WORLD PETROLEUM COUNCIL

Addressing Global Energy Challenges

80th Anniversary Edition 1933-2013



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Happy 80th Anniversary!

By Renato Bertani
President, World Petroleum Council

When Thomas Dewhurst presided over the first World Petroleum Congress, held in London in 1933, he had a dream and a vision. His dream was that the WPC would become an inspiration to all nations, producers and consumers, to promote the use of petroleum resources for the benefit of all mankind. And his vision was that, through cooperation and dissemination of best practices, the then nascent oil industry would grow into the most important energy supplier for many decades to come.

Today we celebrate the accomplishments of both the dream and the vision of our first president. More than an organisation that gathers every three years in the largest conference of the sector, we have grown into a league of countries that represent over 95 per cent of the consumption and production of oil and natural gas, permanently engaging all stakeholders in the pursuit of new solutions to meet society's needs of sustainable, reliable and affordable energy.

Powered by the revolution of communications, we live in an era of breathtaking changes in the social, political and economic fabric of societies around the world. And while the preservation of social values like culture, beliefs and history is becoming more important than ever, so is the economic integration and cooperation among countries, regions and continents. And integration and cooperation are particularly critical in our industry, where capital and technology must flow into the producing provinces just as much oil and natural gas must flow into the consumer markets, to the benefit of societies sitting at both ends and in between.

Today we have a holistic view of the petroleum industry, which we characterise as an economic activity where two stakeholders, regulators and oil companies (including services companies), must achieve their goals while earning from the third one, the Society, the right to perform their activities in the long term. In order to earn such rights certain key sustainability principles, illustrated in the box below, must be delivered. Adherence to all of these principles is increasingly critical to attract the much needed human and capital resources and ensure the long term sustainability of our industry.

Society

Regulatory Principles

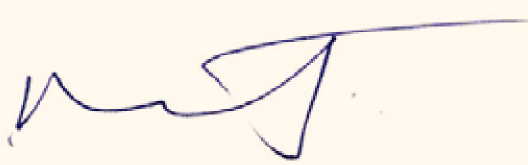
- Steady and transparent access to resources
- Stable and balanced contractual terms
- Clear HSE rules and rigorous enforcement
- Promotion of local, yet globally competitive, goods and services

Governance Principles

- Remuneration of risk and capital, assuring shareholder's long-term return
- Return of proportional share of wealth to society
- Safe operations with positive environmental impact
- Ethics and transparency as part of the business model

This commemorative publication looks back at 80 years of history in the petroleum industry, and the many lessons learned throughout wars, economic cycles and technology revolutions. It also provides us with a new lens to look into the future, where immense new challenges represent just as big opportunities.

Finally, I invite you to join us in the various events that will mark our 80th year of activities, including the anniversary celebration at the Moscow International Oil and Gas Exhibition in June 2013, the 4th WPC Youth Forum and our annual Council Meeting in Calgary in October 2013, culminating with the 21st World Petroleum Congress in Moscow, in June 2014.



Renato Bertani
President
World Petroleum Council

The first 80 years of the World Petroleum Council

The span of World Petroleum Congresses over 80 years takes the oil industry from infancy to maturity, from sole focus on conventional reservoirs to today's increasing production of unconventional oil and gas, from heavy dependence on luck to strong reliance on highly-sophisticated computing in every aspect of exploration and production, from an industry that tended to despise gas to one that prizes its cleaner qualities in a world concerned about climate change, and from an industry in the 1930s still dominated by the US to one with centres of gravity in the Middle East, Russia, the North Sea, Australia, Brazil, Africa and many other producing zones.

Accompanying this evolution, revolution even, has been the WPC. Organisations abound in the oil and gas industry – some technical, some regional, some focussed on producers and others on consumers. But none brings the industry together like our World Petroleum Congresses, which have stayed relevant through the years. Take the 2nd WPC in Paris, which as early as 1937 discussed the technique of directional drilling to which we owe so much subsequent production. The 9th WPC in Tokyo in 1975 was the natural forum to discuss oil reserves and exploration in the wake of the first oil price shock. And the 11th WPC in London in 1983 was quick, after the second oil price shock, to tie the resulting slump in oil demand to the need for corporate restructuring. Taking the industry forward, the 20th WPC in Doha in 2011 looked to the future on the three key themes of cooperation, innovation and investment, and this work will be carried forward at the 21st WPC in Moscow in 2014.

1930s: A League of Nations for oil and gas

The first president of the World Petroleum Congress, Thomas Dewhurst, expressed the hope that the WPC might some day become "a League of Nations for petroleum technologists, and indirectly and subconsciously play a part in international good feeling and fellowship". This wider wish was not realised as the decade descended into war, but the WPC was to become a permanent feature of the oil industry landscape, with an early focus on technology. The 1st Congress in London in 1933 set the tone with much discussion of the new industry of refining and in particular on the need for international standardisation for testing of petroleum products. Such was the interest in this that a heated discussion on the topic of viscosity overran the Congress timetable and could only be ended by the janitor turning the lights off.

The start of this decade appeared to reinforce the dominance of the US. In 1930 the East Texas field was discovered, the largest single find in the US outside Alaska; by 1931 it was already producing 500,000

The delegates at the first World Petroleum Congress in London gather for the group photograph

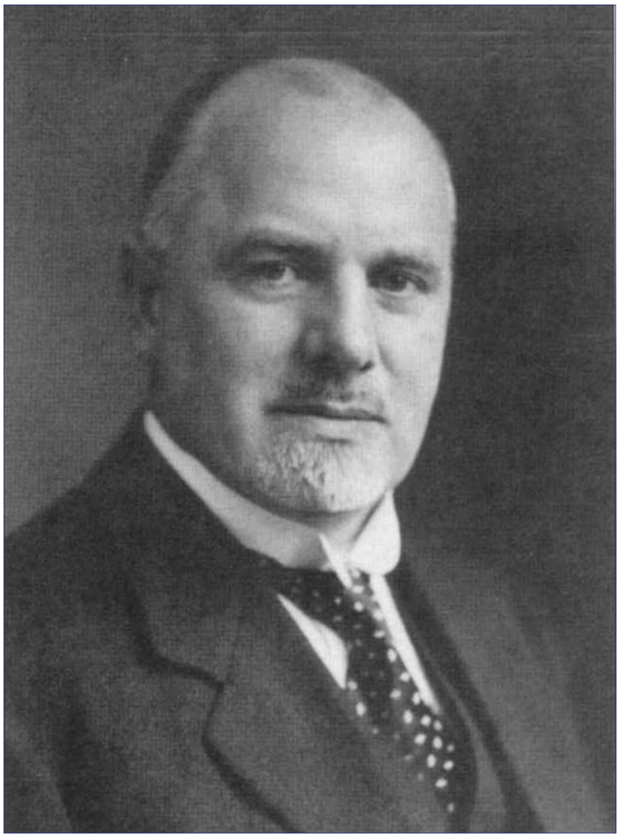
barrels a day. But by the end of the decade there were signs of international oil activity shifting away from the western hemisphere, following nationalisation of the oil industry in Bolivia (1936) and Mexico (1938) and an acceleration in exploration in the Middle East, in addition to earlier discoveries in Iran and Iraq. The 1930s saw oil found in Bahrain, Kuwait, Saudi Arabia and Qatar.

Drilling technology continued to advance through the 1930s, with the landmark invention by Hughes engineers of the tri-cone bit that greatly speeded drilling. By the time of the 2nd WPC in Paris in 1937 drilling was no longer considered to be limited to simple vertical operations, and at that Congress a paper was delivered on the topic of controlled directional drilling that has done so much to revolutionise oil and gas extraction since.

Nationalisations

These started, with the exception of Russia's 1917 revolution, in the 1930s, and they have carried on sporadically ever since. The trend began in Latin America where anti-colonial sentiment was perhaps strongest at the time. While Bolivia and Mexico led the takeover moves, Venezuela pioneered the push for profit-sharing with a 1943 move imposing taxes amounting to a 50/50 split of profits. Over time, all host governments have increased taxes on the extraction of oil and gas,

Thomas Dewhurst, the 'father' of the WPC



which in every country except for the US are in any case owned by the state. However, some states went further to maximise control over their petroleum deposits, especially where these constitute a country's main resource. Nationalisations continued in the 1950s (Iran), the 1960s (Iraq), the 1970s (Kuwait, Saudi Arabia), and even in 2012 (Argentina). This has totally changed the shape of the industry. Up to 1970 it could still be said that the sector was dominated by the original, private sector 'Seven Sisters' which, after multiple mergers, survive in the shape of ExxonMobil, Chevron, BP and Royal Dutch Shell. However, the sisterhood that today controls access to around 80 per cent of the world's oil and gas reserves is state-owned or controlled, such as Saudi Aramco, Gazprom, Rosneft, China National Petroleum Corporation, National Iranian Oil Company, PDVSA, Petrobras, Petronas, Pemex and Statoil.

1940s: The wartime interruption

This decade was fallow in terms of international cooperation – the Congress planned for 1940 in Berlin never took place – but fertile in terms of expansion of resources, technology and operations. The war brought home the centrality of oil. Japan's attack on the US was partly motivated by the oil embargo that the US imposed on it. Germany's failure to capture the Soviet oil fields of the Caucasus and the Caspian played a part in its overall defeat. However, war-time Germany was able to transform coal into fuel oil through the Fischer-Tropsch process, the basis of further post-war development of synfuel projects; the biggest of these is Shell's Pearl plant in Qatar which started operations to turn gas into liquids in 2011.

The decade also saw two landmark events. One was discovery in Saudi Arabia in 1948 of the first of the five reservoirs that make up Ghawar, the world's biggest oil field. These five reservoirs were discovered individually, starting in 1948 with Ain Dar in 1948 and ending with Hawiyah in 1953. But they all showed the contact point between oil and water coming at the same depth, indicating that they were essentially part of one huge reservoir 280 kms long and 40 kms wide. Ghawar's production peaked at 5.7 million barrels a day in 1981, but still amounts to some 5 million b/d. The other landmark event came in 1947 when Kerr-McGee of the US struck oil in the Gulf Mexico using the first offshore platform ever built in water that was deep enough to be out of sight of land (10 miles off the Louisiana coast).

Clever conversions

During the Second World War, Germany used the Fischer-Tropsch process, invented in Germany in the 1920s, to

The birth of offshore exploration – Oil is struck at Ship Shoal 32, about 16 kilometres off the Louisiana coast in November 1947

convert coal into oil. By war's end it had 11 coal-to-liquid (CTL) plants producing 10 per cent of its total fuel and around a quarter of its motor fuel. South Africa is another petroleum-poor but coal-rich country, and during the apartheid era, it developed CTL in order to offset the United Nations oil embargo imposed on it. Today there is somewhat more interest in using the Fischer-Tropsch process to turn gas into oil, given the solution that this provides for 'stranded' gas deposits without easy transport and given that the thermal efficiency in GTL is slightly higher than in CTL. Sasol of South Africa has built the Oryx gas-to-liquids (GTL) plant in Qatar, and has plans to develop GTL in the US to take advantage of cheap shale gas there. For its part, Shell built its first GTL plant in Malaysia, and has now completed the very big, and expensive, Pearl GTL complex in Qatar. At a cost of US$19bn, Pearl is producing 140,000 barrels a day of GTL gasoil, kerosene and naphtha for cars, planes and plastics.

1950s: WPCs revived

The 3rd WPC was held in the Hague in 1951 in what the secretary-general of the time described as "a mood of excitement and challenge" at renewed international dialogue after so long a lapse. For the first time the economics of the industry came up for discussion, in particular influences on oil-pricing such as transport which by now was increasingly by tanker ships. In the background, too, was the growing resource nationalism of oil-producing countries, spreading from Latin America to the Middle East, which was by now increasingly displacing the US in the export market. By 1950 Venezuela had established a 50/50 split of royalties and taxes with the international oil companies, and in 1951 Iran nationalised its monopoly producer, the Anglo-Iranian Oil Company (forerunner of BP), though this was partially reversed after the 1953 coup.

By the time of the 4th WPC in 1955 in Rome, technology discussions gave increasing weight to the development of seismic reflection that had become the main instrument for delineating oil deposits, as well as continued discussion of directional drilling and fracturing as techniques to exploit such deposits. The 1950s saw a surge in alternative use for oil and gas, as a result of the wartime boost given to synthetic detergents (as a substitute for soap) and of the advances in petro-chemistry. But refining of standard petroleum products remained a concern, for instance the discussion at the Rome Congress on

The* Methane Pioneer *carried the first cargo of LNG across the oceans in 1959, from Lake Charles, Louisiana to Canvey Island, UK

how to widen the range of middle distillates to fuel an increasing range of petrol and diesel engines.

The 5th WPC in New York in 1959 was timed to react to two developments. One was the very first transport, in January of that year, of a cargo of liquefied natural gas in the hold of the aptly named Methane Pioneer from the US to Britain. The New York Congress could therefore be reassured that this new form of gas transport was technically and economically feasible, though the first regular LNG cargoes did not start until 1964 with a shipment from Algeria to Britain. The other development was the emergence of nuclear power – following the opening of the first civil reactor in the UK in 1956 – which prompted anxious discussion of the extent to which nuclear might displace oil in the overall energy mix. In the event, such anxiety has proved misplaced.

LNG

Shipment of liquefied natural gas was pioneered in the late 1950s, commercialised by the mid-1960s and today accounts for more than 10 per cent of world gas demand. Qatar and Australia are the biggest LNG exporters, and east Asian countries the biggest importers. There are wide regional differentials in gas prices around the world. At one end of the range is Japan, which is currently willing to pay very high prices for gas after the Fukushima earthquake/tsunami knocked out many of its nuclear plants, and at the other end is the US where the shale gas glut has lowered prices. Such differentials may eventually converge through LNG trade. LNG is a flexible alternative to the rigidities, physical and contractual, of transporting gas by pipeline. Adding further flexibility is the development of floating LNG facilities which allow gas to be liquefied or re-gasified at sea.

One of the first meetings of OPEC after its founding in 1960

Photo: OPEC

1960s: The calm before the storm

Major oil-exporting countries formed OPEC in 1960, angered by the way that the unilateral decision by the international oil companies to cut the official price of crude also unilaterally reduced oil producers' tax revenues. OPEC has since become the major determinant of oil supply, but it was the 1970s before it made a major impact. Much of the work therefore of the 6th WPC in Frankfurt in 1963 focussed on ways to introduce ever more precision into exploration and production. At about the same time, Humble Oil in the US was inventing and testing a form of 3-dimensional seismic.

A feature of both the 6th WPC and the 7th one in Mexico City in 1967 was an examination of oil reserves. An attempt was made to quantify reserves into the categories of proven, probable and possible, but because these categories depend on changing economics and technology no definitive conclusion was reached then, or indeed later. The following year, however, saw a serious addition to oil supply outside OPEC. In 1968 Arco (subsequently part of BP) and Humble Oil (Exxon) struck oil at Prudhoe Bay on Alaska's North Slope. This discovery, plus development of another non-OPEC oil province, the North Sea, provided some balance to OPEC's market power.

Seismic breakthrough

Seismic waves were first used to detect oil in 1924. However, for a long time the technology used was two-dimensional (2-D) seismic recording using straight lines of receivers, which provided only strips or snapshots of information. This was rather like getting a piecemeal photo of a human face that gave no indication of the location of eyes, mouth or nose. But in 1963 came the invention of 3-D seismic surveying, a technique able to provide information continuously through the subsurface and therefore to revolutionise oil and gas detection. In that year Whit Mounce of Humble Oil, a predecessor of ExxonMobil, came up with a method for 3-D imaging. In order to process the far greater volume of data, Humble Oil teamed up with Geophysical Services Inc (GSI) to develop and build the first digital seismic recording system in 1964.

GSI's subsidiary on the project, Texas Instruments, went on to become a global company. Seismic is now used not just in exploration, but also in reservoir management through 4-D seismic which measures flows over time.

1970s: Turbulent times

The 8th WPC in Moscow in 1971 symbolised the new energy interaction between the Communist and non-Communist parts of the world. By then the Soviet Union was selling gas to western Europe and importing pipe and equipment from the west. Nonetheless, these two regions of the world still operated under very different commercial conditions. The Soviet bloc had an oil pricing system only loosed linked to that operating in the non-communist world, where OPEC was beginning to flex its muscles. So there was relatively little debate of oil prices and economics in Moscow, where most discussion focussed, as usual, on drilling and production, on geology and geophysics, and on refining.

However, the world was turned upside down before the next WPC meeting, the 9th Congress, in Tokyo in 1975. The Yom Kippur war broke out in 1973. Arab oil producers embargoed supplies to the US and to certain European countries judged to be supporting Israel. As insurance against future oil cut-offs, the major industrialised countries founded the International Energy Agency, whose primary aim was to devise and maintain a system of oil stockpiling and sharing in future supply emergencies. Rapid moves were made to develop non-OPEC sources of supply; the US approved construction of the Alaska oil pipeline in 1973, while the first North Sea oil came ashore in Britain in 1975. Not surprisingly, the widest interest at the Tokyo Congress was in papers on conventional reserves of oil and on alternative sources such as coal gasification and liquefaction, oil shale and oil sands. However, authors of the papers could not escape the conclusion that most of the word's oil still lay in the Middle East and much of its gas; in 1971 the world's largest conventional gas field was discovered stretching across the Gulf, in Qatar known as North Dome and Iran as South Pars. By the time of the 10th WPC in Bucharest in September 1979, congress participants were showing notable caution in making any forecasts about this volatile world of petroleum. The Iranian revolution, then underway, was in the process of bringing the country's oil exports to a virtual halt with a consequent impact on world oil prices. Iran's oil output fell from 5.3 million b/d in 1978 to 1.3 million b/d in 1981.

From confrontation to cooperation

What might be loosely called the governance of today's oil world emerged in the 1970s, with the development of the Organisation of the Petroleum Exporting Countries (OPEC) as a muscular protagonist of oil producing countries' interests, and the creation in 1974 of the International Energy Agency (IEA) as a countervailing force to protect oil-consuming countries' interests. Both bodies have

The 1973 oil crisis spurred the rapid development of non-OPEC supplies

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Helle Thorning Schmidt
Prime Minister of Denmark

“*As EU commissioner for Energy I would like to express my support to Copenhagen’s and Denmark’s announced candidacy to host the Petroleum Council Congress in 2017.*

Günther H. Oettinger
Member of the European Commission

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evolved since. OPEC is now seen more as a stabilising force in the world oil market, adjusting output to smooth price fluctuations and producing an annual World Oil Outlook publication. A parallel body for gas, the Gas Exporting Countries Forum (GECF), was set up in 2001, though as its title indicates, it is more of a forum for discussion of gas issues than an organisation designed to influence the gas market and prices. The IEA was set up to deal with the oil supply crisis arising out of OPEC's 1973-4 oil embargo on certain western countries, and has an emergency oil-sharing mechanism among its members. But the IEA has evolved into the world's premier body for energy analysis, and forged links with the major energy-importing countries of China and India. IEA and OPEC officials feature regularly at WPC Congresses, and take a major role in the producer-consumer dialogue in the International Energy Forum.

1980s: A new price regime

This was the decade in which the old system of setting of oil prices administratively, first by the international oil companies and then by OPEC, definitively broke down in the mid-1980s, and was replaced by the setting of oil prices through trading. Nationalisations had also by this time disrupted the vertically-integrated operations of the international oil companies which increasingly had to go on to the oil market to buy the crude they no longer owned but which they still needed to keep their refineries going. Futures trading developed, partly for the usual reason of reducing price risk and partly because western oil majors needed a price benchmark to show to their tax authorities (which were now able to take a more active interest in the newly-opened up internal workings of the oil companies). Futures exchanges developed the benchmarks of Brent, West Texas Intermediate and Dubai.

But this revolution in pricing was to come after the 11th WPC in London in 1983. This meeting was preoccupied with the drop in oil demand that followed the surge in prices caused by the Iranian revolution, but also with the rising cost of discovering and producing increasing amounts of oil in frontier regions outside OPEC. By 1985 the non-OPEC share of oil output rose to 69 per cent of the world total, compared to only 50 per cent in 1978. With their lower share of world output, OPEC countries found they could no longer impose their official pricing on the market and the oil price collapsed in 1986. Thereafter OPEC countries switched to controlling their own production through quotas in order to influence prices.

By the time of the 12th WPC in Houston in 1987, the industry was having to cope with a much lower oil price. Some congress participants bravely took the lower oil price to be "a stimulating challenge" to

The Eleventh World Petroleum Congress in 1983 took place in London

continued exploration and production of oil. Ways were discussed of cutting exploration costs, such as the use of 3-D seismic reducing the number of dry wells drilled – or avoiding exploratory costs altogether by focussing on enhanced oil recovery from existing wells.

Today's oil pricing: Legacy of the 1980s

Since the 1980s the level of oil prices has been left to the market to decide, particularly the futures exchanges that trade the benchmarks of Brent, West Texas Intermediate and Dubai off which most of the world's oil is priced. These futures contracts are standardised in everything except price – which makes them an ideal medium for price discovery through trading, but not necessarily for allocating specific grades of oil to specific destinations. So, in parallel with the futures exchanges, over the counter (OTC) trading has developed, using the futures market prices as benchmarks but introducing premiums or discounts to reflect quality, transport and destination. Price reporting agencies such as Platts, based in the US, and Argus, based in the UK, specialise in recording prices in these OTC markets. Unstable prices pose a common problem for both producing and consuming countries, but they have different remedies. Many consuming countries stabilise their retail oil price by loading it with tax, while producing countries in OPEC stabilise the price by controlling output.

1990s: Geo-political and climate change

The ending of the Cold War at the start of this decade had consequences for the energy industry. It allowed the United Nations to present a common front against Saddam Hussein's Iraq for its 1990 invasion of Kuwait (on a pretext over oil), and, under US leadership, to mount a huge military coalition that expelled the Iraqis from Kuwait the following year. However, the fact that Saddam remained in power kept Iraq under UN sanctions which effectively restricted Iraqi oil production for the rest of this decade and into the next one. A second consequence was increased east-west energy trade between Europe and Russia, and a third result of the collapse of communism in Russia was the privatisation of the country's large oil sector. By 1997 the Russians could report to the 15th WPC that they now had 15 vertically-integrated joint stock oil companies.

The first Gulf war produced the third sudden and sharp oil price spike in 17 years. But the oil market, and in particular the IEA's emergency oil mechanism which put extra oil onto the market, coped so well that there was little disruption in the market by the time the 13th WPC met in Buenos Aires later in 1991. The Congress was therefore free to concentrate much of its content on the fact that it was not only the first Congress to be held in South America, but also in the southern hemisphere. There was a focus on Argentina,

Futures trading in the pit at the New York Mercantile Exchange

Oil fields in Kuwait burn during the 1990-1991 Gulf War

Bolivia, Chile, Peru and Brazil, and also on South Africa, Indonesia and Australia.

It was inevitable that the 14th WPC in Stavanger in 1994, Norway's oil capital, would put the spotlight on the environment. Norway is not only the most environmentally-minded of all energy exporters, but Stavanger was also the first WPC since the Rio Earth Summit of 1992. Rio produced many documents on biodiversity and sustainability. However, most challenging for the petroleum industry was the UN Framework Convention on Climate Change, which aims to reduce man-made greenhouse gas emissions that are largely produced by burning fossil fuels. The Stavanger Congress was presented with a WPC Code of Environmental Conduct. This was adopted as voluntary guidelines rather than anything mandatory that would have violated the WPC rule of political neutrality and non-intervention in matters of policy.

The 15th WPC in Beijing in 1997 gave the industry a good glimpse of the future. On the supply side, there was discussion of clever technology such as 4-D seismic (with time constituting the fourth dimension) and the use of microbes to enhance oil recovery. But above all, the Beijing Congress gave participants some idea of what the expanding Chinese economy would soon add to demand for world petroleum. China's petroleum industry has made valiant efforts to match domestic demand with domestic supply; by 1997 Daqing, the largest Chinese oil field, had been producing over 1 million barrels a day for 21 years. But since 1993 China has been a net importer of oil in ever-increasing quantities.

Petroleum use and climate change

In the 1990s climate change became an issue for the petroleum industry as well as for the world, though some companies and countries were quicker than others to recognise this. Some international oil companies began to diversify into renewable energy sources such as wind and solar power. Today most of these companies have returned to what they regard as their core business of oil and gas, while retaining an interest in bio-fuels. However, companies have focussed on reducing the carbon intensity of their own operations in extracting oil and gas and manufacturing fuel. Natural gas, long considered a relatively worthless by-product of oil, began to be prized as the cleanest of the fossil fuels.

2000s: Social Responsibility

This decade saw some huge geopolitical events with ripple effects on the oil market – especially the 2001 attacks on the US, America's riposte in invading Afghanistan and Iraq and the violent aftermath in both countries, and the confrontation over Iran's nuclear programme. But it was a largely a good decade for the industry. The oil price slump in the late 1990s had had two effects. One was to trigger mergers among virtually all the international majors in order to turn themselves into supermajors to gain economies from greater scale. The other was to give the industry what John Browne of BP told the 16th WPC in Calgary in 2000 was "the new agenda of productivity", doing more with less. This set up the industry well for a decade that saw steadily increasing oil demand and prices until the financial crisis hit in 2008.

Brazilian sugarcane being harvested for ethanol production

Photo: UNICA

In these relatively benign market conditions, the industry began to pay more attention to social and environmental aspects and consequences of its operations. The 17th WPC in Rio de Janeiro in 2002 was the first to treat the theme of sustainability – in all its social and environmental aspects – as part of the mainstream of the congress, not just as a side-event, and to include NGO leaders as speakers. This work was carried on to the 18th WPC in Johannesburg in 2005, with a particular focus on maintaining the human sustainability of the petroleum industry by introducing the WPC Students Programme, and to the 19th WPC in Madrid in 2008 that included a special session on water and the energy industry. Corporate social responsibility was made a theme of the Calgary Congress by, among others, Dick Cheney then CEO of Halliburton and shortly to be US vice president. The 17th WPC in Rio de Janeiro in 2002 carried the social responsibility and environmental themes further by integrating them into the WPC itself with the creation of special excellence awards in these areas. Statoil won the technical award at Rio for its underground storage of CO_2, and Schlumberger won the social responsibility award for its education programme. The 18th WPC in Johannesburg maintained the same social and environmental focus. There was a stress on partnerships – not only between national and international oil companies, but also between the oil industry in general and non-governmental bodies campaigning for more transparency and less corruption in the oil sector. This first WPC in Africa was unique in that it was jointly hosted by the five leading oil and gas powers on the continent, giving the major producers – Nigeria (Africa's largest oil producer), Libya (its largest holder of oil reserves), Angola (its main operator in deepwater), Algeria (the leading gas producer) and South Africa (its specialist in liquefaction techniques) – a platform to show their wares. The 19th WPC in Madrid put sustainability into practice and was the first to offset its carbon emissions footprint, an initiative that was copied by future organisers. The discussions in Madrid were dominated by a spike in the oil price to the highest levels in history. Finally, the 20th WPC in Doha brought the Congress for the first time to the Middle East. An extra stream was added to accommodate the great interest in gas, and it attracted the highest number of delegates ever. The 2014 Congress in Moscow will take the issue of sustainability further and address it under such aspects as development in the Arctic.

Corporate social responsibility

The 2000s saw growing awareness that the petroleum industry needed to minimise its impact, not only its carbon footprint but also its pressure on finite water supplies and, via bio-fuels, on food resources. The 2010 Deepwater Horizon accident and massive spillage in the Gulf of Mexico reinforced the necessity for greater safety and environmental precautions. This awareness has made corporate social responsibility a priority for individual companies, not necessarily because of mandatory government regulation but because CSR is considered part of an oil company's general licence to operate in society.

The 2010 Deepwater Horizon accident reinforced the need for greater safety precautions

The Ninth Decade

This anniversary publication looks forward as well as back. It focuses on five key areas for the future: geo-politics and global cooperation in the petroleum industry; major regional developments in Asia, the US and Africa; technical advances; environmental and social sustainability; and organisational and financial issues for the industry.

Geo-politics and cooperation

In recent decades, the geo-politics of the oil industry have largely shifted from confrontation to cooperation. This emerges from the first three articles – by **Abdalla Salem el-Badri,** Secretary General of OPEC, **Maria van der Hoeven,** Executive Director of the International Energy Agency, and **Aldo Flores Quiroga,** Secretary General of the International Energy Forum that organises the global consumer-producer dialogue for the petroleum industry. OPEC, formed in 1960 to defend exporting countries' interests, and the International Energy Agency, created in 1974 as the consuming countries' riposte to OPEC, now cooperate in the International Energy Forum's consumer-producer dialogue instituted in 1991. Largely gone, too, is the era of nationalisations that started in Latin Americas in the 1930s, when the WPC was young, and still sporadically continues there. Today the WPC is a forum for international oil companies (IOCs) and national oil companies (NOCs) to discuss cooperation, as outlined in this publication in separate case studies from **Andrew Brown** of Shell and **Milton Costa Filho** of the Brazilian Petroleum, Gas and Biofuels Institute. A third category – INOCs or International National Oil Companies – has also evolved in the shape of state-owned companies that operate outside their own state territory. For a prime example of an INOC, read the article by **Zhou Jiping**, President of the China National Petroleum Corporation.

Regional developments

Three quarters of China's oil production is domestic in order to satisfy that country's soaring demand. Such is Chinese oil demand today that, as **John Mitchell** of Chatham House shows, it now outstrips what the big Middle East producers have available for export. Luckily for the balance of world supply and demand, the US is now reducing oil imports thanks to its home-grown revolution in hydraulic fracturing to release large quantities of oil (and gas) trapped in shale rock. **J. Robinson West** of PFC Energy examines how this "back to the future" US energy revolution came about, and what it portends. Also to be weighed in the balance against the rise in Chinese oil imports is the expected supply increase from major producers such as Russia. **James**

The Twentieth World Petroleum Congress was held in Doha, Qatar in 2011

Henderson of the Oxford Institute for Energy Studies gives us a sweep of Russia's petroleum industry from its beginnings in the Caspian to its new frontiers in the Arctic. The world of natural gas is very much one of regionally-supplied and regionally-priced markets. But the world-wide development of LNG is beginning to link these markets up, as explained by **Mahmoud Abu-Saad** of Qatar Petroleum.

Technical advances

The bedrock of the industry has always been its technological innovation, always a strong focus of WPC discussions. Drilling techniques have advanced far from what it was at the time of the 1st WPC in London in 1933, the year in which Hughes engineers invented the tri-cone drill bit, greatly speeding up drilling. But the technology about where to put a drill and the information that can be gleaned from drilling has changed beyond all recognition with the development of seismic imaging and of down-hole electronic sensors encased in drill bits. It was Humble Oil, a subsidiary of today's Exxon Mobil that in 1963 invented and tested out 3-dimension seismic imaging, and **Sara Ortwein** of ExxonMobil explains how subsequent development has revolutionised exploration. Schlumberger, the oil service company, has been at the forefront of computerising the interpretation of well drilling, and **Paal Kibsgaard** of Schlumberger sets out what has been achieved in the past 10 years and what to expect for the next 10 years. For his part, **Jeff Miller** of Halliburton focuses on the technology that has made unconventional oil and gas the most exciting development in today's world.

Offshore drilling technology is considerably younger than the WPC. It was the early 1990s before companies such as Petrobras off the shore of Brazil and Shell in the Gulf of Mexico successfully established platforms in water more than 2,000 feet deep. Since then, in these areas and also off west Africa, oil explorers have gone into ever deeper waters. However, the 2010 explosion of BP's Macondo well in the Gulf of Mexico, leading to the biggest oil leak ever, has provided a cautionary lesson about the inherent risks of tapping into high-pressure hydrocarbons at water depths that immensely complicate control of spillages. This serious accident, which killed 11 people, has led to a revamp of safety procedures in the Gulf of Mexico, in the way that the 1988 Piper Alpha disaster, which killed 167 people, caused safety procedures in the North Sea to be overhauled. The relative risk and reward of drilling for oil and gas in deepwater is examined by **Christophe de Margerie** of Total. He has cautioned that extra hazards of remoteness and extreme cold would make it so difficult to deal with an oil spillage in the Arctic as not to be worth the risk. By contrast, gas leaks present no comparable pollution problem, except through methane adding to greenhouse gases in the atmosphere. To increase the productivity of offshore fields, BP, as **Jackie Mutschler** of BP explains, has developed the simple but ingenious solution of using seawater with reduced salt levels to free oil molecules from surrounding rock or clay.

Improved technology means that most of the big fields have probably been found: East Texas in 1931, the Ghawar complex of fields in 1948-52 in Saudia Arabia, the Groningen gas field in the Netherlands and China's Daqing oil field in in 1959; Alaska's Prudhoe Bay in 1968 and the 1971 of the world's biggest gas field stradding the Gulf between Qatar and Iran. But **Chris Schenk** of the US Geological Survey tells us in this publication how much more undiscovered conventional oil and gas the world can expect to uncover.

Sustainability

The degree to which the petroleum industry is responsible for, and responding to, the climate change challenge is examined by **Hege Marie Norheim** of Statoil. The petroleum industry's effort to make more sparing and intelligent use of water is described by **Brian Sullivan** of IPIECA. The WPC's own contribution to social responsibility and sustainability is set out by **Ulrike von Lonski**.

Managing the industry

The industry needs money and people to sustain itself – the new financial challenges facing it are analysed by **John Martin** of Standard Chartered Bank, while the task of recruiting and training new generations is set out by **Antoine Rostand** of Schlumberger Business Solutions. But the industry also has to show itself flexible and resilient when confronted with exceptional emergencies. **Junichi Hatano** secretary general of WPC's Japanese national committee explains how his country's petroleum successfully rose to the energy crisis caused by the Fukushima earthquake. ■

WPC Timeline 1933-2013

1930
East Texas oil field discovered

1933
Invention of the tri-cone drill bit

1933:
1st Congress
London

1937:
2nd Congress
Paris

1938
Mexico nationalises its oil industry

1943
Venezuela tax leading to 50/50 profit split

1947
First offshore drilling out of sight of land

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:
5th Congress
New York

1959
First cargo of LNG carried by Methane Pioneer

1960
Formation of OPEC

1963:
6th Congress
Frankfurt Am Main

1963
Invention of 3-D seismic surveying

1967:
7th Congress
Mexico City

1968
Oil discovered on Alaska's North Slope

1971:
8th Congress
Moscow

1971
Discovery of world's largest gas field in the Gulf

1973
Arab-Israeli war and Arab oil boycott of US

1974
Creation of International Energy Agency

**1975:
9th Congress
Tokyo**

**1979:
10th Congress
Bucharest**

1979
Iranian Islamic revolution

1980
Iran-Iraq war starts

**1983:
11tt Congress
London**

1986
Oil price collapse

**1987:
12th Congress
Houston**

1990
Iraq invades Kuwait

1991
US-led coalition expels Iraq from Kuwait

**1991:
13th Congress
Buenos Aires**

1992
Earth Summit in Rio highlights climate change

**1994:
14th Congress
Stavanger**

**1997:
15th Congress
Beijing**

1998
Oil price drops to US$10 a barrel

**2000:
16th Congress
Calgary**

2001
Al-Qaeda attacks on New York and Washington

**2002:
17th Congress
Rio de Janeiro**

2003
US-led invasion of Iraq

**2005:
18th Congress
Johannesburg**

2008
Record oil price of US$147 a barrel

**2008:
19th Congress
Madrid**

**2011:
20th Congress
Doha**

ASTANA

A TREASURE ON THE NEW SILK ROAD

WORLD PETROLEUM COUNCIL
KAZAKH NATIONAL COMMITTEE

ASTANA 2017

HOST CANDIDATE

22ND WORLD PETROLEUM CONGRESS

THE WORLD PETROLEUM CONGRESS 2017

Dear Council Member,

Kazakhstan is among the top ten largest countries in the world in terms of its land size and the hydrocarbons reserves. International integration of the national energy sector and commercial explorations of the world-renowned oilfields have led Kazakhstan to become a "global player" in the supply of the energy resources to the world markets.

Astana is a dynamic city striving for the future with its modern architecture combining the traditions of the eastern and western cultures. Our young and peaceful capital has quickly become a political, cultural and economic centre over the last two decades.

In 2017, the city will host the EXPO-2017 International Exhibition, one of the most prestigious events in the world. A new city is being planned on a 125 hectare land near the Astana International Airport for this special global gathering. The state-of-the-art conference and exhibition facilities will be surrounded by hotels, shopping malls, social buildings and auxiliary structures. We are honoured to propose to host the 22nd World Petroleum Congress in this new city right after the closing of the EXPO-2017 International Exhibition, in October 2017. With its main theme – Future Energy – the Exhibition would give fresh a impetus to discussions within the World Petroleum Congress attracting extra interest from the international community.

On behalf of the National Committee of the Republic of Kazakhstan, I would like to invite you to our beautiful country to share a unique and unforgettable experience with all of us.

We look forward to welcoming you to Kazakhstan and Astana.

Yours Sincerely,

Timur Kulibayev

Chairman,
National Committee of Kazakhstan
World Petroleum Council

WORLD PETROLEUM COUNCIL
KAZAKH NATIONAL COMMITTEE

ASTANA WPC 2017
HOST CANDIDATE

FROM THE ASIAN STEPPES

TO WORLD MARKETS

"Kazakhstan has established itself as a responsible and reliable supplier of energy resources, contributing to the energy balance of the global economy."

Kazakhstan, which is the size of Western Europe, is located in Central Asia between Russia, Caspian Sea and East of China.

Over the last two decades, Kazakhstan has made considerable progress towards the establishment of a market economy and the provision of an attractive climate for foreign investment.

In the last decade, Kazakhstan has become one of the leading countries attracting significant investment per capita globally.

In 2010, the hydrocarbon sector accounted for almost 30% of gross domestic product (GDP), contributed to around half of GDP growth, and hydrocarbon exports amounted to over 60% of total exports.

Kazakhstan has established itself as a responsible and reliable supplier of energy resources, contributing to the energy balance in the world economy.

Kazakhstan's energy market is transparent and open for foreign players. Over the past 15 years, the country has attracted nearly $50 billion of foreign direct investment, most of which (80%) in the hydrocarbons extraction and processing sector.

Kazakhstan will be one of the ten largest oil producers in the world and the largest energy resource located next door to the world's biggest economy (China) by 2020.

Evaluated by proven oil and gas deposits, Kazakhstan is among the top 15 countries holding 3% of global hydrocarbons reserves.

In Kazakhstan, there are 172 oil and 42 gas condensate fields, more than 80 of these are currently being developed. Oil and gas fields in Kazakhstan occupy 62% territory of the country.

The main oil reserves in Kazakhstan (over 90%) are concentrated in 15 major fields mainly in the west of the country.

Half of the reserves are located in the Kashagan and Tengiz oil fields. The Karachaganak field holds the major part of the total free gas reserves (about 60%) and gas condensate (about 80%).

Currently, operations in the oil and gas sector are carried out under more than 250 contracts for subsoil use.

A majority of the International Oil Companies (IOCs) and many National Oil Companies (NOCs) have operational presence in Kazakhstan.

In the past few years the National Company of Kazakhstan has expanded significantly with international investments in the West of Caspian and East of Europe.

In terms of its wide geography and diversified characteristics, the Oil and Gas Industry of Kazakhstan offers a range of technical and scientific excursions to visitors.

WHY IS ASTANA A BETTER CHOICE FOR YOUR VOTE?

BECAUSE...

...Astana will host the EXPO-2017 International Exhibition, one of the most prestigious events in the world, with the theme: “Future Energy”

...it is expected that more than 5 million visitors from different countries will visit EXPO-2017 International Exhibition in three months

...the proposed venue for the World Petroleum Congress is under development on a 125 hectare site near the Astana International Airport

...the proposed dates for the World Petroleum Congress 2017 are straight after the closing of the EXPO-2017 International Exhibition, in the period around October 2017

...the exhibition stands for the World Petroleum Congress would also be available throughout the EXPO-2017 International Exhibition

...Astana International Airport is only minutes by car (5km) from the EXPO-city and the city centre is only 10 minutes by car (7km)

...in addition to the conference and exhibition facilities, there will be hotels, shopping malls, cafes and restaurants inside the new EXPO-city

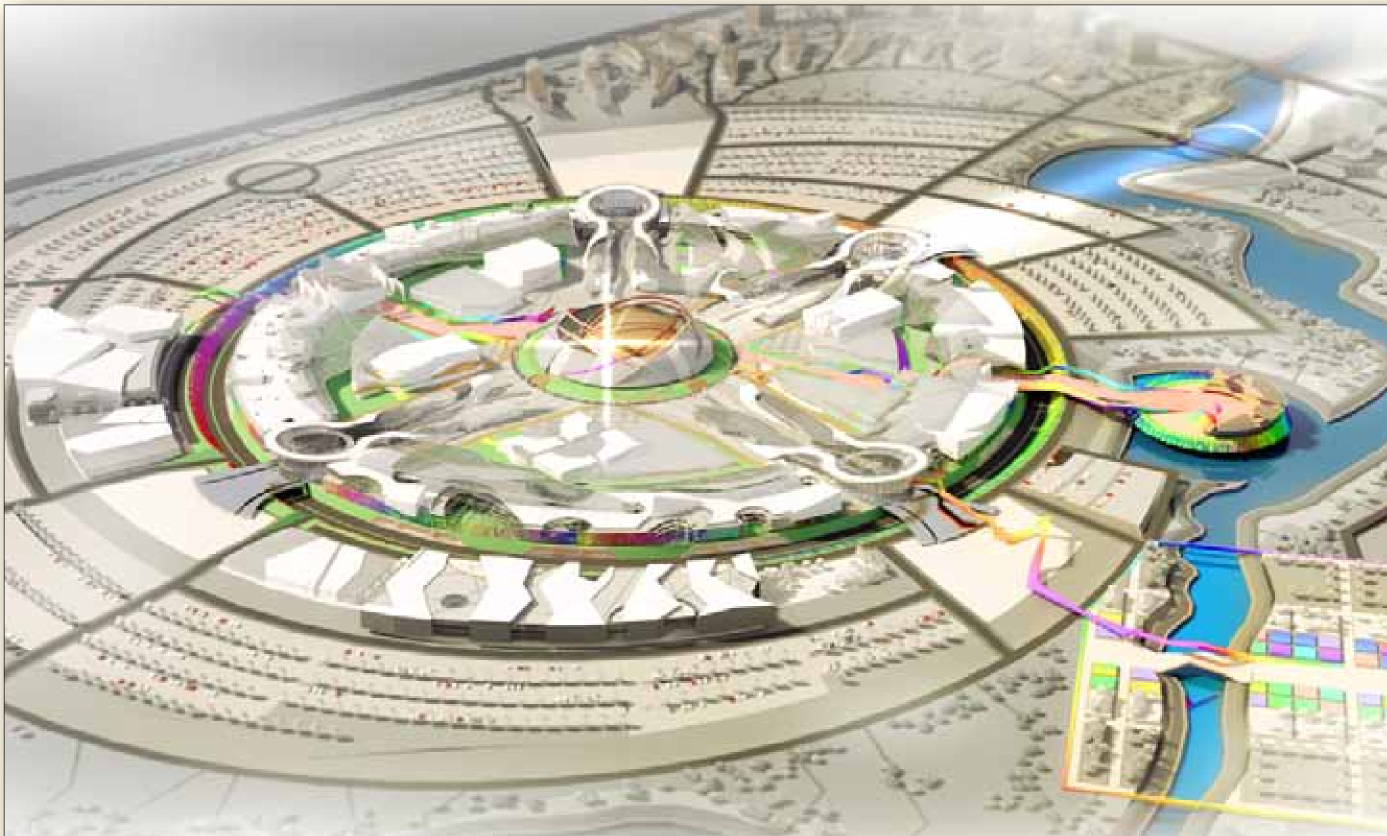
...Astana has hosted significant international political, economic and and inter-religious events, associated with Peace, Harmony and Global Understanding

...it is an historic coincidence that an EXPO with the theme of FUTURE ENERGY would coincide with the Olympics of the Oil and Gas Industry

...Astana is a safe, beautiful and walkable city offering a variety of cuisines from different parts of the world and choices of cultural activities at day and night

...there will be visits to high-technology and scientific infrastructure sites in West Kazakhstan and Caspian Sea Offshore (Kashagan, Tengiz, etc.)

...there will be an excursion to Baikonur Space Station in the West of Kazakhstan as part of the social programme during the World Petroleum Congress



Artist's impression of the design for EXPO-city in Kazakhstan

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Uncertainty creates concern over security of oil demand

By Abdalla Salem El-Badri
Secretary General, OPEC

Energy has been central to much of humanity's progress over the centuries. It has positively impacted the lives of billions. And it will be just as important to our future economic and social progress. It is easy to understand why.

Firstly, the world's population is expected to reach more than 8.6 billion by 2035, an increase of over 1.5 billion from today's level. To put this into perspective, the world will add close to the combined population of India and the United States in just over 20 years.

Secondly, although many uncertainties remain and many challenges need to be overcome to get the global economy back onto a sustainable growth path, the global economy will rebound in the medium and longer term.

And thirdly, with around three billion people living on less than US$2.50 a day 1.3 billion people having no access to electricity and some 2.6 billion relying on biomass for their basic needs, there is huge potential for socio-economic development.

It is clear that world energy demand is set to grow. In OPEC's most recent *World Oil Outlook* (WOO), energy demand in the Reference Case increases by 54 per cent. Fossil fuels, currently accounting for 87 per cent of this, will still make up 82 per cent of the global total by 2035 (Figure 1). For most of the projection period, oil will remain the energy type with the largest share. However, towards the end of the projection period, coal use in the Reference Case reaches similar levels to oil, with oil's share having fallen from 35 per cent in 2010 to 27 per cent by 2035. Natural gas use will rise at faster rates than either coal or oil, both in percentage terms and quantity, with its share rising from 23 to 26 per cent.

In terms of non-fossil fuels, renewable energy grows fast. But it starts from a low base and its share will be still only 3.5 per cent by 2035. Hydropower increases a little, to nearly 3 per cent by 2035. And nuclear power will see a slight decline, with its prospects affected by the ongoing effects of Fukushima. It has a 6 per cent share in 2035.

In OPEC's WOO, demand for oil is expected to increase by over 20 million barrels a day (mb/d) over the period 2010-2035, reaching around 107 mb/d by 2035. This is driven mainly by developing Asia, which is home to 80 per cent of the oil demand growth over this period. In contrast, the OECD region actually witnesses a fall.

There are some who continue to ask whether we can meet this demand growth. There is no doubt that we can. Resources are clearly sufficient. Improved technology and enhanced recovery have over the years increased the resource base to levels well above past expectations. Recent estimates from the US Geological Survey of ultimately recoverable resources are over 3.8 trillion barrels. To put this into some context, cumulative oil production to date has been less than a third of this. And today we are seeing new resources and supplies from a variety of sources, such as shale oil, oil sands and deep offshore.

In terms of supply, total non-OPEC liquids supply increases by more than 10 mb/d over the period 2010 to 2035. Supply growth from the Caspian, Russia, Brazil and US shale oil, as well as steady increases in biofuels and oil sands, are far stronger than declines elsewhere. From OPEC's perspective, its overall liquids production also increases by over 10 mb/d between 2010 and 2035.

These developments mean that OPEC's crude supply needs to rise, but at a modest rate: by 2020, it would be almost 31 mb/d, and by 2035, it would need to be 35 mb/d. The share of OPEC crude in the global liquids supply thus remains similar to today, at around 32 per cent.

To meet future demand expectations, OPEC member countries continue to invest to maintain and expand supply capacities. The latest list of upstream projects shows OPEC member countries undertaking or planning about 116 projects during the 2012–2016 period. This corresponds to estimated investments of about US$270 billion.

Given current assumptions and projections in our Reference Case, as well as natural decline rates in existing fields, it is estimated that total OPEC liquids capacity will rise by 5 mb/d over the period 2012–2016. Thus, OPEC's spare capacity is set to stay at healthy levels. In fact, the WOO's latest figures see OPEC crude oil spare capacity exceeding 5 mb/d as early as 2013-14.

OPEC and its Member Countries continually strive to make sure the market is well supplied and that there are comfortable levels of spare capacity. Moreover, it is important that all stakeholders work to ensure market stability, so as to ensure that the necessary investments are made, that investors receive a fair return on capital and that consumers have an efficient, economic and regular supply of petroleum.

However, the future is rarely a simple continuation of the past. Many uncertainties are associated with oil demand projections, which can be viewed in scenarios from this year's WOO. Two of the scenarios look at plausible economic growth alternatives to the Reference Case, one lower and one higher. And the third scenario examines the possible impact of a liquids supply surge, other than that from OPEC crude.

These scenarios highlight important implications for the range of required OPEC oil and investments, emphasising the uncertainties that lie behind the Reference Case projections. By 2035, expectations for OPEC crude in these scenarios are as low 25–26 mb/d and as high as 43 mb/d (Figure 2).

This underscores that there are genuine concerns over security of demand. And in addition, of concern to producing countries are the policies of a number of consuming countries, particularly those that look to discriminate against oil. Obviously, every country has the sovereign right to set its own policies, but it is essential that these provide a clear picture as to their impact on future oil consumption levels and overall energy supply and demand patterns. They need to be feasible and sustainable.

In the downstream, the WOO 2012 estimates that more than 7 mb/d of new crude distillation capacity will be added to the global refining system in the period up to 2016. Driven by growing demand, the highest portion of this new capacity is expected to materialise in Asia, mainly in China and India, accounting for more than 40 per cent of additional capacity.

However, at the same time ongoing refinery closures, primarily in OECD regions, will offset part of the capacity increases from new projects. At the global level, closures have already reached 4 mb/d and are heading to the 5 mb/d mark, affecting not only small and simple plants, but large and complex refineries as well.

Figure 1: World supply of energy by fuel type

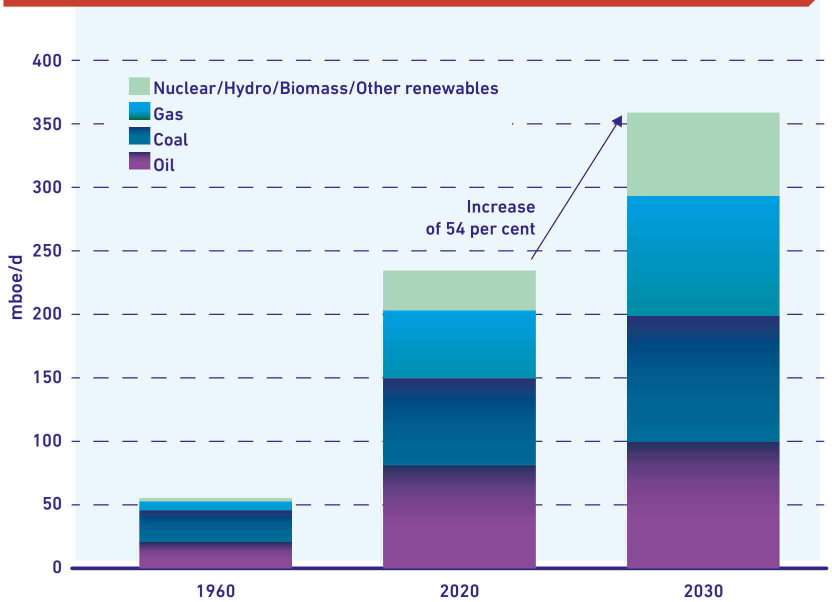
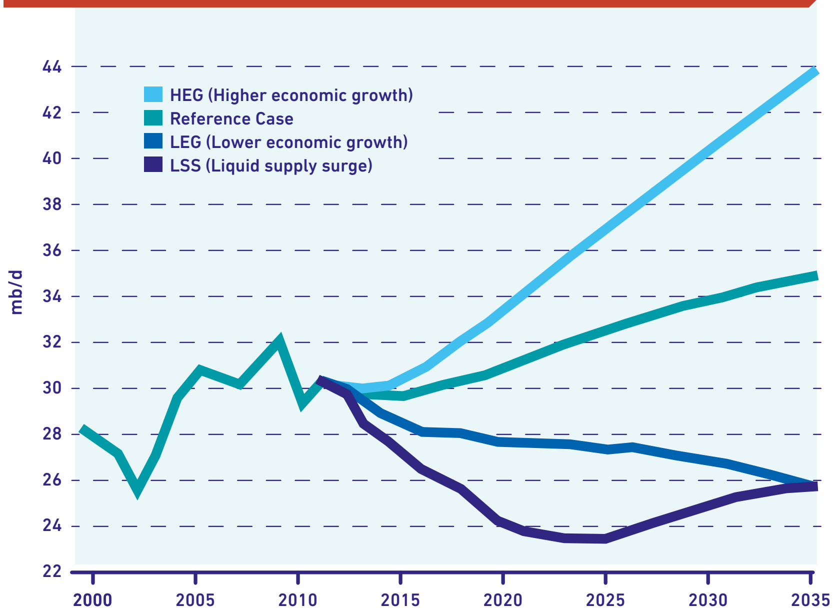


Figure 2: OPEC crude oil supply in three scenarios



Nevertheless, over the medium term, the net effect of new projects and refinery shutdowns, compared with required crude runs, will be a growing capacity surplus – unless more closures take place than those currently being announced. Despite some marginal improvements in refinery utilisation rates expected this year and next, the cumulative capacity overhang in the sector is set to increase by almost 1 mb/d by 2016. This reinforces the expectation that the downstream industry is facing a period of continued weak margins and relatively low utilisation rates.

In the years ahead, it is also important to recognise that there are other specific challenges for the industry's stakeholders, as well as for world leaders.

This includes the ongoing climate change negotiations. OPEC recognises the importance of being part of these negotiations to develop solutions that safeguard the legitimate interests of all parties, with the most recent UN Climate Conference taking place in an OPEC Member Country, Qatar.

It is essential that these multilateral negotiations reach an agreement that is comprehensive, balanced, fair and equitable. Here, it is important to remember that it is vital that every single one of us in the world has access to modern energy services. Energy poverty needs the urgent and critical attention of world leaders.

Another ongoing challenge relates to excessive market volatility and the continuing trend towards oil becoming a heavily traded financial asset. Speculative investment flows can distort the price of crude. However, the challenge is not about eliminating speculation altogether. The issue is excessive speculation and extreme volatility. This is what needs to be tackled.

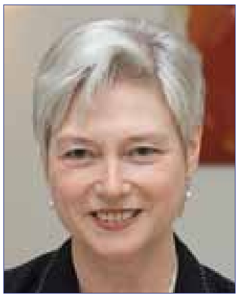
And in a business as labour-intensive as the oil industry, it is essential that there are the right human resources in place to allow the industry to grow. This means concerted efforts to restore this essential capacity, by facilitating education and training in energy disciplines, and making the industry an attractive career choice.

What will underpin our future, in terms of both the challenges and opportunities, are partnerships and cooperation – among producers and consumers, IOCs and NOCs, in fact, between all stakeholders.

With this in mind, it is important to look for shared solutions, where and when appropriate; to have a cooperative environment that is conducive to reaching constructive end results; and to have input from each and every stakeholder. Cooperative exchanges and constructive actions can achieve great things. The shared objective must be a stable and sustainable energy future in an increasingly interdependent world. ■

OPEC oil ministers attend the 163rd OPEC meeting in Vienna, Austria in May 2013

Safeguarding oil security



By Maria van der Hoeven
Executive Director, International Energy Agency

Energy security has been the primary mission of the International Energy Agency since its founding in 1974 following a major oil crisis. Indeed, the Agency was created to provide a framework in which IEA countries could defend their interests as key oil consumers. While that mission has since diversified across the fuel spectrum, oil remains the dominant energy source globally, and oil supply security remains a core responsibility of the IEA. And yet over almost 40 years, how we define and address that responsibility has developed considerably. Taking a wider view of energy and oil security is particularly important given the significant shifts that we are now seeing in the oil market – in terms of rapidly growing emerging market demand, but also in terms of new supply patterns all along the value chain.

Energy security refers to the ability of a given country to obtain uninterrupted availability of its main energy sources at an affordable price. In the short term, energy security is the ability of a given energy system to react promptly to sudden changes in supply and demand, maintaining the availability, affordability, accessibility and quality of energy. Long-term energy security is linked mainly to making timely investments to ensure that the future supply of affordable energy will support economic development and environmental goals.

Traditionally, the IEA has put a strong emphasis on mitigating the risks and effects of energy supply disruptions, particularly within oil markets. Coordinating the use of emergency oil stocks in the event of disruption is a well-known tool, but only one. Analysis to boost transparency in global oil markets, active participation in the Producer-Consumer Dialogue with OPEC and other major producers, and efforts to improve statistical openness, timeliness and accuracy through the Joint Organisations Data Initiative (JODI) all help to reduce the risk of disruption. At the same time, the IEA's tool-kit to respond to acute disruptions goes beyond emergency oil stocks, to include demand restraint and fuel-switching measures. Another important characteristic emphasised by the IEA is resilience – the ability of energy systems to mitigate or withstand disruptions, including in the oil market. Regular emergency response reviews of IEA member countries report on systemic strengths and vulnerabilities of national energy security policies, procedures and infrastructure, and the IEA's Model of Short-Term Energy Security (MOSES) measures both risk and resilience factors for comparison across countries and across fuels.

Yet while the traditional focus on supply disruptions remains important, major changes in the global energy economy since 1974 have required our conceptions of oil security (and energy security more broadly) to adapt. When the IEA was created, the oil market was based on long-term contracts and a stable relationship between suppliers and refiners. That has changed with the globalisation of oil markets, the importance of the spot market, and the development of high-speed information flows. Concerns about supply security of other fuels like gas and electricity, and also the interplay between fuel markets, has broadened the focus of energy security. And indeed we are defining energy security to include long-term concerns, like creating the conditions for sufficient investment and promoting energy access to boost living standards and economic development. We also recognise the linkage between sustainability and energy security – they are two sides of the same coin. Not only do low-carbon technologies help reduce import dependence and diversify the fuel mix, but recent IEA discussions have highlighted the adverse impact of climate change on energy infrastructures. All of this helps to change the nature of the energy security debate.

Perhaps the most significant change is a shift in the global energy map, and specifically the global oil map. Where OECD countries accounted for more than three-quarters of oil consumption in 1974, they will soon account for less than half. The economic rise of emerging markets like China and India have signalled a global economic rebalancing, including within energy markets. IEA analysis shows growing non-OECD demand, particularly in China, to continue over time. Meanwhile oil demand in Europe and the US is stagnating or falling.

That reality is the driver behind IEA efforts to engage with key partner countries in many areas, but particularly with regard to oil security. For several years, we have supported countries like China, India, ASEAN countries, and others in their efforts to improve emergency response measures and in some cases to build their own emergency oil stocks. That has included technical support, those countries' participation in regular IEA emergency response exercises (EREs), and unique tailored EREs in Thailand and India. Going forward, the IEA is working to develop a framework for cooperation with countries outside the IEA in the event of a disruption.

But the shift of the oil map does not just mean the rise of Asian demand, particularly looking forward. Our forecast of the oil market reveals a medium-term future marked by uncertainty, uneven supply and demand changes, and the potential for technological game-changers. That kind of volatility means a very different oil security environment, and one that requires both broad engagement and nimble response.

Despite volatility on both the supply and demand side, we have seen continued market tightness and consistently high prices thanks to contradictory forces at play. The economic recovery is stagnating. OECD countries suffer from persistent debt concerns, notably in the eurozone, and there are signs that even China is slowing. On the supply side, continued political upheaval in the Middle East and North Africa disrupted crude exports from several countries. Also, unplanned maintenance and technical disruptions at mature fields reached record highs last year, rekindling concerns about decline rates in aging plays. These risks are not going away, and contribute to a new "reality of risk" in the oil market.

At the same time, there is also good news on the production side. Despite events in the Middle East, the region has also seen success stories. Saudi production has surged to 30-year highs, and Iraq is also breaking production records. A special IEA report released in October 2012 highlighted Iraq's potential as a game changer going forward. Production is also surpassing expectations in North America, where high prices and new technologies have unlocked light, tight resources that were long thought to be impossible to tap economically. Our 2012 *World Energy Outlook* predicted that the US could become the largest oil producer around 2017 largely thanks to light, tight oil.

Combined with increased efficiency, we expect this overall picture to yield to markets that are less tight over the medium term. While that is generally good for supply security, and helps to lessen the impact of disruptions, it is no reason for complacency. In the US, for example, any talk about prospects for energy independence leaving room for disengagement from global markets or certain regions must be laid bare for the fallacy that it is. First of all, we project the US to continue to import more than a quarter of its oil by 2035. The oil market is global, and no matter its provenance, oil price and availability are still intricately tied with events and availability elsewhere – emphasising the need for cooperative oil security policy. And while supply may be growing globally, both supply and

The Bryan Mound facility in Texas, is one of four sites that make up the USA's Strategic Petroleum Reserve (SPR)

demand growth are exceptionally uneven, with effects throughout the market.

Most of the new supply is expected from the Americas, and most of the new demand from Asia, the Middle East, and the former Soviet Union. These twin changes have clear consequences for the midstream and downstream sectors, those often-overlooked but critical links in the supply chain. International crude trade volumes are forecast to dip, while product trade is expected to grow in both volume and scope amidst resurgent refining capacity expansion in Asia and the Middle East – and reducing capacity in the OECD. Those changing trade and product import patterns affect disruption risks, and also the paradigm for emergency oil stock-holding when it comes to crude/product balances.

Given these new realities – increased uncertainty, volatility, and technological change – we recognise that international oil security governance and emergency response procedures need to react in a timely and decisive manner. We regularly review the assessment procedures for IEA collective action in response to a substantial physical supply disruption. The important element in defining "substantial" is to analyse the potential economic impact against the backdrop of the current market. That is why there is no "one-size-fits-all" response, nor is there a specific size of disruption above which we act. It is also why the changing geographical dynamics of the oil market are so important to understand, as well as seasonal supply and demand fluctuations, refinery demand patterns, crude and product quality breakdowns, spare capacity figures, and timely commercial stock data.

For example, while the IEA used emergency stocks in 2005 in response to the US disruptions caused by hurricane Katrina against a backdrop of tight markets, it did not act at the end of 2008 when hurricanes Gustav and Ike had a similar effect against a backdrop of looser markets and a deteriorating global economic situation. When the IEA last released stocks in 2011 as a result of the crisis in Libya, the size of the disruption was comparatively small and the response was not immediate. That was because production remained shut-in as markets began to tighten seasonally thanks to rising demand in the summer. No two disruptions, and no two IEA actions, are ever the same.

The IEA's responsibility to safeguard oil supply security has been evolving alongside major changes in the global oil economy – particularly a major and ongoing redrawing of the global oil map. As this evolution continues, so changes the nature of our mission. A broader concept of energy and even oil security means focusing on resilience and long-term challenges, as well as response. When that response is necessary, it must be quick and decisive. And critically, safeguarding oil security requires global cooperation more than ever before. ■

Oil tankers cruise out of the Strait of Hormuz off the shores of Tibat in Oman

Pursuing the path pioneered by the WPC

By Aldo Flores-Quiroga
Secretary General, International Energy Forum (IEF)

International energy cooperation has evolved considerably since the establishment of the World Petroleum Council (WPC). Eighty years ago energy diplomacy was, to a significant degree, less about cooperation and more about control: securing energy resources within and outside a country's borders, imposing commercial practices, dictating the distribution of revenues, or exerting pressure to shift policies in one direction or another. Back then, the WPC was one of the very few forums offering a constructive dialogue as a way to promote the healthy development of the global oil and gas sector. Nowadays the nature of international energy relations, while not completely foreign to elements of control, is much more about cooperation and constructive diplomacy. In this regard, the dialogue the WPC pioneered for the oil industry has proven to be a valuable precursor of contemporary energy cooperation.

An institutional infrastructure at the bilateral, regional, and multilateral levels today facilitates energy cooperation in most areas, through a diverse array of initiatives. Producers of oil and gas have arrangements to promote their interests, just as consumers have theirs. Regional organisations work to promote energy integration by identifying specific energy opportunities that can only be seized by countries in the same geographical space. Organisations devoted to identifying opportunities and challenges for specific energy sources and technologies, from oil to gas to nuclear to renewable energies create knowledge while encouraging the adoption of best practices for the use of these energies. Global industry associations showcase technology as they facilitate the matching of buyers and sellers in the marketplace. International oil companies cooperate or partner with national oil companies and service providers to find and develop oil reserves in places that not long ago were considered out of any reasonable reach.

It could not be otherwise. Not only are attempts to enhance energy security through the control of other people's resources anathema to the sovereign rights of nations, and as such the source of much destructive conflict, but the cost and complexity of energy projects, together with constantly expanding energy flows, has increased – making it necessary for countries and companies to join forces more frequently. Put simply, when it comes to energy security, control has become more costly relative to cooperation. This is especially clear when one observes that easy to access oil and gas reserves have become more the exception than the norm. Oil exploration and production have marched from land to sea, from shallow to deep waters, from vertical wells to multidirectional ones, and from rocks with high permeability to rocks that must be fractured to release their bounty. All of this undoubtedly speaks to the triumph of technology, but it illustrates the importance that joint scientific research, technological exchanges, training, information exchange, or simply partnering to solve complex problems now have for energy security.

The mechanisms used today to cooperate on energy issues range from the structured and legally-binding (in principle) to the informal and voluntary. Examples of the first type include the negotiation of treaties, the setting of production quotas, or the release of strategic reserves. Instances of the latter type are typical of the occasional consultation and exchange of information, not necessarily within the framework of a formal treaty. In between these two extremes lie initiatives to conduct joint research, improve national and international energy regulation, increase transparency, and facilitate dialogue – among a broader set of possible actions.

The activities of the International Energy Forum (IEF) lie in the middle section of these extremes, where policy coordination is not the primary focus, nor is research a main activity, but instead where high-level dialogue at the cutting-edge of energy developments is instrumental to develop insights that help promote global energy security. Born as the Producer-Consumer dialogue at the height of the 1990-1991 Gulf War, when uncertainty about oil supplies and prices brought to mind vivid memories of the oil shock of 1979, the IEF has become perhaps the largest and most representative gathering of energy ministers in the world.

In a break with the practice of open confrontation when predictability in oil markets went awry, and when uncertainty was the source of much finger-pointing – as it can still be today at times – the IEF has provided a bridge for producers and consumers to meet each other in the middle, even to cross to the other side, to better understand the aspirations and concerns behind the actions of their counterparts. In doing so, the IEF has filled a void by providing an open, inclusive, flexible and neutral platform for energy ministers and experts to exchange their views on a considerable array of topics.

The IEF opens opportunities for in-depth, focused, and on-going conversation among the world´s key energy decision-makers, increasing their understanding of energy developments while helping them to identify shared concerns and opportunities for mutual gain. It generates knowledge that can only be obtained through dialogue. And by promoting transparency, it helps these actors assess market fundamentals and foster trust, an essential building block for cooperation and well-functioning markets.

Key issues that are part and parcel of today's energy landscape, and are certainly at the core of oil market developments that matter to the members of the WPC, are also at the centre of the ministerial dialogue under the framework of the IEF:

1. The short-term global oil supply-demand balance and its implications for spare capacity – as well as the level and stability of oil prices.

2. The long-term outlook for energy demand and supply, together with its implications for investment requirements, taking into account the level and structure of each.

3. The process of oil price formation, especially as it relates to the greater interaction between physical and financial markets, and the alternative pricing methods used for gas transactions in different regions.

4. The nexus between climate change and fossil fuel consumption, and the notion of addressing it with a combination of policies to promote energy efficiency and the deployment of renewable energies.

5. The management of environmental risks with adequate and globally compatible policies, in the wake of the Macondo and Fukushima accidents.

6. The potential impact of increased production from unconventional hydro-carbon resources – such as shale gas, tight oil, and deep-water oil – on the dynamics of global energy markets.

7. The relationship among IOCs, NOCs, and service companies, as efficient oil and gas production is increasingly dependent on the quality and intensity of the symbiotic interaction of these three essential players.

8. The human resource gap facing the energy sector worldwide.

9.The capacity of national governments and power companies to meet the electrical energy needs of their populations in many parts of the world.

Ministers participate in the producer-consumer dialogue because they recognise that these issues cannot be successfully addressed without international energy cooperation. The many links, synergies, and spillovers that result from daily market interactions – whether on the supply or demand side – translate directly into the realm of international affairs. National energy developments and policies have international consequences, while global energy developments shape the design of domestic energy policies.

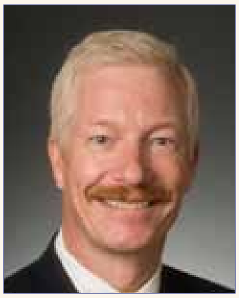
The producer-consumer dialogue has engendered a number of significant outcomes of which three deserve special mention. One is the sustainability of the dialogue itself – in times of both market stability and instability – with the participation of 89 member countries in all their diversity.

A second outcome is the creation of the Joint Organisations Data Initiative (JODI) as an on-going commitment of APEC, Eurostat, IEA, IEF, OLADE, OPEC, and the UN Statistics Division, to provide monthly data on oil market fundamentals. Thanks to this initiative, figures that only 10 years ago were hard to come by, such as oil production, consumption and stock levels from emerging markets outside the OECD or OPEC, are now available for free online. JODI provides a stable base of official monthly data with which to analyse market fundamentals, compare and complement data from other sources, explore trends, and estimate the global energy balance.

A third outcome is the tripartite collaboration of the IEA, IEF, and OPEC to better understand how energy outlooks are generated and what makes them different or similar. Today the experts of the IEA and OPEC meet on a regular basis with experts from other organisations, firms or consultancies, helping to clear up uncertainties inherent in the analysis of energy developments.

I want to congratulate the World Petroleum Council for its first 80 years of undisputed successes. The WPC deserves recognition for being one of the pioneers in the facilitation of dialogue in the petroleum sector. As such, it created new spaces for creative thinking about energy, which no doubt have influenced the course of international energy cooperation. May its next 80 years be just as successful! ■

Houston: Expanding the horizons of energy innovation



By Don Hrap
Chairman, WPC 2017 Houston Bid Committee
and President, Lower 48 and Latin America, ConocoPhillips

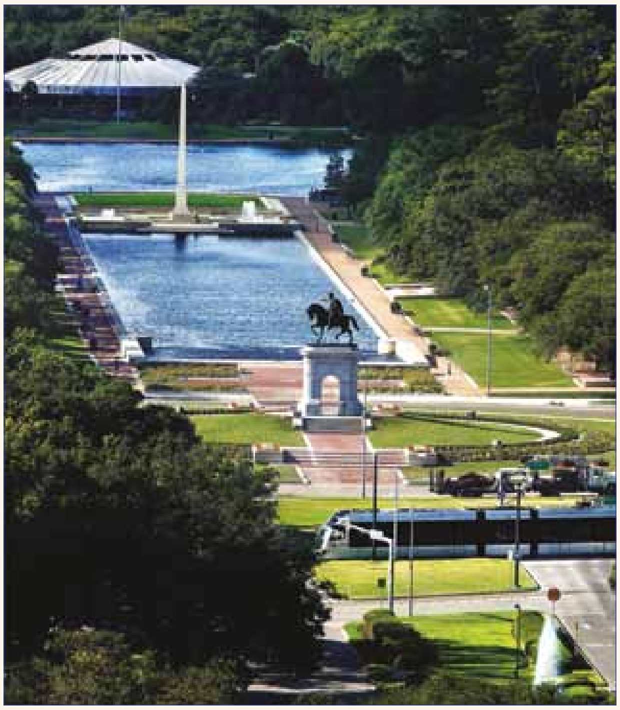
The energy landscape in the United States continues to evolve. Of all the available energy sources, shale is the one that has revolutionised not only the energy industry in the US, but world oil and natural gas markets as well.

According to the May 27, 2013 article in the Wall Street Journal, "this marks a historic and largely unexpected reversal. US crude production has risen to a 21-year high. In 2010, OPEC forecast US and Canadian oil production of 2014 at 11.8 million barrels a day. Just two years later, that forecast has risen to 14.5 million barrels a day."

Estimates of the amount of natural gas from shale and other tight geologic formations continue to grow. In 2000, shale gas provided only 1 per cent of US natural gas production. By 2010, it was more than 20 per cent and the US government's Energy Information Administration predicts that by 2040, 50 per cent of the United States' natural gas production will come from shale gas.

Due largely to innovations like directional and horizontal drilling, microseismic imaging, and technological advances in hydraulic fracturing, shale fields have become both more accessible and economic. In fact, the International Energy Agency projects that the United States and Canada are set to produce about 21 per cent more oil by 2018 than they will in 2013.

Houston's Hermann Park and METRORail system



Houston is at the centre of the North American energy revolution. From major oil companies to small independents to oil field suppliers like Baker Hughes, Schlumberger, and Halliburton, Houston is where cutting-edge technology and highly experienced personnel use their talent and creativity to find solutions to the challenge of meeting the world's ever-growing energy needs.

The energy produced in North America from the shale revolution has the potential to transform other industries and have far-reaching effects all over the world.

For example, Pennsylvania refineries and ship-builders are mobilising to tap into the shale boom. Railroads and chemical industries are being transformed and strengthened as they take advantage of business opportunities stemming from the rising flow and the lower cost of oil and natural gas.

Economists expect a re-emergence in manufacturing, including in sectors that have long been in decline due to cheaper imports such as steel and plastic.

Worldwide deposits of shale gas are now believed to exist in the China, Argentina, Algeria, Canada, US, Mexico, Australia, South Africa, Russia, Poland, France and Libya among others. To what extent these resources are accessed and developed will greatly depend on individual governments working to create systems that will enable regulatory and fiscal structures, as well as allow open market access and free market pricing.

According to Oilprice.com, "despite various conundrums faced across the globe, the consensus is for shale gas to overcome its challenges to have a much larger influence on global energy in coming decades."

As the shale revolution continues to affect world oil markets, Houston will remain the prominent centre of development for the industry. If the World Petroleum Congress (WPC) were to come to Houston in 2017, attendees from all around the world would benefit from having access to a strong programme and technical tours created in conjunction with leaders from America's oil and gas sector. This would provide WPC attendees with the latest knowledge about technology, infrastructure and other topics that could help the advancement of the industry in their own countries.

But Houston's energy leadership role is not limited to oil and natural gas. The city is also at the centre of emerging renewable energy sources such as wind and solar, with many renewable energy companies located in Houston.

Almost every major wind company in the United States has a significant presence in Houston. These companies account for well over half of the wind turbines installed across the nation. In fact, Texas leads the nation in wind energy and is moving along in solar.

Houston is also committed to the future of the industry. The proposed legacy project for WPC 2017 would establish the Houston Centre for the Global Energy Workforce at the University of Houston-Downtown. This project would feature international student exchanges and a biennial International Student Congress in an effort to bring together students, scientists, engineers, and industry leaders to advance the development of 21st Century energy resources.

Houston, with its wealth of expertise in everything from infrastructure to oil rigs, pipelines to refineries, LNG facilities to shale technologies, is well-positioned to remain one of the major energy centres of the world – sharing knowledge, exchanging ideas, exploring opportunities, and expanding the horizons of energy innovation.

The New Houston

Yet Houston's appeal is broader than energy. The New York Times ranked Houston number seven in the list of "Cities to Visit in 2013," the only US city in the top 10, citing the city's award-winning, culturally diverse culinary and art scenes. Houston is home to professional performing arts groups, a 19-museum district and more than 8,000 restaurants with culinary choices from around the world.

Houston's diversity makes the city unique in the United States. It is the only city with no ethnic majority, a widely diverse spread of populations from Europe, Asia and Latin America co-existing amicably in a community where more than 100 languages are regularly spoken.

Houston's bid to host the 22nd World Petroleum Congress in 2017 includes a world-class convention and hotel package. Located in Downtown, the George R. Brown Convention Centre (GRB) at 1.8 million gross square feet, ranks among the 10 largest convention centres in the country – and has earned a LEED Silver Certification recognising its efforts to implement practical and measurable green building design, construction, operations and maintenance solutions.

Houston's space heritage is a major draw

The Marriott Marquis Houston, due for completion in 2016

The hotel package will include the 1,200-room Hilton Americas-Houston Hotel connected by skywalk to the GRB at the south end and a new 1,000-room Marriott Marquis to be connected on the north side of the convention centre. Construction of the Marriott Marquis will begin in 2014 and is scheduled to be completed by mid-2016.

In total there are more than 70,000 hotel rooms available in Houston. 6,000 of those rooms will be located within walking distance of the convention centre, with many other hotels accessible via the city's METRORail mass transit system.

A testament to people-friendly urban planning, the 12 acre Discovery Green park is located in front of the GRB. The park offers a variety of restaurants, entertainment options and scheduled events. Steps away, the GreenStreet complex is home to the House of Blues, Lucky Strike Lanes and an attractive array of dining, shopping and nightlife options. Three sports venues are also located within walking distance of the GRB: the Toyota Centre arena, home of the NBA Houston Rockets; Minute Maid Park, home of the MLB Houston Astros, and BBVA Compass Stadium, home of the MLS Houston Dynamo.

Connecting Houston with most major capitals of the world, George Bush Intercontinental Airport (IAH) provides non-stop service to 68 international destinations in addition to 122 destinations in the United States. The Federal Inspection Facility (FIS) at IAH now offers the fastest entry into the United States and attendees to the 2017 WPC will have a dedicated line upon arrival.

Last year, Southwest Airlines received approval from Houston City Council to build a US$100 million international facility at the William P. Hobby Airport. This means that, pending Federal approval, the City of Houston is on course to have two international airports by 2015. The construction at Hobby Airport will include five new gates and a customs facility, equipped to handle international flights to Mexico and the Caribbean.

Dynamic, welcoming, energetic, and alive with diversity, the new Houston is proud to represent the United States in its bid for the 2017 WPC. ■

Special thanks to the Greater Houston Convention and Visitors Bureau (GHCVB) for their support with the content of this article.

Discovery Green with the George R. Brown Convention Centre in the background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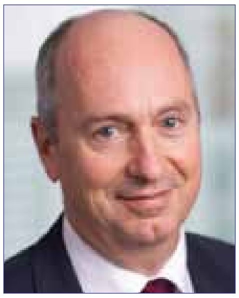
Shell and CNPC venture forth together



By Andrew Brown
Upstream International Director, Royal Dutch Shell

Shell has always been a company built on international relationships and technology, bringing energy to the world. As times have changed, so has the company, evolving and adapting. Today, relationships with state-owned national oil companies (NOCs) are at the heart of the international energy industry. They are driving progress, and unlocking resources.

However, these partnerships between international oil companies (IOCs) like Shell and the NOCs are themselves changing. The NOCs have become more capable, developing their own operational skills and expertise. But at the same time, the challenges of finding and extracting energy have increased. The world is turning to resources that are harder to reach, such as tight gas, or resources in frontier areas, such as deep water or extreme climates like the Arctic.

Partnerships between IOCs and NOCs are therefore developing to meet future challenges, and in ways that will affect the industry for decades to come. Instead of purely transactional relationships, on individual projects in an NOC's home country, we are seeing true, strategic partnerships. NOCs and IOCs are working together, in home countries and ones foreign to both partners. They are increasingly developing technology and expertise together, and addressing economic challenges facing not just companies, but countries.

Our partnership with CNPC, one of China's NOCs, and PetroChina, its listed arm, provides a remarkable example of such a partnership. The strategic nature of this collaboration is most evident in our joint ventures outside of China; in Australia, Qatar and Canada. But it can also be seen in our other areas of co-operation, such as our new mobile well-drilling joint venture. It is a partnership that reflects broader trends in the industry and the world, and one that we expect to continue to evolve, benefiting both partners for decades to come.

Our partnership

The partnership has its origins in China's rising domestic energy demand, and can be traced back to May 2005, when a production sharing contract was signed for the Changbei gas field on the arid edges of the Maowusu desert in northern China, in Shaanxi province. It holds tight gas trapped in dense rock, and the Chinese wanted to draw on Shell's expertise.

Commercial production began at Changbei in March 2007, two years ahead of schedule, with Shell managing and operating the project, and CNPC bringing valuable local knowledge and experience. In July 2012, we extended the agreement to further increase production. Today, Changbei is held up by CNPC as an example of exploration and production success to learn from. Its operational, health, safety and environmental track records are outstanding, and we are also working together to develop natural gas resources in Sichuan province. Our co-operation in China has been a great achievement, driven forward by both companies' expertise, but also the country's growing use of energy.

According to the International Energy Agency, China's primary energy demand could grow by up to 70 per cent between 2010 and 2030 as a result of rising living standards and a growing population. In particular, we expect to see sharp increases in natural gas demand in China. The country sees gas as a way to reduce dependence on coal. According to Chinese energy plans, natural gas consumption will increase from 4.4 per cent of total energy consumption in 2010 to 8 per cent in 2015.

Growing recognition of this rising demand led to a step-change in the relationship in August 2009. Meetings led by Shell's newly-appointed chief executive, Peter Voser, and Jiang Jiemin, the chairman of CNPC, established mutual interests and understanding about the future. Both leaders recognised the energy challenge, and the role that Shell and CNPC could play as strategic partners. They could work across the value chain, internationally and in China, in areas ranging from exploration to liquefied natural gas (LNG), to refining and marketing, with relationships and expertise across the world.

The talks in 2009 led in time to the establishment of four clear strategic priorities, which have underpinned our ongoing cooperation. One is developing unconventional gas in China, and products derived from it, to meet rising demand with cleaner fuels. Another is cooperation on research, development and technology. A third is helping Chinese enterprises grow overseas by, for example, using Chinese suppliers around the world. And a fourth is international cooperation with Chinese partners to bring energy back to China.

Progress has been swift. In March 2010, our companies announced a joint bid to buy Arrow Energy in Australia, which extracts gas trapped in coal seams, then processes and sells it in Queensland, Australia. It supplies 20 per cent of the state's gas demand to industrial customers and local power stations, one of which Arrow owns and operates. The acquisition was completed in August 2010 for A$3.5bn, with each bidder taking a 50 per cent stake.

Together, we have continued to invest in Arrow, and drive it forward. It now benefits from CNPC's and Shell's financial, commercial and technical expertise. For example, today there are about 80 secondees from the parent companies working within it, alongside almost 1,200 local staff.

While Arrow continues to supply gas and power to Queensland, its other objective is a project to turn coal seam gas into liquefied natural gas, which can be transported by ship. The capacity of a potential plant could be 8 million tonnes a year of LNG, to be split between Shell and CNPC, for use and sale internationally. The two parent companies are currently in the front end engineering design process, and will look at taking the final investment decision when appropriate.

The challenges facing Arrow are not just technical. Coal seam gas deposits are typically spread across a large area, and Arrow's leases cover some 54,000 square kilometres. They overlap with a wide range of local townships, prime agricultural land and coal mining operations. Arrow has worked together with a variety of external stakeholders to address concerns and promote co-existence, and continues to do so, drawing on both Shell's and CNPC's expertise in this field.

Our companies have also jointly developed projects in other countries. In May 2010, they agreed to explore for and produce gas onshore and offshore in Qatar, which holds the world's third-largest reserves. I personally played a role, working for Shell at the time as Executive Vice President for our activities in Qatar. The deal involved state-owned Qatar Petroleum, and the three parties are planning to create a major refinery and petrochemicals plant in Taizhou, in China's coastal Zhejiang province.

Shell and CNPC have also been investing together in Canada. We initially agreed to co-operate in Canada in 2010. And in February 2012, PetroChina bought a 20 per cent stake in our Groundbirch shale gas project in

The Shell-CNPC partnership has its origins in the development of the Changbei gas field in northern China

British Columbia. It will further extend our experience of working together to extract tight gas, and extend both companies' expertise.

Such overseas ventures are not the only developments that reflect and deepen our partnership, however. Cooperation on innovation, research and development, and the sourcing of business services have also played an important role in the relationship. We have worked together to grow the scope of the partnership.

For example, our work with CNPC has led us to increase our use of Chinese suppliers of goods and services. In 2011, we spent more than $1.5bn with Chinese suppliers, about half of which was spent exporting Chinese goods and services to our international operations outside China. This has not only helped Chinese industry to play a more international role, but also increased competition between our suppliers.

A shared passion for innovation has further strengthened our relationship. In June 2011, we announced a global alliance agreement, emphasising our intention to invest and work across the world together. But we also announced a more specific agreement at the same time, for a joint venture since named Sirius Well Manufacturing Services. It is an international well-manufacturing services company, in which Shell and CNPC each have a 50 per cent stake.

Sirius will address the need for large numbers of wells to be drilled in rapid succession to extract tight, coal seam and shale gas around the world. In such operations, ultra-low-cost drilling and mobility are essential. The company will use advanced techniques such as automated drilling and optimisation processes that Shell has helped pioneer in its North American and European operations.

One product will be mobile, automated drilling rigs, which will be used by the Arrow venture in Australia, and potentially elsewhere. Mounted on trucks, they will operate in teams from a central hub, which will use computers to control and guide them, and hold supplies such as drilling fluid and pipes. Wells will be drilled in a standardised and repeatable manner.

Sirius brings together Shell's automation technology and manufacturing approach to operations, with CNPC's expertise in manufacturing and managing large rig fleets. Together, we believe the venture has great potential in Australia, North America, Asia, especially China, and elsewhere, unlocking tight gas resources with unsurpassed efficiency. It is an exciting venture, as Shell and CNPC look to the future.

Learning from success

It is worth reflecting on some of the attributes that have made the partnership successful, and the lessons we can all learn. Most obviously, the economic interests of the NOC's controlling nation have to be reflected in a partnership for it to have a truly strategic role. In the case of our relationship with CNPC, it is straightforward to see the role of rising Chinese energy demand, and especially gas demand.

Another lesson is that it is essential for strategic partners to have similar, long-term outlooks. In the case of Shell and CNPC, we both build and manage very large-scale projects with lifecycles spanning decades. CNPC's leaders are clearly thinking how to meet the country's rising energy demand beyond short-term priorities.

Partnerships must be built on the respective strengths of IOCs and NOCs. Shell's position as an integrated IOC, with expertise ranging from extraction all the way through to shipping and refining, make it a particularly valuable partner. For example, China has been increasing its imports of LNG, and Shell is the largest LNG shipping operator in the world. Today our company supplies more LNG to China than any other IOC, and we have signed long-term deals with PetroChina to ship LNG to China from both Qatar and the Gorgon project off the coast of Western Australia.

Both partners must also grow together, and co-operation on research and development, innovation and broader economic development can play a valuable role. We have already seen the way that Shell and CNPC have developed together. Shell expects us both to continue to do so, with the Sirius well-drilling venture, for example. Our four guiding strategic principles help us focus on progress.

Personal chemistry is, of course, vital. This is to some extent about personalities, but also about working to ensure that a partnership is well-managed. Senior executives from Shell and CNPC meet regularly, meaning there is a constant focus on the way the relationship is functioning. At the heart of such close working is also respect. At Shell, we have a very high regard for CNPC and its capabilities, and continually strive to ensure that it sees us in a similar light. With this in mind we both look forward to future opportunities. ■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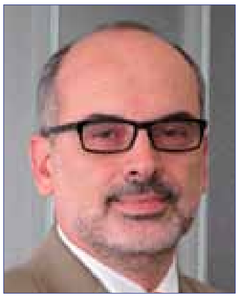
The NOCs' dilemma: Short-term constraints, long-term goals



By Milton Costa Filho
Executive Secretary, Brazilian Petroleum, Gas and Biofuels Institute

Future historians will have a hard time trying to understand and explain what the management of global energy was like in the beginning of the 21st century. Our world will probably appear to them as if it were living a transitional energy period, mainly driven by climate change concerns combined with steady demand. The current technological landscape and the growth in renewable energy production may be interpreted as signs of the beginning of a more diverse and low-carbon energy mix.

Present estimates seem to point to quite a different reality. According to the International Energy Agency's 2012 *World Energy Outlook*, in 2035 more than three quarters of the world primary energy demand will rely on fossil fuels. By then, in fact, global oil demand is expected to have increased by almost 15 per cent, to reach 99.7 million b/d (up from 87.4 mb/d in 2011) and natural gas projected demand will have reached 5 trillion cubic metres (up from 3.3 tcm in 2011).

Considering energy consumption patterns and the large scale use of fossil fuels in power, transport, heating, and many other petrochemicals and refining products – quite apart from the huge infrastructure required to produce and distribute them – the expected transition may take a long time. No doubt the world will go deep into oil and gas for some decades to come.

The current fast-growing energy demand is of pressing concern. The pace of consumption is dictated mainly by the economic development of emerging countries, their rising living standards and urban population growth. By 2035 there will be around 1.5 billion more people to be fed on our planet. Not to mention the unsolved energy poverty. Unacceptable as it may sound in the 21st century, 1.3 billion people do not have access to electricity. Paying this social debt within the frame of the projected growth would mean having around 2.8 billion more consumers of energy, an extra 40 per cent of our present population.

The good news is that the world is very far from running out of oil and gas. According to the IEA, the reserve-to-production ratio based on 2011 levels of production indicates 241 years for natural gas and 189 years for oil recoverable resources. Optimists may argue that these vast reserves coupled to the current pace of technology development that is expected to increase all different forms of energy supply, and the contribution of more rational and efficient use, should suffice to meet future demand.

Nevertheless, in an increasingly interconnected, interdependent, fast-growing world, the fallacious notion of national energy autonomy grows surprisingly stronger by the day. Whereas the legitimate aim for a security scenario of sustainable, reliable and affordable energy remains unaccomplished. There are few long-term energy efforts and no global energy order to coordinate collaborative work. The overall result is that the world is moving towards a growing systemic inefficiency that will prove very costly to coming generations.

In the short term the situation is just as complex. The world has not yet recovered from the 2008/09 global economic downturn and is facing new situations that can take it to further uncertainties and pessimism. The context of tight commodity markets contributes to stubbornly high oil prices that were responsible for the transfer of more than US$1 trillion per year to OPEC during the last two years alone, a shift with high social and economic impact and a considerable burden on importing countries.

This sensation of permanent uncertainty obliges leaders, people and institutions to pay attention to what is going to happen the next day, in a form of defensive survival behaviour that hinders long-term thinking and vision in the formulation of energy policies.

What are the implications for the oil industry's main actors, namely, the national oil companies or NOCs? Are they prepared for such a challenging present and future? Are the oil companies investing the required amount to provide the energy the world needs? According to the IEA, investments in oil and gas sectors combined will need to total some US$19 trillion, out of all the US$37 trillion of investment needed in the world´s energy supply infrastructure between 2012-2035. To ensure universal access to modern energy services by 2030, a further US$1 trillion is required.

Oil and gas are not just the main sources of energy. They also generate the biggest business in the world. They are the most valued traded products, the largest items in the balance of payments and exchanges between countries, their most important revenue and a major factor in geopolitics and socio-economic development.

Oil and gas companies are among the most influential institutions in the world. Their revenues and their scope of influence outstrip those of many national governments. Of the 100 largest economic entities in the world, about half are oil and gas businesses and not nation-states. Compare the ranking of countries' GDP, published in December 2012 by the World Bank, with the ranking elaborated by PFC Energy in its *World´s 50 Largest Listed Energy Firms*, published in January 2013, and the results are astonishing. The combined market capitalisation of those companies was US$3.5 trillion, a wealth equivalent to that of the 5th biggest country´s GDP. The biggest energy company would rank number 28 if it were a country.

It is no wonder the energy sector is mainly run by so-called "big oil": powerful companies that are on the leading edge of technological and managerial skills, human resources capability and financial strength, all required to develop large, risky and complex energy projects. Therefore, many governments decide to control the business directly, through their own national oil companies.

According to a 2013 Petroleum Intelligence Weekly special report, 30 out of the world's 50 top oil companies are state-owned: 20 fully, 7 majority and 3 partially controlled. NOCs are growing in influence because of their dominant resource position – holding above 85 per cent of the oil and gas world reserves – and because of their political and financial strength, and of the recent technological and managerial development of the capabilities required for large and complex projects, both at home and abroad.

Widely diverse though they are, all NOCs are used by their governments to achieve many different objectives. Apart from the usual activities developed by an oil company, NOCs serve as regulators, source for cash, guarantee of security of supply, providers of skilled workers and technology, social developers, just to mention some political objectives. Consequently, it is very difficult to compare NOCs on their performance as mere oil companies. In fact, NOCs emerge as players with a very important role to play. Backed by their governments, NOCs have the legitimacy to fulfil nations' social-economic development aspirations, while pursuing the technical activities indispensable for increasing energy supply.

In times of economic downturn, even the powerful, rich NOCs are in trouble when required to help governments in their urgent political priorities, which may conflict with other key functions, such as the efficient and sustainable exploitation of oil and gas resources. Ironically, while oil companies are heavily influenced by the social-economic context that can impose short-sighted behaviour, they have to deal with predominantly long term energy projects.

Here lies the NOCs' most serious dilemma. As owners of more than 85 per cent of the world's oil and gas reserves, clearly the main sources of energy the world must count upon for the next few decades, they are accountable to provide the affordable, sustainable and reliable energy the world requires. Will they be able to accomplish this, bound as they are by short-term political priorities? Certainly not. Unless a sound, global energy policy is developed.

Leaders with a new mindset

Collaborative governance is the only way out. A new global energy architecture where all countries are committed to change is an urgent need: a concerted action towards developing a sustainable energy mix; implementing rational and efficient use of energy; negotiating a global subsidies strategy; working on the deployment of new technologies; arranging terms for the access to reserves; mitigating effects on the environment and alleviating energy poverty.

The world needs leaders with a new mindset to support the idea of a common global energy community to replace the current narrow, national interests. In the long run, the creation of international organisations with proper mechanisms to implement a global energy policy will result in a more predictable and sustainable energy supply and price.

Putting together the remarkable advances in technology and the drive of a new generation of responsible leaders will certainly give no room for failure.

A worthy example of a collaborative initiative that gathers the most important actors in the oil and gas industry is The World Petroleum Council that celebrates its 80th anniversary in 2013. Their action in a global context with a critical thinking together to address the most important global energy challenges is a clear contribution to build a better, sustainable world. ■

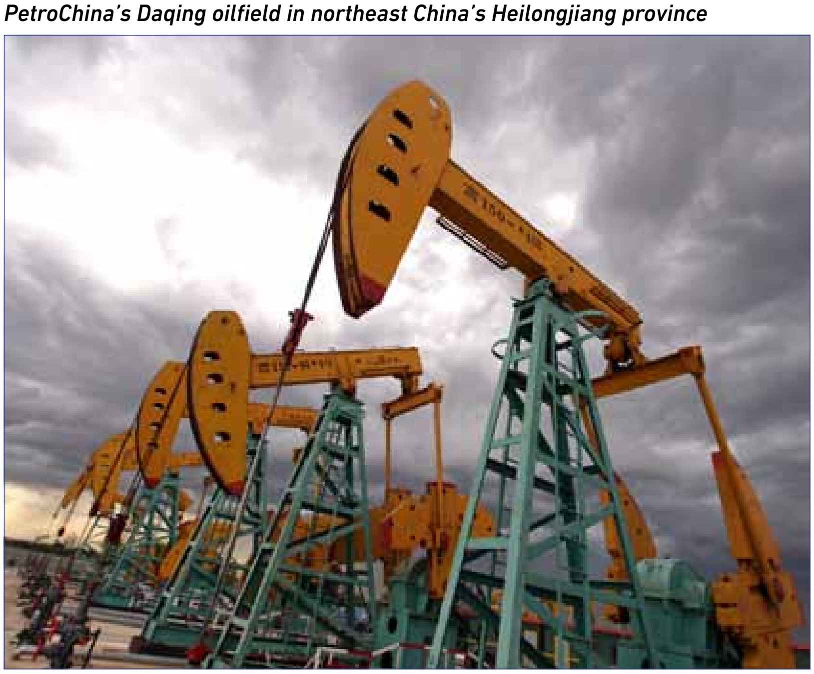
Global energy consumption moves east

Interview with Zhou Jiping
President, China National Petroleum Corporation (CNPC)

What is your view on the trend of global energy development in the future?
In the coming 20 years, the development of global energy will enter into a period of accelerated transition. Profound adjustments will take place in the pattern of energy production and consumption. First, it is expected that oil and gas will maintain the dominant position in the world energy structure. Emerging production growth of shale gas, light tight oil and oil sands is gradually pushing the replacement of resources towards unconventional fields. Resources will become more complicated to develop, as their quality deteriorates – so much will depend on technological innovation and breakthroughs. Second, the accelerated process of industrialisation and modernisation in developing countries, and their ever-growing energy use are pulling the global energy consumption eastward. The US is speeding up the development of indigenous energy resources and reducing imports. The clearer trend towards energy independence will continue to induce major changes in oil markets and trading, adding to the risk of market fluctuations. Third, global climate change is bringing on earlier the era of carbon emission restrictions. In the face of the dual pressure of supply security and environmental protection, alternative energy and renewable energy are given focused attention. Natural gas is placed in a strategic position in energy development. Countries' competition over rights of emission and development is becoming fiercer, and the global pattern of energy interests is readjusting accordingly. It is clear that a revolution reshaping the global energy map in terms of production and consumption is well underway, bringing about unprecedented opportunities and challenges for the oil and gas industry.

What new challenges have the profound changes in the global energy picture raised for the development of the world's oil industry?
The global oil industry today has to address the common challenge – that is, to satisfy the ever increasing need for clean energy and to solve the problem of ever more complicated exploitation of energy resources. The current international financial crisis and geopolitical turbulence increase the uncertainties in oil and gas development. For the sake of domestic economic growth, and for political and social stability, countries have set higher expectations on the oil industry in terms of social responsibilities. Consequently, the industry has to address multiple needs with the concept of sustainable development, and to speed up technological innovation and industrial restructuring, and strengthen win-win cooperation for vital development.

PetroChina's Daqing oilfield in northeast China's Heilongjiang province



What is your view of China's energy security situation, and how does CNPC secure its oil and gas supply?
As the largest emerging economy in the world, China has become a major energy producing and consuming country. In 2012, China's energy production totalled 3.2 billion tons of standard coal, satisfying 90 per cent of its own demand. However, coal accounts for 70 per cent of China's energy consumption mix, inducing severe problems for resources development and for environmental protection. The essential problem of China's energy system

restructuring is still how to reduce the percentage of coal in the energy consumption mix. The key factor in energy security is still the security of oil and gas supply. An accelerated development of natural gas has been chosen as the strategy to increase clean energy supply and the protect the environment. China's petroleum industry still enjoys huge potential for development.

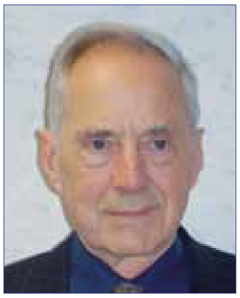
CNPC, China's biggest oil and gas producer and supplier, is also one of the world's largest oil and gas companies. In the face of the dual challenges of satisfying energy demand and protecting the environment, CNPC is speeding up its strategic development of natural gas to build an environmentally friendly enterprise for green development. Meanwhile, the company continues to stabilise crude production, increase refining capacity, and enhance product quality. It is our target that natural gas production will take up 50 per cent of the total corporate oil and gas output by 2015, and 60 per cent by 2020. We are unswervingly strengthening our international cooperation as our overseas business has formed a rather complete industry chain covering exploration and production, refining and petrochemicals, pipeline transportation and storage, as well as marketing and trading. We have basically established five overseas oil and gas cooperation zones and three international operation centres. Our overseas oil and gas operating production exceeded 100 million tons in 2012, most of which was marketed to other countries, contributing a lot to the global oil and gas supply. Following the principle of mutual benefit and win-win cooperation, we focus on the long-term strategic objectives of host countries, including economic and infrastructure development, the utilisation of local supply chains as well as environmental protection for better implementation of our corporate social responsibility, contributing to the sustainable development of local economies.

How will the WPC play its role in pushing energy transformation and industry change in the new era?

It has been 80 years since the establishment of the World Petroleum Council. It has witnessed the vicissitudes of the global oil industry, and made prominent contributions to petroleum technology advancement and international cooperation. Looking ahead, technological innovation is the driving force of sustainable development of the global petroleum industry, while mutually beneficial cooperation is the right path to tackle challenges. The WPC aims to promote cooperation through exchange, and to promote development through cooperation. In the new era, the WPC, as the platform for exchange, can play an even bigger role through exploring new cooperation models. The WPC will continue to guide technological innovation, popularise the application of advanced technologies and promote understanding and trust among countries for win-win cooperation. We believe that the WPC will definitely accomplish a lot in promoting industry cooperation and pushing forward sustainable development of the petroleum industry, making ever-greater contributions to energy for all mankind. ■

Construction works at a PetroChina oil well in Lunnan, Xinjiang

Oil trade at a tipping point



By John Mitchell
Associate Fellow, Energy, Environment and Resources, Chatham House

Much publicity has been given to the recent growth of oil and liquid fuel production in the United States. The expansion of "unconventional" oil and natural gas liquids is the result of aggressive exploitation of oil and gas from shale, and "tight" oil, by a combination of horizontal drilling and hydraulic fracturing. The figures are buoyed by the inclusion of biofuels. Consumption has also declined, due partly to the recession and partly to the combined effects of higher prices and much stricter fuel efficiency standards for automobiles. US net imports fell from 60 per cent of consumption in 2005 to 47 per cent in 2011. The US Energy Intelligence Agency projects a rapid increase in production over the next 10 years, with oil imports falling to around 35 per cent of projected liquid fuel consumption.

The US turnaround is not replicated elsewhere. In the Atlantic region as a whole (the Americas, Europe and Africa) oil production has declined by about 2 million barrels a day since 2005, but so has consumption, leaving a gap in 2011 of around 13 million barrels a day to be met by imports – mainly from Russia. Meanwhile, in the Asia-Pacific region, production has remained roughly steady, while consumption has increased by about 4 mbd since 2005. Both trends are expected to continue.

The future structure of international oil trade therefore looks very different from the past. In the early 1990s the Middle East was the centre of the international trade in oil, with roughly half its oil exports going west. By 2011 imports of around 5 million barrels a day from the Middle East to the Atlantic region were more or less balanced by exports – mainly from West Africa – to the Asia-Pacific.

The change is illustrated in Figure 1, opposite. The blocks show the export surpluses expected from exporting regions, the solid line shows the import demand from the Asia-Pacific region.

Import demand from the Asia-Pacific region is projected to exceed the export capacity of the Middle East. Importers from the Asia-Pacific will increasingly turn, as they are already doing, to supplies from the Atlantic region: notably West Africa and South America.

Ideas of oil security are upset by these changes. The energy security rhetoric and policies of the United States and Europe have for decades depended on fear of instability in the Middle East. Middle East oil exports were disrupted in the oil shocks of 1973 caused by the Arab oil boycott, in 1979 by the Iranian revolution, and in 1980-81 by the Iraq-Iran war. These led to consumers queuing at the pumps and explosions of price which, although temporary, damaged the economies of oil importing countries. The evidence of instability is not over: there were the "tanker wars" of the mid-1980s, the Iraq invasion of Kuwait in 1990, followed by the first Gulf war, the US-led invasion of Iraq in 2008, and now the Syrian civil war and the Iranian nuclear programme and the reactions of United States and others to this perceived threat, What has changed is the physical dependence of the US and Europe on Middle East oil supplies.

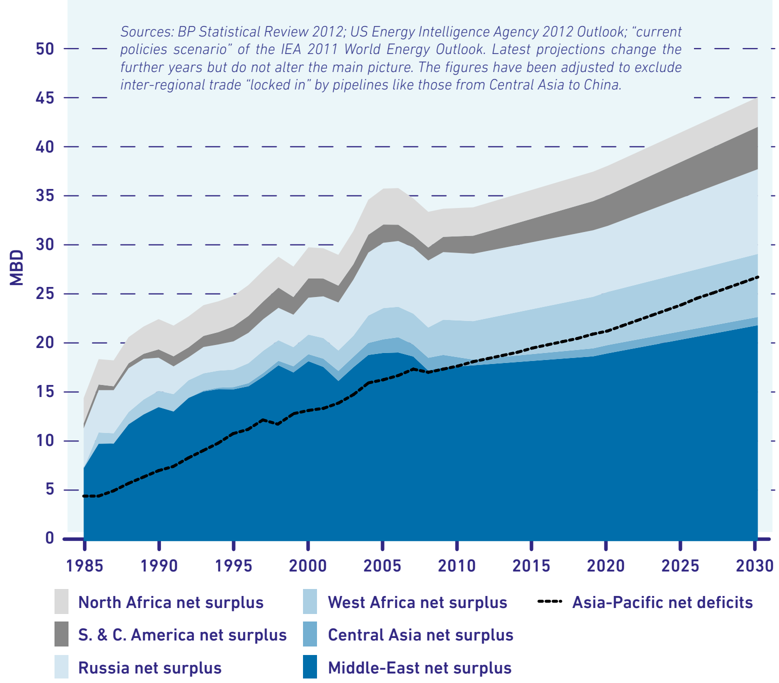
The tip-over of Middle East exports to the east relieves western oil importers of the threat of physical disruptions of supply. The concept of dependency on "countries which do not necessarily have US interests at heart" is no longer a front-line political issue for the US. It does not relieve the US (or Europe) of the threat of price increases which could economically be very damaging. However, price increases do not have the same emotive politics as physical disruptions.

For Asian oil importers the physical security outlook can only get worse. They have always been dependent on the Middle East for their oil supplies but the US and Europe shared that dependence. Now the Asian importers will bear almost the whole impact of any short-term interruption of supply. They are bound to respond in the same way as they did in 1973 and 1979: by bidding for available supplies from outside the Middle East and by paying prices which reflect the pain of the most affected country and company. These "shock prices" will come back to the global market and to those importers who reflect global market prices in their domestic markets – including the US and Europe.

What can be done about this? There are three main possibilities: holding strategic inventories of oil, providing some military protection against disruptions, and reducing dependence on imports in normal times.

The International Energy Agency of the OECD operates an emergency response system which requires member countries to hold strategic stocks of oil equivalent to 90 days of imports and to cooperate in the event of a supply emergency – so that one member cannot "free-ride" on the release of inventories by others. During the early years of the IEA emergency sharing system (the 1980s) Asian countries outside the OECD could expect IEA responses, which would be taken in the interests of IEA members but which would increase supplies to the global market and therefore to Asian countries. Now, and in future, a disruption of Middle East supplies to Asian markets would

Figure 1: Global oil balances 1985-2030



not be a supply emergency for the United States and Europe. Their intervention is not certain. For the IEA oil importers in the Asian region (Japan, Korea, Australia and New Zealand), there would undoubtedly be a supply emergency and if they drew down their stocks the shortage in the Asian region would be made easier, to the benefit of all importers. Stocks held by IEA members in the region are probably less than 50 days of cover of the region's imports from the Middle East. This will fall as imports into the IEA countries are expected to remain static while those to the rest of the region will grow rapidly. China, a non-IEA member, is also building strategic stocks which may eventually provide similar import cover, but their willingness to use the stocks will depend on how they judge their interest at the time. China would share of the interests of the IEA members in limiting free riding by other Asian countries. The IEA is understood to be offering China and India some form of associate membership of the IEA, but this would not involve the same protection or commitments as full members.

The IEA would therefore not necessarily be a reliable source of help for Asian importers in the event of a disruption of Middle East oil supplies. Is there any possibility of an Asian self-help approach to or security?

If all Asian importers of any size maintained substantial strategic stocks, there would at least be more oil available to use in the event of a disruption. It would be even better if the problem of "free riding" were reduced by some prior commitment to consult and if possible co-ordinate the use of stocks. There is no institutional framework for such commitments and associate membership of the IEA would not provide it. An intergovernmental agreement in the region would be necessary. This would require collaboration between countries on energy, but the key countries in Asia are in dispute over territorial waters, territorial sovereignty, and legacies of past wars.

Military protection against disruption of supplies from the Middle East depends on the US 5th and 7th fleets and the US military bases in Bahrain and Qatar. These may not necessarily prevent disruption from events within an exporting country. The US has many reasons for supporting stability in the Middle East, but protection of oil exports to China is probably not high on the list. Given the cost of the US military shield one can expect at the very least the US will demand some contribution from the Asian beneficiaries. This could take the form of money, or commitment to a regional oil security arrangement such as described above. The problem for the Asian states is that some are reluctant to depend on the US, but there are no alternatives available.

Finally, Asian oil importing countries, like all oil importers, can try to reduce their permanent demand for oil. Lower long-term demand will not mitigate supply disruptions, but would mitigate the economic costs of the price shocks which the disruptions cause because the increase in the countries' bills for importing oil would be lower.

The shift to the east in the international oil trade is also a shift in the risks which oil importers face. For the US and Europe, risks are reduced; for Asian importers they are increased. Oil security will slip down the US and European agendas. Asian importing countries will have to do more for themselves when the next disruption occurs. What they do will affect the whole market. ■

America's private sector energy revolution

By J. Robinson West
Chief Executive Officer, PFC Energy

The picture for energy in America has been transformed in the last decade, creating a remarkable change in the US energy narrative. Though discussions of peak oil and falling hydrocarbon production were de rigueur at the beginning of the last decade, high oil prices (by historical standards) combined with new technologies to radically shift the North American energy landscape – "resetting" oil production and growth to levels not seen since the period after the Second World War. As we entered the millennium in 2000, US oil production seemed in terminal decline, having fallen by a third from its 1970s peak. The country needed imports to feed 60 per cent of its 20 million barrels a day (mb/d), and growing, oil habit. In the lower 48 states (excluding Alaska and Hawaii), onshore resources had reached advanced maturity, with cumulative depletion of 75 per cent. Yet this story is not one of government intervention or big oil saving the day: it is one of market forces, entrepreneurship and hard work coming together to create a profound change in US energy in particular and the economy as a whole. PFC Energy sees wide-ranging implications to this "American Energy Reset," with effects much more complex than just higher production and the potential for "energy independence." Actual and expected future production growth holds substantial risks and uncertainties for companies, policymakers and consumers.

Origins and implications

The story begins with natural gas in the 1990s, when George Mitchell, one of many stubborn wildcatters who have written the history of the oil and gas industry, worked doggedly on what many viewed as a quixotic scheme to produce large resources of shale gas (natural gas trapped within fine-grained sedimentary rocks) that had long been known to exist, but always seemed beyond the horizon of commercial viability. It was Mitchell and other smaller companies (not the government or the large oil companies) that, by trial and error and a concentrated focus at first in the Barnett Shale near Fort Worth, Texas, were able to combine horizontal drilling (originally pioneered offshore and perfected in the nearby Austin Chalk play), hydraulic fracturing and other techniques to force gas from shale and other tight formations. By 2001, Mitchell Energy and Development Company had drilled 400 wells and built over 2 trillion cubic feet of reserves, and was considered to have the best growth and inventory story among independent exploration and production companies. Larger oil and gas players began to recognise the potential: Devon purchased the company that year in a US$3.5 billion deal that included a 32 per cent premium over the stock's market price.

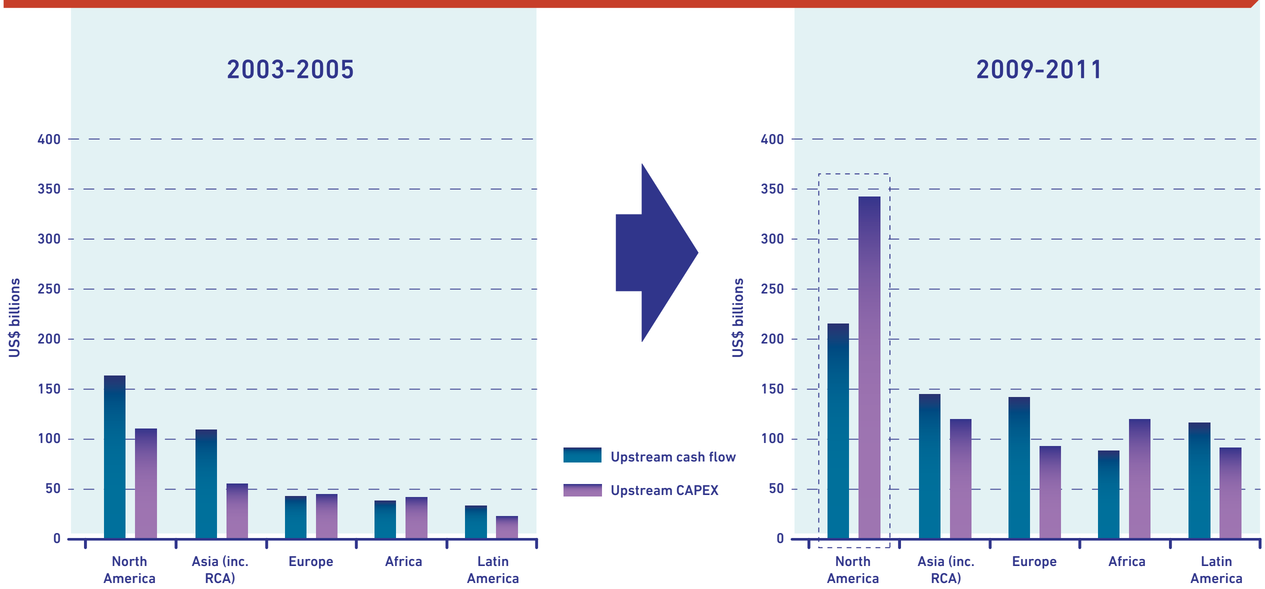
The shale gas revolution has since left the United States both independent and secure in terms of natural gas. Due to its very nature as a gas, the fuel is harder to transport, thus limiting the potential for a globally connected market. Although US gas producers look to make the switch to producing higher-priced oil, gas production remains at record highs, reaching 65 billion cubic feet a day (bcf/d) in 2012 from around an average 52 bcf/d as recently as 2007 – 25 per cent growth. This is an amazing turnabout from earlier in the decade, when the US began building a number of gas import terminals, expecting insufficient future supply.

The confluence of opportunity and technological innovation has had just as profound an impact on oil production. US oil production stopped declining and began growing at rates the country had not seen in decades. As many of the most recent plays have been centred inland, infrastructure that was put in place to deliver oil to these towns and cities has been reversed. As short-term infrastructure capacity has been limited, this has created tremendous price differentials between, for instance, oil produced in North Dakota's Bakken shale and the coast: in the last year, crude produced in the Bakken has traded at up to a US$20 per barrel discount to the price of West Texas Intermediate (WTI) – a major difference for a fungible commodity. This has spurred an infrastructure building campaign to develop the country's ability to both bring crude to major demand centres and export refined products to the global market. Placing this in the context of rising global demand – expected to continue placing stress on supply – will mean a higher price of oil everywhere around the world.

Broader benefits

As the narrative develops, it is increasingly apparent that there are multiple winners from lower natural gas prices. Residential and commercial users have seen tremendously low prices for gas in heating and electricity and domestic industrial users have been

Figure 1: Sources and uses of cash



granted a new competitive advantage – Germany's BASF, for example, has cited low energy prices as a reason for expanding operations in the US. Further, as gas becomes a more competitive fuel in comparison to coal, power producers have scrapped new coal-fired plants in favour of combined-cycle gas turbines – more effective plants with less pollution (not to mention the side effect of reduced carbon output).

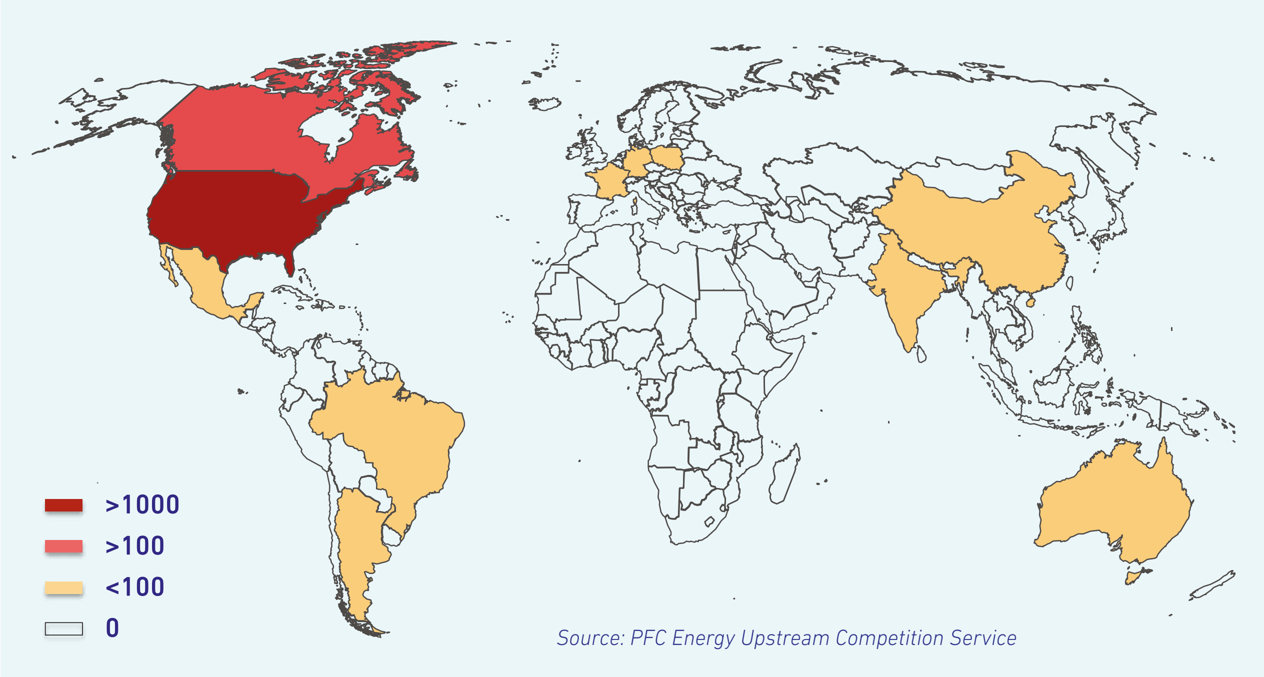
As global oil prices rise, the US is enjoying the upside of domestic production and witnessing increased domestic economic activity rather than exporting capital, which should have the side effect of strengthening the dollar. This is the first time since the 1960s that the rising price of crude has provided a benefit to our country – an important break with past experiences. Still, while the United States has largely become independent and secure in terms of natural gas, the global nature of oil markets means that the "energy independence" – bandied about by both presidential candidates in the recent US elections – remains a misnomer as it pertains to oil.

The changing dynamics of oil and natural gas prices that spurred the reset have made North America a target for investment instead of just a source of revenue. From 2008 to 2010, IOCs made more than US$50 bn (net) investment in the region, compared to the period from 2003 to 2005, when these companies took the free cash flow from North America and invested internationally. Thus the Mitchell-Devon deal was the first of its kind, but proved to be a harbinger of things to come. In fact, Devon has subsequently found so much opportunity for growth and inventory in its North American homeland that it has withdrawn completely from international exploration and production; in 2011, the company completed the sale of its portfolio in one of the world's hottest oil and gas regions, Brazil, to BP. Although the unconventional plays had begun with small companies like Mitchell, and been continued by exploration and production independents like Devon, most of the big international names have joined the trend in recent years, most conspicuously ExxonMobil in 2010 with its US$41bn acquisition of XTO. The clear message from this changing narrative is that markets worked.

Global picture

The American energy reset continues to have implications around the globe. In addition to the basic effects of investment pouring into the United States, the effects of a disconnected American gas market and growth in oil production, companies the world over are studying the technology used in

Figure 2 : Number of unconventional wells drilled, by country



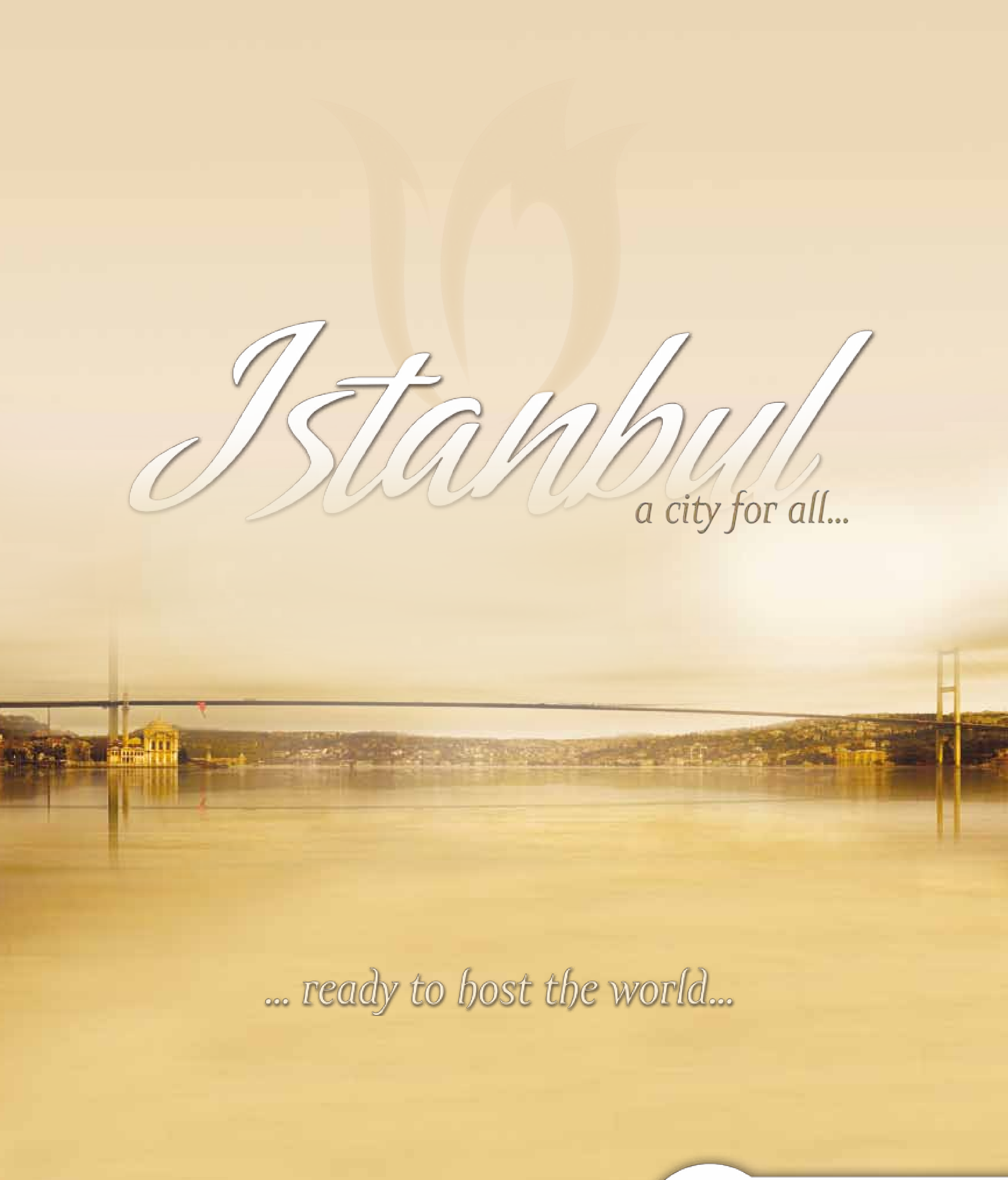
North America to determine how to implement it in a variety of different markets. Yet this success will be hard to replicate: each US play has proceeded through several stages: first, proving the play. The first 30 to 50 wells are needed to prove the producability of the resource. To be successful, the operator must be creative, often ignoring established practices and certainly not expecting to make money from the first well, even when that operator has prior successes in other plays; second, optimise the play. During this phase, which has typically taken from 500 to 1,000 wells, the operator cracks the code of the specific play, making major gains on key metrics, particularly initial production rates and drilling costs; finally, an operator must standardise the practices – learning to "manufacture" wells, mass producing them for scalable production and strong returns.

The challenge facing those who seek to globalise unconventionals is that in all countries outside North America, operations are still at the first "proving" stage. As the map above shows, no other country has drilled even fifty unconventional wells, let alone 500 or 1,000.

Other countries will of course theoretically be able to follow the North American example, but not anytime soon. Unique competitive factors spurred developments in the US that are not present elsewhere, including: property rights clarity; intensive competition between operators (which spurred innovation); a willingness to spend money, including the ability to raise and leverage risk capital; a large, independent and competitive service sector; supportive local and national governments; a developed infrastructure to gather, process and deliver gas (a requirement even for liquids plays, which must handle their associated gas); and a market with reasonable prices to purchase the gas.

While the primary issue of the availability of resource is fairly clear, most of these factors are not present in the handful of countries that have begun thinking about developing unconventional oil and gas reserves. There remains significant potential, but it may take decades.

The US energy narrative has changed because of people like George Mitchell and powerful market conditions that allowed innovation to work. Rising production provides the US with new energy security and surging domestic economic activity. The private sector, not government, drove this historic transformation. ■


Istanbul
a city for all...
... ready to host the world...

Another opportunity for IOCs in Russia's oil industry

By Dr James Henderson
Research Fellow, Oxford Institute for Energy Studies

The history of the Russian oil industry has been a volatile one, with peaks and troughs in both investment and output marking the shift in the industry through various regions of the country's massive geography. The overall trend has been a move from south to north, and Russia is now entering an era in which the Arctic region is set to play a major role in the country's long-term oil output. However, it is useful to consider the historical context of this move into the technically challenging waters of the High North in order to understand the role that domestic and foreign companies may play in this new era.

The first recorded mention of oil in the Russian empire came in the 13th century, when on his journeys to the East Marco Polo noted the presence near Baku in Azerbaijan of a liquid substance that was "good to burn." However, this liquid was only dug from pits in very small quantities for the next 600 years until in the 1870s two foreign family enterprises, headed by the Nobels and the Rothschilds, helped to introduce more modern drilling, production and transportation methods that caused a dramatic shift in both Russian output and the dynamics of the global oil industry. Russia had been a significant importer of oil, in particular from the US, but by the end of the 19th century was producing almost 250,000 barrels a day (b/d) of its own crude, and was looking to markets in Europe and Asia for export sales. The formation of the Shell Oil Company was based upon providing transport for these exports, and by 1911 Shell had also bought up a significant share of Russian production and was challenging Standard Oil for global oil market share. However, the growing unrest in Russia towards the end of the Tsarist era and the impact of the 1917 revolution saw oil production stagnate and exports decline to only 9 per cent of the global total by 1920, from a high of 31 per cent only ten years earlier. Despite some continuing involvement in the Russian oil industry under Lenin's "New Economic Plan" in the early 1920s foreign companies were gradually excluded from the country, and by 1930 the Soviet oil industry was an entirely domestic affair.

However, after a temporary hiatus the departure of the foreigners did not halt the progress of the domestic oil sector, which was set to embark on a major era of growth through the Soviet era. By adapting and enhancing the techniques already introduced by foreign oil companies, Soviet engineers managed to push the country's oil output to 660,000 b/d by 1939, entirely from the original areas in the Caucasus. Then, as decline set in after 1945 and the end of the Great Patriotic War, they discovered a vast new oil-rich province in the Volga Urals region of European Russia, which was exploited with such great skill and success over the following 20 years that by 1965 total Soviet oil output had reached nearly 5 million b/d. Then, as natural decline set in and the drilling of new wells began to have less and less impact the Soviet industry made another transformational move, advancing further north once more to the harsher environment of West Siberia. The tale of the development of this new region is one of dramatic initial success, followed by a first production crisis as well performance began to decline, then a further surge in output as the Soviet leadership ploughed billions of roubles into new drilling, followed by another output crisis as investment funds began to run out towards the end of the Soviet era. During this period Soviet oil production had reached a high 12.5 million b/d, of which 90 per cent had come from Russia itself, but the seeds of the ultimate collapse of the industry had been sowed in the continued use of relatively basic production techniques that relied on vast amounts of drilling and extensive use of water-flooding. As soon as the money to continue these activities ran out oil production went into sharp decline, and the first five years of the post-Soviet era are marked by a fall in Russian oil output from around 11 million b/d to around 6 million b/d (see Figure 1).

This production crisis prompted the new Russian president Boris Yeltsin to seek foreign assistance in the recovery of the country's oil industry, and this initially took the form of numerous joint ventures in the heartland of West Siberia as well as major investments offshore the country's eastern borders at Sakhalin Island. The return of foreign investors brought technology and management experience from the global oil industry and applied it to a Russian sector that had been deprived of exposure to international markets for 70 years, and the results were initially impressive as production first stabilised and then began to tick upwards again by the end of the 1990s. However, the newly privatised Russian companies and their entrepreneur owners soon began to realise that the new techniques that were arriving with foreign companies did not necessarily require foreign ownership of Russian assets, and as a result companies such as Yukos and Sibneft began to operate in tandem with foreign service companies rather than sharing their assets with IOCs. The one exception to this rule was TNK, who formed a joint company (TNK-BP) with BP in 2003, but the fact that this gave BP a unique position in the Russian oil industry for the best part of a decade demonstrates just how little other foreign investment there was after 2000.

Indeed the main theme of the 2000s has been not foreign investment but the re-assertion of state control over the industry, as Gazprom and in particular Rosneft have absorbed large numbers of assets and companies, including most recently Rosneft's acquisition of TNK-BP. However, this increased state involvement in the oil sector has come at a time when the industry itself is going through another period of significant change. The Soviet-era oil assets in European Russia and West Siberia are now in decline, as the recovery techniques used so profitably over the past 20 years are now becoming less effective. This means that if Russia's oil production is to be maintained at or above the current 10.5 million b/d, then new regions must once again be developed, with another move north, into the Arctic, set to be one of the vital new investment arenas. However, Russia's offshore resources have been reserved for the country's state companies, with Rosneft in particular applying for and winning many of the most attractive licences, and as a result this one company has become a magnet for foreign investors as they seek to bring their experience in northern offshore waters to Russia.

Figure 1: Russian oil production since 1985

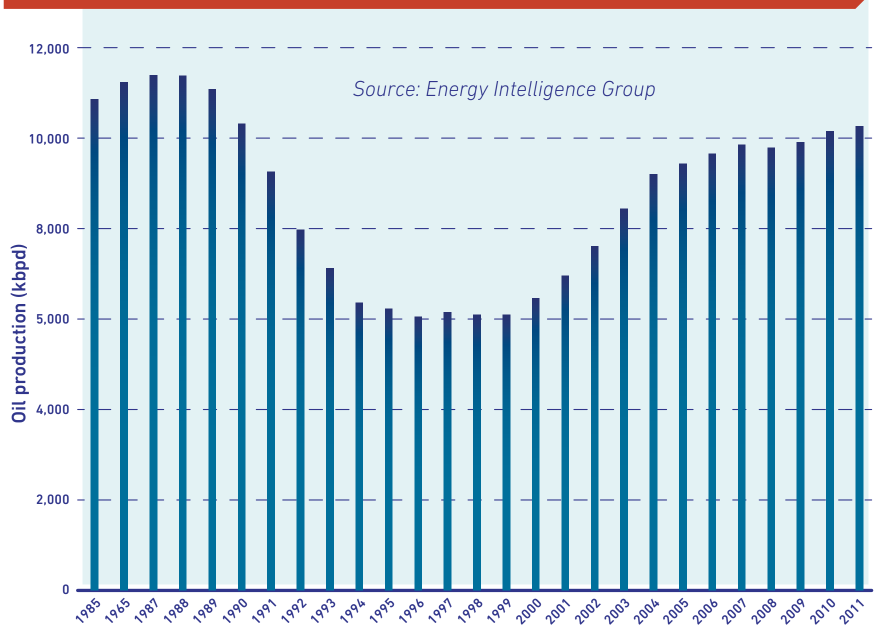
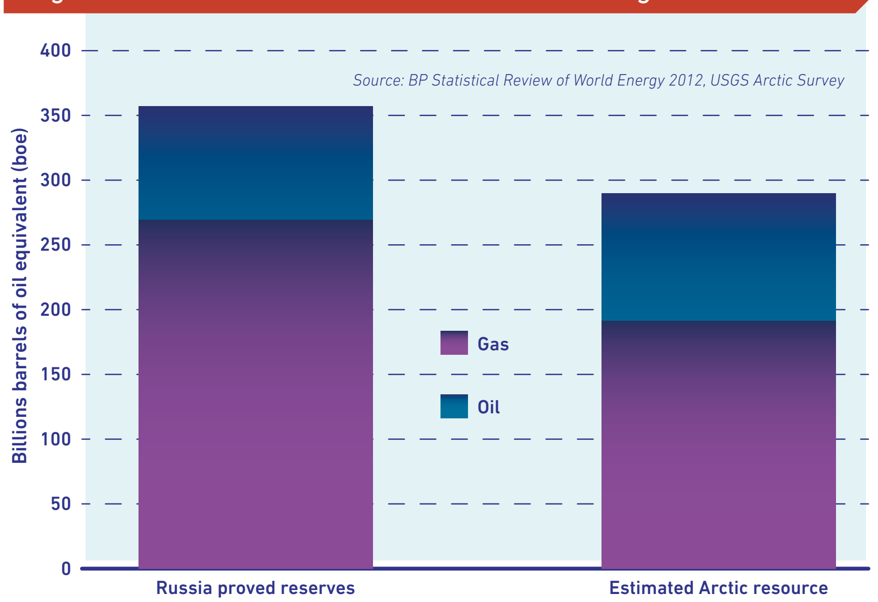


Figure 2: The resource base of Russia's Arctic regions



Rosneft has been happy to welcome companies who can offer a combination of technical expertise and financing to its Arctic projects, and ExxonMobil, Statoil and Eni have all signed very similar agreements with Russia's national oil company. Ownership of the licences has remained with Rosneft, with the joint ventures formed on a two-thirds/one-third basis around a Joint Operating Company (JOC) that has a service agreement with the licence owner. The foreign partners will cover 100 per cent of the initial exploration costs, and will ultimately receive their return from the share of project cash flows that is paid to the JOC, assuming that oil is found. The international oil companies should also be able to book reserves and production from any new field developments, although this has yet to be finally confirmed by their auditors.

The importance of this new shift in Russian oil strategy, and the need to incentivise both domestic and foreign oil company investment, is emphasised by the introduction of a new offshore tax regime which for the first time will offer a profit-based scheme. Depending upon the exact nature and difficulty of the fields developed, the owners will be guaranteed a rate of return in the range of 16-23 per cent thanks to a flexible royalty and the removal of export taxes, and to date this has been enough to encourage foreign companies to make initial exploration commitments with Rosneft. As a result, it would appear that the Russian Arctic, with its resource base estimated at around 250 billion barrels of oil equivalent, could become the foundation of a new era in global oil industry development over the next two decades, potentially transforming the outlook for Russian oil production.

However, the history of the Russian and Soviet oil industries suggests that caution is needed, especially for any foreign investors. It is clear that foreign ownership of "strategic" oil resources will not be welcomed, leaving international oil companies in a service role rather than as direct investors. They will bring new technology and global offshore experience, which is undoubtedly lacking in the Russian oil sector at present, but once these skills have been absorbed the experience of foreign oil companies over the past 150 years in Russia suggests that turbulence may re-emerge. No doubt the IOCs currently in partnerships with Rosneft and Gazprom are aware of this threat, and perhaps this time around the Russians too may see the long-term benefit of interaction with the global oil industry, but finding the balance between Russia's domestic and geo-political goals and the investment parameters of international oil companies could be a considerable challenge over the long term. ■

Rosneft has been happy to welcome companies who can offer technical expertise and financing to its Arctic projects

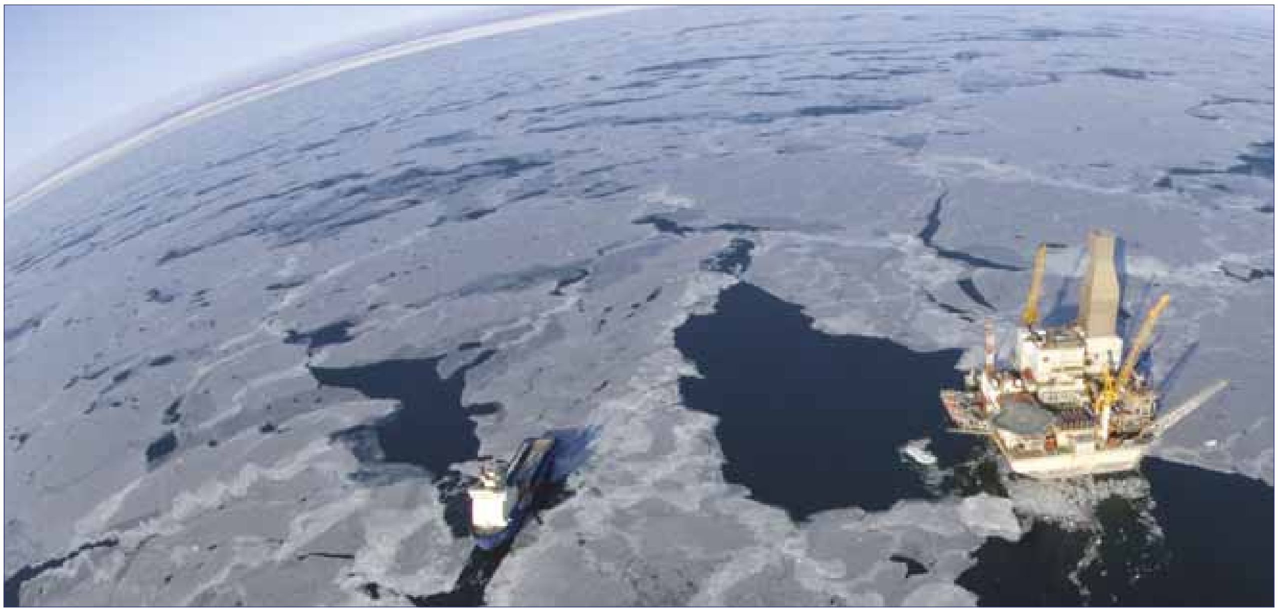


Photo courtesy of Rosneft

Today

CNPC has become an integrated international energy company, with presence in 66 countries worldwide.

1959

Daqing Oilfield was discovered, embarking China's modern oil industry.

1939

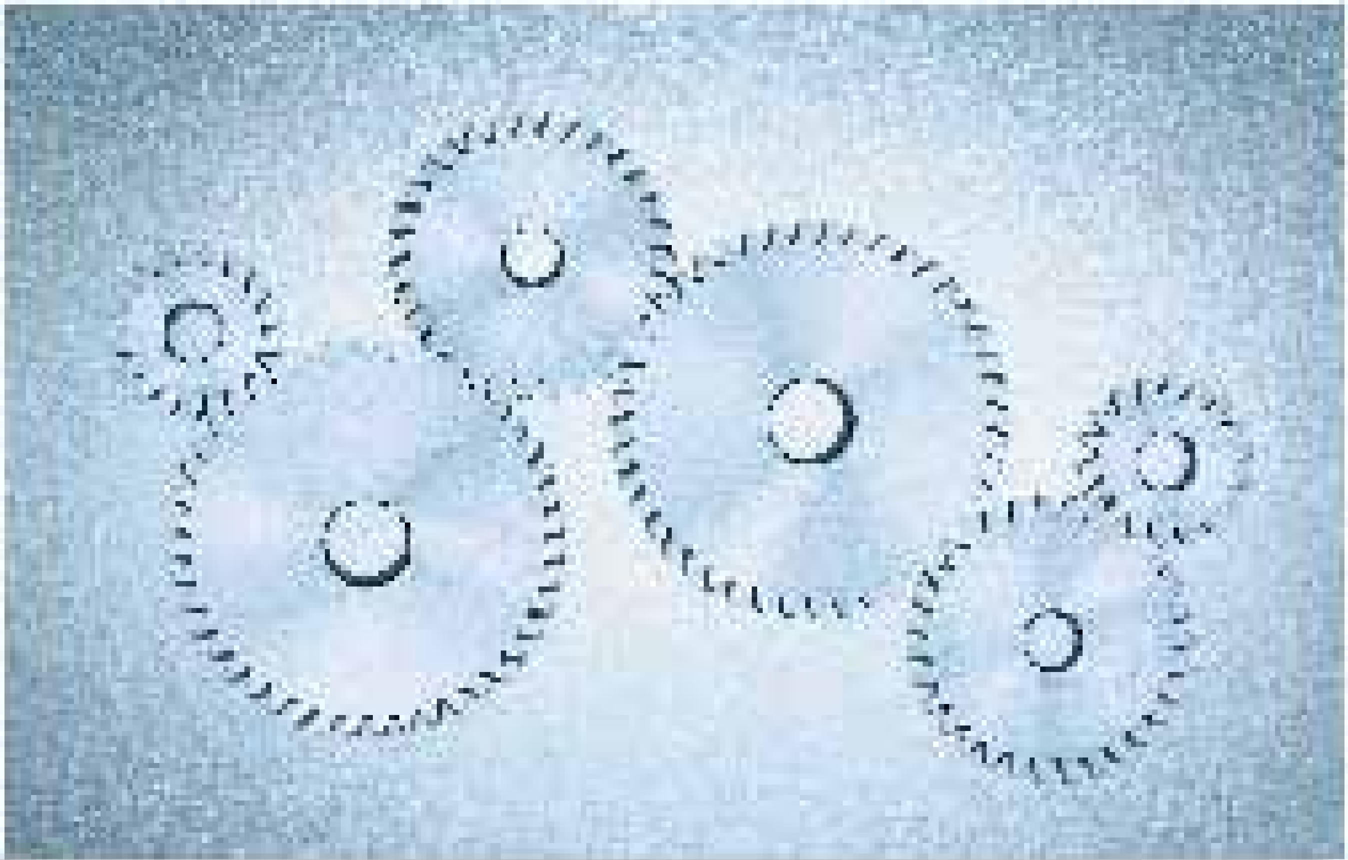
Yumen Oilfield — China's first one — was discovered.

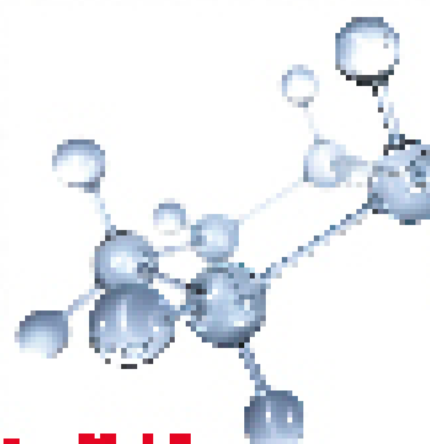
1907

The first oil well in Mainland China was drilled in Yanchang, Shaanxi Province.

CNPC

Over the years, CNPC has inherited and carried forward China's oil industry, being dedicated to support social and economic growth and a sustainable energy future.





Flagship of the world's LNG fleet

By Mahmoud Abu-Saad
Strategic Planning Directorate, Qatar Petroleum

Qatar is a relative newcomer to the global gas market. Its initial appearance dates back less than two decades, but the country is now the largest producer of LNG – a position we have held since 2006, with annual production capacity outstripping the next largest producer by more than two-and-a-half times.

The jewel of the gas industry in Qatar is the North Field gas structure, which was discovered off the coast of Qatar in 1971 by Shell, while prospecting for oil. Although enormous natural gas reserves were discovered – currently estimated at 866 trillion cubic feet (tcf), placing Qatar third in the world after Russia and Iran – gas was not perceived at that time as a valuable resource in an oil-based economy. Furthermore, lack of interest from international oil companies to engage in capital-intensive LNG projects further delayed the monetisation of the North Field by almost 20 years.

At that time, neither internal nor external conditions were conducive to the development of large scale export-oriented gas projects, either as LNG or via pipeline to neighbouring countries. Regional tensions played an important role in delaying the development of the North Field, with the breakout of the Iran-Iraq war in the early 1980s turning the Gulf waters into a war zone, dispelling any hope for LNG projects. Internally, LNG experience and access to large amounts of finance would require foreign partnership to proceed on any gas export development plans, something Qatar could not secure at that time, especially when Shell exited Qatar, further delaying North Field utilisation ambitions. Furthermore, local demands for gas were at that time satisfied by the associated gas from Qatar's oil production.

Gas was becoming more of a global commodity as LNG unlocked the potential of what was previously limited to regional pipeline trade, by providing an effective supply alternative for gas sellers located far from their consumers' markets. In the late 1980s, demand projections emerging from East Asia suggested new opportunities for LNG supply from Qatar. Japanese electric and gas companies were the main buyers of LNG in the world and the first to express interest in Qatari LNG. Japanese companies offered long-term contracts for purchases whilst their government offered favourable financing via loans and export credits, helping to bankroll several new LNG gas supply projects.

In 1984, a joint venture agreement was signed between Qatar and several international partners, laying down plans for the establishment of the first LNG development of the North Field (Qatargas). However, it was not until 1997 that Qatar's first LNG shipment reached the shores of Japan. The project faced a number of internal and external challenges, delaying any tangible benefits.

Qatar realised that owning massive gas reserves was not enough to strike a deal with clients seeking secure and reliable supplies, hence the government embarked upon the construction of appropriate export infrastructure facilities in order to reassure clients. Meanwhile, Qatar partnered up with international oil companies who had access to risk capital, diversified technical expertise and worldwide marketing ties. The strenuous efforts made to overcome the technical, infrastructural, logistical, marketing and funding hurdles finally paid off, opening up the opportunity for Qatar to emerge as a reliable, competitive and long-term supplier of LNG.

The geopolitical instability in the region encouraged Qatar to give more attention to domestic gas development projects and the first large scale gas utilisation project was commenced in 1991. Dubbed North Field Alpha, the project aimed at supplying downstream expanding gas demand from the fertilisers, steel, petrochemicals, and power and desalination sectors.

Consecutively Qatar began constructing a large gas hub at Ras Laffan to host all LNG projects, offering infrastructure, facilities and services, with the aim of providing industries and other stakeholders with an efficient and competitive business environment. The industrial city's facilities include one of the largest specialised hydrocarbons-exporting ports and LNG berths in the world. Ras Laffan became a world-class exporting point, providing a significant stimulus to Qatargas and subsequently to the RasGas projects. Ras Laffan was completed in 1996.

Backed by strong technical and financial resources, as well as possessing a world-class gas hub, Qatar emerged as the new competitive global LNG supplier, opening a new era for Qatar where its energy export portfolio starts to shift to natural gas and to move away from heavy dependence on oil. Its global strategy was built on three pillars: development and ownership of a fully integrated LNG supply chain to capture value, leveraging technology and economies of scale to reduce cost, and building a reputation as a reliable and flexible supplier to break into new markets.

As the enormity of the North Field was becoming more apparent – its vast size extends over an area of 6,000km^2, making it the single largest non-associated gas field in the world – it became clear that the field could not be developed by a single operator. In 1993, the second LNG company, Rasgas, was established to produce LNG and related products. The development strategy was based on phased development where areas are allocated to individual projects which can supply sufficient gas for export throughout the project lifecycle.

With its unique LNG model, Qatar was able to ensure reliable and flexible cost-effective supplies to its customers around the world. Our integrated LNG model includes prudent management of the gas reserves and upstream facilities, development of gas liquefaction facilities, ownership and operation of the LNG fleet, co-investment in regasification terminals and flexible marketing agreements.

At the offshore facilities, we applied advanced technology and optimised investment by maximising production from wellhead platforms and minimising the amount of equipment and associated operational and maintenance staff needed to manage the facilities. Our optimisation schemes include installation of large bore wells to maximise production on each platform and moving the dehydration facilities onshore next to the treating and liquefaction facilities.

Qatar achieved a fundamental milestone for the LNG industry by scaling up liquefaction trains to a record new level using Air Products' proprietary APX process technology. Currently 6 out of our 14 LNG trains have the capacity of producing 7.8 million tons per annum, making them the world's largest LNG trains ever to be built. The use of this technology reduced unit costs to a level unmatched by other producers, giving Qatar a competitive edge in global markets.

Another determinant factor in our LNG value chain was transportation carriers. The cost of shipping, particularly to faraway customers, has a significant impact on project economics, a challenge Qatar was able to overcome by increasing the size of LNG vessels. The new generation of LNG tankers, Qflex and QMax, capable of delivering 216,000 and 266,000 cubic metres of LNG respectively, reduced the capital costs as fewer ships were needed, consequently trimming operating costs. With a huge fleet consisting of 54 vessels, Qatar's Nakilat is firmly established as the largest LNG shipping company in the world. The breakthrough in ship size technology, coupled with low-speed diesel engines and on-board re-liquefaction plants that virtually eliminate cargo loss through LNG boil-off, enabled us to provide our customers with safe and reliable LNG transport.

Our production and transport capabilities were complemented by a dynamic marketing strategy. The customised sales and purchase agreements that fit customers' needs and our rigorous delivery schedules quickly earned us a reputation for reliability. In addition, Qatar's willingness to respond to long-term buyers' unexpected needs brought additional customer loyalty.

Another vital element of our LNG operations is to take an active role in constructing LNG receiving terminals. Currently, Qatar co-owns three receiving terminals, Milford Haven in the UK, Adriatic in Italy and Golden Pass in the US, and leases terminal capacity on a long-term basis, as is the case with Belgium.

As a result of this strategy, Qatar has actually become the flagship in the international LNG industry. We are now by far the largest supplier of LNG in the world with 77 million tonnes of annual capacity. Our LNG supplies are reaching markets in Asia, Europe, North America, South America and Africa. With a huge fleet of tankers, we can efficiently transport LNG supplies to these markets and can dynamically divert cargoes from one market to another as and when needed. ■

With 54 vessels, Qatar has the largest LNG fleet in the world


10 years committed to Colombia,
as the technical authority responsible for promoting the optimal and sustainable development of the country's hydrocarbons.
The ANH enables optimum use of resources and contributes to the development of the country, respecting and harmonizing the environmental, social, and economic interests.

50 years of 3D Seismic, and more to come

By Sara N. Ortwein
President, ExxonMobil Upstream Research Company

As members of the World Petroleum Congress celebrate the organisation's 80th anniversary, we at ExxonMobil join you in also marking the 50th anniversary of 3D seismic technology. 3D seismic was invented by Humble Oil, a predecessor of ExxonMobil, and underpins so many subsurface decisions in our industry that it is worth reflecting on its origin and significant progress.

Prior to the 1970s, the 2D seismic reflection method was the industry's tool of choice exploring for hydrocarbons. However, this approach has well understood limitations in its ability to resolve complex structures in the subsurface.

The invention of 3D seismic dates back to February 1963, when Whit Mounce of Humble Oil proposed a method to conduct a seismic survey that would provide a 3D image of the subsurface. Recognising the relatively massive dataset that would be collected, the Humble Oil team also partnered with Geophysical Services Inc. (GSI) to develop and build the first digital recording system in 1964. GSI's subsidiary on the project, Texas Instruments, has since grown to become a leading global semiconductor design and manufacturing company.

The initial 3D field test was conducted in 1964 and the first production 3D seismic survey was shot in 1967 over the Friendswood field located just south of Houston. Today the Friendswood location remains ExxonMobil Upstream Research Company's primary proving ground for seismic acquisition technology.

Exxon (another predecessor of ExxonMobil) continued to improve the technology and after conducting twenty 3D surveys the company made the first public presentation of results at the 1970 annual meeting of the Society of Exploration Geophysics. Shortly after the meeting, Amoco, Chevron, Mobil (also a predecessor of ExxonMobil), Phillips, Texaco and Unocal formed an alliance with GSI to pursue this new technology, too. The technology race was on.

The first 15 years

Early 3D acquisition systems were adapted from existing 2D technology, but the late 1960s and 70s were a time of rapid technology development. 3D surveys were initially limited to the land environment. Weight drops and dynamite were the early seismic source of choice, although alternative land sources were emerging, such as the "vibroseis" (a truck mounted vibrating source) invented by Conoco.

Similarly, the first marine air-gun source, invented by Bolt Technology, became available in 1964. The low number of recording channels (24-28) required an enormous amount of repeated source effort to cover an area; as a result, survey sizes were on the order of four square miles or less. In 1975, Texas Instruments introduced the DFS V system, which was capable of recording 120 channels. It was a hugely popular system and remained the leading technology for several years.

A critical requirement for understanding a

The world's first marine seismic vessel

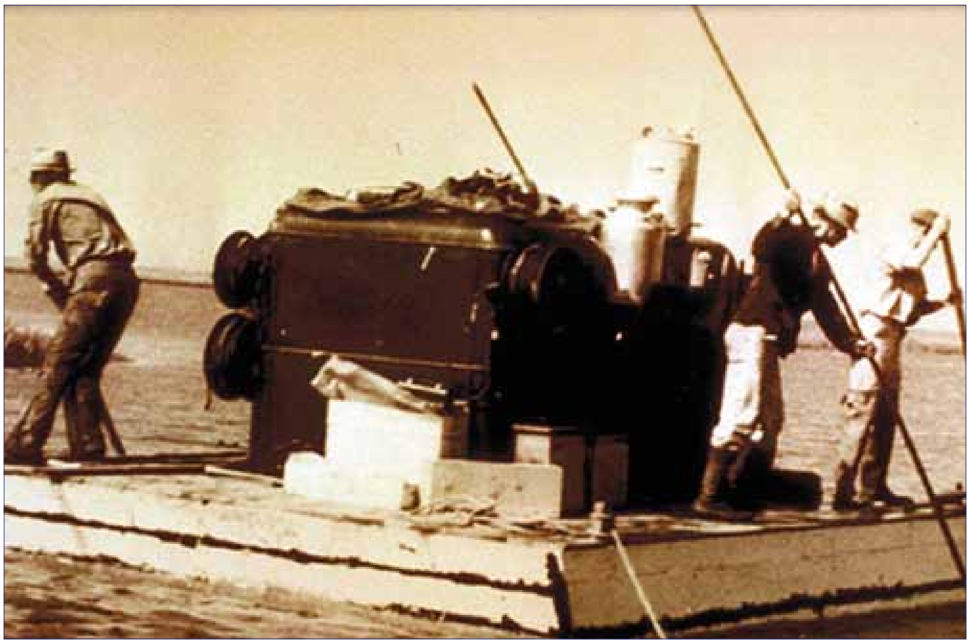


Photo courtesy of WesternGeco

seismic recording is the ability to reposition the recorded seismic energy to its true subsurface origin (reflection point) – a process which is called migration or "imaging." Remarkably, the mathematics of the problem were first described by the British physicist Robert Hooke in 1687. However, prior to the emergence of computers, seismologists were only able locate reflection points using pencils to trace semicircle templates on paper records. In the mid-1960s, ExxonMobil developed a method to reposition data in three dimensions, using analogue processing technology to produce time slices through the seismic image. The data were recorded to film and projected onto a screen, where paper tracings of the data could be made and interpreted.

In 1964, IBM introduced its 360 series of digital computers, which launched the era of modern seismic data processing. As computational power increased, our ability to implement seismic migration theory also increased. However, to this day, our knowledge of seismic wavefield propagation remains ahead of our ability to utilise the full complexity of the recorded data to create subsurface images.

The revolution of the 1980s and 1990s

In the late 1980s channel counts increased to several thousand active sensors, and in the marine environment the transition was made from vessels carrying a single streamer three kilometres in length to vessels towing many streamers of eight kilometres and longer.

At the beginning of this period many of the major oil companies owned and operated their own seismic vessels. As the seismic industry matured and the number of service providers increased, field data acquisition by the majors evolved to awarding seismic contracts via competitive bidding. Later in the period, purpose-built 3D vessels such as Petroleum Geo-Services (PGS) "Ramform" class became the flagship vessels for the global fleet. The first Ramform was launched in 1995 and had the capability to deploy 10 streamers, allowing it to cover a record-breaking one kilometre-wide swath. A few years later PGS broke their own record by launching vessels with 16 streamers.

The motivation for more streamers was simple economics – the more area covered by a single ship in one pass the more cost effective the technique became. 3D surveys grew from a few hundred square kilometres to tens of thousands of square kilometres.

In data processing centres, major oil companies and seismic contractors eagerly purchased the latest in a long line of mainframe supercomputers developed by IBM, Cray, Thinking Machines and Sun in order to apply increasingly sophisticated mathematics in the pursuit of more completely processed data.

An interesting phenomenon was the "commoditisation" of 3D seismic processing. Up until the mid-1980s the computational requirements and complexity of the software algorithms restricted seismic processing to large vendors and major oil companies. However, a former Chevron geophysicist named Rutt Bridges changed that with the development of the ProMAX

A 1970s era seismic vessel

Photo courtesy of WesternGeco

seismic processing system. Originally developed and marketed by Advance Geophysical in 1987 for field quality assurance monitoring, the system matured rapidly and by the early 1990s included the capability to perform 3D processing. The software could run on multiple computing platforms and allowed companies to link their own proprietary code into the system.

In the early 1980s, Mobil geophysicist Royce Nelson was convinced that it was possible to build a computer that would allow for interpretation of 3D data on a workstation. Nelson ultimately left the company and partnered to form Landmark Graphics Company. The first Landmark workstation was introduced in 1984 and very quickly transformed the entire interpretation workflow, making paper and pencil obsolete for 3D interpretation. Landmark Graphics went on to become a Fortune 100 company and was bought by Halliburton in 1996.

With the large growth in vendor technologies, research at international oil companies in the 1990s tended to focus on seismic processing solutions, interpretation workflows, data analysis, operational quality assurance, safety and environment. One example was the development of 3D seismic-based reservoir monitoring techniques known as Time Lapse, or 4D seismic. This was also a period of enormous growth in collaboration with universities such as Stanford, Colorado School of Mines and Delph University of Technology, resulting in many of the underlying algorithms utilised in industry today.

Recent developments and future trends

Since 2000 the pace of advances in 3D technology has not slowed. Channel counts on large land surveys, particularly in the Middle East, have expanded to over 100,000 active sensors. There are research projects in progress to reach one million active sensors. Multiple seismic sources are being utilised simultaneously. Wireless systems enable surveys to be acquired over difficult terrain or in urban settings where cable-based systems would be problematic. A significant enabler has been the replacement of conventional mechanical geophone sensors with micro-electro-mechanical systems (MEMS) sensors. These solid-state devices are operationally more robust, have higher sensitivity and lower weight, and provide the ability to measure waves arriving from different directions.

In the marine environment, many new systems have been developed for "on bottom" use, either with conventional cable or optical fibre, or autonomous nodes deployed by remotely operated vehicles in water depths of 3,000 metres. Although originally designed to "infill" streamer 3D surveys around oil field infrastructure, "on bottom" sensors are becoming the tool of choice in certain settings for entire surveys due to better signal quality compared to towed marine streamers and the ability to include MEMS sensor technology.

3D seismic vessels with up to 24 streamers are now under construction and emerging streamer solutions include both conventional hydrophone sensors and geophone or MEMS-based technologies. In addition, other special purpose vessels, such as the distinctive ULSTEIN X-BOW class, are designed for quieter operations, greater fuel efficiency and arctic operations involving sea ice. Survey designs are becoming more complicated, requiring multiple vessels to image the subsurface from several directions.

As marine seismic use has grown, the industry has proactively addressed environmental concerns by adopting new procedures such as soft starts on air-gun sources, marine mammal observers on board vessels and collaborative efforts to develop alternative seismic source technologies. Another improvement has been the transition from kerosene-filled seismic streamers to solid and gel-filled streamers to reduce the risk of leaks.

Since 2000, the interpretation of seismic data has benefited from the maturation of the seismic interpretation workstation and the inclusion of high-end visualisation centres. Evolution of acquisition and processing technology has resulted in a tremendous improvement in the resolution and reliability of the data. Interpretation has moved from the qualitative to quantitative prediction of rock properties and changes in the rocks and fluids within the reservoir.

On the processing side, much of the seismic signal painstakingly acquired in the field today is removed as "noise" due to limitations of current imaging algorithms and computing capability to handle the complexity in a practical timeframe. However, a new generation of supercomputers is enabling seismic processing researchers to develop and apply algorithms that more completely account for the physics of seismic wave propagation, reducing the need to remove valuable seismic data.

Today, industry is in the early days of implementing a technology called full wavefield inversion, or FWI. The concept of FWI has been known for several decades, but up to now, limitations in both software technology and computer processing power have prevented practical implementation of what is considered one of the grand challenges of geophysics.

ExxonMobil researchers have developed new software algorithms that harness more of the information available within the complexity of the full wavefield. ExxonMobil's patented simultaneous source inversion methodology allows seismic recordings from thousands of individual sources to be processed thousands of times faster than alternative industry methods. To enable practical implementation of this new simultaneous source inversion technology, ExxonMobil installed a high-performance, petascale supercomputer system containing hundreds of thousands of processors and capable of processing a full wavefield seismic dataset in days or weeks, instead of years.

Reflecting on the growth of 3D seismic technology since those early days, it is humbling to consider the significant creativity and innovation that occurred during development of the 3D seismic method. However, realising the full potential of the 3D seismic method is still in its relative youth. From the birth of 3D in 1963, to FWI and beyond, ExxonMobil is committed to the development of high-impact technology in the seismic arena. Our success in continuing the development of this technology will require the same innovative spirit that characterised the first 50 years. ■

Mobil Search: The last heritage ExxonMobil company-owned 3D seismic vessel

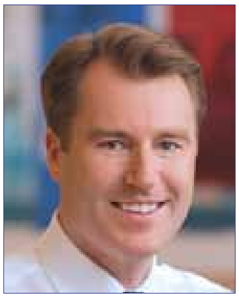
Ramform Titan: PGS purpose-built 3D seismic boat, capable of carrying 24 streamers

Photo courtesy of PGS

Ulstein design Explorer class vessel

Photo courtesy of WesternGeco

A decade of upstream technology innovation



By Paal Kibsgaard
Chief Executive Officer, Schlumberger

For the upstream exploration and production (E&P) industry, the story of the last decade has been one of remarkable resilience, extraordinary innovation, and, despite setbacks, significant gains in safety and environmental conformance. After suffering a brief drop during the 2009 global financial crisis, the demand for oil and gas has continued to ramp up annually, with oil prices rising rapidly. The result today is that the industry is thriving, with oil and gas continuing to furnish 60 per cent of all the world's energy needs.

During the past decade, technological innovation has made a strong contribution to the upstream E&P industry. Three key drivers have been pushing the technology envelope during this time and continue to do so. The first driver is that easy oil has been largely exploited, and what remains is more difficult to extract. Hard-to-extract oil is found in increasingly hostile environments such as deep offshore and the Arctic. At the same time, geology is growing more complex, with discoveries in increasingly fragmented and elusive reservoir structures such as presalt, and in previously untapped basins, in particular unconventional shale liquids.

The second driver is gas, where two revolutions – unconventional gas and LNG – are turning an increasingly global gas market on its head. The third is efficiency. Exploiting oil and gas resources is increasingly sophisticated and expensive, and efficiency gains are important to maintaining margins for both operators and service companies.

Advances in seismic acquisition

Let's start at the beginning with exploration. Harder-to-reach oil requires ever-more precise subsurface imaging; and seismic acquisition, the tool of choice, has seen correspondingly significant advances during the last decade. In the marine environment, the previous deployment of multiple streamers in linear-shooting configurations has evolved to overlapping coil-shooting patterns. This technique provides much-richer azimuthal data essential for improving the subsurface image.

Recently, another step change in image resolution came from recording wavefronts in the three spatial axes rather than the single hydrostatic pressure measured previously. Through an extensive research and engineering programme, Schlumberger developed a new category of seismic imaging that not only includes the acquisition technology but also the algorithms and workflows needed to manage such an unprecedented large amount of data. This improvement in imaging is as profound as was the move from X-rays to 3D scans in the world of medicine.

Accompanying acquisition and imaging advances has been a move to single-sensor recording rather than the traditional group recording. Single-sensor recording dramatically improves the subsurface image processed from raw data, providing superior vertical resolution and opening the door for a more-detailed geologic interpretation. In addition, it more accurately renders the inversion of the seismic image, a technique for estimating all-important rock properties in the seismic cube that help determine the likelihood of a hydrocarbon discovery.

Drilling ahead

Like seismic acquisition and imaging, drilling has seen more than its fair share of technology innovations in the last 10 years. There is continual pressure on drilling to be more efficient; two key challenges are increasing offshore day rates and the common requirement to drill a field from a single location. Efficiency is also required onshore, particularly for the systematic infill drilling of brownfields. One key to efficiency is to understand and simulate the behaviour of the entire combination of the drillstring, bottomhole assembly and bit to ensure stability, maximise penetration and progressively improve drilling performance from one well to the next. Meanwhile, each component has evolved, especially bits. Polycrystalline diamond (PDC) bits, previously used only for hard rock, have developed to the point that they now account for more than 60 per cent of bit use in rocks of all types.

Initiated in the 1980s, horizontal drilling continues to evolve dramatically, with records being broken every month. It is now not uncommon to drill a well that extends 12 kilometres or longer to reach offshore assets from a land base or from a single offshore platform. Additionally, the concept of maximum reservoir contact calls for multiple horizontal drains to be developed from a unique mother wellbore. The design, trajectory management and completion of these modern wells would have been unimaginable 10 years ago.

The enabling technology comprises sensor packages placed close to the bit that communicate to the surface in real time through the mud column and a mechanism downhole to steer the drilling in any desired direction. Virtually every traditional logging measurement has been packaged into the drillstring's bottomhole assembly, a tough engineering feat given the harsh drilling environment. The sensors can now see deeply above and below the current well trajectory, so corrective steering can be invoked in good time to avoid leaving a pay sand, for example. The steering was originally performed using conventional downhole motors with a stationary drillstring assembly, but the latest-generation motors now enable steering while continuously rotating the entire drillstring. The net effect of real-time sensing and rotary steerable system provides the equivalent precision in targeting a reservoir as hitting a tennis court approximately 10 kilometres away.

Sophisticated reservoir modeling

However sophisticated the steering, the viability of each well ultimately depends on correctly understanding the reservoir's shape, size and complexity. Critical to this understanding is reservoir characterisation, which depends on a huge variety of subsurface measurements coupled with the ability to integrate them into a coherent subsurface model. Seismic images and inversions are obviously relevant and are now being systematically combined with data from finer-scale well logs.

First invented in the late 1920s, well logs now measure multiple rock and fluids physical properties – all of which are interpreted to provide a comprehensive model of the producing zone. Perhaps the most dramatic progress in logging has been in sampling the fluids produced from zones of interest. The ultimate test for an exploration well is to flow it to surface and observe and measure the produced fluids and gases.

As a precursor, however, wireline-conveyed reservoir testing tools can isolate and sample fluids produced by each individual zone. Early downhole testing tools had two main limitations: sample contamination by mud filtrate that permeated the formation during drilling, and the requirement that sample analysis be performed at the surface, a costly procedure that irrevocably altered their physical and chemical properties. Today's in situ testing tools solve both of these problems, eliminating the mud filtrate and providing an increasingly sophisticated real-time hydrocarbon-component analysis downhole.

The key value of reservoir characterisation data is the creation of a coherent reservoir model. This requires two essential components: skilled geoscientists and petroleum engineers, and a software platform that can handle multiple data forms, support a multiplicity of processing and interpretation algorithms, and enable iterative interpretation workflows to reduce or quantify uncertainties in the reservoir model. After many years of development, the industry now has such a platform.

Reservoir simulation

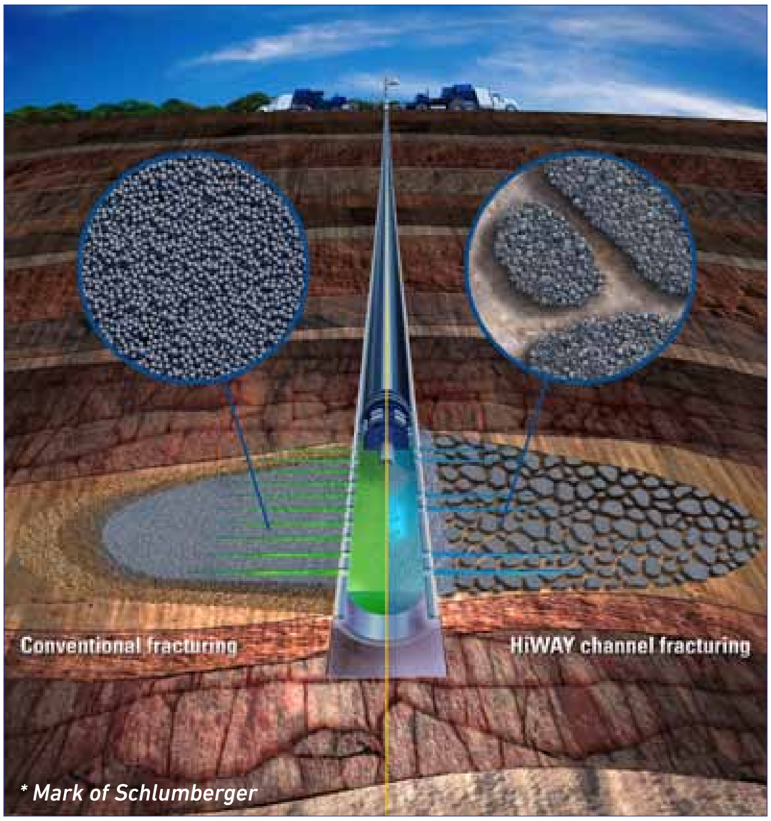
The end goal of the reservoir model is to simulate production with a view that matches the results to actual production and to progressively improve the model so it can be used to predict future reservoir behaviour. We are now into the third generation of such reservoir simulators. Today, simulators handle millions of cells, boast a variable gridding technique to maximise precision near the wellbore, and incorporate thermal and geomechanical effects. Thermal methods are required to handle enhanced oil recovery using steam, and geomechanics is necessary to simulate the compaction and fracturing of a reservoir as pressures decline during production. Geomechanics has fully come of age during the last decade; besides its reservoir application, it is a mandatory element in designing well trajectories to avoid hole collapse and lost circulation.

Advanced production techniques

The technology revolution has equally touched production. Significant advances in completion design now enable selective stimulation of producing zones, and intelligent completions permit real-time downhole mechanical adjustments to optimise production. The most publicised production technology has to do with hydraulic fracturing, a technique that enabled the unconventional gas revolution in the US. Hydraulic fracturing was already a well-established technique, and in the last few years, it has benefited from intense research into each of its key components: optimisation of proppant thanks to material science, improvement in the physical and chemical properties of the fluid used to pump proppant, establishing complex pumping regimes for optimising the proppant injection, and harnessing the discipline of geomechanics – this time for understanding the pressures required to break down the formation.

Meanwhile, subsea production, which is of increasing importance as more and more giant fields are discovered offshore, brings significant challenges including high development costs and complex reservoir well and production dynamics. Recovery rates from subsea developments can be less than half of what we see in conventional topside developments. Accordingly, there has been an evolution of the subsea hardware in increasingly sophisticated architectures, the development of reliable subsea multiphase pumps and the flow assurance understanding required to ensure a trouble-free flow to surface. The key to unlocking the recovery potential of subsea developments, however, will require a total subsea system optimisation from subsurface to ocean floor and up through the riser to the topside. A fundamental starting point in total subsea optimisation is a detailed understanding of the reservoir and the ability to predict well and field production over the lifetime of the reservoir.

The HiWAY technique creates highly conductive flow channels, so hydrocarbon flow is no longer limited by proppant conductivity. A comparison of a fracture packed with proppant (left) and HiWAY flow channels (right)*



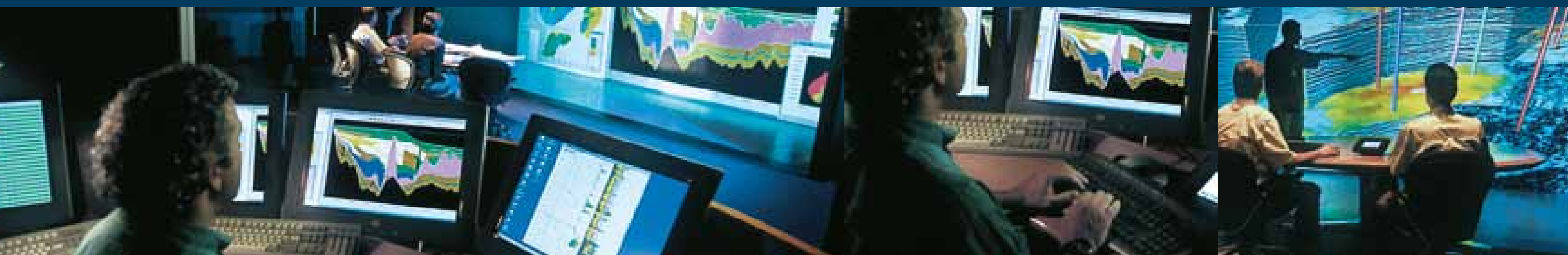
Meeting future challenges

This brief survey offers a mere glimpse at the technology revolution that has been taking place in the upstream E&P industry during the last 10 years and that will need to be sustained to maintain industry productivity and advance efficiency. However, we must not overlook the human element. The availability of expert geoscientists and engineers of all disciplines threatens not to keep pace with technology. The combination of lower recruiting in the 1980s and the progressive retirement of our senior experts threatens forward progress. It is estimated that, by 2015, the upstream E&P industry will be short 5,000 petrotechnical experts. Addressing this imbalance is of upmost importance and a critical factor for future technology breakthroughs.

Finally, we must embrace all new areas of science and engineering critical for ensuring the continuation of technology innovation in our industry. To pinpoint a few, automation of the drilling process must continue. Another key area is material science, especially nanotechnology, which remains to be fully exploited for many upstream areas (e.g., the development of new cement composites for extreme temperatures and gas regimes). Another area is sensor miniaturisation, which has potential applications in seismic surveying, drilling and logging.

In the past, the development of these new ideas fell primarily on E&P companies and service companies. Looking ahead, the E&P industry needs to fully embrace two other key players: academia and technologically driven industries outside of oil and gas. If we remain open to all manners of ideas and advances, we can be confident that this inspiring record of upstream technical innovation will continue for many more decades. ■

In order to get here, we followed the most rigorous safety rules



and the most revolutionary theories.

Throughout its history of over half a century, Petrobras has become one of the largest energy companies in the world. As a leader in exploration and production of oil in deep and ultra-deepwater, Petrobras is already producing in the area that contains the largest oil accumulation ever found in Brazil: the offshore pre-salt layer. To confront this challenge, Petrobras is employing its usual strategy: research, technology, investments and safety. If the future is a challenge, Petrobras is ready for it.

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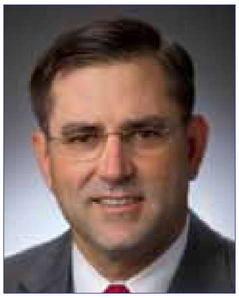
Unconventional tech: Raising the bar, lowering the cost



By Jeff Miller
Chief Operating Officer and Executive Vice President, Halliburton

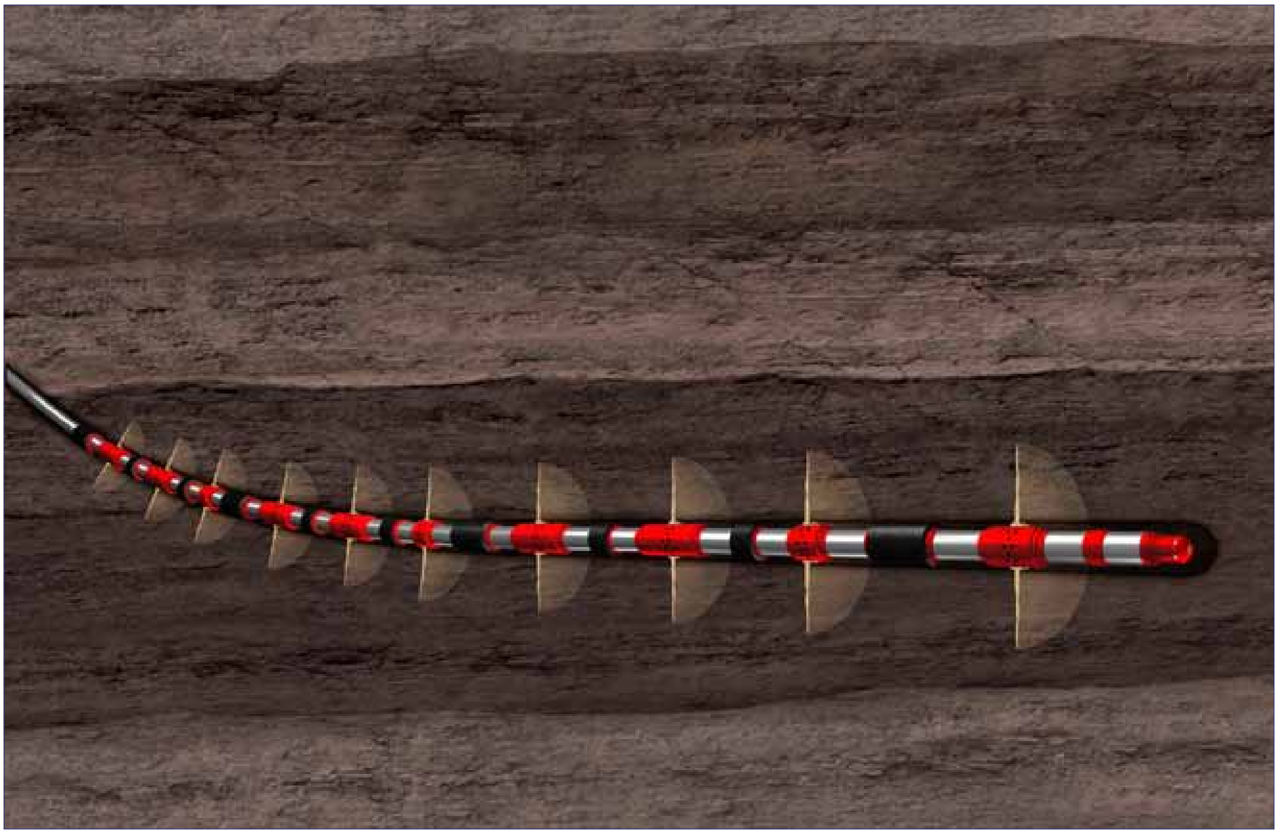
We all know now that 'unconventional' drilling and completion technologies have transformed North American oil and gas markets. It could be said that unconventional technologies are the convention in North America. While dramatic improvements have occurred, unconventional technologies continue to improve. What I see in the future is continued improvements, incorporating and coordinating increased surface efficiency, deeper subsurface insight and more advanced chemistry leading to lower cost and more barrels.

North American oil and gas production both have been on a steep upward slope, nearly 40 per cent higher than they were in the mid 2000s. Energy efficiency initiatives and the economy have kept demand flat, so each new barrel reduces oil imports. There now is serious talk about the US becoming energy self-sufficient in the foreseeable future.

How did this happen? In a word, technology. New methods of extracting oil and gas became available, accepted and cost competitive.

So, where is all of this going? As the world's economy and the demand for energy grow, two trends will dominate. First is the spread of unconventional technologies beyond North America. North America is not the only place with sizeable unconventional oil and gas reserves. In fact, the US and Canada have only about 26 per cent of the world's technically recoverable shale gas resources. Researchers predict that about 70 per cent of additions to the world's hydraulic horsepower would be in countries outside North America. The second is the potential for North America to become an exporter of natural gas. The backlog of applications to the Department of Energy (DOE) for Liquefied Natural Gas (LNG) export licenses represents almost 25 BCF/day of capacity (over 1/3 of current production).

The RapidFrac™ System enables accurate fracture placement with multiple entry points per zone with no intervention



What forces will drive these two trends? The way that I see it, there are two. The underpinning to each is improvements in technology. The first is public acceptance. In the US and Canada, that means extending the industry's track record in developing unconventionals in a manner that reduces the environmental footprint, both seen and unseen. In other countries, the industry will need to convince regulators that the US model (safe and efficient) can be replicated. Technology will answer this challenge by reducing the above-ground operational footprint, improving water-use efficiency and bolstering wellbore integrity.

The second is cost. Unconventional production will grow as fast as it can be developed economically at competitive world market prices. Competition matters, and if our experience in North America tells us anything it's that cost pressures are relentless. The only answer to that challenge is to drill wells and get them into production smarter and faster at the lowest BOE cost possible. This doesn't necessarily mean lowest first cost. It means the best return possible on the investment in the well. Again, that happens when we 1) improve surface efficiencies, 2) develop superior subsurface insights (i.e., understand the reservoir to extract the maximum amount of oil and gas from the reservoir), and 3) apply state of the art chemistry to solve unique production challenges, leaving as little impact on the environment as possible.

Surface efficiency

Demand for materials used to fracture (frac) horizontal wells in shale plays can be daunting when overlaid with the space constraints of most well site locations. Proppant storage is a major space claim on a location. Advanced proppant storage units are oriented vertically, reducing the footprint and are solar-powered, reducing fuel consumption.

Fuel consumption is another significant factor, both from cost and environmental impact perspectives. Dual fuel (natural gas and diesel) engines can decrease the cost of fuel required to power a fracturing spread and supports the goal of minimising the environmental footprint of fracturing operations.

For every barrel of oil or gas produced approximately three barrels of water are produced. Furthermore 10 to 40 per cent of the fluid used in fracturing operations flows back during the subsequent clean-up stages.

The new SandCastle PS-2500 vertical silo helps address problems with space constraints at most well site locations. It offers a reduced footprint with no volume compromise as compared to a traditional horizontal proppant storage unit and is a smarter way of storing proppant, using solar power for all power needs and eliminating the diesel engine normally required

At the same time, access to freshwater is becoming increasingly difficult for operators around the world. Balancing the disposal and/or reuse of this water and access to fresh water in a way that is environmentally acceptable and economically feasible remains a challenge, but clearly solvable.

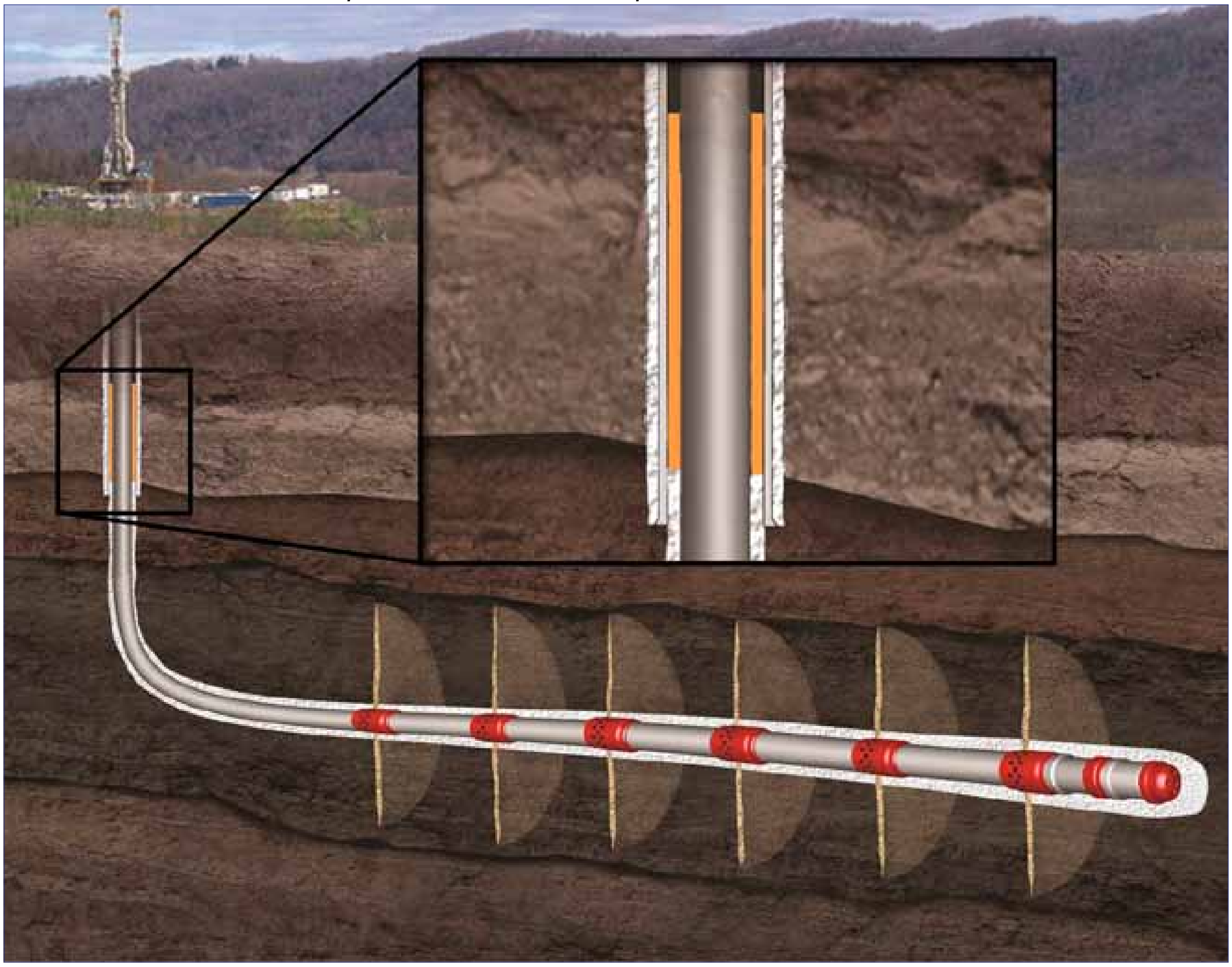
Subsurface insight

Integrated workflows improve economics by identifying the best solutions for well placement, completion, and stimulation using new modeling tools. They are designed to solve specific customer challenges through service and technology collaboration. Through leading-edge data acquisition and visualisation, new tools are being used for reservoir evaluation, field development and planning, and asset optimisation. Because successful stimulation depends heavily on data acquisition and quality, wellbore spacing and placement, and evaluation and drilling execution, the workflow can be used at any point throughout the lifecycle of an asset. The purpose is to create a detailed subsurface model that drives continuous improvement to full-field development using shale-specific attributes, which expands upon the standard attributes for conventional reservoirs.

Knowing the fracture geometry improves economics by increasing reservoir productivity and/or reducing completion costs. This includes optimising individual fracture treatments, optimising fracture length, verifying effective pay zone coverage, or optimising the entire field development in terms of well spacing and well layout. Micro-seismic fracture mapping enables real-time monitoring of fracture height and length, fracture azimuth, fracture asymmetry and fracture growth versus time.

Unconventionals present new geosteering challenges. Well positioning no longer consists of staying clear of known reservoir boundaries.

WellLock™ resin helps provide wellbore integrity, and can act as an annular barricade against water and gas leaks. One foot of resin has been observed to resist a pressure differential of 1,000 psi



Identifying the most desirable formation section requires unconventional evaluation methods: Acoustic logs and elemental analysis help identify zones with high organic carbon and high brittleness index; high resolution electrical images identify naturally fractured formations and indicate the orientation of the stress field; emerging advanced mineralogy assessment methods from cuttings are used to produce a near real-time mineralogy log and guide the well towards the less clayey intervals.

Optimal fracture spacing within a given well also plays an important role in completion success. Stages are selected to span uniform intervals rather than straddling both ductile and brittle intervals.

There are many new options for horizontal multi-stage fracture stimulation completions to provide increased efficiency, improve well economics, and maximise stimulation effectiveness relative to traditional "plug and perforate" methods. Integrated completion systems enable a variety of stimulation treatments and can be tailored to meet the challenges of each application, including ball operated sleeves, mechanically operated sleeves, swell packers and hydraulic set open hole packers.

Wellbore integrity has always been and will continue to be a key factor in ensuring the public acceptance of unconventional technologies. Annular flow of water or gas behind casing and liners (sustained casing pressure) can be experienced anywhere in the world. A properly designed resin system can improve wellbore stabilisation and the hydraulic annular seal by complementing the cement sheath during drilling and completion operations. A resin system also can be used to regain wellbore architecture integrity should remediation be required.

Chemistry

Each shale behaves differently, requiring customised chemistry. Matching the best fluid chemistry to shale rocks during the completion process and during the life of the well can improve well economics and minimise environmental impacts. Attention to water chemistry and bacteria during fracturing prevents production challenges, such as reservoir souring, corrosion, solids formation (scale), and paraffin.

Choice of fracturing fluids is essential and guar-based fracturing fluid systems have historically been the fluids of choice. However, guar residue can significantly damage the proppant pack when produced back following a fracturing treatment. State of the art fluid systems can deliver improved well cleanup, controllable viscosity and salt tolerance.

Biocides and biological control technologies are formulated to sterilise water used in fracturing jobs and help maintain asset integrity due to problems, such as microbiologically induced corrosion (MIC), biomass accumulation, oil carryover and polymer degradation. Ultraviolet light bacteria control processes can also be employed, enabling operators to significantly reduce the volume of biocides used to treat for aerobic and anaerobic (sulfate reducing) bacteria. In some cases, biocide addition can be reduced to zero.

Scale inhibitors can be customised to prevent mineral deposition while also removing deposits which have already formed. From there, a specific scale control program and chemical application can be developed to increase production and reduce the cost of operations associated with scale cleanup, removal and disposal.

Best practice is to use surfactants specifically formulated based upon results from core-sample testing to take into account each reservoir's unique characteristics, leading to increased hydrocarbon production and reduced operating costs.

Hydrogen sulfide (H2S) naturally occurs and may already be present in formations or can be the result of sulfate reducing bacteria. It can be carried in hydrocarbon streams, resulting in severe corrosion in pipes, tubing and pumps, iron sulfide accumulation and leaks in flow and gathering lines, creating high failure rates. H2S scavenger applications and specialty chemicals can help reduce H2S levels and lower overall solids.

Conclusion

By their very nature, unconventional assets are a technology-driven business. When oil and gas was 'conventional' the key to success was winning the race to find the resource and taking the risk that it was actually there. Now, the keys lie in applying what we know to the extraction of the resource at a cost that makes it profitable. Continuous improvement in technology development, deployment and adoption is what we require to make unconventional asset development conventional globally. ■

Balancing risk and reward in deepwater oil and gas

By Christophe de Margerie
Chairman and Chief Executive Officer, Total

The deep offshore is a major achievement of the oil and gas industry. Most people do not realise that it is a relatively recent development. Various attempts were made in the 1980s. Indeed Total drilled its first experimental well in 1982 at 1,740 metres depth. But deepwater production started in earnest in 2000. The corresponding deepwater oil output for that year amounted to 2 million barrels a day (mb/d) and since then production has increased at a sustained pace. It is expected to reach 10mb/d in 2015, a five-fold increase over 15 years.

This rapid development reflects the requirement for additional oil and gas resources to meet growing demand, compensate for the decline of conventional reserves and the need to ensure a geographically more diverse supply. The estimated potential of deepwater amounts to more than 10 per cent of global conventional oil and gas resources and to a quarter of global resources yet to be found.

The geographical concentration of known deep offshore resources has been a bonanza in certain regions such as the Gulf of Guinea, Brazil, Gulf of Mexico, leading to huge local developments. Remarkable technical progress has been made and depth records have been successively breached: 400 metres, 1,000 metres and then 2,000 metres depth. The 3,000 metre mark is no longer too remote a target, thanks to the experience accumulated and improved technology. But how deep is it reasonable to go and is it possible to envisage deep offshore developments anywhere in the world? The Macondo accident in the Gulf of Mexico reminds us that the zero risk does not exist and that crisis management is an art more than a science. Furthermore, it involved top class players operating in an area next to the largest global concentration of oil specialists. It forces the industry to confront the question of limits.

Total feels particularly concerned. We have been playing a pioneering role in deepwater developments. Total is operating today 6 large floating units and expects to operate 10 by 2017 and more than 500 subsea wells in various areas of the world.

Due to the technical complexity and cost of the projects, deep offshore is a business reserved for a small elite of highly qualified players. It is a high-tech industrial niche within the oil and gas industry, which has been able to invent radically new development schemes and new architectures based upon game-changing breakthroughs in technology.

The need for radical innovation is the consequence of the hostile natural conditions imposed by deep offshore: a high pressure and low temperature operating environment, absence of light and with no access for human intervention. These difficulties are frequently exacerbated by the large distance from the coast and reservoir complexity (high temperature, high pressure, high viscosity).

Addressing these challenges has required a diversified set of technological solutions forming the core of a new industry: floating production and storage units, new riser concepts, gigantic subsea architecture including production and transport systems, subsea gas/liquid separation units, all electric remote distance control systems and so on.

Total's Pazflor development offshore Angola, one of the world's largest

The industry has been able to develop all these solutions and to operate them safely and efficiently. I am convinced that we have a large pool of new technology developments ahead of us which will allow us further to improve project economics, increase recovery rates and manage properly ageing installations. In parallel, we have been able to improve exploration techniques and seismic imaging to minimise the number of wells and maximise output.

Environmental challenges are a key part of deep offshore developments. Operating huge subsea and floating infrastructure in the middle of the sea requires minimising the impact of operations and extreme attention to the environment, including preservation of the natural ecosystems, adequate water management and minimal CO_2 emissions. The starting point for sustainable development of deepwater resources is to establish an inventory ahead of each project with a view to determining the baseline for all environmental parameters and the establishment of rigorous monitoring programs.

Biodiversity in the maritime areas concerned is a sensitive issue. Total has conducted surveys in partnership with the French oceanographic institute IFREMER, and we were impressed to discover the abundance and diversity of species inhabiting great ocean depths. We see preservation of oceanic biodiversity as vital and take the appropriate measures to minimise our imprint. With respect to water management, careful monitoring of produced water is required, involving water reinjection in the reservoirs as much as possible. Limiting CO_2 emissions relies upon a mix of solutions. Energy efficiency in the conduct of operations is critical, as deep offshore is an energy consuming activity. Reinjection of associated gas into the wells or collecting it for liquefaction purposes has become normal industry practice.

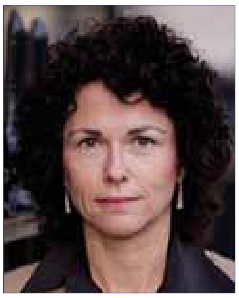
Of course risk must be evaluated in the context of expected return. Total has publicly said that today we would not enter into oil exploration in ice-covered waters in the Arctic zone. I believe that a serious operational failure occurring in an oil development in this area could turn into a major disaster in a context of extreme natural conditions, limited accessibility and the difficulty of reacting quickly and efficiently in case of emergency.

This position does not apply to Arctic gas projects, as the risk of pollution is far more limited with gas. At present Total has several offshore gas projects and a solid technical background in the Arctic zone. We feel able to lead sustainable developments in this area. It is worth doing as the gas potential is large, mainly in the Norwegian and Russian sectors; but it requires operational excellence and extreme precautions have to be taken to preserve the unique maritime polar environment.

Technology and careful procedures have provided the necessary solutions for addressing the complex environmental issues associated with deep offshore production. I am confident that we will be able to properly monitor the environmental impact of new frontier developments in this domain, as well as new opportunities emerging in various parts of the world. ■

Pazflor uses technological world first gas/water subsea separation systems

New ways of enhancing oil recovery



By Jackie Mutschler
Head of Upstream Technology, BP

The oil and gas industry has always followed the same fundamental cycle of exploration and production: finding new resources wherever they may be in the world, exploiting them until it is no longer economical to do so, and then going in search of fresh resources to start all over again.

But as the hunt for fresh oilfields gets tougher, it makes more and more sense to focus on the challenge of recovering more from existing fields. The traditional image of the hardy frontiersmen exploring new corners of the globe for untapped resources is slowly being replaced by one of scientists working in labs to figure out how to tease more oil and gas from reservoirs.

The potential in this area is enormous. Today, in conventional oil reservoirs an average of only around 35 per cent of the available oil is recovered. Increasing this figure by a single percentage point would equate to an increase of around two billion barrels of oil equivalent across BP's fields around the world.

In a typical oilfield, around 10 per cent of the oil can be retrieved by simply drilling a hole, sticking a pipe into the reservoir and letting the natural pressure force oil up the well to the surface. As the oil is produced, so the pressure falls in the reservoir until it can no longer support a column of oil to the surface. At this point, the well stops flowing.

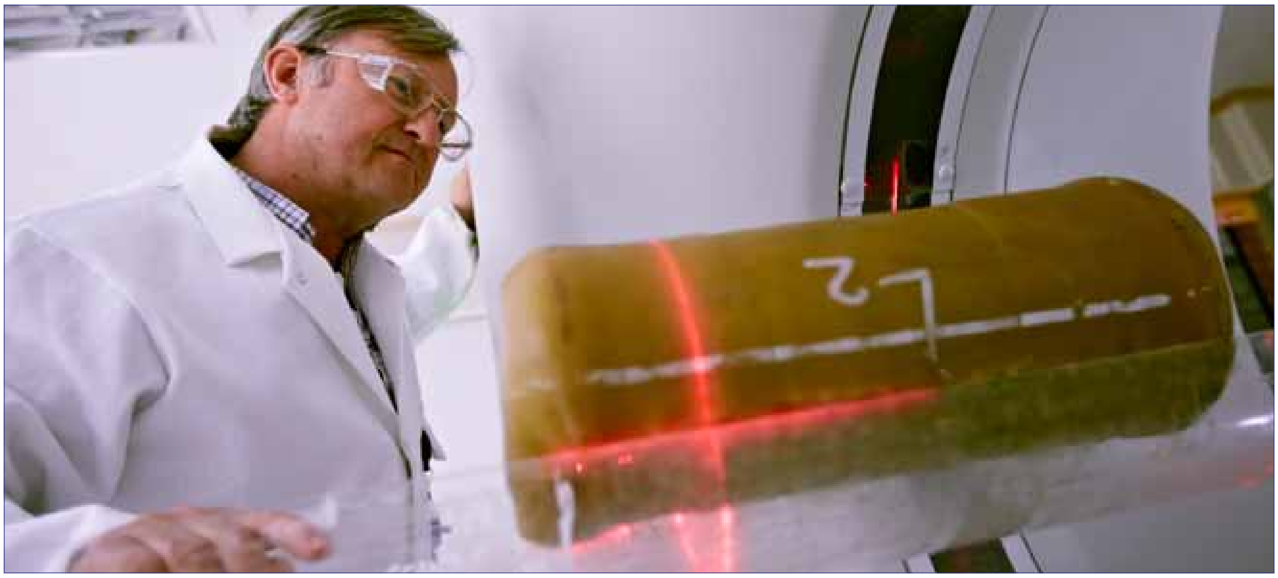
To recover more than that 10 per cent, the pressure needs to be maintained. In most cases, this is done by injecting water or gas, which flows through the pores in the rock, pushing the oil ahead of it. But the oil is "sticky", so only some of it is pushed out of the pores the water or gas reaches and injected water will always follow the path of least resistance and spread from that path as little as possible. So some of the rock is missed completely, resulting in that global average recovery factor of 35 per cent.

BP's efforts to improve that number are led by its Pushing Reservoir Limits™ (PRL) team, one of the company's technology flagship programmes, and the practice of persuading the rock to give up more of its resources is known as enhanced oil recovery (EOR).

An oilfield's recovery factor is calculated by multiplying together four factors:

- Pore scale displacement – how well an injected substance forces oil from the gaps in the rock
- Sweep – how well the injected substance spreads from the point at which it is injected (how far it gets from the path of least resistance)
- Drainage – how much of the reservoir is not in contact with any wells (for example, because they are isolated by natural faults in the rock)
- The cut-off – how long you are able to continue production at the field before it becomes uneconomical due to physical or commercial constraints

A core sample in a scanner at BP's research centre at Sunbury-on-Thames



BP's EOR efforts are focused on the first two of these factors as they have the greatest scope for improvement. Over the years BP's EOR successes have included injecting hydrocarbon miscible gas (methane usually enriched with any combination of ethane, propane, carbon dioxide and butane) into the rock instead of water and using very lean gas to vaporise thin layers of otherwise immobile oil.

Fresh water thinking

Oil industry wisdom says you should not inject anything too 'fresh' into the rock or the clays within the oil-bearing sandstones can swell and reduce the ability of the oil to flow. So BP looked at the fundamental chemistry which makes the oil molecules stick to the rock surfaces in reservoirs. What was discovered was that by reducing the salinity – and hence the ionic concentration of the injected water – more molecules of oil could be released from the surface of the grains of the sandstone rock.

BP's studies showed that some of the oil molecules are attached to clay particles by means of a link. This is in the form of an atom with a double charge such as calcium or magnesium. One charge attracts the oil molecule and one the clay particle. The oil molecule can be released if this double charged atom is replaced by a single charged one since it can only hold onto the clay or the oil, but not both. In high salinity water the oil molecules are pressed down onto the clay and the single charge atoms cannot get in to make the substitution, lowering the salinity causes the oil to expand away from the clay allowing access by the single charge atom and the oil to be released and swept toward the production wells.

LoSal® EOR uses seawater with reduced salt levels, just a few thousand parts per million (ppm) or less. Seawater is typically 35,000ppm and the World Health Organisation recommendation for the salt content of good palatable drinking water is less than 600ppm.

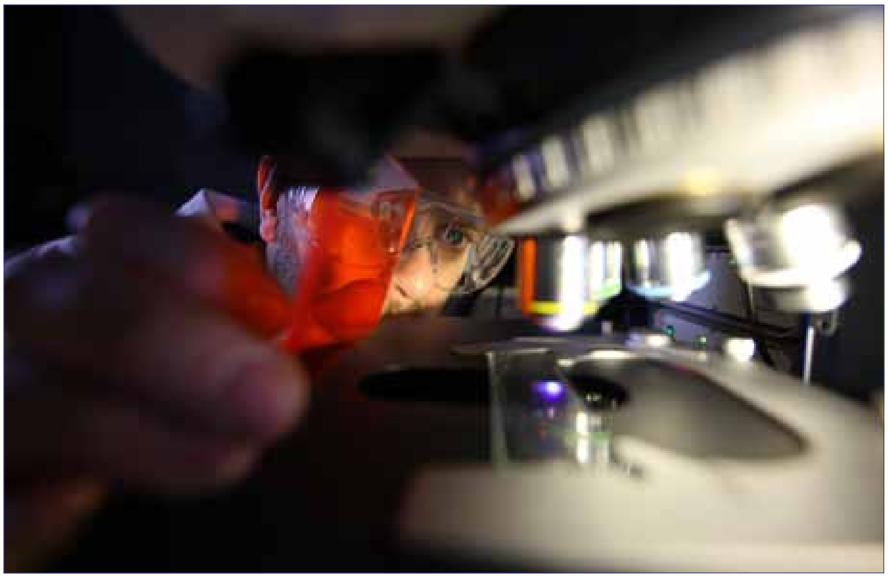
LoSal EOR was developed by the PRL team following a decade of laboratory tests at BP's UK research centre at Sunbury-on-Thames, using sandstone samples from across its global operations. Then, further tests were performed in several oilfields testing larger volumes of rock at guaranteed reservoir conditions. This culminated in a successful inter-well field trial in the Endicott field in Alaska between 2008 and 2009.

Deploying LoSal® EOR

On the back of that successful trial, in September 2012, BP announced that the Clair Ridge development, west of Shetland, UK, had become the first sanctioned large-scale offshore scheme using LoSal EOR. The US$7.2 billion development at Clair Ridge includes around US$120 million for desalination facilities to create the required low salinity water. BP estimates this will enable the production of around 42 million barrels of additional oil compared to conventional waterflooding, making a significant contribution to the estimated 640 million barrels of recoverable oil from the development.

The Mad Dog Phase 2 project in the US Gulf of Mexico is the second offshore project where BP plans to deploy LoSal EOR. The facility will have a low salinity waterflood injection capacity of more than 250,000 barrels of water per day.

The oil retention linkage that LoSal® EOR breaks



From now on, BP will deploy LoSal EOR technology in all appropriate new oil field developments and is assessing whether retrofitting some existing fields might be commercially viable and technically feasible. As a result, there are at least five new and retrofit projects under active evaluation following Clair Ridge.

Improving sweep with Bright Water™

The properties of sandstone vary considerably, depending largely on the size and mix of the sand grains it is made from. Sandstones tend to form as a sequence of vertical layers or with areal variation within the layers; some layers or areas may have low permeability and some high. Often, there are a few layers or areas with much higher permeability than the rest of the field. Fluids always follow the path of least resistance so when water is injected to push out the oil, it is these more permeable regions it naturally flows through.

But the more permeable regions quickly fill with water, which then starts to be produced up the production wells along with the oil. Once this happens, the water injection process becomes very inefficient or wasteful as there is so little oil left to push through those regions, so the water cycles through, down the injection well, rushing through the water-filled zone and up the production well. Because these zones tend to 'steal' a disproportionate amount of the injected water, they are referred to as 'thief zones'.

Detailed studies in BP's Sunbury laboratories unlocked the secrets of LoSal® EOR

To combat this, BP had the idea of blocking off these zones deep in the reservoir between the injection well and the production well. So it co-developed technology known as Bright Water particles: long-chain molecules held in a tightly bound ball – rather like a microscopic ball of wool. These balls are so small that they can be added to the injection water and pass unimpeded through the reservoir rock. When cold seawater is injected, it is warmed up in the thief zone by the hotter, unswept rock above and below it. This breaks some of the links in the Bright Water particle and the ball pops open to around 10 times its original size.

These bigger molecules struggle to get through or become completely stuck in the tighter gaps between the sand grains and the water flow is dramatically reduced. The result is that the injected water is forced to take a new path and sweep new rock, which then increases the oil recovery from the field.

BP has demonstrated the performance of the Bright Water particle in fields in Alaska and its Argentinian joint venture, Pan American Energy, and elsewhere. Bright Water particle treatments performed so far by BP have provided additional hydrocarbon resources estimated to be more than 30 million barrels above what might otherwise have been recovered without treatment, and at an attractive EOR cost.

BP has been a leader in enhanced oil recovery for a long time and the PRL team continues to blaze a trail as the importance of recovering more oil from existing resources grows using its Designer Water® technologies. It predicts that the world's demand for energy will increase by 40 per cent over the next 20 years and demand for oil will grow by around 20 per cent. Existing fields around the world are declining by about 4 per cent a year – that equates to half of Saudi Arabia's annual production. So there's an obvious need to keep exploring new frontiers to find fresh reservoirs. But it's also absolutely vital to focus technical expertise on increasing yields from existing fields if the industry is to meet the great energy challenge of the coming decades. ■

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Pushing Reservoir Limits is a trademark of BP plc
Bright Water is a trademark of the Nalco Company

The world's undiscovered conventional oil and gas resources

By Chris Schenk

World Conventional Assessment Team, US Geological Survey

The US Geological Survey periodically assesses the potential for undiscovered, technically recoverable oil and gas resources in geologic provinces worldwide using a geology-based assessment methodology. For the world assessment released in 2012, the estimated means are 565 billion barrels of conventional oil, 5,606 trillion cubic feet of undiscovered conventional natural gas, and 167 billion barrels of natural gas liquids in priority geologic provinces of the world. The range of resource estimates for each region reflects geologic uncertainty.

The Energy Programme of the US Geological Survey (USGS) has as its core function the assessment of potential volumes of undiscovered conventional and unconventional oil and gas resources of the United States. In order to place domestic resource estimates in a global context, the USGS assesses the potential for undiscovered oil and gas resources in geologic provinces outside of the United States. In this report we summarise geology-based estimates of conventional oil and gas resources in provinces grouped within geographic regions of the world . This latest assessment (2012) expands upon and refines previous USGS world conventional oil and gas estimates (Masters and others, 1984; 1987; 1991; 1994; 1998; US Geological Survey World Energy Assessment Team, 2000), and includes the recent assessment of conventional oil and gas resources in geologic provinces north of the Arctic Circle (US Geological Survey Circum-Arctic Appraisal Team, 2008). Not all potential oil- and gas-bearing provinces of the world were assessed in this current study given the limits of time and human resources.

Assessment Methodology

The assessment methodology for each province begins with a complete geologic framework description, with an emphasis on tectonic and stratigraphic evolution, as well as structural and thermal history. Within this geologic framework we define and analyse all petroleum-system elements, including potential source rocks (organic contents and type, thermal maturation, generation, migration, timing based on modeling), reservoirs (depositional setting, petrophysical properties), and traps (trap formation, timing, and quality). Assessment units (AU) are defined within petroleum systems, and can be established (containing oil and gas discoveries) or hypothetical (containing no discoveries). The definition of hypothetical AUs allows the USGS to include the potential for unexplored geologic or technological concepts. Geologic models based on petroleum-system elements were developed for each AU, and these models formed the basis for the quantitative assessment. Geologic risk can be applied at the AU level on the three main petroleum system elements: petroleum charge, rocks, and timing.

The next step involves a critical evaluation of exploration effort, results, and production history of fields within each AU. Analyses of existing oil and gas field sizes and numbers coupled with exploration effort provide one effective guide to future oil and gas potential. Next, the geologic, exploration, and production data are summarised to develop distributions for sizes and numbers of potential undiscovered oil and gas accumulations. In those AUs with few or no oil and gas discoveries as of 2009, geologic and production analogues were used as partial guides to estimate sizes and numbers of undiscovered oil and gas accumulations utilising a database developed by the USGS following the 2000 assessment (Charpentier and others, 2008). These two distributions, one for undiscovered field sizes and one for numbers of fields, represent the integration of all available geologic and production data within an AU. The two distributions are then sampled in a Monte Carlo simulator using 50,000 trials, resulting in a summary distribution of volumes of undiscovered oil or gas resources. Each AU is assessed separately for undiscovered oil and non-associated gas accumulations. Co-product ratios are used to calculate the volumes of associated gas (gas in oil fields) and volumes of natural gas liquids. This assessment is for conventional oil and gas resources only; unconventional resource assessments (heavy oil, tar sands, shale gas, shale oil, tight gas, coalbed gas) for priority areas of the world are being completed in an ongoing but separate USGS study.

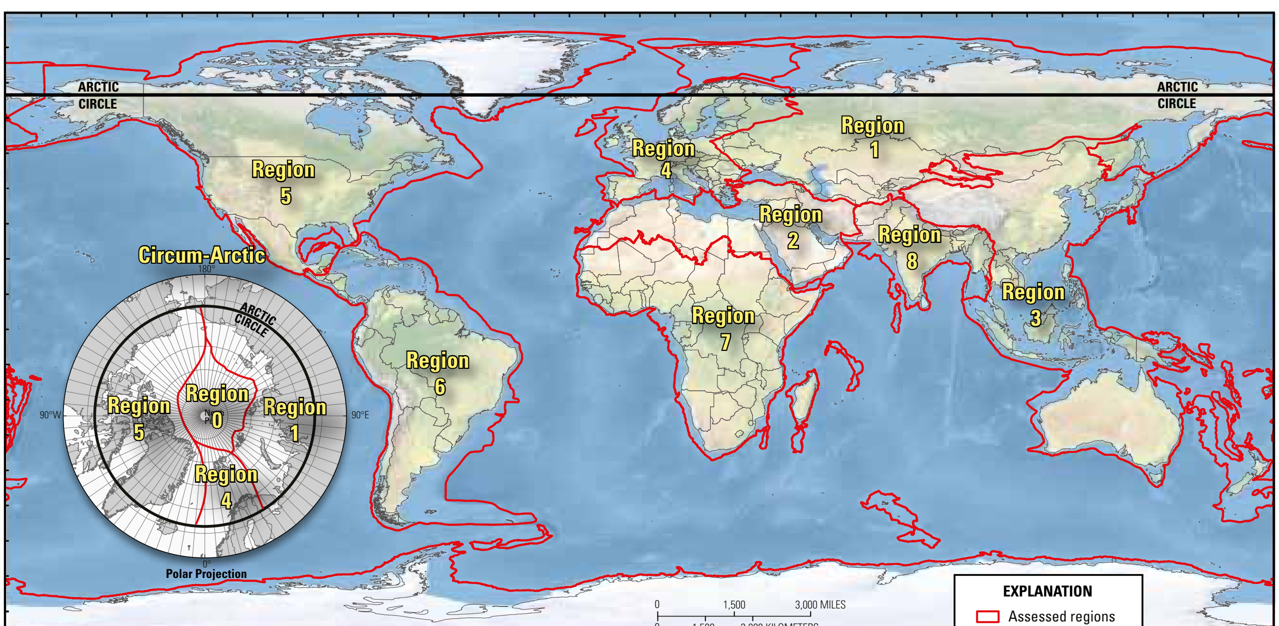
Conventional Resource Summary

The USGS assessed undiscovered conventional oil and gas resources in 313 AUs by region (US Geological Survey World Conventional Assessment Team, 2012). In this report the results are presented by geographic region, which correspond to those regions used in the USGS 2000 assessment and the Arctic assessment (table 1). For undiscovered resources, the mean totals for the world are: (1) 565,298 million barrels of oil (MMBO); (2) 5,605,626 billion cubic feet of gas (BCFG);

Table 1: Assessment results for mean, undiscovered, technically recoverable oil, gas, and natural gas liquids for regions of the world

Regions	Field type	Total undiscovered resources											
		Oil (MMBO)				Gas (BCFG)				NGL (MMBNGL)			
		F95	F50	F5	Mean	F95	F50	F5	Mean	F95	F50	F5	Mean
0. Arctic Ocean and 1. Former Soviet Union	Oil	15,984	45,559	177,175	66,211	54,892	178,640	606,787	237,485	2,083	6,487	19,754	8,193
	Gas					343,396	1,058,432	3,448,972	1,385,046	8,009	25,058	76,955	31,786
2. Middle East and North Africa	Oil	43,316	101,406	212,678	111,201	49,194	124,226	308,443	144,787	1,578	4,026	10,389	4,764
	Gas					334,063	729,200	1,490,538	796,513	10,363	23,220	50,605	25,912
3. Asia and Pacific	Oil	20,950	43,607	87,744	47,544	52,579	117,354	253,416	130,483	1,173	2,742	6,346	3,125
	Gas					269,523	562,461	1,110,663	607,845	7,517	16,340	33,736	17,917
4. Europe	Oil	4,344	8,561	19,417	9,868	6,605	16,422	50,460	21,171	245	570	1,616	710
	Gas					54,072	109,589	249,678	127,454	912	1,924	4,401	2,219
5. North America	Oil	25,500	62,618	208,032	83,386	42,498	112,675	398,902	152,847	879	2,685	11,923	4,103
	Gas					117,885	300,810	1,111,423	420,890	2,910	10,489	43,785	15,164
6. South America and Caribbean	Oil	44,556	108,098	261,862	125,900	99,532	246,922	637,661	295,475	2,909	7,570	20,048	9,119
	Gas					130,015	324,762	838,345	383,062	3,941	9,937	26,532	11,882
7. Sub-Saharan Africa	Oil	40,777	102,961	232,090	115,333	40,553	104,711	262,898	122,188	1,237	3,394	9,237	4,089
	Gas					278,230	557,579	1,190,770	621,341	9,425	20,584	49,935	23,879
8. South Asia	Oil	3,323	5,575	9,339	5,855	8,404	14,648	25,087	15,419	189	337	586	356
	Gas					68,651	134,622	250,144	143,620	1,623	3,197	6,155	3,450
Total conventional resources					**565,298**				**5,605,626**				**166,668**

[MMBO, million barrels of oil; BCFG, billion cubic feet of gas; MMBNGL, million barrels of natural gas liquids. Results shown are fully risked estimates. For gas accumulations, all liquids are included as NGL (natural gas liquids). Total undiscovered gas resources are the sum of nonassociated and associated gas. F95 represents a 95 per cent chance of at least the amount tabulated; other fractiles are defined similarly. Field type: Oil – oil, associated gas, and NGL in oil fields; Gas – non-associated gas and liquids in gas fields. Gray shading indicates not applicable]



and (3) 166,668 million barrels (MMBNGL) of natural gas liquids. The ranges of resource estimates (between the 95 and 5 fractiles) reflect the geologic uncertainty (table 1). The assessment results indicate that about 75 per cent of the undiscovered conventional oil of the world is in four regions; (1) South America and Caribbean; (2) sub-Saharan Africa; (3) Middle East and North Africa, and (4) the Arctic provinces portion of North America. We estimate that significant undiscovered conventional gas resources remain in all of the world's regions (table 1), particularly offshore.

Regions 0 and 1 include geologic provinces within countries of the Former Soviet Union and provinces of the Arctic (fig. 1). Of the mean undiscovered estimate of 66 billion barrels of oil (BBO) in this region, about 35 percent is estimated to be in Arctic provinces. This region also contains significant gas resources (mean of 1,623 trillion cubic feet of gas (TCFG)), about 58 per cent of which is estimated to be in three Arctic AUs: South Kara Sea AU (mean of 622 TCFG), South Barents Basin AU (mean of 187 TCFG), and North Barents Basin AU (mean of 127 TCFG).

Region 2, the Middle East and North Africa, includes the Zagros area of Iran, Arabian Peninsula, southern Turkey, and geologic provinces of North Africa from Egypt to Morocco. This region is estimated to contain a mean of 111 BBO, about 60 per cent (65 BBO) of which is estimated to be in the Zagros and Mesopotamian provinces. This region is estimated to contain a conventional gas resource mean of 941 TCFG, about 60 per cent (566 TCFG) of which is estimated to be in the Zagros Fold Belt and the offshore areas of the Red Sea Basin, Levantine Basin, and Nile Delta provinces.

Region 3, Asia and Pacific, includes geologic provinces of China, Vietnam, Laos, Thailand, Malaysia, Cambodia, Philippines, Brunei, Indonesia, Papua-New Guinea, East Timor, Australia, and New Zealand. Of the total mean undiscovered oil resources of 48 BBO, about 33 per cent is estimated to be in China provinces (15.7 BBO), and 10 per cent is in Australian provinces (5 BBO). Other significant mean oil resources are in offshore Brunei (3.6 BBO), Kutei Basin (3 BBO), and South China Sea (2.5 BBO) provinces. About 45 per cent (335 TCFG) of the undiscovered mean gas total of 738 TCFG is in provinces of Australia (227 TCFG) and China (108 TCFG). The rest of the gas resource is distributed across the other provinces of southeast Asia.

Region 4 includes Europe and several Arctic provinces. Of the mean of 9.9 BBO of undiscovered oil, about 50 per cent (5 BBO) is estimated to be in the North Sea province. Of the undiscovered mean gas resource of 149 TCFG, the Arctic provinces are estimated to contain about 40 per cent (58 TCFG). Significant undiscovered gas resources are estimated to be in the Norwegian continental margin, Provencal Basin, and Po Basin provinces.

Region 5, North America exclusive of the United States, includes Mexico, Canada, and several Arctic provinces. Of the mean oil resource of 83 BBO, about 75 per cent (61 BBO) is estimated to be in Arctic provinces, and 23 per cent (19 BBO) is estimated to be in Mexican Gulf provinces. In this region about 80 percent (459 TCFG) of the undiscovered conventional gas is in Arctic provinces.

Region 6 includes South America and the Caribbean area. Of the mean estimate of 126 BBO in this region, about 44 per cent (55.6 BBO) is estimated to be in offshore sub-salt reservoirs in the Santos, Campos, and Espirito Santo Basin provinces. Other significant oil resources are estimated to be in the Guyana-Surinam Basin (12 BBO), Santos Basin (11 BBO post-salt), Falklands (5.3 BBO), and Campos Basin (3.7 BBO post-salt) provinces. Undiscovered gas resources (mean of 679 TCFG) are less concentrated and are distributed among many provinces.

Region 7, sub-Saharan Africa, is estimated to contain a mean 115 BBO, of which about 75 per cent is estimated to be in coastal provinces related to the opening of the Atlantic Ocean, such as Senegal, Gulf of Guinea, West-African Coastal, and West-Central Coastal provinces. Of the undiscovered gas resource mean of 744 TCFG, more than half is estimated to be in provinces offshore east Africa, including those offshore Tanzania, Mozambique, Madagascar, and Seychelles.

Region 8, South Asia, includes India, Pakistan, Afghanistan, Bangladesh, Nepal, Bhutan, and Burma. Of the mean of 5.9 BBO, about 1.8 BBO is estimated to be in the Central Burma Basin province and 1.4 BBO is in the Bombay province. Of the undiscovered mean gas resource of 159 TCFG, about 39 per cent (62 TCFG) of the undiscovered gas resource is in the three provinces of offshore eastern India.

Although unconventional oil and gas resources, such as heavy oil, tar sands, shale gas, shale oil, tight gas, and coalbed gas, are not included in this study, unconventional resource volumes can be significant. ■

Towards a low-carbon future

By Hege Marie Norheim
Vice President, Corporate Sustainability, Statoil

Just as the Stone Age did not end because of lack of stones, the age of fossil fuels will not end because of lack of hydrocarbons. Instead, there is another shortage that will limit the growth of the oil and gas industry: Lack of sufficient space for greenhouse gas emissions in the atmosphere.

The energy industry is assigned with the task of providing enough energy for a growing world population and a growing world economy. By itself, this task is enormous. In a couple of decades the world will have a population that is 1.8 billion larger than today, and it will be consuming some 100 million barrels of oil per day (mb/d) and some 5,000 billion cubic metres (bcm) of natural gas per year, according to the International Energy Agency's latest *World Energy Outlook*.

In securing these supplies the oil and gas industry not only has to add to existing capacity, but also replace every barrel of oil and cubic metre of gas that is being consumed in the meantime. This will put the industry to the test, given that reserves are harder and more expensive to produce, and that more of new resources are found in areas that are hostile and environmentally vulnerable. To ensure that global demand for energy is met is therefore a huge task compared with any other industry.

However, the challenge is even bigger than this. Because we also need to manage the following dilemma: to supply sufficient amounts of energy, and at the same time reduce greenhouse gas emissions from fossil fuels in a significant way. We need to do both. The good news is that we have some ideas as to what it would take. The bad news is that it will take a lot, not least by way of international cooperation and decision-making. And so far, progress has been dangerously slow.

It is a matter of pure physics and chemistry that the combustion of oil and gas releases CO_2 that finds its way into the atmosphere, where it will reside as a long-lived greenhouse gas. Science has provided evidence that we are rapidly approaching levels of concentration of such gases in the atmosphere to trigger an average temperature increase of two degrees Celsius. In fact, unless we move decisively away from business as usual, we will be confronting even higher temperature increases – with even more damaging results.

The road away from highly destructive climate change consists of multiple step changes. One is to curb demand by improving energy efficiency. By itself, this will help a lot. Energy efficiency is by far the most potent measure against climate change. A second is to replace carbon emitting fuels with non-emitting renewable energy, such as wind and solar. Even here, the potential is big. In most scenarios renewable energy will continue to grow in a significant way, driven by public support, cost improvements and maturing technology.

However, even with huge advances in both these areas, we will still have fossil fuels covering the bulk of global energy consumption for decades ahead. In order to minimise emissions from this consumption two additional things need to happen: First, a major switch away from emission-intensive coal to emission-light natural gas – in particular in the power and industry sectors. And secondly, wide scale deployment of new technology for carbon capture and storage (CCS).

Without all of this it is very difficult to see how the world can cover its energy needs and stay within the limits of its carbon budget at the same time. And this, of course, only adds to the extremely complicated challenges the energy industry would be faced with anyway.

When the Intergovernmental Panel on Climate Change (IPCC) was formed back in 1988 and began to publish their assessment reports on the science of climate change, the oil and gas industry was a reluctant observer. For many years the industry did little more than question the science and advise governments not to act. When the Kyoto Protocol was adopted in 1997 Statoil was among a group of very few companies that embraced the agreement and the philosophy on which it was based: cost efficiency, flexibility and the use of marked based mechanisms to curb emissions.

Today the situation is widely different. The scientific basis for climate change is no longer questioned, and practically all serious energy industry players have implemented some sort of climate change strategy as part of their businesses. Companies have realised that carbon efficiency is more and more going to be an integral part of their competitiveness. In many cases this has translated into large industrial efforts to support the much needed transformation of our energy systems.

Take, for instance, the huge leaps that natural gas has taken during the last decade alone. Admittedly, it is difficult to argue that the shale gas revolution in the US has been driven by concerns for climate change. But at the same time increased competitiveness of natural gas in the US has undeniably contributed to curbing greenhouse gas emissions. And with improved availability natural gas is now better positioned than ever to play its role in the big supply shift that is needed.

The climate challenge already drives energy technology. This is perhaps most evident in the area of renewable energy, where remarkable progress has been made only during the last few years. Consider the competitiveness of solar energy. The IEA expects solar energy, by 2035, to be 26 times the level of 2010, and many believe that this is a modest assumption. In more and more places solar photovoltaics is cost competitive without public support.

The same is true for onshore wind power, where growth is also impressive. Here, the next big technological leap is to take the windmills to the deep offshore, allowing for even bigger turbines and lowered cost per kilowatt produced. For its part, Statoil is strongly engaged in offshore wind, both as a running business and as an area for technology development. We firmly believe that the future of offshore wind lies in large-scale floating installations, and we take active part in that development by utilising our offshore skill base from oil and gas.

Climate change drives technology

Even in the oil and gas part of the energy business climate change has driven technology for years. In Statoil we started to capture and store CO_2 from the Sleipner gas field back in 1996, and later on we applied the same technology on the Snøhvit gas field in the High North. CCS is moving forward, with large-scale projects such as the Quest project in Canada and the Gorgon project in Australia, but we need to see even more projects in order to drive costs down and mature technology further. Statoil is a partner in the world's largest test facility for CCS at Mongstad in Norway. Here, new approaches will be scientifically evaluated in "real" scale, helping to firm up a technology that is much needed in the fight against climate change.

Industry is key to deliver solutions to a more sustainable energy future. However, industry cannot solve the problems alone. There is need for a proper international framework to make sure that the energy transformation is successful. Most important is putting a price on emissions and creating a level playing field so that the market can be fully engaged in providing necessary changes. In our view the EU Emission Trading System is a good policy framework, though in need of improvement. Fortunately, we now see more market based policies being implemented throughout the world.

Only when emissions have a real cost will we see technology, efficiency and supply changes pick up sufficient speed. Such costs must be imposed via political decision-making. While it is fair to say that the oil and gas industry has taken on the challenge of climate change with hesitation, I believe it is equally fair to say that today politics is lagging behind industry.

For years now the oil and gas industry has been ready and awaiting a new agreement to follow up the Kyoto Protocol. We have been asking for a transparent and fair agreement that will make it possible to unleash the full creative powers of the market. If we were allowed to compete on equal terms then what we have already seen in terms of technology development would be thoroughly amplified.

The road to a low-carbon future does not rule out oil and gas, and not even coal, at least not for several decades. The IEA has given us a glimpse into a possible energy future where damaging emissions are brought down and where international cooperation to combat climate change is firmly established. In such a world the consumption of oil in 2035 would be some 80mb/d, 10 per cent less than current levels. The consumption of natural gas, however, increases to almost 4,000bcm, 20 per cent more than current levels. In addition, we should have strong growth in renewable energy and wide spread use of CCS in the power and industry sectors.

To make such a future possible, the energy industry needs to add capacity the equivalent of more than four times Saudi Arabia for oil, and fifteen times Norway for gas, in addition to providing massive growth in renewable energy. There should be plenty of work for industry and politicians alike. Let's get going. ■

Managing water responsibly

By Brian Sullivan
Executive Director, IPIECA

Fresh water is a socio-economic, environmental and key business issue for the oil and gas industry with multiple uses in upstream and downstream oil and gas operations. To produce energy, the industry requires access to reliable sources of water, including fresh water and other types such as recycled waste-water. Water is essential for energy production, and equally energy is essential for water extraction, movement and treatment. The predicted rise in demand for energy means that a focus on water will become even more important in the decades ahead for the energy industry. Balancing the energy-water nexus – the relationship between the amount of water used to generate energy and the amount of energy required to supply and dispose of water – will be an important challenge to address for all sources of energy. Therefore, IPIECA, the global oil and gas industry association for environmental and social issues, is focussing on the responsible management of water in oil and gas operations as a key part of its work on sustainability. For fresh water is already a scarce resource in many parts of the world, and issues around supply have been gaining prominence in recent years.

IPIECA, the oil and gas industry's principal channel of communication with United Nations organisations, is not alone in highlighting the importance of water for energy. The 2012 UN Conference on Sustainable Development (also known as Rio+20) recognised that water is at the core of the sustainable development agenda and linked to a number of global challenges. At the conference the need for water to be integrated in sustainable development was emphasised, as was the need for measures to reduce water pollution, increase water quality, and improve waste water treatment and efficiency.

Moreover, the *UN World Water Development Report* will be publishing a new edition in 2014, with the theme "Water and Energy", which will also be the theme of World Water Day 2014. The decision to focus on Water and Energy was based on recommendations of the Advisory Group on UN Water Publications, and builds on the findings of a global survey conducted during 2011/2012.

For its part, the International Energy Agency (IEA) decided, in the 2012 edition of its *World Energy Outlook*, to put the spotlight on the ways in which energy production depends on water, and how energy industries are vulnerable to physical constraints on water availability and regulations that might limit access to it. The IEA estimates that global water withdrawals for energy production in 2010 were approximately 583 billion cubic metres, or 15 per cent of the world's total water use.

Water has multiple uses in upstream and downstream oil and gas operations, and companies are continually striving to use this key resource more efficiently, by finding new ways to recycle the water it uses. Wherever practicable the industry uses reclaimed waste-water or lower grade water in industrial processes – leaving more fresh water for drinking, sanitation and agricultural use. Additionally the industry is improving water management through the application of new technologies, investing in more efficient production methods, encouraging cross industry partnerships and developing and sharing best water management practices through IPIECA.

IPIECA is working to improve understanding of how and why water is an important resource along the oil and gas supply chain. Efforts to date have been

The oil and gas industry and sustainable development

IPIECA, the acronym for the International Petroleum Industry Environmental Conservation Association, was established in 1974 in response to the formation of the United Nations Environment Programme (UNEP). Thirty-nine years later, IPIECA remains the oil and gas industry's principal channel of communication with the United Nations. Over the decades, the organisation's remit has expanded. Covering both the upstream and downstream sectors of the industry, IPIECA is devoted to improvements in environmental and social performance from the earliest phases of exploration to the end-use of the oil and gas that our members produce. Its membership is broad, covering companies responsible for over half of the world's oil output.

focused on effective water risk assessment with the development of best practice water assessment tools.

Tools

The oil and gas industry is building tools to increase understanding of water risks. In 2011 IPIECA launched a customised oil and gas version of the World Business Council for Sustainable Development (WBCSD) Global Water Tool. This helps companies to map their water use and assess potential risks to their overall global portfolio of sites, considering each part of the value chain. The tool allows for risk screening of water issues at sites by understanding the company's water needs in relation to local circumstances, including water availability, quality, stress, access to improved water sources and sanitation, allowing users to consider questions such as:

- How many of your refinery sites are in extremely water-scarce areas, and therefore at greatest risk? How will that look in the future?
- What percentage of your production volume is currently in a water-scarce area? And in 2025 and 2050?
- How many of your sites are in countries that lack access to improved water and sanitation?

IPIECA also collaborated with the Global Environmental Management Initiative (GEMI) to produce the GEMI Local Water Tool for Oil and Gas. The tool helps companies to assess external impacts, business risks and opportunities, and manage water-related issues at specific sites. When used together with the IPIECA Global Water Tool for Oil and Gas, users can screen for potential risks and then investigate risks on sites. Assessment of the local context helps develop the most appropriate solution for all water users. The oil and gas industry is not the primary user of water and its relative consumption is low. However, water is essential for oil and gas companies. Therefore, efficient and effective water management by all water users is necessary and in the industry's interests.

Overcoming future constraints

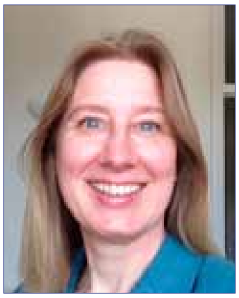
In its 2012 report, the IEA predicts that future water constraints can be overcome, but argues that water will remain (and likely increase in importance) as a key consideration when assessing the feasibility of energy projects. The report further predicts that the vulnerability of the energy sector to constraints in water availability will increase, and recommends that better technology will need to be utilised, and energy and water policies will need to be better integrated to overcome these constraints.

The oil and gas industry is committed to reducing water demand and impacts on freshwater in areas of water stress. The industry continues to learn from its own experience, and through partnerships, in order to improve fresh water management and reduce its impacts. Building more partnerships, such as those already established between IPIECA and WBCSD, and IPIECA and GEMI, will enable cross-sector learning. Participation in collaborative industry initiatives will share and promote good practices across sectors in effective water resource management.

Successful partnerships enable organisations to learn from each other and work in new and innovative ways, such as through open sharing of information and data. Meeting old challenges in new ways requires a considerable investment of time, some changes in behaviour and a willingness to take risks. Ultimately, this innovation and new thinking can help to reduce industry impacts and bring further benefits to the communities and countries in which oil and gas companies operate. ■

The industry is improving its water management

How the oil and gas industry addresses social responsibility



By Ulrike von Lonski
Director of Communications, World Petroleum Council

Although everyone in the oil and gas industry may implement sustainability in different ways, many use similar fundamental values and principles based around its core meaning of linking economic, environmental and social considerations into all aspects of decision-making. The key premise is that sustainability means delivering long-term value to shareholders, while providing social and economic benefits and managing the industry's environmental footprint. It has been shown repeatedly that companies which follow sustainable business practices outperform those with narrower priorities. Sustainability and corporate social responsibility can almost be viewed as synonymous in that they both address the three pillars of economic viability, environmental soundness and social responsibility – the so-called "triple bottom line".

Renato Bertani, President of the World Petroleum Council, describes it as follows: "Social Responsibility must be, more than ever before, an intrinsic part of the business model of any company that seeks long-term growth and profitability. This is particularly applicable in the energy sector, which impacts stakeholders at all levels, from small communities where operations are conducted to social and economic development across continents."

In our era of globalisation enhanced communication and transportation has made the world a smaller place. As a result, markets and issues are no longer confined within socio-political borders. People are connected to issues far from home and locally-focused issues can rapidly escalate to the national and international level. The roles of government and business have shifted. Governments are now more focused on public policy development and enforcement, while providing business the opportunity to supplement prescribed laws and regulations with voluntary initiatives. Along with this, there is growing pressure for business to be more responsible and accountable not only to its shareholders but to a broader range of stakeholders including its workforce, supply chain, communities, NGOs, governments and the general public.

In the business sector, creating value drives decision making and legitimately so. But what does 'value' really mean? Nowadays it means much more than traditional measures such as asset value, retained earnings or net income per share. A report by Cap Gemini Ernst & Young found that institutional investors seriously consider non-financial factors in their decision-making. A minimum of 35-40 per cent of their portfolio allocation decisions are based on factors such as brand, reputation, and employee relations – assets not captured by normal accounting methods. Board members and management face new challenges to meet these emerging issues and expanding stakeholder expectations.

Social Responsibility

In many areas where the oil and gas industry operates, risk is not confined to the geology or financial risk. The application of sound CSR principles becomes critical to business success. Companies are challenged not just to behave ethically, but to contribute to economic development and in doing so, improve the quality of life for their employees, for local communities and for society at large. CSR helps to link business decision-making to ethical values, legal compliance and respect for people, communities and the environment in addition to providing enhanced shareholder value. By delivering social, environmental and economic benefits, we achieve sustainable development.

There are five key elements to Social Responsibility:

- Good business practices
- Strong employee relations
- Healthy partner/supplier and customer relations
- Responsible health, safety and environmental strategies
- Community involvement

Most of these are obvious.

Good business practices consist of ethical behaviour, transparency, avoiding human rights abuses, good governance and anti-corruption. In order to get a social license to operate, businesses have to actively engage with the community in which they operate. Community involvement is much more than financial philanthropy. It is based on two key principles: that communities have a legitimate right to participate in decision-making for issues that affect their lives and that communities deserve a fair share of the benefits derived from the industry's activities. In order to evaluate their impacts and determine their risk management strategies,most companies use in-depth Environmental and Social Impact Assessments. Measuring their performance and sharing them with their stakeholders through a regular Sustainability Report creates the basis for trust from the community. In a step further this can be verified through external assurance provided by an independent auditor and/or a multi-stakeholder group. This facilitates good relationships and partnerships and leads to an improved reputation.

WPC Initiatives

The World Petroleum Council has long involved the discussion of sustainability, social responsibility and community engagement in its Congresses. Starting with the programme itself, where the issues get addressed in a wide range of formats, including by industry leaders in the Plenaries and at the Special Session on Social Responsibility. Industry experts, stakeholders and NGOs jointly discuss the roles and responsibilities of the oil and gas sector and look at practical ways of addressing the challenges.

Over the last twenty years a dedicated Social Responsibility (SR) Programme has been added to the World Petroleum Congress, exploring such themes as Human Rights, Promoting Human Development through Innovative Social Responsibility Programmes and Community Partnerships.

A key part is the Social Responsibility 'Global Village' in the WPC Exhibition area, which showcases projects from around the world that highlight partnerships between NGOs, communities and the petroleum industry in building sustainable projects that promote development and a social license for ongoing operations.

When hosting the triennial World Petroleum Congress, the intention is not only to promote the progress of the global oil and gas industry but to leave a positive impact on the local community of the host country and a long lasting legacy for its environment. The surplus of the events is designed to go towards funding the seeds of a country legacy project proposed by the Host in agreement with the WPC.

Legacy

As a not-for-profit organisation, the WPC, a registered charity in the UK, also ensures that any surpluses from the Congresses and meetings are directed into educational or charitable activities in the host country, thereby leaving a legacy. The concept of leaving a legacy in the Host country started in 1994 with the 14th

Before the 2002 Congress in Rio, the WPC organised a community clean-up

World Petroleum Congress in Stavanger. After the 1994 WPC in Norway the surplus funds of the Congress were put towards the creation and building of a state of the art Petroleum Museum in Stavanger.

The 15th World Petroleum Congress in Beijing adopted the issue of young people as a key aspect of its theme: "Technology and Globalisation – Leading the Petroleum Industry into the 21st Century". To support their education and future involvement in the petroleum industry, the Chinese National Committee donated all the computer and video equipment used for the Congress to its Petroleum University.

Profits from the 16th Congress in Calgary were used to endow a fund that gives scholarships to post-secondary students in several petroleum-related fields. The Canadian Government Millennium Scholarship Foundation matched the amount dollar for dollar to create an endowment which supported over 2,000 students.

The 17th World Petroleum Congress was the first to integrate the concept of sustainability throughout its event, instead of relegating it to a side position. The Congress took responsibility for all the waste it generated. The congress and the accompanying Rio Oil & Gas Expo 2002 generated a total of 16 tonnes of recyclable waste – plastic, aluminium, paper and glass. All the proceeds of the recycling activities were passed on to a residents co-operative with 6,000 inhabitants located in the port area of Rio de Janeiro.

But the sustainability efforts did not stop there and an army of 250 volunteers collected 36 tonnes of garbage in 10 days in a special community effort to clean up the Corcovado area before the Congress, donating all proceeds to the garbage collectors, some of the poorest inhabitants of Rio. The Finlândia Public School also received a new lick of paint from the WPC volunteers. The surplus funds for the Congress of were used to set up the WPC Educational Fund in Brazil, which was further increased in 2005 with tax initiatives added by the Brazilian government.

The 18th World Petroleum Congress also chose a sustainability focus for the first ever WPC to be held in Africa: "Shaping the Energy Future: Partners in Sustainable Solutions". Education was made the focus of the 18th World Petroleum Congress Legacy Trust, set up by the South African National Committee to provide financial assistance to needy young South Africans who wish to pursue a qualification in petroleum studies.

In 2008 the 19th Congress in Madrid was the first one to tackle sustainability in a holistic way and ensure that all carbon emissions from the Congress were offset. Exhibitors also took note and created stands that were wholly re-usable or bio-degradable. The trend was continued in Doha where the 20th Congress also offset the carbon emissions from its 7,000 participants and recognised sustainable exhibitors with an award. The legacy went towards creating a mobile lab to educate children and young people in the region on energy usage and energy efficiencies. ■

Part of the "social responsibility arena" at the Rio Congress

SONANGOL, AN ENERGY MOVING US FOR 37 YEARS

Angola is among the countries with the biggest economic growth worldwide. The social and economic advances reached by Angola over the last years are both notorious and noteworthy. Thousands of kilometres in railways and roads recovered and built, uniting the whole country; the construction of industrial hubs in sectors as diverse as, for instance, an innovative optic fibre cables plant; the extension of the hospital network, now double the size, and the realisation of surgeries that could not be undertaken in the country before. Additionally, there has been a new awakening for the agriculture sector, with environmental responsibility increasingly becoming a focus; the prioritisation of education, with the creation of numerous public and private universities and a strong support to technical training.

These are national achievements. Angola is moving ahead from within and worldwide with creativity, technology, talent and the energy of all Angolans. Sonangol has always been present in this development, taking over a central role in this transformation, as a state-owned oil company. This year, Sonangol celebrated 37 years and if 2012 was qualified as a year of growth in terms of oil production in Angola, with a 4.5% growth rate and an average production of 1.7 million barrels per day, 2013 is expected to be an even better year for the national oil industry. It is estimated that Angola will be able to start producing two million barrels of oil per day between 2013 and 2017.

The company recently presented a vast prospection and research programme, valued at 8.8 million US dollars. The national goal is an annual average growth rate of 7% in oil production. This target is getting closer to being reached and Sonangol is getting ready for this “race” in the best way possible, by hiring qualified staff and following up the important projects in course. For instance, the mega project Angola LNG. In fact, 2013 will also mark the first cargo of liquefied natural gas (LNG) in the country. The LNG plant located in the north of the country, in Soyo, has the potential to produce two million cubic feet of clean gas per day, which will be distributed in the domestic and international markets. The plant will be supplied by the country’s vast reserves, estimated at over 10 trillion cubic feet of gas, available at the blocks located offshore Angola.

In the balance of these 37 years, the potential of the Angolan subsalt cannot be forgotten, especially after the announcement of two significant findings. The possibility of the arrival of a new era in oil exploration is encouraging companies operating in the country as well as the government, since these discoveries would mean an increase in proven reserves. In December 2012, following one year of negotiations, Sonangol has signed eleven production sharing contracts for the offshore Kwanza subsalt basin.

The company’s bet on training Angolan staff has already come into fruition. 2013 will already be in the history of Sonangol as the starting point of an era that we wish will be consequent and lasting. This year, the Luanda Bay witnessed the promotion of a member of staff trained by Sonangol to ship’s captain. Nembamba Camiola Miezi Vita, 36 years-old, from Namibe, took over the command of the “Loengo” oil tanker, at the service of Sonangol Shipping Angola, Sonangol’s affiliated company focused on sea oil shipping. This is a reason for pride, for the country and for our company.

In 2013 and in the years to come, Sonangol will continue with the same energy that drives us to do more and better, every day: the energy to transform the commitment of a great company into a great future for Angola.

Innovative financing for upstream oil and gas

By John Martin
Managing Director, Oil & Gas Group, Standard Chartered Bank

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.

Transformational landscape

Over the past two decades the nature of the upstream E&P business has been affected by restricted access for international oil companies (IOCs) to conventional resources and 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 likely 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 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, with the lack of upstream or midstream industry in these countries 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. Chinese state-owned enterprises (SOEs) have been dominant acquirers and are typically 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 the 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 typically charging 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 cost 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

African Petroleum workers exploring for oil offshore Liberia

Photo courtesy of African Petroleum

demanded in the past. As borrowing from a bank will likely 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 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 focused 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 and understand 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.

It is without a doubt that massive financing needs are expected in the industry; but it will happen in different ways 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 financial 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 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.

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.

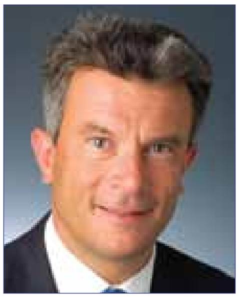
Looking ahead

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 in future years. 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 the 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. ■

Never a better time to be a petrotechnical professional



By Antoine Rostand
Managing Director, Schlumberger Business Consulting

From the mid-1980s onwards, the industry's slow growth and relatively low crude oil prices led oil and gas companies to introduce strict cost control measures. This was an era when recruitment levels were low and interaction with university campuses was limited. The workforce had started to age to the extent that, by the end of 2004, more than 60 per cent of the industry's core technical people were over 40 years old. Moreover, the pace of workplace promotions was slower than in the past.

When the industry started to boom in 2004, human resources (HR) departments needed to reinvent themselves to deal both with the ramp-up of activity and the crew change that was reshaping the exploration and production (E&P) industry. Human resources departments within E&P companies had to learn new ways of recruiting, training and promoting people, and also how to retain them.

In light of these industry HR challenges, Schlumberger Business Consulting (SBC) decided to investigate these issues through an annual Oil & Gas HR Benchmark study. SBC focused its analysis on trends involving petrotechnical professionals (PTPs), a workforce category at the foundation of the oil and gas business, made up of geoscientists and petroleum engineers employed by operators. Over the years, the benchmark has become a reference point for E&P executives seeking to understand industry trends and develop HR strategies. The study continues to highlight best practices and gives insights into the changing environment for recruiting and retaining human talent.

This article highlights the principal HR challenges experienced by the oil and gas industry since 2004, identified and brought to light through SBC's HR benchmark analyses.

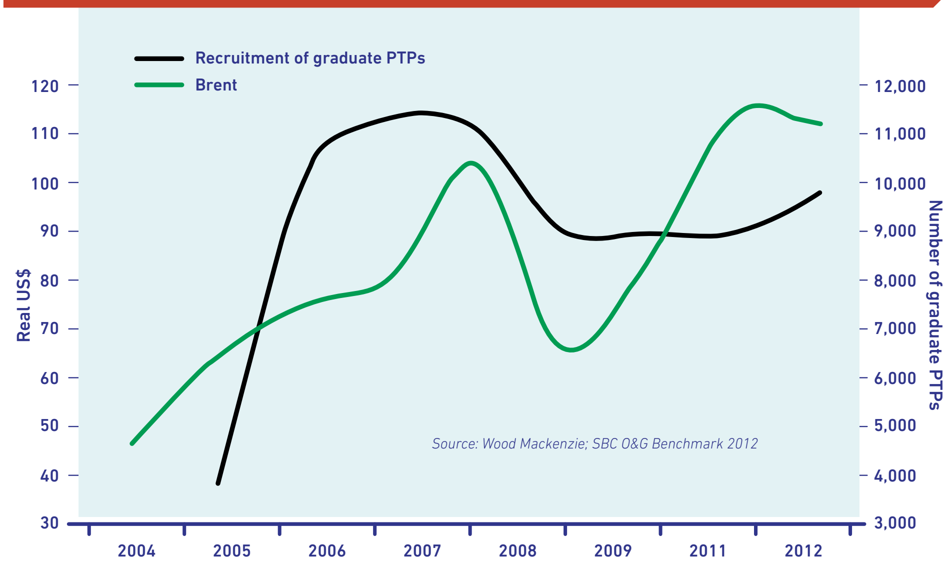
2004-2008: Finding the manpower to cope with industry growth

Rising oil prices from 2004 through 2008 drove up the industry's activity levels, increasing demand for technical talent (Figure 1).

Companies resorted to a mix of graduate and mid-career hiring, putting pressure on universities while driving mid-career attrition to unprecedented levels. Consequently, compensation and benefits increased substantially.

It was in this context that the SBC HR Benchmarks in 2005 and 2006 sought to quantify the so-called "big crew change." This was the first time a study was conducted using information from both universities and companies to assess the supply and demand of petrotechnical professionals. The analyses indicated that the number of graduates worldwide was sufficient to meet global industry demand, even though some imbalances appeared in specific regions, such as the Middle East and the US.

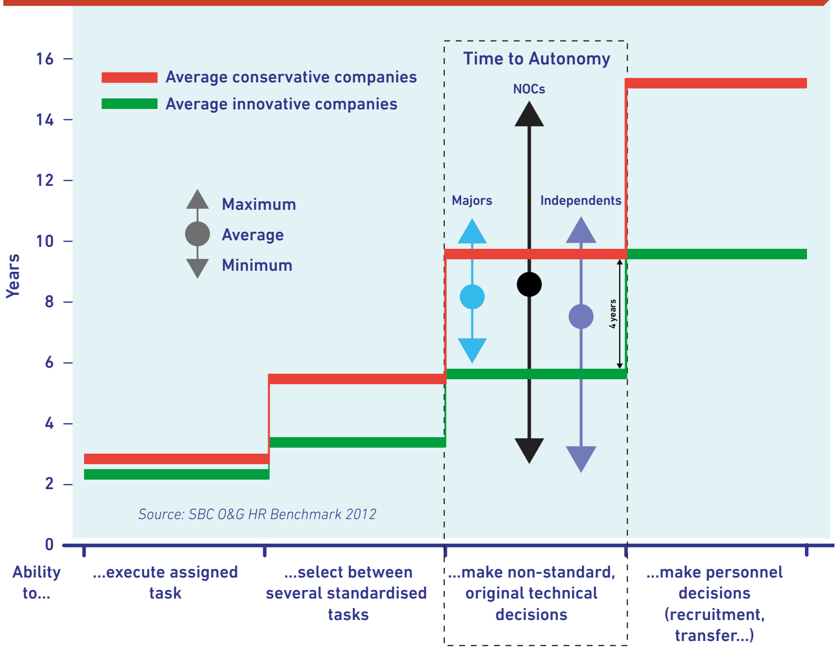
Figure 1: Oil price evolution and recruitments of graduate PTPs



Implementing *Supply Chain of Talent*

In parallel to the supply-demand assessment, SBC developed the Supply Chain of Talent™ concept, which aims to design/create/develop an integrated approach towards HR practices. It involves forecasting manpower requirements based on expected oil and gas indicators such as production, while forging the right recruitment strategy, competency development approaches and career management plans. The comprehensive method taken by SBC's Supply Chain of Talent has been proven to have a more favourable impact than a piecemeal approach where, for example, recruitment does not support production growth ambitions; or where training policies do not address required long-term strategic capabilities or technological advances.

Figure 2: Time to Autonomy for PTP



Understanding *Time to Autonomy*

Due to the high recruiting levels during this period, it was pertinent for companies to understand how long it took an engineer to become technically proficient under minimal supervision. Time to Autonomy™ describes the time needed to develop an entry-level geoscientist or petroleum engineer to the point where he or she can take "non-standard original decisions" in the field. This concept also implies a better understanding of the pace at which these professionals should be promoted.

It has a direct and measurable impact on a company's ability to deliver projects, as will be explained further in the article when we talk about economies of scale related to petrotechnical professionals. Accordingly, companies have acknowledged Time to Autonomy to be an important benchmark in determining the success of competency development.

Accelerating autonomy is principally achieved by introducing well-structured training, which is independent of company size, maturity or geography (Figure 2). The benchmark studies revealed that both international oil companies (IOCs) and national oil companies (NOCs) can either develop people quickly or slowly.

2008-2009: The crisis in the wake of growth tensions

Following a favourable period for the oil and gas industry, the global recession in 2008 led to more volatile and lower oil prices. During this period, the HR Benchmark revealed that NOCs and IOCs were not reacting to the crisis in the same way. Privately owned companies reduced their recruitment targets by 30 per cent between 2008 and 2010, whereas state-owned companies reduced theirs by only 10 per cent over the same period. This was a dismal period for most majors and independents, but less so for the NOCs. Most companies were reluctant to expand their human resources and manage new talent until they saw a recovery ahead.

2010-2012: Recovery in the midst of generational change

In 2010, the oil and gas industry started to emerge from economic recession, exhibiting strong growth (Figure 1). Exploration and production companies were now faced with a high number of vacancies amidst the generational shift from baby boomers to young petrotechnical professionals. Looking at the estimated vacancies for 2016, we see a deficit of 15,300, or about 19 per cent of experienced petrotechnical professionals. Such a shortage prompted SBC to take a deeper look into the productivity of technical talent.

Matching technical resources with growth...

This productivity challenge was at the forefront of the 2011 and 2012 SBC Oil & Gas HR Benchmark analyses. These particular benchmark studies explored the notion of PTP Intensity™, which is the ratio between the number of petrotechnical professionals and the number of barrels of operated production. The analyses revealed a solid correlation between operated production and the number of petrotechnical professionals. Producing more barrels means more technical staff needed to be hired. The statistics showed that economies of scale do not exist in the oil and gas business with technical professionals. To double production, an upstream company needs at least to double its technical staff. In this sense, the oil and gas industry acts more like a professional services industry, such as healthcare, where an increase in patients requires an equivalent increase in physicians. Another important insight that surfaced was that faster-growing companies (high growth) tend to have a higher PTP Intensity than those with slower growth (low growth).

The PTP Intensity concept has important implications for the industry. By proving the close relationship between operated production and technical staff, the SBC HR Benchmark has sent a clear message to the industry – that is, companies need to maintain recruitment levels of petrotechnical professionals to secure stable hydrocarbon production growth.

Figure 3: PTP Intensity – Total number of PTPs vs operated production

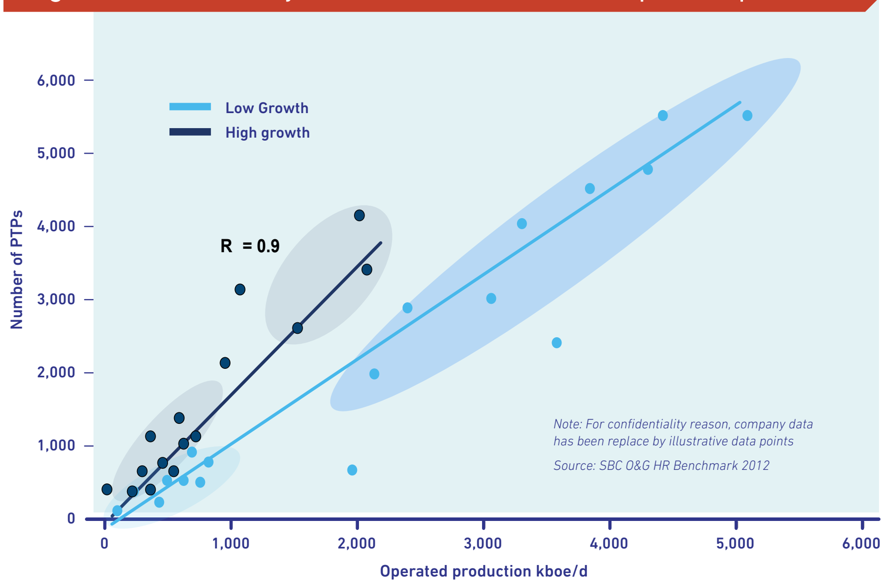
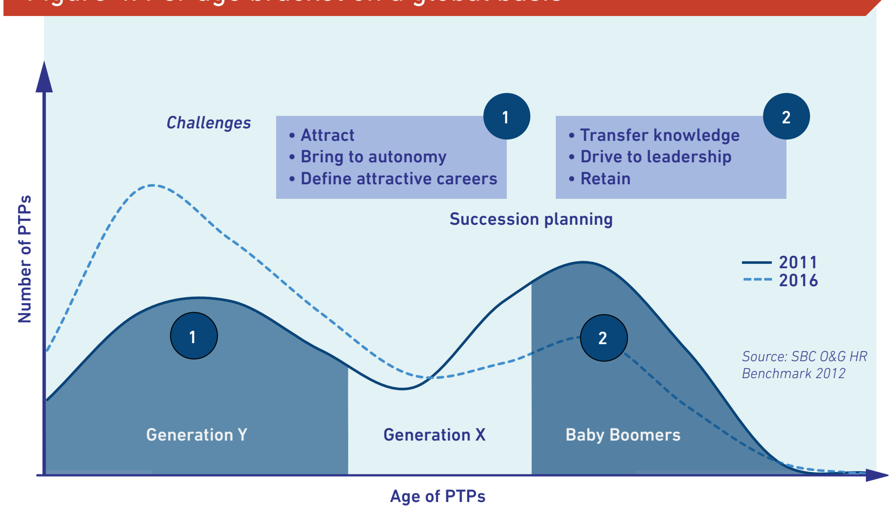


Figure 4: Per age bracket on a global basis



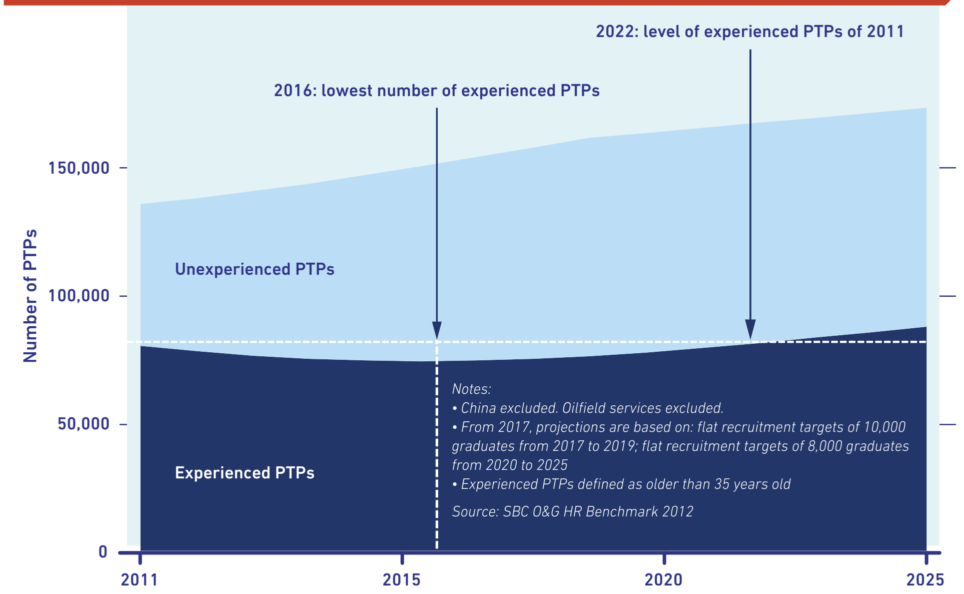
...and anticipating the challenges from the generational reshuffle

The issue of growing oil and gas production becomes more complicated with the ongoing generational change, which is affecting the industry's workforce demographics. Companies need to anticipate and prepare for the upcoming challenges, which the most recent SBC HR Benchmarks have addressed thoroughly. More than 25 per cent of petrotechnical professionals now working for

E&P companies are over 50 years of age, and a significant majority will retire by 2016. As shown in Figure 4, typical majors or independents would have moved from a demographic profile dominated by baby boomers, where seniority prevailed, to one in which young petrotechnical professionals become the majority by 2016.

Some of the crucial areas that companies will need to address due to challenges caused by the generational shift are industry attractiveness, knowledge transfer, as well as succession planning and leadership development.

Figure 5: Number of PTPs on a global basis 2011-2025



The first challenge comes from the difference between the new generation and its predecessor. For newcomers, career prospects, industry image, and lifestyle considerations are as important as monetary compensation and benefit packages. Companies that aim to attract younger-generation professionals will have a competitive advantage over their peers if they can create a more comprehensive employee value proposition.

Secondly, since the number of experienced petrotechnical professionals will decrease in absolute numbers until 2016, the industry will need to produce more oil and gas with less experienced technical talent, while pushing for the successful transfer of knowledge from experienced technical professionals to the younger generation.

The next challenge will arise from the impact that the generational shift has on leadership management and succession planning. First, companies must help younger employees to reach top positions traditionally reserved for older higher-seniority executives. Second, it is crucial that companies prepare detailed succession plans in good time, especially in view of the generational change. Companies need to anticipate the consequences of quicker internal promotions within an organisation, or the risk of failing to integrate experienced hires smoothly into the existing company culture.

Conclusion

The SBC HR Benchmark has consistently sought to provide insights, useful analysis and unique perspectives on how the oil and gas industry may tackle human capital challenges. Its most important message is that investments in recruiting and training should not be based on the latest oil-price fluctuations but on an organisation's expected long-term needs.

Most experienced petrotechnical professionals active today will have left the industry by 2020. As a result, E&P companies face considerable challenges in terms of succession planning and the development of competencies. The good news is that after 2016, predicted tensions on poaching will start to ease and pressure on salaries will soften, as shown by Figure 5.

From a young petrotechnical professional's perspective, today's oil and gas industry offers unique possibilities: the previous generation is leaving while activity is strong. Those capable of tackling the concerns facing the sector will have a chance to play a genuine role in collectively solving the energy challenges of the 21st century. ■

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How Japan's oil industry responded to Fukushima

By Junichi Hatano
Secretary General of Japan's National WPC Committee

The Great East Japan Earthquake and the subsequent tsunami that occurred on 11 March 2011 caused tremendous damage to the Japanese economy, including the oil industry. This paper discusses the responses of the Japanese petroleum industry to the disaster and seeks to clarify some of the future challenges facing the industry.

Immediately following the earthquake and the tsunami, six of the nine refineries located in north-eastern and eastern Japan were obliged to suspend their operations and two refineries caught fire. The refining capacity of the six refineries was 1.4 million BPSD (barrels per stream day, the standard measure of refinery throughput), equivalent to 30 per cent of the total capacity in Japan. Three of them resumed operations within two weeks, but the other three, seriously damaged, remained out of operation for around one year with the refining capacity of the idle facilities corresponding to 600,000 BPSD. In addition, most oil terminals on the Pacific coast had difficulties in shipping oil products due to damage caused by the earthquake and tsunami. Furthermore, about 150 tanker trucks were destroyed by the tsunami and operations were stopped in 40 per cent of the petrol stations in three north-eastern prefectures. From an energy perspective, the electricity and city gas infrastructure was seriously damaged. So petroleum, as a portable and storable energy, was in strong demand from various quarters.

Under these circumstances, the smooth supply of petroleum products was significantly restricted, causing long queues at petrol stations in disaster regions and metropolitan areas. There were also fuel shortages in several types of oil products: diesel oil and heavy fuel oil for emergency power supplies in hospitals and power plants, kerosene as heating fuels in evacuation centres, and gasoline and diesel oil as fuels for emergency vehicles. The restricted supply situation was exacerbated by damage to the transport infrastructure, including roads and ports.

Energy of 'last resort'

In order to provide petroleum products to quake-stricken regions, oil was distributed by tanker trucks from other areas. However, transport over long distances was more difficult than expected for several reasons: drivers were not familiar with the routes and some roads were blocked due to earthquake damage.

Oil terminals, mainly located at ports, were also affected by the disaster. Distributors agreed to share use of less-damaged terminals, which helped the provision of gasoline, kerosene and diesel oil to petrol stations in the quake-hit areas just after the disaster. This marked the first time in the history of the Japanese petroleum industry that oil terminal owners shared with other distributors. To cover shortfalls of oil products in quake-hit areas, refineries in the western part of Japan operated at almost full-capacity and each company suspended export of oil products, while also immediately commencing imports.

In spite of these efforts, some cities in northeastern Japan had no operational petrol stations within a 10-km radius. In such locations, temporary stations were established with hand-turned or pedal-driven pumps in cooperation with the Self-Defense Forces (SDF) and local municipalities.

Immediately following the earthquake, the Petroleum Association of Japan (PAJ), a petroleum industry umbrella organisation, set up a disaster headquarters, operating 24 hours a day, which requested each member oil company to secure oil products for the disaster-hit regions, while also dealing with emergency assistance based on requests from the prime minister's office and the Ministry of Economy, Trade and Industry (METI). As an example, the PAJ handled about 1,400 requests for oil products in March 2011: fuel for emergency vehicles (ambulances, fire engines, police cars, military vehicles), fuel for emergency power generation in hospitals, power plants, and heating fuels for evacuation centres and schools. Moreover, the PAJ arranged provision of approximately 7,000 drums of fuel to the military, as well as donating 2,000 drums of fuel to three disaster-hit prefectures (Iwate, Miyagi, and Fukushima).

In the Great East Japan Earthquake, petroleum fulfilled its capability as a "self-sustaining and distributable energy" that excels in convenience, portability, and stock potential as soon as services of electricity and city gas, energies dependent on supply networks, were suspended. Petroleum played the role of the "last resort" energy that protects the safety and comfort of our national life, so that its importance as energy has been re-acknowledged.

Measures against future emergencies

Based on our experience in the earthquake as mentioned above, the Japanese oil industry has set to work on the maintenance and strengthening of petroleum supply chains in order to ensure stable supplies of oil products to final consumers, particularly in the event of an emergency.

First, oil companies have commenced the strengthening of emergency responses. In oil distribution bases, such as refineries, oil terminals and petrol stations, various measures have been adopted. For example, a satellite phone has been installed in many of the local premises because cellular phone communication was severely disrupted. In many such facilities, countermeasures are focused on protection against tsunami, such as water-resistance measures for electric facilities, and waterproof barriers/doors to protect power-generating equipment for emergency use. There are also cases where shipping facilities for tanker trucks were moved to higher ground within the premises. In addition, anti-seismic reinforcement work and installation of independent power generators have been implemented. Regarding the means of transporting oil products, the usefulness of drums was re-evaluated for its convenience especially for diesel oil and kerosene and, therefore, some oil terminals have newly established drum filling systems.

Second, with regard to petrol stations, their function as disaster prevention centres had already attracted attention following the great earthquake in Kobe in 1995, as there were few incidents such as fires breaking or buildings collapsing. However, this time petrol stations on the coast were seriously damaged by the tsunami and suffered from blackouts. Therefore, measures for continued operation are being undertaken, in particular, installation of power supplies for emergency use and deployment of manually-operated pumps. In addition, efforts concerning their functioning as disaster prevention bases are also being made from the viewpoint of contributing to society, such as by maintaining stocks of emergency goods and provision of evacuation sites.

Many oil distributors faced problems communicating with their shipping bases and in gathering information. Based on this experience, the means of communication are being strengthened by developing a structure in which information from each oil company is centralised by the PAJ in the event of an emergency. Regarding information about petrol stations in operation, which was specifically demanded by consumers shortly after the earthquake, appropriate methods of gathering and disseminating information are being examined.

As far as the government is concerned, Japan has revised the law to hold government-stockpiled oil products, including gasoline and kerosene, in addition to the normal stocking of crude oil. With regards to local municipalities, the PAJ has begun to conclude a memorandum with some prefectures that specifies the items to be considered in preparation for disasters, such as a selection of priority destinations for oil products (the police, hospitals, and public facilities) and the necessary information to ensure efficient provision, including the required type of oil, tank capacities and access to disaster prevention centres.

Lessons learned

Up to now, most security of supply measures have focused on the upstream side: obtaining energy resources, improving the energy self-sufficiency rate and stockpiling of crude oil. Following the earthquake and the tsunami, however, we have recognised that it is extremely important to ensure stable provision through to final domestic consumers, especially in the case of a large-scale disaster.

In conclusion, Japan must further raise its capabilities to utilise petroleum in responding to an emergency. To ensure that petroleum can play its part as the fuel of last resort, we have to maintain and reinforce the supply chain for oil products, including enhancement of the shipping framework (tanker trucks, oil tank trains, vessels, etc) in preparation for an emergency. A further challenge for maintaining and strengthening the supply chain is how to ensure stable demand for petroleum. Specifically, utilisation of oil should be further promoted in heating, hot water supply, and transportation.

The earthquake and the tsunami that occurred in March 2011 have reminded the Japanese people of the possibility of major earthquakes around Tokyo or in the neighbouring Pacific Ocean, which may occur at any time. Based on the lessons we have learned from this disaster, it is imperative for the Japanese petroleum industry to secure stable distribution of oil products to final consumers through maintaining and enhancing its supply chains. ■


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