could bring new risks. A number of countries where large infrastructure construction and investment are expected are highlighted in the following international rankings and lists of transparency indexes for their high levels of corruption.

## Worldwide corruption indexes by country and sector



At the same time, national legislation covering corruption has tightened significantly – one example is the UK Bribery Act 2010, which has an international scope that applies to all companies with UK operations. Overall, regulatory trends increasingly make companies responsible for corruption and bribery carried out by their partners and third parties, with the related penalties and sanctions increasing and having transnational impact. For instance, sanctions include the loss of the company’s ability to undertake contracts in the legislation’s country of origin and the criminalization of its executives. Some examples of legislation can be found below.

## Selection of international legislation – focusing on third-party liability

Selection of applicable international legislation		
Region	Name and year	Scope
	Convention on Combating Bribery – 2011	Relates to third parties over which it has effective control
	Bribery Act – 2010	Art. 7: “An organization is guilty if a <b>person associated with the same bribes...</b> ”
	FCPA – 2004	“An organization is guilty for making a payment to a <b>third party</b> knowing that...”
	Criminal code amendment – 1999	Art. 24: “...if the payment is carried out by the organization or <b>on behalf of a third party...</b> ”
	Bill S-21 – Act concerning corruption of FPO	Art. 3: “...to obtain an advantage, <b>directly or indirectly, pay a bribe...</b> ”
	Ley 10/2010/28 April Código Penal – 2015	The civil code includes <b>liability</b> regarding third parties

**Possible sanctions**

- Criminal liability of executives
- Prohibition on undertaking contracts in certain countries (e.g. US, UK)
- Fines or penalties of economic nature
- Property confiscation

**Principles of action required to mitigate responsibility**

- Developing systems for detection and prevention of risk from third parties
  - Evaluation of the nature and the scope of the risks
  - Proportional measures to existing risks
  - Implementation of prevention and detection systems

Source: FCPA, UK Bribery Act, other regulation, OCDE

Additionally, the growing participation of international development funds in infrastructure projects also increases risk, as they tend to be more severe than national governments when imposing sanctions or penalties.

In summary, the world is becoming an increasingly complex place for international companies to operate. One example of evidence of this statement is that in only 10 months out of 2015,

there have been 10% more corruption cases than in all of 2014, according to the US Securities and Exchange Commission.

However, companies can take steps to mitigate, manage and even create value from this situation. In particular, companies are increasingly using detection and prevention approaches to detect, avoid and manage risk. There are three major benefits to this approach:

- First of all, it allows early identification of potential economic risks. These include financial weakness from a partner or a payment default by a customer, technical issues such as conflicts or delays in recent projects, and compliance issues such as convictions or recent cases of corruption. Early identification of potential risks improves the company’s position when negotiating with third parties and can create significant value.
- Companies that perform and keep records of their third parties can mitigate their liability if cases of corruption arise afterwards. In some recent cases, companies involved in corruption that were able to prove that they had detection and prevention systems in place were able to reduce their sanctions significantly.
- It allows cost optimization, particularly during the business development phases. Preparing bids represents a great cost for the company not only in terms of allocation of its own and external resources, but also in terms of the opportunity cost of allocating those resources to activities that may be more profitable or have lower risks. The ability to detect counterparty risks in advance implies better allocation of resources and better business decisions.

However, the implementation of an adequate detection and prevention system for third-party risk is a complex task in its own right, for the following reasons, among others:

- Construction and infrastructure are among the sector more exposed to corruption (as could be observed in the rankings illustrated before), and this activity increasingly takes place in countries and regions with low transparency according to international organizations.
- Practices and legislation vary between countries, leading to different ways of doing things. For instance, some intermediary business practices that are common in certain parts of the world are not legal in other countries.
- Excessive processes and bureaucracy can significantly reduce agility and become a competitive disadvantage for companies.



Arthur D. Little has worked on the design, development and implementation of systems to deliver third-party due diligence. Our approach aims to answer the following three questions illustrated below:

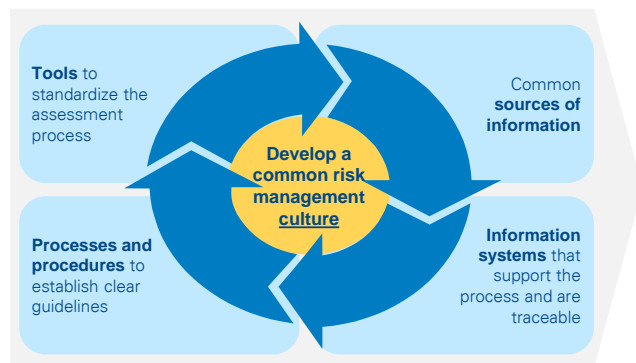
Arthur D. Little approach to third-party due diligence



Source: Arthur D. Little

In our experience all major international construction companies and developers of significant infrastructure projects carry out assessments of their third parties, or at least of some of them. However, this is usually conducted in an unstructured way, without standard procedures, leading to time and cost inefficiencies. To ensure effective and efficient assessments, the following guidelines have great value in the design of third-party due diligence systems.

Necessary elements for effective third-party due diligence systems



Source: Arthur D. Little

Based on our experience, we have identified the following key success factors for successfully implementing a detection and prevention system:

- Holistic perspective:** The due diligence process should include all major risk compliance.
- Risk orientation:** Focusing analyses only on higher-risk situations. From a compliance perspective, legislation

provides the guidelines for selecting the third parties to be assessed. From a technical and financial perspective, volume and criticality of the third party to the company must be the guiding principle.

- Proportionality:** The dedication of resources and depth of the analysis must be adequate. Construction companies are not international intelligence agencies, which means that the added value of the assessment should be higher than the costs of carrying it out, as in any other business.
- Independence and objectivity:** The information included in the financial and technical assessments must be provided independently and objectively. For example, the compliance and financial perspective should be performed by independent units as, for instance, business development teams tend to be more optimistic about third parties than other teams.
- Leverage all available sources of information when assessing third parties:** Reports from reputable sources or institutions bring transparency and credibility, but must coexist with opinions and experience of staff within the organization. There must be a defined methodology for selecting information that assures its traceability and maintains confidentiality.
- Aimed for decision-making:** The due diligence analysis of the third party is not intended to “veto” its selection, but should help to decide which third party to select. Only in extreme cases (for example, imminent bankruptcy or presence on an international sanctions list) should the possible relationship with the third party be vetoed based on the due diligence analysis.
- Willingness to anticipate:** The effort associated with bid preparation and procurement processes is very high, which means that the earlier the assessment is carried out, the earlier the company will make a decision about the third party, and it will avoid incurring unnecessary costs associated with a potential third-party relationship that is too risky.
- Easy assessment criteria:** Criteria have to be easy to apply so that risk level is not a factor subject to interpretation. For example, a criminal conviction of a third party’s executive is a serious issue, but it is not the same if the conviction took place five or twenty years ago. Establishing clear and straightforward criteria and standards on risk adoption needs to be efficient. Risk appetite needs to be a company decision, not a decision that depends on the risk aversion of each employee.

## Concluding questions

Arthur D. Little recommends putting in place detection and prevention systems, especially for companies in certain industries, to achieve the following benefits:

- Improve the selection of third parties, which ultimately will lead to higher company valuation, as it is the straightforward consequence of having more trustworthy customers, partners and suppliers.
- In the case of being involved in a corruption incident involving a third party, the company would be able to reduce its liability and exposure by providing evidence of having risk detection and prevention systems in place.
- Help create a stronger company culture in risk management.
- And last but not least, the costs of developing such systems are, in Arthur D. Little's experience, far lower than the cost of liability, which makes it an attractive value creation opportunity.

## Authors

Javier Serra and Stephen Watson



# What is next for petroleum downstream?

*New business models are critical in a sector in which the supply of energy for mobility is changing*



Petroleum downstream has been adapting to increasing competition and challenging regulations, and is suffering from lower returns than the upstream segment. Industry challenges will intensify, and new energy sources for mobility will impact the entire fuel value chain. Downstream players need to rethink their business models and innovate to protect their share of the mobility market.

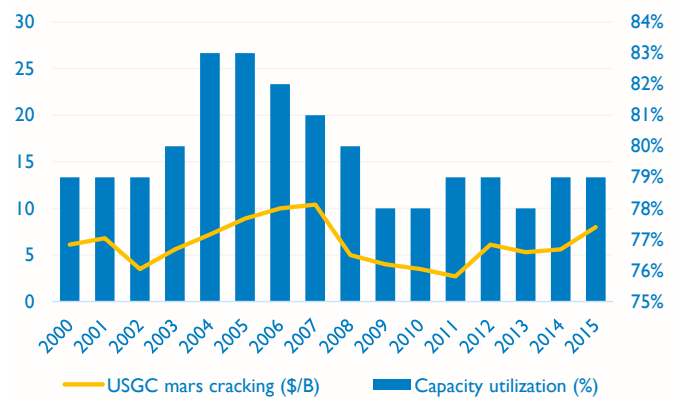
## Recent sector trends

Oil downstream has a long history of adapting to fuel-demand evolution by investing in transforming industrial installations, deploying new technologies and expanding service offerings to wholesalers and consumers. Refining and marketing have traditionally been the natural path for crude-oil producers towards vertical integration, aimed at capturing the full margin along the industry's entire value chain. In the past, international brands invested heavily to expand and renovate retail networks, securing outlets for their refinery production and looking for opportunities to grow their non-fuel business.

For decades now, oil downstream has rendered lower returns than upstream, which has made integrated players lose interest in the segment. This fact, combined with intensified competition, tougher regulations, stronger bargaining power of dealers and mounting threats of environmental liabilities, has compelled major oil companies to divest some of their existing downstream operations and refrain from incremental investment in this segment.

On the other hand, a significant portion of the existing refining capacity worldwide is owned by national oil companies, and most of the foreseen capacity additions are expected to come from them. Despite the challenging business environment, national oil companies typically have different drivers and motivations to invest in refining, such as domestic energy supply security and promotion of industrialization, as well as employment in their host countries.

## Refining margin vs. Capacity utilization



After a century of domination of refined products as the major energy source for mobility, different sources have recently emerged around the concept of the electric vehicles and are rapidly penetrating the transportation market. New participants in the business of battery-charging stations are gaining market share at the expense of traditional oil downstream players.

## Downstream's increasing challenges

**Regional capacity mismatch.** Growth in crude-oil output is increasingly coming from remote locations farther away from fuel-demand-growth regions. The quality of new crude-oil streams does not always suit the configuration of local or regional refineries. Consequently, crude oil- and product-transit time has been increasing for over two decades, and this trend

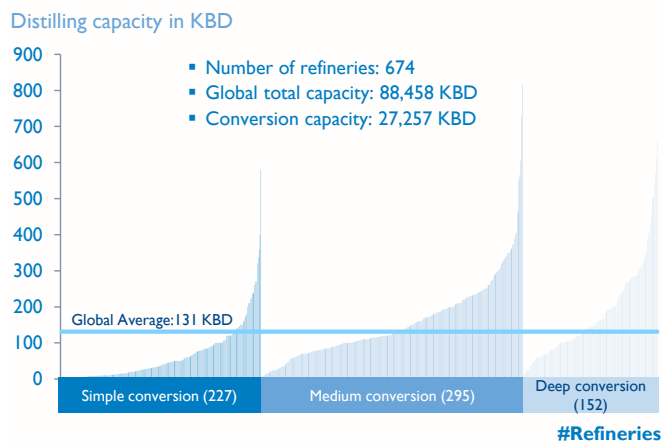
is expected to continue. The impact of higher supply costs and broader exposure to international price variations cannot always be transferred to refined product prices.

**Margin volatility and market rigidity.** Relatively small variations in global or regional refining capacity utilization can have a significant impact on refining gross margins. Refiners focused on supplying domestic markets are not always able to adjust their prices to international levels due to political and regulatory pressures.

**Diminishing feedstock quality and stricter product specifications.** On the feedstock side, average worldwide produced crude oil is getting heavier and its sulfur content is increasing. On the demand side, diesel is the fastest-growing fuel, while fuel-oil consumption is under increasing environmental pressures, with stricter restrictions on use in marine transportation. Fuel-quality specs in most countries are becoming tougher, especially on sulfur content, driven by environmental pressures on engine emissions. Some refinery-product qualities have been virtually swept away from developed markets, making it harder for refiners to find a commercial destination for them.

**Increasing capital-investment requirements.** Refiners are forced to invest continuously in upgrading their facilities just to stay in business. Refinery assets are aging, available crude-oil diets and product-demand patterns change over time, and regulations on product specs are evolving. Often, such investments allow refiners to improve or maintain their competitive position, but financial returns are, in most cases, below expected levels. Construction costs inflation and significant delays, and cost over-runs during EPC complicate the picture, making it harder for downstream capital-expenditure plans to compete with more promising upstream opportunities.

### World refining conversion capacity



Source: O&G Journal, Arthur D. Little analysis

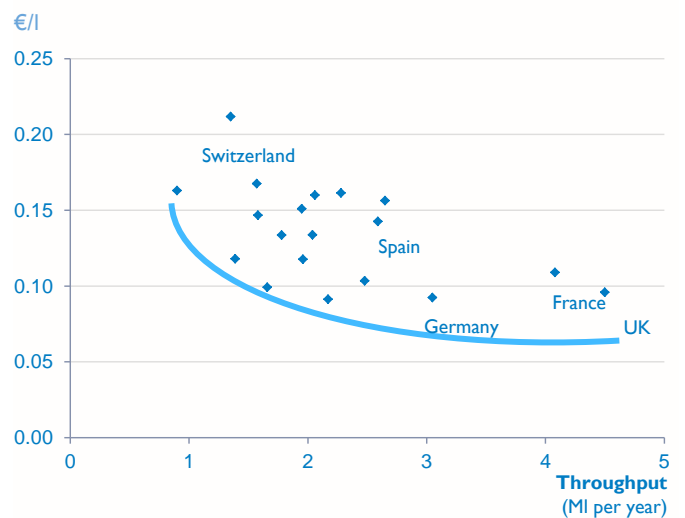
**Vulnerable or unviable refineries.** World refining capacity combines facilities of heterogeneous scales and configurations, with a significant percentage of them not reaching a competitive

scale or lacking the deep conversion configuration needed to match the product-demand mix. As cities developed, hundreds of refining units ended up surrounded by dense urban areas, and now they either lack space to grow or are impeded by environmental regulations to do so. Excessive manpower costs in countries with rigid labor regimes and high energy costs in many places threaten the economic viability of a significant number of refineries around the world. Sooner or later many of these will be forced to shut down.

**Difficulty to replicate successful models.** Very large-scale refining complexes, including integrated petrochemical units, will continue to be the most competitive assets in the industry, provided that they can get access to low-cost energy sources and are well positioned to supply large and growing markets. Niche refineries with location or transportation shields, or those protected by preferential duties or that benefit from fiscal incentives, are also likely to succeed. However, many of these refinery models are legacies of the past, and it is becoming increasingly difficult to justify investment in new grassroots refineries.

**Erosion of margins in fuel distribution.** Fuel distribution is largely seen as a low ROCE segment, and petrol retailers are now focusing on increasing the non-fuel contribution of their business. Market share of independent retailers has been growing since the end of the last century, further deteriorating the historical margins of this segment. Moreover, LPG and compressed natural gas are also increasing their market share in the retail channel, and refiners' ability to capture the wholesale distribution margin is becoming more limited.

### Fuel retail margins by country vs. site throughput



Source: Arthur D. Little analysis

**Challenging retail economics.** In the context of demand-pattern changes, increasing vehicle autonomy, growing price transparency and more aggressive competition from alternative-mobility energy sources, the optimal number of retail sites to supply a given market is no longer related to the market's areal

extension or the number of vehicles in circulation. The strong relationship between fuel-retail margin and a number of sites continues, and in any regulated or oligopolistic market the margin level defines the number of retail points for that market. Also, rising real estate values in urban centers are modifying the relative value and opportunity cost of petrol stations in a company's network.

## What to do next?

In light of this challenging business context, not only will oil downstream players need to excel in the execution of their operational and commercial strategies, but they will also be forced to innovate and transform their business models in order to survive.

### Focus on excellence

Downstream companies around the globe are already making significant efforts to maintain and improve their competitive positions and ensure acceptable returns for their capital. Some of the initiatives that need to be continued and reinforced are:

**Feedstock-supply optimization.** Securing a cost-efficient long-term crude-oil supply that captures logistics synergies is an essential success factor for refiners. Minimizing price-exposure periods (i.e., pricing at own terminal vs. FOB) is a critical aspect of an efficient supply strategy.

**Hedging to protect working-capital value.** Many refining companies are very vulnerable to strong fluctuations in fuel prices while maintaining significant inventories of crude oil and intermediary products feedstock. To mitigate the downside of decreasing fuel prices, crude-price coverages are increasingly available and used by players to limit this exposure.

**Physical upstream integration as a strategic edge.** The downstream sector will continue to undergo traditional cycles that are typical of capital-intensive industries, and are relatively independent of upstream segment cycles. But in some regions and markets, physical upstream integration can provide downstream players with price-risk coverage other than potentially securing an optimum crude slate for their refining operations. Integration also provides options to process or market own crude depending on market conditions.

**Ongoing efficiency improvement in industrial facilities.** Refining is a business in which there are often opportunities to produce an extra barrel or yield a higher-value product mix. Companies should keep making efforts to improve margins at the industrial level by focusing on aspects such as product-quality giveaway, energy efficiency of units and equipment, optimization of plant turnarounds, and application of technologies for advanced control and monitoring.

**Customizing non-fuel offerings.** Retailers must work harder than ever to attract customers. Diversified levels of service mean the proper services for each individual or group out of a diverse customer base. There is no model that suits all markets, regions or types of stations, but in most markets there is room to increase the of share convenience stores in the total retail food-service business. However, customer behaviors regarding food service vary a lot from one market to another.

### Business-Model transformation

Despite their strong efforts to improve competitive position, improve efficiency and deploy value-oriented initiatives, the subsistence of downstream players is still threatened. For these reasons it is imperative that these players start to rethink their business models, redesign their portfolios and fight harder than ever to maintain their current market share of the mobility market. Some potential themes to explore include:

**New portfolio strategies.** Downstream companies need to review their international portfolios, reshaping their asset bases to adapt to new market scenarios and trends. Some portfolio decisions need to consider refinery closures in mature markets and addition of new refining capacity and/or upgrading of industrial plants in emerging markets. Timing and location of product-quality upgrades will be key for defending margins. Other critical portfolio decisions include reshaping of distribution and retail operations in aspects such as network models and ownership.

**Secure positions through the entire petroleum value chain to get "optionality" for trading operations.** International commerce and trading will continue to grow fast, but typical arbitrage opportunities are now limited by greater market transparency. International downstream players could, however, enhance their trading operations by owning or leasing processing capacity, infrastructure, storage, shipping, distribution and retail positions. These positions allow traders to exercise options such as processing or not, or holding inventories for later sales depending on market "arbitrage" opportunities through the value chain.

**Innovate to protect mobility market share.** Downstream oil players are in a privileged position to continue to be the main energy suppliers of the mobility/transportation sector. Major downstream oil players have been reluctant to take a strong position in other energy sources, such as biofuels, which are perceived as competition due to their traditional fuel offerings. It is time to recognize that sooner or later, refined products will lose a significant market share of energy supply to the mobility sector and start taking an active role in developing solutions for that sector. Downstream players will need to take an active role in the supply of alternative-energy sources for mobility. Another paradigm to overcome is the idea that retail transactions are circumscribed to the fuel-retail sites. It is becoming clear that

emerging energy sources for mobility suppliers will offer a variety of locations for filling/charging vehicles.

**Move from “fuel” to “energy-station” model** to capture penetration of competitive mobility energy sources and move out of currently typical outlets. This transition will take time, however; in some markets there is already growing demand for electric cars, and electricity “supercharge” would be an attractive service downstream oil companies could provide – not necessarily within the fuel-station boundary. Another related opportunity is the commercialization of hydrogen gas for powering hydrogen fuel cell vehicles.

### **Insight for the executives**

- Downstream oil industries will face increasing challenges in terms of industrial configuration and efficiency, alternative energy sources competition and customer purchasing-behavior sophistication.
- Profits and return on capital employed in downstream oil will continue to be uneven across different markets and players around the world.
- More than ever, customizing types and levels of service in the wholesale and retail channels would help secure market share for those players that can anticipate sector and customer trends. Any strategy should include multidisciplinary partners and alliances for both traditional and non-traditional offerings.
- The energy-source mix of the mobility sector will change dramatically. Penetration of cleaner energies will happen faster in developed countries than in emerging economies or countries with refined-product surpluses.
- Refining and distribution portfolio decisions need to consider when, where and to what extent these trends will impact the traditional downstream business, and the best way to build a position in the value chain of other energy sources, such as electricity brokerage.
- Retail strategies should consider serving the market with an enlarged menu of energy products to defend the share of the mobility market and leverage the value of non-energy transactions.
- Anticipating the need for transformation and finding the proper balance between focus on current performance and preparing for the future are more important than ever for oil downstream players.

### **Authors**

Daniel Monzón, Rodolfo Guzman, Alfredo Verna and Micaela Carlino





# Can Group 1 base oil come back?

*The impact of the lower crude prices on the global base oil markets*



The global lubricants and base oil markets have had a challenging start to the new millennium. Annual growth has, on average, been well below global GDP growth due to technology improvements in transportation and industry. Furthermore, changing standards are leading to a gradual replacement of Group I-based products to Group II- and III-based products, resulting in plant closures around the world.

However, the lower oil prices might lead to temporary relief for Group I producers and an additional boost for the entire industry.

The global economy is benefiting from declining oil prices due to the higher economic multiplier in the typically poorer oil-importing countries. Consequently, base oil consumption in the transportation sector, as an example, will increase through both growing purchasing power (new and second-hand car sales) and increasing car usage. Even though transportation fuel is a commodity with a low elasticity of around 0.1, the current steep drop in oil prices implies a demand increase of up to 5% over the next few years. This boost is expected to be especially prominent in developing countries, and could potentially (temporarily) curb the decline in Group I base oil demand. It could also mean the “rebirth of Europe”, which will not only benefit from much lower oil prices, but also see the export of Group I products rise.

## What is the global oil market outlook?

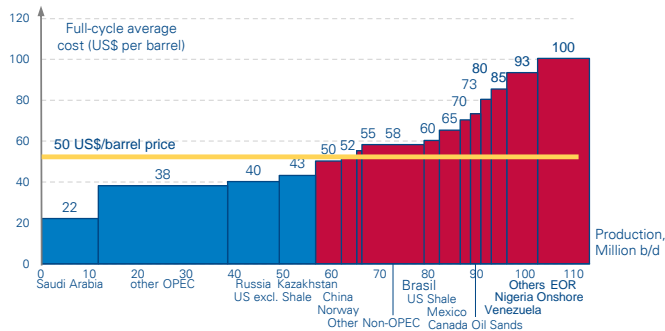
Many factors balance the supply-and-demand equation for oil price. Some have permanent impact (e.g. EOR, alternative resources), while others have temporary effects (e.g. geopolitical events, global economic status). Some can be controlled (e.g. investments in infrastructure, field development), while others are uncontrollable (e.g. natural disasters, oil reserves). The recent overproduction of oil led to the price decline: prices halved within a few months at the end of 2014 and dipped below the 30-year average (52 USD per barrel), with a slight recovery during Q2 2015.

Oil reserves have never been as high as they currently are (1.7 trillion barrels in 2014). Although conventional oil reserves have been declining since 2005, this decline has been continuously offset by the rise of unconventional resources; in 2014, one-third

of the oil supply was provided from unconventional sources. The drop in conventional oil and the increased dependability on more expensive, unconventional resources are pushing the marginal prices of oil higher.

On the other hand, with 2008 being an exception, global oil demand has witnessed a continuous increase (CAGR of 1.3% since 2000). The growth of emerging markets and their thirst for oil have been partially offset by the successful efforts introduced by the OECD countries to lower their consumption (i.e. alternative energies, public awareness campaigns – OECD demand reduction of -0.5% since 2000 [CAGR]). More specifically, the growth of the transportation sector and the further development of the petrochemicals industry are the main drivers of this demand surge in the developing world.

Figure 1: Full-cycle average production costs



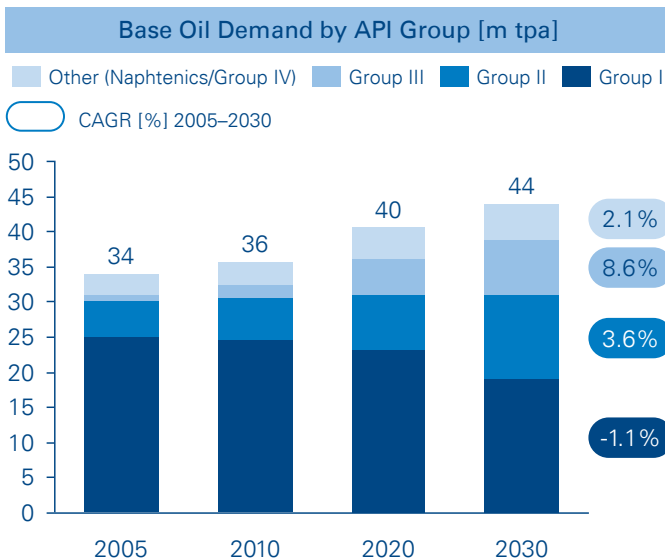
Source: Arthur D. Little including published data from IEA

Current oil prices are below the average marginal production costs for more than one-third of the total oil produced daily. Consequently, in order to enable profitable production, prices are expected to crawl back to higher levels and remain between 60-80 USD per barrel for the next several years. This has occurred during the first half of 2015, although the picture is volatile and further supply shocks could push the prices below this value.

Recap of global base oil trends

Since the early 20th century, base oil production has been dominated by Group I. This dominance is now entering its final stage as a significant drop in demand is expected, mainly in Europe and North America, due to the shift towards Groups II and III. Nevertheless, Group I will remain the dominant base oil for lubricant blending until at least 2020, and demand for Groups II and III combined is forecast to exceed Group I demand by 2030.

Figure 2: The future focus on Groups II and III is justified by the drastic changes observed in demand patterns – Group I is forecast to decline at ~1%, while Group III is expected to grow at ~9% YoY



Source: Purvin and Gertz, Arthur D. Little analysis

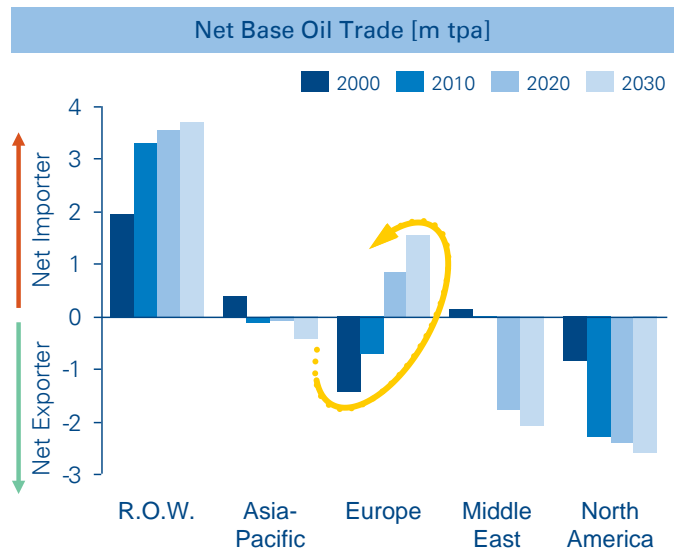
The substitution of Group I is driven by the need for better-quality products in the transportation sector. Governments are pressuring for increased concern about the environment and better fuel economy. Technologies in the automotive sector and in base oil production are fulfilling the regulations: efforts are being invested in the transportation sector to multiply exhaust gas treatments and roll out advanced engine technologies. Similarly, lubricant producers are also increasingly manufacturing cleaner and better-quality base oil with lower SAPS, higher viscosity and lower volatility.

Therefore, despite Asian demand offsetting the situation slightly, the declining demand for Group I will lead producers to operate well below acceptable utilization levels (currently maintained around 70%). This, coupled with an increase in the production costs per barrel due to higher allocations of fixed costs, will result in lower margins and create significant pressure for rationalization of Group I capacities.

This evolving trend is further confirmed by the fact that all (announced) future base oil capacity additions are exclusively in Groups II and III, as observed mainly in the Middle East, and the expected rationalization of Group I capacity in Europe and North America, as exemplified by the planned plant closures (e.g. for 2015, Stanlow [England], Colas [France], Total (Gonfreville) [France]) in Europe.

In summary, Europe is shifting its position from a net exporter to a net importer, due to suffering directly from lower demand for Group I oil. At the same time, the Middle East and Asia will become major base oil exporters due to their new Group II and Group III capacity.

Figure 3: Europe is therefore shifting from net exporter to net importer, replaced by the Middle East, which is aggressively marking its territory in this industry



Source: Purvin and Gertz, Arthur D. Little analysis

### How will the current oil prices impact the dynamics of the base oil industry?

Triggered by the declining oil prices, the global economy will witness enhanced growth due to a higher economic multiplier in oil-importing countries.

The end market of base oil will experience several changes, mainly pertaining to the transportation sector, as the growth of oil consumption will accelerate as a result of both an increased number of automobiles (new and second-hand) and a higher average per capita usage of vehicles. This will happen on the back of, firstly, wealth transfer from oil-exporting to oil-importing countries, which will push global car demand – car sales forecasts show an additional 5 to 7 million units in a short time frame, precisely due to this effect. Secondly, car usage will increase due to lower concern over fuel prices and substitution of public transportation kilometers with car kilometers. The normally low elasticity of transportation fuel will, in this case, driven by the steep, sustained decline in oil prices, result in substantial increase of fuel usage, and hence the use of lubricants.

All API groups are expected to benefit from the declining prices in the medium term. Group I will be boosted in non-OECD countries, in which the numbers of used cars, mainly consuming Group I, will rise with the increased purchasing power. Group II and III consumption will benefit from the increase in purchasing power and the sale of new cars that require higher-quality lubricants.

In addition to the growth of ground transportation, the aviation, commercial road transport and other transportation sub-sectors will also experience slight positive effects (lower cost, higher GDP).

Leading oil-exporting countries, on the other hand, have started to experience significant revenue shortfalls and launched revisions of their growth forecasts. Meanwhile, long-term low oil prices could force them to make difficult economic, social and political tradeoffs. Those countries might consider making use of their cheap access to oil to create substantial advantages downstream.

In summary, the wealth transfer from oil-exporting to oil-importing nations will boost demand for lubricants and base oils of all groups, and the so-called “death of Group I” will be “postponed until further notice.” European base oil producers will benefit from additional export of Group I products and delayed plant closures.

Doubts and uncertainties regarding the attractiveness of base oil in the era of low oil prices are therefore mostly misplaced. IOCs, NOCs, investors and oil and gas-associated sectors should consider the pursuit of opportunities in this field, and depending on their capabilities and expertise, set long-term plans to ensure that market fluctuations play in their favor more frequently than not.

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# Why risk management is failing

*Embracing complexity and uncertainty with value-based risk management*



In today's business environment of uncertainty, complexity and continuous change, conventional risk management approaches are all too often ineffective: they are poor at dealing with complexity, too slow to adapt, and focused on reporting outcomes rather than supporting decision-making. A different approach – “value-based risk management” – can help organizations strengthen their decision-making capabilities and ultimately achieve better alignment with the strategic needs of the business.

## Introduction

Effective risk management requires businesses to manage uncertainty. Industry convergence, accelerating technological disruption and the wide public availability of information increase the potential sources of uncertainty, and so complicate risk management. Organizations typically respond by developing comprehensive risk management systems – often referred to as enterprise risk management (ERM). The great majority of larger organizations already have ERM systems with varying degrees of sophistication.

92% of responses to a 2015 survey indicated **Enterprise Risk Management** systems were already in place

However, despite the prevalence of ERM systems, significant unwanted events continue to occur and cause serious damage to organizations. Those deemed newsworthy are sometimes catastrophic in nature, leading to significant financial impact or loss of life. Recent examples include the highly publicized use of engine management software by Volkswagen to “cheat” on emissions tests and the 2015 record fine of USD 20.8 bn given to British Petroleum following catastrophic events at Deepwater Horizon (the “Macondo Incident”).

As companies face a future of increasing uncertainty, disruption and complexity, there are questions as to whether conventional approaches – such as ERM – are up to the job. We believe there are several practical ways to improve the effectiveness of risk

management and better align decision-making with the strategic needs of the business. Collectively, we call our enhancements value-based risk management (VBRM).

## The limitations of conventional approaches

We classify conventional risk management approaches as either “accountant” or “assurance,” explained below. Both are widely adopted and used to manage a very wide range of risks from safety through to operational, asset and reputational risks. Both, however, have limitations that may lead to unforeseen risks emerging to damage the business.

### “Accountant” approach

This approach focuses on comprehensive risk screening, evaluation and reporting. Systems described as “ERM” (i.e. including a broad portfolio of different risks) are often synonymous with the “accountant” approach. The principal weakness of this approach is that the high-level nature of reported risks is difficult to assure. (“How do I know risk x has been mitigated effectively?”) This assurance is further complicated by the often-comprehensive documentation and reporting of risk data, but not of information for decision-making, which can create a false sense of security that risks introduced by the strategy (what the organization wishes to achieve) are being properly managed (“blinded by numbers”).

## “Assurance” approach

This approach focuses on known key risks and their mitigation. It is popular in high-hazard industries such as oil and gas, in which the significant risks are well known, but can be limited in its ability to identify new risks as circumstances change, given its focus more on upfront mitigation and less on ongoing management over a prolonged period. This particularly applies to risks applying across more than one strategic dimension – for example, a safety and reputational risk. The “assurance” approach often fails to adequately deal with complex systems. These are systems in which the relationships between cause and effect are often unpredictable, even with the application of expert knowledge – not recognizing the inherent uncertainty that this brings to risk management.

## The benefits of VBRM

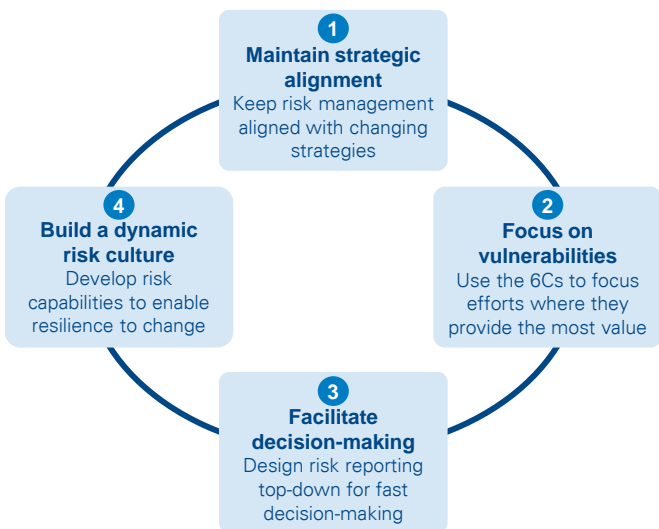
VBRM is balanced enhancement of these conventional approaches that concentrates on decision-making as opposed to simply risk reporting.

The defining characteristic of **value-based risk management** is a focus on decision-making rather than simply risk reporting

We describe this approach as “value-based,” as it leads to healthy questioning of what is required to support decision-making. In our experience, these questions often lead to a significant reduction of effort expended on activities that do not prove to be core to agreed strategic priorities of the business.

A review of risks using such an approach addresses the weaknesses of both “accountant” and “assurance” approaches, focusing risk management efforts where they will deliver the most value to the business.

There are four main pillars of VBRM.



We have experience of applying a VBRM approach effectively in large organizations with existing ERM systems in situations

in which unwanted events persisted, and in companies that were not getting the return they were expecting from their considerable ERM investments.

We describe each further:

## Maintain strategic alignment

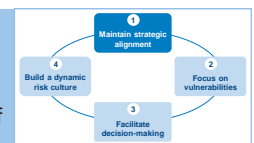
At its simplest, strategy is a high-level plan to achieve one or more goals under conditions of uncertainty. Strategies can be developed and changed rapidly, but the supporting management systems and processes that implement the strategy have much greater inertia. The root causes of poor risk management are often found in this disconnect between the strategy and the management systems and processes that are required to deliver it, when the former have changed but the latter have not kept pace. This is increasingly important in today’s uncertain business environment, in which agility and the ability to flex strategies rapidly is a key success factor in staying ahead.

Maintaining alignment means avoiding making decisions that do not support strategy, and communicating priorities clearly to business units. This requires companies to “let go” and simplify, focusing on areas in which expert systems can provide meaningful results that support decision-making.

Maintaining alignment also means allocating clear risk ownership, defining responsibilities and determining suitable empowerment for adapting systems and processes to respond to changing risk profiles. Some major risk areas will naturally align with business and functional units, and ownership will be clear. Others may not – requiring governance to be specifically agreed.

## Case study: aligning business cases to strategy

A multinational automotive manufacturer critically needed to improve the likelihood of project success on time and with expected quality. We developed new risk metrics that indicated the timing of emergence of key risks during the project lifecycle. The metrics were used to develop business cases showing why some projects should be stopped at the earliest opportunity, and others selected based on likelihood of success. This enabled the manufacturer to focus its effort on projects with much higher likelihood of success, and avoid wasted resources on projects which were less likely to succeed and not aligned with strategic business priorities.

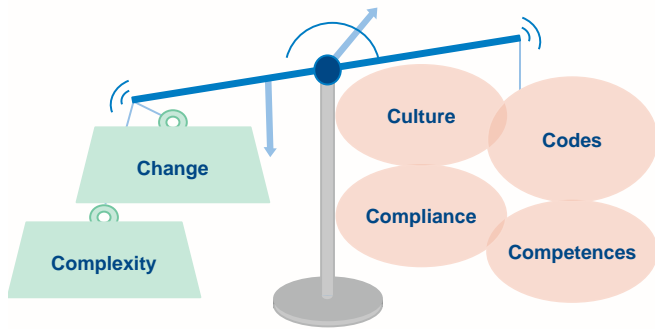


## Focus on vulnerabilities

One of the drawbacks of the “assurance” and “accountant” approaches is that they are often poor at indicating where to focus effort to make risk controls effective. This is important, because different hierarchies within the business often implement risk controls. Failure to understand why those hierarchies may be poor at implementing the controls prevents effective risk management implementation. This could be, for

example, the absence of appropriate competencies within business units to understand a required risk-control measure.

There are few pragmatic diagnostic models available to the risk manager for assessing vulnerabilities across all risk dimensions. An approach developed by Arthur D Little to help in this process is the so-called 6C model (illustrated below).



The 6Cs are Codes, Compliance, Competency, Complexity, Change and Culture. A 6C assessment considers the suitability and completeness of rules, standards or practices (Codes), followed by the degree of Compliance with them. In many existing approaches this is as far as the assessment goes. However, the 6C approach goes on to consider two other important factors that can greatly escalate risk: Competence (the degree to which staff have the necessary skills and experience) and Culture, which refers to how supportive and mature the culture is for delivering risk controls. Set against this is the impact of Change on risk management, based on the degree to which the business environment is changing, and Complexity, the inherent intricacy of the business and its environment.

Our experience shows that pragmatic review against these six categories reveals a good understanding of vulnerabilities without detailed and time-consuming quantification.

**Case study: identifying cultural vulnerabilities**

A national utilities operator had struggled to implement ERM effectively. We completed a 6C assessment of the operator’s risk management arrangements and pinpointed cultural “risk denial” in reporting risks to the board, as it was viewed as a management failure to allow those risks to occur. We helped the operator introduce organizational incentives, championed by the CEO, which made risk a topic of conversation with the board and rewarded decision-making based on awareness of risk.

**Facilitate decision-making**

One of the most common shortfalls in ERM systems is that the mode of reporting to the executive or board does not lend itself well to making decisions. Risk reports often acquire a state of semi-permanence and end up as “wallpaper” behind

more pressing top-management reporting information. This is a particular problem when situations are changing rapidly

One of the key features of the VBRM approach is therefore to ensure that top management has the right risk management reporting systems to enable rapid response and decision-making, in order to trigger actions that reduce risks before they materialize. This way, the links between strategy, execution and risk management controls remain close. This means designing reporting tools that are concise in how they summarize/aggregate risk data and tailored to organizational requirements. For example, the figure below links conventional rating of risk level (high/medium/low) with the time available to mitigate a risk before it materializes (in this case, during project execution).

		<b>ACT NOW</b>	<b>URGENT</b>	<b>PLAN</b>
<b>Risk level</b>	<b>High</b>	5, 16, 28, 32, 38, 40	21	45
	<b>Medium</b>	2, 4	1	MONITOR
	<b>Low</b>	MONITOR	MONITOR	MONITOR
		1 month	1 quarter	1 year
		<b>Time for action</b>		

A chart aggregating data across one or more dimensions can replace several charts – providing top management with a simplified means of rapid review of risk status.

**Case study: board-level reporting of risks**

A national rail infrastructure manager had a complex portfolio of risks, but no way of reporting these coherently to the board. Risks were presented in different formats with no ability to robustly prioritize investment decisions. We developed a method of translating different risks onto a single risk matrix, to better inform the board about the total risk profile and enable stronger risk-based investment decisions.

**Build a dynamic risk culture**

One of the most effective levers to ensure that a company’s risk management approach is able to cope well with change and complexity is to focus on strengthening capabilities, culture and awareness. This provides the means to identify

new and emerging risks, and to take the right actions to adapt management systems and processes rapidly in response.

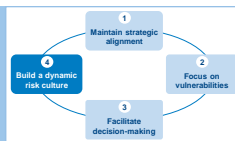
Of course, culture change within any organization is difficult, and risk management culture change is no exception. However, the VBRM approach includes a number of measures, including providing a clear management path to excellence and engaging employees in pilot projects, to embed new practices.

Most importantly, a culture requires a key risk focus – such as a “burning platform” – as a key way to promote risk awareness and the importance of pragmatism and action-orientation.

## Case study: improving incident investigation

A national infrastructure operator had an accident that revealed specific weaknesses in incident investigation.

The operator publicized the accident as its “burning platform” and reissued its internal guidance. It identified resources across the business, who were given special training against the new guidance. The resources were released from normal duties for a period of time each week to run a pilot showcasing improved incident investigation techniques. The CEO released a webcast highlighting the recent accident as the reason for the initiative.



## Insight for the Executive

This paper describes how conventional risk management approaches can be ineffective: they deal poorly with complexity, are slow to adapt to changing circumstances, and overemphasize reporting. In our work we have seen how these problems can be overcome with a more dynamic and focused approach to risk management. VBRM is such an approach, applied by companies irrespective of the ERM systems they already have. The essential elements of VBRM are:

- **Maintaining alignment of risk management with changes in strategic direction.** This requires establishing clear risk-based priorities and empowering risk owners to adapt management systems and processes as required.
- **Focusing risk management efforts on areas of vulnerability,** ensuring that risk management takes into account not only Compliance but also factors such as Competence, Culture, Complexity and Change (the 6Cs).
- **Designing risk-reporting systems that enable rapid top-management decision-making.** This should include specific risk data for key projects, provide concise summaries and include a ranking of urgency for action.
- **Building a dynamic risk culture through active involvement** in pilot projects, engaging the organization in progressive evolution towards excellence, and identifying a genuine burning platform that people understand and believe in.

The business world has moved on since ERM was first introduced. We think it is time for a change.

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Stephen Watson and James Perry





## Arthur D. Little

Arthur D. Little has been at the forefront of innovation since 1886. We are an acknowledged thought leader in linking strategy, innovation and transformation in technology-intensive and converging industries. We navigate our clients through changing business ecosystems to uncover new growth opportunities. We enable our clients to build innovation capabilities and transform their organization.

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