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# Contents

## Foreword and Introduction

<table>
<thead>
<tr>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Welcome to the Official 21st WPC Congress Publication!</td>
<td>13</td>
</tr>
<tr>
<td>Renato Bertani [President, World Petroleum Council]</td>
<td></td>
</tr>
<tr>
<td>The ‘Petroleum Olympics’ return to Moscow</td>
<td>15</td>
</tr>
<tr>
<td>Dr Pierce Riemer [Director General, World Petroleum Council]</td>
<td></td>
</tr>
<tr>
<td>WPC Timeline 1933-2014</td>
<td>16</td>
</tr>
</tbody>
</table>

## Strategies and Leadership

<table>
<thead>
<tr>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>How technology led to tectonic shifts in oil and gas supply</td>
<td>20</td>
</tr>
<tr>
<td>Daniel Yergin [Vice-Chairman, IHS and Pulitzer Prize-winning author]</td>
<td></td>
</tr>
<tr>
<td>Unlocking opportunity with innovation and cooperation</td>
<td>24</td>
</tr>
<tr>
<td>Rex Tillerson [Chairman and Chief Executive Officer, Exxon Mobil Corporation]</td>
<td></td>
</tr>
<tr>
<td>Developing new technologies to meet expanding demand</td>
<td>26</td>
</tr>
<tr>
<td>Bob Dudley [Chief Executive Officer, BP]</td>
<td></td>
</tr>
<tr>
<td>US unconventional output redraws the global energy map</td>
<td>28</td>
</tr>
<tr>
<td>Maria van der Hoeven [Executive Director, International Energy Agency]</td>
<td></td>
</tr>
<tr>
<td>Energy security is vital for producers as well as consumers</td>
<td>30</td>
</tr>
<tr>
<td>Abdalla Salem El-Badri [Secretary General, OPEC]</td>
<td></td>
</tr>
<tr>
<td>Unconventionals add new dimension to dialogue</td>
<td>33</td>
</tr>
<tr>
<td>Aldo Flores-Quiroga [Secretary General, International Energy Forum]</td>
<td></td>
</tr>
<tr>
<td>A helping hand in developing Africa’s energy resources</td>
<td>36</td>
</tr>
<tr>
<td>Mark Simmonds [Minister of State for Africa, Foreign &amp; Commonwealth Office, UK]</td>
<td></td>
</tr>
</tbody>
</table>

## Exploration and Production

<table>
<thead>
<tr>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Is a shale revolution possible in Russia?</td>
<td>44</td>
</tr>
<tr>
<td>Vagit Alekperov [President, LUKOIL]</td>
<td></td>
</tr>
<tr>
<td>Mexico opens up energy sector and frees PEMEX to change</td>
<td>48</td>
</tr>
<tr>
<td>Emilio Lozoya Austin [Director General, PEMEX]</td>
<td></td>
</tr>
<tr>
<td>Fiscal and cultural barriers to raising recovery in Russia</td>
<td>52</td>
</tr>
<tr>
<td>Ildar Davletshin [Lead Analyst, Oil and Gas, Renaissance Capital]</td>
<td></td>
</tr>
<tr>
<td>Maximising ultimate recovery from unconventional reserves</td>
<td>54</td>
</tr>
<tr>
<td>Jeff Miller [Chief Operating Officer, Halliburton]</td>
<td></td>
</tr>
</tbody>
</table>
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High hopes for Angola’s pre-salt potential 56
Paulino Jerónimo Vice-President, Angolan National Committee of WPC and Executive Vice-President, Sonangol

Changing the world: America’s tight oil revolution 58
Harold Hamm Chairman and Chief Executive Officer, Continental Resources

Making the most of what’s left in the North Sea 60
Sir Ian Wood Former Chief Executive Officer and Chairman, Wood Group

Refining and Petrochemicals

The global refining industry adapts to new realities 64
Toril Bosoni Oil Industry and Markets Division, International Energy Agency

A Renaissance ‘made in the USA’ 67
Charles T. Drevna President, American Fuel & Petrochemical Manufacturers

Gulf refiners expand capacity and opportunity 70
Bassam Fattouh Director, Oxford Institute for Energy Studies

Prospects and problems facing European oil refiners 74
Pedro Miras Salamanca Chairman, CORES, Chairman, IEA Emergency Group and Chairman, Spanish National Committee of WPC

India leads Asia in exports of petroleum products 76
Nishi Vasudeva Chairman and Managing Director, Hindustan Petroleum Corporation

Biofuels and oil: More than just competitors 80
Luiz Augusto Horta Nogueira UNIFEI, Brazil and Ernani Filgueiras de Carvalho IBP, Brazil

Natural Gas Supply and Demand

Global gas prices: A random walk or inevitable convergence? 84
Howard V. Rogers Director, Gas Research Programme, Oxford Institute for Energy Studies

Towards a gas-fired era 88
Dr Mohammed bin Saleh Al-Sada Minister of Energy and Industry of the State of Qatar

LNG to grow twice as fast as overall demand for gas 90
Steve Hill President, Global Energy Marketing and Shipping, BG Group

Australian LNG floats to the top 92
Peter Coleman Chief Executive Officer and Managing Director, Woodside Energy

The EU takes an option on developing shale gas 96
Dafydd ab Iago Brussels Correspondent, Argus Media Group

Natural gas engines hit the roads of North America 98
David Demers Chief Executive Officer, Westport
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## Sustainability

<table>
<thead>
<tr>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Preparing and promoting the energy transition</td>
<td>102</td>
</tr>
<tr>
<td><em>Christophe de Margerie</em>  Chairman and Chief Executive Officer, Total*</td>
<td></td>
</tr>
<tr>
<td>Make a start to climate action by cutting flaring</td>
<td>104</td>
</tr>
<tr>
<td><em>Rachel Kyte</em>  Vice President &amp; Special Envoy, Climate Change, World Bank Group*</td>
<td></td>
</tr>
<tr>
<td>Is the future of natural gas leaking away?</td>
<td>108</td>
</tr>
<tr>
<td><em>Laszlo Varro</em>  Head of Gas, Coal and Power Markets Division, International Energy Agency*</td>
<td></td>
</tr>
<tr>
<td>Balance of power in Russian partnerships</td>
<td>110</td>
</tr>
<tr>
<td><em>James Henderson</em>  Oxford Institute for Energy Studies and <em>Alastair Ferguson</em>  Former Head of Gas, TNK-BP*</td>
<td></td>
</tr>
<tr>
<td>Realising Africa’s full oil and gas potential</td>
<td>114</td>
</tr>
<tr>
<td><em>Dr Donald Kaberuka</em>  President, African Development Bank*</td>
<td></td>
</tr>
<tr>
<td>Energy and development: A rallying call to action</td>
<td>118</td>
</tr>
<tr>
<td><em>Suleiman J. Al-Herbish</em>  Director-General, OPEC Fund for International Development (OFID)*</td>
<td></td>
</tr>
<tr>
<td>Local content rules: From compliance to shared value</td>
<td>120</td>
</tr>
<tr>
<td><em>H. Sola Oyinlola</em>  Chairman, Africa &amp; Global Head of Sustainability, Schlumberger*</td>
<td></td>
</tr>
<tr>
<td>Developing local industry: The Kazakh case</td>
<td>123</td>
</tr>
<tr>
<td><em>Dr József Tóth</em>  Senior Vice President, World Petroleum Council*</td>
<td></td>
</tr>
<tr>
<td>Using petroleum wealth to diversify the Kazakh economy</td>
<td>124</td>
</tr>
<tr>
<td><em>Umirzak Shukeyev</em>  Chief Executive Officer, Samruk-Kazyna*</td>
<td></td>
</tr>
</tbody>
</table>

## Managing the Industry

<table>
<thead>
<tr>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Innovative financing for upstream oil and gas</td>
<td>128</td>
</tr>
<tr>
<td><em>John Martin</em>  Managing Director, Global Energy, Standard Chartered Bank*</td>
<td></td>
</tr>
<tr>
<td>Private Equity: Working hand in hand with oil and gas</td>
<td>132</td>
</tr>
<tr>
<td><em>Will Honeybourne</em>  Managing Director, First Reserve*</td>
<td></td>
</tr>
<tr>
<td>Fuelling the oil and gas industry with innovation</td>
<td>135</td>
</tr>
<tr>
<td><em>Olivier Appert</em>  Chief Executive Officer, IFP Energies nouvelles*</td>
<td></td>
</tr>
<tr>
<td>The human challenge in the oil and gas industry</td>
<td>138</td>
</tr>
<tr>
<td><em>Milton Costa Filho</em>  Secretary General, Brazilian Institute of Petroleum, Gas and Biofuels (IBP)*</td>
<td></td>
</tr>
<tr>
<td>Fostering talents for the future with a stress on field practice</td>
<td>140</td>
</tr>
<tr>
<td><em>Professor Zhang Laibin</em>  President, China University of Petroleum-Beijing*</td>
<td></td>
</tr>
<tr>
<td>Coping with cycles in educational enrolment</td>
<td>142</td>
</tr>
<tr>
<td><em>Professor Daniel Hill</em>  Department Head, Petroleum Engineering at Texas A&amp;M University*</td>
<td></td>
</tr>
<tr>
<td>Preparing specialists for the future</td>
<td>144</td>
</tr>
<tr>
<td><em>Professor Anatoly Zolotukhin</em>  Gubkin Russian State University of Oil And Gas*</td>
<td></td>
</tr>
</tbody>
</table>

Grateful acknowledgements to
Welcome to the 21st World Petroleum Congress

Energy lives here™
Following three years of planning, organising and sheer hard work we are now here to celebrate the 21st World Petroleum Congress in Moscow. As one of the largest and most significant events in our industry, the World Petroleum Congress brings together facts and figures thorough discussion and critical reporting, strategic evaluations and comprehensive analysis, on a wide range of issues affecting all those involved in the global oil and gas sector. The Official Publication of the 21st World Petroleum Congress mirrors the discussions during the event itself. Its in-depth reports and high-level articles from key industry figures on the theme of “Responsibly energising a growing world” frame the discussion and provide essential back ground on some of the greatest challenges and opportunities our industry is facing.

The global economy is gradually recovering and energy demand continues to grow. Oil and gas will remain key components of the energy mix in the decades to come. With innovative technologies, creative thinking and the necessary capital expenditure, our industry will be able to continue delivering reliable, affordable and sustainable energy to all around the world.

By sharing innovative ideas and strategic evaluations, we aim to promote dialogue between the key stakeholders and to address the long-term goals that our industry must pursue in order to ensure the delivery of our mission: sustainable exploration, production, and consumption of oil and natural gas and their products for the benefit of all.

Through the Youth Magazine, which is also part of our Official Publication, the new generation of the industry share their innovative ideas and the way they envision our industry decades ahead. Here they lay out their view of the legacy that they will take over one day and their vision of potential scenarios and developments under their own leadership.

As the industry prepares to meet increasingly challenging demand for oil and gas, under ever more strict requirements on environmental standards and business ethics, the 21st World Petroleum Congress and its Official Publication will certainly deliver a lasting legacy to all stakeholders in the energy sector.

Renato Bertani
President
World Petroleum Council
MOL Group is a leading international oil and gas company from the heart of Europe with presence in more than 40 countries. We have over 75 years’ experience, 29,000 employees on 3 continents, exploration assets in 13 countries and 1,700 service stations in Europe.
W
ith over 55,000m² of exhibition space, 5000 attendees and more than 500 CEOs, presidents and government ministers attending, the 21st World Petroleum Congress will be the largest oil and gas event in 2014. The Congress provides unparalleled opportunities for networking and building international cooperation, and a unique chance to learn about the latest scientific and technological advances in the global oil and gas industry.

This huge event is being organised by the Russian National Committee of the World Petroleum Council under the leadership of the Russian Federation and the heads of relevant Russian Ministries. The Government of the Russian Federation has issued two decrees on this matter and formed a high-level Organising Committee. The Deputy Prime Minister of the Russian Federation, A.V. Dvorkovich is the Chairman of the 21st WPC Organising Committee. This committee includes the heads of the largest Russian oil companies and banks, representatives of the federal government as well as the leading scientists of the Russian Academy of Sciences.

With industry leaders and decision makers addressing the Congress, the comprehensive technical programme will cover the whole spectrum of the oil and gas sector, including upstream, downstream, gas, sustainable management of the industry and the Arctic. High-level plenary sessions, special sessions, forums, round tables and best practice keynotes will provide expert views and knowledge about the latest developments in the industry.

Ministers from countries such as Angola, Colombia, Kazakhstan, Kuwait, Nigeria, Qatar, and Norway will be addressing the Congress, as well as the heads of companies and organisations such as Rex Tillerson, Chairman of the Board of Directors at Exxon Mobil Corporation, Maria das Graças Silva Foster, CEO of Brazil’s Petrobras, HE Abdalla Salem El-Badri, the OPEC Secretary General, Bob Dudley, Group Chief Executive of BP, Maria van der Hoeven, Executive Director of the IEA, Dr Daniel Yergin, Vice Chairman of IHS and Pulitzer Prize-winning author of The Prize, and over 500 other industry leaders and decision makers.

The theme for the 21st World Petroleum Congress in Moscow is “Responsibly Energising a Growing World.” The Congress will address this ambitious goal by debating all aspects of energy supply and energy use. Access to energy is fundamental to development and improving peoples lives. The Congress will focus the debate on solutions and innovation in producing energy, and on its reliable, sustainable and wise use in both a near- and long-term perspective.

To meet the global energy demand, the producers, consumers, society and governments need to work in close cooperation to develop energy resources in a responsible way.

The Social Responsibility Programme at the 21st World Petroleum Congress has adopted the theme of “Earning a Social License to Operate.” This theme was selected in recognition of the important role that the petroleum industry can, and does, play in promoting the economic and social progress of communities in which they operate. Understanding and managing societal expectations in resource extraction is key to establishing positive working relations with communities and the bodies that govern them. It has often been said that while governments grant permits, it is the community that gives permission, and ultimately a social license to operate.

Social responsibility has evolved to be much more than just “doing good deeds”. Today it must seek to inform, involve and inspire stakeholders and those impacted, in order to make them advocates and partners in the development and ongoing operations of our industry.

The Congress will explore how best to fully integrate social responsibility as part of an overall business strategy, opening new doors to exciting opportunities when used effectively. High-level sessions will bring together industry leaders and stakeholders to explore these issues. Ministers and heads of companies including IndianOil, Repsol, Ecopetrol, and the OPEC Fund for International Development will be addressing how the need for energy, vital for economic development and progress, can be met while addressing environmental and social impacts associated with increasing demand for energy resources.
WPC Timeline 1933-2014

- 1930: East Texas oil field discovered
- 1933: Invention of the tri-cone drill bit
- 1938: Mexico nationalises its oil industry
- 1943: Venezuela tax leading to 50/50 profit split
- 1948: Discovery of Ghawar, world's biggest oil field
- 1951: 3rd Congress The Hague
- 1955: 4th Congress Rome
- 1956: Invasion blocks oil transport through Suez canal
- 1959: First cargo of LNG carried by Methane Pioneer
- 1960: Formation of OPEC
- 1963: Invention of 3-D seismic surveying
- 1967: 7th Congress Mexico City
- 1968: Oil discovered on Alaska’s North Slope
- 1971: 8th Congress Moscow
- 1991: US-led coalition expels Iraq from Kuwait
- 1990: Iraq invades Kuwait
- 1986: Oil price collapse
- 1980: Iran-Iraq war starts
- 1974: Creation of International Energy Agency
- 1973: Arab-Israeli war and Arab oil boycott of US
- 1971: Discovery of world’s largest gas field in the Gulf
- 1968: Oil discovered on Alaska’s North Slope
- 1963: Invention of 3-D seismic surveying
- 1959: First cargo of LNG carried by Methane Pioneer
- 1956: Invasion blocks oil transport through Suez canal
- 1951: 3rd Congress The Hague
- 1955: 4th Congress Rome
- 1950: 9th Congress Tokyo
Timeline of the WPC

1973: Arab-Israeli war and Arab oil boycott of US

1974: Creation of International Energy Agency

1975: 9th congress, Tokyo

1979: 10th congress, Bucharest

1980: Iran-Iraq war starts

1981: Oil price collapse

1983: 11th congress, London

1985: 12th congress, Houston

1987: 13th congress, Buenos Aires

1991: 14th congress, Stavanger

1994: 15th congress, Calgary

1997: 16th congress, Beijing

1999: 17th congress, Rio de Janeiro

2000: 18th congress, Johannesburg

2002: 19th congress, Madrid

2005: 20th congress, Doha

2008: 21st congress, Moscow

2011: 22nd congress, Doha

2014: 23rd congress, Rio de Janeiro

2015: 24th congress, Marrakech

2018: 25th congress, Buenos Aires

2021: 26th congress, Geneva

2023: 27th congress, New Delhi

2025: 28th congress, Tokyo

2027: 29th congress, Paris

2029: 30th congress, New Delhi

Record oil price of US$147 a barrel

US-led invasion of Iraq

Al-Qaeda attacks on New York and Washington

Oil price drops to US$10 a barrel

Earth Summit in Rio highlights climate change

Iraq invades Kuwait

Iranian Islamic revolution

Creation of International Energy Agency

Israel war and Arab oil boycott of US

Responsibly Energising a Growing World
The challenge of expanding energy supply to meet the demands of the world’s rising number of people and their rising expectations is set out by Daniel Yergin of IHS. He is confident the challenge can be met, above all through technology that is leading to geographic shifts that are as big on the supply side as in demand. Rex Tillerson of ExxonMobil shares his optimism, seeing solutions through such cooperative ventures as his company’s partnership with Rosneft, and through the innovation unlocking of shale gas and tight oil in North America. Industry can deliver supply, once governments have set sound and stable policies. This theme of industry’s capacity to exploit below-ground resources provided above-ground conditions set by governments are investment-friendly is taken up by Robert Dudley of BP. Nonetheless, the industry has its own task list of ensuring safety for employees and the environment, imposing greater capital discipline on itself and coming up with new technology, sometimes to do old things in new ways, such as raising recovery rates in existing oilfields.

New technology is redrawing the world’s energy map, and possibly its economic map, due to the competitiveness boost for US manufacturing from cheap shale gas, writes Maria van der Hoeven of the International Energy Agency. Exports of this US shale gas should help erode the oil pricing formula – for which the IEA no longer sees any justification – on which much of the gas sold in Europe and Asia is based. The IEA remains bullish on tight oil output, which for a period will make the US the largest producer, if not exporter, of oil. Abdalla Salem El-Badri of OPEC welcomes US tight oil as providing depth, and therefore stability, to global supply, but enters a note of caution about its longer-run sustainability. As important as security of supply is stability of price; on the upside, OPEC warns about financial speculation and, on the downside, about price falls that undermine energy investments. Bringing the IEA and OPEC together is one of the functions of Aldo Flores-Quiroga’s International Energy Forum. While these two consumer and producer organisations differ quite sharply in their central projections about tight oil in the US, their dialectic in the IEF helps them recognise uncertainties in their own positions.

Many of the most promising oil and gas finds in recent years have been in Africa. Seeking to offer North Sea expertise and advice about good governance to Africa’s many new energy producers is Mark Simmonds, the UK minister responsible for relations with Africa and international energy issues. He sets some of the geopolitical challenges facing African producers and what outsiders can do to help.
The world oil and gas industry is being reshaped by two major developments. The first is driven by economics; the second, by technology. They are rebalancing global energy and changing international alignments.

A decade ago, the oil price was destined, or so it seemed, to be US$20 forever. Indeed, companies that did not throttle back on their capital budgets in those years were likely to be punished by investors. Yet, ironically, that was exactly when the oil price began its epic climb to heights that the world hardly thought possible – but a level to which it has now become accustomed.

The rise in prices was a register of an historic change in the world economy – the rise of the emerging market countries and the surge in their need for energy. For the price increase was triggered by the ‘demand shock’ that came from those countries. This reflected the success of globalisation – strong economic growth and rising income in developing countries. A new milestone on this road came this spring when the World Bank declared the Chinese economy is now bigger than that of the US. This whole development meant growing demand for energy – on a scale and speed that took the world oil industry by surprise.

As late as 2000, two thirds of world oil consumption was concentrated in the ‘advanced industrial countries.’ Today, over half of world demand is to be found in the developing world. In the developed world, oil demand is either flat or declining – owing to sated car demand, more fuel-efficient vehicles and changing demography. Virtually all the growth in oil demand in the years ahead will be elsewhere – in the ‘emerging market’ world as the income of people in those countries rises.

**Changing structure**

This shift in the dynamics of world demand is reflected in the structure of the industry. Consolidation has reduced the number of western IOCs – international oil companies. But it has brought important new players onto the stage. Less than a decade and a half ago, the three major Chinese oil companies were just establishing themselves as independent companies and implementing their IPOs. Today, they are among the major energy players of the world.

However, the world oil industry faces the challenge of meeting this growth in demand. The answer is to be found in technology. In the previous periods of ‘running out of oil,’ technology has been a very important part of the answer. So it is today. This time, the technological advances have taken the form of the ‘unconventionals.’ One example is ultra-deep water development. Another is the breakthroughs around Brazil’s off-shore pre-salt. This resource, along with the fading of Venezuela, will likely make Brazil the number one oil producer in Latin America. Saudi Arabia has implemented complex mega-projects that, by themselves, would constitute a significant oil producing country.

Canadian oil sands are another resource that is registering a global impact. By the end of the 1990s and the beginning of this century, a combination of technological advance and more realistic fiscal terms turned oil sands from a fringe resource into a global one. Oil sands output has increased from 0.6 million barrels a day (mbd) in 2000 to an estimated 2.1 in 2014 and is expected to hit 3.8 mbd by 2025.

Yet the most stunning example of technological breakthrough came in the United States, and it did so in the midst of an on-shore industry that was supposed to be moving off into a sunset of terminal decline. The breakthrough, of course, was shale gas.

**Trial and error innovation**

It took until the late 1990s, after a decade and a half of trial-and-error innovation in the face of much scepticism, to demonstrate that commercial natural gas could be extracted from shale rock. It took another half decade, until 2003, to successfully yoke that innovation to horizontal drilling. Yet it was not until 2008 that the impact began to be widely recognised in the oil and gas industry in North America.

Some still doubt its lasting power. In Europe, one hears it dismissed as the ‘shale gas bubble.’ But the reality is evident. A decade ago, shale gas was two per cent of US natural gas production; today, it is 44 per cent. Estimates of the resource continue to grow.

The same technology, applied to what has become known as ‘tight oil,’ has had a dramatic impact. Between 2008 and the spring of 2014, US crude oil output expanded by 3.2 mbd – a 64 per cent increase. The significance is not just to be measured in terms of production. The economic impact of this “unconventional revolution” is considerable; it supports over two million jobs, a number that is going up. When
I interviewed Ben Bernanke at CERAWeek in March 2014, in his first major public appearance since leaving the chairmanship of the Federal Reserve, he summed up the impact this way – “one of the most beneficial developments, if not the most beneficial development, since 2008.”

Shale gas is also changing the competitive balance in the world economy. The abundance of this resource has driven down natural gas prices in the US to one-third the level of Europe, and one-quarter to one-fifth the level in Asia. This is giving energy-intensive manufacturing in the US a major competitive advantage over Europe. Over US$100 billion of investment in new manufacturing in the US – from both American and non-American companies – is now scheduled, owing to the abundance of inexpensive natural gas.

**Energy costs and competitiveness**

European industrialists and political leaders are alarmed that European manufacturing will lose out in the global marketplace because of higher energy costs. This is of particular concern in Germany, which relies on exports for half of its GDP, and which has been embarked on a high-cost renewable energy strategy. The German economics minister, who is also the leader of the SPD party, has warned that Germany faces a “dramatic de-industrialisation” unless it brings down its energy costs.

The US remains the world’s second largest oil importer, behind China, but its import level has gone down significantly – from 60 per cent of total demand in 2005 to less than 30 per cent today. This is dramatically changing the flows of global oil – in a way that reflects both the major trends. Countries that formerly relied on the American market are having to accelerate the re-direction of their exports to Europe or Asia, and, in a knock-on, countries that counted on Europe are also having to shift more towards Asia.

Moreover, owing to the configuration of its refineries and the build-up of supply, the US has also become a major exporter of petroleum products – indeed, at almost 4 mbd, the largest refined products exporter in the world. The US refining system cannot absorb all the light tight oil that is being produced, and the ban on exporting crude oil looks soon to be lifted. That would mean that West African crudes, which have already lost their market on the US east coast, would also be competing with US light oil in Europe and Latin America.

Will the unconventional revolution go global and, if so, when? That is a big question throughout the global industry. In terms of resources themselves, there is ample opportunity. IHS has identified the 23 most promising tight oil plays outside North America. Work has begun in two at the top of the list, in West Siberia in Russia, and in the Vaca Muerta formation in Argentina. But it is still very early days. China is thought to have significant shale gas resources and – owing to urban

*At the heart of the US shale revolution, the process of mixing water with fracking fluid*
air pollution – strong incentive to develop it. There, too, however, it is still early days.

Moreover, development in the US benefitted from favourable circumstances – an entrepreneurial upstream industry with a large number of independents, a well-developed eco-system in terms of services, private ownership of mineral rights, and state rather than national regulation. Canada shares most of these attributes, as well as being highly integrated with the United States. But the absence of these conditions in most other countries will slow development there.

Yet the unconventional revolution is already changing the global market – and having some impact on global politics. Had the US remained on course to be a major LNG importer, the global LNG industry would have been much more stretched and challenged to respond to Japan’s desperate need for LNG after the Fukushima nuclear disaster – and Japan would have been in an even more difficult position.

The big turn-around

But, in the years ahead, it is no longer a matter of the US just not importing LNG. A big turn-around is at hand. In 2008, the general expectation was that the US would soon become a major importer of LNG in order to meet what was perceived to be an imminent deficit of supply. But now the US is preparing to become a major exporter of LNG. The first shipments of LNG will probably begin around the end of 2015 or early 2016. By the beginning of the next decade, the US will be on track to rank with Qatar and Australia as one of the “Big Three” of LNG exporters. But it will not be alone in entering the LNG export market. There will also be other new exporters – East Africa, British Columbia in Canada (also from shale gas), Russia, and potentially the eastern Mediterranean. This will make the world natural gas market more diversified and more competitive.

The world oil market has been hit by a number of disruptions in the last few years, as well as the sanction-driven reduction in Iranian exports. Yet the oil price has been remarkably stable. The shortfalls – and the requirements of increased demand – have been met by a combination of increased Saudi output growing output from North America plus some additional output from other Gulf countries. It can certainly be argued that the surge in US production – a million barrels per day in 2012 and another million in 2013 – was critical to the impact of sanctions on Iran, helping to push it into negotiations on its nuclear programme.

Another impact can be seen in terms of Mexico’s energy reforms to open its oil industry to the world. The decline in Mexico’s oil output has long signalled the need for a change, especially since oil revenues provide about 35 per cent of the national budget. But it took the unconventional oil and gas revolution in the US to help jettison a 76-year legacy of the 1938 nationalisation. Mexico could see the speed and scale of the revolution next door in the US – with Texas alone now producing more oil than Mexico. Mexico needs reliable, reasonably-priced natural gas to support its manufacturing industry; and shale gas resources could help assure that energy. But that requires foreign investment and technology.

Diversifying away from each other

It is much too soon to assess the consequences of the Ukraine crisis on world energy markets. But it is obvious that Europe will be seeking to diversify its sources of natural gas. That could include imports of shale gas in the form of LNG from the United States. In response to the crisis, German Chancellor Angela Merkel declared, “There will be a new assessment of our entire energy policy.” Will that mean that Germany will also lift its de facto moratorium on natural gas drilling and begin to tap its apparently considerable shale gas resources?

For the last several years, Russia has been looking to diversify its gas exports away from Europe to the growth markets of Asia. New LNG projects have been announced. In the aftermath of Ukraine, Russia had further incentive to work out the disagreements on pricing arrangements that have, until now, held up pipeline gas exports to China. This strategy took a dramatic step forward in late May with the agreement for Russia to supply China with around one trillion cubic metres of gas over 30 years.

Amidst all of the changes and tumult of the last ten years, the oil and gas industry still faces the fundamental challenge that became so evident 10 years ago – meeting the world’s need for energy to fuel economic growth. While the ongoing rise in costs has become a pervasive concern throughout the industry, technology continues to augment the industry’s capabilities to do so. Yet it is that challenge that defines the industry’s mission. For that challenge is also a responsibility.
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Unlocking opportunity with innovation and cooperation

By Rex Tillerson
Chairman and Chief Executive Officer, Exxon Mobil Corporation

The 2014 World Petroleum Congress is an excellent opportunity to consider the energy challenges facing a dynamic and changing world. Through dialogue and international cooperation, leaders from our industry can help shape the decisions made by government, industry, and society, so the world can safely and responsibly meet our shared energy challenges. Understanding these challenges begins with recognising the universal need for energy. Global progress requires people everywhere to understand that there is a humanitarian dimension to the global efforts to expand supplies.

Today, approximately 1.3 billion people around the world lack access to electricity for basic needs like clean water, cooking, sanitation, light, and safe storage for food and medicine. Whether an economy is developed or developing, there is a shared need for energy to drive growth and power technological advancement.

Understanding the challenges of the future also requires the public and policymakers to acknowledge that the global need for energy will grow in the years ahead – and it will grow significantly. Population growth, rising urbanisation, and economic expansion will increase global energy demand by about 30 per cent by the year 2040. To meet this growing need, the world will need to pursue all sources of energy – wherever they are economically competitive. The world will also need to develop and deploy technologies that expand supplies, increase efficiency, and reduce the environmental effects associated with increased energy use.

In spite of these pressing challenges, there is reason for confidence and even optimism. Time and again the energy industry has proven that the world can meet these challenges safely and responsibly. We can achieve society's shared goals with ingenuity and cooperation, with disciplined investment and effective risk management, and by developing and applying new innovations. In recent decades, national and international energy companies have pioneered new technologies and best practices all across the energy chain – from Prudhoe Bay to the construction of the Trans-Alaska pipeline, from polar bear radar detection to the first iceberg-resistant gravity-based structure at Hibernia. More recently, ExxonMobil’s joint operations with Rosneft in Sakhalin have shown that industry can safely and responsibly produce energy in extreme and Arctic-like conditions using advanced technologies – such as land-based directional drilling – while adhering to the highest standards of safety and operational integrity.

ExxonMobil is working to build on these successes at Sakhalin-1. Through a historic partnership with Rosneft, we will unlock new supplies of energy in Russia’s Kara Sea, in Western Siberia, and beyond. As these achievements show, the key to every success in the energy industry is – and will always be – innovation and cooperation. That is why ExxonMobil is committed to making sustained and disciplined investments in research and development to create technologies that improve exploration, risk management, and emergency response. It is also the reason Rosneft and ExxonMobil have established a joint Arctic Research Centre in Russia as well as an over-arching technology sharing agreement to support our joint ventures worldwide.

Shale gas & tight oil: A global opportunity

There is a second area where the global energy industry will need to build on our past achievements, and that is in the development of shale gas and tight oil.

To deliver the energy that enables global progress, the world must build on past successes and apply proven technologies and risk-management techniques to new and promising resources. Two areas, in particular, show great potential for expanding world supplies through the application of innovation and cooperation.

The Arctic: Successes past and potential

The Arctic represents the world’s largest remaining region of undiscovered conventional oil and natural gas. In the decades ahead, the Arctic will play an increasingly critical role in meeting global energy needs. As activity expands in this region, industry leaders must communicate to the public and policymakers that the Arctic is not unfamiliar territory. It has been a major oil and natural gas producer for nearly a century.

Ninety years ago, ExxonMobil was the first to operate in the Arctic at Norman Wells in Canada. In the ensuing decades, we have pioneered new technologies and best practices all across the energy chain – from Prudhoe Bay to the construction of the Trans-Alaska pipeline, from polar bear radar detection to the first iceberg-resistant gravity-based structure at Hibernia. More recently, ExxonMobil's joint operations with Rosneft in Sakhalin have shown that industry can safely and responsibly produce energy in extreme and Arctic-like conditions using advanced technologies – such as land-based directional drilling – while adhering to the highest standards of safety and operational integrity.

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Less than a decade ago, few could have anticipated the far-reaching impact of innovation on the production of shale gas and tight oil. Yet, today, the energy industry
can point to extraordinary examples of how the integrated use of technology is bringing both economic and environmental benefits.

In North America, the industry can now recover oil and natural gas from extremely dense shale and tight rock. The result has been vast, new supplies of energy. Since early 2011 alone, US oil production has jumped nearly 50 per cent – from 5.4 million barrels per day (b/d) to the current daily production rate of 8.2 million barrels. That is an increase of 2.8 million barrels produced in the United States every day. And the US Energy Information Administration predicts that US production will continue to expand to approximately 9.4 million b/d by the end of 2015.

Just as significant has been the impact of this new economic supply of natural gas, which is spurring economic growth, increasing manufacturing competitiveness, and supporting millions of jobs as well as billions of dollars in government revenues. The impact of the new abundance of natural gas is going beyond US borders by strengthening the flexibility and diversity of the entire global energy portfolio.

In addition to these economic benefits, abundant and reliable natural gas has already begun to yield significant emission reductions by displacing coal in power generation. According to the US Department of Energy, the shift to natural gas has helped to reduce carbon dioxide emissions in the US to levels not seen since the mid-1990s. Even more remarkably, these gains have been achieved in an economy that is 60 per cent larger than in the 1990s with 50 million more energy consumers.

**Sound policy: Roles and responsibilities**

The benefits of this energy revolution need not be limited to North America. There is significant potential to further expand supplies by applying hydraulic fracturing, horizontal drilling, and proven risk-management techniques to other parts of the world. But to expand the global supplies of energy, whether in North America, South America, Africa, Asia, or Europe, we must understand the respective roles of government and industry in delivering technological and environmental progress.

The world will need to find ways to enable investment, innovation and technological advancement. Government can help most by providing access and by putting in place sound and stable policies – policies that enable investment, continuous operational improvement and effective risk management. When policymakers provide such a foundation, the energy industry will respond to such incentives with long-term planning, research, and the development of new technologies, techniques, and ventures.

Government policymakers can also help by creating a clear regulatory roadmap for permitting, compliance, and accountability. Only government can maintain a level playing field for all competitors as well as promote free trade among nations.

The energy revolution in North America and beyond has proven that industry can expand supplies and help reduce CO₂ emissions. In particular, as new technologies unlock cleaner-burning natural gas around the world, developed and developing economies can meet growing power generation needs while reducing greenhouse gas emissions.

The challenges ahead will not be easy. But success in the global energy industry has never been easy. Fortunately, history has shown that our industry’s successes transform the world. Reliable and affordable energy has been – and will be – instrumental in alleviating poverty, raising living standards, and creating economic opportunity for billions of people around the world. With sound policy, sustained investment, and international cooperation, the energy industry can discover and deploy new technologies and unlock new supplies of energy in a safe and responsible way, building progress and prosperity in every nation.
In the world of energy there are few nations that can rival Russia, the host of the 2014 World Petroleum Congress. Today, Russia is a world leader in the production of oil and gas and has vast resources that offer even greater potential for tomorrow. And while acknowledging its vital importance to global energy supply today, it is important also to remember that Russia is an energy industry veteran.

Russians were extracting and refining crude oil in the Caspian and North Caucasus regions in the mid-19th century. Several of the world’s biggest producing oilfields are in Siberia, including Samotlor, a resource that continues to produce large volumes of crude oil some half a century after its discovery. Reservoirs like these can, with the right technology, continue to provide energy for many decades to come.

Our industry has always been a pioneering one, deploying the latest technology to bring energy to our homes and workplaces from increasingly remote and challenging surroundings. Today these include ultra-deep water, extremes of heat and cold and complex geological formations such as those containing shale and ‘tight’ gas and oil.

The industry is constantly developing new technologies to enable us to find and then produce these reserves to meet the world’s expanding appetite for energy. According to the BP Energy Outlook 2035 we expect the demand for energy to increase by as much as 41 per cent between 2012 and 2035, based on current and expected trends in demand, supply, policy and technology.

Demand continues to rise with improving living standards in the developing world. However, we are increasingly confident that the incremental demand can be met if the resources that undoubtedly exist below the ground are matched by investment-friendly conditions above, including open markets, open access and policy frameworks that encourage competition and innovation.

This is being seen most notably in the so-called ‘shale revolution’ driven by technological advances in directional drilling and hydraulic fracturing. This is now extending from North America to Russia, China and other parts of the world. Meanwhile, explorers will extend the reach of offshore oil and gas drilling into even deeper water. Several nations, including Russia, want to extend the exploration horizon into the Arctic. These areas offer huge opportunity but they also involve major challenges.

So what are the major priorities for the industry in this context? The oil and gas industry’s first task is to ensure that its operations are safe for people and the environment. Added to that responsibility is the need to provide financial returns to shareholders, as well as providing energy for customers and revenues for governments. The cost of producing the marginal extra barrel in deep-water offshore and in heavy oil and tar sands is growing. Cost pressures coming from two directions are affecting the economics of oil and gas. On the one hand, we see shortages of equipment, rigs and skilled personnel, all of which drive up the costs for explorers. On the other hand, we know that governments are under pressure to deliver more and better public services to their populations. They need to strike a careful balance between the demands of public spending and the need to stimulate investment.

It is no secret that the oil industry is currently engaged in a drive for capital discipline, greater efficiency and lower costs, a new mind-set that is to be expected after a long period of high investment. However, for innovative companies, the challenge can also have the good effect of stimulating new thinking and encouraging the fittest to adopt new ways of doing things.

The lesson we have repeatedly learned in challenging times is that technology is frequently the key to unlock the opportunities.

For example, at BP, we are deploying new ways of acquiring seismic imaging onshore which can cut the time it takes to survey exploration acreage by as much as 80 per cent. At the same time, we have invested in the world’s largest supercomputer for commercial research. Based in Houston, it can process two thousand trillion calculations per second, powering our research into the next wave of seismic imaging technologies. In several fields in the North Sea and in Azerbaijan, the technique of 4D seismic enables us to detect changes in a reservoir over time. In this way, we can optimise a field’s development to maximise recovery.

State-of-the-art frontier technology is a bonus but the greatest gains can sometimes be achieved by looking at the familiar in a new way. Instead of looking ever further afield at greater expense, the prize can sometimes be found beneath our feet. By improving recovery from existing producing oilfields, the world could, we believe,
achieve very significant increases in oil production at relatively low cost. On average, worldwide, only 35 per cent of the oil in place is recovered from the reservoir. An improvement in the recovery rate to 45 per cent would contribute an additional 1 trillion barrels, the equivalent of about 30 years of global oil demand, at current rates of consumption.

At BP, we have developed several proprietary enhanced oil recovery, or EOR, technologies which can significantly improve oil recovery rates. For example, our scientists discovered that the recovery factor achieved by water flooding mature oil reservoirs could be raised by between 5 and 10 per cent by using low salinity water to displace trapped oil – a technique known as LoSal® EOR. We believe LoSal® EOR has the potential to unlock more than 500 million barrels of incremental oil from across BP’s portfolio. The world’s first full-scale deployment of LoSal® EOR will take place at Clair Ridge, in the North Sea. Due to start up in 2016, we estimate that we will recover an additional 42 million barrels through LoSal® EOR, at an incremental cost of just US$3 per barrel.

LoSal® EOR and similar innovations, including BP’s Designer Gas™ EOR technologies, have been tested and proven at several giant, mature oilfields, including Prudhoe Bay in Alaska. The Prudhoe Bay field was discovered in 1968 and at the time it was believed that only 9 billion of the 25 billion barrels of oil in place were recoverable. However, last year the cumulative total of barrels produced exceeded 12 billion. EOR technologies will play a key role in increasing our original recovery estimate of 38 per cent to more than 60 per cent.

Recovery can beat discovery
At the Rumaila oilfield in Iraq, a supergiant field discovered in 1953, BP has worked with our Chinese and Iraqi partners to achieve a 40 per cent increase in the output of the field over a period of three years, using BP’s reservoir management and depletion planning expertise. In fact, we now believe that the potential gain in output from applying EOR technology to known hydrocarbon resources exceeds the potential from new discoveries.

We are now looking ahead to a new generation of major projects which will deliver energy from giant fields for many decades – examples for BP and our partners include the Shah Deniz 2 project in Azerbaijan, supplying gas to multiple countries as far away as Italy, and the new Khazzan tight gas project in Oman. We can be confident that new technologies will be developed in the coming years that extend the life of tomorrow’s projects as well as today’s.

The world in which oil companies and oil producing nations make their living today is almost unrecognisable from the world as we saw it less than a decade ago. New drilling technologies have upset the dynamics of supply and made the world’s biggest oil consumer – the US – almost self-sufficient; worries about peak oil have evaporated; major new developments are underway in Russia; but at the same time the physical and economic challenges of producing energy have increased.

Businesses and nations that thrive in this demanding new environment will need to be fleet of foot in seizing opportunities. But above all, they will need continual advances in technology, developing new innovations, integrating them into existing operations and maximising the benefits they deliver over time.
n 2012, we at the International Energy Agency wrote that North American oil and gas developments were redrawing the global energy map – and many of those changes have accelerated since. Technology and high prices are unlocking new supplies of oil and gas that were previously thought to be out of reach. Yet the impacts of that phenomenon on prices vary in different regional markets, and that has made energy prices a live issue in political debate – especially in terms of affecting competitiveness.

Natural gas is a prime example. While unconventional production of natural gas may herald a golden age of gas, with major impacts on CO₂ where it displaces coal, its concentration in North America for the coming years means that the effects on natural gas prices globally are mixed. The most immediate impact is to exacerbate structural gas and electricity price differentials among the major consuming regions of North America, Europe, and Asia. Gas prices in Europe are currently about three times those in the US, and in Japan they are still around four times the US level.¹ That has implications for industrial competitiveness, particularly in energy-intensive industries.

There is more to those differentials than the availability of relatively cheap, abundant natural gas supplies in North America, however. They are also a function of the way natural gas is priced in Europe and Asia, where long-term import contracts are still all too often indexed to oil prices – a legacy pricing method still commonly used with Russia but also with Australia and the Middle East. The use of oil indexation in long-term contracts is rooted in the idea that oil and natural gas are interchangeable and can easily be substituted for each other as boiler fuels for power generation or industrial use. That was long the case, but the power sector has moved on, and oil and gas are no longer the competing fuels they once were. And while long-term contracts can provide demand security for very expensive projects, they also make for less liquid, less flexible, and less integrated gas markets.

The issue of gas pricing is hotly debated, but the way in which gas markets are developing is strengthening the arguments for moving beyond oil indexation. The historical argument for the practice revolved around the scope for physical substitution between the two fuels. This has all but disappeared in Europe and the US, while in Asia there is still meaningful oil-fired generation. However, high prices are driving oil out of the power sector and concentrating it in the transport sector, where oil is almost totally dominant. As a result, gas and oil demand are increasingly decoupling in Asia, undermining that particular rationale for oil indexation. It is not just pricing mechanisms that make contracts inflexible, but many traditional contracts also contain destination clauses that prohibit resale. These restrictions made sense when market actors were limited and the possibility of losing sales to an individual market posed a major investment risk. Yet the LNG industry is maturing, with more large players as oil majors give gas an increasing role in their upstream portfolios.

LNG exports from North America’s gas bonanza can play an important role in that market development process – because while the bulk of new LNG supplies will follow the same long-term, oil-indexed model, an important and growing amount will not. North American spot contracts, together with secondary re-exports from Europe and elsewhere, will significantly increase flexible global supply. In the case of Asia, these flexible supplies can help provide liquidity to a developing Asian gas hub.² The impact of American LNG exports will be to provide a competitive (often spot-priced) alternative to oil-indexed contracts. While volumes will in no way be enough to replace those contracts, they will provide leverage to push the negotiated prices lower. In fact, many would argue that just the prospect of US exports is already having such an impact. And when considering the costs of allowing those exports to go forward, it should be noted that the upward impact of LNG exports on North American gas prices is likely to be negligible.

When it comes to oil, light tight oil (LTO) output has grown from almost nothing in 2005 to about 2.3 million barrels a day today, and our scenarios indicate that fracking will help push the US to become the largest oil producer (if still not the one with the greatest production capacity). Together with oil sands, conventional deep-water offshore resources from Brazil, and increased natural gas liquids, LTO will help to reduce OPEC’s aggregate share of supply over the next decade. At the margin, then, unconventional oil eases pressure on tight global supply, helping to minimise upward price pressures from production shortfalls elsewhere.

But our central World Energy Outlook scenario...
sees global LTO production peaking by around 2030. In any case, LTO is relatively costly and requires a significant price floor to remain viable. So, we should not exaggerate the role of LTO relative to conventional production, or proclaim oil abundance. Supply and prices over the medium to long term will depend heavily on sufficient investment into conventional production, often by traditional suppliers.

Still, all new sources of oil will be crucial to meeting a 14 per cent increase in global demand to 2035 – particularly since the vast majority of investment will need to go to replacing declining production from mature fields. Meeting global demand growth will be an investment requirement over and above maintaining current output.

**Demand unevenly spread**

Meanwhile, that demand growth will be like energy demand growth generally – geographically uneven. While it is barely changing or even falling among OECD countries, growth is moving ever more to Asia. This trend is not new, but within Asia, the balance shifts. In the 2020s, India and Southeast Asia will take the lead from China in driving up consumption. The Middle East is also taking on a role as one of the major consuming regions.

One of the consequences of those changes is a transformed global product supply chain. New, non-OECD mega-refineries are challenging OECD refining economics, at least outside the US. Their expanding reach is accelerating the globalisation of the product market, particularly in the case of refineries geared toward export. With this shift come not only the benefit of greater market flexibility in the dispatch of product supply, but also longer supply chains, higher reliance on stocks to meet demand, diminished visibility in inventory levels, increased disruption risks, reduced market transparency and, possibly, greater price variation between key markets and also between seasonal peak and troughs in demand.

While unconventional oil and gas production in North America is on the rise, and certainly dominates headlines, the prospect of “energy independence” should not be misunderstood. Even with these developments, the US will remain deeply tied into the world energy economy, and the economic and political impacts of unconventional oil and gas will be no less than global. The ramifications of North American production will be less potent as direct political tools or cause for political disengagement, and more so in terms of their impact on market structures. That is the case for gas exports, which even in small volumes can affect long-term contract negotiations in Europe and Asia. It is also the case for LTO, which may not usher in an era of oil abundance or diminish OPEC, but which together with demand shifts can contribute to an entirely new map of crude and oil product trade.

1. We do not see North American gas prices as “set in stone.” We expect them to continue a general rise from their 2012 lows, as well as to fluctuate. Due to structural factors, however, we still expect them to remain well below European and Asian contracted prices.

2. In February 2013, the IEA released a report showing how that process can play out: IEA (2013), Developing a Natural Gas Trading Hub in Asia, Paris.
Energy is central to everything we do; for individuals, for businesses, for governments. All of the goods and services we often take for granted depend on access to energy – from mobile phones to motor vehicles, pharmaceuticals to plastics, computing to construction and agriculture to aviation. And in the coming decades, population growth, economic expansion and the fact that some 2.6 billion still rely on biomass for their basic needs and some 1.2 billion people still have no access to electricity, means demand for energy is set to grow.

In OPEC’s World Oil Outlook (WOO) 2013, global energy demand is expected to rise by 52 per cent over the period between 2010 and 2035.

There is no doubt that some of this demand increase will be supplied by non-fossil fuels. Renewables, from wind, solar, small hydro and geothermal, are expected to grow at over seven per cent per year, often as a result of government support and incentives. They certainly hold promise; but globally their share of the energy mix will still be less than three per cent by 2035, given their low initial base. And both the share of biomass and nuclear are expected to remain at steady levels throughout the period 2010-to-2035, at around nine per cent and just below six per cent respectively.

However, it is fossil fuels that will continue to play the dominant role in meeting demand, although their overall share will fall from 82 per cent to 80 per cent. Throughout most of this period, oil will remain the energy source with the largest share, although its overall share declines from 33 per cent to 27 per cent. Coal’s share remains relatively stable at around 27 per cent. The share of natural gas, however, is expected to rise from 22 per cent to 26 per cent. Thus, by 2035 the shares of oil, gas and coal in the overall energy mix are expected to be relatively similar.

In terms of oil, the WOO’s projections see liquids demand increasing by 19 million barrels a day (mb/d) over the period to 2035, with the developing Asian region accounting for close to 90 per cent of this increase. There is expected to be a steady decline in demand in all OECD regions. In terms of who provides the supplies, the WOO expects to see the call on OPEC liquids increase by over 10 mb/d by 2035, slightly higher than the increase in non-OPEC supply over the same period, at just under 9 mb/d. OPEC members are committed to invest, and to ensure that consumers receive oil when they need it.

Of course, this will also mean significant expansion in the downstream. For example, in the WOO it is expected that there will be around 20 million barrels a day of additional crude distillation capacity required in the period to 2035. The majority of this is in the Asia-Pacific and the Middle East.

The industry is capable of meeting the big demand increases, through its huge resource base. The US Geological Survey estimates the world’s ultimately recoverable resources of crude oil and natural gas liquids at more than 3.8 trillion barrels.

Moreover, there are the recent tight oil developments in North America. This is welcome news – it adds depth to global supply, aids market stability and provides further proof that the world is not running out of oil. However, some questions remain over how sustainable tight oil developments will be in the long term.

It is important to appreciate, however, that these projections only tell part of the story. Forecasts are what they say they are. We can present a vision linking market stability with other key global issues, notably sustainable development and the environment, but none of us can exactly predict the future as there are a wide variety of issues and uncertainties that may have an impact on how the oil industry evolves. And these can have significant impacts on investment in future capacity to meet the rising levels of demand.

A two-way street

A central facet to better understanding the future is energy security. It means an appreciation of the reciprocal nature of energy security. It is a two-way street. Security of demand is as important to producers, as security of supply is to consumers. For producers, it is critical to have a better understanding of demand-side policies and developments. If not, it can lead to investment uncertainty, and in turn, future market instability. Moreover, energy security cannot only be viewed as a short-term conundrum. It needs to cover all foreseeable time-horizons. Security tomorrow is as important as security today.

Security begets stability. And this is crucial for the industry as it looks to invest in projects and technology and turn these resources into supply.

Related to this is the issue of price stability. There are two elements to this.
Firstly, the industry needs to continue to keep a watchful eye over speculative activities. We cannot avoid speculation and volatility altogether; they are part of the market, but it is vital for the market to focus on actual market fundamentals, and to continually look to mitigate extreme volatility and excessive speculation. Extreme price fluctuations are not conducive to the effective functioning of the market, particularly given the long-term nature of investments.

And secondly, we need to ask the question: what price is required to make each energy economically viable? Every energy, and every investment project, has a break-even cost associated with it. Whether producing conventional oil and gas, coal, Canadian oil sands, ultra-deep offshore oil, renewables or biofuels there is an associated marginal cost. If prices fall below certain levels, then many investors will find their developments no longer viable. And if low prices lead to energy investments across the world being put on hold or cancelled altogether, then there is the potential to sow the seeds for extreme high oil prices in the future, if a lack of investment leads to supply failing to keep up with future demand increases. This has happened in the past.

It underscores the importance of a stable and fair price for all – one that is satisfactory for both producers and consumers and allows the energy industry and the global economy to grow.

Of course, there are other challenges and uncertainties for the oil industry. There are those that are known, such as a potential human resource shortage, the need for more reliable and transparent data, and rising costs, all of which the industry can analyse today and where possible, take actions and decisions that helps provide more stability to the industry’s future. And there are those that are unknown, such as future geopolitical developments and weather-related events that the industry will need to manage, as and when they arise.

It is clear that the long-term market outlook is a favourable one for the oil industry. The industry will see growth in the years ahead, as oil demand expands. There are plenty of opportunities for investors in the industry, but at the same time it is important to ask the question: what will the industry need to turn available resources into delivered supply?

The key words are order and stability, for both producers and consumers. When planning for the future, whether this is five, ten or even 20 years hence, we need to have the best available information to have the best idea of where the market is heading. This will then allow the industry to look at the forecasts and try to put the best framework in place to overcome challenges and arrive at a future that works for us all.
SONATRACH, achievements & commitments

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The global energy dialogue is never more robust than when a sizeable number of stakeholders are facing a particularly thought-provoking topic. Commitment to the global energy dialogue tends to strengthen when policymakers and industry executives face an issue of common concern. The history of the dialogue has shown this to be true. In 1991, as market actors struggled to manage the volatility of crude prices in the wake of the first Gulf War, a small group of energy ministers agreed that a resolution to the issue was more likely to be found through dialogue than through rhetoric. The first meeting of what would later come to be known as the International Energy Forum took place in Paris in July of that same year. Since then the dialogue has matured significantly, with a permanent secretariat ensuring its development and continuity in line with the tenets of the IEF Charter signed in February 2011. Just last month, we held our 14th International Energy Forum Ministerial right here in Moscow.

Does the unconventionals revolution represent a topic of equal interest and importance as crude price volatility, which engendered the IEF over twenty years ago? From the perspective of the IEF, the answer is a resounding yes, given its global reach and the number of “known unknowns” and “unknown unknowns” on technological and strategic fronts. In light of the engagement we have seen on the topic globally, the rise of unconventionals has certainly served to stimulate the producer-consumer dialogue.

Regarding natural gas, the increasing availability of unconventional supplies from shale and deep-water deposits is already influencing producer-consumer relationships, yet the end game is hardly clear. Market observers are weighing the likelihood that consuming countries in Asia will continue importing LNG from long-standing suppliers against the possibility that they may seize the opportunity of a more diverse supply base to seek out new sellers or renegotiate existing deals, in a pattern that bears resemblance with Europe.

Many see a natural gas game changer that merits further analysis and dialogue on at least three fronts:

First, it may be the beginning of a trend towards an integrated global gas market, where price differences among North America, Europe and Asia – the three main international gas markets – will decline or disappear altogether, much as it is the case in the oil market.

Second, to the extent that the necessary levels of liquidity are reached, it may lead to the establishment of a new pricing mechanism based on a combination of spot transactions and long-term contracts, or at least prompt more widespread interest in the possibility of more flexible long-term contracts.

And third, over the long term, fuel switching in favour of gas is a possibility should its greater abundance trump the price competitiveness of other fuels, most notably oil.

How likely is the shift from our conventional world of three separate regional gas markets to an “unconventional” one of a single global gas market? How probable is it that the conventional method of pricing gas through long-term contracts in Asia and most of Europe may give way to the less conventional method of doing so through short-term, spot transactions? Producers and consumers alike have been engaging with each other through neutral platforms such as the Asian Ministerial Energy Roundtable (September 2013, Seoul) to better understand these questions and to craft their policy and commercial responses.
Accordingly. While no definite conclusion has been reached, as consumers would like to see more flexible contracts and producers prefer the current long-term contract regime, the global energy dialogue has taken on a greater intensity and strengthened as a result.

Turning to crude, the potential impact of light, tight oil (LTO) on global markets has sparked a wave of conversations on the topic and on assumptions regarding what the future may hold. Views on the impact that LTO may have on global markets vary widely across the spectrum of experts, with the perspectives of the International Energy Agency (IEA) and the Organisation of the Petroleum Exporting Countries (OPEC) carrying significant weight.

Given their provenance these diverging views cannot be discounted out of hand and merit further analysis. The provision of platforms for dialogue on topics of such global interest and importance is the first step towards the improved understanding that is pivotal to better decision-making. To highlight just one such platform for dialogue, the outlook for LTO was discussed at the Fourth IEA-IEF-OPEC Symposium on Energy Outlooks (Riyadh 2014), during the plenary sessions, the coffee breaks, and in the background paper prepared jointly by the IEF and Duke University.

In its World Oil Outlook 2013 report, OPEC projects that LTO supply in the United States and Canada will peak around 2017-2019 – with the largest annual production growth already seen in 2012 – and then gradually decline over the remainder of the projection period. OPEC believes that by 2035, LTO production in the United States and Canada will just slightly exceed the current production level.

In contrast, the IEA projects that the LTO revolution will last longer. It expects LTO supply in North America to plateau around 2025 and not taper off until the beginning of the 2030s. According to the World Oil Outlook 2013, growth in LTO as well as NGLs from shale plays will propel the United States past Saudi Arabia as the world’s largest oil producer by 2015, retaining that position until the beginning of the 2030s.

The sharp contrast in LTO projections may result from different perspectives on the impact of rapid decline rates on field production, or assumptions regarding the resource bases and sustainability of investment activity. It could also relate in part to the different definitions of LTO and natural gas liquids. Although the IEA acknowledges the challenges of LTO’s faster decline rates than conventional oil and the initial targeting of “sweet spots”, it projects that continuous investment in new rigs and discoveries of new fields, as well as other technological advances, will maintain LTO production at a high level.

While OPEC and the IEA hold different views on the long-term prospects for LTO, they concur in acknowledging the uncertainties about the future. In its WEO2013, the IEA points out that downside risks may include new LTO plays (beyond the Bakken/Three Forks, Eagle Ford and Permian basins) being less productive and more expensive to develop, with the possibility of a lower oil price inhibiting the development of LTO. In its WO02013, OPEC considers a more optimistic LTO supply path in its Upside Supply Scenario, in which existing major LTO plays are productive and more plays are added to the production profile. In this scenario, LTO production from North America will be 2.5 mb/d higher than the Reference Case by 2035, though the production is still expected to peak around 2020, earlier than IEA’s forecast.

As for LTO resources outside North America, both the IEA and OPEC adopt cautious estimates due to a lack of global commercial experience and a scarcity of thorough and detailed worldwide resource assessments.

Platform of choice

Given the potential game-changing impact of unconventional and the number of related yet unresolved questions, we expect the global energy dialogue to continue to be revitalised by unconventional as the market actors seek each other out to exchange ideas, explore scenarios, and jointly shape our collective energy future.

The IEF is tasked with being at the leading edge of the global energy dialogue and is the platform of choice for the promotion of global energy security. While the IEF was founded by ministers for ministers, the Forum likewise maintains strong ties with industry through our 50-strong Industry Advisory Committee, which will soon cover a much broader spectrum of the stakeholders in the energy supply chain.

We remain ready, willing and able to do our part to strengthen the global energy dialogue. But the effectiveness of any dialogue is a direct function of the engagement of its participants. Towards that end, let’s talk.
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Geopolitics and energy have long been interlinked in every region of the world. The crisis in Ukraine has once again brought into sharp relief the importance of securing Europe’s long-term energy security. And yet, as we look intensely at these traditional suppliers, the global energy picture has changed dramatically over the last 5 years with new producers and new consumers redrawing the energy map. As a result, the African energy sector is now more tied into the global energy system than ever before – presenting numerous opportunities, but also risks and difficult policy choices in the process. As the UK’s Minister for Africa, I have a keen interest in the outcome.

The growth of energy demand in emerging economies, particularly China, India and the Middle East, is the major trend in the global energy market. Oil is already Africa’s biggest export to China – making up over 60 per cent of total exports. Several of the major producers like Angola have well established energy ties with China. But we might expect others to build links with consumer countries in Asia and elsewhere, forging new geopolitical alliances based on energy in the process. I visited China at the end of April this year for discussions on this very issue.

African economies are of course a major part of the demand growth story. In 2012, five African nations had economic growth rates higher than China’s. The International Energy Agency sees Africa making up eight per cent of global energy demand growth to 2035; double the share of the OECD in that demand growth. This should lead to greater regional energy flows within Africa, raising the stakes for cooperation between governments.

Energy flows to and from the continent are likely to become increasingly complex. The decline in US oil imports has already affected transatlantic oil flows from Africa. But the major change is likely to be increasing global gas trade, driven by the wider distribution of reserves. Competition in the global LNG market will increase. Countries that can develop import-export infrastructure and secure contracts will be ahead of the game; and LNG shipping cargoes in and around Africa will increase.

Growing opportunities
Africa is on the rise as an energy producer. The long-term prospects for traditional suppliers in North and West Africa remain good, and recent East Africa oil and gas finds have real potential. It will take time to develop energy sector capabilities in the region, just as it took time for the UK in the North Sea. Embracing external expertise will be important, bringing them together with local companies and institutions. And closer regional cooperation will help generate more efficient infrastructure decisions.

But while resources are growing, energy access is an acute problem in Africa. Over half a billion people lack access to electricity. Power cuts occur on a daily basis in many countries. Governments with energy resources face tough choices on whether to maximise revenue through exports or concentrate on domestic supply. Investment in the power sector and electricity grid will certainly help. Most of Africa’s infrastructure needs have yet to be built, and governments can benefit from the latest technological advances.

Renewable energy is also an important opportunity, given its ability to operate at different scales. Africa’s vast resources remain largely untapped: only eight per cent of the continent’s hydropower potential has been realised. Several African governments have responded by introducing legislation, but more work is needed to implement and deliver projects.

Remaining risks
The ‘resource curse’ continues to haunt many corners of the world, and Africa is no exception. Resources are too often squandered as countries are stripped of their minerals behind a veil of secrecy. Cronies and middlemen get rich, while the people in those countries stay poor. The African Development Bank estimates this cost Africa US$1.4trillion between 1980 and 2009 or around US$50billion per year – an incredible figure and one of the principal constraints to poverty reduction.

Governance is a critical risk. Transparency and accountability are part of the solution. The work of the Extractive Industries Transparency Initiative (EITI) in Nigeria has exposed multi-billion dollar discrepancies between what companies pay and what the government receives for oil. Chatham House estimates that oil theft in the Delta also amounts to around 100,000 barrels per day. When I visited the Niger Delta in February, I saw from the air the devastating impact that illegal oil theft has had on the environment. The challenge is huge, but President Jonathan has pledged to tackle these systemic risks in Nigeria, and new energy producers can learn
from these and other EITI experiences on the continent. Africa is still a region affected by conflict. The situations in South Sudan and the Central African Republic illustrate the way conflict and instability destroy livelihoods and undermine development. Elsewhere there are risks over the rights to energy resources, particularly where there are unresolved border disputes. Whether it is South Sudan’s pipelines or the Grand Renaissance Dam in Ethiopia, it is clear that African countries must work together; not doing so can have serious consequences.

Security remains a perennial concern for the energy sector worldwide: Africa is no exception. The tragic loss of life in the terrorist attack on the In Amenas gas plant in Algeria in 2013 was a painful reminder of the threat that terrorism poses to energy installations and the people that operate them. Companies and countries need to work together to counter this threat.

UK energy relations in Africa are rooted in history, with personal and commercial ties built up over generations. And we remain one of the biggest contributors of development assistance to African nations. But we are not resting on our laurels.

We are improving our presence on the ground, and we are backing this up with more effective high-level engagement. I have recently established, with other UK government departments, High Level Prosperity Partnerships with Angola, Côte d’Ivoire, Ghana, Mozambique and Tanzania. Energy is a key part of our relationships with all of these countries.

I firmly believe UK companies are best placed to support the development of Africa’s energy sector over the coming decades. I am leading the UK Government’s efforts on oil and gas in East Africa. We see this as one of five High Value Opportunities across the continent. But the UK offer is not only a commercial one. We want to build partnerships, not just win contracts. In Nigeria, we have 45 new partnerships. I want more across the continent, drawing on the UK’s strength in depth across the whole supply chain and on regulation, licensing and safety; offshore development; research and education; and low-carbon goods and services. That is why in the last year the Presidents of Mozambique and Tanzania have both visited Aberdeen to see for themselves the world class expertise there.

We are not alone in pursuing these aims. That is why I have also proposed a new UK-Norway initiative to support the development and management of East Africa’s oil and gas resources. The aim is to build on our joint experiences in the North Sea, and coordinate our bilateral work on development, transparency, trade and investment. Working together we can have more impact helping African governments to manage their resources in the best way, building up local industries and jobs.

Elsewhere, UK engagement is supporting the UN Secretary General’s Sustainable Energy For All Initiative, and the UK Department for International Development’s programmes are helping low-income countries diversify sources of energy. The UK has provided £95 million to capitalise a new Green Africa Power financing facility. This programme signed off its first project in January – a large solar power project in Rwanda, which should provide electricity to 15,000 additional households.

There is more to do to bring together energy and climate change policies in Africa. UK policy seeks to work with African countries to bring about a new global climate deal through the UN. We want an ambitious, legally binding deal to be agreed in Paris in 2015.

Of course, security and stability are the bedrock for economic growth. The UK is playing a leading role in reducing conflict and improving security across in Africa. We work with the African Union on crisis response and peace-keeping. We are supporting humanitarian activities in the Central African Republic and South Sudan. We are working on counter-terrorism from North Africa and the Sahel through Nigeria to Kenya and Somalia: all energy rich regions. We are also contributing vessels to the naval missions combating piracy off the Horn of Africa and keeping energy supply routes open.

Finally, there is much more work to do on energy sector governance, transparency and accountability. These are central to the UK’s approach. We put transparency right at the top of our G8 Presidency in 2013 and have been working with governments and companies to build capacity and take action. We strongly support EITI’s efforts in Africa, where 14 nations are already compliant and new nations, like Ethiopia, continue to sign up. Information and accountability are vital too – to ensure resources are well used and to hold people, companies and institutions to account. The UK welcomes the IEA’s plans to write an Africa Energy Outlook special report in 2014 as part of this effort.
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Nigeria diversifies to embrace emerging opportunities

Petroleum activities in Nigeria date back to 1908, but the first commercial discovery was made in 1956. The government’s involvement in the industry was initially confined to collection of taxes, rents and making regulations, while active involvement of acquiring participating interest in multinational companies started in 1972 shortly after Nigeria joined OPEC.

Consequently, the government’s active involvement as a partner placed it in a position to strongly influence investment within the industry. However, arising from the need to grow the nation’s reserve base, in addition to maximising government take, without allowing a situation whereby companies would execute projects mainly on a joint venture basis, led to the opening up of deep offshore areas under the Production Sharing Contract (PSC) arrangement in 1990.

Based on the combination of the above factors, a lot of projects came on stream in the deep offshore, contributing about 36 per cent of Nigeria’s production from the deep offshore terrain. In spite of these developments, Nigeria still has great potential for the development of and production from its deepwater resources. It should be noted that there are various discoveries in the terrain which are yet to come on stream, and future development of these prospects is expected to add several thousand barrels of oil per day to the nation’s production mix.

The licensing round being planned in the conventional acreage, including onshore and shallow water, is for marginal fields, which by definition carry zero exploration risk. This new round would take cognisance of the challenges faced by the awardees in the maiden bid round of 2003 by ensuring more robust economics that will enable them to raise funds for development of the fields.

One way to address some of the challenges is through the awarding of fields with over five million barrels of oil reserves in the new exercise. Upon the conclusion of the marginal field round, the nation would then embark on a licensing round for blocks after the evaluation of the activities of current license holders and the revocation of licences of those found to have performed below the stipulated work obligation.

With the changing dynamics in the global oil market, Nigeria has little choice but to realign its national interest and explore new markets for its crude oil and gas stock. This comes on the heels of the dwindling demand levels to about 8 per cent of what it used to be from the United States, which had hitherto been the principal importer of Nigeria’s crude. The United States at peak used to import about 37 million barrels per month from Nigeria, as observed in July 2010, and this plummeted to about 3 million barrels per month in December, 2013. Nigeria, therefore, is looking towards China and India to cover the vacuum left by America’s decreasing demand. Incidentally, the demand from Asia is strong and high enough to encourage Nigeria to increase its production levels in order to fill the gap and meet its domestic demand.

As a result of changing demand for Nigeria’s crude oil, the country is encouraging investment into the downstream sector in order to balance both the export and local consumption of its crude oil. To this end, the downstream sector is going through a revolution to maximise capacity in local processing, via a three-pronged approach involving a comprehensive turnaround in the maintenance of existing plants, establishment of refineries by big investors and encouragement of modular refineries by small operators and entrepreneurs. The first of the initiatives, wherein companies that built the existing refineries are engaged to carry out thorough refurbishment of the plants is already under way. The refurbishment
work on two of the plants, Kaduna and Warri, has been concluded while the one in Port Harcourt is nearing completion. The second part of these initiatives is already witnessing appreciable results as one of the major investors in Nigeria recently announced the intention to build a 400,000 barrel per day refinery in the Lagos area. The guideline for the third initiative, which involves the establishment of modular refineries, will soon be rolled out. Apart from adding value to the commodity locally, the initiative will save such companies the cost of crude oil handling and minimise the impact of crude oil losses on their small production.

The government’s desire to create more wealth and diversify the economy has stimulated investors to come up with gas utilisation projects, leading to an unprecedented growth in gas demand both in the domestic and export markets. The current gas demand for these projects stands at about 7.2Bscf/d and is expanding even more with the ongoing power sector reforms and planned implementation of the Gas Master Plan.

Additionally, soon-to-go-on-stream export projects like the Escravos Gas to Liquids Project and others proposed such as the Brass LNG, OK LNG, NLNG Trains 7/8, and Trans Sahara Pipeline Projects would require a guarantee of significant gas reserves volume to achieve Final investment Decision (FID).

Nigeria currently produces about 8.23Bscf/d of gas, out of which 5.16Bscf/d is associated gas, resulting from oil production and the remaining 3.07Bscf/d is produced non-associated gas.

Nigeria is recording an all-time low in the volume of gas flared, at an average of about 1.03Bscf/d. We are making great strides in the gas flare reduction initiative, as the nation has been reducing flaring. By 2005, the nation was flaring about 36 per cent of the gas produced and this has further gone down to about 12 per cent in 2013, as a result of the government’s aggressiveness in imposing the already existing penalty on gas flare.

On the environmental side, the government is still determined to do more to eliminate the menace of routine flaring but constrained to take the radical decision of shutting down non-compliant fields because revenues from oil production remains the mainstay of Nigeria’s economy.

But we are not done yet. The goal is to extinguish all gas flares within the shortest possible time, knowing full well that limited infrastructure is the main obstacle to extinguishing the remaining flares occurring in isolated fields. Even for these stranded gas pockets, we are coming up with an initiative to commercialise them in-situ, by encouraging the operators to invest in small scale gas-utilisation projects such as urea, methanol and similar plants.

Oil and gas shall continue to be a dominant driver in the dynamics of domestic/global energy demand for the forseeable future. Nigeria’s oil and gas industry therefore requires sustainable policy initiatives & strategies for reserve replacement and growth in order to remain relevant.

Applicable regulatory framework will be ensured in the promotion of a favourable environment for the key stakeholders and new investors in the Nigerian oil and gas sector. In addition, reforms are being undertaken to open the gas industry to greater competition, improve efficiency and attract new investments. Though there were some perceived threats to the industry in the past, plans have already been put in place to transform such threats into opportunities.
The shale revolution can transform mature oil and gas provinces into new frontier zones. This is what Vagit Alekperov’s LUKOIL company has been seeking to achieve in West Siberia, where the Bazhenov shale oil formation is one of the biggest in the world. But in Russia – lacking North America’s fortuitous combination of geology, liberal regulations, private ownership, service skills and physical infrastructure – it will be more evolution than revolution. But Russia needs to develop shale oil, which may prove easier to exploit than the Arctic. It should not, in Alekperov’s words, “find itself sitting on a bag full of food but unable to eat any of it”. The main concern of Ildar Davletshin of Renaissance Capital is the neglect of enhanced recovery techniques in mature Russian fields, due to the lack of tax incentives and to the limited number and technological conservatism of oil service companies.

Policy changes can also be transformative. Emilio Lozoya Austin of PEMEX explains how Mexico’s historic new energy reform will allow foreign companies to compete with PEMEX for the first time in 76 years, and how PEMEX is transforming itself to meet this competition. The particular technological and human resources challenge for the Mexican national champion is to expand exploration and production in the deep water Gulf and onshore shale reserves, and to attract sufficient talent in E&P skills in the face of new foreign competition. Further north on the same continent, the US revolution in tight oil has been led by Continental Resources, whose Harold Hamm says the US is now within striking, or drilling, distance of becoming self-sufficient in crude oil production. He therefore complains of the pointlessness and inconsistency in the continued US government ban on export of US crude oil, though not of petroleum products.

The future growth of US oil and gas production may depend in large part on maximising the ultimate recovery from unconventional oil and gas fields, whose output typically peaks and declines quickly. Jeff Miller of Halliburton explains that given the short drainage radius of their fractures, unconventional reservoirs require spacing wells more closely through the art of drilling new infill wells without disrupting existing ones. Maximising recovery is also the theme of the review conducted for the UK government by Sir Ian Wood of the UK’s Wood Group. Setting out the task of how to make the most of what is left in the UK section of the North Sea, Sir Ian proposes stronger regulation to coordinate more proactively exploration and production in line with infrastructure.
Considering the explosive growth of production in the US, we are justified in speaking of the "shale revolution". But is this term correct? It is an illusion to view the transformation of the US oil and gas industry as a one-time breakthrough. The companies had been improving their field development techniques for years and had invested billions of dollars before they achieved such great success. The shale revolution was preceded by decades of increased R&D spending, the creation of a sustainable innovation system based on fundamental science, venture business and tax incentives.

For the time being, the “shale success” cannot be replicated, since only the US and Canada have experienced such a fortuitous combination of circumstances, including geology, liberal regulations, private ownership of mineral resources, available credit funds and oil transportation infrastructure. Compared to North America, we can say that shale production in Europe has pretty much failed, due to difficulties such as environmental legislation and such factors as population density in the producing regions. Some countries are breaking fresh ground in shale: China is systematically developing expensive technologies to start its own industrial production, while Japan performed shale extraction for the first time in its history in 2013.

Of course it is impossible to accurately forecast these projects; shale production has its own peculiarities, advantages and disadvantages. However, production of hard-to-recover reserves may in the long run turn into a strategic argument in the global market for the countries seeking to achieve energy self-sufficiency. In this context the issue of shale production in Russia is becoming ever more important.

Let us compare the situation in Russia to the US along basic parameters. According to the calculations made by the US Energy Information Administration, Russia is the world’s leader in terms of oil shale reserves, while the US holds second position. At the same time, the US produces around 8 million barrels of oil per day and oil shale accounts for nearly one third of cumulative production; while Russia produces around 600,000 tons (4.5 million barrels) of shale oil per year. The importance given to shale oil in Russia is quite different from that in the US. Unlike the Americans, who use this feedstock for domestic consumption, the Russian government seeks to prevent a reduction in the export proceeds to the state budget with the aid of shale oil (according to the pessimistic scenario of Russia’s Ministry of Energy, oil production may drop from 500 to 370 million tons per year over the next decade or two).

Structural political and economic conditions still prevent Russia from stepping up its shale oil production. While acknowledging the need to pay taxes the companies are at the same time facing an investment deficit. The country is in great need of new breakthrough technologies. While new wells are constantly being drilled, the issue of expedient feedstock transportation is appearing on the agenda.
In the end, the profitability of shale oil production and export is quite doubtful. Unlike a great number of small and medium-sized independent companies operating in the US, only major players are engaged in shale projects in Russia, while the rest of the companies simply cannot afford it. Many market analysts believe that Russia regards shale oil production as an “image issue”, a so-called sport for the oil elite. To what extent are they right?

The current situation with the resource base is as follows: nearly all Russian shale oil reserves are located in the Bazhenov formation, a rock horizon in West Siberia at a depth of more than 2 km. The area of occurrence exceeds one million square metres, and the oil-bearing formation is 20-30 metres thick. According to different estimates, the oil reserves in the formation vary from 140 to 170 billion tonnes, out of which between 20 and 50 billion tonnes are comparable to Brent oil quality.

State-owned Rosneft and Gazpromneft (in partnership with ExxonMobil and Shell, respectively) are developing the Bazhenov formation along with the private companies LUKOIL and Surgutneftegaz, which run their projects separately. Major oil servicing organisations, including Weatherford, Schlumberger, Baker Hughes and Halliburton, act as contractors.

LUKOIL has been conducting pilot operations in two sections of the Bazhenov formation for several years. We believe that in the foreseeable future we will be able to select the best available drilling techniques and start commercial production. While applying conventional horizontal drilling and fracturing techniques, we stake our claim on the thermal gas formation stimulation technique and in-situ combustion maintenance.

The formation has huge potential; according to many foreign analysts, under favourable conditions it may be capable of producing 100-120 million tonnes of oil per year by 2020. In fact, during the last 20-year period cumulative production in the Bazhenov formation slightly exceeded 5 million tonnes. That said, the average current unit costs associated with this type of production are more than double the costs associated with conventional projects. Irrespective of individual achievements, in general the projects implemented by the companies and through joint ventures are at the initial stage of research and the introduction and testing of approaches and techniques.

However, recently the government has started to reform the fiscal system to boost hard-to-recover reserves production. A law on tax incentives came into effect in 2013, according to which a zero mineral extraction tax (MET) rate for a one-year period was granted to the fields located in four shale suites with a 3 per cent reserves depletion rate. The issue of promoting tax incentives is currently under discussion. In addition, there is a plan to establish a Coordination Centre for Geologic Exploration and Non-conventional Hydrocarbon Production under the auspices of the Rosgeologiya state holding. Thus, progress in the area of the hard-to-recover reserves production is certainly underway.

**LUKOIL’s Korchagin oil field in the north Caspian Sea**
Need for energy tax reform

Meanwhile, those measures are not enough to considerably change the status quo. It is necessary to dramatically reform the fiscal system in the fuel and energy complex and create more favourable conditions for the introduction of new techniques. As for the companies, the above reform also means changes in their investment patterns. Instead of drilling a well producing oil and generating income during a guaranteed period of time, they will have to make regular investments, change conditions and ensure the tactical mobility of production.

Historically, shale deposits could have played a great role in the diversification of the Russian oil and gas industry. Their production started in the mid-19th century; the establishment of the shale industry goes back to the first years of the Soviet Union.

Oil shale was predicted in 1962 by the famous Siberian geologist Fabian Gurari, while another legendary oilman Farman Salmanov for the first time succeeded in getting shale oil inflow in the Bazhenov formation in the early 1970s. Incidentally, the fracturing and horizontal drilling techniques were developed in the Soviet Union in the early 1960s, and in 1971 specialised R&D institutes recommended thermal and gas formation stimulation technique.

However, the hard-to-recover reserves could not then compete with the huge resources of Siberian oil discovered in the mid-20th century. For many years, huge resources of conventional hydrocarbons satisfied the demand of the country for energy and guaranteed budget income, thus making extraction of “difficult” oil somewhat optional. It is a paradox, but the abundant resources available actually resulted in a lag in terms of developing new technology.

Today, conventional fields are being depleted while new ones occur in structures with complicated geology and at great depths. The reliance on offshore fields is not so unambiguous to many experts and market players, either. In their opinion, development of the Arctic Region is a strenuous task and calls for immense investments, while in the mid-term the future belongs to other hard-to-recover reserves, namely, oil shale, bitumen, and coal-based methane. On the other hand, other analysts believe that Russia should focus on conventional reserves, since they are far from depletion. Russia should promote geologic exploration and discover new fields of conventional oil and take measures to enhance their oil recovery.

I believe that it would be a mistake to identify a single priority, for the oil industry should utilise both approaches. The accumulated experience in the area of conventional oil production does not negate the need to develop hard-to-recover reserves. In the future Russia must not find itself hungry sitting on a bag full of food but unable to eat any of it. There is no conflict between the different approaches used by our companies to implement production projects. Development of our own techniques and acquisition of foreign solutions produces a mutually beneficial effect upon the industry and enhances its competitiveness. Some think that Russia should wait until foreign developments become cheaper. Do we have enough time for that? It is possible to catch up with the US within the next 5-10 years, but the leader will go far ahead during this period. For this reason, today the Russian oil industry is making investments and an effort to promote non-conventional resource production.

Thus, the world’s leaders in terms of shale oil reserves, namely, Russia and the US, find themselves in stark contrast in terms of the starting conditions to discuss and compare their outlooks. However, the benchmark analysis of the whole range of structural conditions will enable us to gain a better understanding of what we are waiting for and what shale oil can give us. In my opinion, considering all our economic and industrial peculiarities, Russia can experience shale evolution rather than shale revolution – in other words, evolution of the oil strategy.

Development of shale and hard-to-recover oil in the country should boost industrial development. As for the country, it will form the basis for the establishment of qualitatively new relations with the business community. Implementation of the new strategy will require great flexibility, as well as a quick and accurate choice between tactical alternatives. The technological progress in the area of shale oil production should produce a multiplier effect upon the various branches of science and the nation’s production potential. I agree that the future belongs to hard-to-recover hydrocarbons. It is for oilmen and the government to decide what this future will look like.
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On December 20, 2013, President Enrique Peña Nieto enacted the much needed and anticipated Energy Reform, which will allow private companies to invest in the oil and gas sector in Mexico. This bill will allow PEMEX to compete with other companies for the first time in its 76-year history in an open market. I am confident that competition will make us more efficient and transparent, which will increase our competitiveness and let PEMEX become a trustworthy partner for other companies.

The age of easy oil is almost over in the world. Thus, we have a huge challenge to generate more output through better practices and partnerships by sharing our expertise, technology and risk management. The energy bill will allow private oil companies to invest in Mexico through different types of contracts, with the Mexican state retaining full ownership of hydrocarbons.

The energy reform and PEMEX’s imminent entry into the competitive market will bring many challenges for the company. In exploration and production we will focus on increasing the reserve replacement rate as well as the exploration success rate. We need to improve the recovery factor of our brown fields, while at the same time to reduce decline rates. Furthermore, we must reduce the operational costs and accelerate the development of new production.

Much has been done to improve our deep water and ultra-deep water fields in the last few years. Still, it has not been enough to have a meaningful impact on overall production. We need to inject capital into our new projects and generate value for the company.

Likewise, we need to double our investment in the prospective new plays so that we can take advantage of the energy revolution in the rest of North America. The shape of the demand is changing, since the US aims at energy self-sufficiency through plentiful non-conventional resources. These advances have been enabled by new technologies. The fast pace of change in the technical landscape has become more capital-intensive and with a different risk management profile. We must keep up with this trend, and that is the reason why it is vital for us to be able to establish joint ventures and cooperation agreements with other oil companies, especially in regard to non-conventional resources.

PEMEX is the most important company in the country, providing a third of the federal government’s fiscal revenues. The Energy Reform will consolidate PEMEX’s place as Mexico’s most important company and a leader in world oil and gas. It will be a ‘game changer.’ However, PEMEX cannot explore and drill all the Mexican plays alone. We need international oil companies to come and invest in our resources.

Corporate transformation

To succeed in this new context, we are transforming ourselves. PEMEX has not changed its corporate structure since 1992. Today, we require a much more agile enterprise so we can act swiftly and efficiently. We have already started to restructure the company in order to eliminate red tape and produce an efficient model of corporate governance that will free us to manage our budget.

One of our first fundamental changes is the modernisation of PEMEX’s buying methods, with the creation of a directorate for procurement and supply to streamline the buying process and make it more transparent. This will

Positive outlook: PEMEX has one of the highest deep water success rates in the world
save 5-10 per cent of this year’s US$40 billion worth of purchases. It will also allow us to base spending on our long-term needs, and to develop a trustworthy list of suppliers and contractors. Along with this, we will transform the four subsidiaries into two business units for upstream and downstream. These changes will give PEMEX the tools to compete in an open market, just as any other oil company in the world.

**Challenge of the talent trap**

One of the biggest challenges we foresee is the ‘talent trap’. We need to make sure that we attract and retain the best human capital. Therefore, we need to work very closely with the universities in Mexico, which are producing thousands of engineers every year. However, their skillset has to adapt to the needs of the industry. We have created a corporate university in order to certify our employees on various tasks, as well as provide training on leadership skills that will be important in competing with the private sector. Hitherto, PEMEX has been the only entity attracting talent in Mexico in the oil sector, particularly in exploration and production. Competition and an open market will surely change this state of affairs. This is why attracting and retaining talent is the number one job for the company, although we realise this is also a problem for the whole industry.

Competition will force PEMEX to be more transparent as well as efficient, as we improve accountability and show our operations to be highly trustworthy to our potential new partners and stakeholders. A main concern is to enforce zero tolerance for corruption. Regulatory institutions such as the Energy Regulation Commission (CRE) and the National Hydrocarbons Commission (CNH) will help enforce transparency controls, with public disclosure of information becoming part of the company’s everyday operation.

**Round Zero**

PEMEX has been given the opportunity to retain assets and exploit resources during the so-called ‘round zero’ before the open bidding for blocks. The company requested to retain exclusive rights to prospective oil resources. This is mostly where it has already been drilling and in fields currently exploited or in advanced development, where its exploration strategies have proved effective, and in fields with a strategic role. PEMEX applied for a portion of Mexico’s vast exploration opportunities. But this still leaves ample parts of the Gulf of Mexico’s deep water and shale gas formations available to private players. Additionally, even in areas where PEMEX is given exclusive rights, we will be free to pursue joint ventures or cooperation agreements.

The Energy Ministry, aided by the counsel of the CNH, has until September 17 to decide which of the requested projects will be assigned directly to PEMEX. Their decision will seek to maintain balance between keeping resources to meet PEMEX’s needs and encouraging the entrance of new players. Round Zero, for the time being, leaves the majority of the Mexico’s potential in shale-rock formations open to private sector investment.

PEMEX is currently one of the top five oil producers in the world and the most important in shallow waters. But our oil production from these areas, although very important, has declined in the last few years. With the certain plateauing of Cantarell output, we have focused on the diversification of our production. We
have increased the output of fields such as Ku-Maloob-Zaap, Ixtal, or Crudo Ligero Marino. In addition to that, we revitalised mature fields such as Ebano, Delta del Grijalva and Cinco Presidentes through an integrated exploration and production contract model. To keep up with production, we need to increase our reserve inventories with new discoveries and reclassify our existing proven reserves. PEMEX has been able to replace its reserves above 100 per cent since 2008, and is investing the largest amount in its history.

Nevertheless, our production has stabilised at 2.5 million barrels per day, down 25 per cent from the 3.3 million barrels per day produced only nine years ago. To increase production back to the 3 million barrels per day mark within six years, we need to invest approximately US$60 billion every year, a feat we will only be able to accomplish through partnerships with other oil companies. Mexico has a potential of 160 billion barrels in hydrocarbons, and most of it is in non-conventional resources, that is, in deep water and shale oil and gas reserves. Thus, we need to expand our horizon beyond shallow waters.

One of the biggest challenges for PEMEX was leaving shallow waters to explore the potential we have in deep waters in the Gulf of Mexico, because deep water exploration implied new technologies and practices. Nevertheless, we have proven to be very successful. In 2011, we were the second most active company in terms of deep water drilling in the world and, since then, we have been increasing our participation in the area. Our exploration success rate was of 50 per cent, above the international average. We currently have four deepwater platforms with the most advanced technology drilling off the coasts of Veracruz and Tamaulipas.

The probability of commercial success in deep waters ranges between 20 and 50 per cent around the world. This implies that for every 100 exploratory wells, there is a loss on average of between US$14 billion and US$8.75 billion in dry wells. Although PEMEX has one of the highest success rates and the potential losses have been minimised, we have to increase our drilling in the Gulf of Mexico. More importantly, we need to share risk with other oil companies. The oil industry in Mexico needs investments of around US$10 billion a year until the year 2025 from PEMEX and other oil companies.

Unconventional resources will play a major role in contributing to Mexico’s energy security. We have the sixth biggest proven shale gas reserves in the world. With the current rate of consumption, we would have enough barrels of oil equivalent for 10 years, and including probable and possible reserves, we have enough barrels of oil equivalent for 30 years. Our country has prospective non-conventional resources for almost 100 billion barrels of crude oil equivalent.

The Energy Reform will allow us to increase the production of natural gas too. Mexico is part of the North American market, which has the lowest gas prices in the world at US$3-4 per million BTU. The differential of this with US$10-12 in Europe, and US$15-16 in Asia creates a great business opportunity and economic boon for the country. With private investment, Mexico will start producing more gas and will also develop more gas pipelines. We have already started the ambitious Los Ramones pipeline project, which will go from the northern border to the centre of the country.

Our strategic vision is to broaden the international business lines for PEMEX by searching for new export markets, since all the forecasts predict diminished demand from the US, which is currently our biggest client. Hence, we have signed agreements with several Asian oil companies for the sale of oil, and we have started exporting on a regular basis to the Far East. We expect to strengthen our commercial links with India, China, Japan and other Asian countries.
When it comes to maximising your nation’s natural gas potential, forging the vital link between upstream and downstream operators and generating consistent national wealth and development, there’s no need to reinvent the process. The National Gas Company of Trinidad and Tobago (NGC) has successfully crafted a globally-recognised model for gas-based energy sector development, including investment in key sectors of the local gas value chain. Trinidad and Tobago has exploded onto the world stage as a major exporter of ammonia, methanol, DRI and LNG. NGC has constructed a 56" diameter Cross Island Pipeline (CIP), the first pipeline of this size in the Western Hemisphere.

Boasting an asset base valued at over US$6 billion, not only does NGC construct, operate and maintain pipeline networks and gas inlet facilities, we also compress, transmit, distribute and sell natural gas to energy industries and commercial concerns. In addition, we provide world-class industrial facility management and marketing services. With year-on-year gas sector growth averaging 5 percent for more than a decade, the Trinidad Gas Model is a success.

NGC can do it for you.
Fiscal and cultural barriers to raising recovery in Russia

By Ildar Davletshin
Lead Analyst, Oil and Gas, Renaissance Capital

The Russian oil and gas sector is entering a new era in which the conventional legacy West Siberian fields are being quickly replaced by frontier plays and even traditional fields need new approaches to continue producing profitably as natural depletion accelerates. Continuous decline in flow rates at new wells in West Siberia, coupled with rising water level and escalating lifting costs, are signs of a dangerous trend.

This creates conditions for what looks to be a perfect marriage between international oil companies (IOCs) and Russian oil companies. The IOCs are believed to be able to offer modern technologies, while they get access to new resources which Russian companies can offer them, making such partnerships a win-win situation for both sides.

However, the actual results achieved by various partnerships in the Russian oil and gas sector have been mixed, with barely a single example of a true success story. The typical reasons put forward to explain this relatively unexciting track record relate to overall sector conditions including onerous fiscal terms, limited access to resources and lack of strong institutions. While all this seems correct, the broader context of the Russian oil sector is often left out.

It is worth remembering that the Russian government is the biggest stakeholder in the sector in two ways: as the biggest beneficiary through its fiscal function (over 70 per cent of the oil price goes into state taxes) and as the biggest investor in the sector, controlling about half of the Russian oil output and about 80 per cent of gas production. There is an inherent conflict between these two roles, however consistent they may appear at first glance. Tax policy prioritises short-term returns over the long term, as half of the current government spending is funded by the oil and gas sector. At the same time, as a shareholder, the government aims to maximise the ultimate value of its investment which often means investing more now and getting benefits in the future.

When two goals are pursued simultaneously, the result is that the only projects to get approval are those with immediate pay-off. The same situation occurs when investors apply an extremely high discount rate to evaluate projects, as often happens in high-risk countries. Essentially this means that the cost of capital is indirectly lifted for most operators in the sector. This pushes operators to select projects with a quick payback period, naturally limiting overall investment in the sector.

An additional problem for international companies is related to poor recognition of earnings stream from Russian assets that are normally discounted by a much bigger factor. It is quite telling that dividends from the Anglo-Russian company TNK-BP accounted for up to 90 per cent of total dividends paid by BP itself in 2011, the last year before agreement was reached between Rosneft and controlling shareholders of TNK-BP over the future acquisition of their interests. Yet, TNK-BP accounted for less than a quarter of the total value of BP, according to the consensus valuation.

If full value is not assigned to the income from Russian operations, this discourages IOCs from investing in future growth in Russia, although at the same time IOCs can continue to rely on their Russian operations as a valuable source of cash to fund their growth projects in other parts of the world (including shale and deep offshore projects in the US).

One conclusion that can be drawn from this is the need to move to profit-based taxation, away from the current revenue-based fiscal regime.

Moreover, numerous tax benefits and exemptions motivate companies to seek access to assets in more remote areas as they will get tax credits, while neglecting mature fields where additional production from enhanced oil recovery (EOR) is bigger than what most green-field operations can deliver. As a result, foreign companies seek to partner with state giants like Rosneft and Gazprom, which have the best access to new assets and enjoy tax benefits. Such a situation creates interesting opportunities in neglected mature assets, because the potential from EOR is utilised very modestly and mature fields are left relatively under-valued. Russian companies have only recently started using horizontal wells with multi-stage fracking, not to mention more advanced techniques with chemicals. Even traditional water flood techniques are often used in quite a simple way, leaving a lot of oil in the ground.

The main constraint on more active use of EOR at mature fields in Russia is not lack of technical knowledge or skilled personnel, but rather the poor state of the service market and a different culture. These two issues need to be well understood by oil companies if they are to extract maximum value from
their brownfield operations.

The Russian service market comprises a few international companies focusing on R&D, with Schlumberger the market leader, several domestic providers of basic services and equipment, with Eurasia Drilling and CAT Oil being the leaders in drilling and hydraulic fracturing, and many small providers of other low-quality services. Rosneft and Surgutneftegas keep large in-house service companies. This is in stark contrast to North America, where hundreds of providers compete on costs, quality and technical solutions that they offer to their clients. Unlike their North American peers, Russian companies have to work within a limited universe of suppliers.

The situation is further complicated by the old age of most assets of the Russian oil services companies with 60 per cent of rigs being more than 20 years in operation and soon to be retired.

One way to overcome this issue is to expand along the value chain to minimise time and costs. For example, Gazprom Neft and Shell are building their own polymer plant in Russia to produce polymers to be injected into reservoirs and to improve efficiency of water flooding. At first sight, this goes against conventional wisdom that advocates lean structures and focusses on core competencies, but in Russia this should help in managing costs and thus expand the reserves base that can be accessed economically. This longer value chain to fight costs can be structured in different ways, with direct equity ownership being just one of the examples. Other options include joint ventures, alliances and various forms of contracts that incentivise suppliers to be more cost-efficient.

This leads to the second issue in developing mature reserves economically – which is culture. While the Soviet Union collapsed more than 20 years ago, its legacy is much stronger than most people think, especially in the oil and gas sector. Most companies are organised in a very hierarchical manner, where risk taking is highly discouraged and the key incentive is meeting annual targets. A reservoir engineer in a Russian oil company would typically prefer a solution that leads to a pre-agreed production target as distinct from one that could lead to lower costs or quicker production growth with some element of risk and uncertainty. The consequences of not meeting original targets are much higher than the benefits from potential optimisation.

As a result, budgets are normally inflated in terms of required time and costs while production targets are understated. Even if oil operators have adopted a different culture, they will be inevitably dealing with suppliers of an older culture, and they may bear the consequences as a result (delays in project executions, cost over-runs, final quality below original expectations). To avoid these constraints oil operators may consider different contract terms with their suppliers with final compensation linked to future performance or other risk and profit–sharing arrangements. Developing further vertical integration in order to control the supply chain better is also one of the possible solutions.
Maximising ultimate recovery from unconventional reserves

By Jeff Miller
Chief Operating Officer, Halliburton

This is certainly a golden age for drilling and completion technology. Across the board, in deep water reservoirs, in unconventional formations and in mature fields our industry continues to innovate and invent new ways to produce more oil and gas more efficiently. Necessity truly is the mother of invention. One of the things that really excites me about this business is how we as an industry consistently use technology to meet growing energy demand in the face of a more challenging resource base.

Looking forward, almost all analysts see a demand for energy that would be difficult, if not impossible to meet if we were simply doing things “conventionally.” We are becoming more efficient at using energy, but most analysts still expect the world’s energy demand to grow at about 1.5 per cent a year for the next 20 years. Even at that historically low rate of growth, the world will be consuming energy at a rate that is 35 per cent higher in 20 years than it is today.

At the same time, the “easy” oil and gas are gone forever. There are very few places left in the world where you can drill a well on dry land and expect oil or gas to come out of the ground on its own. If we are going to meet demand, we must forge into increasingly harsh environments, such as deep water and the Arctic and become increasingly clever at coaxing oil and gas out of the ground from resources that had been previously unreachable or from reservoirs that we believed had been tapped out.

The most exciting thing that has happened in the energy industry in my lifetime has been the phenomenal growth in oil and gas production from unconventional formations. We have all known for a long time that shale rocks held huge quantities of oil and natural gas. What was missing was the technology necessary to bring those hydrocarbons to the surface. Around 2007, operators and the service companies began to master completion technology. Across the board, in unconventional formations and in mature fields our industry has increased from about 1,000 billion cubic feet (bcf) in 2007 to over 10,000 bcf in 2013. Oil production from shale reservoirs has increased by about 47 per cent over the same period. Companies are investing in LNG liquefaction plants and pretty soon, the US will be exporting gas. Some analysts even believe that North America may start to export oil in the next five years. Going forward, there is a lot of optimism about the size of the unconventional resource. This is true in the US, where the resource is developed, and internationally where the resource is still being evaluated. Various estimates show reserves of natural gas increasing by 60 per cent in the US and 20 per cent globally and reserves of oil increasing by about 25 per cent both in the US and globally.

It is clear that to sustain this trend, we must find better, faster and cheaper ways to get every gas and oil molecule out of every field and formation. We have always known that we leave a lot of oil and gas in the ground when a well or a field comes to the end of what we normally think of as its economic life. The average recovery factor is 70 per cent for gas and 35 per cent for oil. For conventional resources, there is a wide variety of techniques: CO2 and water flooding, infill drill and artificial lift that can create a new peak of production, extend the life of the well and increase its recovery rate. Those techniques are proven to be effective and have very favourable economics. Incremental oil and gas production from mature fields has been and will continue to be an important piece of the energy supply puzzle.

A similar narrative is unfolding for unconventional resources. There is a lot of uncertainty about the amount of effort required to sustain and grow production to the levels assumed by current forecasts. We just do not have enough experience to reliably estimate the expected ultimate recovery (EUR) of unconventional wells. For conventional wells, we know a lot about how quickly a well’s production will peak and how long it will take for the production to decline to a level where it is not economical to keep producing. The US Energy Information Administration recently released an analysis of well-level data for tight oil and noted that “EURs based on only the first year of monthly production ranged from as much as 386,000 barrels higher to 173,000 barrels lower than the EURs based on four years of production”. That is a pretty wide range, when you consider that the average EUR for a well drilled in 2012 in the Eagle Ford formation is about 191,000 barrels.

Unconventional resource plays have been developed at an extraordinary rate. Many of them are already mature, meaning their production has moved past its (first) peak. Unconventional plays typically reach their hydrocarbon peak and quickly decline, hastening the time that they can be labelled mature assets. Extending their mature productive life and ultimate recovery is
paramount. That is going to require us to think about longer-term developmental drilling and completion strategies. Fortunately, there are a lot of solutions to this challenge already working their way into the market.

**Infill drilling and its challenges**

Unconventional reservoirs have very low permeability. Because of the short drainage radius of a given fracture, the reservoirs require more closely spaced wells to properly drain the reservoir and boost production rates and incremental hydrocarbon recoveries. Infill drilling, particularly focussed on down-spacing, has become the most widely used method to accomplish proper drainage and enhance the recovery of a field.

Aptly designated, down-spacing involves decreasing the space between wells laterally to optimise overall economics and increase the present value of the field. In some plays, like the Eagle Ford shale, operators in their multi-well pad drilling programmes have reduced the amount of acreage allocated to each well from 160 to 40–60. While this infill drilling methodology reduces costs and improves efficiencies, it also comes with daunting challenges. The biggest of these challenges is well interference, which occurs when a new infill well is drilled between two existing wells, intercepting hydrocarbons flowing toward those wells and reducing their productivity.

We have developed technologies to mitigate well interference and provide more optimal fracture networks on infill wells including diversion technologies designed to increase uniquely stimulated areas of the reservoir and optimise fracture growth in infill drilling applications.

It is also well documented that initial production rates and EUR can decline as a result of “gaps” in the fracture network along the lateral. Thousands of existing wellbores have vast untapped hydrocarbon reserves in existing perforation clusters that did not receive effective stimulation. These unproduced or bypassed portions of the reservoir may be exaggerated if they were under-stimulated when compared to the more recent stimulation techniques and perforating designs.

Most unconventional multistage horizontal wells become potential re-stimulation candidates at some point in their life, particularly those completed early in a play’s development. In some basins re-stimulating, using only the existing perforations, is yielding up to 50 to 60 per cent of the original production. The success or failure of re-stimulation can have a big impact. Treatments involve reusing the existing wellbore can potentially deliver a cost savings of US$2–4 million in some North American wells compared to drilling a new well.

We work in an industry that is alive with challenges and opportunities. Demand is growing, the resource is getting tougher, but technology continues to outpace both of those forces. Our industry has always stepped up again and again when it looked like the cost and availability of energy might be a drag on the economy. The types of innovative approaches to increasing the productivity and efficiency of unconventional resources are an example of this. When I look at innovations like these, I cannot help but be optimistic and excited about the future of our business.
How do you see the prospects for Angola’s pre-salt oil resources? When is production from the blocks awarded in 2011, and those expected to be awarded this year, likely to start?

From a Declaration of Commercial Discovery (DCD) until first oil, the turnaround to put an oil field into production is four to seven years – so, for instance, the Cameia oil field, in block 21, is supposed to begin production in 2017, while the 2011 awards blocks will start production more or less seven years after DCD.

How similar is Angola’s pre-salt to Brazil’s, and what lessons can Angola learn from the Brazilian experience so far?

The Angola and Brazil sedimentary acreage are twin Basins, and used to be joined together in the continent of Pangaea 250 million years ago. Along the Neocomian Geological Edge, 250 million years ago, there began the opening of the Atlantic South (Rift Phase), over a period of fifty million years, with the deposition of lacustrine shales in the Grabens (source rocks) and lacustrine carbonates in the top of the Horst, during the edge sin rift and saga phases (reservoir rocks) in both Basins. Taking into account that Petrobras drilled and discovered pre-salt oil first in Brazil, their experience is extremely important for Angola, as we have the same source rock and reservoir mode.

From a development and production perspective, there are valuable lessons from Brazil that we can apply to the Angolan case. For a start, they have been working in the pre-salt longer than we have. For instance, their approach in conducting extended well testing to better define the reservoir characteristics, behaviour and so forth, is something we can adapt to our own work.

Petrobras’s current investment programme (much of it dedicated to exploring Brazil’s pre-salt reserves) has placed the company under severe financial strain. What is the estimated cost of developing Angola’s pre-salt resources, and how will the country fund this development?

The estimated cost of developing Angola’s pre-salt reserves can be worked-out using the so-called ‘Value Pyramid’. According to the pyramid, the pre-salt blocks will generate a seismic cost of US$1 billion, with a further US$10 billion going to fund exploration wells, and US$100 billion on development, with an expected value of US$1 trillion of oil revenue recoverable.

Looking at the technical challenges, how much harder will it be to develop Angola’s pre-salt resources than the country’s current oil production, which is mostly in deep water?

In term of exploration, the new technology such as “Broad Band”, Bi-Directional Drilling and Wide Azimuth, generate high resolution imaging, reducing the risk of dry wells, as required by the Sonangol Concessionaire responsible for oil exploration in Angola.

The first discoveries of oil and gas in the pre-salt are being achieved in new areas where logistical infrastructure and support is practically non-existent along the coast. There will be a need to construct new docks or ports, heliports, drilling mud plants, cement and chemical product storage facilities, etc. Environmental constraints are also expected to impose a number of challenges.

What about the associated gas? Angola now has an LNG facility which uses its associated gas – will increased oil production require the expansion of this LNG plant?

It is a possibility, but may we also use gas for other applications such as power generation plants in other parts of the country, etc.

How will the exploration of the pre-salt affect the country’s local content and ‘Angolanisation’ policies?

The pre-salt exploration activity will require a surge in the development of local Angolan companies, in terms of local G&G Centres, local services companies and so on.

There will be expansion of local fabrication yards, more involvement of the local companies in the oil and gas business. There are plans for massive recruitment of talent, along with plans to support local universities with their programmes in the development of petrotech personnel. Many students are being sent abroad for scholarship programmes. In addition, we are preparing personnel by means of job assignments with international oil companies, both in and outside the country, in order to prepare and equip them with the competencies we will require to meet the challenges in developing the pre-salt.
FOR 38 YEARS, WE HAVE BEEN
THE ENERGY THAT MOVES
YOUR WORLD

There is an energy that moves us forward, that motivates us to reach further, and make every day better. An energy that is applied in social, environmental and economic development projects, thus assuring a greater well-being and a brighter future for all Angolans.
America has a long history of achieving the impossible. We landed on the moon. We invented the Internet. And now we can add horizontal drilling to the list of American innovations that have changed the world forever.

As chairman of the Domestic Energy Producers Alliance (DEPA) and as CEO of the company that co-developed the first field ever drilled exclusively with horizontal drilling, I was in the unique position to be one of the first to see American energy independence on the horizon three years ago. And as technology continues to advance and new supplies of premium crude oil are discovered, today I see first-hand what is necessary to continue this oil and gas renaissance not only in America, but across the world.

In October 2011, DEPA boldly predicted American energy independence by 2020. America’s independent oil and gas producers have unlocked the technology and resources that make this a reality. As a result, we can mark the 40th anniversary of the OPEC oil embargo by ending the era of oil scarcity in America and, along with it, ending the last of the shortsighted regulations passed during that period.

We are entering a new era of energy abundance in America and the world. Until recently, we have only been able to extract hydrocarbons from reservoir-quality rock, primarily through vertical wells. But through technological breakthroughs in precision horizontal drilling, we can develop resources previously thought to be unattainable. It is time for the world to hear the truth about the real source of our modern-day oil and natural gas renaissance – horizontal drilling.

This technology allows us to access 5,000 to 10,000 feet of resource rock compared to just a fraction of that with conventional vertical drilling. Prior to horizontal drilling, we could recover only a small portion of the oil in place in tight reservoirs of low permeability and porosity. With the advent of horizontal drilling, today we can recover much more. The industry foresees that number reaching 10 per cent or more with future technological advancements. We’re talking Saudi Arabian numbers here. America now counts its natural gas supply in centuries, and experts including the International Energy Agency agree the US will be energy independent in terms of crude oil within a decade or two.

Not only has horizontal drilling increased America’s supply of crude oil, but also it has improved the quality. Primarily the oil produced through horizontal drilling is light, tight, low-sulphur crude, making it the best quality in the world. It is environmentally friendly, it promotes jobs, it is fuelling a manufacturing and petrochemical industry comeback in America, and we need to make sure we do not disadvantage this high quality oil with refining capacity problems overseas.

In October 2013, America marked the 40th anniversary of the OPEC oil embargo. In the wake of the oil price shock and long gasoline lines that followed this event, a series of federal laws were passed to manage our country’s energy supply. This wave of legislative activity proved to be short-sighted and reactionary.

Unintended consequences

The federal laws passed in the 1970s artificially controlled the supply, demand, and price of US energy and brought about unintended consequences. For example, one law even banned the use of natural gas as a boiler fuel and mandated US power plants to switch to a less environmentally friendly alternative, coal. Today America is still struggling to rectify the aftermath of this rash regulation.

In the years since the enactment of these laws, our elected officials have recognised our global energy industry has changed dramatically. Thankfully, in response to these changes, legislators have repealed or let expire nearly all post-embargo regulations save two: the Energy Policy and Conservation Act of 1975 and the Export Administration Act of 1979, which together essentially ban US crude oil exports.

The “scarcity mentality” that led to the creation of these laws no longer reflects the economic reality of the global energy marketplace. Even US Energy Secretary Ernest Moniz acknowledged recently that oil exports deserve a second look in the face of our nation’s dramatic supply-demand rebalancing.

The popular belief is that the US is not exporting petroleum. Nothing could be further from the truth. Major refining companies are exporting refined petroleum products like gasoline and diesel with no limitations to the tune of 4 million barrels a day (mb/d) (see EIA graph below). Why shouldn’t independent producers be allowed to do the same? Are we to be their milk cows? This would be like telling American farmers they cannot export their wheat, yet allowing Pillsbury to export all the flour they want.
Over the years, some have argued granting US crude oil producers free access to world markets would drive up the cost of gasoline and other petroleum products for American consumers. The opposite is actually true. By imposing trade restrictions on a single segment of the energy industry, namely domestically produced crude, our government is arbitrarily subsidising some US refineries by giving them the ability to source American oil at prices well below the world market price, while at the same time giving them the “green light” to sell petroleum products into higher-priced international markets.

Energy independence is working – US gasoline and diesel prices are down 20 per cent. But America’s oil and gas renaissance is in jeopardy. These outdated crude export restrictions have prevented domestic oil exploration and production from achieving its full potential – slowing potential job growth, restricting supply, and negatively affecting global refined product balances, which sends the wrong message to our trading partners around the world. Many refineries overseas, designed to only process light, sweet crude similar to US grades, find it difficult to compete profitably with US refiners with access to domestic crude at artificially low prices, forcing many to close and thereby reducing supplies of refined products on the global market. This effectively raises prices for consumers in the US and all around the world. Many refineries in the Caribbean, Europe, India and South America are closing or operating at sub-optimal levels as they cannot compete with US refiners running on discounted domestic crude oil. And, when supplies of gasoline and diesel fuel are restricted in the global market, the global demand for US gasoline and diesel increases, thereby driving up the price US consumers must pay at the pump.

Indeed, crude oil is no different than any other commodity, product, or service demanded by consumers. Lower prices are only brought about by increased supply, greater competition amongst sellers, weaker demand, or improved efficiency in the manufacturing and distribution process. When governments attempt to legislate lower prices through regulations, no matter how well-meaning the laws may be when introduced, market distortions and unintended consequences inevitably result: supply and competition among producers is rendered short of potential, and the consumer ends up paying higher prices at the gasoline pump and in their monthly energy bills.

Let us export our US crude
American energy independence does not mean being isolationist. As we have seen before, closed societies do not work. Energy independence means energy security. It means a chance for America to step back into a global leadership role by creating a world of balanced interdependency as opposed to dysfunctional interdependency. And it means no one can choke off supply, turn on the tap, or otherwise distort the market.

The world has drastically changed since the OPEC oil embargo and reactionary enactment of US federal regulations in the 1970s. Even then the ban was symbolic, as we had no oil to export. Americans and consumers of all nations would benefit from the immediate lifting of restrictions that inhibit the export of crude oil produced in the US.

### Monthly petroleum product gross exports (mmbbl/d)

Source: US Energy Information Administration
Making the most of what’s left in the North Sea

By Sir Ian Wood
Former Chief Executive Officer and Chairman, Wood Group

Over the last five decades, I have seen Britain become a major international player in the oil and gas industry, something we have achieved because of the success of our own offshore industry.

To date we have produced 42 billion barrels of oil and gas from beneath the seas around the UK. The industry currently supports employment for over 400,000 people across the country and it exports more than £7 billion per year in goods and services to more than 100 countries across the world. Our international success is sustained by a vibrant offshore industry at home. The more active we are in the UK, the stronger the demand for our expertise abroad.

UK production is now declining, having peaked in 1999. Yet despite the UK continental shelf (UKCS) being considered one of the most mature offshore basins in the world, up to 24 billion barrels of oil and gas remain to be recovered from both existing fields and still-to-be discovered new plays and frontier areas.

Encouragingly, today there are many new developments underway in the UKCS, unlocked with the help of government fiscal allowances and contributing to the record £14 billion of capital spent last year in developing new oil and gas fields. The challenge now is to sustain this current wave of activity in the decades to come, but there is concern that fewer companies in recent years have been exploring for new oil and gas. Unless we see some significant commercial finds, capital expenditure is forecast to fall significantly over the next three or four years. We need to act now to avoid a downturn in activity and under-recovery of our oil and gas resources.

Yet the landscape of the UKCS has changed considerably over the past twenty years. It is much more complex, with the range of companies active in the North Sea growing in diversity. The number of fields in operation has increased to over 300; new discoveries are much smaller; many fields are marginal and very interdependent; and there is strong competition for ageing infrastructure. In short, the UKCS is now a patchwork of interconnected and interdependent operations. There is also growing competition from many international offshore regions. At the same time, the number of people involved in carrying out the regulatory function of the Department of Energy and Climate Change (DECC) has halved in size over the last 20 years and they now lack the broader capability and resources to perform the much more demanding stewardship role that is required.

Given such wide-ranging challenges faced by the industry, Edward Davey, the Secretary of State for Energy and Climate Change, deserves great credit for instigating a review of oil and gas production and regulation in the UK. I was pleased to be asked to lead this review on how we could maximise recovery from the UKCS in the years ahead. Over the last eight months, I have consulted widely and interviewed key players both in the UK and abroad. My final report, published at the end of February, calls for a fresh approach by both government and industry and proposes significant changes to the way the industry is regulated.

The current licensing model has worked well. Over the last 50 years £300 billion has been invested across the North Sea, earning the UK exchequer more than £300 billion to date in production taxes. To build on this success, the Review concludes the need for a new tripartite strategy for Maximising Economic Recovery involving HM Treasury, industry, and a new independent government regulator. This does not change the lead position of the operators who provide the significant investment of funds, people and skills. The primary task of the new regulator will be to provide more effective long term stewardship and encourage much more collaboration and alignment between the companies exploring and producing oil and gas from the UK Continental Shelf. The new regulator must be low in bureaucracy, high in facilitation skills and experience, and strong and pragmatic.

The UKCS is facing stiff and growing competition from many international offshore regions and we need to step up our game to recover more of our reserves and attract more investment. I am heartened by the strong support from both industry and government for my proposals. There is a huge prize at stake, and I believe the government must implement the key recommendations, including the creation of a new regulator, as quickly as possible. UK offshore oil and gas is a great industry which has made an immeasurable and vastly underestimated contribution to the UK economy.

The good news for UK investors is that the review provides the opportunity to revitalise the UKCS with a better resourced, more capable and more involved regulator that will help fully exploit our outstanding reserves and take us closer to the 24bn boe prize potentially still to come. This should provide better rewards for existing investors and good opportunities for new incoming investors.
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common feature of the global refining industry is simply that it is becoming more global. As Toril Bosoni of the International Energy Agency explains, the sector is evolving from a regionally and locally oriented industry, in which each plant is primarily intended to supply its surrounding market, to a more geographically integrated one with the emergence of large international refining hubs with a global reach. Nevertheless, the changing landscape of refining still to a large extent reflects regional shifts in oil demand. So, the mature European market has seen both its oil demand and refining capacity contract, while oil consumption and refining capacity continue to expand in Asia and the Middle East. Indeed, given the long lead time of refining expansion, some refiners have over-anticipated in the increase in oil demand in China, so that, as the IEA points out, they are having to scale back expansion plans in line with more moderate estimates of Chinese oil consumption growth. However, as Nishi Vasudeva of Hindustan Petroleum underlines, India is maintaining its refining expansion, which now makes it the largest exporter of petroleum products in Asia.

The big exception to the stagnation of refining and petrochemicals in mature OECD markets is the US. Charles Drevna of the American Fuel and Petrochemical Manufacturers says his member companies are now enjoying their best competitive advantage in exports for 30 years, thanks to North America’s shale gas revolution providing cheap feedstock and fuel input. Existing ethylene capacity is being expanded and new crackers planned. America’s gain is to some extent Europe’s loss, as Pedro Miras Salamanca of CORES, the Spanish oil stockholding agency points out. Europe’s structural imbalance in its relative supply and demand for gasoline and diesel is compounded by its inability to compete with new cost-efficient supply, not only from the US, but also from Russia and the Middle East.

Nonetheless, despite being a saturated market with over-capacity, Europe will still be the target of much of Middle East refining expansion, according to Bassam Fattouh of the Oxford Institute for Energy Studies. As global demand growth for diesel falls and net exports from Asia, much of the Gulf states’ diesel exports will head for Europe, where the diesel deficit is still growing because European refineries remain largely gasoline and naphtha-based. However, Gulf exporters have their own problems arising out of price subsidies that inflate domestic demand. Rising energy consumption at home may leave little of the expanded refining and petrochemical output for export.

For the moment, the oil industry has little to fear from the biofuels sector as a competitor. Indeed Luiz Augusto Horta Nogueira of the Federal University of Itajuba and Ernani Filgueiras de Carvalho of the Brazilian Petroleum, Gas and Biofuels Institute point out that the oil and biofuels industries should increasingly be seen as partners. Biofuels producers depend on oil companies as customers and logistics operators, and will increasingly provide a path to sustainable mobility.
The global refining industry adapts to new realities

By Toril Bosoni
Oil Industry and Markets Division, International Energy Agency

Rarely has the contrast between “winners” and “losers” in the refining world been more pronounced than in 2013 and 2014, when new global players disrupted the traditional order. Refiners in mature economies in Europe and the Pacific continue to confront challenging market environments, while those in the US are profiting from the region’s supply-side revolution. In less than a decade, the US has gone from being one of the world’s largest product importers to its largest product exporter. Investment plans are being drawn up to further take advantage of regional supply growth. By contrast, outside the OECD, the tides are turning against the refining industry. A marked slowdown in Chinese apparent demand growth has prompted a large-scale reassessment of refinery expansion plans in the very region where most of the growth had been coming from in the last 10 years, and which until recently had been expected to contribute most of it in the medium term. While the fortunes of Asian refiners are waning, a new era in Middle Eastern oil history commenced with the start-up of Saudi Arabia’s Jubail refinery last year.

For the last decade, the refining story largely mirrored underlying developments in the broader economy and global oil demand. As both economic growth and oil demand shifted towards emerging markets, so did investments in the downstream sector and in turn refinery capacity and crude oil throughputs. Mature OECD markets saw both their oil demand contract and their refining industry consolidate, while the non-OECD, and in particular Asia, experienced unprecedented growth. Due to the long lead time of refining expansion projects, emerging-market economies tried to anticipate future demand growth by aggressively investing in the downstream sector. Thus global refining capacity has been migrating even faster than end-user demand from one half of the global economy to the other. While non-OECD economies are only expected to overtake the OECD in oil demand some time this year, in the downstream sector the shift already occurred in 2011.

While the overall trend of declining oil demand in the OECD came to an abrupt halt in 2013, with demand inching up 75 thousand barrels a day (kb/d) year-on-year, OECD refiners continued to cut capacity and curb utilisation levels. A further 0.8 million barrels a day (mb/d) of capacity was closed last year, most of it in Europe and OECD Asia Oceania, bringing total refinery closures since the 2008 financial crisis to 4.5 mb/d. A further 0.8 mb/d has already been committed to shut for 2014. The capacity reductions have not been enough to lift margins, however, resulting in significant industry losses and low utilisation rates. While benchmark margins in key refining hubs in Europe and Singapore remain in the doldrums, US refiners have fared much better.

As widely publicised, the US refining industry has rebounded over the past five years, thanks largely to the surge in regional shale gas and light, tight oil supplies. Access to discounted oil and gas compared with international benchmarks provided a windfall to domestic refiners. Cheap natural gas, used as refinery fuel and the largest contributor to operating costs, has also provided an important boost to US refinery margins – especially relative to those of international competitors. Surging US light, tight oil supplies and heavy Canadian crudes have led to significant price discounts to international benchmarks, providing further value. US and Canadian crude oil has at times been discounted by more than US$25 a barrel for WTI and US$55 a barrel for WCS (Western Canadian Select) compared with Brent, as the crude has been stranded by both pipeline capacity constraints and export restrictions in the US. As a result, US refinery throughputs have increased, lifting crude runs by 0.3 mb/d year-on-year (y-o-y) in 2013 and by an even more impressive 0.7 mb/d y-o-y in the first quarter of 2014. As a consequence, US product exports surged to a record high of 3.5 mb/d in December 2013, with Mexico and Latin America as key destination markets, though increasing volumes of distillate are flowing to Europe.

As US refiners ride the wave of surging regional crude and liquids supplies, investment plans in the sector are being scaled up to accommodate rising light, tight oil production. More than 500 kb/d of new refinery capacity, most in the form of simple topping units or condensate splitters, have recently been proposed for the next few years. A relaxation of current condensate export restrictions currently being discussed could derail some of these plans quickly.

America’s gain has been Europe’s loss – at least up to a point. While the European refining industry
troubles have been brewing for some time, they intensified in 2013. Regional throughputs sank to 25-year lows in October last year. Despite a slight recovery since then, European crude runs plummeted by 650 kb/d year-on-year for 2013 as a whole, with annual contractions in the second half of the year amounting to more than 1 mb/d. Yet regional benchmark margins failed to improve.

Not surprisingly, chronically dismal and structurally weakening throughputs and margins have encouraged European refiners to shed capacity. Since the recession of 2008, 1.7 mb/d of refining capacity has been closed in Europe. In the same period, demand contracted by a steep 1.9 mb/d. The threat of more closures looms.

The adverse effects of the US refining boom are not limited to Europe. Even in China, until recently the main driver of refinery expansions and investments, both national champions and international players are rethinking and scaling back ambitious plans.

Surging Middle Eastern capacity is accelerating this retrenchment. The start-up in Saudi Arabia in 2013 of the state-of-art Jubail refinery, set to reach full capacity some time this year, opened a new chapter in global refining, in which the Kingdom joins, at least for now, the club of global oil product players. Middle Eastern products are starting to hit international markets, albeit in small volumes so far. Saudi Oil Minister Ali Al Naimi announced in January that another 400 kb/d plant, the Yanbu refinery which it is building with China’s Sinopec on the Red Sea, is on track to be completed by the third quarter of 2014. Meanwhile, the UAE’s new 420 kb/d Ruwais refinery could also be commissioned before year end, adding to the product glut out of the region.

In the medium term, several other large-scale projects are set to be completed. While these refineries are largely intended to meet rampant regional demand, they are also expected to export part of their output.

**Demand and supply continue to surprise**

Hence the scaling back of Chinese expansion plans. Only a year ago, a whopping 4.3 mb/d of incremental refinery capacity had been expected to come on stream in China over the five-year period to 2018, though the IEA cautioned even then that some of those projects may not be sufficiently supported by Chinese demand growth forecasts of 2.4 mb/d over the same period. Indeed, a year later, the project list has been drastically scaled back, with only a fraction of projects firm up or confirmed. National oil companies CNPC and Sinopec have both voiced concerns over a looming surplus capacity. CNPC has delayed two projects, while Sinopec’s Chairman and CEO said in March he was concerned about surplus capacity. And Sinopec’s latest business plan, released in early 2014, only includes one refinery in its major project list, the Guangdong integrated refining and petrochemical project, including a 300 kb/d refinery, due on stream in 2017. Shell last year pulled out of the 400 kb/d Taizhou refinery project, which it was developing with CNPC and Qatar Petroleum International, and BP has decided against investing in a Chinese refinery with CNPC. Also, Rosneft, which was planning to build a 400 kb/d plant with CNPC in Tianjin, said recently that a final investment decision will only be taken in 2017. Corruption scandals and increased public outrage over pollution have helped slow the expansions. Shandong province put a halt to the approval of all new projects in a move to tackle overcapacity and increasing air pollution.

Other Asian emerging economies have also been slowing somewhat recently. For the first time in over a decade, Indian refinery activity contracted for four consecutive months around the New Year. Ebbing demand, in particular for diesel on the back of subsidy reductions and a temporary lull in new capacity build, underpinned the slowdown. The imminent start-up of the much delayed Paradip refinery, around mid-year, will lift Indian capacity by another 300 kb/d however. Nagarjuna’s 120 kb/d Cuddalore plant will follow. While still some way off, Petronas’ board of directors finally approved the 300 kb/d Rapid refinery and petrochemical plant in Malaysia due in 2019.

Regardless of the specific timing of refinery expansion plans around the world, one fact remains: the sector is rapidly evolving from a regionally and locally oriented industry, in which each plant is primarily intended to supply its surrounding market, to a more globalised and geographically integrated one, characterised by the emergence of large international refining hubs with a global reach. Demand and supply side factors continue to surprise, and the global refining industry is constantly adapting to new realities.

**For a full update on the implication of these developments on investment, crude and product trade and balances, see the Medium-Term Oil Market Report 2014, http://www.iea.org/publications/medium-term-reports/**
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Greek philosopher Heraclitus believed in the doctrine that change is the only constant in life. Although he was known as the “weeping philosopher,” I believe he would be wearing a smile knowing that his theory has again been validated. In the United States we have seen a dramatic, tectonic if you will, change in energy production and consequently, the nation is on the cusp of an economic and manufacturing renaissance.

Unprecedented supply and production of US oil and natural gas has resulted in American refiners and petrochemical manufacturers combining low-cost raw materials and fuels with advantages in existing infrastructure and diverse manufacturing capabilities. As these factors continue to align, they put our nation on the right path to a bright and promising future. But, we need to ensure we stay the course to reap the great benefits that lie ahead for our country and our citizens, as well as much of the world.

The current state of affairs of the petrochemical and refining industry is quite different than it was in our recent past. Over the course of the past 20 years, petrochemical manufacturing capacity was stagnant. Then, at the turn of the new century, rapidly decreasing domestic supplies led to escalating cost increases of natural gas and oil. This left domestic producers at a severe competitive disadvantage with the only option to reduce or shut production in the US and move operations overseas to regions like the Middle East and Asia, where feedstocks were more affordable and available. Then, in late 2007, the US saw the beginning of the worst recession since the Great Depression and the entire manufacturing sector suffered even further.

An unexpected recuperation
Around that same time, the shale revolution and the boom in other unconventional oil and gas development signified the early stage of a re-birth of the US manufacturing sector. A combination of the resulting decline in the price of feedstocks and energy costs, along with advantages in infrastructure, diverse manufacturing capabilities and the ability to innovate quickly, put America in a competitive position in chemical manufacturing for the first time in decades. The result has been a dramatic reversal from the mid-2000s, when the US was one of the world’s most expensive locations for manufacturing chemicals, to today where it is among the most affordable.

Shale development has since been instrumental in generating a wealth of natural gas liquids, a vital feedstock that is the building block for the magnitude of products supplied by US manufacturers. Responsible development of these reserves has allowed the US petrochemical industry to enjoy its best competitive advantage in more than 30 years.

As a result, chemical companies which had abandoned the US, along with others around the world, have taken notice and have announced planned or possible investments in the US worth more than US$91 billion. According to IHS Global Insight, by 2025, nearly 515,000 manufacturing jobs will be supported by unconventional oil and gas development and, along with energy-related chemicals, will contribute nearly US$533 billion annually to the gross domestic product by that time.

Steps to success
A vibrant petrochemical manufacturing sector, however, is just the first step in a resurgence of the manufacturing sector. Petrochemicals provide a ripple effect on the manufacturing industry as a whole because they are a key component of the supply chain for many other industries. A strong overall manufacturing sector can foster a robust and stable economy with well-paying jobs that are vital to our way of life. Workers in manufacturing jobs receive nearly 20 per cent more in pay and benefits compared to workers in non-manufacturing sectors. According to the National Association of Manufacturers, every US$1.00 spent in the US manufacturing sector overall returns US$1.48 to the economy, the highest multiplier effect of any economic sector.

The members of the American Fuel & Petrochemical Manufacturers (AFPM) are committed to the realisation of a manufacturing renaissance. After a decade of almost zero capacity expansion in US petrochemicals manufacturing, shale development has prompted many of our members to invest billions of dollars in ethane cracker capacity to harness vast new supplies of natural gas liquids for petrochemical manufacturing and in new technologies to improve efficiency and reliability.

According to Platts, more than 20 projects to increase ethylene capacity have recently been announced, including expansions at existing manufacturing locations, as well as new crackers throughout the US. If these projects are implemented, by late 2017 US ethylene production capacity will grow by more than...
10 million tonnes per year, or by around 35 per cent of the current capacity. In addition, billions of dollars in planned development in projects and facilities including integrated projects from polymer and other derivative capacity additions to complement olefins expansions and facilities are in the works.

Setting the right expectations
What exactly does the future hold and how can we set the right expectations? It is important to acknowledge that the manufacturing renaissance will come in waves. We have already experienced enhanced recovery of natural resources and development of the necessary infrastructure to extract the resources. Now it is time to ensure that existing infrastructure is enhanced to transport and refine natural resources into useful manufacturing feedstocks.

As a nation, we must pledge to take the right steps today in order to encourage this development, not immobilise it. AFPM is actively doing its part to ensure the re-birth of manufacturing in the US continues and grows into the powerful global economic force it can be. In 2013, in coordination with several academic institutions, national manufacturing and labour groups as well as non-governmental organisations, we formed the American Shale & Manufacturing Partnership. The group has launched a series of national-level discussions on how best to revitalise the US manufacturing sector. The discussions, still ongoing, focus on the nation’s shale development and are designed to provide educational and discussion forums for decision makers, industry leaders, labour, top academics and other stakeholders. Forums focus on the manufacturing supply chain in detail, the potential impacts of responsible shale development, and the role of and need for innovation.

The end goal of this series is to produce a policy blueprint on how to realise the full manufacturing potential of the shale revolution. The final product is intended to be comprehensive in its scope, which will include federal and state policies; infrastructure; research and innovation; workforce education and jobs creation; and the environment.

Environmentally friendly growth
As this effort moves forward, we will continue to act responsibly to ensure the development of the future work in conjunction with environmental responsibilities – the two are not and should not be mutually exclusive. During the past three decades, industry has invested hundreds of billions of dollars to reduce emissions as reported by the US Environmental Protection Agency (EPA). As a result of these reductions, criteria pollutants have been significantly reduced during that time period. According to the EPA’s recent Toxic Release Inventory, emissions from petrochemical facilities have been cut by 98 per cent since the report was first compiled in 1988.

The US refining and petrochemical industries are just as committed to clean air and water and waste reduction as we are to ensuring that manufacturing again becomes a part of America’s success story. Powered by ingenuity and innovation, our industries will work diligently to take the right steps to ensure responsible development of our resources. These affordable, abundant, and efficient energy feedstocks will jump-start the revival of the US petrochemical and refining sectors. In a world that is constantly changing, this is change we can all stand behind, with a big smile.
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Gulf refiners expand capacity and opportunity

By Bassam Fattouh
Director, Oxford Institute for Energy Studies

Refining capacity in the six Gulf Cooperation Council (GCC) states is set to increase by at least 2 million barrels a day (b/d) by 2018, an expansion that will have important implications for global trade flows in petroleum products.

This will constitute an additional source of competition for Asian and European refineries that could weigh down on refining margins, especially in Europe. While this represents an export marketing challenge for refineries in the GCC states – Saudi Arabia, Kuwait, Qatar, UAE, Oman and Bahrain – it also opens up opportunities for regional national oil companies to build their trading capability in product markets and diversify their export base.

The GCC has a well-developed refining sector. In 2012, the GCC had 18 refineries and two gas-to-liquid (GTL) plants with total capacity of around 4.6 million b/d. Saudi Arabia is the biggest refining centre in the region with a total capacity of around 2.1 million b/d, followed, a long way behind, by Kuwait with a total refining capacity of 940,000 b/d. In 2012, GCC refineries produced 3.1 million b/d of the four key petroleum products: gasoline, diesel, kerosene, and fuel oil.

Overall, diesel accounted for the highest share of the GCC’s refinery output, followed by fuel oil, kerosene, and then gasoline. But these aggregate figures hide some very different dynamics between countries. In the case of the UAE, more than 47 per cent of the combined output of the three refineries is kerosene, which contributes to the UAE’s surplus of kerosene available for Dubai International Airport and for export markets. In Qatar, kerosene accounts for the largest share, followed by gasoline and diesel, while fuel oil constitutes a small proportion of the fuel mix. Similarly, in Oman, the share of fuel oil in the product mix is quite low. This reflects the fact that the power sectors in Oman and Qatar rely heavily on natural gas (entirely in Qatar’s case), while in Saudi Arabia and Kuwait liquid fuels constitute an important share of the fuel mix of the power sector.

In the 1970s and 1980s the GCC’s refineries were able to meet domestic demand and establish an important position in the trade of petroleum products. However, in the last three decades, refining capacity has failed to keep pace with the rapid growth in demand for petroleum products. According to the US Energy Information Administration, GCC demand for petroleum products increased more than five times, from 840,000 b/d in 1980 to 4.2 million b/d in 2012, making the region an increasingly important source for global oil demand growth.

Rapidly expanding population, robust economic growth, and improved living standards have contributed to increased car ownership and higher electricity consumption. But a key factor is low prices of petroleum products. In countries such as Saudi Arabia, heavy fuel oil and diesel are supplied to the power sector at a fraction of the prices prevailing in international markets. Such low, subsidised, prices distort pricing signals, and result in a misallocation of resources, wasteful consumption and smuggling of petroleum products into neighbouring countries. Government initiatives to reform these subsidies have moved at a very slow pace. Following the political shockwaves in the aftermath of the Arab Spring, many governments in the region have been reluctant to undertake a comprehensive reform of energy pricing.

While there has been a reduction in the demand for fuel oil, its share in the demand mix is still quite high. Despite the increasing penetration of natural gas into the power sector, liquid fuels are widely used for electricity generation in some GCC countries. For instance, Saudi Arabia relies heavily on crude oil, diesel, and fuel oil for its power generation – in 2012, the share of these liquid fuels accounted for 54 per cent of the power sector fuel mix. Similarly, in Kuwait 36 per cent of power demand is met through fuel oil and 24 per cent by crude and diesel burn, with the combined peak summer demand for liquid fuels around 270,000 b/d.

Surging domestic demand, which has outpaced the growth in refining capacity over the last decade, has eroded product export capacity by most GCC producers, while others have become increasingly dependent on imports of products, mainly gasoline. For instance, Saudi Arabia continues to export kerosene and fuel oil, but it has been importing increasing volumes of gasoline and diesel. Overall, Saudi net exports of the four main petroleum products almost halved between 2005 and 2012, from 320,000 b/d to 160,000 b/d.

In terms of gasoline, the GCC was a small net importer for most of the last decade, while in terms of diesel it is a net exporter, although the volume of diesel exports has declined rapidly in the last decade from around 340,000 b/d to 160,000 b/d. In contrast, exports of kerosene have
seen some growth in the last few years, while exports of fuel oil have been quite volatile, depending on its domestic use in the Saudi and Kuwaiti power sectors.

**Pressure from domestic demand**

Mainly due to pressure from domestic demand, the GCC governments have announced new refining projects, which if all implemented on time, would increase refining capacity of more than 3 million b/d by 2018. However, some of the announced projects will face delays or even cancellation. For instance, in Kuwait, the political context remains highly volatile and the country has seen several years of political wrangling between the government and the parliament over the downstream expansion plans. In Bahrain, uncertainties about financing could delay the expansion of the BAPCO Sitra refinery, and there is also the risk that pushing back the proposed completion date could undermine Bahrain’s downstream objectives, as other regional rivals expand their own refining capacity. In Oman, the Oman Oil Company (OOC) and Abu Dhabi’s IPIC (owned by the government of Abu Dhabi) are looking to build a new refinery, which is expected to be completed by 2017. However, there has not been a tender for the Front End Engineering Design (FEED) and the award of the EPC contract has been delayed. With all this in mind, it is reasonable to expect total refining capacity to increase by around 2 million b/d by 2018.

This will still be a considerable expansion. This will result in a healthy rise in refineries’ output in the next five years. In terms of gasoline, this would increase capacity from around 650,000 b/d in 2012 to just above 1 million b/d, but the most rapid increase will be in diesel capacity, expected to double from around 1.1 million b/d in 2012 to close to 2 million b/d. Kerosene and fuel oil output will also rise by 170,000 b/d and around 400,000 b/d, respectively. Overall, across these four products, the GCC is expected to increase its output by more than 1.8 million b/d.

A key question is how much of this growth will find its way to international markets, and that largely depends on domestic demand trends such as the rapid growth of gasoline consumption in Saudi Arabia and the role of fuel oil in Kuwaiti power. It is likely that the impact on gasoline markets of the new refinery expansions will be felt mainly through a reduction of imports (or maintenance at the current level), rather than through an increase in gasoline exports.

In terms of diesel, the picture is different. While the region is likely to witness an increase in diesel consumption during this period, the GCC is expected to increase its exports of diesel almost four-fold between 2012 and 2018. Most of the increase will come from Saudi Arabia and the UAE, with Abu Dhabi National Oil Company (ADNOC) becoming the first Gulf producer to export ultra-low sulphur diesel, mostly for Europe. The growth in net kerosene exports is likely to be more modest, mostly from Saudi Arabia and the UAE as well as Kuwait. Gulf countries will also increase net exports of fuel oil. The UAE will account for the bulk of this increase, establishing itself as a major regional bunker fuel hub competing with Singapore and Rotterdam and providing an export market for the GCC producers with a surplus of fuel oil.

A fairly large proportion of the increase will continue to head to Asia. But this is happening at a time when
the Asian refinery landscape is also undergoing some major transformations. Asian refining capacity has risen sharply in recent years and is mainly biased towards hydrocracking. This is most evident in China, where a massive increase in refining capacity has helped boost product exports – including diesel. Furthermore, as China rebalances its economy towards domestic consumption away from energy-intensive exports, domestic diesel demand growth has started to slow down, and last year China became a net exporter of diesel.

**New trade flows**

As demand growth for diesel falls and net exports from Asia increase, a significant portion of GCC diesel exports is likely to head to Europe, a region where the diesel deficit is still rising despite stagnant to falling demand, as refineries in Europe remain largely gasoline and naphtha biased. But all major export refining hubs with a diesel bias are earmarking Europe as their top destination, especially as Europe, Latin America, and parts of Africa are the only regions in the world that will be left with a growing appetite for diesel imports. India currently exports around half a million b/d of diesel mostly to Europe and Africa, but the GCC, with the advantage of lower shipping costs to Europe, is likely to give India stiff competition. Russia, too, is firmly committed to raising diesel exports to Europe in the coming years.

Furthermore, export capacity growth in the US refining industry, fuelled by cheap domestic feedstock thanks to the shale revolution, has seen US diesel exports surge to over 1 million b/d and a large proportion of these have started to reach Europe. So the new and expanded GCC refineries might be competing in a very crowded export market, and they may have to find new markets for their diesel in Latin America and Africa.

These changes in trade flows of oil products and stiffer competition represent a challenge for GCC refineries. But they also present an opportunity for the region to step up its game in the area of oil products trading by creating trading hubs, establishing committed trading arms (as Saudi Aramco has done with Aramco Trading), and enhancing its expertise in the marketing of petroleum products. This will be more challenging than trading crude oil, given the different specifications of the products and evolving regulations in international markets.

In the medium to long term, the refining sector in the GCC will continue to be shaped by local dynamics, particularly by the ability of some of the countries to expand and upgrade their refining capacity and, more importantly, by the evolution of domestic demand. In the absence of any serious energy pricing reform that could rationalise the growth in demand for refined products, the race between expanding refining capacity, satisfying rising demand, and maintaining exports will continue. It is the outcome of this race which will ultimately determine the region’s position in global products markets in the next decade.

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**Refining capacity in the GCC states is set to increase by at least 2 million barrels a day by 2018**

[Image of refining facilities]
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Fundamental changes in the oil sector are redefining the worldwide refining industry model with long-term implications for this industry. The revolution of unconventional resources such as US shale oil production, and the growing demand of the emerging countries, among others, are causing large changes in the way oil is being produced, processed, traded and consumed around the world. In this process, the role of the refining industry in the global supply chain is changing as refineries move closer to the wellhead and to growing non-OECD markets, and as international trade in refined products continues to grow. New refining hubs that are being established in emerging economies are creating new oil product exporting areas. In these circumstances, countries are reconsidering their refining industry models in order to keep up with, and take advantage of, the changes in global markets.

In Europe, the low demand of recent years and weak profit margins are making a major impact on the refining Industry. Proof of the industry’s increasing vulnerability is the shut-down of 15 European refineries since 2008, with an eight per cent decrease in capacity and a loss of more than 10,000 direct skilled jobs and at least 40,000 indirect jobs. Capacity utilisation is also reduced at those refineries which are still working. In addition, there have been ownership changes, with Russian, Chinese and Indian players as well as trading companies entering the market, as the oil majors have continued to refocus on the upstream.

The main, continuing, trend in light product demand in Europe is that of a decline for gasoline and an increase in that for diesel fuel. The key drivers of this structural shift are the change in private car ownership patterns that have been seen across Europe for the past 20 years, which are expected to continue, combined with growth in commercial diesel demand for road transport. Tax plays a part. Across most of Europe, lower taxation of diesel fuel compared to gasoline at the pump results in diesel being significantly cheaper for the motorist. As a result of the decline in gasoline demand and increase in diesel and jet fuel demand, Europe is structurally long on gasoline and structurally short on both jet/kerosene and gasoil and diesel. The European refining industry has become increasingly out of balance with domestic demand, with the result that the region is

Prospects and problems facing European oil refiners

By Pedro Miras Salamanca, Chairman, CORES, Chairman, IEA Emergency Group and Chairman, Spanish National Committee of WPC

Recent changes to European refining assets

Source: OECD/IEA 2013
increasingly reliant on trade flows to balance demand with supply. This imbalance can, however, also be an opportunity to explore growing markets, as Latin America and Africa have a huge appetite for petroleum products.

Moreover, the European refining environment remained extremely challenging, as margins headed for record lows in 2013. The decline was led by gasoline crack spreads, as producers struggle to market their surplus production. The industry responded by reducing utilisation rates, which failed to offer relief as imports were quick to fill the supply gap. Integration between refining, trading and marketing should be a source of marginal competitive advantage.

Europe’s fundamental problem lies in the inability of its refining industry to compete with new, cost-efficient supply from Russia, the Middle East and the US. High energy costs erode profit margins, being 60 per cent of refining costs in Europe versus 30 per cent in North America, mainly because of cheap shale gas in the latter. The high crude oil prices are also putting a lot of pressure on the refining industry. These energy concerns are of course shared by other energy intensive industries in Europe.

The main objectives of energy policy are to assure access to energy at an affordable price, and in an environmentally sustainable way. These objectives are not independent of each other and it is therefore not easy to attain any one of them without trade-offs affecting the others. In addition, there is the question of the impact on the economy and on industry. This factor is increasingly underlined by the fact that, in Europe, refineries are at particularly high risk of closure over the next few years as margins and utilisation rates are expected to come under more pressure and higher-cost refineries will face greater competitive challenges.

European regulation over the last 20 years has been focused on environmental issues, starting with the Auto-Oil programmes that reduced emissions both from vehicles and fuels and continuing with the “20-20-20” energy and climate policy targets, established in 2008. These have resulted in various legislation affecting the refining industry, including the Industrial Emissions and Fuel Quality Directives as well as a tightening of the Emissions Trading System.

All this regulation has imposed additional costs on the refining industry, requiring investments in order to achieve compulsory emission reductions both in the industrial process and in the oil products themselves. These investments have modernised the sector, which is now ready to process a wider range of crude oils, on the assumption that regulation will not create artificial entry barriers to any crude oil. For example, the Spanish refining industry has invested more than €6 billion between 2008 and 2012, in order to adapt its facilities to the new scenario.

The European Commission appears to be aware of these challenges within the sector. The Energy roadmap 2050, drawn up by the Commission in 2011, establishes that “keeping a European presence in domestic refining is important to the EU economy”. The Commission’s Directorate-General of Enterprise and Industry is carrying out “a fitness check” on the refining sector in order to make a quantitative assessment of the impact of relevant legislation and policies on costs and expected revenues of the sector, as well as a qualitative assessment of effectiveness, efficiency, coherence and relevance of measures. The results of this are due in September 2014.

The refining sector in particular and the energy sector in general need to improve their communication skills with regulators and with society as a whole, to underline its efforts of adaptation and its benefits to European economy.

Beyond the impact of changes and regulation on the refining industry itself is the impact on security of supply. Due to the global energy changes, Europe is at risk of becoming disconnected from the main crude oil and oil products market flows, affecting security of supply. The imbalance between production and demand of oil products has also increased product import dependence. In order to improve security of supply, oil products stockholding is required under a 2009 EU directive. This imposes an obligation on Member States to maintain minimum specific stocks of petroleum products, and to ensure that at least one-third of their stockholding obligation is held in the form of products.

The future of the European refining industry is linked to competitive and regulatory pressures. According to some analysts, the simple truth is that Europe needs more refinery closures to rebalance the market. However, measures aimed at maintaining Europe’s refining industry should be promoted, given its key role in Europe’s energy supply and security.
India has rapidly established itself as a major player in the global refining industry in the last decade. The country has been a net exporter of petroleum products since 2001-2, and since 2009 has been Asia’s largest exporter of petroleum products.

The speedy expansion in capacity, from 62 million metric tonnes per year (mmtpa) in 1998 to 215 mmtpa in 2013, has been the result of deregulation of the sector in 1998 and investment-friendly government policies. Of the country’s 22 refineries, 19 are in the public sector (including joint ventures) with a combined capacity of 135 mmtpa, and three in the private sector with a total capacity of 80 mmtpa. Refining capacity now exceeds domestic demand.

The capacity increase reflects the government’s strategic commitment to providing safe and convenient energy at competitive prices, and with as few shocks and disruptions as can be reasonably expected. Addition to refining capacity enhances energy security, and provides flexibility with the option to process crude or import product. This flexibility is important for an energy importing country like India, because crude markets are generally larger and more stable than product markets, which are significantly smaller, lack depth and therefore are more volatile.

With proven reserves of just 758 million tonnes of oil and 1,355 billion cubic metres of natural gas, India is inescapably dependent on imports. So it has consciously built refining capacities and capabilities over the years by focussing on processing imported crude oil and leveraging its strategic geographical advantage rather than depending on import of petroleum products to meet domestic demand. This has resulted in several direct, indirect and induced benefits, both economic and social, for the country and society at large.

Over the next few years India’s GDP is expected to grow at 5.5-6 per cent a year, making it one of the largest economies in the world. The current per capita primary energy consumption for India, at 466 kilograms of oil equivalent (kgoe), is low compared to both the Asia-Pacific average of 1,329 kgoe and the global average of 1,853 kgoe.

The energy required from oil and gas is going to almost double by 2030 to around 410 million tonnes of oil equivalent. Growth in energy demand will be driven primarily by the transport sector, which is presently the largest consumer of oil in India, representing 50 per cent of total demand, followed by agriculture (18 per cent) and industry (11 per cent). Fossil fuels are expected to account for 85 per cent of Indian energy consumption in 2030, compared to 92 per cent at present.

From an insignificant exporter of petroleum products just a decade earlier, India now surpasses Singapore as the largest exporter of petroleum products in Asia.

**Figure 1: Refining capacity over the years in India (tb/d)**
as Asia’s largest refined product exporter. Most of India’s product exports remain in the Asian region, where demand is growing, but shipping data show significant increases in exports to OECD Europe, which has a deficit in diesel and where refinery capacity is shrinking. Shipments also went to Latin America and the Middle East, regions that have seen up to now limited refinery expansion. Diesel and gasoline led Indian product exports, accounting for 39 per cent and 25 per cent of the total, respectively. In value terms, India’s imports of crude oil, petroleum products and natural gas increased from INR 2,030 billion in 2005-6 to INR 8,812 billion in 2012-13. This increasingly high import cost was partially offset by the increase in exports of petroleum products which increased from around INR 500 billion to about INR 3,200 billion in 2012-13.

India’s energy requirements will rise as the economy grows. Barring major oil and gas discoveries, India’s import dependence is likely to increase in future, suggesting continued exposure to international price trends. Meeting the increased demand is challenging. There are structural imbalances in product demand, such as growth in auto fuels versus decline in fuel oil and low-sulphur heavy stock oil, and the fact that many of the existing refining assets in India are not configured to produce more of light end products.

However, apart from being located strategically, India has other advantages. Production and labour costs are significantly lower than in the developed world, while skilled labour and high-quality capital are relatively abundant. Captive domestic demand and its projected growth will be a natural hedge against volatility of external demand. The government encourages private and foreign direct investment, and has also announced special economic zones, such as the Petroleum, Chemicals and Petrochemical Investment Regions (PCPIRs) in four locations across the country for setting up world scale refinery-cum-petrochemical complexes and associated downstream industries.

The industry’s key challenges will be around upgrading technologies and revamping existing refineries to produce products as required by stringent new environmental regulations and to bring safety, environmental and operating parameters into line with global standards. In addition, acquiring land near demand centres for setting up new refineries will be difficult in view of the recent changes in land acquisition procedures.

For exports, India is likely to face export pressure from refineries starting up in the Middle East which will be well-head refineries and will have lower shipping costs to European markets.
India has a net deficit in most petrochemical products with the exception of benzene and currently polypropylene, which is forecast to move into deficit, based on projected demand growth and domestic capacity additions. With increasing LNG imports and availability of natural gas, Indian national oil companies (NOCs) are increasingly looking to invest in newer technologies to leverage available surplus products and add value to them.

Companies which focus on the regional demand and export opportunities for integration will create more value, given the high logistics costs for inland transportation and vast coastline that India has. Integration with petrochemicals and employment of technology to enhance oil recovery present Indian NOCs with the opportunity to expand refinery capacity to capture more value from local oil. For instance, Rajasthan’s Mangala crude, which is waxy, viscous crude with a high pour point and paraffinic content, is better suited for processing into petrochemicals. Given the volatility in oil and gas prices, the industry is likely to achieve integration across the value chain, and to diversify into petrochemicals through revamps and setting up new capacity expansion projects.

For India to continue to be a net exporter of products and evolve into a pre-eminent refining hub, a constant and secure supply of imported crude is essential. Indian NOCs are entering into partnerships with local and global organisations to develop oilfields in Africa and South America. The government is setting up strategic reserves of crude oil, through Indian Strategic Petroleum Reserves Ltd (ISPRL), in order to minimise the impact of disruptions in the import of crude oil. There will be cavern storage for crude oil with total capacity of 5 million tonnes at three locations – in Vizag on the east coast and at Padur and Mangalore on the west coast.

In parallel, augmenting port infrastructure both for receiving crude and exporting petroleum products will be essential for India, if it is to be competitive and an alternative to the Singapore market, which has emerged as the marker crude location for determining oil prices in Asia.

To keep pace with the increasing demand for liquid fuels in India and to ensure energy at affordable prices, India’s refining capacity is expected to grow to 314 mmtpa by 2017. Roughly three-quarters of this growth will be led by India’s NOCs. The key determinant of success will be the ability of India’s downstream NOCs to achieve optimisation through integration within existing refineries, and to expand capacity by establishing world-scale refineries, with input flexibility, integration with petrochemicals and capability to produce high value products.

![Figure 3: Petroleum products exports by Asian countries (mmtpa)](source: Energy Statistics OECD/IEA 2013)
2014 International Bidding Rounds in Peru

Blocks III & IV for Exploitation in NW Talara Basin

Block 1-AB for Exploitation in North Marañon Basin

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06 OFFSHORE Exploration Blocks

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an attractive country to invest in oil and gas activities
All modern fuels have the same origin: the sun, a gigantic nuclear fusion reactor that provides our planet with an amount of energy equivalent to around 28 million barrels of oil a second. Coal, oil and natural gas preserve the solar energy accumulated by living creatures hundreds of millions of years ago, concentrated and stored deep underground. We can nowadays recover it, wherever we are. More recent photosynthetic processes have led to the development of biofuels which only a few months before had been mere carbon gas in the atmosphere, water and sunlight falling on the leaves of vegetables.

Conventional fuels and automotive biofuels such as ethanol and biodiesel are similar in other ways: they share basically the same logistics chains and are used in engines that are essentially the same, especially when mixed with other fuels, as is frequently the case. Indeed, nowadays in many countries it is practically impossible for motorists to tell whether they are using pure conventional fuel, derived from oil, or one mixed with biofuel, currently sold in gasoline stations in more than 60 countries.

Bioenergy was the first form of energy consumed by humankind in the bonfires that illuminated pre-historic caves, and it remained our main energy resource for many centuries. It was only with the advent of the industrial revolution that wood began to give way first of all to coal and later to oil and natural gas, resources that currently account for 80 per cent of the global energy consumption, while biomass energy contributes approximately 10 per cent of this consumption, mainly as firewood in developing countries.

When the automobile industry appeared, some of the first fuels used by its pioneers included peanut oil, adopted by Rudolph Diesel in his engine, and corn ethanol enthusiastically championed by Henry Ford. With the increase in oil production and improvements in refining technology in sync with the evolution of engines, gasoline, diesel fuel and subsequently also aviation kerosene almost completely prevailed in the important markets of passenger and freight transport fuels. Brazil was one of the few places where biofuels remained in regular use. As the country did not produce oil locally, since 1931 mixing ethanol with all the gasoline consumed was mandatory. It was initially at a level of 5 per cent (E5), rising to 25 per cent (E25) with the oil shocks of the 1970s, and subsequently consolidated with pure ethanol (E100) in flex-fuel vehicles that nowadays comprise most of the Brazilian vehicle fleet.

In recent decades production and use of biofuels have been stimulated in various countries. Depending on the available resource base and with the aim of fulfilling objectives linked to the environment (through the reduction of local greenhouse gas emissions), energy supply security and the development of agro-industry, countries have fostered biofuel programmes usually to produce ethanol/gasoline and biodiesel/diesel mixtures. It is estimated that liquid biofuels currently account for 2.4 per cent of the world consumption of energy in the transportation sector, which is equivalent to around one million barrels of oil a day – 90 per cent as ethanol and 10 per cent as biodiesel. A growing number of countries – currently around 60 – are establishing mandatory norms and mixture targets, most notably in the US, the European Union, China and of course Brazil.

Prospects and potential

Various studies show that the biofuels market will grow significantly in the coming years. BP estimates that biofuels may account for 5 per cent of transportation energy consumption in 2030. In the same year the International Energy Agency expects that, if renewable energy is stimulated, 7 per cent of the auto fuel market will be supplied by biofuels. Indeed, the production of biofuels is growing faster than the production of conventional oil.

All conditions are in place for this expansion. Even with this significant increase in production, the share of biofuels in agricultural production will continue to be relatively small. The net requirement of arable land for the production of biofuels will increase from 14 million hectares in 2004 (1 per cent of the world is cultivated land) to 53 million hectares in 2030 (3.8 per cent of land used for agriculture), according to the IEA, depending largely on the mix of raw materials that will be used, and also on the technologies adopted. For example, with only a small improvement in cattle-raising methods, large areas of low-quality pasture could be made available for crops without affecting food production. This is the case in Brazil where, during the past 35 years, areas devoted to pasture have fallen by 8 per cent while the cattle herd has increased by
155 per cent, substantially expanding beef production.

Indeed, recent studies have shown that, in many cases, the production of biofuels increases food security. In addition, they contribute to environmental preservation by absorbing carbon dioxide during the plant-growing process; they contribute as well to the economy by mitigating the impact of oil product imports on the trade balance and to social progress by increasing the number of years of schooling, reducing illiteracy and the number of child workers employed, as well as by keeping more people in the countryside.

In addition to liquid automotive fuels, other bioenergy sources, such as bioelectricity and biogas have grown and become increasingly competitive. Currently, more than 9GW of thermal plant output is totally based on sugarcane waste in Brazil and around 6,000 biogas digestors are producing and injecting biogas into natural gas pipelines in Germany. The new technologies are maturing fast and their prospects are good. A case in point is the enzymatic hydrolysis of lignocellulose (a second generation biofuel), with its first commercial plants beginning to operate in Europe, the US and Brazil. Another promising area is aviation biofuels, which is being strongly supported by the aerospace industry and airlines. There are already regular weekly intercontinental flights on aircraft that run on a mixture of conventional aviation fuel and biofuels.

Biofuels can be used to advantage as a high-quality component to specific products in the oil industry, and in many cases they are highly competitive. For example, ethanol is an octane booster and biodiesel can be used as a lubricity additive in ultra-low sulphur diesel.

This context represents an important “win-win” opportunity for the oil industry. Indeed, some on-going joint projects show how cooperation between oil and biofuels can be viable and constructive. In Brazil, in 2008, Petrobras created a subsidiary focusing on the production of ethanol and biodiesel with the aim of becoming one of the main players in this market. The company sees biofuels as a business opportunity in the export area, taking advantage of its presence, visibility and track record in handling ethanol and as an eventual offset to any future loss in market share in conventional fuels. BP has also been operating ethanol plants since 2008. In 2011 Shell and Cosan joined forces to create Raízen, currently Brazil’s leading ethanol producer. In Finland, Neste Oil became world leader in the supply of biodiesel.

More than competitors, the oil and biofuels industries should increasingly be seen as partners. Biofuels producers depend on oil companies as off-takers and logistics operators. It would be difficult to promote biofuels without them. Biofuels and oil can both share and develop the same transportation markets, improving the quality of products and enhancing the energy sector’s overall sustainability.

Fantastic volumes of liquid fuels are consumed daily. The share of oil products in the global energy mix has fallen by six percentage points during the last 35 years. Thus, the opportunity for biofuels has become real and clear. It is difficult to establish a single path towards sustainable mobility during the next decade. All options are necessary. Oil has found it difficult to meet total demand, while well-managed biofuel reserves are eternal.

These and other aspects were debated at the International Biofuels Seminar, an event promoted by IBP – the Brazilian Petroleum, Gas and Biofuels Institute and WPC – the World Petroleum Council, which took place on March 17-18 this year in São Paulo, Brazil, and was attended by 140 professionals in the sector. The seminar’s main conclusions will be presented at a special session of the 21st World Petroleum Congress in Moscow.
Natural Gas Supply and Demand

There is still regional divergence in the world’s main gas markets – abundance to the point of self-sufficiency in the US, declining production and weak demand in Europe because of recession and competition from renewables in power generation, and avid thirst in Asia, especially Japan, for LNG. The result is a wide spread in US, European and Asian prices. Howard Rogers of the Oxford Institute for Energy Studies raises the question of whether changes in gas trade flows might lead to a more connected, if not convergent, global gas price system. But the answer is clouded over the next decade by uncertainties as to the trend of demand in China – potentially the most significant LNG importer in the world – and as to the degree to which the US will become a major exporter of LNG. Price convergence would only come about if very substantial quantities of hub-priced US gas were to flow to Asia, undermining the system there of gas contracts based on long-term, oil-indexed contracts.

LNG industry commentators are clear this is not going to happen any time soon. Mohammed bin Saleh Al-Saba, Qatar’s energy minister, concedes that US shale gas is a challenge to the global LNG industry, but expresses confidence that LNG will still be dominated by long-term contracts, giving buyers, sellers, financiers and governments certainty. Steve Hill of BG predicts that only a quarter of currently proposed US export capacity will materialise by 2025, because of local opposition in the US, the desire of buyers outside the US to maintain diversity of supply and the emergence of other suppliers in Canada, East Africa and elsewhere. Moreover, the industry’s track record is one of delivering projects that are considerably fewer, and consistently later, than anticipated. Regional pricing is likely to stay differentiated for some time, and gas is therefore some way from becoming a globally traded commodity like oil. Peter Coleman of Woodside stresses Australia’s proximity to the core Asian market for LNG, points out that his country’s seven LNG projects under construction account for two-thirds of new global investment in LNG, and cautions Asian buyers about the market price risks of taking Henry Hub-based LNG from the US. As for Europe, production of indigenous shale gas is unlikely to dull its appetite for imported LNG because, as Dafydd ab Iago of Argus Media points out, it is generally making a slow start to shale exploitation. But the European Commission has given a green light to fracking in the European Union’s 28 member states, provided they take due environmental precautions. On the demand side for gas, David Demers of Westport highlights the new uses for gas in road transport. In North America, fleets of heavy trucks and vehicles are turning to gas engines, fuelled by LNG units, in order to capitalise on cheap gas, relative to the price of diesel.
With many informed studies predicting natural gas to be the fastest-growing fossil fuel, in terms of global energy market share over the next few decades, it is nevertheless strange that perceptions of gas and its ‘value’ still vary so much across geography and supply chains. The relatively low energy density of natural gas, the relatively high cost of transporting and storing it – by pipelines or as a liquid (LNG) at minus 160 °C – has allowed many gas markets to remain separated by geography, with disparate price levels and formation structures. However, change is afoot. The huge disparities between regional gas prices at the present time has awakened the powerful force of ‘enlightened economic self-interest’. Where this coincides with receptive government and regulatory policy we have the potential for the creation of new channels for gas trade-flows (through investment in infrastructure) by market players seeking to exploit regional price differentials. This paper examines how this dynamic, mapped onto today’s regional gas price disparities might serve, through arbitrage, to bring about a more connected, if not convergent, global gas price system.

Regional gas prices 2007 to 2013

The chart opposite shows the key regional gas prices, and for reference the Brent price expressed in US$/million British thermal units (mmbtu), for the period 2007 to 2013. While prices were reasonably bunched in the 2008 commodities ‘bull run’ era, the post-2010 period has seen a marked divergence, such that by end 2013 Asian spot LNG prices were almost five times the US Henry Hub price.

With the build-up of shale gas production in the US running ahead of demand growth, the post-2010 period has seen Henry Hub prices below $5/mmbtu. Although the trend since 2012 implies a slow recovery to levels where marginal dry shale gas drilling remunerates investment (in the range of $5 to $7/mmbtu) further price recovery will likely be slowed by coal-gas fuel switching in the US power sector.

New LNG supply capacity from Qatar and elsewhere came on stream in 2010 and 2011. While prices were reasonably bunched in the 2008 commodities ‘bull run’ era, the post-2010 period has seen a marked divergence, such that by end 2013 Asian spot LNG prices were almost five times the US Henry Hub price.

The current state of play

The current situation can be best described by looking at the motivations of key groups of players and some of the key overarching uncertainties which may temper their business strategies.

The first group are the participants in the long list of proposed US LNG export projects to reconfigure import terminals through investment in liquefaction plant into export facilities. Some 70 billion cubic metres per annum (bcm/a) of export approvals have been granted to date with offtake agreements or Heads of Agreements for a total of 110 bcm/a. Sabine Pass is the only project currently with all necessary approvals in place and start-up is expected end 2015. Depending on the time taken for further project approvals the main ‘wave’ of US export capacity should come onstream around 2019. Even at a Henry Hub price of $6/mmbtu these projects could
deliver LNG to Asia at around $12/mmbtu (attractive at today’s oil-related LNG contract prices) and to Europe at current hub prices of around $10.50/mmbtu.

In addition to US supply, there is very significant potential for new LNG supplies from Canada (West coast), East Africa, Russia and Australia. These are either greenfield projects or expansions in locations which will likely suffer high construction costs. To date such projects would have relied on traditional oil-indexed contract prices at crude prices above US$100 a barrel to ensure project viability.

The third group of players, the Asian LNG buyers and in particular Japan, would welcome a reprieve from current contract and Asian spot LNG prices. At present (excluding TEPCO) the largest nine Japanese power generation companies are collectively losing US$10 billion per year with nuclear plant closed and high LNG prices. Although there is a lack of consensus on what a more suitable price formation mechanism might be, prospective LNG volumes from the US priced at Henry Hub plus liquefaction and transport costs have much more appeal than new supplies at JCC contract prices from elsewhere.

The final player in this dynamic is Russia. While it has made concessions to lower prices in Europe from a ‘pure’ oil indexed price for pipeline gas, its position of market power (supplying 25 per cent of European’s gas) is unlikely to materially change. With up to 100 bcma of production capacity headroom, it will probably become the ‘shock absorber’ in an increasingly connected international system. A change to hub-indexation for its contracts to Europe would still leave it in a position to influence European pricing through physical flow management. While high hub prices would be desirable the consequences would be a further reduction in demand and the encouragement of more LNG export projects in the US.

These players will be subject to two major ‘known unknowns’ over the course of the next decade, namely the future growth trend for Chinese LNG imports and the price-production response of US domestic producers. Chinese LNG import requirements are a function of future natural gas demand (highly uncertain) and the supply contribution from domestic production (including shale gas and coal bed methane), the scale of future pipeline imports from Turkmenistan and Central Asia and whether the much awaited agreement

*Transporting LNG is the only way for linking the world’s major gas markets*
for pipeline gas from East Siberia will be signed. Thus the most significant fast-growing LNG market in the world is extremely difficult to forecast.

With the overwhelming majority of commentators betting on robust US shale gas production for decades to come, this is perhaps a strange uncertainty to highlight. Much of the current production surge is from wet gas shale plays including a ‘backlog’ effect in the Marcellus play where many wells have been drilled and still await pipeline infrastructure. As LNG exports from the US commence, will wet shale plays be sufficient to supply the additional volumes, or will the industry move back into dry shale gas areas – and at what price trigger? This US production price response will impact the spread between US and destination market prices and so impact the physical quantity of US LNG exports.

Prospects for Price Convergence

In a balanced market the emergence of material flows of US LNG and the actions of arbitrage could result in a world where Henry Hub is around $6/mmbtu, European hubs around $10 or $11/mmbtu and Asian spot LNG price around $12 or $13/mmbtu. Whether Asia moves away from pricing gas on Japan’s TCC oil import prices by creating, in time, a liquid hub on which to base its future LNG contract reference price is a moot point. The commercial advantages conferred on US energy-intensive industries in such a world is obvious. The main driver of such regional price differentials is the cost of liquefaction plant, and to a lesser degree, shipping costs. Whether technological or competitive changes can reduce these fundamental costs of the LNG value chain is as yet unclear.

There is still room for great uncertainty. If Chinese LNG demand grows less quickly than expected we have the prospect of increased LNG volumes looking for a home in Europe, causing Russia to ponder whether to protect price or market share. A price war is a possibility which could reduce hub prices in Europe, the US and Asia in an attempt to reduce shale drilling in the US. Another possibility is that potential LNG projects other than those in the US delay investment into the 2020s in order to avoid competition with US LNG volumes. This would tend to amplify the LNG ‘commodity cycle’ on the supply side but also perhaps bring some much needed cost control and competition into this sector.

Regional Gas Prices 2007 to 2013 (US$ millions)

Source: Platts, EIA, Argus, Own Analysis
This year we’re celebrating our company’s 60th anniversary, 30 years of domestic gas production and 25 years of LNG exports. From humble beginnings we’ve overcome significant challenges since listing on the Australian Securities Exchange on 26 July, 1954.

Today, Woodside is proud to be Australia’s largest independent oil and gas company. It’s a tribute to the hard work and dedication of many, especially our employees.

Through innovation, a commitment to excellence and fostering strong partnerships, we’ve continued to deliver world-class projects such as the recent successful start-up of the North Rankin Complex.

Our company’s future is built on strong foundations.

woodside.com.au
Towards a gas-fired era

By Dr Mohammed bin Saleh Al-Sada
Minister of Energy and Industry of the State of Qatar

After a decade of rapid economic development, a global redesign of the world economy is at work, redefining the geography of energy demand. Today, the world energy system faces two major challenges: how to secure the supply of reliable and affordable energy; and how to rapidly transform to a low–carbon, efficient, and environmentally harmless energy supply.

Asia and the Middle East as a whole has become a major consumer of energy, thanks to the increasing development of regional manufacturing industries. More oil will be required to satisfy the aspirations to mobility of an expanding middle class. Similarly, more natural gas will be needed to meet power generation growth and industrial activity.

This global redesign has consequences over the direction of energy supply flows, and the investments that are made throughout the hydrocarbon industry’s value chain.

Recently published outlooks share a common view regarding worldwide energy consumption: they show an estimated increase of over 50 per cent in demand between now and 2035. Nearly 90 per cent of this global energy demand growth is expected to come from non-OECD countries, led by emerging economies like China and India, which are expected to witness strong economic growth and substantial oil and gas demand in the long run.

A new paradigm is settling in, where emerging countries are in the driving seat of energy demand. This statement is valid for oil and gas, as well as for coal, nuclear energy, and renewable resources. As the energy demand is fuelled by industrial projects and durable goods purchases, the outlook appears remarkably robust.

Role of natural gas in the energy mix

The United Nations COP 18 climate conference in Doha has successfully clarified the procedural steps towards a new global climate protocol, and strengthened the operational mechanisms around coordinating policies, technology transfer, and finance. As a result, natural gas usage—because of its environmental qualities—emerged more than ever as the fuel of choice to achieve CO2 emission reductions.

Among other advantages, gas is abundant, widely distributed, and has a reasonable price. As a result, gas usage is driven by economic reasons, while at the same time reaping the benefits of reduced pollution.

For these economic and environmental reasons, I believe that natural gas should continue to be promoted in static usage like power generation and industrial heating, while extending mobile usage to road and maritime transportation. To meet this end, cooperation should be the keyword in consumer-producer relations, both at the governmental and private sector levels.

A key component to using natural gas as a transportation fuel will be the establishment of the right fiscal incentives to...
enable the infrastructure investment, an unbiased fuel competition, and collective global value creation in the energy sector.

**LNG flows vs price structures**

As more and more gas is required, more and more supply will need to be developed. A new gas map is slowly emerging, with new players leveraging technological innovation to explore new gas resources. Innovation has played a pivotal role in the US shale gas revolution and will continue to make available new unconventional gas resources throughout the world.

The emergence of shale gas has changed global LNG flows and will continue to create new challenges in the long term.

Such developments have always fuelled the debate over the future of gas prices. In short, we believe that the LNG industry is, and will continue to be, dominated by long-term contracts, which give all LNG industry players, including buyers, sellers, financiers and governments, the confidence to make the large investment decisions required along the LNG and gas value chain.

**The need for sustainability**

There is a growing global need for energy that is required for economic development. While most such development is aimed at reducing poverty and global inequalities, greater emphasis should be placed on policies that do not harm the environment, and manage to preserve it for future generations. This places a heavy burden on the shoulders of scientists and engineers, as well as on governments to help create innovative and sustainable solutions to the energy problems.

It is clear that a substantial amount of work and coordination still needs to be undertaken before any joint international effort to address climate change and its environmental consequences is effective. Further efforts have to be deployed to improve energy usage efficiency and reduce the level of emissions. This includes the development of technologies that will allow the world to mitigate greenhouse gas emissions and adapt to the impacts of climate change.

Qatar is committed to taking a proactive approach in this matter, and is embarking on implementing a number of projects, such as the Al-Shaheen Gas Flare Recovery, for example. This project represents a tangible reduction of gas flaring by re-injecting gas back into the field. Qatar is also committed to financing ambitious research programmes both domestically and internationally, to build and promote solar energy projects, to produce energy efficient devices like LEDs, and to innovate with green buildings.

Above and beyond its individual commitment and effort, Qatar is working with its friends and partners to address the environmental impacts of global energy use, as well as to ensure sustainability. The energy community at large is expected, more than ever, to make available adequate financial and human resources, as well as regulatory frameworks, to support energy innovation.

**Qatar’s place in the gas value chain**

A key component of Qatar’s success has been its ability to develop a clear vision for the future. With the guidance of His Highness Sheikh Tamim bin Hamad Al-Thani, the Emir of the State of Qatar, the National Vision 2030 has been the guiding force behind Qatar’s energy policy aspirations. Besides defining the broad future trends and reflecting the aspirations, objectives and culture of the Qatari people, this roadmap has enabled us to share a common set of objectives, like energy and food security, economic growth and diversification, and social development and environmental management that can be achieved through the use of fossil fuel energies as well as development of renewable energy sources.

As a result, Qatar is enjoying unprecedented prosperity that is rapidly transforming the country into one of the Middle East’s favourite and most attractive business and investments spots. This fast but perennial economic development will ensure the wealth of Qatar’s future generations.

However, as the business environment changes, we will need to meet the challenge of redeveloping mature assets using modern technologies which could provide a huge leverage to Qatar’s investment in the oil and gas industry. We will also need to leverage value along the international gas value chain through global investments and redevelopments.

In all cases, Qatar will continue to be the partner of choice in the years ahead for both consuming and producing countries, and play a definitive positive role in energising a growing world in a gas-fired era.
LNG to grow twice as fast as overall demand for gas

By Steve Hill
President, Global Energy Marketing and Shipping, BG Group

Fifty years ago, in October 1964, the world’s first commercial cargo of LNG was imported into the UK from Algeria by the UK’s Gas Council, a forerunner to BG Group.

Fast forward 50 years to the present day, and it is clear that our industry has grown significantly following this first global LNG trade, clocking up around 75,000 cargoes and expanding to 27 importing countries and 17 exporting countries worldwide. That is quite a track record, and we are an industry that is showing no signs of slowing down.

**Future demand**
Looking forward, BG Group projects that LNG will grow at around 5 per cent per annum to 2025, twice as fast as overall gas demand growth. Asia will be the key driver of this global LNG demand growth, underpinned by strong regional gas demand growth.

Residential use of gas in Asia is being driven by increasing urbanisation and higher living standards. Urban centres are growing by almost four million people each month. In China, this trend accounts for some 20 bcm of gas demand growth each year.

Industrial demand in Asia is the result of strong economic growth in its emerging markets and the increased availability of gas to replace higher cost liquid fuels. Across Asia, coal is still the dominant fuel for generating electricity. However, as increasingly prosperous urban populations demand cleaner air, we are seeing a shift to gas in the wealthier regions.

There are also increases in demand in other new and exciting areas, such as transportation. Latest estimates suggest that there are now over 60,000 heavy trucks in China alone, running on LNG.

**Potential new suppliers**
By 2025, most industry commentators expect that the global LNG trade will reach over 400 million tonnes per annum (mtpa).

Meeting this LNG demand will be a significant challenge, although new potential large-scale suppliers are emerging.

All eyes are understandably on the US, where there is currently close to 270 mtpa of export capacity proposed in the form of 31 projects. That is far more than has ever been proposed in a single country before.

Given that the total global LNG trade in 2013 was only 240 mtpa, clearly not all of the proposed US projects will get built.

The total volume of US exports will be shaped initially by the US licensing process and timing of federal regulatory approvals. Then later, by a number of factors including: additional Department of Energy reviews, local opposition, developer capability, access to financing, and the desire of buyers to maintain a diversity of supply sources. Of these factors, we believe local opposition, developer capability, and buyer supply diversification will ultimately drive how much US export capacity gets built.
Bearing all of this in mind, we believe that only a quarter – around 60 to 70 mtpa – of currently proposed export capacity will be in place in the US by 2025. In addition to the US, over the past two years western Canada and East Africa have also emerged as potential large-scale suppliers. A combination of the constraints on US exports and of the buyers’ desire to diversify supply sources will bring on new projects in these locations. The current wave of capital investment in both Canada and East Africa by buyers is evidence of this.

What is less certain about these projects are the proposed delivery times. In our industry, projects are often sanctioned later than anticipated and then come onstream later than planned.

LNG supply projects are by nature complex, large-scale and capital intensive. Data from PFC Energy shows that nearly half the new LNG capacity currently proposed worldwide has lead partners with no previous LNG development experience. That lack of expertise in LNG project delivery represents significant execution risk, particularly when environmental challenges are considered.

Our industry needs to add around 150 mtpa of new capacity, above that already under construction, by 2025 in order to reach the trade levels forecast by most industry commentators. Even with the large slate of proposed projects in the US and elsewhere, we believe that supply, rather than demand, remains the key challenge for the industry. We also believe there is significant upside to current forecasts of demand; particularly those for Asia. As a result, we do not foresee proposed new supply projects creating an oversupply in this timeframe.

Pricing evolution
In addition to future supply and where it’s going to come from, LNG pricing is another subject being scrutinised at present.

Although the market is clearly evolving, there is a myth that Henry Hub priced US LNG exports will provide a significantly discounted LNG supply source to Asia. This is not the case. Full cycle costs of US LNG exports delivered to Asia markets will have at least a US$6 to US$7/mmbtu premium to Henry Hub prices. This is based on the cost to liquefy and ship the LNG to Asia, and this is before a seller margin is added.

LNG prices will continue to be driven by the same fundamentals that have driven the LNG market in the past. Price levels will be set by supply and demand for new long-term volumes – as has always been the case. In a world where Asia continues to generate the bulk of new demand and pull volumes in competition with other markets, it will remain the price setting region.

Domestic supply availability, market regulations and structures will still determine whether gas hub pricing is possible. In practice, it is unlikely to happen in Asia for some time.

As a result, we expect that regional markets will remain differentiated in terms of pricing mechanisms and oil indexed contracts will remain a key part of the pricing mix in Asia for the foreseeable future. Despite the current focus on Henry Hub indexed pricing, oil indexation is far from dead.

Another factor underpinning our view on pricing is the still largely inflexible nature of the LNG market. Although the level of flexible volumes in the industry has increased markedly, from 4 per cent in 2000 to 17 per cent today, the addition of flexible exports from the US only acts to keep these volumes steady as a proportion of total trade. So, not only will the world not be awash with ‘cheap’ US LNG, it will not be awash with flexible LNG.

Changing dynamics
Looking at the LNG industry today, the dynamics are clearly changing. We are clearly an evolving industry, with new suppliers, markets and players emerging. We have also seen increasing flexibility and an evolution in LNG pricing.

However, despite the changes over the past few years, we are still some way from gas becoming a globally traded commodity such as oil. That, however, does not mean that the industry should not be proud of its achievements thus far.

Since the first 12,000 tonne cargo of liquid methane arrived at the Canvey Island Terminal in the UK from Arzew in North Africa 50 years ago, our industry has come a long way. There are now over 380 LNG ships in operation around the world and in 2013 around 240 million tonnes of LNG was delivered, representing around 10 per cent of all gas consumed worldwide. Looking forward to the next 50 years, I am certain that LNG will continue to play an increasingly important role in the world’s energy mix.
It is an exciting time to be a part of the Australian Liquefied Natural Gas industry, which is on track to become the world’s biggest supplier of LNG in the next decade.

We did not get to this position by chance. Crucial to our success has been hard work, innovation, strong partnerships with Asian joint venturers and customers, and support from community and governments.

As the CEO of Australia’s largest independent oil and gas operator, Woodside, which celebrates its 60th anniversary in 2014, I am proud to share some insights on the rise of Australian LNG.

In the early 1970s, vast quantities of natural gas and condensate were discovered beneath the seabed on Australia’s remote north-west continental shelf. It was a discovery that marked the birth of Australia’s largest oil and gas resource development – the Woodside-operated North West Shelf (NWS) Project.

In 1984, the NWS Project began producing domestic gas and in 1989, the first cargo of Australian LNG arrived in Tokyo Bay, Japan. Since then, the NWS Project has invested more than A$27 billion in its facilities, which include offshore production platforms and subsea infrastructure, onshore processing and storage facilities at the Karratha Gas Plant, loading facilities, jetties, associated infrastructure and LNG ships.

Today, the NWS Project is one of Australia’s three operating LNG projects and includes five production units (or trains) and produces up to 16.3 million tonnes per annum (mtpa) of LNG. Woodside also operates Pluto LNG, which has one 4.3mtpa production train, and achieved the milestone shipment of its 100th cargo in early 2014. In Australia, another seven LNG projects – representing a total investment of more than A$200 billion – are under development. Still more are on the drawing board.

Today, we have the fastest growing LNG sector in the world, with the seven projects currently under construction representing two-thirds of new global investment in LNG production and equal to around 20 per cent of global LNG supplies.

LNG expansion in Australia continues to be underwritten by a robust demand profile within our region, both from legacy North Asian importers and Asia’s major emerging economies.

Early investment by Asian foundation customers and joint venturers has been crucial in the development of Woodside’s premium Australian projects, allowing us to reliably deliver more than 3,800 cargoes to Asian customers. We are fortunate that there is a robust growth outlook for LNG – based on a combination of global demand for natural gas and the increasing role of LNG in the global gas supply mix.

It is expected that by 2030 global demand for LNG will be more than double the current 2013 level of approximately 240mtpa, corresponding to an average annual growth rate of 4-5 per cent.

The Asia-Pacific remains the core market for global LNG demand (about 70 per cent of global demand). Demand from traditional buyers (Japan, Republic of Korea) is complemented by significant growth across India, China and South East Asia.

In addition to LNG demand growth in power generation, commercial and residential gas use, LNG demand for transport use is also growing rapidly. There is increasing investment in infrastructure for LNG as a fuel for ships and heavy-duty trucks, particularly in China, Europe and North America.

A changing dynamic

No other country appears better placed to meet Asia’s long-term LNG demand than Australia. However, Australian LNG is operating in an increasingly competitive environment. The list of potential LNG projects includes new developments in existing supply regions, such as Russia, as well as emerging supply regions, including North America and East Africa.

Alongside these new supply options, we are seeing a boom in re-gasification terminal construction throughout Asia; a growing number of short-term and spot market sales; and the likely advent of regional gas trading hubs.

These factors are driving a regional market in which LNG will, over time, become an increasingly fungible commodity – buyers and sellers will both have greater flexibility to seek the best deal. We are already seeing this evolution taking place in the Asian market and the Australian LNG industry needs to be prepared.

Woodside is doing just that by bolstering its marketing, trading and shipping capabilities. In 2013, Woodside established a trading office in Singapore and we commenced trading with the Woodside Goode – our first LNG ship not dedicated to a specific project.

Our company is also focused on technology and
innovation in order to maintain our competitive edge in this new operating environment. We have established a technology division which is developing new in-house capabilities and ensuring we are leveraging off the very best service and technology providers. We are doing work on initiatives like construction-led design, subsea compression, deepwater production systems and ‘float-in’ facilities.

For us, floating LNG is an economic game-changer and an attractive model because it takes care of a big chunk of costs associated with logistics, movement of workforces and civil works programmes. A key milestone for 2013 was the agreement by the participants in the Browse Joint Venture to adopt FLNG technology as the basis of design in order to go ahead with early commercialisation of the world-class resources of Western Australia’s Browse gas fields.

Without this technology, the Browse resources could not be commercialised. FLNG ensures that we can be competitive and remain a partner of choice for our Asian customers. Australian LNG companies like Woodside will need to remain very focused in the years to come – on remaining competitive, productive and a partner of choice – in this new era of global gas.

**Proximity to premium markets**

As the major Australian supplier, Woodside’s key marketing strengths are its reputation for reliability, long-term relationships with key buyers, proximity to premium Asian markets and the stable political and fiscal regime in which it operates.

In the future, even as new supply sources enter the Asia-Pacific region, Woodside believes that buyers will continue to maintain diversified supply portfolios, and have Australian LNG as a key component.

For some Asian buyers, the higher calorific value of LNG from Australia’s conventional offshore projects is attractive. Woodside’s growth projects will be able to meet our customers’ requirements for high heating quality gas at a time when most emerging supply areas will be offering lower calorific supplies.

For all of our Asian customers, the proximity of Australia’s gas resources is a big plus. The longer the supply lines, the higher the cost and the greater the exposure to risk. This proximity remains an enduring advantage.

The increased distance from market is a key reason why we believe that US LNG exports delivered to Asia will be competitive, but not low-cost. Buyers who take on Henry Hub-linked LNG will also take on US market risks, where pricing has been both volatile and seasonal.

The rise of Australian LNG would not have been possible without the support of state and federal governments, which have provided a strong, stable regulatory environment for our projects to go ahead.

For the Australian LNG industry, becoming a global leader will not just be about getting projects across the line and becoming the biggest exporter. Our industry has a world-class safety and environmental record and a commitment to the communities in which we operate. Woodside is particularly focussed on the qualities we commonly associate with leadership: reliability; vision and long-term planning; values and integrity; and commitment to excellence in everything we do. We are active in promoting these qualities across the industry, ensuring that Australia can truly call itself a global leader in LNG in the years to come.

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Woodside marks its 60th anniversary in 2014, including 25 years of LNG exports to the Asia Pacific region
Launched in 2001, FFI's Flagship Species Fund has provided almost £1 million to protect 56 'charismatic' species – species that have important ecological roles and whose protection helps conserve other plants and animals living in the same habitats. These include mountain gorillas, spider monkeys, marine turtles, Cao Vit gibbons, Siamese crocodile, Irrawaddy dolphins, snow leopards, cheetahs, Sumatran tigers...

EMERGENCY RESPONSE

FFI was the only international conservation organisation to help co-ordinate the immediate emergency response to the Indian Ocean Tsunami in Aceh, Sumatra in December 2004. FFI has been working in Aceh since 1998, and was able to help where other organisations could not. FFI has developed a post disaster programme, helping to secure a multi-donor grant of US$17.6 million for forest protection.

HALTING AMAZON DEFORESTATION

FFI is working to halt the 'arc of deforestation' in the Brazilian Amazon, one of the top global biodiversity hotspots. FFI made an emergency land purchase within the borders of the Cristalino State Park, saving it from clear cutting. The Park is strategically placed to stop deforestation from reaching the heart of the Amazon, and is part of the Teles Pires 'Corridor', a potential conservation area of 44.5 million acres. This corridor contains entire watersheds that determine rainfall for communities to the south.

BIODIVERSITY & HUMAN NEEDS

FFI wants to ensure that conservation and rural livelihoods are compatible. In the vast Niassa Reserve in Mozambique we helped develop policies that gave the 20,000 reserve residents a say in how the Reserve is managed and used, to protect their rights and traditional practices. In Liberia we helped to draft national legislation that incorporated community interests into forest land use planning.

THE ARCADIA FUND

The Arcadia Fund was established in 1998 to secure important areas through land purchase and local land stewardship. Since then we have committed US$9 million and have leveraged over US$47 million to protect land, contributing to the conservation of over 11.5 million hectares, an area larger than the state of Arizona or twice the size of Denmark.

BUSINESS AND BIODIVERSITY

Fauna & Flora International works with the private sector to try to ensure that business activities are not undertaken at the expense of biodiversity. We believe that constructive engagement is key to influencing the environmental policies and practices of business and achieving sustainable development. A key part of our approach involves working with the private sector to enable it to understand and manage its impacts on biodiversity.

We need your support to protect the world's threatened species and ecosystems worldwide.

www.fauna-flora.org
TFI works in over 40 countries, and is involved in more than 180 projects. Here are a few of them...

THE FLAGSHIP SPECIES FUND
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From his first days in Brussels, European energy commissioner Günther Oettinger has stressed the right of the European Union’s member states to choose which energy resources to exploit and the general structure of their energy supply. This principle, enshrined in the EU treaty, has also made the European Commission hesitant about proposing binding legislation throughout the EU on shale gas and other unconventional hydrocarbons. This is all the more the case given the very different strategies that individual member states have so far adopted towards shale gas. National approaches range from government support in Poland and the UK to mediatised moratoria and even bans on hydraulic fracking in France and Bulgaria.

Politically, the Commission may have chosen the wisest option. It did not propose a binding EU regulation that would govern the extraction of unconventional hydrocarbons in the same way throughout all 28 EU member states. The Commission also avoided a more flexible but still binding directive that would have to be implemented by member states. The option chosen was that of a non-mandatory recommendation. This is Brussels’ relatively lightweight approach: member states are under no legal obligation to follow the recommendation.

The Commission’s non-binding recommendation was not ‘market-moving’, partly because its accompanying estimates of European shale gas reserves, and of the price impact of their exploitation, were relatively low. The Commission is following estimates of approximately 16 trillion cubic metres (tcm) of technically recoverable shale gas resources in the EU, which is substantially smaller than comparable estimates for the US. Officials in Brussels also expect the direct price effect on European regional gas markets to remain “moderate” with relatively low volumes and higher production costs than in the US. Prices in Europe are still largely set through long term oil-indexed contracts.

But even if not market-moving, this tentative step towards a policy framework covering 28 EU countries on unconventional hydrocarbons may be significant in the long term. Significantly, EU member states are being asked to implement the recommendation’s principles within six months. The Commission will then review implementation. Officials talk of possible legislation after 18 months, depending on how well the recommendations have been implemented.

The recommendation also signals a shift towards a systemic overview of the legal tools available to the Commission when regulating unconventional oil and gas. One of the main relevant pieces of legislation.
relates to the EU’s 2006 regulation on the registration, evaluation and authorisation of chemicals (Reach). The 2011 environmental impact assessment (EIA) directive also requires a full impact assessment for projects extracting over 500,000 cubic metres of gas per day as well as a screening for deep drilling projects. Water framework and groundwater directives are also applicable.

“The shale gas revolution is probably going to leave our continent as the only one dependent on energy imports.”
— Herman Van Rompuy, President of the European Council

The Commission certainly sees the need to ensure a level playing field arising from a fragmented and complex operating framework. Differing national interpretations of existing EU legislation may also be legally challenged. The Commission is also seeking to fill perceived gaps in EU environmental legislation that pre-dates the use of high volume hydraulic fracturing in Europe. Particular issues are strategic environmental assessment and planning, underground risk assessment, well integrity, baseline and operational monitoring, capture of methane emissions and disclosure of fracturing fluid composition on a well-by-well basis.

Aside from clearing up ambiguities in existing EU legislation, another rationale for the EU’s involvement is the cross-border nature of several shale plays, whether between the UK and Ireland, Bulgaria and Romania as well as Poland and the Baltic States. The Commission also notes that public health and environmental effects risks or concerns may also be of a cross-border nature.

Reactions to the Commission’s recommendation have been predictable on both sides. Carl Schlyter, a Green Member of the European Parliament (MEP), claims “serious” proposals on shale gas and fracking would have to include binding measures. He stressed the need for compulsory environmental impact assessments for exploration, and bans in environmentally-sensitive areas. On the other side, Polish MEP Jerzy Buzek urges Europe not to set unrealistic climate targets but to follow the US example. Mr Buzek, a former Polish prime minister, calls for a focus on indigenous sources of energy like shale gas.

The International Association of Oil and Gas Producers (OGP) welcomed the recommendation as a step in the right direction. But OGP expressed concerns about what the European Commission will do after reviewing implementation of the recommendation in 18 months. OGP maintains that there is adequate legislation at both EU and national level.

EU energy ministers, too, have been predictable in their responses. The French environment and energy minister was “comforted” by recent confirmation of a ban on shale gas exploration by France’s highest court. But during recent debates between EU ministers, Belgium was the most vociferous in its opposition. The proposed Commission recommendation provides “insufficient” guarantees for the necessary harmonisation of EU law in this area, according to Belgium which calls for the Commission to come up with legislation.

On the other side of the argument are Poland and the UK. Polish environment minister Maciej Grabowski said that the Commission, by and large, had chosen a good approach by not proposing any legislation. Grabowski sees the current legal framework as safe enough for the shale gas industry. At national level, Poland is to propose enhanced powers for environmental inspection as far as shale gas is concerned. For his part, Ed Davey, the UK energy and climate change secretary, pointed to US shale gas, rather than EU renewable and climate policy costs, as the competitiveness issue for European industry. Shale gas would allow Europe to change the terms of trade with US industry and keep Europe’s energy-intensive sectors in the global game.

What Brussels recommends

The Commission recommendation on the exploration and production of hydrocarbons using high-volume hydraulic fracturing calls on member states to ensure that: strategic environmental assessments also evaluate possible cumulative effects before granting licences; site specific assessments identify risks of underground exposure such as induced fractures, existing faults or abandoned wells; wells are properly insulated to avoid groundwater contamination; water, air and soil quality are checked before operations to monitor changes; venting and flaring is minimised with gas captured for use. Member states must inform the public about chemicals used in individual wells and ensure operators apply best practices throughout the project.
The International Energy Agency (IEA) expects that natural gas use in road and marine transportation will increase – a trend driven by abundant supplies and global concerns about oil dependency, climate change and air pollution. North America is witnessing this shifting dynamic in road transportation, with a growing number of trucking fleets now using natural gas to fuel light, medium and heavy-duty trucks.

This revolution stems from the growing abundance of relatively cheap natural gas, thanks to the exploitation of North American shale formations. The pace of the revolution is driven by the likelihood of a sustained and stable price differential with diesel, which at the time of writing was at an average price of US $3.92 compared to US $2.09 for compressed natural gas (CNG) and US $2.76 for liquefied natural gas (LNG), for the equivalent amount of energy.

Westport, a Canadian company based in Vancouver, is at the heart of this change. Last year, Westport and our joint venture with US-based Cummins – Cummins Westport (CWI) – shipped over 3,500 units specifically to go into medium and heavy-duty Class 8 trucks in Canada and the US. This represents a market penetration of around 1.7 per cent of the overall Class 8 truck market in North America. We predict our share of this Class 8 truck market share will rise to approximately 3-5 per cent in 2014, almost triple the number of natural gas trucks on the road in 2013.

The engine that has caught the attention of many transportation fleets is the Cummins Westport ISX12 G. We only began production of this 400HP engine in August 2013, but fleet operators such as UPS, FedEx and Seaboard have already adopted this revolutionary product, which is the only dedicated natural gas option currently available for Class 8 trucks. Westport and both of its joint ventures, China-based Weichai Westport and CWI, are experiencing growing demand for natural gas engines and fuel systems, and to date we have sold more than 120,000 natural gas engines.

In urban markets, our joint venture with Cummins, CWI, increased shipments by 52 per cent from 2012 to 2013. Over the same period volumes in the international market also increased by 38 per cent, as a result of large deliveries for fleets in China, South America and Russia.

Westport’s first generation high pressure direct injection technology (Westport™ HPDI) created a viable market for natural gas engines, and demonstrated that when fueled with liquified natural gas (LNG), heavy duty engines can offer equivalent performance to their diesel counterparts. Westport is now working with seven original equipment manufacturers with engine sizes ranging from trucks to trains at various stages of development on Westport™ HPDI 2.0, the next generation evolution of high pressure direct injection.

As the potential for natural gas is now evident in both on-road and off-road market segments, HPDI 2.0 will allow original equipment manufacturers to introduce high performance, fully integrated products that match state-of-the-art diesel performance. It signals a new stage of commercialising natural gas engine production. For it enables reduced costs, higher volumes and better efficiency by leveraging economies of scale. A recently announced injector production agreement with Delphi Automotive, a leading global supplier of car and truck technologies, solidifies a key partnership to enable large scale production of medium and heavy duty engines.

Today, a diverse range of companies across Canada and the US are using either first generation Westport HPDI or spark-ignited engines from CWI, to carry a variety goods in vastly different climates and geographies. This can range from hauling hay and grass across the southern states of the US in temperatures up to 46°C, running a transit...
To meet the fuel demand produced by the growing number of new on-road natural gas vehicles, fuel providers are investing along a number of high traffic trucking routes. Shell has invested in LNG transport corridors in North America through small-scale liquefaction units. Other companies like Blu and Clean Energy are investing in stations, with 91 LNG on-road fuelling stations, and another 67 stations are planned. Westport has co-marketing agreements with Clean Energy, ENN and Shell.

LNG stations are being built in strategically positioned locations, particularly along major trucking corridors and the interstate highway system to enable the movement of freight across the US, as well as in major metropolitan areas. Permanent or mobile LNG stations, like the Westport JumpStart, are also being offered near natural resource extraction sites, such as natural gas fields, to supply fuel to local heavy-duty trucking fleets operations.

As LNG infrastructure develops, Westport believes heavy haul fleets will transition to cold LNG, thanks to its storage and range advantages compared to both warm LNG and CNG. The Westport iCE PACK™ LNG tank system, released in 2013, is designed to enable the growing number of fleets driving with the Cummins Westport ISX12 G to fill up with cold LNG and take advantage of its unique benefits. Cold LNG is stored at low pressure, 50 psi, and as a result it offers increased driving range, since it contains significantly more energy than warm or super-warm LNG. In addition, cold LNG is capable of being stored for five or six days longer than saturated LNG.

Westport technology is also available in the North American and European automotive markets. In the US and Canada, Westport is Ford Motor Company’s largest qualified vehicle modifier. The Westport WiNG™ Power System is available on a range of Ford vehicles, from the dedicated CNG 3.7L V6 engine Ford F-150 to the bi-fuel 6.2L V8 engine Ford F-350.

Westport’s bi-fuel system enables a truck to run on CNG first, then once empty, it switches to gasoline, alleviating anxiety about lack of range and infrastructure. On average, CNG costs about US$1.80 less than gasoline on a per gasoline gallon equivalent basis in North America and as a result an increasing number of fleets are purchasing natural gas vehicles to achieve significant operating cost savings. For instance, Dana Storey, fleet manager for the American Automobile Association in Oklahoma, calculates that the automotive club in her state is saving close to US$400,000 annually on fuel, thanks to its fleet of 30 Westport-powered Fords.

Internationally, through our companies OMVL and EMER, Westport is the source for key components in the global light duty vehicle market, products sold and supported in more than 40 countries. All products are designed to meet Euro IV emissions standards.

In Russia, host of the 21st World Petroleum Congress, Westport and the GAZ group, leader in the Russian commercial vehicle market, are working together to design and develop spark ignited natural gas systems for GAZ’s CNG buses, trucks, and commercial vehicles. Westport’s new WP580 EMS will be applied to GAZ’s YaMZ-530 4.4L and 6.6L diesel engines and will incorporate Westport proprietary components and technology. The first product is on track for commercial manufacture this year.

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**Driving range and LNG hold time**

<table>
<thead>
<tr>
<th>Range (miles)</th>
<th>Hold time (days)</th>
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<tbody>
<tr>
<td>Cold LNG (50 psi)</td>
<td>10</td>
</tr>
<tr>
<td>Warm LNG (150 psi)</td>
<td>9</td>
</tr>
<tr>
<td>Super Warm LNG (225 psi)</td>
<td>8</td>
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Sustainability

The pressure has never been greater on the petroleum industry to be sustainable, in terms of reducing its environmental footprint, cooperating with host countries and local partners, increasing local jobs, improving local skills and alleviating energy poverty. Christophe de Margerie of Total explains that all industry players need to cooperate more closely, not just to control oil and gas project costs but also to make a collective public effort to reduce greenhouse gas emissions and even to promote the energy transition. Increasingly, host countries are asking oil companies to develop alternative energies in order to preserve their oil and gas reserves and to widen local access to energy. Yet Rachel Kyte of the World Bank says the oil and gas industry has so far failed to show collective leadership on climate change, to address issues of over-investment and over-valuation of hydrocarbon assets in a carbon-constrained world, and to accept carbon pricing. She shows, graphically, how far some countries, especially Russia, have to go in reducing the flaring of gas. However, even worse for the climate is the escape into the atmosphere of un-combusted methane, which has a medium-term greenhouse gas impact now estimated to be 82 times greater than a comparable volume of CO₂, according to Laszlo Varro of the International Energy Agency. He calls for far greater care in the sealing of gas wells and infrastructure, if methane leakage is not to undermine the relatively favourable climate case for gas and make gas be seen as part of the problem, not the solution.

Partnering between international and local companies is an essential feature of today’s industry. But the partnership dynamics can be tricky, especially if the foreign partner lets itself become overly-dependent on the local partner for manoeuvring through political and bureaucratic obstacles in countries such as Russia with weak institutional frameworks. In their survey of joint ventures in Russia, James Henderson of the Oxford Institute for Energy Studies and Alastair Ferguson, formerly with TNK-BP, find that successful partnerships involve the foreign partner making a serious effort to acquire its own local political know-how. Local content regulations have become a widespread issue as developing countries seek to maximise the local benefits of foreign investment in their oil and gas resources. Sola Oyinlola of Schlumberger shows that tensions over local content rules between international companies and local regulators can be avoided by the former taking a pro-active approach, particularly to training engineers, sometimes initially outside the country in question. Failing to meet a local headcount target immediately may not represent lack of progress, if local recruits are training elsewhere to work more safely and professionally when they return. József Tóth, formerly with Hungary’s MOL, comments on the local content issue in Kazakhstan which a Hungarian company is helping resolve. Umirzak Shukeyev of Samruk-Kazyna sets out how the national holding company is help to diversify the Kazakhstani economy. In tackling energy poverty, Suleiman Al-Herbish explains how his OPEC Fund for International Development (OFID) is partnering with several international oil companies, and is also involved in the Global LPG Partnership to provide a cleaner cooking fuel in developing countries. In recognition of the nexus between energy, food and water, OFID is putting more money into projects that address this inter-relationship.
Preparing and promoting the energy transition

By Christophe de Margerie
Chairman and Chief Executive Officer, Total

The theme of the 21st World Petroleum Congress is a call for the oil and gas industry to be responsible energy suppliers. There are two components to this responsibility. Not only do we have to meet energy demand by delivering steady supply at reasonable prices, but in doing so we also have to provide customers with better energy in order to meet the requirements of challenging climate change.

Moscow is an apt venue for the Congress. Russia is a key player on the global energy stage, through both the scale of its oil and gas production and resources and its geographic situation at the crossroads of Europe and Asia. The latter region accounts for a growing share of its markets. Russia’s combined oil and gas output makes it the world’s number one producer, and the country is home to the world’s biggest gas reserves.

Global energy demand is forecast to grow by more than 30 per cent to 2035. Most of this growth will be led by emerging economies, driven primarily by increasing electricity consumption and car ownership.

It will take all types of energy to meet this higher demand. Renewable energies will experience strong growth, but will still only account for a small share of the energy mix in 25 years’ time. In our scenario, which is close to the International Energy Agency’s, we anticipate that the share of new energies – mainly wind and solar – will rise from one per cent in 2010 to six per cent in 2035; such an increase represents a real challenge and I do not think that we can realistically expect more. Fossil fuels are expected to continue to dominate; we estimate that they will still make up 74 per cent of the energy mix in 2035. While oil’s relative percentage will fall to 28 per cent, the amount consumed will be slightly more than today, growing at 0.6 per cent per year. We predict that natural gas’ share of the energy mix will increase from 22 per cent to 25 per cent, as its use as a substitute for coal in power generation spreads. That is because natural gas is abundant and flexible and emits only half as much carbon dioxide as coal.

Oil and gas will continue to play a vital role in energy supply because they are very convenient and effective energy sources and considerable resources of them remain. Advances in technology and the unconventional oil and gas revolution mean that estimates of resources have been revised sharply upward. Oil resources, excluding oil shale, are currently estimated at 80 years of consumption; natural gas, excluding gas hydrates, at 140 years. And these figures may climb again, since so far North America is the only region where unconventional resources have been inventoried with any degree of accuracy.

But the existence of abundant resources is no guarantee that demand will be met. The challenge for our industry is to make them available. The fact that there is no “peak oil” does not protect the world against the risk of a capacity peak. To meet slightly increasing oil demand and offset declining production from mature fields, we have to develop 55 million barrels per day of new production capacity by 2030. That is equivalent to replacing 60 per cent of current capacity. For natural gas, which will experience stronger growth, we will have to create as much capacity again as currently exists, by 2030. And with the LNG market expanding at five per cent a year, more than a doubling of capacity is required by 2030.

The issue of project costs and profitability is crucial for our industry. Today, new developments involve more complex geological formations and harder-to-access areas. Project technology, size and costs are all rising. Expectations in terms of safety, environmental impact and social responsibility are rightfully growing. Meeting them requires tremendous effort, having a significant impact on our development and operating costs. This occurs in a context of continuing double digit project cost inflation. Upstream spending jumped by more than 15 per cent a year from 2002 to 2012, while oil and gas production only increased by 1.8 per cent a year. It has reached a point where the sustainability of the overall model is now at stake, leading possibly to underinvestment in the short term, and potentially putting at risk the ability of the industry to meet demand in the medium term.

Keeping project costs under real control is essential, as well as being more selective in the definition of project architecture and in the process of project approval.

At Total, we have done our share of investing to bring new resources on stream. Our capital expenditure peaked at US$28 billion in 2013, with 80 per cent allocated to the upstream. We have a number of major projects under way that illustrate the diversity of our technological expertise and our global reach; let me cite, among many others, Yamal LNG (Total 20 per cent) in Russia, the Fort Hills oil sands development in Canada (Total 39.2 per cent) and the deep offshore Libra licence in Brazil (Total 20 per cent). We are on our way to more than doubling our LNG and deep
offshore production capacities from 2007 to 2017. Our current projects should enable us to lift our oil and gas production from 2.3 million barrels of oil equivalent per day (boe/d) in 2013 to 2.6 million boe/d in 2015. Ultimately, our objective is to raise our production potential to 3 million boe/d by the end of 2017.

Globally, the considerable investment with a high technology content required and the need for tighter cost control mean that everyone – international oil companies, national oil companies, service companies, contractors and suppliers – will have to contribute and to cooperate more closely and intensively with each other. Majors will play a key role in leading the way for the industry into finding appropriate solutions. National oil companies from producing countries that control the majority of reserves have a particular responsibility. The international expansion of Chinese companies over the past decade has been remarkable, and Total has forged many partnerships with them on major projects in different regions of the world.

**Developing sustainable energy**

Climate change must be taken into consideration in any discussion of the energy future. As the work of the Intergovernmental Panel on Climate Change has determined with a very high degree of certainty, greenhouse gas emissions from human activities are a factor in global warming, which is worsening alarmingly. Sixty per cent of greenhouse gas emissions come from the production and consumption of fossil fuel-derived energy. That puts oil and gas companies directly on the front line when it comes to tackling the problem.

Global warming is, as its name implies, a global issue. Solving it requires a concerted international response involving the main “offenders”: China accounts for 24 per cent of global carbon dioxide emissions; the United States, 18 per cent; and the European Union, 12 per cent. Only the European Union has managed to reduce its emissions — by 14 per cent — from 1990 levels, versus an increase at the global level of 48 per cent. The UN Climate Change Conference that will be held in Paris in 2015 must produce genuine reduction commitments by the biggest emitters.

At our level, we in the oil and gas industry have the ability to take steps to help reduce emissions. Providing our customers with better and cleaner energy is our duty and our responsibility. Substituting natural gas for coal on a large scale is an efficient way to do this. I believe that natural gas can play a key role in meeting the challenges of more sustainable growth. Shale gas development in the US, with the resulting decrease of emissions, is a good example of this.

Enhancing the energy efficiency of our operations and reducing flaring are also important avenues. At Total, we cut our associated gas emissions by 40 per cent between 2005 and 2013. Our target is 50 per cent by the end of 2014. And we offer our customers better solutions and advise them how to make their energy use more efficient.

I think it is important for oil and gas producers to report more uniformly and transparently about what they are doing to protect the climate and to prepare the energy transition, what targets they are aiming at and how well they are performing in this area. This will facilitate dialogue with stakeholders and allow us to build mutual trust and to gain a better shared understanding of solutions to be implemented. We have proposed an initiative of this type to our peers in the industry.

We also have to help diversify the energy supply. This is a necessity in the long term to meet demand. First, it contributes to climate protection. Second, host countries are increasingly asking us to help them develop alternative energies so that their oil and gas resources will last longer. And third, in many developing countries that lack adequate energy infrastructure, renewable energies can be a faster path to access to energy. We believe that meeting these aspirations and expectations are part of our responsibilities. That is why we have developed our activities in the areas of solar energy and conversion of biomass into transportation fuels and petrochemical feedstock. Our 66 per cent-owned affiliate SunPower is a global leader in photovoltaic solar energy and the leader in terms of technology, with large scale solar projects in various areas of the world.

Our industry faces many challenges – satisfying continuously growing energy demand, increasing oil and gas production capacity, helping to develop renewable energies and reducing carbon dioxide emissions to protect the climate. It will take a combination of technological excellence, careful monitoring of development costs and a strong sense of responsibility to successfully accomplish all this. If these conditions are met, the oil and gas industry will have the bright future it deserves.
The most recent International Panel on Climate Change (IPCC) report frames the growing challenges of unmitigated climate change in terms of risk: the risk of sea level rise, risk of inland inundation of cities, risks of food insecurity, risks to infrastructure. I could go on. The report makes clear that climate change is adding to uncertainty and it paints a picture of a world very different from the one we live in today, for everyone. “Everyone” includes the oil and gas industries.

This is not news for those in petroleum. But where does this put those who have played an important role in economic development to date? Where does that leave an industry whose involvement in fossil fuel extraction and methane’s escape to the atmosphere, now understood without scientific argument to be contributing to risks that threaten to undermine the industry itself, as well as the world it has traditionally served?

At the World Bank Group we are dedicated to ending extreme poverty and boosting shared prosperity. Support for low-carbon growth and investment in resilience are now central to our work.

The costs of failing to act are staggering in the lives affected and investments lost. Globally, weather related losses and damage have risen from an average of about US$50 billion a year in the 1980s to close to US$200 billion a year over the last decade. In the poorest countries, climate change threatens to increase the cost of development by 25-30 per cent.

Back to the science, the IPCC makes clear that the warming will affect every region differently, but no one will be exempt. That includes Russia. Russia is not only a contributor to global GHG emissions, but especially vulnerable to its effects. In 2008, the National Hydro-meteorological service (Roshydromet) warned that Russia experiences climate change to a greater extent, with temperatures increased by 2-3 degree Celsius in Siberia over the past 120-150 years, in contrast with average global temperature rise of only 0.7 degrees over the same period.

The implications are potentially alarming. The recent fires that devastated Russian lives and the economy contributed to the food price spikes that played a role in the events of the Arab Spring. They can be repeated. The melting of the permafrost will not only be a global concern with releases of methane that will speed warming, but it will threaten the structural integrity of infrastructure, large buildings, power stations and airports, as we have seen in Yakutsk. Damage to oil and gas infrastructure 93 per cent of natural gas and 75 per cent of oil production is in areas of discontinuous permafrost will significantly increase the economic and social costs to the country. That threatens, according to Russia’s own estimates, up to 5 per cent of GDP. The cost of dealing with extreme weather events would amount to US$2 billion each year.

Russia is not alone and should not be singled out, but it is impossible to curb emissions to arrive at a world with an increase of only 2 degrees celsius, which is the internationally agreed arrival point for climate action, without oil and gas producing countries and companies deciding to act, and act now. They need to mitigate their impact as much as possible, while the bigger conversation takes place about energy transitions away from concentration on fossil fuels and about business models to accompany this necessary and inevitable trend.

So, at this point, what does leadership...
look like for the industry? First is the recognition that climate change does not threaten individual companies and individual business lines it threatens the industry itself. We know from our interaction with leading companies in the sector that this conversation has advanced, but this industry, unlike others, has not yet embraced the need for collective leadership. Collective leadership from the bulk of the industry will be needed to make progress. Key questions to be addressed include the shape of the industry, over-investment, over-valuation of upstream assets, adaptation, and inevitable prices on carbon whether through explicit taxes, emissions trading or implicit policies. Coinciding with these questions is the issue of how to develop carbon capture, utilisation and storage at scale.

But there are short-term actions that can have an immediate impact. These actions can show the industry in a different light and can hint at the roles it will play in the future, from the industry’s technological depth to the strength of its R&D.

I want to focus on just one: ending the wasteful flaring of natural gas. We realise that any action needs partners downstream but this industry can show leadership right now by rallying behind the 32 oil companies and oil producing countries that are part of the Global Gas Flaring Reduction (GGFR) Partnership. Launched in 2002, with representatives of governments of oil-producing countries, state-owned companies, major international oil companies, and donor countries, this partnership has broken ground on an issue that had been neglected for too long.

About 140 billion cubic metres (bcm) of gas is flared or burned every year around the globe, resulting in about 350 million tonnes of carbon dioxide in annual emissions. This is equivalent to almost one-third of the European Union’s gas consumption. Eliminating the flaring would, in emission terms, be equivalent to taking some 70 million cars off the road.

GGFR is working with its partner governments and companies to stop wasting this gas, and to create markets in which to sell it and put it to productive use. It promotes effective regulations and government incentives to unlock the opportunities now burned into thin air. Tapping this energy resource requires infrastructure development. GGFR is monitoring technology advancements and widely disseminating information to help ensure that the otherwise flared and wasted natural gas can be utilised to support growth and progress in underdeveloped regions across the world.

Gas flaring is a contributor to another climate forcing agent – black carbon. While flaring may be a relatively minor source of black carbon emissions globally, it is particularly important in the Arctic. Early-stage research suggests that flaring may contribute 40 per cent or more to the black carbon (soot) deposited on snow and ice in the Arctic because it absorbs heat in the atmosphere and reduces the ability to reflect sunlight when deposited on snow and ice (albedo).

Back in 2004, GGFR introduced a “Voluntary Standard for Global Gas Flaring and Venting Reduction.” The standard provides guidance on how to achieve reductions in the flaring and venting of gas associated with crude oil production worldwide. The parties that support the standard have chosen to endorse the

The top 20 gas flarers based on satellite data (bcm)
principles laid out and to work in cooperation with GGFR partners to overcome barriers that prevent flaring and venting reduction. The standard also implies that countries and companies will avoid flaring in new oil developments.

The GGFR partnership experience has shown that cutting flaring to a minimum is possible. In some countries, the change has been dramatic.

In Mexico, for example, gas flaring has been reduced by 66 per cent in just two years, mainly from its Cantarell field. Mexico’s Ministry of Energy, PEMex, and the country’s regulators deserve credit for this achievement.

In Azerbaijan, the national oil company (SOCAR) reduced gas flaring and venting by almost 50 per cent in two years.

The Republic of Congo implemented a 350-megawatt gas-to-power project that feeds two power plants with associated gas from the M’Boundi oil field. Over 300,000 people in Pointe Noire are now getting electricity as a result of this project.

In Nigeria, GGFR partners invested more than US$3 billion to cut gas flaring by 4 bcm over five years. Going forward, we hope that partial risk guarantees provided by the World Bank will make a positive impact on the financial integrity of the delivery chain for gas to power plants in order to support access to reliable electricity for more households and businesses.

Saudi Arabia, Qatar, the UAE and Kuwait, some of the largest oil and gas producing countries, have implemented huge programmes worth tens of billions of dollars to reduce gas flaring and bring associated gas to productive use. As a result, these countries have now reached levels of flaring intensity that are among the lowest of the oil producing countries.

According to satellite data (see graph on the previous page), Russia is by far the world’s largest flarer. Russian regulation required that by 2012 oil companies would have to utilise a minimum 95 per cent of their associated gas or be subject to fines. Unfortunately, the utilisation rate is far from the required level, but it seems clear that these and other measures have accelerated utilisation of associated petroleum gas by companies such as Rosneft, Sibur, Surgutneftegaz, Lukoil, TNK-BP, and Gazprom Neft, as well as local governments in Khanty-Mansiysk AO, Yamal-Nenets AO, and the Republic of Tatarstan. All are working to reduce flaring while also seeking gas utilisation projects.

The World Bank Group and GGFR stand ready to work with all interested parties to help develop and implement solutions for eliminating flaring of gas associated with oil production. We must raise the bar and further deploy existing and emerging technologies, collaborate more, and build the needed infrastructure for gas utilisation.

At this 21st WPC Congress, I challenge all of us to do more to pursue a world free from routine flaring of natural gas. If natural gas finds its place as a fuel that helps the transition towards a low-carbon future, productive use of flared gas is essential. We simply cannot afford to waste it anymore. And neither can our climate-challenged planet.
THE OIL AND GAS INDUSTRY’S VISION FOR A SUSTAINABLE FUTURE

Dedicated to the oil and gas industry, WPC CSR Leadership Conference is a global event for organizations that are taking responsibility for defining a commercial future based on the values of corporate citizenship, transparent accountability, lifecycle stewardship, strategic sustainability and conducting fair business in a manner that delivers a shared future for all stakeholders.

This premier global edition organized by the World Petroleum Council will be held in 2015. The date and venue will be announced at the 21st World Petroleum Congress.

For more information, please contact Ulrike@world-petroleum.org or Afrah@mee-events.com

FIND US AT THE 21ST WORLD PETROLEUM CONGRESS

Stand No. 15 C11, Social Responsibility Global Village, Crocus Exhibition Center, Pavillion 3, Hall 15, 16 – 19 June 2014, Moscow, Russia

http://www.21wpc.com/
In the autumn of 2013, the Intergovernmental Panel on Climate Change (IPCC) dropped a quiet bombshell. Reflecting the evolving scientific understanding on the underlying physics of climate change, the IPCC raised the assessment on the medium-term (20 years) greenhouse gas impact of methane from 72 to 86 times than that of CO$_2$. This means that one ton of methane emitted today will have the same impact on climate 20 years from now as 86 tons of CO$_2$ emitted today. The lower figure itself was also the result of an upward revision made in 2007 from a previous estimate of 62. Consequently there has been a decade of bad news for the climate impact of methane. The longer-term, 100-year warming potential of methane was also revised up from a lower base, but that matters less: while we are all dead in the long run, the battle to tackle climate change will be lost or won in the next couple of decades. Strangely, this series of bad news has made very little impact on the discussion on the future role of natural gas in either energy policy or corporate strategies. This is a mistake. While the optimism is justified that gas has an important and positive role to play in the transition to a low-carbon system, methane leakage has the potential to completely undermine the case for gas and make it part of the problem rather than part of the solution.

Let’s illustrate the scale of the challenge: a major GW-sized modern coal plant replaced by an equally modern combined cycle gas turbine (CCGT) running in mid merit saves around 2 million tons of CO$_2$ emissions, which is equivalent to taking 1.2 million cars off the road. Indeed, natural gas is one of the few options that can lead to large-scale rapid reduction of CO$_2$ emissions based on existing technologies without the complete rebuilding the energy infrastructure. However, under a conservative assumption of 1 per cent leakage rates across the gas value chain, around 7,000 tons of methane will leak before reaching the gas turbine. These 7,000 tons of methane has the greenhouse gas impact of 600,000 tons of CO$_2$, eliminating one third of the advantage of switching from coal to gas. This makes a difference, since in large parts of the world gas is much more expensive than coal, consequently the environmental advantages need to be large to make the expensive shift worthwhile.

If we still want to achieve 2 million tons of CO$_2$ emissions reduction, compensating for the greenhouse gas impact of the 7,000 tons of methane with the old 62 methane impact estimate, that is equivalent to building 270 windmills next to the CCGT to reduce the operations of the gas turbine, while using the turbine to turn wind into a baseload resource. The revision to the estimate of 86 means that we need to build an additional 100 windmills next to the CCGT to have the same climate benefit. As the scientific understanding has improved about how damaging the emissions impact of methane really is, gas has had to run faster and faster just to stand still. In fact, given that in good winds, the 370 windmills would provide 0.6 GW next to the 1 GW gas plant, one could reach the conclusion that we should replace coal with renewables and use gas only to the extent that it is necessary to compensate for volatility and guarantee supply security. Of course, gas does remain extremely important for keeping the lights on, but in terms of volumes, demand will be greatly constrained by the deployment of low-carbon sources and given the abundance of resources a substantial proportion of them will stay underground for centuries.

Response from industry required

Given the importance of the problem for the strategic future of gas and its role in a decarbonising system, there is a need for a comprehensive management response from the industry. Currently, in the overwhelming majority of upstream projects and midstream infrastructure, methane leakage is not properly monitored, measured and reported. According to IEA data methane emissions from the oil and gas industry have been rising at roughly the same rate as global oil and gas production; consequently, the situation is not improving. Nevertheless, these data are not measurements, they are estimates from energy flows. There are also a host of academic studies with different measurement methodologies and broadly diverging results generating controversy, but not much disclosure from the industry.

So far, the message of the gas industry to society has often been to reassure without providing the necessary transparency and hard data to be reassuring. The social and environmental concerns leading to demonstrations and protests against shale gas development are usually not focused on methane emissions.
leakage, and of course, methane leakage is by no means unique to shale gas. Nevertheless methane leakage concerns are often woven into a broad set of concerns about local environmental and water use impacts. Parallel concerns exist about the local sustainability and the global desirability of gas. Therefore this is not a desirable strategic position for gas.

In a sense, however, the water-related concerns about fracking and the climate-related concerns about methane leakage are analogous, because the proper responses are similar. Both have the potential to undermine social acceptance of gas and thus stop what we at the IEA have called a “Golden Age of Gas” in its tracks – but they do not have to if these legitimate concerns are addressed at both the corporate and the policy level. Whether the issue is the proper handling of fracking liquids or methane leakage, the most likely cause for an environmental and safety problem is not a natural or technical accident but inadequate project management. The gas industry has all the technologies and capabilities to keep methane leakage to a minimum level and enable gas to remain firmly as a part of the solution. These skills are usually not very high tech either, but good old-fashioned maintenance, well completion and operational excellence. These issues are being addressed in a comprehensive fashion by the IEA Unconventional Gas Forum which as a follow up to our publication of 

Golden Rules for the Golden Age of Gas, brings together governments, energy companies as well as academic institutions to discuss and develop best practices in the environmental management of shale gas projects and thus ensure broad social support. Some of the lessons from the Golden Rules are applicable to conventional gas operations as well.

The very first Golden Rule is “Measure, disclose and engage”. This should be applicable to both water quality as well as to methane. Measurement is a first step towards management control and transparency is the foundation of social trust. Progress is being made, but the journey is not nearly over. We have a Golden Rule on “Isolate wells and prevent leaks”. This sounds self-evident, and indeed it should be, but we cannot emphasise enough the importance of operational excellence in maintaining environmental integrity. Specifically for methane, the green well completion techniques that were originally developed to tackle volatile organic compounds luckily also all but eliminate methane emissions as well. They should be universally applied on every fracked well. It would be better if this happened through a voluntary industry standard and we could avoid the industry being forced to comply through formal regulation. The same applies to midstream operations – valves, bearings and compressors can be made to minimise leaking, but there needs to be a robust management framework that ensures this.

Keeping gas on the right side

One of the most important Golden Rules is “Eliminate venting, minimise flaring”. There should be a clear consensus that gas flaring is not acceptable. Wasting a valuable natural resource that causes environmental destruction should be one of the bad dreams of the 20th century that we left behind. Except that we have not. Moreover, due to imperfect burning, a degree of methane leakage is almost inevitable when gas is flared. There is a long history of anti-flaring measures, but we need to do better. One elegant solution to turn the tables for pipeline leakage as well as flaring, is to apply a generic carbon price on the leaked methane based on its greenhouse impact. A modest US$20 a ton carbon price applied with an 86 greenhouse gas factor would create a value for avoided methane leaks of around US$37 per million BTU, or over five times current US market prices. There is no doubt that this would unleash the technical creativity and management prowess of the gas industry on this low cost – high value greenhouse gas abatement option.

Gas can have, and should have a bright future. The Golden Age of Gas that we at the IEA have outlined is a safer, cleaner and economically more efficient energy system than most of its alternatives. But its attractiveness crucially depends on gas being an ally for environmental objectives. The advantage of gas over coal is obvious in view of the particulate and SO2 emissions that blight the megacities of the coal-dependent nations of Asia, but it is not enough. Addressing methane leakage is less visible and has a longer-term impact, but it is equally important to keep gas on the right side of environmental concerns.

1. I assumed 1 GW of supercritical coal with 5000 hours load factor replaced by CCGT. A windmill is assumed to be 2MW with 2000 hours average load factor and operating between 10-80 per cent depending on wind speed.
The recent joint ventures between Rosneft, Gazprom, Novatek and a number of international oil companies (IOCs) over the past two years have highlighted a return to the partnership strategy that had been in decline during the 2000s but is part of a long-term cyclical trend. The history of foreign company participation in the Russian oil and gas industry goes back almost 150 years, but has often been one of unfulfilled potential. In the earliest years of the industry, companies such as Royal Dutch Shell and Nobel Oil founded their dynasties on the back of oilfield developments in the Caucasus region, only to be stripped of their investments in the 1917 revolution. During the Soviet era foreign contractors were occasionally welcomed when the need for new technology became urgent, but essentially domestic players dominated the industry until the start of the 1990s, when the end of the Soviet Union catalysed a sharp decline in what then became the Russian oil and gas industry.

This collapse, caused by a lack of funds for investment in increasingly mature and dilapidated fields and infrastructure, offered the potential for significant cooperation between Russian and international oil companies in a region containing 12 per cent of the world’s proved oil and gas reserves. Foreign oil companies had the capability to provide technology, management expertise and capital, while the domestic players had access to reserves as well as an understanding of how to operate within the emerging Russian commercial environment. The potential contribution of foreign companies was recognised by the political elite at an early stage, with President Yeltsin welcoming companies such as Shell, Exxon and Total into the first (and ultimately, only) Production Sharing Agreements (PSAs) granted in Russia, while numerous smaller joint ventures were also formed. However, the subsequent privatisation of the Russian oil industry, and the resulting fight among domestic entrepreneurs for cheap assets, undermined the investment opportunities for IOCs, as they were often regarded as competitors for assets rather than potential partners in their development.

The arrival of President Putin in 2000 brought an end to an era of somewhat anarchic politics and domination by the business elite known as the “oligarchs”, and suggested that more stable times would herald increased foreign investment. The formation of Russia’s largest international joint venture, TNK-BP, in 2003, prompted a resurgence in IOC interest, but then the bankruptcy of Yukos and the consequent rise of Russia’s national oil company, Rosneft, introduced a period of

**TNK-BP was Russia’s largest international joint venture until it was absorbed into Rosneft**
state consolidation in the energy sector that once again limited significant foreign involvement.

Renewed relevance of IOCs

However, the natural progression of the Russian oil industry from the exploitation of Soviet-era assets, which have continued to produce wealth for the country and its oil entrepreneurs for the past 20 years, towards more remote and challenging new fields has created a new opportunity for foreign oil companies. Suddenly their technical experience and financing capability are relevant to Russia again, as is their long experience of managing large oil and gas developments in the global arena, especially offshore. Joint ventures (JVs) between Rosneft and Exxon, Statoil and Eni have focused on Arctic development and unconventional oil assets where domestic companies have little previous experience, while BP’s position as a 19.75% per cent shareholder in Russia’s national oil company is a further example of the evolving foreign involvement in the country’s oil sector.

However, Russia is not an easy place for foreign companies to operate. Although there have been notable success stories, many international partnerships have failed, particularly among the JVs formed in the oil and gas industry over the past 20 years. As a result, at a time when JVs are again emerging as a key platform for international investment in the oil and gas sector, we believe that important lessons can be learned to increase the chance of future success.

An extensive review of the history of JVs in Russia, which we have carried out via a number of case studies and interviews with foreign and domestic actors in the oil and gas industry, has led us to conclude that the concept of local knowledge is a vital part of the relationship between the two partners. All the foreign partners whom we interviewed, whether successful or not, acknowledged that an understanding and ability to deal with local political, operational, and business issues in an ‘asymmetric environment’ was vital to the ongoing development of their business in Russia. Furthermore, some foreign partners also recognised that they traditionally had relied too heavily and for too long on their domestic partner, and had ultimately been undermined by their inability to demonstrate an increase in their own local knowledge and to maintain their relevance to a JV in Russia. Others decided either to make a big effort to develop a personal local network, and thus balance their domestic partner’s biggest strength, or to try and find alternative methods to maintain their position within the partnership.

A statistical analysis of the causes of success and failure in 33 joint ventures further confirmed that, in an institutional environment which remains relatively weak, where an understanding of how to operate in the complex web of relationships, influence and politics is vital to success, partnership with a domestic entity is seen as a necessity by IOCs. Furthermore, it seems to us that this local knowledge of the business environment, and in particular the use of contacts, influence and relationships, is a core competence used by domestic entrepreneurs to build their businesses, and is also used as a bargaining tool in any JV formed with a foreign company. This skill is used to balance the IOC offering of technical expertise, management experience and, where needed, financing, and indeed often outweighs it, because the balance of bargaining power within joint ventures is established by an implicit “race to learn” in what is effectively a “competition for knowledge”. The winner in this competition will be the partner who can most quickly acquire his counterpart’s skills, and given the complex and enigmatic nature of local knowledge, this is most likely to be the domestic partner, as the acquisition of IOC skills tends to be a simpler procedure and indeed is often encouraged by the foreign partner as part of the partnership process. As a result the foreign partner can often find his relevance to a partnership undermined, leaving himself in a weaker bargaining position and often unable to maintain his status.

In response to this issue we have developed a “7R” engagement model (see below) which we believe can provide a positive outcome for foreign and domestic investors in a business environment such as Russia’s, if a rigorous and systematic approach to the potential problems is adopted. This primarily necessitates a foreign partner not only acquiring local knowledge himself but most importantly applying it by becoming more involved in issues concerned with the domestic business environment, in other words being proactive in the process of knowledge transfer and effectively spending significantly more time on the ‘soft due diligence’. In the pursuit of this positive strategy, we believe that both protective and proactive measures can help to maintain the relevance of foreign companies
in a weak institutional environment. We believe that there is a need to fully understand the reality of the environment in which they are operating, using rigorous analysis and a wide network or relationships to create as full a picture as possible of the situation. Through this process, it can become clear that, although there are challenging issues to be addressed, they are by no means insurmountable, and that the opportunities available in Russia can more than compensate for the effort needed to access them. We also believe that foreign companies can optimise their chances of success by continuously renewing their knowledge base and their contributions to any JV, by offering reciprocity both of assets outside Russia but also of mutual learning inside the country, and by ensuring that the resources they offer, in particular the staff they contribute, are of a high quality and are adaptable to the domestic environment.

The “7R” Engagement Model
It is easy to categorise Russia as having a flawed business and political environment and to dismiss it as too difficult to deal with, but the expanding number of foreign companies now beginning to re-enter the Russian oil and gas sector suggests that the opportunities remain both interesting and very tempting. After more than 15 years of studying and working in the country we remain firm believers in the potential for partnership in Russia but also see the need for both a constructive and a sustainable engagement model. We believe that with the right practical approach, both mental, cultural and operational, foreign companies can be successful if they adopt a systematic process of engaging with the full range of key individuals, politicians, industry experts and domestic employees who will be at the heart of their business. Although this engagement can often be uncomfortable, in a working environment that is tough and confrontational, it can also provide huge mutual benefits to all the partners and stakeholders involved. Indeed, it can provide valuable experience for companies to use across their global operations; Russia is not unique in having a weak institutional environment where local knowledge is vital. We hope that the lessons drawn from our analysis can provide useful insights which can assist in the formation of partnerships in many other countries where the governance of commercial transactions is more reliant on individual decision-makers than traditional institutional mechanisms.

Source: International Partnership in Russia: Conclusions from the Oil and Gas Industry, J. Henderson and A. Ferguson, Palgrave Macmillan, 2014
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Africa’s oil production in 2013 was around 6.3 million barrels per day, some 7 per cent of total world supply. It is estimated that Africa has almost 10 per cent of the world’s proven oil reserves, and some 8 per cent of its proven gas reserves. However, potential is in fact probably underestimated, as Africa is by far the least prospected continent across a range of natural resources, including oil and gas.

A number of countries in Sub-Saharan Africa, such as Angola, Gabon, Nigeria and Republic of Congo, have well-established hydrocarbon operations. Over the last decade, operations have expanded to include new producers such as Ghana, following the discovery of the offshore Jubilee field. Increasing estimates of hydrocarbon reserves in Eastern and Southern Africa are also significant, with several countries progressing towards commercial development of their new discoveries. For example, Kenya, Uganda and Madagascar are well positioned to be the next new oil producers on the continent. Kenya, following recent discoveries, could potentially start exporting oil by as early as 2016. Mozambique is working towards liquefied natural gas (LNG) exports by 2018 to meet the Asian demand, with Tanzania expected to follow suit. The shale gas boom in the US has also created similar interest to replicate unconventional gas production in Africa, notably in South Africa, which by some estimates possesses the world’s fifth-largest unconventional gas reserve.

Opportunities

Hydrocarbon development clearly offers a range of opportunities, to support not just the continent’s growing energy needs, but the Sub-Saharan African economies as a whole.

Countries with hydrocarbon operations stand to receive significant revenues from developing their assets. But the extent to which these revenues will reduce poverty, improve human development and bring about inclusive growth will largely be determined by the policy choices that countries make.

Countries which have made recent hydrocarbon discoveries can learn from the successes and failures of others, by designing transparent policy and fiscal frameworks to deliver an attractive investment environment, to maximise revenue, and - crucially - to invest their resources for the long term to enhance growth and to share the benefits for all.

As an example of success, Ghana’s Petroleum Revenue Management Act of 2011 provided a foundation for governance and accountability, including the creation of an independent regulatory body, the Public Interest and Accountability Committee, to monitor how oil revenues are handled. Furthermore, it established the Ghana Stabilisation Fund and the Ghana Heritage Fund, for the purposes of budget stabilisation and savings for future generations.

If countries manage their hydrocarbon resources well in terms of getting the right level of rents (royalties, taxes, production shares and other revenues) and managing the resulting revenues wisely, they could significantly shorten the time required for a previously low-income country to achieve middle-income country status. Experience shows that African countries receive significantly lower royalty rates when compared to Latin American countries. However, the optimal level of taxation needs to take into account the overall risks of the project, such as the perceived country risk, the geological risk inherent in the nature of the hydrocarbon deposit, and, for ‘frontier discoveries’, the uncertainty associated with lack of reliable geological data.

Oil- and gas-related rents can provide a foundation for the establishment of Sovereign Wealth Funds (SWFs), which a number of African countries, including Nigeria and Angola, have put in place. Such funds can be an important source of development finance, provided they are well designed and implemented. While most African Sovereign Wealth Funds focus on stabilisation objectives, they could do more to benefit socio-economic development by providing financing for infrastructure and financial sector development – not just in their countries, but in Sub-Saharan Africa as a whole. They need to be based on clear and transparent rules balancing stabilisation and investment, contributing towards policy objectives, and not becoming a parallel source for budgets. To mitigate these risks, to improve the attractiveness to investors and to maximise tax revenues, countries can benefit from an integrated package of support from development partners such as the African Development Bank.

While oil and gas are typically not labour-intensive sectors, they do present an opportunity to generate employment, skills development and technology
transfers, by nurturing the economic linkages between extraction operations and local business. The latter can provide ancillary services such as logistics, finance, power, communication, and engineering services.

National discoveries, meanwhile, could also have regional implications, as seen, for instance, in new gas-fired power plants in Mozambique and Tanzania which are serving entire regions.

**Challenges to realise full potential**

However, Africa’s oil and gas potential is far from being fully realised. The African Progress Panel has confirmed that – in terms of human development outcomes – resource-rich countries actually lag behind non-resource-rich countries with similar levels of income. For example, a recent McKinsey report found that these resource-rich countries have poorer quality infrastructure. The challenges to realise the full potential of developing hydrocarbon resources effectively range from improving the governance structure determining the allocation and use of resources derived from the oil and gas sector, to overcoming infrastructure bottlenecks, and managing environmental and social issues.

Crucially, countries need to be realistic in managing their citizens’ raised expectations where natural resources are concerned. There is usually a significant time gap between the start of exploration and the time when revenues are generated. Citizens often expect rapidly improved standards of living, and they will be frustrated when these standards are slow to materialise, or if they fail to do so. Transparency in how policy decisions on resource exploitation are taken, and how revenues are used, is the first step to create dialogue and trust between the state and its citizens. Around 10 oil and gas producers in Africa are part of the Extractive Industries Transparency Initiative (EITI), a voluntary scheme under which producing companies and governments commit to disclose and reconcile payments from their extractive industries.

But transparency is only the first step in the process of accountability. Civil society organisations, parliaments and independent watchdogs need to be able to interpret the data and the intricacies of oil and gas contracts, and to have the political space to engage government, and hold them to account. An open and informed dialogue means better policies, and clearer rules for investors.

Infrastructure is often a major constraint to effective hydrocarbon development. For instance, Uganda’s plans to export oil have been partly delayed due to difficulties in selecting export routes, arising from its landlocked status. There are now plans for an oil pipeline from the Ugandan oilfields to Lamu (a new port on Kenya’s northern coast) which could be operational by 2019. Uganda, Kenya and Rwanda have also agreed to the extension of an existing pipeline in Kenya to Uganda and Rwanda. Such projects are crucial, and they need multi-billion dollar investments to be built.

Significant challenges stand in the way of creating the linkages between the oil and gas industries and the wider domestic African economies. Nigeria has seen a recent increase in the role of indigenous companies, with local companies now controlling over 30 per cent...
of the upstream sector, up from less than 10 per cent in 2010. This has been driven by initiatives over the last decade to increase the share of goods and services provided by local companies, and by more recent sales of assets by major multinationals (such as Eni, Shell and Total) to local companies. But this might be harder to achieve for less established oil producers, with higher margins of uncertainty. The right policies need to be put in place, informed by evidence-based analysis on the country’s competitive advantage. These can create the right incentives for companies to pool resources to invest in skills development and training certification schemes, and to define the standards of local content that allow local business development.

However, African domestic markets often remain too small to create the strong economies of scale necessary for ancillary domestic industries to thrive, with trade constraints and limits to labour movement acting as brakes to development. Regional integration to create wider markets and allow the transfer and sharing of skills remains a crucial element in realising the full potential of the oil and gas industries, beyond just revenue collection.

Now is the time for Africa to address these challenges, to establish itself as a stable and attractive investment destination, and to ensure it has the right policies and frameworks in place to reap the full benefits of oil and gas development. However, it must do so before the current market structures change radically. For example, the United States – hitherto the largest buyer of Nigeria’s crude oil – is expected to become a net exporter within a decade, while Australia is on a path to becoming the world’s biggest LNG exporter by 2020, with a focus on supplying Asian markets. This implies that Sub-Saharan countries need to focus on providing the right enabling environment for their planned large-scale oil and gas projects to come on-stream soon, in order to secure a place in global markets.

Across the world – and especially in Sub-Saharan Africa countries with hydrocarbon resources – governments need to respond to citizens’ rising expectations of employment and social development. In order to do so, they must understand the true value of their assets, develop a vision of how to use them to promote development, and communicate that effectively to their citizens.

Fortunately, help is at hand. It comes from OECD countries, and increasingly from South-to-South exchange, for instance from countries like Trinidad and Tobago. The African Development Bank Group acknowledges the importance of stewardship of oil and gas resources, and is scaling up its financing, advisory services and capacity building support to its regional member countries.

The Bank offers a combination of public and private sector investments in the hydrocarbon sector and associated infrastructure. To this, it adds advisory support and capacity building through the Africa Legal Support Facility, which can help countries address the complexities of designing and negotiating the right concessions and contracts. In addition, the Bank’s recently established African Natural Resources Centre will provide technical assistance and advice in designing the institutional and policy frameworks for managing the extractive sector and maximising its benefits for the domestic economy. It will build the capacity of governments, of civil society, and of parliaments. Crucially, in combining technical assistance and advisory services for both renewable and non-renewable resources, the Centre will be well placed to advise on the main trade-offs between using finite extractive resources and alternative renewable resources.

Africa’s focus on regional integration – as exemplified by the Programme for Infrastructure Development in Africa (PIDA), led by the African Union Commission (AUC), the New Partnership for Africa’s Development (NEPAD), and the African Development Bank – also provides opportunities for Sub-Saharan African countries to exploit their regional value chains more effectively. It offers the possibility for broader economic transformation, for instance through investment in petrochemical-related industries.

The private sector, too, has an important role to play by ensuring that private sector activities and investments are aligned with national and local community needs. It is stable partnerships such as these which are essential for enabling large-scale investments and creating broad-based prosperity and development.

Africa has a great opportunity to realise full potential of its oil and gas resources to transform its economy and support the livelihoods and the quality of life of its peoples. It can learn lessons from others in putting in place the legal governance and the environmental and financial reforms to achieve its ambition.
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Energy and development: A rallying call to action

By Suleiman J. Al-Herbish
Director-General, OPEC Fund for International Development (OFID)

Access to modern energy was a notable omission from the Millennium Development Goals (MDGs) launched in 2000 amid great fanfare and expectation. Now, more than a decade later, the global community has finally woken up to the irrefutable fact that poverty eradication and sustainable development are impossible to achieve without access to reliable and affordable sources of energy.

At long last, energy poverty has penetrated the global consciousness and rides high on the international agenda. Moreover, it is now acknowledged that a new sustainable energy paradigm represents the key to a secure, equitable and prosperous future for our planet and its people.

Coordinating the global response is the United Nations Sustainable Energy for All Initiative (SE4ALL). Launched by Secretary-General Ban Ki-moon in late 2011, SE4ALL seeks to make universal access to modern energy services a reality by 2030. It also addresses two additional and equally important goals: improving energy efficiency and boosting the share of renewables in the global energy mix.

As the initiative turned from an action plan to implementation on the ground in 2013, SE4ALL has grown into a powerful movement, supported by governments, development finance institutions, civil society organisations and the private sector, headed by an Advisory Board and co-chaired by the president of the World Bank and the secretary general of the UN. Its objectives – including energy poverty alleviation – will form a core component of the Sustainable Development Goals being drawn up to replace the MDGs after 2015.

While such action is welcome, few would deny that it is long overdue. The facts speak for themselves. Despite living in an age of unprecedented scientific and technological progress, some 1.4 billion people around the world are still without access to electricity. Moreover, almost 40 percent of the global population relies on the burning of biomass for cooking and heating. As if these statistics were not damning enough, new research shows that there are around four million premature deaths every year from household air pollution – proof that energy poverty does not just deprive; it kills.

In terms of human development, access to modern energy is quite simply life-changing. It can be the difference between a girl going to school, or spending the day collecting firewood, and between a mother giving birth with life-saving equipment to hand, and delivering her baby by candlelight.

Crucially, modern energy is also the engine that drives economic growth, as clearly demonstrated by the experiences of the BRIC countries and the manufacturing economies of east and south east Asia. In these countries, the mechanisation of industry – through increased investment in energy – has reduced production costs and increased competitiveness, leading to higher productivity, more jobs and greater wealth.

There can be no doubt that energy could have the same transformational effects on the agriculture-dependent economies of sub-Saharan Africa and elsewhere, by powering irrigation and adding value to crops by enabling their drying, processing and packaging.

Indeed, this potential is borne out by studies conducted by both the World Bank and the United Nations Industrial Development Organization, which estimate that energy poverty costs Africa 2-3 per cent of its GDP.

For well over a century, the oil and gas industry has been a leading player in the energy mix, advancing industrialisation and social progress around the world. As we move forward with the creation of a new energy paradigm, the industry has an even more critical role to play. Beyond being a provider of fuel, it must also serve as a source of technical expertise, business solutions and funding. Indeed, some would argue that this is more than a responsibility; it is a moral obligation. Curbing gas flaring can both save the environment and provide clean energy at cheap costs. Shipping and distributing LPG can stop deforestation of woods and stop premature deaths. Using existing retail outlets for providing all forms of energy can help lower costs.

OFID’s Energy For the Poor initiative

As an institution that has pioneered energy poverty alleviation since 2007, OFID is a key partner in SE4ALL, serving on the advisory board and lending its expertise and leveraging power to the campaign. With the full backing of our member countries, we are committed to using all resources at our disposal to step up interventions both at an advocacy and an operational level.

Already, in the past two years alone (2012-2013), our energy sector approvals across all financing mechanisms have amounted to over US$915 million. These funds are supporting a broad range of projects, from large, capital-intensive investments such as power plants and grid expansion to local, small-scale renewable solutions, where speed is of the essence.
The strategic framework for these activities is OFID’s five-year-old Energy for the Poor Initiative (EPI), which is funded through a revolving endowment of US$1 billion, a sum pledged by the institution’s governing body, the ministerial council, in its June 2012 Declaration on Energy Poverty.

We are already seeing results. These confirm the soundness of our strategy. Nevertheless, our contribution is but a ripple in a very wide ocean. If SE4ALL is to be successful, unprecedented supplementary resources will have to be mobilised – an estimated US$50 billion annually to achieve universal access; a total US$600 billion – US$800 billion every year to realise all three goals (including targets for energy efficiency and renewable energy) by the deadline of 2030.

Equally important will be close cooperation amongst all stakeholders in order to maximise synergies and avoid wasteful duplication and overlap.

**OFID’s co-operation with the oil industry**

OFID, for example, enjoys a highly successful partnership with the Shell Foundation. Both Total and ExxonMobil are co-financiers in other projects we are supporting. The Global LPG Partnership is also a recipient of an OFID research grant to expand the use of LPG as a clean and modern fuel. We would like to see this kind of collaboration replicated and to explore other avenues of cooperation between the oil and development finance industries. Later this year, in partnership with the WPC, we will host a forum at our headquarters in Vienna to do just that.

As urgent as the energy problem is, however, there is wide acknowledgement that it is a challenge that should not be tackled in isolation. Water and food security are equally pressing and form an inseparable part of the same equation. Just as water is needed for almost all kinds of energy production, so energy is required to treat and transport water. Meanwhile, both water and energy are essential for growing and processing food.

Such interdependence can only increase in the future, as population growth and urbanisation create increasing demand for these three key resources. By 2030, it is predicted that the world will need 30 percent more water, 40 per cent more energy and 50 per cent more food.

An integrated, holistic approach can address the challenges across the board. For this reason, OFID has placed the water–food–energy nexus at the heart of its 2016–2025 strategic plan. Already in 2013, we committed US$752m to projects across all three elements of the nexus. Political will alone, however, does not deliver results. We need resources – financial, human and technical – and we need definitive, coordinated action from all actors. Waves, not ripples, will carry us to a better future for our planet and its people.

**Pooling synergies to shine a light in Africa**

OFID recently teamed up with the Shell Foundation and social enterprise d.light to distribute solar lanterns in Kenya and Tanzania, two of the most severely energy-poor countries in sub-Saharan Africa. The aim of the twelve-month project was “to empower formerly energy-poor consumers to live a life of new freedoms and opportunity.”

By the end of the period, almost 85,000 units had been sold, empowering the lives of some 424,000 people, more than triple the original target.

Donn Tice, CEO of d.light, says a new financing strategy contributed to the overwhelming success of the project. This involved the setting up of a revolving capital pool, which made low-interest loans available to rural distributors to boost their working capital and enable them to buy and stock large supplies of the lanterns.

As all loan repayments, including interest, are re-injected back into the revolving fund, the scheme is not only self-sustaining but growing year on year. Another crucial element of the project was the training programmes that were organised for distributors and brand activators to help them develop more professional business skills and become more effective sales agents. To promote consumer awareness, potential customers were given free home trials of the d.light lanterns.

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**Family reading using d.light solar lanterns in Tanzania**
In oil and gas producing nations worldwide, ‘local content’ policies are intended to increase local employment, enhance technology transfer, expand local procurement, improve social conditions, and build local infrastructure to drive sustainable economic growth.

The wealth unleashed by oil and gas extraction can empower national economies through well-known ‘multiplier’ effects that generate growth in other sectors. In this article, we suggest areas in which governments, regulators, and industry players might collaborate to create shared value and minimise project costs, delays and social unrest through better local content planning and implementation.

Decades ago, Norway enacted legislation to accelerate the development of its national oil and gas resources, requiring international operators and oilfield service providers to hire Norwegians for local projects and bring research, procurement and manufacturing activities in-country. Norway’s success at ‘in-country value creation’ led many other oil producing countries to emulate its approach to local content.

From a global perspective, local content legislation falls into two broad categories. First, nations such as Brazil, Angola, Nigeria, Uganda, Kazakhstan, Indonesia, Malaysia and Ghana have local content laws already in place. They may have set targets for the recruitment and training of nationals, for technology transfer, for the procurement of domestic goods and services, or for partnerships with local investors and locally owned enterprises. Non-compliance can have serious consequences, although regulators may waive penalties when company plans demonstrate a strong commitment to local content.

Second, nations such as Kenya, Tanzania, and Mozambique are currently investigating or developing ways to meet their local content aspirations. These and other nations have no formal legislation, but observe which companies incorporate significant local content in their project plans, and those which do not. They approach the issue carefully, consulting, scrutinising contracts, and offering incentives to those who hire nationals, who domicile facilities such as engineering design, platform construction, and refineries, partner with nationals, and who invest in social infrastructure such as education and health care.

Not surprisingly, the rapid expansion of local content legislation worldwide has led to a certain amount of tension between regulators and international corporations. Companies that do not actively invest in local content run the risk of disrupting their business, while those who are proactive may gain competitive advantages. We encourage global organisations to treat emerging local content policies as a strategic opportunity to create shared value, rather than an unpleasant issue to be ‘managed’.

**Talent development**

Ensuring national diversity was part of the Schlumberger approach long before our host countries began establishing target headcounts. However, we approached talent development differently from most current regulations. If, say, 20 per cent of our revenues came from a country, we would recruit 20 per cent of our workforce from its population.

Depending on a country’s stage of exploration and
development, we take a long view on how best to develop local talent. For example, to support our customers’ exploration programmes, some recruits work as trainee engineers in our reservoir characterisation or drilling segments. To ensure that our petrotechnical professionals (PTPs) become competent, competitive and autonomous, we offer opportunities to work in-country, regionally, or elsewhere in the world. All of our engineers undergo identical training in the same world-class facilities, regardless of their nationality or geographic location. When they return home, they bring richer skills due to experience in diverse oil and gas provinces and operations.

In the exploration stage, therefore, not immediately meeting a local headcount target may not represent a lack of progress, if local recruits are training elsewhere to work more safely and professionally when they return.

Nevertheless, many local content laws today require operators and service providers to hire a specific percentage of their in-country workforce from the national population. Reaching these targets can be challenging, given the small pool of qualified PTPs in some nations. In those places, governments need to invest more in the educational infrastructure, and STEM education in particular. Then industry participants can provide additional training opportunities, investments in STEM infrastructure, and teachers to further develop technical talent and spur economic growth.

**Shared value approach**

Shared value is a management strategy that addresses social problems that intersect with the business. Not only does it help resolve the issue, but it creates additional business value. Rather than reactively managing social risks, a shared value approach provides a proactive, holistic view of the company’s place in a local socio-economic ecosystem. The goal is to create win-win outcomes.

At Schlumberger, our shared value approach leverages existing corporate strengths – for example in recruiting and research and engineering (R&E – to tackle specific gaps in local content, such as local manpower, and solve local oil and gas engineering challenges. When local regulators take a similar ‘long view’ and collaborate on local content, host countries win in the long term. They gain an abundance of well-trained personnel for every stage of E&P activity and, eventually, the multiplier effect extends to other sectors of the economy.

Several years ago, Schlumberger crafted our global shared value strategy to guide local content initiatives and begin moving beyond mere compliance with hiring quotas and contractual obligations. We developed a set of ‘guiding principles’. We held strategy workshops in several countries to educate regional managers, better understand each host country’s aspirations, and determine how to align our competences to deliver more effective outcomes and accelerate execution of local content plans.

Our guiding principles include the following:

- Proactively engage with regulators and customers (oil and gas companies) to understand their local content priorities, and jointly determine how best to satisfy them.
• Develop national capabilities in five critical areas: local employment, local procurement, local R&E and manufacturing, technical partnerships with indigenous operators, and alliances with indigenous service companies.
• Apply rigorous and compelling metrics to monitor and report local content compliance, identify gaps, and highlight situations in which we can, in fact, go beyond compliance.
• Analyse the needs of host communities, develop a portfolio of social investment programmes, and collaborate with other stakeholders to enhance national education systems to enlarge the talent pipeline and eliminate short-term impediments to local participation in the supply chain.

By reviewing each country’s requirements and marrying them with our core competences, Schlumberger is actively filling gaps in local capabilities. **Local talent:** For example, in many frontier countries, our shared value approach dictates that we recruit locally while training and developing talent globally to quickly build the pool of available PTPs. We invest in local technical institutions and universities to build their capacity, equipping their labs and providing industry-standard software.

**Local research, engineering and manufacturing:** We constantly review locations for new manufacturing, research and engineering centres, wherever the strategic economic value added by local operations can justify the often prohibitive costs. Currently Schlumberger has 125 research, engineering, manufacturing and sustaining centres throughout the world. Although most are still in North America and Europe, we have adopted a policy to relocate more capacity to under-represented countries. In recent years, for example, we have established R&E or manufacturing facilities in Russia, China, Malaysia, Singapore, Brazil, and Saudi Arabia. With additional incentives, host governments can encourage more international investors to locate industrial and technological activities in their countries.

**Local sourcing:** Our shared value approach also ensures that more product sourcing comes from countries in which we operate depending, again, on economic considerations. Our strategy is to ‘procure where we work’ by helping local suppliers develop their capacity to meet the quality specifications of our industry. This enables us to continue to work safely, with sound environmental practices, hopefully with quicker deliveries from local vendors. For example, Malaysia’s investment in telecommunications infrastructure led companies such as Schlumberger to establish large regional centres for seismic processing, back office accounting, and IT. Today, Malaysia’s technically proficient talent pool in electronics assembly and manufacturing provides thousands of high quality jobs, not only in oil and gas.

**Local partnerships:** Finally, we create shared value through new integrated services business models with indigenous oil and gas companies. Not only does the Schlumberger Integrated Project Management (IPM) segment deliver high-quality integrated services, but we help empower local E&P customers to become self-sufficient, world-class operators through collaboration, training, state-of-the-art technology transfer and technology mastery. We believe we will prosper as our customers grow. Together, we can develop greater opportunities for future generations.

**Recommendations**

Despite making considerable strides in recent years, many foreign operators and service companies still struggle to meet local content expectations. Clearly, it will take more time. However, those who make local content a strategic priority will both differentiate themselves and help the global industry retain its social license to operate in the coming years.

We recommend the shared value approach to other industry players. In countries that need to show purposeful growth in employment and oil and gas infrastructure, they should target incremental investments in local centres of excellence in procurement, training, research, engineering, manufacturing, local service companies and so on. Meanwhile, host governments should provide financial incentives, faster decision making, re-export licensing, and other collaborative initiatives to encourage greater foreign investments in their economies. Governments today also have unique opportunities to differentiate themselves from other oil and gas producing nations based on their ability to attract inward investments. Collaboration toward shared growth and development should be the primary measure of success for all who have a stake in this important industry.
The Executive Committee of the World Petroleum Council has launched an inter-Congress programme, the WPC Expert Workshops, with the aim of sharing experience and to promote cooperation between WPC members and to present the main conclusion of such workshops in a special session during the next Congress.

One of the first expert workshops was organised in the Kazakh capital, Astana by the Kazakh National Committee selecting a very topical theme: Local Content Development – International Experience and Best Practices. The Kazakh initiative dealing with the theme of local content issue is based on the implementation of an accelerated industrialisation programme in Kazakhstan.

It goes without saying that the long-term sustainability of the petroleum industry will depend on how the local suppliers of goods and services are promoted. The presentations in the workshop have emphasised the necessary availability of vital components in their countries. Nevertheless most of the presentations drew the attention to further measures to be introduced. The suppliers of goods and services have emphasised the necessity to increase the incentives for local content creation. The papers presented at the workshop by a variety of authors, in particular by the Brazilian Petroleum Institute (IBP) in view of that country’s up and coming oil industry, highlighted how important it is to improve the efficiency of the education system focussed on the real needs of the labour market and to expand opportunities for historically disadvantaged persons.

At the workshop, the Kazakh government outlined its intention to redouble efforts to increase the local content of goods and services that meet international standards. However, the tone of some presentations were critical concerning the achievements so far. They pointed out that the low level of local content in procurement by major oil and gas project operators was due to a number of problems. The reason for the Kazakh content in the purchases of goods not exceeding eight per cent in 2012 is due to a number of factors, which included:

- Language barriers.
- As a result, the Kazakh government and major oil and gas operators signed “the Aktau Declaration” in 2012 with the aim of decreasing the obstacles and increasing local content.

This declaration is designed to facilitate the integration of separate programmes run by the major oil and gas operators in Kazakhstan. Such endeavours include the establishment of new production facilities, unification of standards and also procedures used by the major oil and gas operators. The Aktau Declaration also calls for the establishment of a consolidated database of Kazakhstan industry, for better personnel training and support of scientific research.

MOL, the Hungarian oil and gas company, has focused on another approach to help to develop local manufacturing industry in Kazakhstan. The company is the operator of an exploration block in western Kazakhstan and is preparing to invest in an above-surface facility.

MOL has intervened at its Hungarian supplier DKG-East Oil and Gas Equipment Manufacturing Company to create a joint manufacturing operation in Kazakhstan. This will make various valves and wellhead equipment, using Hungarian technological know-how and employing Kazakh workers who have been trained by DKG in Hungary.

Workers at D Island, the main processing hub for the Kashagan oil project, in the northern Caspian Sea.
What is the investment strategy of Samruk-Kazyna?
In the investment portfolio of our national holding company, we have 138 projects worth a total of US$139.4 billion, with the aim of creating more than 124,000 jobs during the construction period and more than 43,000 jobs during the operational phase. To date, 25 of the 138 projects have been implemented. Our goal is to diversify our economy, moving away from dependency on raw materials and towards high-tech industries. The projects include railways, factories, plants, production, technology and housing. As examples, Kazakhstan Temir Zholy has built in Ekbastuz a plant for the production of cable cars, with 3,340 built so far, and Kazakhtelecom is building a network of fibre-optic subscriber access in Astana, Almaty, and many regional cities.

At the same time, we are developing new industries. One such is the chemical industry. We are creating special economic zones in Atyrau and Taraz to attract partners and investors in chemical production, with natural gas supply laid on, and we have a United Chemical Company, which is implementing a project to produce petrochemical products. Another aim is to build a stable, balanced electricity supply through our company Samruk-Energy, and we have also begun developing alternative energy, such as wind and solar stations. A third area is mining, through our company Tau-Ken Samruk. Its task is to bring in modern technology for exploration, production and processing in mining metallurgy. One of our priorities is final processing, especially for gold because all our gold has been, until recently, exported in half-finished form. A fourth direction of new investment is real estate development. We recently initiated construction of the Zelyoniy Kvartal (Green Quarter) for “EXPO -2017”. Finally, we are thinking about how to develop civilian engineering through our company Kazakhstan Engineering, which hitherto has been confined to the defence sector.

Is the sale to the population of minority interests in subsidiaries and the sale of non-core assets intended to free up funds for new investments?
The privatisation programme aims to restructure companies and make them more business like. Ownership of non-core assets distracts the managers of our companies, as well as ourselves, from our core business, where we need to make money. This is the ultimate priority for us. It is also important in attracting technology and capital, and in improving corporate governance, which also increases efficiency and transparency at these companies.

What are the State’s main objectives in this regard?
Primarily, the development of our share of small and medium-sized businesses, to increase their contribution to the economy and also develop the stock market. In our opinion, the participation of Samruk-Kazyna’s portfolio companies will achieve these goals.

Of the 599 companies included in the structure of the Fund, 122 companies will be introduced into a competitive environment – of these 16 consist of non-core assets and 106 of core assets. We are going to sell at auction businesses considered unattractive to the market, such as holiday houses and hunting lodges, while those which have a good dividend base and have generated profits in the past few years are going to be transferred to the stock exchange. In order to improve the prospects for attracting investment into electricity generation (Samruk-Energy) and transmission (Kegoc), the government is working to improve the system of tariff formation. A new policy will be approved by the middle of this year. This will enable an upgrading of the relevant infrastructure.

In our privatisation programme, we are very conservative in estimating risks. We also plan to carry the programme out with maximum transparency and we intend to publish the data on the sale of assets to the private sector.

How has the corporate governance of Samruk-Kazyna changed as a result of this process?
First, we need to understand what is meant by corporate governance. As interpreted in the West, it is the ‘art of management’. Since the establishment of our national holding company in 2006, a great deal of work has been carried out to form boards of directors, to set up the Institute of Independent Directors, and to build up external and internal audit systems.

All our documents are based on OECD standards. In 2009 the Organisation developed its methodology of corporate governance diagnostics, which we
have put into practice. We evaluate our level of compliance in line with these standards and calculate our so-called corporate governance rating on an annual basis. Today, a number of major companies, such as KMG, KTZh, Kazpost, Kazatomprom and Kazakhtelecom, have achieved the level of 70 per cent in terms of compliance with OECD standards. The leader is Kazakhtelecom at 80 per cent, a listed company with several major shareholders. This once again confirms that the placing of shares with the public, and privatisation, increases management efficiency. We aim to raise the average corporate governance rating for major companies to 75 per cent by 2015. Raising the corporate governance rating for a company will effectively lower its cost of capital, and attract investors. For any person or company willing to invest it is important to know that their funds will be recovered and will work for them. The corporate governance rating is a litmus test by which to evaluate potential risks.

Transparency is not just a disclosure of information, but the authenticity of financial statements, and the absence of corruption

But you cannot rely solely on ratings. Shareholders should monitor the results of corporate activities, revenue, market conditions, and assume responsibility for the selection of the board of directors and, in general, pay attention to the transparency of the company. Transparency is not just a disclosure of information, but the authenticity of financial statements, and the absence of corruption and fraud. And the board of directors should ensure the protection of the interests of the shareholders, creditors and ordinary employees.

Accordingly, the professional composition of the boards of directors is important for us. We have conducted international benchmarking and determined that, in the leading companies of the world, boards consist of at least 10 people, and that most of them are high-class professionals with rich managerial experience, some of them ex-CEOs or partners of leading audit firms. But at the moment, our companies’ boards consist of six people on average. This is why, in the medium term, we will increase the number of people on our boards and change their composition.

What are the reasons for the delay in resuming oil production at the Kashagan field?
The delay is related to the problems with the integrity of the pipeline system intended for the transportation of oil and gas from the seaport of “D Island” to the “Bolashak” land installation of the oil and gas processing complex. Oil production started in September 2013, but was halted in October after repeated gas leaks from the pipeline, due to sulfide stress cracking caused by localised excessive metal hardness. At present the operator of the North Caspian Project is developing a plan of repair and renewal operations which should be completed by mid-2014.

When Kashagan production resumes, will Kazakhstan require a new infrastructure to export the oil, or are the trunk pipelines to Russia and China sufficient?
In the short-term perspective of increasing oil production volume in Kazakhstan, including the planned production from Kashagan, no additional infrastructure for oil export will be required. This is because capacity in the Caspian Pipeline Consortium is being increased to 67 million tonnes per year, of which the capacity of the Kazakhstan region is being increased to 52.5 million tonnes per year, and because the capacity of the Kazakhstan-China oil transportation system is being increased to 20 million tonnes per year.

Is Kazakhstan, an exporter of crude oil but an importer of petroleum products, planning to increase its refining capacity?
Kazakh oil processing is currently strained to capacity. The growth of our dependence on imports of oil products is related to the growth of internal consumption, which is rising at approximately five to six per cent a year. Moreover, Kazakh refineries are not at present configured for full production of high-octane gasoline, of which 30-35 per cent has to come from Russia. But the aim is to meet all domestic demand with domestic refined products by 2017. The modernisation programme includes the construction of complexes for production of aromatic hydrocarbons and deep oil processing, and the modernisation of Pavlodar CPC, ensuring the possibility of processing up to 5.2 million tonnes a year of Kazakh crude and of PetroKazakhstan Oil Products, including production of Euro 4.5 environmental standards from 2016.
Managing the Industry

To keep the industry going requires money, technology and above all people, and as the industry changes, so do its requirements in these areas. John Martin of Standard Chartered Bank says the financing consequences of the industry’s structural changes are often under-appreciated – for instance, the need to think creatively about ways to fund mega deep water projects in Brazil or to realise the extra cost of developing offshore assets in the totally new gas provinces of East Africa. He also cautions about the rising cost of borrowing from banks which now must keep higher capital ratios and take care to match funding more closely to the maturity of their assets. He suggests the industry may have to look more to the bond market for funds. Nonetheless, the classic funding mix will remain equity and cash flow for IOCs, debt for NOCs, and private equity for smaller independents before they can approach debt or equity markets. Will Honeybourne of First Reserve explains the wide role of private equity, funding not only explorers and producers but also service companies. He points out that private equity contributes as a provider not only of capital but often of expertise through active participation at the board level of companies within their investment portfolios.

In an interview, Olivier Appert of IFPEN explains the need to create a continuum between science and industry. Formerly the Institut Français du Pétrole, IFPEN has widened its remit to embrace low-carbon energy, but still focusses on oil and gas technology, conventional and unconventional, in which it has created several spin-offs. IFPEN also offers training programmes for the industry and runs a graduate engineering school. In one of three in-depth looks at university training of future recruits to the world oil and gas industry, Professor Zhang Laibin describes the emphasis that China University of Petroleum-Beijing puts on giving students field practice while also promoting company involvement in growing the talent they would want to hire. Professor Anatoly Zoloukhin of Gubkin Russian State University underlines the stress that his university places on its foreign exchange programmes in order to keep its students abreast of “the international pool of knowledge” about oil and gas. Professor Daniel Hill of Texas A & M University explains how Texas’ very first petroleum engineering programme has evolved over the past 85 years, and also how which his university copes with enrolments that can fluctuate dramatically with the oil price by adding many non-tenured professors of engineering practice. Finally, Milton Costa Filho of the Brazilian Institute of Petroleum, Gas and Biofuels sets out what the industry to do to attract what he calls the Y and Z generations, and what the WPC does through its Youth Forum.
The huge scale of investment required to meet energy demand over the next 20 years is well known to the petroleum industry, with the International Energy Agency (IEA) estimating that some US$1 trillion a year will need to be invested over this period. In all segments of the petroleum industry, structural changes are now underway which are altering its fundamental nature. What is perhaps less widely discussed is that such changes will have a significant impact on how the industry is financed in future years.

Over the past two decades, the nature of the upstream exploration and production (E&P) business has been affected by restricted access for international oil companies (IOCs) to conventional resources and by the need for the development and application of new technology to exploit new areas. There are no easy reserves anymore, and opportunities for worthwhile exploration in traditional oil basins still open to the international players have become scarce. Companies need to replace their depleting reserves and are forced to do so either through acquisition or through drilling in technologically or politically challenging ‘frontier’ areas. Both alternatives may rely on external finance, but the financial risks and funding structures are substantially different.

IOCs increasingly have to find and extract new reserves from more difficult locations, such as ultra deep water, utilising advanced technologies. Only a relatively small proportion of this technology is proprietary to the IOCs, which has led to a surge of new opportunities for the oilfield services sector. Overcoming these challenges and developing new technologies is going to require heavy capital expenditures with associated financing requirements, and service companies will play a central role in their development.

In Brazil, recent oil discoveries in the large offshore ‘pre-salt’ play of the Campos and Santos basins will probably transform the country into one of the largest oil producers in the world. However, there are considerable technical, infrastructure and resourcing challenges which need to be overcome. Given the scale of the planned developments, the financing needs are going to be massive, especially as numerous major developments are being undertaken simultaneously by one operator (Petrobras). Project sponsors will have to come up with creative ways to raise funding to fulfil these developmental capital costs.

Meanwhile, the shale revolution in the US is causing tectonic shifts in the industry, with the IEA predicting the US to become the world’s largest oil producer by 2020. As technology evolves, more unconventional shale resources are becoming commercially extractable; but with the rapid decline rates these plays require constant re-investment to maintain production. Oilfield services companies have expanded in response to the increased demand. Liquids-rich plays have become the focus for the industry as shale gas oversupply has been responsible for low Henry Hub gas prices. In the short term, low natural gas prices will prove to be a boon to economic recovery in the US. However, over the medium term, reduced drilling of shale gas plays (due to marginal economics), increased demand for gas (for example, in transport) and the export of gas via LNG could all be contributors to a rise in the US gas price. Players such as Shell, Chevron and, recently, ConocoPhillips, are now replicating these technologies in China to explore and develop the shale potential there.

New exploration plays do, however, continue to be unearthed – often by independent oil companies. An example is east Africa, which...
has become a headline story with a recent string of gas discoveries off the coast of Mozambique and Tanzania. Close to 100 trillion cubic feet of gas has been discovered and possibly more is to be booked as drilling continues. The immediate focus is to commercialise these vast discoveries, most likely through the development of multi-train LNG projects. These LNG projects are strategically well placed to be able to export to gas-hungry regions and, in particular, to provide diversity of supply for Asian buyers. The gas play in the region is still in the nascent stages, and the lack of an upstream or midstream industry in these countries is likely to impose additional costs. In addition to the need to build infrastructure and access, there are increased costs and potential risks due to inadequate security and transparency. These roadblocks will need to be tackled together for the commercialisation of east African projects.

Changing relationships
National oil companies (NOCs) control well in excess of 70 per cent of proven oil and gas reserves in the world and are responsible for over 60 per cent of output. Unlike the IOCs, whose major aim is to maximise shareholder returns, the objectives of NOCs also include the strategic agenda of their parent country, such as improving energy security. Over the past decade there has been a significant increase in ‘international’ merger and acquisition activity by NOCs as they seek to access opportunities that meet the strategic goals of their respective governments. Asian NOCs, and in particular Chinese state-owned enterprises have been dominant acquirers, and typically they are cash-rich or have easy access to additional finance from Chinese financial institutions. Initially, such acquisitions were focused on developing countries, but more recently they have also targeted OECD countries, as in the Chinese National Offshore Oil Corporation’s acquisition of Canada’s Nexen, placing them in more direct competition with IOCs.

For IOCs wishing to invest in countries such as Brazil and Nigeria, ‘local content’ rules are a means by which policymakers attempt to maximise value creation in their local economies. Local content requirements stipulate the inclusion of the NOC or local oil companies and govern employment, infrastructure development, capital and operational expenditure for IOCs operating within a host country. There are pluses and minuses to this approach. The laudable aim is that in partnership with foreign firms it can allow indigenous companies to develop skills and aid in technology transfer to local industry. However, inexperienced local companies, a lack of vital technical skills and the bureaucracy associated with local content rules can limit the efficient development of resources for the host government.

Resource-rich NOCs can also require ongoing funding for asset investment when their cash flow goes to their state treasuries. International banks, local banks (for ‘local content’ reasons they may be included in loan syndicates and they typically charge higher interest rates than international banks) and even IOC partners themselves may provide funding to ensure the necessary investment in assets.

Funding environment
In parallel with a changing petroleum sector, the banking and finance industry is undergoing fundamental changes. A new regulatory framework is being imposed through the implementation of the Basel III accord in the wake of the financial crisis. There is additional uncertainty for banks as national regulators attempt to translate global standards into local rules. Banks will face the challenge of choosing the right strategy and operating model in implementing the new rules and the changes will be a good indication of the strengths and weaknesses of financial institutions. Banks’ future positions will depend on how they can use their current capabilities and how they invest in new ones that will keep them in a competitive position among their peers.

In the tightened regulatory environment, banks will be required to keep higher capital against loans. At the same time, in order to keep a stable funding ratio, their funding will have to be better matched to the maturity of their assets. This is likely to result in higher costs of funds for banks and eventually higher borrowing costs for oil and gas clients because banks will not benefit from the relatively lower costs of shorter-term deposits. The availability of long-term finance for projects will be crucial given the huge capital requirements of new developments in the industry in the following years. However, project finance is an asset class that will be impacted by the new regulations of Basel III. This is because of the long tenors and associated development and operating risks which will attract higher capital adequacy requirements than has been demanded in
the past. As borrowing from a bank is likely to be more expensive than in the past, fixed income investors are the possible new players in the financing landscape of the petroleum industry. The bond market can partly fill the gap left by banks’ reduced ability to offer project finance. Pricing is now becoming a crucial factor in matching risks and returns for banks and, therefore, as costs of funds from banks are rising, oil companies will be looking more into the international bond market when it comes to financing upstream projects.

Financial needs
The industry comprises many different types of players (majors, IOCs, NOCs, independents) who are focussed on a diverse range of geographical regions and segments. Therefore the financial needs and risk profiles of these players vary widely. For oil and gas developments which require financing, lenders will examine the financial, managerial and technical capabilities and strengths of the project sponsors, service company contractors, as well as many other factors such as political risks and project economics. Such factors will influence financing structures, loan conditions, tenors and pricing.

Given the changing landscape of the industry, lenders have to keep pace with an understanding of the risks in areas such as ultra deep water, oil shale, new technologies, new provinces, in order to continue to assist in the future growth of the industry.

The industry’s financing needs are expected to be massive, but they will be different for different players. Oil majors will most likely continue to utilise their own equity funds and internal cash flow supplemented by tapping the international bond markets. However, they may raise limited recourse project finance from international banks in those cases where joint venture partners are unable to meet the project development costs from their own resources.

Many of the NOCs will require various forms of debt finance to supplement their internal finance resources. Most NOCs have experience in raising project finance from international banks, but the cost of such debt will vary depending on the relevant country’s credit rating. For those countries with investment grade or near investment grade ratings, the international bond markets may offer a competitive alternative to the international bank market. There is usually sufficient appetite from bond investors for attractive oil and gas assets.

Smaller independent companies have frequently proven to be successful in discovering commercially viable oil and gas reserves. There have been several recent examples in east and west Africa. Often the capital costs of developing such reserves are substantial compared to the capitalisation and managerial resources of the companies. For smaller players, the role of private equity providers will be important. They will need equity capital to finance their exploration before they can tap either private placement or public bond markets, or obtain project financing in the form of reserve-based lending from banks for their future developments. Without the right equity investors and finance providers, smaller companies may end up as potential takeover targets as they face the challenges of growing their reserves and production through project development and acquisitions. This is sometimes a key feature of their strategy.

The important role of service companies in project developments will require financing on their side as well. Their funding needs will require banks to provide working capital, corporate performance bonds, buyer or supplier credits or bank guarantees.

Major structural changes are poised to transform the petroleum industry. They will have a major impact on how oil and gas assets and companies are financed. The scale of the industry’s required investments will necessitate greater diversification of funding sources and more innovative financing structures from a range of equity and debt providers. International banks will continue to play an important role in providing reserve-based loans, limited recourse project debt and various other loan products. Multilateral agencies will remain important as both producing and consuming countries promote energy developments. However, reflecting tougher regulatory requirements, the capacity of the bank market for long-term debt may be a challenge and is likely to be available at a higher cost than in the past.

The increasing importance of NOCs means that IOCs will face more competition for funding new developments, often in higher risk environments, and this may impact the financing costs. However, despite all the challenges and changes in the industry and bank financing environment, by combining the various sources of funding, the financing needs of the oil and gas industry should be met in the future.
According to the International Energy Agency, over US$38 trillion of global investment will be required to support energy resources, equipment and services and midstream/downstream activity in the next 20 years. It is, therefore, no surprise that Private Equity (PE) continues to be an important supporter of oil and gas industry participants. Upstream examples of PE-backed companies include those pioneering deepwater and offshore exploration and development, and onshore companies pushing forward the shale revolution. Also benefiting from PE collaboration are equipment and services companies needed across the hydrocarbon life-cycle, as well as midstream infrastructure providers to accommodate new production and enablers of the global transportation of LNG and crude oil supply. So, what is PE and its role within the oil and gas industry?

PE firms execute their business by raising and investing funds from a variety of sources including state and industry pensions, university endowments, sovereign wealth funds, and high net worth individuals. These funds seek longer term investments and range in size from a few hundred million to several billion US dollars.

More than just capital
PE firms with extensive global networks and strategic industry experience can not only provide growth capital, but also acquire and build non-core subsidiaries, fund joint ventures, make pre-IPO investments, and participate in taking private undervalued publicly-listed companies. Prior to investing, PE firms have macro-level considerations (sector trends and investment themes, geopolitical landscapes) and deal-specific deliberations (size of funding, business outlook, competition, strategy). At First Reserve, an essential element for our investment review is a strong management team, with commercial and technical qualifications and a proven track record. Through discipline and establishing necessary governance, we also insist on high levels of health, safety, environmental and ethical standards throughout our portfolio as early adopters of the United Nations’ Principles for Responsible Investment.

With this model and focus, PE continues to be a strong global partner to the oil and gas industry throughout the energy value chain. Most PE firms contribute their expertise through active participation at the board level of companies within their portfolios. This is often further enhanced with board appointments of experienced industry professionals. To illustrate this concept in action, I turn to the following examples from First Reserve’s portfolio.

In the upstream E&P sector, PE has helped discover and extract hydrocarbon value both on and offshore through the deployment of modern technology in the hands of world-class portfolio company teams.

• American Energy Utica is one of six onshore E&P companies in our portfolio mostly focused on the development of unconventional resources in the US. Formed in 2013 by Aubrey McClendon, former CEO and founder of Chesapeake Energy, with over 90 per cent support from First Reserve and the Energy & Minerals Group, the company has agreed to acquire acreage in the core Southern Utica totaling approximately 260,000 net acres, and is currently ramping up drilling.

• Offshore, Brazil-based Barra Energia (one of three portfolio companies committed to deepwater E&P) is led by João Carlos de Luca, formerly President of Repsol Brasil and E&P Director of Petrobras, and by Renato Bertani, former President of Petrobras Americas who currently serves as President of the World Petroleum Council. Founded as a start-up in 2010, Barra is a participant in the development of the Atlanta and Oliva fields and a partner in...
Carcará, a significant pre-salt discovery which was the largest Brazilian offshore discovery in 2012.

- First Reserve also participated in the start-up of KrisEnergy, established in 2009 and led by the former founders of Pearl Energy. Headquartered in Singapore, the company has 18 contract areas totalling nearly 70,000 sq km in Southeast Asia including Bangladesh, Thailand, Indonesia, Cambodia and Vietnam. The portfolio balances cash flow-generating producing assets with growth potential development, appraisal and exploration assets. In 2012, KrisEnergy attracted Keppel as a shareholder to provide additional growth capital and ultimately became the largest E&P listing on the Singapore Exchange in 2013.

As the demand for oil and natural gas reaches unprecedented worldwide levels, the equipment and services that support the industry also hold opportunity for PE investors.

- Based in Houston, Texas, AFGlobal is a global manufacturer of products and services for the oil and gas and power generation markets. With 30 facilities in 5 countries, AFGlobal’s products include assemblies used in frac spreads, drilling risers, production risers, blowout preventers and buoyancy modules. Since its PE acquisition in 2012, the company has already completed three follow-on acquisitions, broadening its geographical scope and product offering.

- Saxon Energy Services, taken private in 2008 by First Reserve and Schlumberger, is a provider of technically advanced international land drilling services. With the strategic and financial support of its investors, the company has multiplied its rig fleet by over ten times and expanded to over 3,600 employees on four continents.

- Dresser-Rand, the largest global supplier of rotating equipment solutions to the oil, gas, petrochemical and industrial process industries, originated as a PE-backed carve-out from Ingersoll Rand. A leader in its niche product markets, the company had competitive structural dynamics and a capable management team to take advantage of a perceived prolonged up-cycle in oil and gas capital spending. With standalone capabilities and accretive add-ons put in place, the company completed a successful IPO and, today, has a market cap of over US$4 billion.

Further along the energy value chain, the shale revolution also heavily impacts the midstream and downstream sectors where – again – PE has stepped in as a solutions-driven partner.

- Crestwood Midstream Partners focuses on the gathering, processing, storage and transportation of North American crude oil, natural gas and natural gas liquids (NGLs). In 2013, the company substantially expanded its midstream footprint through a merger with Inergy, creating a platform with a combined enterprise value of around US$8 billion. The new Crestwood operates in nine premier shale plays in the US.

- Downstream from Crestwood, favourable NGLs feedstock pricing also created an opportunity for TPC Group, a leading producer of products derived from niche petroleum raw materials. After being taken private by PE in 2012, the company has received the capital support necessary to re-start an idled dehydrogenation unit to process NGLs and export product under long-term contracts. In addition, TPC is driving additional volumes and margin growth, remaining well-positioned to benefit from macro oil and gas industry trends.

- Connecting the global supply with advancing demand, First Reserve partnered in 2008 with industry-leader Vopak to acquire the Bahamas Oil Refining Company International, a liquids storage terminal facility in the Caribbean with the ability to store, blend and transship fuel oil, crude oil and various clean products. Under this ownership, the asset was significantly refurbished, expanded to 21.6 million barrels of storage capacity, and transformed into a key logistics commercial hub for the global petroleum industry.

**Ongoing opportunity**

As the industry continues to expand – from upstream technology developments and the continued shale revolution, to significant offshore exploration success and advancements in hydrocarbon discovery and recovery in countries around the world – PE will be a valued strategic ally to the oil and gas industry. Working in unison with company management, PE has created global job opportunities; contributed to the modernisation and commercialisation of developing economies, and connected distant sources of oil and gas supply with emerging centres of demand. PE is not just an industry investor, but continues to be a contributive partner in the building of sustainable companies in many sectors of the worldwide oil and gas industry.
A New York Times Bestseller

“**A masterly piece of work.**” *(The Economist)*
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ENERGY, SECURITY, AND THE REMAKING OF THE MODERN WORLD

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—*TIME*
What does innovation mean to your company and how does it impact your business strategy?
Technological innovation is a key driver of the oil and gas industry, and innovation is our ‘raison d’être’. IFP Energies nouvelles (IFPEN) is a public-sector applied research centre focused on innovation in the fields of energy, transport and the environment. That means all our R&D strategy, based on scientific excellence, is market oriented and aims to meet the needs of industry. We have close partnerships with industrial players, we provide industry with the innovative and competitive technical solutions, we create new companies in order to transfer our technology to the market, we support the innovation efforts of small and medium-sized enterprises. So we contribute to economic value and job creation.

How do you encourage a culture of innovation within your organisation?
One of IFPEN’s strengths is our ability to anticipate industry requirements. To achieve it, we develop forward-looking thinking on a continuous basis. We also use the strategic analysis methodology, as the industry does, that helps focus R&D towards the production of innovations. Patent filing is a key component of our research strategy, taken into account from the launching of the project. The aim is not only to protect R&D results, but also to ensure technology transfer. To enhance our innovative focus, we recently set up an in-house ‘incubator’. It aims at bringing out new ideas that could result in breakthrough technologies, speeding up the development of innovative, low-carbon solutions, and helping create eco-industries that grow new ideas and new jobs.

To conduct cutting-edge, innovative research, IFPEN also needs to maintain a high level of scientific expertise. Doctoral theses are another way of contributing to the emergence of new ideas. Our doctoral students, as our researchers, are closely linked with industrial challenges.

We are convinced that a continuum between science and industry is mandatory to bring solutions to the challenges associated with the energy transition. For example, Yves Chauvin, a former IFPEN employee who received the Nobel Prize for Chemistry in 2005, developed different processes now widely deployed within the industry.

What new vistas does innovation open for energy production and consumption?
We must innovate to take up the challenges facing energy and the environment, to boost the competitiveness of the industry and to meet societal challenges. Engaging energy transition implies important research and innovation efforts following two main axes:
  • Firstly, improving the existing technologies to explore, produce, transform and use the energies in order to increase their efficiency and reduce their environmental impact. For instance, we are deeply involved in conventional and unconventional oil and gas technologies. We also work on Enhanced Oil Recovery technologies, production being a key challenge worldwide. Likewise, by optimising industrial systems thanks to more efficient processes and equipment, 15 to 20 per cent of the actual energy consumption in industry could be saved.
  • Second, developing breakthrough innovations to use alternative energies in place of fossil energies, such as biomass, hydrogen, storage technologies and smart grids. Renewable energies cannot yet replace fossil energies. Several challenges must first be tackled for renewable energies to reach technological maturity, ensure their cost effectiveness, their storage, their social acceptance, and then put in place the related industrial channels.

At the crossroad between research and industry, IFPEN puts technological innovation at the heart of its action. For the third consecutive year, in 2013, IFPEN was ranked by Thomson Reuters in its list of the Top 100 Global Innovator organisations.

Can you elaborate on how IFPEN transfers to industry the results of its research?
As I mentioned earlier, our research is totally market oriented. Transfer from the laboratory to industry takes the form of industrial partnerships, the creation of subsidiaries or shareholdings and support for innovative young companies. Thus, over the years, IFPEN created Technip, whose success is well known, as well as Axens, Beicip-Franlab, IFP Training and Prosernat, and it took shares in Heurtey Petrochem and RSI.

Beicip-Franlab is a leading international consultant and software provider in exploration and production. It provides its customers with advanced consulting services in oil and gas exploration and field develop-
ment. Its geosciences software solutions benefit from the leading research and innovation capability of the IFP Group. Beicip-Franlab has a unique track record in the exploration of offshore and onshore basins worldwide, and in the development of newly discovered as well as mature fields of all sizes and types.

Created by IFPEN in 2001, Axens has become a key player in the supply of refining technologies and catalysts, especially for deep conversion and production of clean fuels. For example, the company markets processes for catalytic cracking gasoline desulphurisation (Prime-G+™) and a complete chain of processes for aromatic production (ParamaX™).

After years of R&D cooperation with IFPEN and Total, Prosernat has become one of the leading providers of natural gas sweetening licences and is an important player in the gas drying unit market. For this Prosernat has won references worldwide.

IFPEN is the reference shareholder in Heurtey Petrochem, one of the leading suppliers of process furnaces for hydrocarbon conversion and hydrogen production. Heurtey Petrochem’s expertise extends from feasibility studies to the completion of turnkey projects.

The RSI Group is fully dedicated to process and control simulation. RSI merged recently with IFP Training, and takes the advantage of IFP Energies nouvelles’ unparalleled source of expertise in high level process modeling.

Cutting-edge technology requires highly qualified professionals – how do you train them?

Human resources are a major challenge for our industry, for NOCs and IOCs as well as for supply and service companies. Within our group, we offer a wide range of training services. IFPEN includes a graduate engineering school, IFP School, to prepare future generations to take up the challenges of energy supply, transformation and use. Every year, more than 600 students from around the globe graduate from IFP School.

IFP School offers graduate programmes in French and in English for young engineers and professionals. The students are mostly sponsored by a company or an institution that finances their living costs during the programme and contributes to their tuition fees. IFP School has also created several off-site programmes tailored to the specific needs of the host country, and designed to meet the same standards as the programmes delivered in France. These programmes are created in partnership with a university and are sponsored by a company.

In addition, IFPEN created IFP Training to cover permanent training needs. It is very active worldwide, offering training programmes to about 15,000 employees from industry. The programmes cover the whole oil and gas industry needs as well as automotive and energy management. IFP Training can help all professionals (technicians, engineers, managers and executives) throughout their careers with information courses, foundation courses for people taking on a new job, specialised technical training, advanced level training and professional development.

R&D into the challenges of energy supply, transformation and use
The current fast-growing energy demand is of pressing concern. The world’s energy consumption will grow by 56 per cent between 2010 and 2040, according to the International Energy Outlook 2013, elaborated by the US Energy Information Administration. The pace of consumption is dictated mainly by the economic development of emerging countries and their rising living standards, the new high-tech way of living and the growth in urban population.

According to the 2012 revision of the United Nation’s World Population Prospects there will be approximately 9 billion people in the world by 2040. This means that 2 billion more people will require energy to live, in addition to the 1.3 billion people who currently have no access to modern energy.

There is no doubt that this entails an extraordinary challenge to the world as a whole, given energy’s all-importance. Everything we eat or use has energy in it. Energy is not only vital for shelter, nourishment, health and education, but it also allows humankind to take the path towards freedom, through mobility and communication. “Sustainable development is not possible without sustainable energy. Access to modern energy services is fundamental to human development and an investment in our collective future”, according to the UN’s Sustainable Energy for All (SE4All) Initiative.

Fossil energy is still the planet’s main driving force, a fact that has led to the expansion of exploration activities all over the world, aiming at incorporating reserves that will sustain the increasing demand for oil and gas. As there is no ‘easy’ oil left, the industry has advanced, thanks to cutting edge technology, towards frontiers unimaginable only two decades ago. Today the exploration of hydrocarbons is undertaken in the most severe environments: in the frozen regions of the Arctic, in the offshore depths of the pre-salt layers in Brazil and in heavy oil and unconventional reservoirs onshore.

The information technology era has bestowed the necessary new tools upon the industry. However, highly complex technology in its turn demands new professional skills and expertise. Escalating global demand, dynamic geopolitics and environmental concerns keep oil and gas prices relatively high, requiring increasing investment in the industry. However, the industry is growing so fast that it cannot hire the appropriate people to fulfil a wide range of new skilled positions as well as to cover the shortages that result from demographic changes.

Schlumberger Business Consulting’s annual oil and gas HR benchmark surveys have consistently warned about the demographic transition: the so called “big crew change” that is now taking place. Indeed, half the entire oil and gas workforce could be retired by 2015, according to Derek Massie, former senior vice president for human resources for Seadrill.

Such a change will bring about mass retirements in an ageing workforce and could lead to a permanent loss of capabilities, causing major increase in operating costs and, most importantly, affecting safety in the global oil and gas industry.

Therefore the great challenge lies in capturing, training and retaining enough human capital in the required time. The oil and gas industry has to find talents among the new generations and the so far overlooked female workforce.

The Y and Z generations

One of the main tasks of the industry worldwide is to conquer the new generations known as Y or Millennial (those born in the
1980s) and Z (born in the late 1990s). They have values that are different from those of their predecessors (Generation X), and their high awareness of social and environmental responsibility often leads them to perceive the oil and gas industry as dirty, dangerous and out-dated.

Generation Y has witnessed great technological advances. Connected to the world through the Internet, they are very interactive with, and open to, social networks. Multi-taskers with a sense of purpose and meaning, they praise work-life balance, and are always in a quest for dynamic, creative environments and challenging projects. They are highly attracted by new high-tech products and services.

An even stronger challenge is that of addressing future professionals who will join the labour market during this decade: Generation Z. Sedentary digital natives who were born among PCs, mobile phones, MP3 players and Internet connections, they do not know life without technology.

For these challenges to turn into opportunities, the oil and gas industry should leverage the features and preferences of young people of those generations through recruitment processes and training courses that can rapidly provide them with the required skills.

In a market that is struggling for talent, why would the industry overlook such a promising workforce as that formed by women? With the current talent environment, no industry can afford to cut itself off from 50 per cent of the talent pool. Women have been under-represented in the oil and gas industry at all levels. Effort is required from this male-dominated industry to become more receptive to women workers.

In order to get better gender balance, companies need to implement a new corporate culture, with values, structure, processes and everyday practices aimed at developing an attitudinal change in the long run. Diversity brings a different perspective, broader debates and improves the decision making process.

What can be done?

First things first: if the aim is attracting new talent, the industry should start by enhancing its reputation among stakeholders. Potential recruits must get to know the industry as it is – the way it strives to operate in an economically sound, environmentally friendly and socially responsible, not to mention its commitment towards innovative processes and advanced technologies designed to overcome the formidable challenge of feeding the world with energy.

Strategic as it has become to the success of the industry as a whole, the human resources issue is to be handled as top priority by CEOs. Moreover, the search for innovative, effective human resources management goes beyond corporate frontiers and requires the combined commitment of different society stakeholders.

World Petroleum Congress Youth Forum

At the Brazilian Petroleum, Gas and Biofuels Institute (IBP), an institution that represents the national oil and gas industry, we are seeking to build up a generation of human resources to face the huge challenges brought about by a fast growing industry.

Various actions are being undertaken in parallel with both government and oil company initiatives as a starting point towards a more structured programme. We focus on three different groups: high-school and university students and young professionals.

For an early start, targeting the Z generation high-school students, IBP is organising events to make them acquainted with the oil and gas industry and the STEM subjects. In 2002 IBP created the Professional of the Future Programme and has since then been uninterruptedly focussing on the development of university students through their attendance and actual participation in renowned conferences and exhibitions such as Rio Oil & Gas, OTC Brazil and Rio Pipeline. Thousands of students have thus had the opportunity of studying oil and gas related subjects before attending the mentioned events.

With the same aim, in 2007 IBP set up a Youth Committee composed of young professionals up to the age of 35, from all sectors of the oil chain. This committee has fostered a series of actions to attract future leaders and support the development of their careers in the oil, gas and biofuels sectors. Among others, it promotes the Brazilian Meeting of Young Oil Industry Leaders, in partnership with associated companies.

A major IBP objective is to bring to Brazil for the first time the 5th WPC Youth Forum, another worthy example of a collaborative initiative from the World Petroleum Council that gathers the views and perspectives of the young people towards the oil and gas industry worldwide.
It is the mission and obligation for institutions of higher learning to involve themselves in social and economic development. China University of Petroleum in Beijing (CUPB) has always dedicated itself to fostering technological and engineering talents for the petroleum and petrochemical industry by meeting the needs of the industry, by initiating innovative programmes and especially by strengthening field practice, collaborating with enterprises and building a strong faculty. In this respect CUPB has made great efforts and much encouraging progress along the way.

The lack of field practice has always been the weakest component in higher engineering education. So CUPB has made consistent efforts over the years to build a field practice system with the core aim of improving students’ innovation and creativity through practicum (work placement) teaching, work field practice training and scientific research.

Field practice sessions are included in the courses of all major programmes. In doing this, we have paid special attention to taking into consideration the characteristics and realities of each programme, so that the field practice sessions can cover all the major components or areas of the programme. For professional master programmes, the courses offered are the result of discussions and consultations among three parties – CUPB supervisors, technological experts and on-site supervisors from the corporate sector, thus establishing a curriculum system based on basic theory plus programme-specific modules. At the same time, senior technological experts from companies and researchers from home and abroad are invited to give case-study or state-of-the-art lectures, aiming to bring students nearer to research frontiers, foster their engineering application capabilities and broaden their international horizons.

Besides the simulation training conducted on campus, CUPB has been sticking to the principle of “authenticity” – putting students through real tests in authentic environments – as an important aspect of engineering education. For the undergraduates on the Outstanding Engineers Programme – part of China’s ‘national outstanding engineers initiative’ sponsored by the Ministry of Education and the Chinese Academy of Engineering – they will finish their graduation project in the enterprises. For the postgraduates on the professional master’s programmes, their field practice will be done mainly in the high-level field practice centres jointly established between the university and the enterprises. These centres provide an extensive range of field practices in engineering, covering R&D, engineering design, engineering technology application and technological processes, offering a platform and support for the promotion of students’ innovative and practical capabilities.

It is our principle to combine practice and scientific research. In order to make full use of its strengths and resources in key disciplines, CUPB has made all laboratories open to undergraduates free of charge, so that they can have access to these laboratories and participate in research projects. In the past two years, more than 70 per cent of the graduation theses are relevant to their supervisors’ research projects and for those related to key petroleum subjects, the figure can be as high as 90 per cent. We have also created a series of brand competitions, like the National Petroleum Engineering Design Contest and the SPE Quiz, to combine study, contest and research.
thus establishing a comprehensive field-practice platform by incorporating application, innovation and communication.

**Strengthening company collaboration**

CUPB has made great efforts to promote in-depth involvement from enterprises in developing talent and has adhered to the principle of fostering talents jointly with the industry and the research institutions. This offers companies three degrees of involvement. Two courses offer enterprises full participation. One is the Tailoring Solutions Programme, whose curricula are tailored to the needs of the employer with whom the students will sign a recruitment contract in order to work for the employer after graduation.

The other is the International Cooperation Programme, aimed at fostering talents with global perspectives. In some cases, students are exposed to English-speaking teachers, lectures and textbooks and will do their thesis in English. In others, students will learn another foreign language such as Russian, Spanish, Arabic or French, and then do their studies in a contracted university in a target country.

By full participation, enterprises involve themselves in the whole educational process – selection, education, examination and employment. In the Tailoring Solutions Programme, CUPB works out customised programmes jointly with the enterprises by adding or altering some courses and strengthening field practice sessions so that the programmes or students are tailored to the needs of various employers. This helps meet enterprises’ demand for badly-needed talent.

A form of more partial participation by companies is the establishment of joint research centres for postgraduates within the enterprises themselves, with students assigned to do their theses or graduation projects in these research centres. Since 2000, CUPB has established such joint research centres and started master programmes in more than 50 petroleum or petrochemical enterprises which undertake state key scientific research projects and which enjoy good reputation and conditions for fostering talents. CUPB invites experienced senior researchers and high-level academic experts to be on-the-site co-supervisors in these company research centres. This not only helps students develop practical innovative capabilities but also helps students have a better understanding of the enterprises. Quite a number of students have chosen to work for them after graduation and the companies can also take this opportunity to screen and select potential employees. Evidence shows that joint research centres are an effective way to foster high-level engineering talents.

Finally, enterprises can participate indirectly by sponsoring scholarships and lectures, naming classrooms, and by taking part in academic exchanges with researchers or in part-time or guest professorships for senior company executives – in short, mounting a display of corporate culture on campus.

**Forging a strong faculty in engineering**

A strong faculty, experienced in engineering is key to fostering high-quality engineering talents. Therefore, CUPB has adopted a series of policies in teacher recruitment and further education to enrich their engineering experience in the faculty, especially among the newly-recruited teachers. Post-doctoral study is compulsory for new teachers. All would-be teachers will have to do a two-year post-doctoral study – doing teaching and research at a post-doctoral station in the university or in a contracted enterprise – before signing an employment contract with the university.

As teaching assistants, newly-employed teachers will have to supervise at least one undergraduate field practice trip to help themselves acquire a better practical understanding of engineering field practice.

CUPB has also optimised its faculty structure by drawing on not only teachers on the faculty but also guest teacher/expert resources: the teachers on the faculty are mainly responsible for theoretical and laboratory work, while guest teachers from enterprises do engineering case studies, and foreign experts give state-of-the-art lectures and help bring students to the frontiers of research.

Evidence reveals that this in-depth involvement of enterprises in engineering education is not only beneficial to the fostering of talents but also to better meeting the needs of the development of the petroleum industry. The rate of employment for CUPB graduates on petroleum-related programmes remains above 95 per cent and CUPB graduates have received positive comments from employers. The benefit for the enterprises is that they can find and select more easily the talents that they are so badly in need of.
In 1928-29 the Board of Regents approved plans to establish a course in petroleum production engineering at Texas A&M University, the first in the State of Texas. Petroleum Engineering courses were offered for the first time in 1929. In 1949, Dr Harvey T. Kennedy spearheaded the development of a graduate programme in petroleum engineering. The first MS degree was conferred in 1951 and the first PhD was conferred in 1953. Since the start of the programme, the Texas A&M petroleum engineering department has granted more than 6,400 degrees. Degree programmes in the petroleum engineering major include the undergraduate degree of BS (Bachelor of Science), and the graduate degrees of MEng (Master of Engineering), MS, (Master of Science), and PhD (Doctor of Philosophy).

Our mission is to create, preserve, integrate, transfer and apply petroleum engineering knowledge and to enhance the human capability of its practitioners.

The undergraduate curriculum in petroleum engineering is structured into four academic years. The goal of the curriculum is to provide a modern engineering education with proper balance between fundamentals and practice, and to graduate engineers capable of being productive contributors immediately but also prepared for life-long learning. The curriculum is comprised of four major components:

1. Fundamental math, science, and communication;
2. Engineering science;
3. Petroleum engineering science and technology;
4. Petroleum engineering design.

The first two years of the curriculum are devoted primarily to the first two components. Petroleum engineering science and technology instruction occurs mainly in the final two years. Finally, the students are given design experiences incorporated in courses throughout the curriculum, and culminating in a capstone design course in the final semester.

All undergraduates in the programme are provided with unique opportunities for interaction with industry. Before progressing into the fourth-year courses of the curriculum, students are required to complete at least one six week employment experience. Most students are able to and choose to participate in more than one employment period during their undergraduate study. In the US petroleum industry, summer internships for undergraduate students are prevalent, and in fact, for many companies are the primary tools for evaluating students for full time employment. Students are also required to participate during each of the last two years of the curriculum in the department annual student paper contest, in which they present the results of an independent study to a panel of industry engineers. More than 100 professionals from industry volunteered to serve in judging technical presentations in the 2014 contest, making significant contributions to the development of critical professional communications skills in our graduates.

Another significant interaction between industry and the undergraduates occurs in the capstone design course in the final semester. In this course, students use field data provided by...
industry sponsors, and present their final project results to panels of industry experts.

Dramatic changes in enrolments have always challenged petroleum engineering programmes in the United States to adjust to periods of rapidly increasing, or rapidly decreasing enrolments. The chart shows historical enrolment data in the US since 1972. The job market for petroleum engineers changes dramatically in response to prevailing world oil and gas prices, and the number of students seeking petroleum engineering education responds rapidly to changes in perceived demand.

**Flexible faculty numbers**
To maintain a high quality educational programme, a petroleum engineering department needs to be able to add faculty when enrolments are increasing, but also be able to potentially reduce numbers if a dramatic decrease in enrolment occurs. At Texas A&M, we are achieving this balance by gradually growing our tenured/tenure-track faculty during the past ten years of enrolment growth, while also adding significant numbers of non-tenured professors of engineering practice. These professors of practice are petroleum engineers with 25+ years of industry experience who share their experience with our students. We currently have 23 tenured/tenure track assistant, associate, and full professors, and 13 lecturers and professors of engineering practice.

The graduate programme is a major part of the petroleum engineering educational enterprise, having grown rapidly for the past ten years at Texas A&M University. There are currently about 110 PhD, 150 MS, and 160 MEng students in our department, with almost all of the MEng students being distance learning students. About one third of all Texas A&M Petroleum Engineering degrees conferred over the past 15 years have been graduate degrees.

The curriculum for graduate students is much less structured than that for undergraduates. MS students take eight graduate courses, with the courses selected in consultation with their research supervisor and are chosen based on the student’s background and the thesis topic. All MS students conduct research and write a thesis. PhD students typically take an additional eight to ten graduate level courses, with the selection guided primarily based on their dissertation topic.

The Texas A&M petroleum engineering department offers a large, broad graduate curriculum, with over 30 different graduate courses on each year. These courses cover the entire spectrum of petroleum engineering activities.

A rapidly growing part of our graduate programme is the Master’s of Engineering obtained through distance learning. Graduate courses being taught on the College Station campus are videotaped and streamed on the internet to students who can reside anywhere with internet access. Most of these students are practicing engineers with full-time jobs who take one or two courses per semester. Distance learning MEng students take 11 courses and write a Master’s report, which is usually based on work they are doing as part of their job. Interactions with the course instructor and teaching assistants occur through the course website. More than 160 students are currently participating in this programme with 20 to 30 graduating per year.

The heart of graduate instruction is the individual supervision of graduate research by a faculty member. Thus, the graduate educational experience is an integral part of the department’s research programme. With external research funding of about US$9 million a year, the department is able to provide research assistantships to a large majority of the MS and PhD students. Other students have their own funding provided by a company or government. Because about 70 per cent of the research funding is from industry, most of the graduate students have extensive interaction with industry through review meetings and other contacts. The research done by the graduate students with their professors results in publication of numerous technical papers. In 2012, the faculty and graduate students presented 89 conference papers and published 59 refereed journal papers.

The Texas A&M petroleum engineering graduate population is very international in nature. Currently, students from 48 different countries are enrolled in the graduate programme. The Texas A&M University petroleum engineering programme has benefited the petroleum engineering profession throughout the world. Our graduates are also educating the next generation of petroleum engineers in many locations around the world.

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Preparing specialists for the future

By Professor Anatoly Zolotukhin
Gubkin Russian State University of Oil And Gas

As with any other higher educational institution, Gubkin University’s overall goal is to supply society with a steady stream of the best graduates. Our area of expertise is upstream, mid- and downstream sectors of petroleum industry, and we strive to graduate the best specialists. However, to achieve this result without international cooperation in education is simply impossible.

In 2010 Gubkin University acquired a new and very high level status – that of a National Research University – which has brought with it a number of challenging responsibilities. One of them is to establish and implement standards in education and research in petroleum related areas of knowledge.

Russia’s strategy of innovative development is, to a great extent, based on state policy in education fostering international integration; extensive training together with the leading international education centres; and adoption of international standards in education, research, and greater mobility for students and teachers.

The rationale of international collaboration also stems from a certain lag of technology development in some sectors of industry including petroleum. International collaboration based on cooperation between universities and research centres is one of the effective tools to close this gap. It is vital, however, that this collaboration is supported by the industry. Among all the forms of collaboration perhaps, the most efficient are knowledge exchange programmes – joint programmes with partner universities at master and PhD level and post-doctoral internship programmes. The benefit of such collaboration is multiplied when it is supported by energy and service companies.

Gubkin University has established a number of international master programmes in different areas of expertise in order to compensate for the gap with the international pool of knowledge and of new trends, approaches and technologies. In order to be efficient, a programme requires an exchange of students and teachers, joint research projects, and short- and long-term internships at the partner university.

The university established joint programmes with the leading international higher education institutions, which cover the areas of strategic focus for both the university and the industry. These include Applied Petroleum Geoscience, Reservoir and Production Engineering, Offshore Field Development Technology, Energy Saving Technologies for Gas Transportation Systems, International Management of Resources and Environment, Project Economics and Management.

The perestroika transition period in Russia had a damaging effect on the quality of Russian higher education. Since then it has to catch up with leading international management, competence, experience and standards. Joint activity is the best way to learn the new trends and accumulate new experience and knowledge.

Other important reasons for running joint degree programmes are to gain insight into different cultures with different values, and to be able to talk the language and understand future partners from other countries. Joint degree programmes also focus on forming up the proper moral and ethical attitudes of their students. Joint programmes lead to fuller understanding of technological developments. Technology itself can be bought, but wider understanding of how to use it, to its full capacity, has to be taught.

Re-establishing Russia’s reputation

High priority is given to fundamental courses at Gubkin University (Math, Physics, Chemistry, Statistics and Stochastic Processes), while our partners focus more on applied courses. Combining the two types of course creates a heavy workload for students, but it equips them with unique combination of knowledge and skills, which makes the graduates of joint degree programmes proud of their achievement. Russia has to re-establish its professional reputation in the world. Education is the best way to do that. Many of the strengths of the Soviet education are lost now, but some remain and could be used as the basis for its revival.

International contacts require permanent attention – they have to remain live to remain fruitful and productive. But everyone has a limited capacity for establishing and maintaining productive relations – a management system is needed to support active international cooperation. Modern education is team work, and professional management at universities is equally important to high quality teaching and research. There are a lot of challenges ahead in developing international programmes, but we believe that we have paved the road for the education of responsible professionals for the future.
WE ARE GOING DEEPER AND DEEPER, AND THE OIL INDUSTRY, FURTHER AND FURTHER.

With the Brazilian pre-salt, new milestones in the oil industry have been set. We have doubled our number of proven reserves and, in only 6 years, reached a production of 428,000 barrels a day, a new record. But the benefits from this achievement go much further beyond our company; they boost technological development and push new exploratory frontiers, increasing the global offer of energy. This certainly brings results for the oil industry and for people all over the world.