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PROMOTING COOPERATION, INNOVATION AND INVESTMENT
THE OFFICIAL PUBLICATION OF THE 20TH WORLD PETROLEUM CONGRESS
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Finding solutions to provide global access to reliable, affordable and sustainable energy through cooperation, innovation and investment.
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Promoting Cooperation, Innovation and Investment

BY DR RANDY GOSSEN
PRESIDENT, WORLD PETROLEUM COUNCIL

I would like to welcome each and every one of you to the 20th World Petroleum Congress in Qatar. This Congress will be a “First” in many ways: the first time for the World Petroleum Council to hold its triennial event in the Middle East, the first time to reach over 2,000 submissions for our Call for Papers, and the first time we have a sold out exhibition nearly a year before the event takes place. I am sure there are many other “firsts” to share with you. They all point to the fact that this event has been exceptionally well targeted and organised and that we have selected the right theme for the Congress to unify all that will be happening in Doha from 4-8 December 2011.

It is clear that there is not any single solution to our energy challenges but a union of the following: Investment, Innovation and Cooperation. We will be addressing these challenges throughout our extensive programme at the Congress, but we have also asked some of our key speakers and other industry leaders to share with us their thoughts on how we can provide energy solutions for all.

One of the keys will be investment. Although economic growth and the liberalisation of markets all over the world have spurred significant demand for oil and gas over the last decade, we are now going through more difficult times which has significantly impacted the oil and gas sector.

This has resulted in a major cutback in new investments in the industry. The IEA estimates global demand for oil to rise to 106 mb/d in 2030. 80 per cent of all energy comes from fossil fuels and that level is not expected to change very much by 2030 or even 2050. Much of this increase in supply will have to come from unconventional oil and gas which will require higher sustained prices. According to the IEA, 64 mb/d of gross capacity needs to be installed between 2007 and 2030 – six times the current capacity of Saudi Arabia – to meet demand growth and offset decline. In the current economic situation it is unlikely that these levels of investment will be met, although those that are cash rich and have access to credit will be able to take advantage of new opportunities.

However one of our greatest assets are the people in our industry and investing in the next generation and engaging them early and fully will provide us with the necessary tools to succeed in meeting the future energy demands.

The second driver is innovation. With conventional reserves of oil and gas that are easy to access and inexpensive to produce largely gone now, the industry is exploring in ever more challenging new frontiers where large oil and gas discoveries are still being made. The development of such new discoveries will require deployment of cutting edge technologies delivered in an environmentally safe manner. Enhanced oil recovery is still one of the more promising areas to increase reserves and production from existing fields. The development of new technologies is significantly increasing recovery factors and prolonging the life of mature oil and gas fields. Unconventional oil and gas resources are quickly becoming technically feasible and economically very attractive.

None of these can work without cooperation. Despite the current economic situation, many of the largest oil and gas companies are actually maintaining or raising their capital investments to address the ongoing need to add reserves and grow production. This brings about new opportunities for international oil companies (IOCs) to partner with national oil company (NOCs) on a long-term, sustainable basis. The economic crisis can therefore be a good time to focus on forming and strengthening strategic alliances, particularly with NOCs.

Cooperation between IOCs and NOCs is not without its challenges: there are significant cultural, philosophical and social differences that can make working together awkward at best and sometimes impossible. In addition, the possibility of government changing the rules can pose a real risk and induce added uncertainty. Furthermore, government playing the combined roles of policy maker, regulator, partner and investor is a complex mix requiring considerable skill, understanding and flexibility. Notwithstanding these challenges, the rewards of enhanced cooperation are significant for both parties. The World Petroleum Council (WPC) can facilitate the building of important bridges for the two sides to find ways to work together.

Strategic alliances enable businesses to gain competitive advantage through access to a partner’s resources, including knowledge, markets, technologies, capital and people. Teaming up with others adds complementary resources and capabilities, enabling participants to grow and expand more quickly and efficiently.

Cooperation is not restricted to building relationships between companies, it also applies to enhancing relationships with governments, non-government organisations, academia, international institutions and the public. For critical issues such as climate change, no one sector of society can provide the answers on its own, but will require cooperation among all sectors.

I look forward to sharing with you the thoughts of our industry leaders on these issues here and at the 20th World Petroleum Congress.
We help her build her skills and future...

we also take pride in being part of building our nation’s growth.

We are committed to helping the generations of the future piece together the elements of a promising life.

Our support and sponsorship of diverse and constructive community activities is just one way of living up to that commitment.
WPC’s role in forging the past and crafting the future

BY DR PIERCE RIEMER
DIRECTOR GENERAL, WORLD PETROLEUM COUNCIL

To welcome delegates to the 1st World Petroleum Congress in 1933 its founder Mr Thomas Dewhurst, a geologist by profession, expressed the view that “Since World War I the developments which have taken place in each and every branch of petroleum technology have been astounding, actually like a revolution. The stage has therefore been reached when it is not merely desirable, but even imperative, that representatives from as many countries as possible should meet to discuss problems of this newer and better world of petroleum technology”. He was speaking to representatives of 28 nations in London and here we are now in Qatar in 2011 with over 90 countries attending.

Our forefathers in 1933 had a dream. Mr Dewhurst stated “Some day the World Petroleum Congress might become a ‘League of Nations’ for Petroleum Technologists, and indirectly and subconsciously play a part in international good feeling and fellowship.” Good feeling and fellowship was maintained by the WPC throughout the years and after Doha we move to the next Congress in Moscow in 2014.

The purpose of the WPC was “The management of the world’s petroleum resources for the benefit of mankind” and that purpose hasn’t changed. Content and issues have. In the beginning it mainly comprised oil and gas technology and science. Today the much broader agenda includes managerial, financial, environmental and social issues. Mr Dewhurst and his colleagues would be surprised to see these accomplishments today, but I am sure would also be very happy to observe that what they started is continuing to go from strength to strength.

Energy is the lifeblood of economic and social development. The share of oil and gas is essential and rising. Oil and gas will not last forever, but it will be vital for global development in the many decades to come. Transitions will take place towards other forms of energy production and use but the oil and gas industry will always be an active leader and partner and the people who will shape the future will be at the 20th WPC in Doha.

With the focus on the future and what is required from a technological point of view we often forget that we will need more people on the ground to do the work. This is a real issue and the number of young people joining the industry or even graduating in relevant areas has been steadily decreasing in many countries. This growing skills gap may impede the industry’s very ability to operate, especially in respect to major exploration and production projects. This challenge is particularly significant in the context of the world’s rapidly growing demands for energy and calls for greater adherence to responsible social and environmental practices.

In response to this challenge the World Petroleum Council formed its youth policy. A Youth Committee was created that has grown in size each year since its formation in 2006. It brings a higher profile to the issue and forms an alliance with young people themselves in order to find possible solutions to our challenges. We feel that it is important that young people are at the forefront of resolving the issues, as they are the ones who will inherit this industry and should be involved in crafting its future. The Youth Committee has prepared a unique programme of activities for young people at the Congress including a special round table with industry leaders to discuss the burning questions of today.

The future of the WPC depends on its ability to stay neutral and non-political. It is imperative to be willing to intelligently and comprehensively discuss issues no matter how controversial. The greatest impact will be achieved by working closely with other organisations and professional bodies. Not only those who work in the industry but everyone.

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I have great pleasure in welcoming you to the 20th World Petroleum Congress (WPC) which is being held under the patronage of His Highness Sheikh Hamad bin Khalifa Al Thani, the Emir of the State of Qatar.

We are honoured and delighted that the State of Qatar is hosting the 20th WPC, as this is the first time since its inception in 1933 that this event is being held in the Middle East. This is a great testament to the importance of Qatar as a key member within the GCC region and the global energy industry.

The WPC is undoubtedly the biggest and most prestigious event in the oil and gas industry calendar, and we have ensured that the legacy of the Congress continues far beyond 2011 and this Congress is set to be the biggest yet. We are delighted to welcome an expected 4,000 delegates, 40 Ministers of Energy, 600 press and media, 550 presenters, 500 exhibitors and more than 12,000 exhibition visitors to the Qatar National Convention Centre (QNCC), where iconic design and cutting edge facilities come together in the latest green technology venue in the Middle East.

I am sure the Congress will be a successful and memorable occasion that will not only celebrate the achievements of the petroleum industry, but also make a valuable contribution to the sharing of information and ideas within the energy sector. The theme – “Energy Solutions for All: Promoting Cooperation, Innovation and Investment” – provides an excellent opportunity for delegates to discuss the petroleum industry’s role in delivering reliable, affordable and sustainable energy to the global market.

A broad range of topics will be discussed at the Congress – such as the role of gas in the global energy mix, innovations in the supply chain, complementary energy sources and, importantly, the industry’s commitment to sustainability. Given the high calibre of the speakers that will be present at the Congress, I am sure that even the most experienced industry professional will come away from the Congress having learnt something new.

I would like to thank all sponsors, official partners and participants for their support and commitment to the 20th WPC. I am sure that the Congress will be an historic landmark for all the participants and we can all celebrate the global achievement and impact that the energy sector contributes to our day to day activities.

Finally, I hope you enjoy your stay in Doha, Qatar, and I wish you a very successful event.
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

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oil accumulation ever found in Brazil: the offshore pre-salt layer. To confront this challenge, Petrobras will employ its usual strategy: research, technology, investments and safety. If the future is a challenge, Petrobras is ready for it.
Cooperation is essential in the world petroleum industry, where companies, which compete in downstream retail markets, are equally important to manage energy’s geo-politics and economic impact.

For the producers, Ali Al-Naimi, the oil minister of Saudi Arabia, the world’s ‘swing producer’ of oil, Abdalla el-Badri, the secretary general of OPEC and Leonid Bokhanovsky of the GECF, acknowledge consumers’ desire for security of energy supply but stress producers must also have some security of energy demand if they are to make the necessary investments. The importance of the Middle East in general, and Qatar in particular, is underlined by Abbas Ali Naqi, and Dr Mohammed Bin Saleh Al-Sada. Producers can take reassurance about demand from China, which has become the world’s ‘swing consumer’ of all forms of energy and which, as Professor Wang shows, finds it hard to actually restrain its rate of growth. Another driver of oil demand is India, as articles by the oil minister, R.P.N. Singh, and Dr Parikh show. Producers and consumers differ over causes of oil price volatility, but share an interest in removing it. One way is to make the oil trade more transparent by publishing more information through the JODI oil data initiative, coordinated by the International Energy Forum. Noé van Hulst, IEF secretary general, delivers a gentle rebuke to countries lagging behind in providing better monthly oil data. It’s not surprising there are laggards. Nearly 100 countries participate in the JODI oil initiative, which may be expanded into gas.

Bob Dudley of BP points out that the once clear divide between international (IOCs) and national (NOCs) oil companies is beginning to blur in some cases with the emergence of some INOCs – national oil companies going international. Their ability to do so, and indeed the whole industry’s capacity to explore new frontiers and achieve new efficiencies, is in very large part due to the service companies, whose evolution is charted by Dave Lesar of Halliburton and Andrew Gould of Schlumberger. Nonetheless, as WPC president Randy Gossen says, IOC-NOC cooperation is “not without its challenges.” But it would be inefficient, argues Christophe de Margerie of Total, for NOCs to stick to their own reserves and IOCs to focus only on unconventional oil and gas. Joint ventures are the way to share experience and technology, and the best are those that develop a culture of their own out of a synergy between their parent companies. Nigeria’s oil minister, Diezani Alison-Madueke, stresses partnership with foreign companies.

Cooperation must also extend to stakeholders in the wider community, addressing environmental and climate concerns. Aron Cramer of BSR calls on energy companies to “join efforts to puncture the view that short-term shareholder advantage is the sole way to define fiduciary responsibility”, while Keith Myers suggests that governments in energy-rich countries sharing more information with their own parliaments would make for more settled oil policy regimes.

A cooperative approach can also be essential in the delivery of energy, not in the oil tanker trade whose separate problems are described by Juliet Walsh, but as illustrated in the articles by Reinhard Mitschek, John Roberts and Sheila McNulty on international pipelines. Fixed infrastructure can raise questions of security of supply, and cause friction even between the best of neighbours.
Partnering to meet the challenges of the future

BY BOB DUDLEY
GROUP CHIEF EXECUTIVE, BP

It is fitting that this 20th World Petroleum Congress is being hosted in the Middle East. It recognises the region’s importance for energy in the past and the present, but, more important – it signals just how significant the Middle East will be for the future.

The Middle East has been central to the world’s energy supplies since the time of the first Congress in London in 1933. That was a time when the foundations of the oil and gas industry in this region were being established – with major discoveries in Iraq, Iran, Bahrain, Kuwait and Saudi Arabia.

Indeed, in that same year, the forerunner of BP, the Anglo-Persian Oil Company, formed a joint venture called the Kuwait Oil Company, which a few years later discovered the Burgan anticline structure – one of the largest oil fields in the Middle East.

As we all know, such discoveries continued – and today the Middle East accounts for over half of the world’s oil reserves and almost half its gas.

However, this event is primarily a time to look ahead – and projections show that this region is likely to become even more important for energy supply in the future.

For example, our own analysis in BP suggests the region’s share of oil production will grow from around 30 per cent today to 37 per cent by 2030.

What’s more, the Middle East is becoming very important in terms of consumption as well as production. Energy demand in this region is expected to increase by nearly 80 per cent by 2030, twice the rate projected for the world as a whole.

Meeting the rapidly increasing demand for energy – here and around the world – is a huge challenge that will require all of our capabilities as an industry. It is therefore appropriate that the Congress theme is Energy Solutions for All – Promoting Cooperation, Innovation and Investment.

Global Energy Outlook
In BP’s recent analysis of the future energy landscape – our Energy Outlook 2030 – we painted a picture of great opportunity but unprecedented challenge. The headlines indicate that in the most likely scenario, 40 per cent more energy will be required globally within the next 20 years, with over 90 per cent of this growth expected to come from emerging economies.

In terms of sufficiency, the industry has to go to new frontiers – in deeper water, in unconventional gas, in heavy oil, and in remote areas like the Arctic Circle in order to meet the growing demand. This brings a new scale of risks for our collective industry to manage.

In terms of energy security, we see a growing disparity between producer and consumer countries. History tells us that the pursuit of so-called ‘energy independence’ is often impractical, whereas greater co-operation combined with energy diversity offer the greatest benefit.

In terms of sustainability, whether or not there is a major international agreement on greenhouse gas emissions, we must press on with actions that are good for all seasons – not only to address climate change but also energy security. Among these are energy efficiency, renewable energy sources, technological innovation, open markets and an economy-wide price for carbon.

These three sets of challenges – sufficiency, security and sustainability – are ones that are beyond any one company or government’s capacity to resolve. All three challenges
ask big questions about trust: trust that industry can deliver sufficient supplies; trust that governments will support the market in delivering security; and trust that industry and governments can together find ways to limit greenhouse gas emissions without damaging economies.

Trust and co-operation are two sides of the same coin. And it is by finding new and deeper forms of co-operation built on trust that we will meet these challenges.

Let us look at two areas of co-operation which I think are fundamental to the way we need to operate going forward – first, partnership in managing risk and, second, partnership between International Oil Companies (IOCs), National Oil Companies (NOCs) and governments.

Managing Risk
One of the most fundamental areas for potential co-operation in our industry is safety and risk management. The Gulf of Mexico oil spill in which 11 colleagues lost their lives was a tragic accident. We are grateful for the way in which many industry partners worked with us to solve the unprecedented challenges of sealing a well a mile below sea level, containing oil and responding on the shore.

Over one year later, we are still working hard to meet our commitments. On the ground, our focus has shifted from response to recovery. Across BP, we are resetting the company as we make progress against the three priorities we laid out earlier this year. These are: putting safety and operational risk management at the heart of the company; rebuilding trust with those around us; and taking steps to deliver value for our shareholders.

Starting with safety, we have created a powerful new safety and operational risk organisation (S&OR) which sets requirements and provide deep technical expertise to our operating businesses. This team of professionals, with experience in high-hazard industries, from nuclear power to chemicals as well as energy, has the authority to stop operations and drive corrective actions. We have many examples now where line managers, working with S&OR, have decided to halt activity to ensure safe operations.

We have developed new and more rigorous standards which exceed industry norms. For example, we have decided that a BP-contracted rig will not drill a deep water reservoir from a dynamically positioned drill ship unless it has two sets of blind shear rams. In the Gulf of Mexico, we are implementing a new set of voluntary deepwater oil and gas drilling standards which go beyond existing regulatory obligations and reflect our determination to apply the lessons learned from the incident.

We are conscious that others are interested in what we have experienced and learned and BP is working with others in the industry to help improve safety, better prevent accidents, and enhance the industry’s response capabilities. Without in any way minimising our own responsibilities, we believe it is important to share what we have learned in a spirit of partnership as the industry takes on the challenges of working at new frontiers such as ever deeper water and the Arctic Circle.

We have briefed governments, regulators and partners in 20 countries and held over 50 engagement events. We are continuing to work productively with the US regulator, the Bureau of Ocean Energy Management, Regulation & Enforcement and many other regulatory bodies worldwide. We have shared equipment and technology within the industry, for example with the Gulf of Mexico’s Marine Well Containment Company.

A process safety advisor at the Tangguh plant in Papua, Indonesia, discusses a permit to work with BP contractors.
Our work also includes providing ‘top hat’ containment systems to the UK North Sea, managing the UK Oil Spill Prevention and Response Advisory Group (OSPRAG) project to construct the next-generation capping stack, and building a new BP global capping and containment system that is ready to be transported by air freight anywhere in the world in the event of a crisis.

Earning back trust takes time, but it is encouraging that during 2011 we have seen new acreage awards in Australia, Indonesia, Azerbaijan, the UK, the South China Sea and Trinidad, among others. A high-quality, material position in Brazil has been achieved with the completion of the acquisition of Devon Energy’s Brazilian assets, as well as a groundbreaking deal in India with Reliance Industries. In Brazil, the regulator said BP had shown itself to be one of the most prepared companies in terms of operational security in deep waters. It is now up to us to live up to this through our actions.

BP’s strategic priorities
Continuing to embed safety and restoring trust are the foundations for fulfilling our role of providing the energy that the world demands and rebuilding value for our shareholders.

We plan to grow value in a safe and sustainable way, investing in the factors that drive successful performance over the long term – safety, capability, assets and of course, strong relationships.

We are reshaping our portfolio, divesting non-strategic assets worth more to others, investing in a series of new major projects and focusing on distinctive strengths such as exploration – in which we are on track to double investment.

We expect the momentum of our recovery to build into 2012 and 2013 as new projects come on stream, particularly in higher-margin areas; as we complete current turnaround activity; as uncertainties reduce; and as we resume drilling in the Gulf of Mexico, subject to the regulator’s permission.

We also continue to reposition our downstream segment, investing in businesses which underpin long-term growth and improved returns, and divesting others for value.

A common theme across all this activity is partnership. One of the primary skills of managing energy investment is that of bringing together the right blend of partners for each project – to complement our capabilities and experience and to share the risks as well as the rewards.

This process is now leading BP into some innovative new types of relationships – particularly with National Oil Companies and governments.

The role and relationship of IOCs, NOCs and governments
NOCs originated as state organisations, established to serve national interests; while IOCs have always been private companies, accountable to shareholders in many countries.

In very simple terms, the first chapter of the oil industry story was dominated by IOCs, while the second, starting in the 1970s was dominated by NOCs.

Whereas once IOCs controlled 80 per cent of the world’s oil and gas reserves, the figure is now closer to 8 per cent.

However I believe we are now entering a third chapter that will be characterised much more by partnership than rivalry.

The once clear divide between IOCs and NOCs is starting to blur. NOCs are rapidly expanding beyond their national borders – the ‘INOC’ has emerged – and
some are gaining new shareholders. At the same time, IOCs have recognised the importance of serving national interests where they operate.

Today we are privileged to work with many NOCs and governments worldwide, combining our capabilities to discover and develop resources. Each project has its own demands and therefore these partnerships all take different forms.

We believe it is important to share what we have learned in a spirit of partnership as the industry takes on the challenges of working at new frontiers.

For example, Iraq is a country where investment and capability have been damaged by war. The task there is not only to produce reserves but to foster national recovery. In terms of BP’s work, the commercial challenge is to increase production from the supergiant Rumaila field from one to nearly three million barrels per day. But the wider goal is to create wealth, to provide over 9,000 jobs and to build the capability of the workforce.

To unlock these benefits we have formed a new kind of partnership, not only with an Iraqi NOC, but with a Chinese NOC, PetroChina. We bring our experience in giant fields. PetroChina brings access to drilling, manufacturing and engineering resource. And the Iraqi South Oil Company brings a 5,000 strong workforce, keen to develop its skills. We added over 10 per cent to Rumaila production last year and one analyst called it an example of “seamless IOC/NOC co-operation.”

We are working with governments and NOCs in many different ways in different countries – in Angola where we are building local capability, in Azerbaijan, where we are unlocking the energy resources of the Caspian, in Trinidad where we have helped create a national fabrication sector.

In Indonesia, we are working with the government, BPMIGAS and Pertamina at the Tangguh liquefied natural gas (LNG) plant in Papua which ships 7.6m tonnes of LNG each year to China, Korea, Mexico and Japan – helping to provide energy security and supplying an alternative to coal.

We have set ourselves the challenge of making this operation a real force for sustainable development. We’re employing local villagers. We’re training local businesses. We’re handling security with great care. We’re supporting education and health programmes. And this careful approach has helped us create the foundations to expand our operations, with more LNG production and exploration now being planned.

Conclusion
I strongly believe that the safe and sustainable approach is also the successful approach – and it nearly always involves partnership.

The future of energy will be an exercise in collective problem-solving. The opportunities are of a new order. The challenges are of a new order. And the solutions need to be of a new order. We can find them, but only if we are prepared to work together – not only to discover new resources – but new levels of partnership.

As the 2011 Congress explores ways to provide reliable, affordable and sustainable energy, I hope the issue of co-operation will never be far from the centre of discussion.
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Where **talent** and **knowledge** meet opportunity
Seeking oil market stability

BY HIS EXCELLENCY ALI AL-NAIMI, MINISTER OF PETROLEUM AND MINERAL RESOURCES, KINGDOM OF SAUDI ARABIA

The themes of the 20th World Petroleum Congress in Qatar are cooperation, innovation and investment – three vital components for the energy industry as it looks to the future. The Kingdom of Saudi Arabia has continued to cooperate, innovate and invest in 2011 and will do so in 2012 and beyond. It is in all of our interests, and in the interests of consumers and producers around the world, that we all strive to further strengthen our ties, make additional investments in capacity and infrastructure, and continually innovate in an effort to seek more efficient and cleaner energy consumption.

And let me state for the record at the outset, whatever short-term issues arise, whatever the day’s headlines or expert predictions, one thing is certain: global economic growth will continue to rely on oil – and in that, consumers can rely on Saudi Arabia.

I would like to reflect on the three themes of this conference, particularly regarding the future direction of the global economy and the challenges – as well as the opportunities – which lie ahead for the energy industry.

It is predicted that the global population will increase by another two billion people by 2030, predominantly in developing nations, with global energy demand growing by 40 per cent or more over the next two decades. This is a quite staggering proposition, presenting extraordinary opportunities for the industry.

Estimates indicate that more than 200 million people will join the middle class this year in Asia, the Middle East, Latin America and Africa. Such economic and population growth, and rising living standards, will be accompanied by a considerable expansion of cities. In fact, the number of cities with one million people and above in the emerging economies is currently estimated at about 300 – and this number is continually rising.

This growth means rising demand for oil. It was only 20 years ago that industrialised countries accounted for 70 per cent of global oil demand. It is striking to note that emerging and developing economies are on course to surpass OECD industrialised countries in terms of oil demand – a first in the history of the oil industry.

It is clear that Asia’s continued economic growth is the big driver. Saudi Arabia and other Gulf producers have already helped Asia’s development by supplying much of the energy needed to fuel this prosperity – as Asia’s economies have grown, so have our exports of petroleum to the region. This cooperation and investment is benefiting both sides. Roughly two-thirds of the Kingdom’s crude oil exports now go to Asia, and we are the largest single supplier to major markets like China, Japan, Korea and India. And given the scale of our reserves and production capacity, our continued investment in technology and talent, as well as infrastructure, our clear and consistent energy policies, and our collaborative relationships with producers and consumers, we are determined to be Asia’s petroleum supplier of choice for many decades to come.

Key to satisfying future global demand will be price. However, volatility in commodity markets continues, despite efforts from all parties to reduce fluctuations to a minimum. The economic crisis of 2008 proved we are more interconnected than ever, and sharp commodity price rises and falls in 2011 underline the fact. Yet regardless of attempts to increase cooperation and coordination between producers and consumers, price stability remains elusive.

Over the past decade, we have witnessed dramatic shifts in the global economy, and consequently in commodity markets, including oil. Shifts in commodity markets, in recent memory alone, give us a snapshot of oil price unpredictability, with prices per barrel for WTI crude-oil swinging from the historic low in 1998 of US$11 to an all-time peak of US$147 in 2008.

But oil was not suddenly scarce during that decade, nor during 2011, so what was the problem? Of course there are many factors – both real and imagined – which impact on the price of oil. But I continue to believe that it can be explained, in part, by the fact that in recent years oil has become well established as an attractive asset class for a growing and diverse set of investors.

This trend appears unlikely to abate any time soon. In fact, it will likely contribute to ongoing volatility as investor money moves in and out of oil futures markets based on a variety of factors which may have very little to do with basic oil market supply and demand fundamentals.

This is a serious challenge for the industry – and for governments around the world. Oil producers and consumers share a common interest in promoting stable markets and ensuring affordable and fair prices. Petroleum is a long-term, capital-intensive industry, with exploration, discovery and development taking long lead times of many years to bring new fields and increments to production.

As such, adequate financial returns, stable prices, and transparency and predictability of future demand are required. Wildly fluctuating prices are not conducive to future investments to ensure that crude oil, refined
products and natural gas supplies are delivered when and where they are needed.

Like all businesses, the oil industry needs a reasonable level of certainty to undertake massive investments in new capacity. Efforts by the International Energy Forum, particularly its Joint Oil Data Initiative, certainly help take producer-consumer cooperation to a higher level.

Such dialogue encourages the greater openness and understanding necessary to reduce volatility, because transparency is vital for both producers and consumers, so that they can collect, exchange and consider reliable and timely data.

Ongoing innovations in dialogue and the study of volatility and transparency issues within the G20 framework have also been constructive, allowing the international community to improve its understanding of various factors that contribute to energy market instability.

So as we head into 2012, where is the global economy heading and what role for oil producers? After a period of turmoil and severe economic downturn, recovery may be underway in large parts of the world, although it remains patchy. Many developed countries have unacceptable levels of unemployment and some nations are struggling with outsized national deficits and debts. Against this backdrop concerns remain about global economic growth.

Some have also expressed worries that rises in oil prices in 2011 could signal a return to the conditions of 2008, when prices approached US$150 per barrel, and there are those who are anxious that a significant rise in oil prices could send the global economy back into recession.

While there is reason to be vigilant about price, the current situation is different from 2008. In the short term, I am confident that oil markets are relatively balanced and that recent price rises have less to do with supply-demand fundamentals than with other factors, such as gyrations in the value of the dollar and in traders seeking to test new price levels.

There is definitely adequate spare capacity in the system. Inventories in all key markets are ample, and there is significant spare capacity in Saudi Arabia.

It is clear that markets and higher oil prices are being driven by doubts and uncertainties. These include the future of non-OPEC conventional supplies, whether OPEC will make investments to significantly expand production capacity, and whether non-conventional sources, such as oil sands, can meet growing demand without passing on their higher costs to the consumer.

These questions are not new, and there will always be some who discount the role of technological progress in making vast new reserves economical to produce in the future. We have heard talk about peak oil for decades, but peak demand may well arrive before we ever reach a peak in supplies. After all, the world turned away from whale oil long before the end of whales.

There has always been a level of doubt about the industry’s ability to meet growing global requirements for energy – and there always will be. But time and time again, the petroleum industry has risen to the challenge, and it will continue to do so in the future. Again, dialogue and cooperation between consuming nations and producers will be vital.
Of course, meeting future energy needs will require contributions from across the spectrum of sources – including renewables, nuclear, natural gas, coal, and of course, oil. Such great demand will mean that the more established energy sources will be called to the fore, given their known quantities including supply, infrastructure and end-use technologies.

But the gap between the readiness of fossil fuels and that of renewables, which still must overcome hurdles on the way to making an appreciable contribution, makes a compelling argument for the place of oil in the energy mix. The world does not have the luxury of discarding any particular energy source, marginalising or penalising its competitiveness through policy, public opinion, regulatory measures, or distribution of subsidies and incentives to unfair advantage. The effect of such an approach would be damaging to global economic development and to efforts to raise living standards for the billions of people still living in poverty.

A level playing field that encourages the investment needed for all viable energy sources to fully contribute is vital for a secure energy future. Likewise, that level playing field should seek to minimise government intervention policies as these tend to manipulate demand and create uncertainties through artificial means rather than market signals.

The traditional fossil fuel energy sources, especially oil, will continue to serve as the “base-load” for meeting growing world energy demand for decades to come. Just as energy outlooks concur on a 40 per cent jump in energy demand over the next 20 years, they also indicate that more than 80 per cent of that demand will be met by fossil fuels – of which oil will deliver the lion’s share. This will be true at least through mid-century, and perhaps even longer, thanks to human creativity.

One fact remains clear, and I make no apologies for repeating myself. Saudi petroleum policy, implemented under the directions and direct supervision of the Custodian of the Two Holy Mosques King 'Abd Allah ibn 'Abd al-'Aziz, remains constant. It stresses moderation, cooperation and stability.

Moderation means the Kingdom’s ongoing efforts to promote peace, justice, international cooperation, regional and international stability, and human prosperity, as well as employment of all resources to achieve such objectives. Cooperation means working with companies and countries, both with OPEC and non-OPEC producers, and with consuming countries. This cooperation is crucial to guaranteeing oil’s positive contribution to global economic growth and prosperity. And stability means creating the conditions for additional investments in capacity and infrastructure, which will also lead to further advances and innovations as the world’s demand for energy grows.

Whatever the future holds, it is clear that sustained cooperation, unceasing innovation and continual investment will be essential. If we can seek to dampen price fluctuations – by increased dialogue and transparency – the better for the industry, producers and, ultimately, consumers.

A super tanker berths at the Ras Tanura Sea Island Terminal, the main Saudi loading port
Scientific curiosity and technical innovation have been part of the Schlumberger culture for more than 80 years. Today, these characteristics lie at the foundation of our vision of helping customers improve performance and reduce technical risk in oil and gas exploration and production, water resource development, and carbon dioxide storage.

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The Organisation of Arab Petroleum Exporting Countries (OAPEC) is a regional intergovernmental organisation located in the state of Kuwait, concerned with the development of the petroleum industry through fostering cooperation among its members. It contributes to the effective use of the resources of member countries through sponsoring joint ventures. Among these joint ventures, which were set up in the 1970s, are the Arab Maritime Petroleum Transport Company, the Arab Shipbuilding and Repair Yard Company, the Arab Petroleum Services Company, and the Arab Petroleum Investments Corporation, whose main activity is oil project finance.

Kuwait, Libya and Saudi Arabia undertook the establishment of OAPEC on January 9, 1968. The founding members wanted the organisation to be restricted to Arab countries in which oil revenues constitute a "significant source of its national income". However, it was decided on December 9, 1971, to relax membership conditions to be open to any Arab country for whom petroleum forms an important source of national income, rather than just a main source of national income.

The founding countries (Saudi Arabia, Kuwait, and Libya) were later joined by Algeria (1970), Bahrain (1970), United Arab Emirates (1970), Qatar (1970), Syria (1972), Egypt (1973), Iraq (1973) and Tunisia (1982). Tunisia's membership is in suspension.

Therefore OAPEC has 10 active members spread across two continents, Asia and Africa. As of 2010, OAPEC member countries with a combined population of 218 million people, representing 62 per cent of the Arab population. OAPEC total GDP amounted to US$1,635 billion, accounting for 81 per cent of total Arab Gross Domestic Product measured in current prices.

OAPEC member countries occupy a significant position in the international oil and natural gas markets. They are located in a region where economic, political, and security factors are interlinked in a manner unparalleled in other regions of the world. Their significance – present and future – can be illustrated by the main parameters of their reserves, production, consumption and exports of oil and natural gas.

World total oil proven reserves have undergone a sharp rise in the last decade, increasing from 1,104.9 billion barrels in 2000 to 1,188.7 billion barrels in 2010.

OAPEC member countries account for about 35 per cent of the increase in world proven reserves. OAPEC proved reserves increased from 640.2 billion barrels (57.9 per cent of world total) in 2000 to 670.1 billion barrels (56.4 per cent of world total) in 2010. Five OAPEC members (Saudi Arabia, Iraq, Kuwait, United Arab Emirates, and Libya) hold about 53 per cent of world proven reserves. This puts OAPEC at the top versus other international groupings or regions, as shown left.

As for natural gas, world proven reserves increased from 154.3 trillion cubic metres (tcm) in 2000 to
188.3 tcm in 2010. Natural gas reserves are more dispersed than those of oil, with the Commonwealth of Independent States (CIS) accounting for 32.6 per cent of world total, and OAPEC coming next with a share of 28.3 per cent rising from 25.2 per cent of world total in 2000, as shown right.

At the end of 2010, OAPEC natural gas reserves reached 53.3 tcm, and they are concentrated in Qatar which holds 47.6 per cent of the OAPEC total and 13.5 per cent of the world total.

In terms of crude oil (excluding condensates and NGLs), world production also witnessed a sharp rise between 2000 and 2010. World production increased from 67.1 million b/d in 2000 to 72.1 million b/d in 2010. By the end of 2010, OAPEC crude oil production reached 19.7 million b/d, even though its share receded to 27.3 per cent of world total compared to 28.9 per cent in 2000, as shown below.

The bulk of OAPEC crude oil production is concentrated in Saudi Arabia which holds 22.3 per cent of world proven reserves. Saudi Arabia produced 8.1 million b/d or 11.3 per cent of global output in 2010, followed by the United Arab Emirates and Kuwait with 2.3 million b/d or 3.6 per cent each of world total.

**Key spare capacity holder**

OAPEC members play a central role in balancing the world market, not only because of the size of their production, but also because of their spare production capacity. Saudi Arabia, the leading world exporter, with total capacity of around 12.5 million b/d, holds the bulk of the world spare capacity – defined as oil that can be brought onstream within 30 days and sustained for 90 days.

It is worth noting that OAPEC oil production share of the world total (27.3 per cent) is much less than its share from world proven reserves (56.4 per cent). The opposite is true for other regions such as the North Sea, North America, and CIS where their share in total production is higher than their share in world total reserves. This fact strengthens OAPEC capacity to meet the expected increase in world oil demand, and indicates the organisation’s member countries will play a more dominant role in the world oil market.

Among the world top 18 producing countries, each of whose output exceeded 1.5 million b/d in 2010, there were seven OAPEC countries, headed by Saudi Arabia followed by the UAE, Kuwait, Iraq, Algeria, Libya and Qatar.

Turning to marketed natural gas, world total production in 2010 was estimated at 3,193.3 billion cubic meters (bcm).
compared to 2,504.6 bcm in 2000. OAPEC production of natural gas witnessed a similar increase from 255.4 bcm or 10.2 per cent of world total in 2000 to around 443 bcm or 13.9 per cent of world total in 2010. The bulk of OAPEC gas production in 2010 was concentrated in Qatar, which produced 26.3 per cent of OAPEC total (3.6 per cent of world total), followed by Saudi Arabia (18.9 per cent), Algeria (18.2 per cent), Egypt (13.8 per cent), and UAE (11.5 per cent).

Growing Consumption
Generally, OAPEC countries witnessed a steady increase in consumption of both oil and natural gas. Oil consumption increased from 3.2 million barrels of oil equivalent per day (4.2 per cent of world total) in 2000 to 4.9 mboe/d (5.6 per cent of world total) in 2010, representing an annual growth rate of 4.3 per cent, while production was close to 20 million b/d. The difference between OAPEC member countries production and consumption of oil illustrates their significance to supplying energy-deficit countries.

Domestic consumption of natural gas increased from 2.7 million boe/d (6.3 per cent of world total) in 2000 to 4.7 million boe/d (8.6 per cent of world total) in 2010, with an average annual growth rate of 5.5 per cent. Consumption varied from one country to another due to the differences in availability of oil and gas resources, energy-intensive local industries and standard of living in each country. Saudi Arabia consumed 25 per cent of OAPEC total, followed by the UAE (23.7 per cent) and Egypt (12.7 per cent). OAPEC countries’ relatively greater surplus of production over local consumption – compared to other regions in the world – magnifies the importance of their role in the international gas market.

The net trade balance between regions is a good indicator of the importance of countries in the oil market. The Middle East is the largest exporting region in the world with net oil exports of 16.9 million b/d in 2009. Exports of oil and oil products from OAPEC countries played vital role in the last decade, irrespective of the fact that their 2009 level was the same as that for the year 2000, as shown in the graph on the next page.

During 2009, OAPEC crude oil exports were estimated at 14.2 million b/d, and oil products exports estimated at 2.6 million b/d. Total OAPEC oil exports represented 29.1 per cent of the world total, followed by exports from Western Europe (14 per cent), Eastern Europe and FSU (13.2 per cent) and Asia-Pacific (11.7 per cent).

The net position of OAPEC members in 2009, shows that OAPEC hold the largest surplus of oil and oil products in the world reaching 16.8 million b/d compared to deficits of 16.3 million b/d in Asia-Pacific, 9.7 million b/d in Western Europe and 8.2 million b/d in North America.

Of the world’s 15 largest oil exporters – each exporting more than 1.0 million b/d – there were seven OAPEC countries in 2009, headed by Saudi Arabia with an export level of more than 7 million b/d.

OAPEC members played and continue to play a vital role in the world oil trade. Their share in total imports of crude oil and oil products exceeded 27 per cent in 2009. In fact OAPEC countries supplied 18.8 per cent of North America total oil imports, 14.6 per cent of Western Europe and 44.2 per cent of Asia-Pacific during that year.

As regards gas, OAPEC exports more than doubled in the last decade, rising from 83.5 bcm in 2000 to 164.3 bcm in 2009, and accounting for 18.1 per cent of world total in 2009.

Approximately 60.3 per cent of OAPEC natural gas exports were in
the form of Liquefied Natural Gas (LNG), while the rest were pipeline gas from Algeria, Egypt, Libya. Qatar is OAPEC’s largest exporter of gas (41.5 per cent of OAPEC), followed by Algeria (32.1 per cent) and Egypt (11.2 per cent).

The net trading position of natural gas during 2000 – 2009, indicates the significance of OAPEC surplus, at a time when western Europe, Asia-Pacific, and North America were incurring increasing deficits as shown in the graph below.

In 2009, OAPEC surplus exceeded 135 bcm, versus deficits of 209 bcm in Western Europe, 87.9 bcm in Asia-Pacific and 4.1 bcm in North America.

**Conclusion**

OAPEC member countries occupy a significant position in the international oil and natural gas markets, as they held more than 56 per cent of world oil reserves, and more than 28 per cent of natural gas reserves. On the other hand, OAPEC accounted for approximately 27.3 per cent of world oil production and 13.9 per cent of world natural gas production highlighting the significance of OAPEC members in meeting rising world demand.

The net position (oil balance) in 2009 shows that OAPEC contributed around 17 million b/d toward covering the increasing oil deficits in other regions such as North America, Western Europe, and Asia-Pacific. In fact, one third of world total oil imports in 2009 came from OAPEC member countries, supplying one fifth of North American imports, 14.6 per cent of Western Europe, and 44.2 per cent of Asia-Pacific during that year.

OAPEC member countries are likely to continue to play a major role in meeting future world demand for oil and natural gas, contributing effectively towards market stability. OAPEC major producing member countries (Saudi Arabia, Iraq, Kuwait, and the United Arab Emirates), accounting for around 53 per cent of the world proven reserves, will be the world’s main oil suppliers in the medium to long term. But for this to be realised, the producers will need to add production capacity requiring large investment outlays. This will take place only if they are confident that anticipated demand for their oil will materialise and they have access to sufficient funds.
Despite the crises of the last decade, the world consumed energy in 2010 at a level that was not expected to be reached before 2015. This did not come from demand in the OECD countries, but from that of the developing countries. In spite of this, energy poverty remains a major issue with nearly 1.6 billion people around the world without access to electricity.

I would like to examine the subject in terms of the major events and trends of the 2000s that have had, or will have, a lasting effect on the exploration and production industry. I will try to relate these to the strategies that I think will be necessary for the next two decades. These choices will naturally be personal, and not necessarily those of Schlumberger where I have spent the last 35 years.

Oil and gas supplies have always been subject to political and geopolitical interference. Fear of disruption has governed political action almost since the birth of the industry and the quest for energy security has motivated every form of such action.

The last decade was marked by a fundamental shift in the security of supply which had been the preserve of the OECD nations for the last hundred years. We discovered that China, and to a lesser extent India, had assumed the mantle of demand driver with the world waking up to China’s energy needs through the spectacular increase in demand of 2004. In terms of oil alone, China’s apparent consumption more than doubled in ten years. This was the first, and undoubtedly the most important, shift of the past decade.

The second shift was undoubtedly the emergence of Russia as the single largest producer of oil and gas. Following the collapse of the Soviet Union, Russian production collapsed to as low as 6.1 million barrels a day (mb/d). In the six years following 1999, it rose by more than 50 per cent and became the major reason why oil prices did not rise much faster, much earlier.

When supply and demand balances started to tighten in the early 2000s, the industry faced its first supply challenge in 25 years. The cushion of excess supply created following the oil shocks of the 1970s began to shrink. The decline of the three key pillars of the 1970s, Alaska, Mexico and the North Sea, was evident. The age of the production base was becoming obvious and exploration and production capital expenditure duly exploded leading to a period of frantic growth in activity that in turn had major effects on the exploration and production industry’s structure.

The first of these was the re-emergence of resource nationalism. This was not new – countries have expelled foreign interests in the past after all. Nor was resource nationalism limited to foreign interests, as the capture of greater shares of petroleum rent takes many forms; very often in the form of taxation. However, whatever the form the consequences are the same – creating uncertainties about the stability of the investment climate and restricting capital flow, both of which slow the supply response.

In the 2000s, resource nationalism was rife. Russia changed investment rules to capture a greater share of the rent. Venezuela closed again, and the Middle East did not open significantly. Mexico did not open at all. Iran and Sudan remained largely off limits through sanctions. And after a spate of extraordinary discoveries Brazil started to close again – not to investment but to the notion of foreign operators in the pre salt domain. Consequently, perhaps 75 per cent of the world’s known conventional oil reserves are today closed to international private capital while 60 per cent of production originates from international and independent oil companies.

Wide range of national companies
Largely as a result, national companies form a vast range – both in structure and ability. Some are major offshore operators; others have mastered complex project management. Several are sophisticated technology users, and are often more ambitious than their international colleagues. They are determined to learn, and can compete with the best. They manage their resource as part of the national wealth. Others are emerging with increasingly large international portfolios as they respond to their countries’ energy demands.

The role of the service industry in providing technology and process to the national oil companies has been much debated. From time to time it has been believed that by providing these services to the national oil companies the service industry has slowed international capital access to closed domains. In fact, the role of the service industry has not changed; their big opportunity came after the nationalizations of the 1970s and their role has gradually expanded through more sophisticated offerings during a period when international oil companies reduced research and development expenditure while encouraging service industry competition.

Another aspect of access that should not be ignored is the ability of pressure groups to restrict access to some of the most promising remaining reserves. The example of the United States is obvious where even prior to the
Deepwater Horizon accident the ability of various lobbies to convince politicians to restrict access was legendary. These restrictions have led international operators and independents to opportunities offshore and in harsher and more remote environments. Furthermore, newly discovered conventional oil accumulations have become smaller while sources of conventional production are increasingly complemented by unconventional oils. In addition, heavy or unconventional oil projects including shale oil and various conversions from coal or gas are massive undertakings of long duration that require huge amounts of capital.

As a result, if there is one common characteristic in the oil exploration and development projects to be executed in the next 20 years, it is that they will become more complex, more difficult to execute, and more expensive.

If the 2000s were a decade of tremendous change for oil it was equally true, if not more so, for gas. Conventional oil is completely fungible, where constraints in the distribution of either crude or products have become minor. From well head to consumer a full competitive chain with many alternatives exists. The same is not true of gas where movement to market by pipe or LNG is still an incomplete chain.

During the last decade, the entire gas infrastructure and its sources of supply came into focus. Consumption increased rapidly, as did supply. The huge LNG and pipeline infrastructure projects begun in the 2000s have the potential to fundamentally change traditional wisdom and completely allay fears of rupture in gas supply in Western Europe. The rapid development of gas resources in Australasia considered stranded only ten years ago has changed the availability of long-term supply for China, Korea and Japan. And in the US, the development of shale gas has changed the dynamics of domestic supply. Of these factors, the huge expansion in LNG and the development of shale gas in the US truly marked the decade and although markets are currently oversupplied following the dramatic drop in demand in 2009, this effect will be eliminated in a few years time.

The US shale revolution required technology, market forces and entrepreneurship. Today’s combination of horizontal wells and hydraulic fracturing has made certain shales economic, but technology will have to move much further to systematically extract full value from every shale as current extraction methods are both wasteful and expensive.

Shale gas enthusiasm has been sufficient to lead to major revisions in US reserves. In the rest of the world, where knowledge of shales is vastly inferior to that of the US, countries and companies are actively searching...
to understand the potential of their own shale gas resources. But much remains to be done before we can be assured that the world’s shales are as prospective as those of the United States. Environmental, water and land considerations, among others, must be resolved.

No review of the last decade would be complete without mention of the tragedy that occurred in April 2010 in the US Gulf of Mexico. Eleven men lost their lives on the Deepwater Horizon, the accident led to the largest oil spill in US history, and the incident received one of the largest media exposures ever seen. This one event will have major effects on the way the industry operates in the foreseeable future.

Having now outlined the major changes of the past decade, I would like to turn to some of the objectives I believe the industry will need to examine.

The first and most important will be to re-establish the confidence of the regulator and the public in the industry’s capacity to find and produce deepwater oil and gas resources safely. In the last ten years, more than half of all new resources discovered worldwide have lain offshore. Partly as a result, offshore production is expected to supply approximately one third of the world’s needs late in the next decade. And with deepwater production increasing steadily, its contribution will correspond to approximately 10 per cent of global supply by then.

Regulation will therefore become stricter, standards upgraded and oversight increased. Safety and management systems will be constantly tested and improved. Comprehensive spill response plans will be required. Technology will become increasingly critical for deepwater success and those who possess it will derive competitive advantage. Automation and instrumentation will have to be adapted to create a control environment similar to the aerospace or nuclear industries. Above all, the industry will require increasing numbers of competent and well-trained people to execute improved processes. As a result, the overall time to new deepwater production will increase, costs will escalate and those who do not adapt will lose.

The second objective for the industry will be the need to dramatically improve its project management skills. Projects have become larger and more costly as complexity has grown. There are now over 200 projects worldwide that have budgets in excess of US$1 billion. It is extraordinary that national and independent oil companies now represent over 80 per cent of total industry capital expenditure. It is also extraordinary that 40 oil and gas companies have annual capex budgets in excess of US$4 billion – up from only 10 in 2001.

Size and complexity are consequently enhancing the role of project management as a core industry skill. In the past, this has been found in just a few companies – the super-majors in particular. But with more companies executing larger projects, often in remote or complex environments, the need to train seasoned project managers is becoming acute. Such a skill is not rapidly acquired as it mixes technical and organisational capability with strong leadership ability. It involves constant evaluation of options and their potential implications and is, to a large extent, a transferable skill with many other industries.

The third objective that will be important in the next two decades concerns the true viability of shale gas. There is no doubt that the resource is large. However, so many unknowns remain that it is extremely difficult today to estimate its ultimate potential. We have insufficient data, and we do not have the reservoir modelling capability to lend credibility
to reserve or recovery numbers. Our traditional geological and petrophysical models do not apply. We cannot use the usual evaluation methods to identify productive zones. The production mechanism itself is not understood and the decline patterns even less.

Today’s method of extraction puts the wellbore in communication with as much of the rock as possible to get gas to flow through created fracture networks. To do this, long horizontal sections are completed with staged sets of perforations that are then massively hydraulically fractured. The process uses huge amounts of horsepower, sand, proppant and above all, fresh water. Such a brute force approach has resulted in huge variability in individual well production.

If we are going to exploit the full potential of shale gas, we need a technology package that allows optimisation of completion design as a function of reservoir quality. In time, the industry will find ways to map reservoir quality, tying shale responses directly to wireline or logging-while-drilling measurements. This will help optimise well design, completion design and fracturing treatment. Only then will we then drill the best wells, and fracture the best intervals. Shale gas undoubtedly has a major contribution to make to future energy supply, but technology will have to evolve considerably for it to realize its full potential.

As a fourth objective, the industry must face the fact that it will be desperately short of experienced human resources if it is to maintain the rhythm of exploration and production necessary to sustain oil and gas supplies. The 16 years of low oil prices after 1986 meant that little recruiting was done, and many earth science and petroleum engineering faculties were closed. In the 2000s, the industry recognized the problem and recruiting and training began to pick up.

All operators alike – international, national and independent – are relying on technology to a large extent to increase the productivity of their petrotechnical professionals. Only the majors are counting on processes of standardisation and codification to a large extent to be able to staff projects with more junior people. The independent and national operators appear to be relying on outsourcing to better utilise their staff. It would seem to me that increased project size and complexity require that better process be essential to proper manpower utilisation with outsourcing not being an adequate solution on its own. A failure to implement process will also make it more difficult to comply with the regulator as competency assurance will become an essential tool for certain key positions.

If the industry is to meet the challenges it faces, it will need much greater training to create the technical population it will require. Technology and process will help, but they cannot remove the need for a highly technical and competent workforce.

Finally, no discussion of oil and gas for the next two decades would be complete without mention of greenhouse gas emissions. Energy-related carbon dioxide (CO2) emissions have increased by over 40 per cent over the past two decades with forecasting agencies projecting similar relative increases over the next 20 years. The sustainability of such a rise has been questioned by many leading climate experts. A reduction to the levels recommended at recent G20 summits would require a portfolio of carbon abatement options, among which energy efficiency would clearly have the largest impact and lowest abatement cost.

Analyses by the International Energy Agency and other organisations have, however, shown that carbon capture and storage (CCS) has the potential of providing nearly 20 per cent of the reductions required by 2050. But in order to achieve this ambitious target, CCS needs five main ingredients – financial mechanisms, legal and regulatory frameworks, technological innovation and cost reduction, international collaboration, and public acceptance.

The Cancun climate change conference made some progress on financial mechanisms through the adoption of CCS as a clean development mechanism but there is still a long road ahead for carbon abatement prices to reach levels that would make CCS fully commercial. Enhanced oil recovery using CO2 could help speed-up the learning curve to some extent, as well as providing an economic incentive and developing part of the surface infrastructure. Storage applications from the main emitters such as power plants would need CO2 prices far above the level currently foreseen in emission trading markets. The focus over the next few years should probably therefore be on building experience through pilot projects to serve as public confidence builders as well as technological test beds.

I believe that the issues I have raised, post-Macondo operations, project management, shale gas technology, human resources and energy emissions will all be important issues for the two decades to come. I also believe after three and a half decades in this business that the resourcefulness and enthusiasm of the people who work in the oil and gas industry will be equal to overcoming the challenges. This is a very different industry from the one I joined in 1975.
Over the years, the World Petroleum Congress has built a reputation as one of the most authoritative international energy forums. We recognize that the Congress represents an enormous opportunity not only for Rosneft to network with our international partners but also for the company to take an active role in shaping the global energy agenda while discussing the main trends and challenges that key global energy players face today.

One of the main challenges facing the energy industry is increased demand for energy resources and the gradual depletion of traditional deposits with easy-to-recover reserves. With renewables not yet integrated fully into the energy mix, we need to develop new oil and gas provinces to avoid facing global energy shortages in the near future. It is our firm conviction that, shelf deposits, including the Arctic, will offer the greatest opportunities.

In terms of hydrocarbon reserves, Russia’s shelf fields are amongst the most promising areas in the world. Total recoverable resources on the Arctic shelf are estimated to reach nearly 700 billion barrels of oil equivalent – over 20 percent of the global total. Rosneft owns 17 licenses for different blocks on Russia’s shelf fields. They are grouped into three key zones: Western Arctic (the Barents and Kara Seas), the Sea of Okhotsk and the Sakhalin shelf as well as the Southern seas (Black, Azov and Caspian Seas).

Significantly, Rosneft is taking firm steps to develop its shelf fields. In August 2011 Rosneft signed a Strategic Cooperation Agreement with ExxonMobil focusing on joint exploration and the development of three shelf blocks in the Kara Sea and one in the Black Sea. With a combined estimated resource potential totaling 110 billion barrels of oil equivalent, the Kara and Black Sea blocks are among the most promising on the Russian shelf. The development of shelf deposits therefore aims to balance supply and demand on the world energy market, avoid energy shortages and ensure global energy security in the near future.
The scale of projects in the Arctic is unprecedented and both Rosneft and ExxonMobil are fully aware of the technical and environmental challenges they will face in the course of implementing these complex projects. The Arctic presents Rosneft and ExxonMobil with a number of challenging technical tasks dictated by the difficult ice situation. Indeed, the sea is ice-bound for 300 days of the year and extremely low winter temperatures plunge to −46°C and beyond in the Arctic. Whilst the challenges are well-documented, we believe that ExxonMobil and Rosneft have the relevant expertise to overcome these challenges. This expertise comes from the Hibernia project, in which ExxonMobil is a partner, and which shares key similarities with the Kara Sea shelf and Sakhalin 1 projects. In addition, as part of the strategic partnership, Rosneft and ExxonMobil will create an Arctic Research and Design Center for Offshore Developments (ARC), which will focus on creating, consolidating and adapting technologies to support joint projects in the Arctic. We anticipate that Arctic cooperation will stimulate the development of new technologies across the industry. The center will strongly focus on environmental monitoring and the development of environmentally-friendly technologies. Environmental monitoring will benefit from the two companies’ environmental protection experience, including environmental and geo-environmental monitoring and obtaining licenses to carry out environmental protection activities.

Importantly, we believe that the Arctic projects will be a stimulus to economic growth for the energy sector, spurring development of all related industries. We anticipate that the development of the energy sector in the Arctic will have a major effect as projects to develop deposits will set challenging and far-reaching tasks for other industries. Oil production in the Kara Sea will spur demand for oilrigs and there will be increased demand for tankers to ship both oil and LNG. On top of that, there will be a need for new infrastructure creating new jobs and opportunities.

The development of projects in the Arctic and elsewhere in Russia will therefore not only ensure the balance of supply and demand is maintained in the global energy market but will also stimulate economic growth for the whole industry. Arctic resources will be of benefit to future generations, but we strongly believe that only companies with relevant technologies, expertise and environmental protection experience should have access to developing projects in the region.

About Rosneft

Rosneft is a Russian oil industry leader and one of the largest public oil and gas companies in the world. Rosneft’s main operations are exploring for and extracting oil and gas and manufacturing and selling oil products and petrochemicals. The company is a strategic Russian enterprise. OJSC Rosneftegaz is the main shareholder in the company (holding 75.16% of shares) and is 100% owned by the Russian state. Approximately 15% of the company’s shares are in free float.

Rosneft’s exploration and production activities spread across all of Russia’s main oil and gas provinces: Western Siberia, Southern and Central Russia, Timan-Pechora, Eastern Siberia, the Far East and the Arctic Sea shelf. The company also has projects in Kazakhstan, Algeria, Venezuela, Abkhazia and the UAE. Rosneft has seven large refineries spread across Russia from the Black Sea coast to the Far East, while the company’s sales network covers 41 Russian regions. Rosneft has a 50% interest in Ruhr Oel GmbH, which owns stakes in 4 refineries in Germany.

According to an independent DeGolyer & MacNaughton audit, Rosneft’s proven PRMS reserves were 2.5 billion tons of oil and almost 800 billion cubic meters of gas at the end of 2010. As such, Rosneft’s international standard proven reserve replacement ratio in 2010 was 106%. Total proven hydrocarbon reserves amount to 22.8bn barrels and proven liquid hydrocarbon reserves have placed Rosneft at the top of global ranking tables among publicly traded companies. As at the end of 2010, Rosneft’s hydrocarbon reserves will last for 25 years, with oil reserves lasting for 21 years and gas reserves enough for 67 years.
In a globalised and inter-connected world, where knowledge, competence and technological innovation are continuously shared, international oil companies must ask themselves what their future role will be and how they can best cooperate with their national counterparts.

Although often turbulent and sometimes tense, it is a cooperation that has ultimately proven to be long lasting and mutually beneficial. It has made it possible to forge partnerships, ensure a transfer of knowhow and highlight the benefits of aligned interests.

As we steer in uncertain waters, marked by structural changes and challenges, it has become difficult to make a clear-cut distinction between IOCs and NOCs. Our common external conditions range from an unstable economic environment, fluctuating and geographically uneven demand patterns, tightening climate change parameters, geopolitical turbulence and an overhaul of a long established financial system.

Against this backdrop of uncertainty, consumption levels continue to rise and our common task is to ensure that demand is being met. The reliable supply of energy sources to consuming markets thus increasingly supersedes the distinction of whether the producing company is private or national.

Furthermore, as the energy mix continues to evolve and host countries pave the way for the future by increasingly taking into account issues such as climate change-related concerns or the final use of their resources, IOCs and NOCs must seize the opportunity to take their cooperation to the next level. Their ability to adapt to the new environment, produce new forms of energies and view each other as equal partners will shape the oil industry for some time to come.

A common goal
As uneven demand patterns, exposure to volatile oil markets and tightening environmental regulations increasingly affect the oil sector, NOCs and IOCs are gradually shedding their distinction and must be seen as producers. Security of demand and security of supply are concerns that affect them both.

Our industry cannot live in isolation and the environment in which it operates is undergoing fundamental adjustments. Over the past 18 months, structural changes have marked our times: they included, only to name a few, the growing role of the state in key market-based economies, where the debt crisis had devastating effects on the eurozone, the worst oil spill in US history which led to a fundamental rethink, strict adoption and sometimes readjustment of Health Safety Environment protocols across the oil industry and the catastrophic consequences of a natural disaster which badly hit Japan and highlighted amongst other things the inherent contradiction of clean and risk-free energy sources.

The necessity of industries like ours to restore trust and confidence with the public has emerged even further as a key issue while consumers continue to centre their objective around secure, accessible and reliable energy sources.

On the political level, new and unprecedented forms of governance are gradually emerging in the Middle East and North Africa – the outcome of which is still unknown.

External risks expose NOCs and IOCs alike as they weather common challenges while they strive to achieve common objectives, that is to say provide oil and gas supplies in a reliable and secure manner.

What is certain, is that today’s conditions in which both have to navigate are more unpredictable and rapidly evolving, than they were 20 years ago.

Bridging the gap
As NOCs continue to differ in their competence, size, market share and know how, they face similar constraints but in different ways: while some NOCs produce less than they need for their domestic market, such as the Chinese NOCs, others produce more (i.e. Saudi Aramco). A number of distinctive differences between NOCs and IOCs spring to mind:

• Host countries remain the largest reserve holders controlling about 75 per cent of the world proved reserves and more than 55 per cent of the world production. Oil production policy determines the production of these reserves, the timing of production, as well as the legal and tax regime applicable to oil and gas developments. Their national companies remain inevitably defined by policy orientations as set by the energy ministries; they build and implement a long-term national reservoir management and development strategy; they contribute to the turning of the country’s natural wealth into long-term socio-economic development.

• IOCs are tied to their international markets, consuming states and demand centres. As demand continues to climb, it has to be met in a timely manner. Indeed, one of the main and most stimulating tasks of IOCs is to sustainably align the respective requirements of both host countries and their customers abroad, or, in other words, to act as...
facilitators between producing countries and consumers.
• IOCs have a diversified and worldwide experience, which creates excellent conditions to innovate. As a result, IOCs can offer wide-spread technological expertise as well as an integrated approach for the most challenging resources (very deep offshore, extra-heavy oils, tight and sour gas etc). In the Pazflor project, offshore Angola, for instance, Total implements in partnership with Sonangol a new subsea gas/liquid separation concept, a world technology first, which is the result of our extensive R&D efforts.

Converging interests
As owners of the largest part of world reserves, NOCs often call upon their international partners to jointly develop technically most complex areas where the deployment of innovative technology is paramount. The production and development of oil and gas resources remain evidently a key objective of any oil company; a world where IOCs and NOCs would grow separately, one where NOCs would manage their own resources and where IOCs would be focused on the development of non conventional hydrocarbons in other areas, is not a vision one should wish for. Such a split would not be efficient as it implies no cooperation, no cross-fertilisation of their experiences and no risk mitigation.

Alignment of interests for parties remains, however, an unconditional element of a successful partnership. When IOCs are being offered suitable contractual terms paying for the risk taken and giving sufficient incentives to bring the best of their expertise, the joint venture acquires a life of its own, with its own culture, a product of the host country, the NOC and the IOC. One of the best examples of this being the giant Jubail Refinery being built by Satorp, a company where Aramco and Total employees have a unique goal: joint success.

But producing states might ask themselves ‘what is it in for me?’ Indeed, what can an IOC effectively bring?

Research and Development: R&D and the consequent technological innovation continue to be shared between IOC, the host country’s NOC and the contractor. But it is up to the oil companies, both IOCs and NOCs, through their extensive knowledge of the resources’ challenges, to define the required technology and R&D programmes that are needed. In this spirit, Total spends US$1bn annually on R&D. Technological breakthrough, resulting from well focused R&D, can bring beneficial responses in our constant struggle to control cost, such as for instance the modularisation of LNG plants, or the concept of ice resistant floating processing platforms designed for the extreme sea and weather environment of Arctic regions.

As partners in increasingly complex projects, NOCs and IOCs have a common interest in delivering successful production units.

Exposure and knowledge: expertise brought in from other projects can add substantial value. The capacity to reach markets can add further commercial value. The example of QatarGas springs to mind: Total’s capacity to access markets through its regasification terminals and customer portfolio allowed Qatar to sell LNG to previously inaccessible markets. In another vein, IOCs have accumulated experience in managing large and complex developments and are used to handling huge, multi-billion dollar projects. This is clearly demonstrated when looking at the growing share of deep-offshore, heavy oil, ultra-deep gas reservoirs, and LNG projects in their portfolio, such as the Yemen LNG project and the Akpo development, offshore Nigeria, both operated by Total. IOCs are also managing large, integrated projects, beyond just exploration and production: such projects involve the midstream section (power plants and desalination) and the downstream section (refining and petrochemicals) of their corporate activities. In some cases, they also implement, as operators or key partners, trans-national projects, such as the Qatar-UAE Dolphin project.

Risk mitigation: As NOCs are increasingly internationalising their activities, IOCs, whose core business is located by definition in international markets, can help mitigate risks. But successful joint investments inevitably require joint objectives. They need to be aligned, technology needs to be shared, training needs to be provided and access to new countries can be offered. Working in association with NOCs outside their country of origin, especially so as NOCs expand worldwide, has taken the oil sector into a new phase. We often forget that most IOCs were once state-held. Examples range from the partnership between Total and Qatar Petroleum International in the Taoudeni exploration permits in Mauritania to our JV with CNPC and Petronas in Iraq; from our partnership with Kufpec in Yemen and Sudan to our affiliation with Sinopec in Canada and Yemen or even the very ambitious LNG project we have in Australia with Petronas.

Preparing the future: IOCs are committed to preparing the energy future as new, increasingly complex and more diversified energy sources are necessary to meet
growing energy demand, and to limit CO₂ emissions associated with energy consumption. Considerable R&D and technology related work are needed before these new energies become competitive. It makes sense for an oil and gas company to get more involved in alternative energies as we have to stay in step with the long-term energy transition that our industry, and the world, are facing. It is in NOCs’ best interest to cooperate with IOCs in the challenging domain of new energies, and many producing countries, concerned by the diversification of their energy mix, are presently developing projects in the field of renewable energies. In the UAE for instance, Total is building a 100 MW solar power plant in association with Masdar and the Spanish company Abengoa. Innovative investment, if performed today, will pave the way for securing energy needs in the next decade, including in oil-exporting countries.

Building sustainable relationships

Upstream projects are long in duration and wide in scope: IOCs and their host country learn in time to understand their respective cultures and exchange know-how in a sustainable manner. Total has been working with many countries for 50 to 75 years, thus giving us an intimate understanding of a country’s culture and expectations; they are ingredients for building mutually beneficial relations based upon common trust and respect.

Two essential and organic trends result from a successful joint venture between an NOC and its international partner: one, which starts with a human experience whereby the project staff create their own culture, one of the project. Their drive to make their mission a successful one supersedes quickly their affiliation to the NOC or the IOC. They become affiliated to the JV, the project. This meeting of the cultures, perceptions and know-how inevitably gives the project a successful dynamic.

The second element refers to the benefits of a JV in a given host country: job creation, training, transfer of technology, business opportunities for local suppliers, social and environmental impact. In many countries our presence is not limited to the upstream but it extends to other domains: refining, petrochemicals, research centres, renewables. And for us, there is no better example of a wide-ranging and successful partnership than Qatar where this World Petroleum Conference is being held.

In short, IOCs must build the host country’s development expectations into their wider thinking and contribute to local socio-economic development: where it operates, it should behave as a local player and be entirely recognised as such.
Where do the children get their energy from?
It’s sure to be from OMV as well, because right now they’re meeting tomorrow’s energy needs.

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We have cause for great optimism and enthusiasm about the future of our industry. Innovation and experience are making complex reservoirs – such as shale deep water – economically viable and boosting reserve estimates to levels that would have seemed fantastic a few years ago, while also helping increase production from mature reservoirs. In the next decade we will see enormous opportunities in exploration and production – if we evolve to meet the challenge.

Service companies in particular are changing. I want to sketch the changes and investments we are making that will enable us to provide a higher level of service and realise the opportunities that are coming into view. I also want to discuss the key themes that will persist in all phases of our business cycle; these are the areas where we will be making investments year in and year out.

Two themes are likely to intensify and dominate the next decade because they are the foundation of the higher level of service and value creation that complex reservoirs demand. These themes are the holistic approach to reservoir development, and the acceleration of innovation and organisational learning.

Holistic solutions for complex reservoirs
Whether it’s tight gas in the Middle East, pre-salt plays offshore Brazil, or shale oil in the Bakken, the geological and technical complexity of these enormous new basins – combined with their capital intensity and long development times – make a holistic approach the only economically viable option.

Deliverability throughout the life cycle of the reservoir requires operators and service companies working together to take time and cost out of each step – from prospect generation to production. And each step needs to be integrated with the others to become a holistic solution that includes all the elements – from reservoir description to drilling, well completion and production management. Helping operators achieve that holistic solution is the way service companies are adding the most value.

This is demanding changes in the way service companies operate. In technology, we create the cross-functional workflows needed for holistic development. And we are changing organisational structures, training, and work processes to help us speed up our learning and help us mobilise the right expertise at the right moment for the particular reservoir development need. We take a holistic approach to creating holistic reservoir solutions.

Integrated workflows create efficiency at the wellsite
The definition of cost-effective service delivery is evolving. In complex reservoirs, it is not enough to deliver a discrete service at the lowest cost. The service must be optimised for the well, and it must also contribute to optimizing the whole. At the wellsite, this means using services that incorporate real-time data capture and respond to real-time decision making, and services that integrate into holistic development planning. Cost-effective services are now ones that minimise costs for the whole project and provide information and knowledge that can be used to help optimise the plan. And these are also the services that can feed organisational learning, create databases and expertise that help optimise the next project in that basin, and provide insights useful for developments in other basins and other continents.

Integrated workflows in a collaborative environment, which combine discrete services, are the next level in value creation in complex reservoirs. Such workflows in reservoir evaluation, real-time stimulation and completion design, and an optimised drilling process, are producing dramatic results in North American shale basins, and they are equally applicable to complex reservoirs worldwide. In the future, we expect that similar advances developed for India or Brazil or Russia will also set new standards of productivity.

For example, we are linking specialised reservoir evaluation and modeling technologies to select the correct rock to stimulate. By fracturing only the most productive rock, we have increased production up to 30 per cent in one reservoir, compared to offset wells. In another project, by fully integrating drilling services, drill bits and drilling fluids, the operator saw a 55 per cent reduction in drilling days over the course of drilling 50 wellbores – a great illustration of the power of rapid learning. On the same project, by combining logging, stimulation and completions, the operator was able to almost double the number of producing zones completed in a month.

The trend is toward treating larger pieces of the project as a whole, because that is where we can create the greatest value. In one North American basin, we partnered with the operator to optimise full field development starting with the first well. By integrating 3D seismic, microseismic...
fracture modeling, geological interpretation and completion data, and by modeling to optimise both the well construction parameters and completion strategies, we estimate the operator will see a 20 per cent increase in ultimate recoveries and a 10 per cent unit cost reduction over the life of the field.

**Reducing environmental impact**

Our work is increasingly being judged not only by the energy produced, but also size of the operation’s footprint and the ultimate impact on the area. These concerns and this scrutiny will most likely continue to increase.

Our response is to create and introduce technologies with these goals in mind and plan developments that will maximise safety and reliability and minimise footprint for the long term. These are substantial investments, but they are necessary for our long-term success. We do not consider these efforts optional extras; we regard them as part of our core competency.

For example, in North America, hydraulic fracturing has become a much-discussed question as shale development moves into heavily populated areas. We anticipated this, and have introduced a suite of fracturing technologies that set new standards for minimizing impact. These include a fracture fluid system comprised of materials sourced entirely from the food industry, a service that uses ultraviolet light instead of chemical biocides to control bacteria in fluid systems, and a system that uses electrocoagulation to treat flowback and produced water to make it reusable. These technologies are in service now, helping to reduce our footprint and overall impact.

**People are the core**

Delivering these solutions also requires another set of changes, the second theme I mentioned at the outset: we are changing to speed up organisational learning and knowledge management.

Creating integrated workflows is dictating a change of emphasis within the organisation, because it requires an organisation that cultivates and values collaboration across business units and across disciplines. This is a substantial cultural change that is taking place in stages. One successful collaboration begets the next, and gradually the number of integrated workflows grows, and the scope of the integration broadens to become more holistic.

The ability to mobilise the right expertise anywhere in the world to solve the particular development challenge is a more visible source of value. We think of it as bringing the full intellectual capital of the company to bear on the situation – knowledge management in its highest form. Our Consulting and Project Management product service line is explicitly built along these lines. It exists outside our divisional structure and pulls experts from all disciplines for specific challenges.

North America’s shale basins provide an illustration of how the knowledge management approach can work. We invest in reservoir understanding, and in developing holistic solutions based on that understanding. We have a ‘tech team’ assigned to each basin – a multi-disciplined team of individuals who are the experts in that basin. They have the knowledge and experience to develop and apply the total solution that draws upon all the capabilities of the company. They are the ultimate integrators and the architects of the holistic solution.

Part of their mission is sharing their knowledge and insights with the rest of the organisation. They link up with tech teams from other basins. They make their data and results available, and they consult with other teams where they can contribute. This will be especially important outside North America, where 75 per cent of the shale reserves are located. Sharing the tech teams’ knowledge with our staff in other regions where shale development is just getting started will be crucial to accelerating value creation.

To help speed this process, we bring experts from other regions and embed them with our North American tech teams for a year or more to acquire first-hand experience in reservoir knowledge, scenario testing, development planning, and engineering for every phase of the project. This will shorten the learning curve for emerging complex plays. The process will also work in the opposite direction, as insights and techniques developed for offshore Brazil or Indonesia are transferred to North America. The systematic sharing of cutting-edge expertise will be a permanent part of our life.

These trends also influence the way we recruit and develop employees. We search the world for top engineering and business talent, work with universities on every continent to help shape curricula and promote the opportunities in our industry. And we provide employees with a breadth of assignments to help them become more flexible and more able to contribute to holistic solutions.

Greater integration across disciplines also demands a new level of reliability and predictability in service delivery, →
ADNOC & its Group of Companies
which in turn requires a new generation of competencies and skills. In response, we are broadening our training and formal competency system to provide both a predictable inventory of skills for the organisation, and a clear path to advancement for employees.

At the same time, we are standardising work methods around the world to provide both greater uniformity in the services we deliver, and more flexibility and responsiveness to new needs. Standardised work processes will help speed up innovation and learning. Innovations in practice can be captured faster and spread across the organisation. People can more easily transfer to new geographies. We can roll out new technologies more rapidly. In short, these practices will help speed organisational learning and contribute to developing and applying holistic reservoir solutions.

**Flexibility and rapid response**

There are other long-term changes that contribute to flexibility and rapid learning. To help us develop tailored solutions, we have created regional technology centres in India and Singapore. Currently there are some 250 technologists working in these two centres. And we are building centers in Saudi Arabia and Brazil that will have a similar mission – technology, applications and experience for specific customers and challenges. And the knowledge created in these basins will be a valuable asset to be shared throughout the organisation.

We are also distributing our manufacturing capacity and supply chain around the world and bringing them closer to customers and basins; this helps the organisation respond more quickly to local needs. Combined with an efficient global logistics operation, we can better manage materials and equipment so they are where they are needed most.

Finally, faster organisational learning and faster, more uniform spread of best practices will help with regulatory compliance. We expect the regulatory environment to become more uniform and more detailed across the globe. To succeed in that environment, service company practices will also need to become more consistent and uniform. And by doing this, service companies will also be able to contribute to effective regulation. For example, we are collaborating with authorities to develop new standards for offshore work in the Gulf of Mexico. And consistent, uniform regulation will help us create the technologies and practices that reduce our footprint and environmental impact. After all, the fundamental challenges are the same worldwide.

The world needs big ideas, big energy projects and big results now more than ever. To get them, we will need the horsepower and work ethic service companies have provided for generations. And we will also need smart, high-performing service companies that can help operators develop optimised solutions for their complex reservoirs and speed up the process of innovation and organisational learning. If we build organisations with those needs in mind, we will once again overcome all the pessimistic forecasts and deliver the energy our civilisation needs.
In a world that is ever more inter-linked, with international trade, greater personal mobility and mass communication bringing us all closer together, it has become increasingly important to appreciate the scope and intricacies of the global energy system. It is a system that helps support the fabric of our everyday lives. Thus, it is essential to learn from the past, understand the present, and comprehend the possible energy futures the world may face. It is a path of perpetually evolving analysis, as the energy system faces both local- and global-impacting events.

This has been strongly evident over the past few years with the world economy undergoing a recession that turned out to be the deepest in more than six decades. No one was immune from the downturn, but the degrees to which industries, countries and regions were affected have differed. This has been apparent in the economic recovery.

Emerging economies, with China and India to the fore, have returned to strong growth rates, and the challenge now comes from overheating and rising inflation. This is in contrast to many OECD countries that are juggling the need for additional monetary and fiscal policies to support fragile growth and the necessity for fiscal consolidation. In the US, growth has slowed this year, and in the eurozone, despite efforts to avoid the contagion risks from the Greek sovereign debt crisis, serious concerns have emerged about a worsening situation in other countries.

In addition, this year has also seen a number of other unforeseen events, such as the multiple disasters that hit Japan — earthquake, tsunami and nuclear accident — and the unrest that has been witnessed in a number of countries in North Africa and the Middle East.

The knock-on impacts of these developments to oil and energy markets have been varied. For example, the initial impact of the global recession was a demand drop off in both 2008 and 2009, although demand has grown appreciably in the period since. A number of energy investments were initially put on hold, although many of these are now being implemented; and of course, jobs were lost. In terms of Japan, the disaster led to a sudden decline in the country’s oil use. However, this was broadly offset by the need to substitute some of its shut-in nuclear capacity — whose future is now being questioned, as it is elsewhere — with oil- and gas-based generation. Moreover, reconstruction efforts are expected to lead to higher energy use. And in North Africa and the Middle East, there has been interruption in supplies from Libya, as well as

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**Figure 1: Relationship between WTI prices and net long positions of money managers**
market fears that disruptions might spread. These developments underscore some of the multiple challenges facing the market, but it should be noted that oil markets have rapidly adjusted to these events. Over the period highlighted here, there has been no shortage of oil anywhere in the world. It is essential that all stakeholders look to maintain oil market stability in the months and years ahead.

That is not to say that the market has been free from volatility. This is clearly underscored in the price swings witnessed over the past few years. In mid-2008, crude prices reached a peak of US$147/b, with crude prices earlier that year fluctuating by as much US$16/b on a single day. The magnitude of the price volatility was not at all consistent with market fundamentals. Then, driven by the global economic downturn, they plummeted to the low US$30s in December of the same year. In 2009, prices rose steadily, to end at close to US$80/b at the end of the year, and it remained around this level throughout 2010. However, the early part of the year saw a surge in oil prices to above US$120/b, although prices in the second and third quarters saw some movement in the opposite direction on the back of bearish economic concerns.

As in 2008, the volatility in the first half of this year has in part been driven by speculation. This can be observed in speculator activity on the Nymex, which surged to record highs in the first part of the year. For example, by mid-March, the volume of open interest contracts for Nymex WTI was 18 times higher than the volume of daily traded physical crude. Such an increase was the result of concerns of a further deterioration in supply. The build-up of large speculative positions on the crude futures markets was a key factor behind the increased crude oil price volatility. Figure 1 highlights the relationship between WTI prices and the speculative activity of the net long positions of money managers. A curb in speculative activities is needed.

It should also be noted that the price rises in the first half of this year were even more pronounced at the consumer end, where the effect of consuming country taxation is greatly felt. While OPEC has played its role by ensuring the market remains well supplied in crude, it is of course helpful if consuming countries that have a high level of taxation on oil products consider revising down these levels, at least when prices reach certain levels, to alleviate the impact on consumers.

The last few years have been an unpredictable time and the industry continues to face many hurdles and challenges. Yet, there is still good reason to look ahead with optimism. As economies expand, the global population grows and living conditions improve, energy demand will continue to increase. By 2035, world energy demand is expected to be more than 50 per cent higher than it was in 2010. With this expansion in mind, it is clear there is room for a variety of energies, but it is important to appreciate what each can actually offer. Which energies will form the core of our future? And which energies will play a more complementary role?

Renewable energy, mainly wind, solar, small hydro and...
Geothermal, is expected to grow fast, as a result of massive government support and incentives. Globally, however, its share in the energy mix will remain modest, given its low initial base. Hydropower should also expand, but given the limited scope for further expansion in many developed countries, it is expected that much of this will be in developing countries.

Biofuels are also expected to play a greater role, supported by direct and indirect government subsidies, but not at levels once assumed. For first-generation biofuels, much concern has recently been expressed over the competition between food and fuel. There have also been reports on their possible negative impact on biodiversity, their potential to make scarce water resources, even scarcer, and, in most cases, their relatively high greenhouse gas emissions, when land use change effects are fully taken into account. Second generation biofuels can overcome some of these concerns, but they are still far from being available for commercial use.

Nuclear power had witnessed something of a revival in recent years, with a number of countries looking to build nuclear plants. Events earlier this year at the Fukushima nuclear complex in Japan, however, have led to many questions being asked about nuclear power, particularly in terms of safety, waste and decommissioning.

It means that fossil fuels will maintain their prominent role, continuing to supply over 80 per cent of the world’s energy needs by 2035 (Figure 2). Even with a number of energy policies that to a considerable extent seek to reduce oil use, it is clear from OPEC’s World Oil Outlook (WOO) 2011 that oil’s leading role in the energy mix will continue for most of the period to 2035. Towards the end of this timeframe, however, it will be surpassed by coal, with oil’s overall share falling to around 28 per cent in 2035.

Fossil fuels also have challenges, such as their environmental footprint, in particular in terms of CO2 emissions. It should be recalled, however, that the petroleum industry has a long history of successfully reducing its environmental footprint, for example, in drilling, gas flaring and plant emissions. And the automotive industry, as well as the refining industry, has a good track record in continuously reducing the pollutant emissions of vehicles.

It is essential that we continually look to advance the environmental credentials of oil, both in production and use; improve operational efficiencies and recovery rates, and push for the development and use of cleaner fossil fuel technologies, such as carbon capture and storage.

Looking ahead, developing countries are set to account for most of the long-term oil demand increase, with consumption rising 26 million barrels a day (mb/d) over the period 2010-to-2035 to reach almost 62mb/d. Around 80 per cent of the net growth in oil demand in this period is in developing Asian economies. Transportation is the main source of this growth, and developing countries’ percentage of passenger cars globally will increase from around 23 per cent to 49 per cent in 2035.

In fact, the hub for oil demand has been progressively shifting towards Asia in recent years. For example, since 2005, OECD oil demand has contracted by around 3.7 mb/d, while developing Asia actually saw an increase of almost 4.8 mb/d over the same period.

Nonetheless, energy poverty
will remain. Energy use per capita in developing countries has always been well below that of the OECD and this remains the case in the future: in 2035 the OECD will be using on average three and a half times as much energy per capita as developing countries (Figure 3).

From an oil perspective, the world also has plenty of resources to meet the expected increase in demand. The end of oil has been talked about since the very beginning of the oil age, more than 100 years ago. However, it has never come to pass, and since the early 1980s, ultimately recoverable reserves of conventional oil worldwide have doubled and the figure continues to rise. Technology has resulted in new discoveries, increased recovery rates and improved efficiency. Today, we are also seeing the vast potential for the expansion of non-conventional sources of oil.

While suppliers continue to face significant challenges, such as the impact of the global financial and economic crisis, market volatility and the role of speculation, and an often unclear demand picture as a result of a number of consuming country policies, investments to turn resources into capacity are being made. In the medium-term to 2015, OPEC Member Countries are expected to invest an estimated US$310 billion in upstream projects. OPEC remains committed to future investment plans to boost its capacity.

It is important to stress, however, that the pace of future energy demand growth, and in turn investments, is affected by many uncertainties. This includes the possibilities of varied economic growth paths, consuming countries’ energy and environmental policies, technology and consumer choices.

For example, OPEC’s WOO 2011 shows that demand for OPEC crude by 2025 could be as low as 31 mb/d or as high as 38 mb/d. These scenarios point to an uncertainty range in the billions of dollars. Such fears constitute a great challenge for all stakeholders.

If there is no confidence in there being additional demand for oil, there is no incentive to invest. Why waste precious financial resources on unneeded capacity? On the other hand, if investments are not made in a timely and adequate manner, then future consumer needs might not be met. The supply and demand balance is essential to the overall health of the industry. Oversupply or a supply shortfall is detrimental to both producers and consumers. It is important to appreciate and better understand the two sides of energy security: security of supply and security of demand.

The oil market has been — and will continue to be — an ever-changing arena. This is because oil is so vital to the world economy, it is present in everyone’s daily lives and its market is truly global. This underscores the importance of dialogue and cooperation, on both a bilateral and multilateral basis, to meet both the challenges and opportunities facing the industry. While differences of opinion will obviously occur, it is important to try and reach an underlying consensus on, at least, the major issues that concern all parties — such as pricing, stability, security of demand and supply, investment, environmental issues and sustainable development. This will hopefully ensure that the world oil market continues to operate efficiently and effectively in the future, for the enhancement of everyone across the globe.
**GECF: A new participant in the natural gas market**

BY LEONID BOKHANOVSKY  
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Today’s globalised world, interconnected more than ever by technology, politics, economics, social and environmental issues, requires platforms for dialogue and fora for converging the interests of countries that want to make rational use of their resources. International organisations represent such platforms and therefore developed and developing countries, producers, exporters, importers and consumers of natural resources must continually appreciate the actions of international organisations.

Within this context the Gas Exporting Countries Forum (GECF) plays a significant role as an organisation that contributes to maintain energy security worldwide and stability in natural gas markets, considering that the global financial crisis and the ensuing economic slowdown together with volatile energy prices have created indeed a unique set of challenges for the gas industry.

The Gas Exporting Countries Forum is an intergovernmental organisation established as a Forum during the 1st Ministerial Meeting held in Tehran, Iran, in May 19-20, 2001, by the governments of Algeria, Brunei, Indonesia, Iran, Malaysia, Oman, Qatar and Russia, with Turkmenistan and Norway as Observers. The meeting promoted by Iran aimed to bring together the main gas exporters with the purpose of increasing the level of coordination and strengthening collaboration, exchanging information about their corresponding industries and technical know-how and debating on common concerns and goals on crucial issues of gas market development and future planning. The GECF seeks also to build a mechanism for a more meaningful dialogue between gas producers and gas consumers for the sake of stability and security of supply in global natural gas markets.

Since the first meeting of energy ministers, it started an active process that involved a series of meetings of the different governing bodies of the Forum; as a result, the Agreement on the Functioning of the Gas Exporting Countries Forum and the Statute of the GECF were signed by the representatives of the governments of 11 Member Countries during the 8th Ministerial Meeting held in Moscow on December 23, 2008, thus transforming the GECF into a fully-fledged international organisation. However, in the name of the organisation the word “Forum” was kept to reflect its open and democratic nature.

The next step of the organisational development involved the submission of five ratifications as per the Agreement, which entered into force on October 1, 2009.

Afterwards, the Headquarters Agreement was signed with the State of Qatar in December 2010 and the first Secretary General of the Forum was appointed by the 9th Ministerial Meeting and his tenure started in February 2010.

The structure of the Gas Exporting Countries Forum as laid down in its Statute is as follows:

- The Ministerial Meeting: this is the supreme governing body of the Forum. It holds meetings at least once a year and adopts Decisions in the form of Resolutions. In 2011 the Minister of Petroleum of Egypt is holding the rotating Presidency of the Ministerial Meeting, while the Alternate President is the Minister of Energy and Energy Affairs of Trinidad and Tobago.

The Ministerial Meeting formulates the general policy of the Forum and determines the appropriate ways and means of its implementation; appoints the Secretary General, as well as the Chairman and Alternate Chairman of the Executive Board; decides upon applications for membership of GECF and approves the budget of the Forum.

Besides the first one in Tehran in 2001, Ministerial Meetings have been held in Algiers, Algeria (February 2002); Doha, Qatar (February 2003); Cairo, Egypt (March 2004); Port of Spain, Trinidad and Tobago (April, 2005); Doha (April 2007); Moscow, Russia (December 2008); Doha (June and December 2009); Oran, Algeria (April 2010) and Doha (December 2010). The 12th Ministerial Meeting was held in Cairo, Egypt on June 2, 2011.

- The Executive Board: this directs the management of the affairs of the Forum and the implementation of the decisions of the Ministers; approves the work programme of the Secretariat and draws up its budget, among other functions. The Chairman of the Executive Board for 2011 is the representative of Trinidad and Tobago, while the Alternate Chairmanship is held by Egypt.

- The Secretariat: this organises and administers the work of the Forum and carries out its executive functions in accordance with the provisions of the Statute under the direction of the governing bodies. It consists of Secretary General – the authorised representative of GECF – and staff.

Today, the GECF is a gathering of the world’s leading gas producers. The Member Countries of the Forum are: Algeria, Bolivia, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Qatar, Russia, Trinidad and Tobago and Venezuela. Kazakhstan, the Netherlands and Norway have the status of Observer Members. With the current number of Members the GECF is a strong player in the world gas market and among international energy organisations. Its potential
rests on the enormous natural gas reserves of the Member Countries, which all together accumulate 70 per cent of the world proved natural gas reserves. The Forum highly values the potential of its Member Countries and Observer Members and at the same time is looking forward to further increases in membership and welcomes new members that share the common interests and objectives of the Forum’s Statute.

The GECF takes into account the importance of long-term contracts and fair pricing for natural gas at levels reflecting market fundamentals and parity with oil prices

The main objective of the GECF is to support the sovereign rights of Member Countries over their natural gas resources and their abilities to independently plan and manage the sustainable, efficient and environmentally conscious development, use and conservation of natural gas resources for the benefit of their peoples. According to the Statute, these objectives will be promoted through the exchange of experience, views and information on such topics as:

- Worldwide gas exploration and production trends;
- Present and anticipated supply-demand balance for gas;
- Worldwide gas exploration, production and transportation technologies;
- The structure and development of gas markets (regional and global);
- Transport of gas: pipelines and LNG carriers;
- Interrelationship of gas with oil products, coal, and other energy sources;
- Technologies and approaches for sustainable environmental management, taking into account environmental constraints, national regulations and multilateral agreements on environment and their impact on volume and sustainability of gas consumption;
- Techniques and approaches for maximising the contribution of natural gas resources, at all stages of the value chain, to the promotion of sustainable economies and human resources development in member countries.

Based on these objectives, the main tasks of the GECF are related, on the one hand, to the development and implementation of necessary steps to guarantee that Member Countries derive the most value from their gas resources, since natural gas is a non-renewable source of energy. In this regard, GECF takes into account the importance of long-term contracts and fair pricing for natural gas at levels reflecting market fundamentals and parity with oil prices for ensuring the energy security of producers and consumers. This condition is a prerequisite for the development of gas reserves and the success of important infrastructure projects related to gas. However, even though the GECF Ministers support oil-gas price parity, this does not imply that the Forum has plans to regulate the volume of gas exports or to determine prices.

It is clear that without well thought-out investments and infrastructure development in the gas industry it will not be possible to talk about sustainable growth in the world’s major economies, as global gas consumption will only increase over the next decade. The GECF considers necessary to establish a more predictable and reliable global gas industry and member countries can contribute to the progress of a coherent framework for strong, sustainable and balanced economic growth. Moreover, the Forum finds that the present gas market dynamics pushes its main participants to closer cooperation.

On the other hand, the GECF promotes the development of dialogue between natural gas exporters and importers. It is ready to study and discuss problems concerning the interests of all Member Countries (including pipelines gas and LNG exporters), as well as problems relating to the security of supplies. The Ministers of the Forum have stated positions on issues such as the stimulation of cross investments and technological exchanges between gas consumers and producers based on growing interdependence between them, but without unjustified barriers, especially those related to carbon taxation. The GECF also considers that meeting local demand for natural gas in the producing countries is a priority.

The GECF is progressively becoming a reference in the gas market and in the next years it will play a more relevant role as a factor of stability and cooperation among Member Countries and consumer countries, in a scenario where the natural gas will grow in importance in the global energy mix, considering its advantages as a clean, abundant and safe fuel of choice capable of contributing greatly to global energy security. These and other issues are part of the discussions to be held at the first ever summit of heads of state and governments of the GECF countries in Doha in November 2011, in the most important event of the GECF this year: the 1st Gas Summit of the GECF in Qatar.

Cooperation
Synergy for Energy

Cooperation . Innovation .
Development
China has become the world’s second largest economy, but its biggest energy consumer. China’s gross national product only surpassed that of Japan last year and was only 41 per cent of the US. But China’s energy intensity – the ratio of energy input to economic output – is 3 times that of the US and 5 times that of Japan. Accordingly, there is a very high potential capacity to improve energy efficiency in the future. How far China succeeds in increasing the efficiency with which it uses energy will have an enormous influence on world energy markets.

The economic and energy boom during the past five years
During the 11th Five Year Plan (2006-2010), China’s economy developed at an extraordinary pace, as did its energy industry. The 11th Five Year Plan for China’s Energy Development had limited growth in China’s primary energy consumption to 2.7 Gigatons of coal equivalent (Gtce) a year by the end of the plan period. This would have amounted to roughly 4 per cent annual growth. However, by 2010 the actual energy consumption figure had reached 3.25Gtce, reflecting an annual growth rate of 7.66 per cent, or 6.7 per cent after a revision of the 2005 base data. So, from 1949, it took China 41 years to reach 1Gtce/year’s consumption, another 14 years to reach 2Gtce/year by 2004, but only five years after that for China’s energy appetite to exceed 3Gtce/year.

Moreover, coal dominated China’s primary energy consumption mix. The 11th Five Year Plan was to reduce coal’s share in total energy consumption to 66.1 per cent. However, in the past five years, the share of coal has stayed steady above 70 per cent, with coal consumption reaching 3.2Gt, or 0.65Gt higher than indicated in the Plan.

The unusually fast growth of energy consumption dramatically accelerated energy production in the 2006-2010 period. The actual annual growth rate of production was 7.75 per cent (after adjusting for the base data, still as high as 6.72 per cent), far higher than the planned 3.54 per cent yearly increase. By the end of 2010, total energy production peaked at 2.99Gtce, a 45.22 per cent increase over the year 2005 and 22.04 per cent higher than the plan. The unplanned production growth in crude oil, natural gas and nuclear power was not as significant as that of coal and hydropower. Given the relatively small volume of hydropower capacity, the excess in total energy production came mostly from coal, while the excess in coal production was in turn driven by excess growth in domestic power consumption.

But the most eye-catching growth rates were in natural gas and hydropower. For the reason that the proportion of natural gas in China’s energy structure had always been lower than the world average level, the growth of natural gas production was seen as a major element in the 11th Five Year Plan strategy to improve the country’s energy structure. Natural gas production increased at record rates and at record volumes during the 11th Five Year Plan. The annual growth rate reached 14.45 per cent, and production nearly doubled over the five years. As the last phase of Yangtze Three Gorges Hydropower Project was completed and put into operation, China’s hydropower capacity grew at an annual growth rate of 10.77 per cent.

Explaining the excess
Why did actual energy consumption and production so over-shoot the planned targets? One reason was statistical – the national bureau of statistics had underestimated the level of energy consumption and production for the 11th Five Year plan’s base year of 2005. But there were two more fundamental reasons.

First, the whole Chinese economy grew faster than the plan. The 11th Five Year Plan for National Economic and Social Development clearly laid down that China’s target annual GDP growth rate would be 7.5 per cent. However, the actual annual average growth rate turned out to be 11.2 per cent, or 3.7 percentage points higher than expected. As the plan for energy consumption and production were made on the basis of National Economic and Social Development Plan, the greatly underestimated level of economic growth had the effect of pulling up the growth rate of energy consumption. In fact, each percentage point of extra expansion in the general economy led to a disproportionately larger increase in energy consumption.

Second, less energy efficiency was achieved through industrial restructuring than was hoped. Aside from technological and management factors, China’s economic development status and industry structure account for China’s low energy efficiency compared with developed countries. Statistics show that a one percent increase in the share of the tertiary sector, or services, in the whole economy will reduce total energy consumption by around 0.1Gtce. From 2005 to 2010, the share of the tertiary sector in the economy went up by 2 per cent, at the expense of agriculture (but not of mining) which reduced the
relative size of the primary sector. The energy intensity of manufacturing and services is higher than that of agriculture. So the aim of reducing energy consumption through industry restructuring did not work out.

In addition to China being in the high energy consumption phase of urbanisation, the financial crisis also hindered China’s steps toward industry restructuring. In order to offset the impact of the global financial crisis on China’s economy, the Chinese government took countermeasures such as the Major Ten Industries’ Rejuvenation Plan to stimulate economic growth as well as to create employment opportunities. However, those measures in fact encouraged the revival of high energy-consuming industries, making it harder to conserve energy and reduce emissions.

The outlook for the next five years

In the 12th Five Year Plan (2011-2015) for National Economic and Social Development, there are three constraint indicators which are closely related to energy consumption. These are that non-fossil energy consumption should rise to 11.4 per cent of total primary energy consumption; that energy consumption per unit of GDP should fall by 16 per cent; and that carbon dioxide emission per unit of GDP should decrease by 17 per cent. Among the three, non-fossil energy consumption indicator is the most important.

Assuming that the 16 per cent decrease in energy intensity from 2010 to 2015, the economy will still be able to grow at the expected growth rate of 7 per cent, provided the annual growth rate of primary energy consumption will be 3.95 per cent. This would allow China’s total primary energy consumption to grow to at least 3.945 Gtce by 2015, from 3.25 Gtce in 2010. Assuming that non-fossil energy consumption per GDP will increase to 11.4 per cent of total primary energy consumption, the proportion of natural gas in energy consumption structure will have to rise so as to realise the goal of reducing energy consumption and carbon dioxide emission per GDP.

China’s natural gas production is on the rising track. Assuming that future growth rate of production equals the average annual growth rate in the 11th Five Year Plan period, China’s natural gas production will be 190 Bcm. Add 70 Bcm of net imports, and China’s natural gas demand should reach 260 Bcm (0.31565 Gtce) by 2015, accounting for 8 per cent in the 3.945 Gtce of total primary energy consumption. In the next five years, demand for crude oil will rise steadily, rising to 0.51 Gt or 10.2 million barrels a day, accounting for 18.4 per cent in the total.

Domestic oil production is impossible to increase much. So demand growth will mostly have to rely on the international market. By 2015 China will probably depend on imports for nearly 60 per cent of oil, but at the same time it isfilling up its Strategic Petroleum Reserve which should contain 270 m barrels by the end of 2012. The Middle East and Africa will remain China’s dominant sources of imported oil. But, with the Russia-China crude pipeline in commercial operation since 2010, the second phase of the Kazakh-Chinese crude pipeline finished, and several ‘loans-for-oil’ deals signed with South American suppliers in the last couple of years, Beijing is diversifying its sources of supply. The rapid pace of upstream investment by China’s three oil majors will also consolidate these companies’ trading power.

The huge residual of this equation is the demand for coal, whose consumption is virtually guaranteed to increase to 3.44 Gt by 2015. But the share of coal in total energy consumption will have to shrink a little if non-fossil energy is to increase its share to 11.4 per cent in total energy consumption. Among low carbon sources, hydropower will continue to dominate, with nuclear power second and a fast-growing contribution from wind.

<table>
<thead>
<tr>
<th>Planned Energy Consumption in 2015</th>
<th>2010 Actual</th>
<th>2015 Estimated</th>
<th>2015 Proportion (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total energy consumption - Gtce</td>
<td>3.25</td>
<td>3.945</td>
<td>100</td>
</tr>
<tr>
<td>Coal - Gt</td>
<td>3.20</td>
<td>3.44</td>
<td>62.2</td>
</tr>
<tr>
<td>Crude oil - Gt</td>
<td>0.43</td>
<td>0.51</td>
<td>18.4</td>
</tr>
<tr>
<td>Natural gas - Bcm</td>
<td>104.80</td>
<td>260</td>
<td>8</td>
</tr>
<tr>
<td>Non-fossil energy - Gtce</td>
<td>0.21</td>
<td>0.45</td>
<td>11.4</td>
</tr>
</tbody>
</table>
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Weatherford’s Tactical Technology™ and flexibility can change the way you think about your service needs.

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Future uncertainties

Many uncertainties surround forecasts about China and energy. The biggest uncertainty, given what happened during the 11th Five Year plan period, is the country’s overall growth rate. My analysis, and the government’s, is based on the assumption of 7 per cent average growth in the coming five years. But if the growth rate were to average 10 per cent, the total primary energy consumption would rise to 4.3Gtce, even if efforts to reduce energy intensity were to do well.

In the next five years natural gas will play an important part in energy consumption optimisation. But a crucial factor here is pricing reform. If the natural gas price is still relatively low, motivation to develop unconventional gas would be reduced. Thus, any delay in the price reform may directly influence the realisation of the goal of natural gas taking 8 per cent in the total primary energy consumption structure.

Development of the gas market and the expansion of wind power are both related to energy infrastructure. Future growth of China’s natural gas consumption is closely tied to the construction of three major cross-border gas pipelines – the Central Asia-China gas pipeline coming from Kazakhstan and connected to the domestic West-East gas pipeline, the China-Myanmar gas pipeline and the Russia-China gas pipeline – as well as the construction of LNG import facilities. Improvements in the domestic gas network and strategic gas storage are also vital to meet the rapid growth of demand. In 2010, China’s wind power capacity was an astonishing 33 times bigger than in 2005, rising from 1.26m kw to 41.82m kw over that period. This amounts to a quarter of world wind power capacity. However, to maintain this rate of growth requires constant improvement in grid connection.

The Fukushima nuclear accidents in Japan may affect China’s medium and long term plan for nuclear power development, especially if new safety measures raise the cost of nuclear construction and operation, affecting the competitiveness of nuclear power. But the influence on the 12th Five Year Plan period will be relatively limited, because of the long lead time in building nuclear power plants. Plants now under construction will be completed and put into use in the 12th Five Year Plan period. Even if future projects are postponed, the impact will only show in the more distant future.
India, like China, is expected to be one of the main drivers of world energy consumption as India’s economy continues to grow at a rapid rate. Indeed its energy needs could be even more dynamic than those of China. In addition to a quasi-Chinese rate of economic expansion, it is also undergoing rapid population growth. Moreover, it is chasing the ever-moving target of trying to link all its people to the electricity grid. Of the 1.5bn people who according to the International Energy Agency lack access to electricity in the world, nearly 400m live in India. However, India’s RGGVY (Rajiv Gandhi Grameen Vidyutikaran Yojna- Rajiv Gandhi Village Electrification Scheme) has the objective to electrify all villages and connect free of cost all estimated around 25 million households below the poverty line by March, 2012. If successful, this massive effort of electrification would have consequences for world energy producers vying to supply this modern form of energy to the Indian economy, as well as being of enormous benefit to the currently power-less poor of India.

Since 1994, the energy intensity – the ratio of energy input to economic output – of India’s economy has been declining, as in most countries of the world. In figure 1 we see that it has fallen from 0.0259 kgoe/rupee in 1994 to 0.0208 kgoe/rupee by 2009. This also shows the growth in total primary commercial energy supply (TPCES); the reason for defining it as ‘commercial’ is to exclude the considerable use in the Indian countryside of firewood and animal dung which do not enter the regular economy. Commercial energy grew from around 210 Mtoe in 1994 to around 474 Mtoe in 2009. The twin drivers of this growth in energy use have been economic expansion and population growth. In the period of 1994 to 2009 India’s GDP grew at an average growth rate of 7 per cent, whereas in the latter part of this period (2003-2009) the rate of economic expansion accelerated to an average of 8.3 per cent.

**Table 1: TPCES until 2030**

<table>
<thead>
<tr>
<th>Year</th>
<th>Population (billions)</th>
<th>GDP (Rs billions) at 1993-94 prices</th>
<th>TPCES* (Mtoe)</th>
<th>GDP growth rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2009</td>
<td>1.169</td>
<td>23098</td>
<td>474</td>
<td>8%</td>
</tr>
<tr>
<td>2010</td>
<td>1.176</td>
<td>24946</td>
<td>502</td>
<td>9%</td>
</tr>
<tr>
<td>2015</td>
<td>1.254</td>
<td>36654</td>
<td>657</td>
<td>8%</td>
</tr>
<tr>
<td>2020</td>
<td>1.326</td>
<td>53856</td>
<td>860</td>
<td>9%</td>
</tr>
<tr>
<td>2025</td>
<td>1.389</td>
<td>70132</td>
<td>1114</td>
<td>8%</td>
</tr>
<tr>
<td>2030</td>
<td>1.44</td>
<td>116271</td>
<td>1445</td>
<td>9%</td>
</tr>
</tbody>
</table>

Source: http://www.censusindia.net, and RBI (2010), Table 2

---

**Table 2: Projected electricity requirement until 2030**

<table>
<thead>
<tr>
<th>Year</th>
<th>Total energy requirement at GDP growth rate</th>
<th>Energy requirement at GDP growth rate (BkWh)</th>
<th>Projected peak demand (GW at GDP growth rate)</th>
<th>Installed capacity (GW) required at GDP growth rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>2010</td>
<td>2010</td>
<td>2010</td>
<td>2010</td>
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<tr>
<td>2020</td>
<td>2020</td>
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<tr>
<td>2030</td>
<td>2030</td>
<td>2030</td>
<td>2030</td>
<td>2030</td>
</tr>
</tbody>
</table>


- based on falling elasticities of 0.95 from 2004 to 2010, 0.85 from 2010 to 2020 and 0.78 from 2020 to 2030.
- Electricity generation and peak demand is the total of utilities and non-utilities above 1MW size.
Table 1 shows how population, economy and energy use are likely to rise in absolute numbers over the next 20 years to 2030 and how these trends translate into India’s future electricity needs is illustrated in table 2.

What would be the impact on electricity requirements if all households were connected to electricity?

To estimate this, first of all we need to establish a baseline by projecting from the last household energy consumption survey of 1999-2000 what household energy use would be in 2030. This takes account of the fact that as households’ income rises so does their overall energy consumption, but it assumes that within their overall energy consumption, their pattern of fuel use (as between electricity, firewood, dung etc) would remain unchanged. Table 3 shows the result.

It should be noted that the requirement of electricity, kerosene and gas for household consumption are included in the projection given in Table 3. The impact of the RGGVY scheme, which targets provision of electricity to all by March 2012, will alter the demand for electricity. To account for this impact, household demands are projected from 2010 onwards using the energy use pattern of only those households, which had electricity in the 1999-2000 household consumption survey. These projections are given in Table 4.

The differences between the two tables give us the impact of electrification of households on their energy consumption. This is summarised in table 5. The differences are substantial only in 2015, as even without the acceleration in rural electrification planned under RGGVY, most of the households will have been electrified by 2020. It is worth noting that for the year 2015 electrification does not reduce kerosene consumption significantly. This is rational. As long as kerosene is available, especially subsidised kerosene, what is saved from lighting is used as fuel and the consumption of dung goes down. This substitution is more convenient and the dung saved has greater value as fertiliser.

Electricity demand grows by 5 mtoe which is around 16 bkwhr in 2030, for which we have projected a requirement of 3100 to 3600 bkwhr. Even after adding T&D losses and auxiliary consumption, additional demand for households comes to be around 0.5 per cent of the total projected electricity requirement.

Electrification of all the villages would not only increase household demand but also increase consumption for productive industrial activities.

Since many rural households use dirty bio-fuels such as wood and dung, they suffer from indoor air pollution with significant adverse impact on health particularly of women and children. It is estimated in 2001 that 25m adults had symptoms of respiratory diseases with 17m having serious symptoms.

Also 30bn person hours are spent in gathering bio-fuels often by girls who are kept out of school. Due to these externalities on health and education, India’s integrated energy policy plans to provide entitlements of liquid petroleum gas (LPG) to all households appropriately subsidized for the poor households. The additional requirement of subsidized LPG in 2015, if the programme is fully implemented by then, is estimated to be around 15

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**Table 3: Projected energy consumption by households in India 2030 (Mtoe)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Fire wood</th>
<th>Electricity</th>
<th>Dung</th>
<th>Kerosene</th>
<th>LPG</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>8%</td>
<td>9%</td>
<td>8%</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>2005</td>
<td>87</td>
<td>87</td>
<td>16</td>
<td>17</td>
<td>36</td>
</tr>
<tr>
<td>2010</td>
<td>93</td>
<td>93</td>
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<td>2015</td>
<td>98</td>
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<td>2020</td>
<td>101</td>
<td>102</td>
<td>48</td>
<td>52</td>
<td>42</td>
</tr>
<tr>
<td>2025</td>
<td>104</td>
<td>105</td>
<td>59</td>
<td>63</td>
<td>41</td>
</tr>
<tr>
<td>2030</td>
<td>106</td>
<td>106</td>
<td>68</td>
<td>70</td>
<td>41</td>
</tr>
</tbody>
</table>

**Table 4: Impact of electrification on household energy demand (Mtoe)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Fire wood</th>
<th>Electricity</th>
<th>Dung</th>
<th>Kerosene</th>
<th>LPG</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>8%</td>
<td>9%</td>
<td>8%</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>2010</td>
<td>88</td>
<td>88</td>
<td>30</td>
<td>32</td>
<td>32</td>
</tr>
<tr>
<td>2015</td>
<td>92</td>
<td>92</td>
<td>44</td>
<td>31</td>
<td>14</td>
</tr>
<tr>
<td>2020</td>
<td>96</td>
<td>97</td>
<td>57</td>
<td>31</td>
<td>14</td>
</tr>
<tr>
<td>2025</td>
<td>99</td>
<td>100</td>
<td>68</td>
<td>29</td>
<td>14</td>
</tr>
<tr>
<td>2030</td>
<td>102</td>
<td>102</td>
<td>75</td>
<td>29</td>
<td>14</td>
</tr>
</tbody>
</table>

**Table 5: Changes in energy consumption by households in 2030 with electrification (Mtoe)**

<table>
<thead>
<tr>
<th>Fire wood</th>
<th>Electricity</th>
<th>Dung</th>
<th>Kerosene</th>
<th>LPG</th>
</tr>
</thead>
<tbody>
<tr>
<td>8%</td>
<td>9%</td>
<td>8%</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>Difference</td>
<td>-4</td>
<td>-5</td>
<td>-11</td>
<td>-1</td>
</tr>
</tbody>
</table>

**Table 5: Changes in energy consumption by households in 2030 with electrification (Mtoe)**

<table>
<thead>
<tr>
<th>Fire wood</th>
<th>Electricity</th>
<th>Dung</th>
<th>Kerosene</th>
<th>LPG</th>
</tr>
</thead>
<tbody>
<tr>
<td>8%</td>
<td>9%</td>
<td>8%</td>
<td>9%</td>
<td>8%</td>
</tr>
<tr>
<td>Difference</td>
<td>-4</td>
<td>-5</td>
<td>-11</td>
<td>-1</td>
</tr>
</tbody>
</table>
mtoe which would reduce over time as incomes increase and fewer households qualify for subsidy. Thus, the implications of energy access to all are really modest and benefits significant.

Supply Options
India’s options for energy supply are limited. It has very small reserves of crude oil and currently nearly 80 per cent of consumption of petroleum products is based on imports. While some more reserves of natural gas have been located in the Krishna-Godavari basin, these deep sea reserves pose formidable challenges to exploit. Domestic gas is not expected to constitute more than 20 percent of India’s primary energy supply. The most important resource is coal. India will continue to depend on it for the next few decades. Even for coal, the presently estimated extractable reserves would be exhausted in 40 to 45 years if coal consumption keeps growing at the current rate of growth of 5 per cent per year.

Among the renewables hydro-power is important. However, assuming full development of India’s potential, it can generate no more than 450 bkwhr of electricity. Compared to the projected requirement for 2030 of 3400 to 4000 bkwhr, this is less than 15 per cent. Wind power potential is much smaller and with the current technology the estimated potential of 45 GW can generate about 90 bkwhr which will be less than 3 per cent of the needed generation in 2030.

Other renewables such as ethanol, bio-diesel and wood plantation have limited scope as India is short of land and these would compete with food production. Cellulosic ethanol, when the technology is developed can make a substantial contribution if ethanol can be produced from agricultural wastes such as wheat straw or rice straw.

The sources that have sizable potential are solar energy and nuclear power. India’s strategy is to use its limited uranium reserves to run first generation plants that also produce plutonium along with power, using the plutonium in fast breeders reactor that produce more plutonium than what is put in, and then using in the third stage its abundant resource of thorium can provide 4 to 5 million MW of power for more than 100 years. The catch here, however, is the time required to realise this. By 2030 one can expect no more than 100 GW of nuclear capacity.

Solar is abundant and the land requirement does not have to compete with agricultural land. The problem is its high cost. Today solar power costs 5 times as much as coal power in India. Yet there is lot of hope that solar power can be made cost-competitive with coal power by 2020. India’s long-term hope for energy security rests critically on realising that goal. Energy efficiency is a major resource and should be pursued with the highest priority. Nonetheless there are limits to what it can deliver. Our projections based on falling elasticities do embody gains from energy efficiency to a large extent.

Table 6: Percentage of energy use met by domestic production

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Coal</td>
<td>99.7</td>
<td>97.8</td>
<td>96.1</td>
<td>93.02</td>
</tr>
<tr>
<td>Lignite</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Oil</td>
<td>32.6</td>
<td>42.8</td>
<td>30.3</td>
<td>27.59</td>
</tr>
<tr>
<td>Natural gas</td>
<td>100</td>
<td>100</td>
<td>100</td>
<td>69.30</td>
</tr>
<tr>
<td>Hydro</td>
<td>100</td>
<td>99.93</td>
<td>99.96</td>
<td>95.94</td>
</tr>
</tbody>
</table>
* Projected; Note: Excludes nuclear and wind power; does not take into account increases in domestic gas production from 2009

Figure 2: Structure of Commercial Energy Supply

Source: BP (2011)
An integrated
OIL and GAS Group

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Reliable and flexible pipeline transportation network.
India: Maximising output, while facilitating imports

BY R P N SINGH
MINISTER OF STATE FOR PETROL EUM AND NATURAL GAS, INDIA

As the world’s fourth largest oil importer, and as a major refining hub, India’s role in the world’s energy markets is growing. With an economy of 1.2 billion people growing annually at 8 per cent or more, India’s energy needs are growing, and to secure these needs the country is taking a multi-pronged approach.

We have taken several steps to increase domestic production of oil and gas. The New Exploration Licensing Policy (NELP) launched in the year 1997-8 has seen investments of US$14.2bn and has resulted in 87 oil and gas discoveries, with three blocks in production. NELP offers all the necessary ingredients of a favourable investment climate: macro-economic and fiscal stability, transparency and the rule of law, contract stability, minimal policy-induced uncertainties, and ensures a stable legal and regulatory framework. We have just completed the 9th round of NELP covering a sedimentary area of about 88,000 sq km, which saw participation by 37 companies including eight foreign ones.

The Mangala fields in Rajasthan have shattered the misperception that India was devoid of hydrocarbon potential. These fields, which commenced production in August 2009, are the biggest discovery since “Bombay High” in the 1970s, and at peak production will contribute about 25 per cent of the country’s domestic oil production. Similarly, the KGD-6 gas field, which commenced production in 2009, has led to a 75 per cent increase in India’s domestic production of natural gas. BP’s recent decision to buy a 30 per cent stake in the KGD-6 gas field for US$7.2 bn, one of the largest foreign direct investments in India, is a concrete example of the tremendous opportunities.

In petroleum refining, India has witnessed a silent revolution and has emerged as a major export hub in the recent years. During 2010-11, India exported 56m tonnes of petroleum products valued at about US$40 bn, making petroleum products our largest foreign exchange earner in the merchandise category. With three new greenfield refineries coming up at Bina, Bathinda and Paradip in the year ahead, India will have an even larger exportable surplus of petroleum products. We look forward to forging close trade ties with countries looking for refined products.

Presently, natural gas accounts for around 10 per cent of India’s primary energy basket as against the world average of 24 per cent. As natural gas is a more versatile fuel besides being environmentally benign, the Government has embarked on a path of increasing the use of this fuel in the country’s energy basket. The Government has initiated gas pricing policy reforms, to incentivise production of natural gas. Alongside, to cater to the huge demand for LNG, the country is investing heavily in the creation of LNG re-gasification facilities. With new RLNG terminals coming up at Dahej, Kochi and Dabhol, the country’s current import capacity of 12.5m tonnes a year is set to increase to 20m tonnes a year by 2012-13.

We are keen to diversify our source of LNG supplies and are looking to LNG exporters across the globe for tying up our growing requirement of LNG imports. Recently, we have signed a long-term contract with an Australian company for supply of LNG over the next 20 years. We are interested in not only buying additional quantities of LNG, but also seek to have equity participation in existing and upcoming LNG liquefaction projects globally. We are also keen to explore farm-in opportunities in producing oil and gas blocks whenever they may be available. To transport natural gas to different parts of the country, we have launched an ambitious pipeline development programme. GAIL (India) alone is expanding its existing pipelines by 5,000 kms in the four years ahead. Private operators are adding another 5,000 kms.

We are seriously pursuing the development of shale gas. We have undertaken the mapping of India’s shale gas resources and are working to put in place a regulatory regime for licence rounds by December 2013. We are also harnessing coal bed methane: so far, we have held four licence rounds, and commercial production has commenced at Raniganj in West Bengal. As India has one of the world’s largest coal reserves, we want to work with international companies having the requisite experience and expertise in coal seam gas.

While we have significant achievements under our belt in the petroleum sector, there are huge challenges before us: our dependence on crude oil imports has grown to the extent of around 75 per cent of our requirement. Naturally, being the fourth largest oil importer in the world, we are deeply impacted by a rise in the international oil prices. As an emerging economy, India can ill-afford growing budgetary deficits or high inflation; and high international oil prices can lead to both. Hence, as a leading player in the International Energy Forum, we have been vocal about our demand for greater transparency and stability in the price formation of oil.

India firmly believes that enhanced energy security for the world can only come through inter-dependence among the producer, consumer and transit countries. We need greater investments in the upstream sector if more oil and gas are to be brought to the international markets.
A socially responsible company at the service of national development
New producer-consumer dialogue: What to expect?

BY NOÉ VAN HULST
SECRETARY GENERAL, INTERNATIONAL ENERGY FORUM

In an historic meeting in Riyadh on 22 February 2011 ministers and representatives from 86 energy producing, energy consuming and transit countries signed a fresh charter for the International Energy Forum. Since then, Azerbaijan has joined as the 87th member. The IEF Charter marks a new era of international energy cooperation, signalling a reinforced political commitment to an informal, open and continuing producer-consumer dialogue in the global framework of the IEF. It creates a solid foundation for a productive dialogue that fosters greater mutual understanding between energy producing and energy consuming countries on key energy policy issues, seeks to narrow differences in views and helps build trust in policy intentions. With all the major energy producers and consumers in this enhanced dialogue framework, this fact alone sends a powerful signal to the energy world and energy markets that difficult issues can and will be tackled in a global context, whenever necessary. It is understandable that the signing of the IEF Charter has raised expectations. So what can realistically be expected?

Recent events rock energy markets

Since the IEF Charter was signed, we have witnessed significant political events in some Middle East and North African countries, as well as in Japan that have increased energy market volatility and uncertainty. Energy market volatility has been, and will continue to be addressed in the cooperation programme with the International Energy Agency and the Organisation of Petroleum Exporting Countries that underpins the IEF Charter. The first pillar of this joint programme is the shared analysis of energy market trends and energy outlooks. The IEA, IEF and OPEC held their first Symposium on Energy Outlooks in Riyadh in January 2011, with the objective to improve the clarity and understanding of the various short-, medium- and long-term outlooks, particularly those of IEA and OPEC. It turned out that there was more consensus between IEA and OPEC on the oil market outlook than is often acknowledged in the press. However, it was recommended to move “towards harmonising definitions, where possible and appropriate, and disclosing more data, in a more timely manner, to enhance comparability between the outlooks.”

Obviously, as noted before, things have changed significantly since early 2011. Analysts have identified a host of factors that may have contributed to the increase in prices and in volatility, ranging from increased financial market activity to unanticipated strong demand in Asia and quality demand/supply mismatches following the loss of Libyan sweet, light oil, as well as overestimated geopolitical concerns. Some producing countries attempted to bring back more stability by increasing production and a group of consuming countries released some of their emergency stocks. However, despite these efforts, oil prices are more volatile and currently at more elevated levels than in 2010.

Meanwhile, it is worth pointing out that the fundamentals of oil demand and supply for 2011/2012 still look relatively comfortable. Both IEA and OPEC still project oil demand in 2011/2012 to grow in step with oil supply, with OPEC’s remaining spare capacity at adequate levels (around 4 mb/d). In addition, there is ample spare capacity downstream and commercial inventories remain high.

Furthermore, we see, for now, no major change envisaged in the medium term supply/demand balance for 2015/2016. Significant oil investment projects are under way in both OPEC and non-OPEC countries and oil demand does not seem to grow significantly faster than projected supply. Producing and consuming countries are both committed to step up efforts to improve energy efficiency, as this will help dampen demand growth and thus improve the demand/supply balance. Similarly, producing and consuming countries are fully aware of the importance of facilitating adequate investment, both upstream and downstream, in a timely manner. IEA, IEF and OPEC are working closely together in moving towards greater harmonisation of definitions and disclosing more data, in a more timely manner, to enhance the comparability of the outlooks. They will provide more transparency on their respective publications on the outlook for 2012.

Physical and paper oil market linkage

The second pillar of the IEA/IEF/OPEC cooperation programme is the linkages between physical and financial energy markets. A first joint workshop was held in November 2010 in London, back to back with a Regulators Forum. This event showed a continuing divergence of views on the implications of the emergence of oil as an asset class for the physical oil market. However, there was a consensus on the need for greater data transparency in both the physical oil market (in particular on oil inventories) and the financial oil market (in particular the OTC market), the need for strong international coordination of regulation and the need to continue the horizontal dialogue between physical and financial oil markets (including the regulators). Again, we have seen changes since the end of 2010 in this area.
If anything, the interaction between the physical and financial oil markets seems to have intensified in 2011, with paper oil market trading reaching new record levels. At the same time financial regulators (CFTC, FSA, EU and others) around the world are designing important new rules for paper oil markets which may have a significant impact. This underscores the need for further improving data transparency in both the physical and financial oil markets, international coordination of regulation and continued physical-financial market dialogue. IEA/IEF/OPEC cooperation on physical and financial markets’ linkages and energy markets regulation will be taken forward in a new joint workshop and Regulators Forum in November 2011.

**Improving data transparency**

There is an urgent need to significantly improve the performance of countries in providing timely, complete and reliable data to the Joint Organisations Data Initiative (JODI) on oil, as well as on natural gas. Despite repeated assurances of their commitments to this issue, the actual performance of the nearly 100 JODI-participating countries on delivering better monthly oil data has lagged. JODI is coordinated by the IEF and its partner organisations include APEC, IEA, EU, OLADE, OPEC and UNSD. The JODI organisations will have to step up the pressure on those countries failing to deliver adequate market transparency. Better physical market data transparency is key to any effort to mitigate energy market volatility. The extension of JODI to cover monthly natural gas data is well under way, including cooperation with the Gas Exporting Countries Forum (GECF), and will hopefully result in the first launch of JODI-gas to the market before the end of 2011.

The extension of JODI to annual oil data on upstream and downstream capacities and expansion plans will start with oil and is currently under way, with first results expected at the earliest in 2012. This extension is very important to improve the visibility of the medium-term demand/supply balance in the oil market.

The G20 group of countries has requested the IEF, IEA, OPEC and IOSCO to produce a joint report on how the oil spot market prices are assessed by oil price reporting agencies and how this affects the transparency and functioning of oil markets. This report will be submitted to G20 Finance Ministers by October 2011. In addition, the G20 asked the IMF and IEF, in cooperation with IEA, OPEC and GECF to develop by October 2011 concrete recommendations to extend the G20’s work on oil price volatility to gas and coal. It is too early to elaborate on the content of this work in progress. However, it is interesting to note that the IEF, as the neutral facilitator of the energy dialogue and the most global international energy body, is becoming more involved in the G20 energy work.

**Facilitating NOC-IOC cooperation**

A final focus on a couple of key topics that the IEF is also currently working on. NOC-IOC cooperation has been identified as of crucial importance to improve the global energy investment climate and meet the huge investment challenge of nearly US$33 trillion up to 2035. The IEF has organised two NOC-IOC Fora (2009, 2011) which have underlined the need for innovative long-term partnerships based on mutual trust and respect. In an increasingly demanding environment, NOCs and IOCs need to explore new models of cooperation that go beyond simple resource development, and integrate host country’s expectations, such as economic development, technology transfer, infrastructure development and support of the local economy. Building on the findings of the last NOC-IOC Forum in April 2011, we will work with the IEF’s Industry Advisory Committee to formulate a set
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of general principles or best practices defining successful cooperative schemes between NOCs and IOCs. These guidelines will be presented to the 13th IEF Ministerial and 5th IEBF meetings in Kuwait in 2012 for discussion and endorsement.

Energy efficiency is the fastest, cheapest and cleanest way to meet the world’s energy demand and enhance energy security for both energy producing and consuming countries alike. IEF acts as a platform to engage developing countries in the effort to harvest the huge potential for improving energy efficiency in order to curb the demand growth. In many emerging economies the demand growth pushes up oil and gas imports as well as emissions. In most oil and gas producing countries domestic demand growth is increasingly crowding out the potential for growth of oil and gas exports to world markets. In all developing countries, the issue of sound energy pricing and the tackling of inefficient, wasteful energy subsidies in a socially responsible manner needs urgent attention. On the basis of the findings of an IEF Symposium held in Jakarta (June 2011), the IEF Secretariat will report to Ministers at the 13th IEF in Kuwait in 2012 on concrete recommendations on how to improve energy efficiency in both producing and consuming countries.

Energy poverty remains one of the world’s most urgent problems. The fact that more than one billion people lack access to electricity and modern cooking fuels inhibits economic and social development and the achievement of the Millenium Development Goals, particularly in Sub-Saharan Africa and South-East Asia. With roughly one-quarter of the IEF membership from developing countries, energy poverty will stay high on the agenda of the IEF, and will be discussed at the 13th IEF in Kuwait in 2012, on the basis of results from an IEF symposium in Vienna in November 2011.

With the new mandate provided by the IEF Charter, the IEF Secretariat will work hard to deepen and enhance its role as a neutral facilitator of the global energy dialogue. Working together with all relevant international organisations, including the big sisters IEA and OPEC, as well as with industry (both NOCs and IOCs), we will do everything we can to deliver concrete results to the G20 on their requests and, first and foremost, to the 13th IEF Ministerial Meeting in Kuwait in March 2012.
Eurasian Pipelines: From Beijing to Berlin

BY JOHN ROBERTS
ENERGY SECURITY EDITOR, PLATTS

Turkmenistan’s gas flows east to China, north to Russia and south to Iran. In the past Turkmen gas has reached as far west as Germany and, there are serious plans for it to do so again. From one field alone, South Yoloten, it has the capacity to supply large volumes of gas from Beijing to Berlin, from Amritsar to Zagreb.

But there is a whole series of paradoxes concerning the development of the vast span of pipelines that stretch from one end of Eurasia to the other. One is that Russia, the world’s biggest gas producer and the holder of the world’s largest gas reserves, is now focusing at least as much on developing new ‘bypass’ pipelines – lines that essentially replace existing pipeline systems across transit countries that Russia now prefers to avoid – as on development of actual fields to ensure that new lines carry new gas to market.

Another is that Iran, holder of the world’s second largest gas reserves, remains a net importer, its export ambitions thwarted as much by its own internal consumption as by international sanctions. A third is that Turkmenistan, owner of the world’s largest onshore gasfield, considers that it is for others to develop the pipelines that might carry its output to international markets.

The net result is that companies or consortia seeking to develop pipelines in Eurasia have to be incredibly determined to overcome a welter of political and commercial obstacles. And of these, the China National Petroleum Corporation (CNPC) is clearly the most determined. In 2012 gas from Turkmenistan is scheduled to reach Hong Kong. To get there, it will have to pass through a complex set of interlocking systems, notably the Trans Asia Gas Pipeline (TAGP) from Turkmenistan to Western China, the newly revamped and enlarged West-East pipeline in China; then its spur to the south-east of the country; and finally the 293 km sub-sea line from the mainland to the Special Administrative Region of Hong Kong, currently under construction.

All these have been or are being developed by CNPC. Indeed, ever since it began building the West-East system a decade ago, CNPC has been at the heart of some of the biggest pipeline projects in the world. In July 2007 it signed an agreement to build the 2,200-km TAGP from Turkmenistan through Uzbekistan and Kazakhstan to Urumchi in Xinjiang. In December 2009, less than 30 months later, the first Turkmen gas entered China. By 2015, the TAGP’s twin 20 bcm/y (billion cubic metres a year) lines are expected to be carrying close to 40 bcm/y of gas from Turkmenistan, Kazakhstan and Uzbekistan to China. In addition, plans are in hand for a third 20 bcm/y string.

But Turkmenistan is not CNPC’s only focus, and CNPC is not alone in focussing on Turkmenistan. CNPC is also developing the twin oil and gas pipelines intended to link the Burmese port of Kyaukphyu (Sittwe) in the Bay of Bengal with Kunming in China’s Yunnan province at a cost of around US$2.5bn. These lines have the advantage that as well as enabling China to tap into Burma’s own gas resources, notably the offshore Shwe field, it can also by extension use Burmese ports to bring oil from the Middle East and Africa to south-west China without passing through the Malacca or Sunda straits. Pipeline construction officially began in October 2009. The 771-km, 12 mt/y (240,000 b/d) oil pipeline will terminate at Kunming, Yunnan’s capital, while the 12 bcm/y, 2,800-km gasline will extend much further into the heart of China, to Guangxi.

The Chinese projects may yet be matched by the emergence of a new pipeline system intended to carry gas from the Caspian to Europe. At the time of writing there was no indication as to which of the contenders seeking to secure Azerbaijani gas for their various pipeline projects would actually win the approval of the developers of Azerbaijan’s giant Shahk Deniz gas field and of the Azerbaijani government itself.

But the very fact that a connection is to be made to Europe reopens the question of whether Turkmenistan will find a way to plug its gas resources into such a system. Ashgabat has always viewed the opening of the TAGP as one stage in a process of developing what it terms a multi-vector policy for its gas exports. It needs such a policy because of South Yoloten, a field which is now thought to contain at least six trillion cubic metres (tcm) and – quite probably – around three times that amount. At the time of writing, fresh audit figures for the field were still awaited. But at 18 tcm, only the 34.6 tcm reserves in the giant offshore North Field/ South Pars resource shared by Qatar and Iran in the Gulf would be bigger, while South Yoloten would come close to accounting for one-tenth of the world’s total gas reserves.

So it is no wonder that the Turkmens are also keen to develop a variety of new export pipelines. Their immediate priority is development of the 1,760-km, 33 bcm/y Turkmenistan-Afghanistan-Pakistan-India (TAPI) pipeline, a project being jointly developed by the four countries concerned. The Asian Development Bank is providing significant technical backing but actual implementation has to await an improvement in security conditions in
Afghanistan. Security issues are also likely to impact on both Iranian proposals for a major new gas pipeline to cross Iraq and Syria and on Iraqi plans for both oil and gas pipelines to reach new export terminals on the Mediterranean and to link up with the existing Arab Gas Pipeline that carries Egyptian gas to Jordan and Syria.

What happens to Iranian and Iraqi gas has an impact on plans for Caspian gas exports to Europe – and thus on proposals for major pipeline projects to Europe. The biggest of these projects, Nabucco, was originally predicated on the concept that it would carry gas from both Azerbaijan and Iran through Turkey and the Balkans to the Central European gas hub at Baumgarten in Austria, although in recent years Iran was replaced by Iraq as a prospective supply source. Azerbaijan’s choice concerning export routes for its gas was not known at the time of writing, but what was clear was that whatever choice Baku made to carry gas from the giant second stage of the Shah Deniz Gas field to market, its implementation would raise the question that if Azerbaijan could export large volumes of gas to Europe without passing through Russia, then why could Turkmenistan not follow suit?

**Possible Trans-Caspian pipeline**

For Turkmenistan to achieve this goal requires construction of a trans-Caspian pipeline, and that is exactly the goal that Turkmenistan and the European Commission hope to achieve negotiations planned for the autumn of 2011.

The reason the Turkmen require the development of a large scale – say 30 bcm/y – Trans-Caspian Gas Pipeline is because the country is still suffering from the loss of most of its exports to Russia in the wake of what can only be described as the engineered explosion of 9 April 2009 on the main line carrying Turkmen gas to Russia. Russian technicians, wanting to reduce the flow of Turkmen gas exports to Russia, gave their Turkmen counterparts insufficient time to close down input, resulting in a build-up of gas that caused an entirely predictable explosion. The long term consequence was that when Turkmen exports were eventually resumed nine months later, it was at a rate of around 10-11 bcm/y, in contrast to annual rates of around 30-40 bcm anticipated by Ashgabat. So Turkmenistan, whose gas in Soviet days fuelled the first giant pipelines to western Europe, now faces a real prospect that it could wind up selling less gas to Russia than it does to China or even Iran – and thus needing a trans-Caspian line to reach European markets if it cannot reach agreement with Moscow on access to the Russian pipeline system for access to markets beyond Russia.

As for Russia itself, it is pressing ahead with both its Nord Stream and South Stream projects. The first string of Nord Stream, a 1,200-km pipeline through the Baltic from Russia to Germany, is already operational although not carrying anything like its 27.5 bcm capacity. But it does fulfill a major function for Russia in providing it with direct access to the EU without having to transit other countries, an important issue in the wake of major disputes with Ukraine in 2006 and 2009.

In 2011 Gazprom has been busy setting up a formal corporate structure for South Stream which has still to signify specific routes, costs or projected volumes for a system intended to link Russia with Southeastern Europe and Italy. In 2009 the CEO of Eni, the Italian partner in South Stream, put the cost of the project at €25bn and said it was intended to carry 63 bcm. Since then, Marcel Kramer, South Stream’s CEO, has been more cautious concerning potential costs, whilst noting that only one-third of the line’s capacity would likely come from new fields.

Although Eurasian pipelines are often seen in terms of big projects for lines extending for thousands of kilometres, a key element is the massive development of a host of distribution lines at either end of the Eurasian landmass. These are the internal systems that serve the giant Chinese and European Union markets, epitomised by the link to Hong Kong and the multiplicity of small-scale interconnectors and regional lines in central and southern Europe intended both to bring gas to wholly new markets and to ensure that, in a crisis, no EU member state is solely reliant on just one single supply system.

There is one last peculiarity of Eurasian pipeline proposals that is worth considering. Pipelines are usually considered the alternative to plans for maritime transportation in the form of liquefied natural gas (LNG). Eurasian producers may be changing this paradigm using pipelines to carry gas from fields located in one country to LNG facilities in another. Azerbaijan is considering doing this with an LNG facility on Georgia’s coast, and a shuttle fleet of LNG tankers in the Black Sea to carry the gas to Europe. Turkey has proposed the construction of LNG facilities at Ceyhan, with feedstock coming from both Azerbaijan and Russia – and possibly even Iran. For the time being, pipelines remain the preferred choice for evacuating gas from the landlocked states of Central Asia. But it is just possible that at some future date they may also come to serve LNG terminals that would enable Caspian gas to access an even wider range of markets than is possible through current and prospective Eurasian pipelines alone.
Nabucco is Europe’s flagship project in what has become known as the southern corridor linking demand in European markets to the abundant and almost untapped supply of gas in the Caspian region and the Middle East beyond.

As the new gas bridge from Asia to Europe, Nabucco is the first pipeline project that will connect European and Turkish markets and the South East European national grids. Nabucco will run from the eastern border of Turkey via Bulgaria, Romania and Hungary to the Central European Gas Hub near Vienna in Austria and have off-take points in every country. Once completed, the 3,900 km pipeline will have a capacity of 31 bcm. Six shareholders make up the Nabucco consortium: Germany’s RWE, Austria’s OMV, Hungary’s MOL, Romania’s Transgaz, Bulgarian Energy Holding and Turkey’s Botas. Each of them holds equal stakes on the project company.

Increasing demand for natural gas

The issue of supply security is one of the biggest challenges that Europe will have to cope with in the energy sector in the coming years. Further diversification of natural gas supplies and the creation of new transit routes are therefore of the utmost relevance. Consequently, it is crucial that new infrastructure will be established to meet the future growing demand in Europe for natural gas, and thus contribute to a stable and secure future of European energy.

Europe will need additional gas, for in the light of dwindling indigenous gas resources it will have to import more and more of it. According to estimates from the International Energy Agency, demand for natural gas in Europe will rise from the current level of 555 bcm (in 2008) to 653 bcm in 2030. According to the IEA the reasons lie in the increasing abundance of affordable natural gas, coupled with rising demand for the fuel from China and the fall-out from the Fukushima nuclear disaster in Japan. The latter has called into question the future role of nuclear power and prompted re-evaluation of related policies in many countries, for instance, Germany which has decided to accelerate its exit from nuclear power. Acquiring new sources and suppliers of gas is therefore the right thing to do. In turn, Azerbaijan, Turkmenistan, Iraq and Egypt are developing new gas fields and raising production. These are the world’s richest natural gas regions. They have huge reserves, which taken together are significantly higher than those of all the other regions of the world.

Nabucco is therefore the answer to the energy security challenge outlined above, and consequently will open up a new transport route to Europe. It is also the most viable transport route from the Caspian basin, both logistically and economically, making it more attractive than other alternatives being discussed. Nabucco will enable Europe and Turkey to diversify their energy sources and contribute considerably to gas supply for the next decades.

Nabucco legal framework finalised

The Intergovernmental Agreement (IGA) was signed in Ankara on 13th July 2009 and ratified by all national parliaments by March 2010. It marks an important milestone in the development of Nabucco, as it is a treaty between the governments of the Nabucco transit countries – Austria, Hungary, Romania, Bulgaria, and Turkey - which harmonises the legal framework and grants stable and equal transport conditions for all partners and customers. It is also the first treaty ever concluded between Turkey and EU Member States for an energy project.

The signing of the Project Support Agreements (PSAs) - a bilateral agreement between NABUCCO Gas Pipeline International GmbH and the responsible ministries of the five transit countries - took place in Kayseri, Turkey, on 8 June 2011. The PSAs set out the practical aspects and uniform standards for the construction and long-term operation of the pipeline in each country. The main elements of the PSAs are the affirmation of an advantageous regulatory transit regime under EU and Turkish energy law; the protection of the Nabucco Pipeline from potential discriminatory changes in the law; and support for legislative and administrative actions for the further implementation of the project. The PSAs also mark a commitment by each government to support the project. Together with the IGA, the PSAs are a necessary prerequisite for the successful financing of the project. They create the stable, long-term regulatory regime, which is required by the group of international lenders to secure the financing of one of the largest multi-national gas transmission projects worldwide.

Route selection

The route selection was a complex process in which many different factors have been taken into account; areas with high population density, protected areas and areas with valuable cultural heritage have been avoided as far as possible. In addition existing energy supply corridors will be fully utilized to minimise the impact on the environment. Extensive surveys were conducted to select the route, such as subsoil investigations as well as
geological, archaeological, ecological, social and climatic assessments. A comprehensive Environmental and Social Impact Assessment under strict European standards is currently work in progress by international experts to assure long term cooperation between our pipeline project and the people living along the route.

**Project financing**
In September 2010 a mandate letter was signed by the European Bank for Reconstruction and Development (EBRD), the European Investment Bank (EIB), the International Finance Corporation arm of the World Bank Group, and the shareholders of Nabucco and NABUCO Gas Pipeline International GmbH. The signing of the mandate letter marks the start of the appraisal process of the Nabucco project, a required step towards a potential financing package of up to €4 billion. The current investment figure of €7.9 billion for the Nabucco construction is based on the technical feasibility study. We are currently reviewing our calculations of the capital expenditure estimate in order to better reflect the intermediate results of the Front End Engineering Design and a number of recent developments in the market and adjustments to the technical and commercial parameters. The results of this review will be available in the upcoming months. The investment will be raised from shareholders, international financial institutions, export credit insurance companies and the commercial banking market in accordance with internationally recognized social and environmental standards. 30 per cent of the investment will be funded by the shareholder consortium and 70 per cent by lenders.

**Project status and next steps**
As soon as gas commitments will be negotiated between the suppliers and the Nabucco shareholders Nabucco will start with the open season process and the final investment decision will be taken by the shareholders. Before construction will start, detailed planning as well as the Environmental and Social Impact Assessments (ESIA) must be finalised. The ESIA process is currently ongoing and the long lead items such as line pipes, bends and valves will be ordered in a transparent tender process after the final investment decision will have been taken. Nabucco already carried out a pre-tender process where potential suppliers from around the world participated and the best companies were identified. This assures that the actual tender will be carried out most efficiently.

Pipeline projects such as Nabucco, which open new sources for gas traders and customers, are of crucial importance in terms of more diversification and greater market liquidity. Nabucco offers the opportunity to negotiate long-term transport contracts with a pre-arranged tariff structure. That is an important incentive for investors. 'Open Season' is the name of the process for reserving capacity. It consists of two phases. In the first phase, shareholders will be given the opportunity to reserve a total of 50 per cent of the transport capacity. In the second phase, it will be possible for third party market participants to reserve capacity on the same terms. This means that 16 bcm of transport capacity every year will be offered to third parties.

In sum, Nabucco provides Europe with a unique opportunity to obtain gas directly from Central Asia, rather than via alternative routes. We must now utilise this mammoth opportunity. The shareholders will be negotiating gas supply contracts with potential gas supply countries in the coming months and thus a further foundation for a decision on construction by the shareholders is laid. Start of construction is planned for 2013. First gas will flow from the eastern border of Turkey to the Central European Gas hub in Austria in 2017. The southern corridor between the Caspian region, the Middle East, Turkey and Europe will then be a symbol for a new and viable partnership. Or as European Commission president Jose Manuel Barroso put it so succinctly: “Gas pipes may be made of steel, but Nabucco can cement the links between our peoples.”
P resident Barack Obama came to office in 2009 promising to do his part to stop global warming. Two years later, not only has Congress failed to pass any comprehensive carbon-reducing energy policy, but Mr Obama even failed to put solar panels on the roof of the White House by summer 2010 as he had promised. For their part, environmentalists have been focusing their anger on a project they fear will actually increase carbon emissions. The project — the Keystone XL pipeline from Alberta’s oil sands across the US to Texas refineries on the Gulf Coast — would be the third such pipeline importing what environmentalists always refer to as tar sands.

According to the IHS CERA consultancy, on a life-cycle basis fuels produced solely from oil sands result in 5 to 15 per cent more greenhouse gas emissions than the average crude oil refined in the US. But it also points out that the Canadian oil sands are poised to become the largest single source of foreign oil to the US market and building the pipeline will mean new jobs. The proposed US$7 billion Keystone XL pipeline is among the biggest “shovel ready” projects in the US. At a time of weak economic growth and high unemployment, the question is whether the Obama Administration will put what environmentalists dismiss as the short-term gain in jobs before emissions, particularly when, they say, clean energy jobs are a more secure and long-term path for economic recovery.

The US Department of State must make a decision which route to take by year’s end. The last time Secretary of State Hillary Clinton was put in this position – less than a year after President Obama had taken over, in August 2009 – she approved the Alberta Clipper pipeline to carry oil-sands fuel from Canada into the US, saying, “approval of the permit sends a positive economic signal, in a difficult economic period, about the future reliability and availability of a portion of the United States’ energy imports.” The State Department noted the project would provide construction jobs for US workers. But this time around environmentalists insist the US already has two pipelines (the first was approved by the Bush Administration) bringing in oil sands fuel and does not need another. “We’re already taking as much oil as Canada can give us,” said Susan Casey-Lefkowitz, international programme director at the Natural Resources Defense Council, the environmentalist group.

Pipeline critics point to a series of spills from the first Keystone pipeline in its first year of service, which led US authorities to suspend its operation temporarily in summer 2010. TransCanada, which operates the pipeline, gained approval to restart the Keystone pipeline within a few days and responded to concerns by noting the last incident, at a pumping station in Kansas, had involved less than 10 barrels of oil. “Almost all the oil releases over the past 12 months on Keystone have been minor – averaging just five to 10 gallons of oil,” according to Russ Girling, TransCanada’s president and chief executive. But that the first Keystone has suffered 12 spills in its first year remains a worry for Ms Casey-Lefkowitz, who fears they are the result of the highly corrosive nature of bitumen in the oil sands. This is of particular concern, she says, because the Keystone XL is to cross the Ogallala Aquifer, a freshwater source for eight states. “This is one issue where the president has total control — he has to grant or deny the necessary permits,” according to Bill McKibben, an environmental activist. “Congress can’t get in the way. It’s where Obama can get his environmental mojo back. But we need him to lead.”

The problem for critics is that the US has set a precedent by approving two previous pipelines to funnel oil sands into the US. Jim Vines, partner at King & Spalding in the Energy Environmental Practice, says it would be tough for the State Department to reject the Keystone XL on the grounds that it is any different. “Given high gasoline prices combined with high unemployment,” he said, “the public will demand convincing evidence in the public record that the Keystone XL is ecologically unsound before they buy the anti-oil sands environmental rhetoric.”

Yet a growing number of officials have spoken out against the 2,673km oil pipeline, including the mayors of 25 towns and cities, who wrote a letter on March 24 to Mrs Clinton, expressing concerns about additional tar sands oil imports: “We are concerned that expansion of high carbon projects, such as the proposed Keystone XL tar sands pipeline will undermine the good work being done in local communities across the country to fight climate change and reduce our dependence on oil. “The oil industry believes, despite the outcry, the pipeline will get built. Jim Mulva, chief executive of ConocoPhillips, said, “It’s very important to energy security. Any delay in infrastructure development has an impact on the flexibility of supply.” Given the rise in oil prices, spurring the International Energy Agency to release strategic petroleum reserves this year, there is no doubt energy security has grown in importance for the Obama Administration.

However, that it is a high priority has not translated into permitting unfettered drilling in the Gulf of Mexico,
which regulators have scaled back significantly since the Macondo disaster. And it has not meant promoting the use of natural gas with subsidies and incentives despite the rapid growth in supply brought on by technological advances. Indeed, the US has so much natural gas in the lower 48 states that it is moving to export it. And plans to bring gas down from Alaska through a massive US$35bn pipeline are at real risk. However, in terms of natural gas, one of the two competing plans, by BP and ConocoPhillips, was cancelled in May after the oversupply of gas from shale pushed down prices so low there was insufficient demand for Alaska gas from gas shippers.

The other project, involving TransCanada, the Canadian pipeline company, and ExxonMobil, is moving ahead. Rex Tillerson, ExxonMobil’s chief executive, has said the company still is interested in building a pipeline to bring gas out of Alaska down to the lower 48 states. “The gas has basically been developed,” Mr Tillerson said. Oil companies have been pushing it back down into the ground to aid in enhanced oil recovery and could just as easily put into a pipeline and send it out of the state. “It would be a supply that would be available for years and years,” he said. The big hurdle in accessing that supply in the lower 48 states remains Alaska’s fiscal regime, which is uncertain, in addition to the regulatory and technical challenges involved in building the pipeline itself. But if that can be overcome, Mr Tillerson has said he believes “the gas can be competitive.”

Whether the pipeline to get that gas down from Alaska to the lower 48 states will ever be built remains to be seen. Ms Casey-Lefkowitz notes tar sands development uses natural gas for fuel: “There are valid concerns that expansion of the tar sands will mean Alaska natural gas feeding into Alberta and being used there as fuel. That means using a relatively clean fuel to make a dirty fuel and less natural gas coming to the US.” But the merits of that is an argument for another day. For this year, the focus of both environmentalists and the energy industry is on the Keystone XL – a pipeline whose fate rests solely with the priorities of the Obama Administration.
Tanker owners weather stormy economic conditions

BY JULIET WALSH
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That 2011 has been a tough year for shipowners is well documented, with earnings across all sectors coming under varying degrees of pressure. The flow of new ships into the market has continued to outpace demand, and the inevitable result is lower spot freight rates, as competition for business increases. Add to the mix net increases in bunker costs over the year to date, and owners’ margins in some sectors have been reduced to zero, and have even at times slipped into negative territory.

Focusing on the crude tanker market as an example, estimates have suggested that the fleet will expand at up to twice the rate of demand in 2011. Tanker rates are at their lowest since 2008 in broad terms, and as tankers ordered in happier economic times through 2007-2008 enter the market this year, they are finding returns falling far below the necessary levels to repay the debts incurred. Breakeven levels on Suezmaxes (130-145,000 tons) and Very Large Crude Carriers or VLCCs (260-280,000 tons) ordered three to four years ago have been calculated in the US$46-48,000/day range, based on timecharter equivalent measures. Falling Worldscale spot rates and increased costs have led to earnings coming down to around US$2-3,000/day in the middle months of this year, leading many to predict bankruptcies among owners.

The industry’s confidence level has slumped, and coupled with the increased post-credit crisis struggle to find funds for new investment or to shore up existing operations, the pressure on owners is intense. There has not yet however been a major cull among ship owners and as shipping company shares have been low for some time without their becoming the prey of creditors or of acquisitive companies, there have at least been some cautious suggestions that most shipping companies will manage to ride out the current storm.

Beyond current financial woes, one of the clouds hanging over tanker markets is the growth of the Chinese shipping fleet, and the stated aim of the Chinese government that by 2015 half of oil imports into China will be carried on Chinese-built tonnage. It is estimated that China’s oil demand for oil imports will increase as a percentage of total consumption from around 50 per cent to 65 per cent, but that the increase in its VLCC fleet will be sufficient to cover the increased demand, and to meet the government’s target comfortably.

Growth in the Chinese fleet is already being felt by owners traditionally working the Mideast Gulf-China route, among them European owners in Greece and Norway. So while increased demand from both China and India should help the shipping market, this may be somewhat offset by China’s huge expansion of its own VLCC fleet.

One of the routes ship owners could take to relieve the oversupply in the market is to increase the scrapping of tankers well before they reach the 15-year cut-off point where a vessel is deemed properly to be old. The global fleet is, however, now relatively young, after a round of scrapping of single-hull ships in 2009-2010 took a large number off the market, while the rate of new build has only increased in the past few years.

Just two years ago, around 35 per cent of the world fleet was less than ten years old, and now up to 65-70 per cent of the total are under ten years old, which clearly limits the prospects for using an earlier cut-off point for taking ships into the demolition yards. While there is still a market for ships up to 25 years old, most oil companies have already taken the step of not chartering or receiving vessels which are more than 15 years old. But, despite this, the rate of new ships coming into the market has still markedly reduced the average age of ships employed in the international oil trade. Falling prices for older ships for demolition also weakens owners’ incentives to scrap them, and the number of ships of all sizes heading for demolition is set to fall in 2011.

As awareness grows of the part the shipping industry must play in the goal of reducing emissions – and as costs have risen due to higher bunker fuel costs – slow-steaming has become more prevalent. More than 200 ship owners have slowed their vessels down from 25 knots to 20 knots. At least one ship owner has adopted the super-slow steaming approach, reducing ship speeds to 12 knots, with fuel consumption and therefore emissions reduced by up to 30 per cent.

An incidental by-product of slow-steaming is that the increased duration of voyages increases a vessel’s utilisation over time. While this means fewer journeys undertaken, it does help to alleviate the oversupply situation, particularly in relation to long-haul routes, and has been used by some owners as a means of improving employment rates of their ships. The loss of potential earnings is offset – in theory at least – by decreased costs and a reduction in the time spent idle waiting for the next charter party to hire their ship.

As rates on many routes for both clean and dirty tankers reached critically low levels in the summer months, talk of laying up ships re-emerged. This involves taking them out
of the market for maintenance or into dry dock, to wait for better times. In practice, few owners have done this because they still have an incentive to keep ships moving, even on slim or non-existent margins.

Some years ago when more of the global fleet was owned by oil majors, the laying up of vessels was more commonplace. But now, with owners in many cases in debt to financial institutions, their creditors take the view that a small repayment on their loan is better than nothing at all. In some cases ships are fully paid for when they come into the market, and owners are not compelled by financial backers to keep their ships moving. But while in theory laying up a ship and taking it out of circulation could be a reasonable response to poor margins, in practice most owners appear to take a dogged approach, put their heads down, and try to stay in the game.

Looking ahead to possible structural changes in the shipping market, the expansion of the Panama Canal has been much vaunted as good news for tanker owners, as it widens the range of ships able to make use of the canal. Larger ships should be able to take advantage of increased Latin America demand for products, and the higher demand from China for crude. Crude exports from Venezuela and Brazil to the US west coast would also become logistically easier, as well as to Asia generally. But improved logistics may prove academic, if demand for the grades of crude available does not line up with the preferences of refiners in the respective regions, and if canal transit tolls were to rise significantly in order to recoup from the market the cost of expansion.

**The growing problem of piracy**

Piracy represents a growing problem for owners, as attacks have increased in number overall this year, as well as specifically those on oil tankers. In the first half of 2011, the International Maritime Bureau’s (IMB) Piracy Reporting Centre said that 100 out of 266 piracy attacks were targeted at oil tankers. The total of 266 was an increase of 70 over the same period in 2010, but the proportion of the total accounted for by tankers was more or less unchanged, at 37 per cent. Somali pirates carried out 163 of the total 266 attacks, placing them at the top of the league table in terms of the proportion of attacks attributed to them. Ship owners have been faced with higher costs both to insure their ships, and to increase the security of crew and cargo at sea. Armed guards on ships are now commonplace, and while the piracy problem continues to mount, there has been some evidence that the steps taken by owners are having a positive impact.

The IMB Piracy Reporting Centre research showed that while the number of attacks by Somali pirates has increased, the number of successful hijackings fell in the first half of 2011, compared with the same period in 2010. Increased naval intervention and the processes which contribute to ‘vessel hardening’ – the steps taken on board to repel attack – are thought to be behind the fall in the pirates’ success rate in the first half of the year.

Another small positive for the tanker market in 2011 which could contribute to a longer-term reversal of fortune is the slower than expected rate of deliveries of new ships to the market. Taking VLCCs as an example, around 47 were due for delivery in the first half of 2011, but estimates suggest only around 34 came into service. In some cases plans were put on hold, and in others plans were changed. Several VLCC orders have been converted into orders for LNG ships for example, reflecting the relative strength of that market against crude oil. In general across the tanker sector, new orders are shaping up to be lower this year than the average for the past two decades. This should eventually see a narrowing in the gap between ship supply and demand growth.

If, and it remains a large ‘if’, some bankruptcies do result from the year’s travails, this could allow for a period of consolidation and companies merging to create a more coherent market. One of the reasons the markets struggle in tough economic times is widely felt to be the huge spread of owners with different agendas, differing approaches to best practice. A less fragmented market in terms of ownership of the fleet would probably be beneficial long term.

But bankruptcies may not result on any meaningful scale. Owners taking the long view – which holds that the market operates on a 25 year cycle, not a five year plan – will hunker down, and try to find a way to get through hard times. There remains plenty of despondency, not only among owners, but more widely among brokers and even charterers of oil tankers. Depressed demand obviously means less business and less commission for brokers. Even charterers, once they take a step back from their immediate aim of getting the best deal on a given day, will concede that a sickly shipping market ultimately harms everyone, not least because slow demand points to a wider malaise in the international market for oil, but also because the market needs strong owners who maintain high standards within the industry, all of which comes at a cost.
Building a truly sustainable energy system

BY ARON CRAMER
PRESIDENT AND CEO, BSR

The world’s economy is undergoing several fundamental transitions at the same time, from a rebalancing of political and economic influence, to the digital revolution, to massive urbanisation. Underlying all these changes is the drive to ensure an energy system that enables economic growth for the planet’s growing population with sharp reductions in carbon intensity.

The public debate over this is often sterile and facile, characterised by false choices that obscure the overarching truth: simultaneous action is needed on a number of fronts. Charting a path to a sustainable energy future depends on five key tracks: (1) innovation, (2) efficiency, (3) consumer engagement, (4) public policy, and (5) financial market reform.

Energy companies that create strategies based on this model will be best positioned for a world in which carbon-intensive energy becomes more expensive and less politically acceptable. Companies that fail to make this shift may find themselves on the wrong side of this great transition, risking social and political opposition that could be hard to overcome, and relying on products and technologies that may no longer be viable. Several leading energy companies are actively investing in exactly this kind of comprehensive approach, although greater acceleration is needed to achieve anything like the goals established by many countries in recent years.

Innovation: New forms of energy are clearly needed if the engine of economic growth is to continue, and continue sustainably. Unconventional oil is receiving much attention inside in the industry, and renewables are considered essential to a low-carbon future. And while unconventional oil has a role to play, the overall mix will only change if renewables gain more market share. One key to making this happen is innovation.

It is clear that the energy mix will need to change to achieve both economic and environmental objectives, and innovation will be a big part of this story. The way this innovation happens is as noteworthy as the innovation itself. One of the unique features of innovation in the 21st century is how “co-creation” of innovative solutions is growing more important – and more widespread. In recent years, we have seen some non-traditional partners join forces to drive innovation faster, further. Examples range from Shell and Cosan’s new biofuels venture, Raizen, and Total’s purchase of SunPower, a leading solar energy producer, as well as many others. There remains scepticism about how committed industry incumbents are in following through on these investments. Given the industry’s long history of joint ventures and cost-sharing, it is positioned very well to embrace the era of collaborative innovation, so long as these efforts are directed towards cleaner forms of energy.

Efficiency: The energy industry has also made great strides in efficiency. While many sustainability strategies are presented as “win-win” solutions when in fact they may not be, efficiency is undeniably beneficial both economically and environmentally. In 2009, McKinsey & Co. released a well-received study that estimated that the United States alone could save US$1.2 trillion by 2020 through reasonable energy efficiency measures, with 40 per cent of these savings available from industrial operations. This survey, and many others like it, asserts that as much as 35 per cent of energy produced in the United States is wasted, with smaller, but still substantial amounts wasted in other economies. Industry observers agree, with ExxonMobil for example saying that efficiency “is one of the largest and lowest cost ways to extend our world’s energy supplies and reduce greenhouse gas emissions.” Indeed, the IEA estimates that 80 per cent of reductions in carbon emissions through 2030 can be achieved through efficiency measures.

This is why companies like Petrobras have invested in efficiency measures that it estimates to have reduced carbon emissions per unit of energy consumed by 20 per cent, according to IPPECA (the International Petroleum Industry Environmental Conservation Association). Chevron reports an overall increase of 33 per cent in energy efficiency in its global operations since 1992. More is needed, and the phase-out of flaring is one step that the industry can accelerate to achieve even greater efficiency gains.

Consumer engagement

The other aspect of efficiency that receives little attention, but is quite interesting, is how leading companies encourage consumers to use less. Chevron’s “Will You Join Us” campaign and Shell’s “Let’s Go” campaign have blasted a trail with the general public to get them to use less of these companies’ core product – an unusual but highly valuable effort to moderate sales of a core product.

The importance of public campaigns to reduce energy use is crucial. With mature economies facing an era of economic stagnation, and rising economies straining to maintain growth without incurring economic or environmental...
collapse, finding new ways to enable consumer efficiency is absolutely necessary, especially in rising economies where millions of “new consumers” enter the marketplace every year. It is therefore essential to shift from a sterile debate about more or less consumption, to one that promotes better ways of delivering value to more and more people across the globe. Doing this also requires investment in infrastructure in smart buildings, smart meters, and new pricing and taxation schemes to enable and incentivise smarter behaviour that saves consumers money.

Public policy
Virtually everyone walked away from recent United Nations climate summits disappointed, and disagreement between governments on whether and how to address climate remains intense. While some see this discord as being in the interest of business, in fact, the failure of policymakers to reach agreement introduces very unwelcome instability into the energy system. Policies are inconsistent both conceptually and in application. Policymakers in mature economies seem more often to respond to telegenic accidents than long-term needs. Leaders of rising economies prioritise economic growth, and seek technology and financial transfers. These positions may well be negotiating stances more than anything, but they have so far locked the global system in stasis.

Business has an interest in promoting long-term thinking in government, something that has been sorely lacking on energy and climate. To do this, business needs to resist the temptation to maximise every single dollar today, in an effort to create a more predictable and wise framework for tomorrow. There are good examples to build on, such as the promotion of regulatory frameworks and disclosure rules for hydraulic fracturing, now being developed in the United States, Europe and elsewhere, the US Climate Action Partnership, and “Combat Climate Change.” Energy companies can also play a role here by encouraging mandates for efficient buildings and transportation systems, which reduce energy demand. And at the end of the day, this also means support for market-based systems that lead to a steady reduction of carbon intensity. Business should embrace such efforts, since they provide the market certainty needed to support investments in innovation.

Reforming financial markets
Finally, one of the fundamental changes needed to enable further gains in CO₂ reduction is the reform of financial markets. Changes in listing requirements for publicly-traded companies would do a great deal to unlock greater potential for the innovation and efficiency efforts already underway.

There are three specific changes that, if adopted, would enable companies to compete on the basis of the long-term shift to a lower-carbon future. First, companies should report on their strategies to address climate risks. This effort is already underway, with the US Securities and Exchange Commission deciding in 2009 to begin considering rules doing exactly that. Second, companies can support the ongoing integration of financial and sustainability reporting, as a way of promoting greater awareness both with investors and within their own companies of the links between investments today in a lower-carbon future and a competitive future. Finally, companies in the energy sector can join efforts to puncture the view that short-term shareholder advantage is the sole way to define fiduciary responsibility.

This agenda is a broad one. The energy industry’s future rests on its ability to develop energy in more technologically complex, environmentally sensitive, and politically challenging environments. But all of the technological prowess in the world won’t get the job done without an equal commitment to addressing these “soft” aspects of the overall energy system. Companies embracing the five dimensions presented here will strengthen their ability to proceed with their core business, and will also be the ones that shape a future that delivers on the vision of sustainable energy the world needs to achieve comfortable and dignified lives for all.
For the past two years, in my work for Revenue Watch, I have advised parliamentarians in African and Middle Eastern nations that have recently discovered oil or recently discovered democracy, providing training to members of parliament (MPs) and helping analyse oil policies and legislation. I was motivated by the conviction that parliaments are central to good governance, representing the voice of the people, making laws and holding the executive to account. I still believe that, but the complex challenges posed by oil wealth in today’s Africa and in the emerging Middle Eastern democracies means parliaments across the continent struggle to fulfil these roles.

Oil governance is founded on the principle that petroleum rights are vested with the State on behalf of its citizens and that the State’s primary role is to maximise the benefit from the exploitation of the subsoil resources to the owner of the resources – its citizens. The rulers of the state, i.e. its Government, or Executive, is responsible for making the policies that achieve this goal whilst the Parliament is responsible for making the laws that enact the policies. The Government creates and enables a series of institutions, typically a National Oil Company and a Regulatory Body to implement policy and ensure the legal and regulatory framework is complied with. The Executive is accountable to Parliament, and ultimately its citizens, for the effectiveness of its policies and their implementation. Parliament therefore plays an essential role in the governance of a nation’s petroleum.

It can be easy for rulers in oil-rich nations to become detached from those they rule as oil revenues flow in centrally from companies rather than through popular taxation. The events of the 2011 Arab spring with the pro-democratic popular uprisings in Tunisia, Egypt, Libya, Syria and Yemen (all countries with substantial oil endowments) emphasise that the accountability of rulers to those they rule is an essential requirement for stability in oil producing countries. For Egypt, Tunisia and Libya a functioning parliament trusted by its citizens will be essential if democracy is to be effective. So what lessons do I draw from my work with parliamentarians?

In Uganda a billion barrels has been discovered in the Lake Albert region on the border with the Democratic Republic of Congo. The next step is to agree a development plan that maximises the benefits to the owners of the resource (the Ugandan people) and delivers a return for the providers of capital and know-how (the foreign oil companies). However, Uganda has still to create the necessary legal and regulatory framework and the regulatory institutions. In Ghana some two billion barrels have been discovered since 2006 and production started in December 2010 and is currently around 80,000 barrels per day. Production started before oil management laws were passed and before infrastructure to exploit associated gas was built. In Iraq, the Baghdad Government has signed contracts with foreign oil companies to increase production to 12 million barrels per day whilst the regional authorities in Kurdistan have signed separately numerous exploration agreements with no coordination with Baghdad. Iraq has no depletion policy – i.e. how much oil does it need to produce? 12 million barrels is 4 times its historic OPEC quota. Again no national oil policy or law is in place – a draft law has been before parliament since 2007. Why do many parliaments find it difficult to fulfil their function effectively? I believe the answer relates to three failings – lack of information, lack of expertise and a failure to prioritise the ‘National’ interest over self and clan interests.

Two years ago, I was invited by a senior MP from a ruling party in an African country to visit the parliament building after I led an oil workshop for MPs and civil society. His business card listed his parliamentary committee memberships on one side; on the back were his business interests in a school, a hotel and a travel agency.

“You need to be wealthy to be an MP in Africa,” he explained. It seems his constituents expected him to fix things for them – pay for schooling for their children, repair the road to the village etc. So African MPs need to be wealthy, but even this MP found it hard to defend his constituents in a rural area where oil had recently been found. Consequently, some of his constituents were driven off lands they had used for livestock grazing, by outsiders apparently linked to the country’s elite. The MP claimed he had tried to represent their interests but had been subjected to many threats. It was too dangerous for him to continue to represent their interests and he wanted an outside NGO, such as Revenue Watch, to take up their cause. African MPs need not only to be wealthy, but also brave. This is also true in Iraq where each parliamentarian has 30 bodyguards to protect them.

If representing your constituents interests can be challenging for an MP, how about the law-making function? Oil is not a renewable resource and its exploitation impacts both today’s and future generations. Law-making therefore requires a long-term vision for both national development and the role of oil and gas in it. Without this vision,
large oil revenues can be captured for the short-term gain of those in power. However, I have witnessed that achieving a consensus around a long-term vision is often problematic in many African democracies. The Executive may try to curtail debate by submitting laws to Parliament under emergency powers that severely limit the time for scrutiny. Or else, where national policies are unclear or not consensual, laws are submitted to parliament but not passed for years – for example in Nigeria and Iraq.

Tribalism is never far beneath the surface and is a major barrier to achieving a national consensus. For many Africans, tribal allegiances are strong, and identification with the nation weak. The same could be said of Iraq. Crafting unity in a nation created by imposed colonial boundaries remains a distant concept – witness the breakup of Sudan – and often impedes efforts to garner widespread support for a national oil or mining policy. Failed efforts to build national consensus around policy objectives can lead to situations like Ghana’s, where the country has begun oil production without coming to agreement on a national oil policy, instead following an outdated law drafted in 1984 with few regulations to ensure the country derives the maximum benefit from its finite resources.

Another common weakness in African law-making is the lack of detailed technical regulations and enforcement. An oil law on its own is not enough. Oil production is a complicated and hazardous business. Without adequate technical regulations and an effective regulator, countries can take on enormous risks. Regulations and a competent regulator are too often absent. Deep water wells, like the BP well in the Gulf of Mexico that spilled millions of barrels of crude, are regularly drilled off Africa’s shores. Foreign oil companies and their contractors effectively regulate themselves in places like Ghana and Sierra Leone. The lack of explicit regulations gives too much leeway for officials’ discretion in approving activity, and too much risk of their making personal gain from their official position.

Any African or Iraqi MP who wants to hold their government to account for its stewardship of the oil sector will, in my experience, struggle to access oil sector data and often lack either sufficient knowledge of the oil industry or credible research support to analyse what information they could obtain.

Take the example of the billion barrels discovered by foreign oil companies in Uganda. Most Ugandans I met assumed that they had been sold short by either their government or the oil companies. In fact, in my review of the contracts the Ugandan government negotiated, the agreements were tough and compared favourably with other countries. The problem was that MPs did not have easy access to the contracts, which had confidentiality clauses, leaving only leaked copies available. In one workshop in Uganda, there was an angry and long exchange between the chair of the parliament’s Natural Resources Committee and its members, as the chair insisted members had been given access to the oil contracts for review and the members claimed they had not. The argument went on for over an hour and was not resolved. If MPs can’t even agree whether or not they can access the contracts, how can Ugandans have trust in the system? “We don’t need to publish them,” one Ugandan lawyer joked, with telling cynicism about Ugandan governance. “If you pay an official at the Ministry a few dollars they will photocopy it for you. Corruption has some advantages.” In fact, the contracts can now be viewed by MPs in the Parliament library but cannot be removed even though digital copies are available for the oil companies and their advisors. There are so many difficult decisions to make about oil governance and yet so much energy and time is expended fighting for the right to access information.

I am under no illusions as to the challenges MPs face on oil governance – tribalism, vested interests, temptations of personal enrichment, national dissent over oil’s role in development, unenforced regulations, and only nominal power to hold governments to account. However, I have met many courageous and able MPs, hungry for knowledge about oil, who want to make a difference. In Sierra Leone, I saw MPs from the governing party and the opposition commit themselves to work for national consensus on oil policy. In 2010, Ghanaian MPs rejected the government’s draft petroleum exploration and production bill following cross-party training on oil governance, insisting that the bill include provision for a new independent regulator. After a training session in February 2010, a group of Ugandan MPs submitted a petition to publicly disclose oil agreements and have sought the opinion of the country’s attorney general on this matter. In Iraq, parliamentarians have called for a halt to further licenses being awarded until an oil law is passed.

MPs have a tough job and need much more support from NGOs, and particularly international organisations. The World Bank, International Monetary Fund and United Nations Development Programme have neglected parliaments and should do more to engage with and support parliaments in their essential role in governance.
Qatargas, established in 1984, pioneered the Liquefied Natural Gas (LNG) industry in Qatar. Today, Qatargas is the largest LNG producing company in the world, with a production capacity of 42 million tonnes of LNG per annum (MTA), realising its vision to deliver LNG to its customers in all four corners of the world, from its world-class facilities in Qatar.
Qatar has rapidly increased gas production. What is its future production profile? Which new LNG trains will come on stream?

Under the wise leadership of His Highness Emir Sheikh Hamad Bin Khalifa Al Thani, Qatar has become the world’s largest producer and exporter of LNG. This is a significant achievement, particularly when you consider that, in just 14 years, Qatar has gone from producing no LNG to having an installed production capacity of 77 million tonnes per annum.

As for the future, our priority is to ensure the efficient operation of our existing capacity and to complete all major projects already under construction.

As you are aware, in 2005 a moratorium was placed on further North Field projects. Therefore, our production forecasts for the North Field are limited to projects approved under the moratorium. These projects are due for completion after 2014.

A detailed study is currently being conducted on the North Field to evaluate the reservoir, and to ensure that future utilisation of the finite resources is done wisely and effectively.

What is Qatar’s pricing policy, given that gas prices are under pressure in some regions, notably Europe, because of the knock-on effect of US shale gas? How disruptive of the market is US shale gas? Can Qatar keep linking its gas prices to oil in Europe?

We understand that prices are not constant and are influenced by many factors beyond our control. These include the drop in demand as a result of the global economic crisis, the unexpected boom in shale gas production and the surge in global LNG capacity.

When considering the impact of these factors on Qatar’s LNG business, there are two important things to note. First, Qatar is in the fortunate position of having a mix of secure long-term supply contracts, and flexible supply arrangements. This flexibility allows us to divert volumes to take advantages of market opportunities. As such, we are very confident that the development of shale gas in the US will not disrupt our current or future investment strategies.

The second point to note is that LNG projects are long term investments. Although today’s gas market is rather uncertain, the long run fundamentals are sound and it is these long run fundamentals that will ultimately drive investment.

On the link between oil and gas prices, it is clear that while we have seen oil prices recover over the past months, these price rises have not been matched by increases in gas prices. This has resulted in the price of the gas per British thermal unit becoming far less than the price of its oil equivalent. While we
→ hope this is a temporary phenomenon, we believe it would be prudent for gas producers to examine the causes that led to the disparity and in this regard we stress the importance of open dialogue between producers and consumers.

Qatar exports to more than 20 countries outside the Middle East. Given growing gas requirements of Gulf countries, might Qatar start providing gas to its home region?
In addition to being an important supplier of gas to markets in Europe, Asia and America, Qatar is already invested heavily in supplying the Gulf region through its flagship pipeline project – Dolphin Energy. This project links the North Field with markets in the UAE and Oman via a subsea pipeline which supplies around two billion cubic feet a day of sales gas.

The overall investment in the Dolphin Energy Project has made it one of the largest energy-related ventures ever undertaken in the Middle East and is a clear illustration of Qatar’s commitment to regional development.

How does Qatar see the role of the Gas Exporting Countries Forum, if the forum is not for member countries to set export prices or agree on export volumes?
Clearly the purpose of the GECF is not to set export prices or agree on volumes but rather to provide a forum to enhance dialogue between gas producers and consumers.

We view the GECF as a valuable opportunity to discuss issues of mutual interest with other major players in the global gas market. These issues include investment opportunities in member countries, the exchange of capital, financial data and know-how and the promotion of stable gas markets.

In Qatar we host many international energy conferences that address similar issues. You could say that Qatar is becoming a facilitator to the industry in that we are staging events that bring together producers, consumers, industry experts, technology providers and project developer. The World Petroleum Congress is a prime example of such an event.

Qatar is also an OPEC member. What is its likely oil production and export profile?
Qatar currently has nine oil fields in production – three of these being operated by Qatar Petroleum (QP) and six via production share agreements with major energy companies. These fields produce some 800,000 barrels a day making us a relatively small producer among OPEC members.

In recent years, QP has invested heavily in its crude oil business. This investment is set to continue with plans to invest over QR (Qatari rials) 18 billion at QP operated crude oilfields and facilities over the next 5 years. Over the same period, an additional QR 7.7 billion will be invested by QP’s partners in contractor-operated fields.

The latest development phase at the Al Shaheen field has recently been completed, and to date, QP’s investments have added significant production capacity. QP continues to work with the operators of other fields to assess their potential and maximise value.

In addition to the Al Shaheen redevelopment, Integrated Reservoir Studies are being carried out on all QP operated fields. The end result of these studies will be full field development plans, which we expect to be completed by 2012/2013.
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- Qatar Marine Crude Oil
- Al-Shaheen
- Al-Rayyan
New foreign oil investment in Nigeria appears to be on hold until the Petroleum Industry Bill is passed. Why is it so important and what are the chances of the National Assembly passing it by the end of this year?

Looking at the situation from a cursory perspective one might be tempted to say that new foreign oil investment in Nigeria, as you put it, "appears to be on hold until the Petroleum Industry Bill is passed." While it is true that the PIB is introducing far-reaching reforms, it will not have any adverse effect on investment. I would emphasise that the PIB is not a punitive law.

The Nigerian oil and gas industry is still witnessing a flurry of investments. The reality is that I do receive a lot of requests and proposals for participation in the Nigerian oil and gas industry by a host of reputable foreign firms especially in the gas sub-sector where we are currently negotiating various new investments valued at over US$5 bn.

Only in March, this year, the government signed upstream and infrastructure MOUs with reputable companies to establish gas based industries to jump-start manufacturing activities in Nigeria. That investment alone is worth over US$10 bn. In spite of the delay in the passage of the Petroleum Industry Bill (PIB), the oil companies operating in Nigeria as well as new entrants into the business continue to make investments in the industry.

Going by the speech of the Senate President during the inauguration of the various committees, the current National Assembly considers the PIB as key legislation to be passed in order to support the President’s transformation agenda. I am very optimistic that sooner rather than later, the bill would be passed and that will certainly increase investor confidence.

Is the Bill so important?

The PIB is an omnibus legislation that establishes clear rules, regulations, procedures and institutions for the efficient administration of the petroleum industry in Nigeria. It will establish the legal and regulatory framework, institutions and regulatory authorities for the Nigerian petroleum industry. It also stipulates guidelines for operations in the upstream, midstream and downstream sectors and for purposes connected with the same. Given the high expectations of the PIB, I would say that the bill is very important. Its significance of course reflects the importance of the petroleum industry in Nigeria, which accounts for a very high percentage of foreign exchange earnings and accounts for more than a quarter of GDP.

At present, most petroleum products are sold below the cost of production, which discourages refining inside Nigeria and encourages imports. How difficult is it to raise prices to market levels?

It is true that our downstream sector still bears the heavy weight of regulation which tends to discourage investment. What I can confirm to you is that the present administration of President Goodluck Jonathan is committed to deregulating the sector and allowing market dynamics to come into play. This will definitely create a level playing field that will encourage more investment in the sector.

The government is considering ways of effecting realistic liberalisation of petroleum product pump prices that will at the same time minimise unintended adverse impacts on the more vulnerable citizens. We would like to carry along a vast majority of our people and the critical segment of the society to enable them to see the imperative of effecting realistic pricing of petroleum products in the country. To achieve this, a robust safety net that will provide relief for the citizens is being worked out by the government prior to the implementation of liberalisation of the downstream sector.

What are the prospects for deepwater exploration and production in the Nigerian waters?

Our deep offshore remains prolific, judging by the successes recorded in the area. Many mega fields such as Bonga, Erha, Agbami, Akpo and Abo, have come into production, thereby contributing about 30 per cent of the nation’s total daily crude oil production. We expect Usan field with 180,000 barrels per day installed capacity to come on stream by the first quarter of 2012. Further studies and evaluations of existing vintage data indicate new play opportunities for further exploration activities. The identifiable prospective areas have been coordinated into open blocks for offer by the government. International companies are encouraged to participate when the bid rounds commence.

How well is the Local Content Law working in the Nigerian Oil and Gas Industry?

In spite of the short period of the existence of the Nigerian Content Act, it is pertinent to note that a
great deal of activity has taken place with the Nigerian Content Development and Management Board (NCDMB) acting as facilitator.

The drive to have an appropriate percentage of the oil and gas industry’s projected US$20 bn annual expenditure spent in Nigeria has started yielding the desired results. So far, the Act’s implementation has laid the foundation for the creation of over 30,000 direct employment and training opportunities in the next three years.

The sheer volume of industry work-load previously performed abroad that now has to be done in-country is driving investments in capacity development. Over US$2 bn investment is needed to establish critical facilities and infrastructure required to support the Nigerian Content scope in the Act, and plans are already afoot for a healthy proportion of these investments to upgrade existing plants and establish new ones in the country.

Specifically, within the last year, compliance with the Act has guaranteed the utilisation of the only pipe mill in Nigeria, the SCC Pipe mill in Abuja which was recently upgraded to produce line pipes for the oil and gas sector. Already, pipes produced by the SCC Pipe Mill are being utilised in the operations of some oil and gas companies.

In the area of capacity development, the NCDMB has been collaborating with the Petroleum Technology Development Fund (PTDF) and major operators to train over 10,000 young graduates and technicians in entry level skills. To ensure that the funds available for training are optimised, training providers in the industry have been brought together under the Oil and Gas Trainers Association of Nigeria (OGTAN) to standardise the requirements for the industry and ensure that local training results in internationally recognised certification. Similarly, the Nigerian Institute of Welding (NIW) has been empowered by the Board to play their traditional role in the training and certification of welding practice in the country. In summary, the Nigerian Content programme has huge potential for the development of the Nigerian economy.

A United Nations Environment Programme report has said more should be done to clean up the oil spills in the Niger Delta. What more do you think can be done?

For us the issue of health, safety and the environment is a major focus, not only in the oil and gas industry which I supervise but also for the entire machinery of the Federal Government of Nigeria. Before the UNEP report, the Nigerian Government had put in place the Ministry of the Environment which is saddled with the responsibility of formulating and enforcing environmental policies.

The Department of Petroleum Resources (DPR), the government’s regulatory agency for the oil and gas sector, has also launched “The Environmental Guidelines and Standards for the Petroleum Industry in Nigeria” (EGASPIN) to regulate safety and environmental activities in the oil and gas industry. Operators in the oil and gas sector are expected to fully comply with this provision to reduce incidences of crude oil spillage.

When the UNEP Report was released, the government immediately set up a Presidential Committee of which I am the Chairperson to study the report and recommend appropriate implementation plans. The Committee has since commenced work and will soon present an actionable plan with timelines for the restoration of Ogoni land.

A lot of Nigerian gas is still being flared. Do expensive gas export pipeline projects, like the Trans-Saharan Pipeline to take Nigerian gas to Europe, make sense while this gas is still being flared?

Nigerian gas reserves of about 187 trillion cubic feet include associated and non-associated gas. However, in the course of crude oil production, some associated gas that is also produced is flared.

The current plan is to harness and utilise both the associated and the non-associated gas resources to the benefit of Nigeria.

The plan is encapsulated in the Nigerian Gas Master Plan (NGMP) which is a robust infrastructure blueprint that accommodates all the flared and stranded gas for both domestic and export market.

The Trans-Saharan Gas Pipeline Project is just one of the new export projects being considered alongside the Brass LNG and OKLNG projects. Other existing gas projects are the Bonny LNG and the newly completed West African Gas Pipeline.

Already the proportion of gas flared has decreased from 70 per cent in 1999 to 40 per cent today. The Nigerian Gas Master Plan when fully operational will eliminate gas flaring, commercialise the gas and improve the environment.
The Nigerian National Petroleum Corporation (NNPC), is responsible for harnessing the nation’s oil and gas reserves for sustainable national development. It explores, produces, refines oil, and markets/retails petroleum products; it also develops its abundant natural gas for both external and domestic consumption, renders oil & gas engineering services and supervises government investments in the upstream sector.

NNPC is at the starting point of a strategic journey. Our vision in the transformed NNPC is to be the premier Nigerian integrated oil and Gas Company operating at world class levels to create high value opportunities for Nigeria and Nigerians.

Nigeria is the world’s 7th largest exporter of crude oil and the 7th largest holder of natural gas reserves. On the African continent, the country holds the largest reserves in both oil and gas. It is poised to play a greater role in the global energy market given the potentials and opportunities that abound in the oil and gas sector.

The petroleum industry today is the mainstay of the Nigerian economy. It is the main source of foreign exchange earnings (90 per cent) and development finance in the country accounting for 85 per cent of total government revenue, 28 per cent of Gross Domestic Product (GDP) in 2010 and employs a sizeable number of Nigerians, both directly and indirectly.

The planned growth and potentials of the industry will create significant opportunities for Nigeria and investors. Current crude oil production is over 2 million barrels per day (mbd), while oil reserves and production capacity are 35.0 billion barrels and 3.0 mbd respectively. Natural gas reserves have also increased to 187 trillion standard cubic feet. While the sector has remained the pillar of socio-economic development and growth, it is poised to play an even greater role in the larger Nigerian economy with current efforts to increase crude oil reserves, monetize the vast natural gas resources and integrate the power sector into the nation’s gas sector in order to expand electricity generation capacity. The on-going institutional and organizational restructuring, capacity building as well as the local content development strategy will also accelerate overall national development.

Furthermore, the on-going transformation in the petroleum industry is part of the Federal Government’s overall reform agenda to place Nigeria on the path of growth and sustainable development. These reforms are therefore intended to revitalize the sector into becoming a catalyst and engine of growth to national development. The petroleum industry is being opened up for private sector investment in order to infuse capital and technology. Nigeria, being the gateway to oil and gas business in Africa and with a record of stability of agreements in sub Saharan Africa, is the natural choice of investors in oil and gas business.

In order to reposition the industry, the Nigerian National Petroleum Corporation (NNPC) is being restructured into a world class National oil company to mid-wife reforms in the entire industry. The repositioning strategy runs through the entire spectrum of the industry; upstream, midstream, downstream and gas.

Natural gas
A lot of investment opportunities abound in the natural gas sector of the Nigerian petroleum industry. More attention is now being paid to this vital sector. Government’s aspirations for the gas sector include creating new industries out of the old oil industry, capturing economic value and generating as much revenue from gas as from oil. Others are developing the domestic gas market as well as ending gas flaring.

Remarkable progress has been recorded towards the realization of these objectives. Of the current annual gas production of about 2, 000 Bscf, about 40 per cent is flared. This is a drastic drop from the 70 per cent proportion flared before 1999.

Domestic gas consumption is expanding as a result of the on-going power sector reforms while gas export which was non-existent prior to 1999, has received a boost. Comprehensive and integrated gas utilization Master plan/ programmes have been embarked upon, in which LNG and IPP developments are being given priority as demonstrated by the launching of the gas revolution by the President in March this year.
On behalf of the Board Chairman, Management and staff of the Nigerian National Petroleum Corporation (NNPC), I sincerely welcome all the delegates to this year’s World Petroleum Congress taking place in Doha, Qatar.

As you are aware, the World Petroleum Congress is one of the biggest industry events conducted every three years. Doha, a beautiful and serene city in the hydrocarbon rich middle East Country of Qatar, is no doubt a conducive and well-thought out venue for this big event.

In view of the importance of the oil and gas industry to Nigeria’s national economy and those of other countries in the West African sub-region and in-deed Africa, it is no surprise that we are witnessing a high level of participation from the Continent.

The continued global dependence on fossil fuel dictates that our Corporation along with other stakeholders across the world will continue to map out effective strategies to meet the global demand for oil and gas.

To this end, NNPC is undergoing a robust transformation which will ultimately galvanize into a phenomenal industry growth. And in line with the theme of this year’s conference - Energy Solutions For All – Promoting Cooperation, Innovation And Investment, it is pertinent to emphasize that with proven reserves of 37 billion barrels of oil, and gas reserves of 187 trillion cubic feet, Nigeria’s onshore, deep offshore and continental shelves remains highly prolific.

It is worthy to note that under the leadership of Nigeria’s President Goodluck Jonathan GCFR, our Corporation is more than determined to ensure the success of the transformation efforts not only in the interest of the Nation’s national oil company, but also that of the Nigerian economy.

In this regard, concerted efforts have reached advance stages to attract investments across the globe to supplement those made by the IOCs that have been operating in Nigeria in the last 50 years.

Investment in Nigeria’s vast gas resources also remains one of the most rewarding ventures for discerning investors. In recent time, Nigeria is partnering with world class companies from Saudi Arabia, China and India in the area of investment in petrochemicals, refining and fertilizer plants to the tune of over US$10 billion.

At full maturity, the investment promises to be of tremendous benefit to Nigeria’s industrial landscape with the added advantage of providing job opportunities and also serving as a veritable source of revenues for economic development of the country. Similarly, I like to state that efforts are in top gear to also transform the downstream petroleum sector in Nigeria to ensure a level playing ground among participants and to also guarantee commensurate cost recovery in order to attract the much needed investments to the sector.

It is in this regard that I like to seize this opportunity to encourage interested investors in our downstream to take advantage of the full liberalization of the sector that is currently being pursued by the present Administration of President Goodluck Jonathan.

I will not conclude this message without reminding delegates and our business partners that the Nigerian Content Act remains an integral part of the industry’s contribution to our country’s economic growth.

Our experience so far with the implementation of the Act shows that the industry has embraced Nigerian Content. Indeed, the Nigerian Content Act has made doing business in Nigeria much more exciting and interesting. May I therefore seize this opportunity to disabuse the minds of those who had thought that the Nigerian Content was an “Investment unfriendly” piece of legislation. It is not and will never be, as experience has so far shown.

I thank the Government and good people of Qatar for the excellent arrangements made for this conference, while wishing all delegates the best as we savour the rich cultural heritage on offer in this part of the globe.
Promoting E&P in Peru’s mature and frontier basins

The Peruvian Government’s goal of making the country a net exporter of oil and gas by 2014 will require fresh investment in both the Amazon and offshore regions.

Creating in 1993 by the Organic Hydrocarbon Law (No. 26221), Perupetro S.A. is the State enterprise of Peru’s energy and mining sector with primary responsibility for the promotion of investment in hydrocarbons exploration and production (E&P), as well as negotiating, underwriting and monitoring License Contracts.

In its chapter on Environment and Natural Resources, the Political Constitution of Peru states that both renewable and non-renewable natural resources are the patrimony of the State, which is responsible for their sustainable use as well as the conservation of biodiversity and protected habitats and the development of the Amazon region.

Peru has 18 sedimentary basins with hydrocarbon production potential. To date, however, E&P activities take place in only six of these, while oil and gas production is concentrated in just three of them. The remaining basins contain important unexplored and under-explored areas, as evidenced by the low number of exploratory wells drilled thus far.

However, the US$ 2,122.32 million of private investment in exploration activities and US$ 3,917.81 million in production activities invested in Peru between 2006 and 2011 should serve as a wake-up call to investors that the Peruvian market is ready for large-scale private investment in its hydrocarbons industry.

The challenge of searching for new reserves is of paramount importance in order to ensure significant increases in the country’s oil and gas production levels. In order to achieve this, Perupetro has developed a combined policy and incentives programme intended to increase the country’s attractiveness to oil and gas companies.

One of Perupetro’s main targets is to reach a daily level of oil and gas production that will enable the country to become a net oil and gas exporter. In order to reach this threshold, fresh investment is required in areas with a proven track record of exploration success.

Peru benefits from a policy which combines a competitive fiscal regime, a convenient royalty scheme and a first-order contract model aimed at reducing risk and uncertainty, as well as proximity to markets, a developed infrastructure to support E&P activities and the potential for important commercial discoveries both onshore and offshore.

Once signed, contracts assign companies exclusive exploration and production rights and ownership of all hydrocarbons produced in their block, subject to royalty payment. The size of the royalty will be determined by future production levels after declaration of commerciality. The contract duration is currently set at seven years for the initial exploration phase, with an additional 23 years for the exploitation phase in the case of oil production and 33 years in the case of gas production. The exploration phase may be extended to ten years on request.

The Marañon, Ucayali and Madre de Dios basins in the Peruvian Amazon and the free areas in the offshore and coastal regions have attracted the interest of exploration companies for many years. To date, the most prolific basins are Marañon and Ucayali in the jungle and Talara in the coastal region. However, despite a significant number of exploratory wells having been drilled in these basins, there remain important areas that are either unexplored or under-explored.

Peru’s oil industry dates back to the early 1970s when a number of highly successful discoveries in the jungle region took place. Since that time, there have been no major discoveries with the notable exception of the Camisea natural gas fields, which were discovered in the 1980s.

In the offshore areas hydrocarbon exploration and production activities have been concentrated in shallow waters, at water depths of less than 100 metres. Even in the northern part of the country, where oil and gas have been produced for more than 50 years, exploration has gone to depths of no more than 120 metres.

Due to the application of Perupetro’s new policy, investment in hydrocarbon exploration and exploitation has increased rapidly in recent years, and this is expected to rise still further in the near future, especially in the exploration and development of heavy oils in the northern jungle and the E&P activities for natural gas and LNG in Camisea and the surrounding areas.

As a result, due to the renewed activity in hydrocarbons exploration and exploitation since 2005, important discoveries have been made in both the Amazon basins and offshore region. Perupetro continues to organise campaigns to attract new investment and bolster the country’s oil and gas reserves, with new blocks due to be offered in future rounds.

The company has great expectations for the forthcoming bid rounds, bolstered by the news that Peru has been ranked 76th in the world for oil and gas investment by the Fraser Institute. This represents a remarkable leap forward compared to its ranking of 85th place just a year ago.
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From the inventions of the tricone drill bit and 3D seismic onward, the petroleum industry has steadily innovated. To maintain this record, Rex Tillerson of ExxonMobil warns of the acute need to educate tomorrow’s innovators in the fundamental skills of science, technology, engineering and maths, and in this regard points to the Qatar Foundation’s work in Qatar.

Such skills are being tested far from the Arabian Gulf. Perhaps the toughest project currently underway is offshore Brazil where, as Guilherme Estrella describes, Petrobras and its partners are drilling in deepwater under a salt layer up to 2km thick. Petrobras has also set itself the additional task of capturing the CO2, and re-injecting it into the reservoirs – a subject that Brad Page of the Global CCS Institute writes about more broadly, noting that the oil and gas industry has been the pioneer of CCS technology.

On the Arctic, Anatoly Zolotukhin provides the essential perspective from Russia which alone accounts for around 180° of the Arctic circle. He gives the Barents, Kara and Pechora seas the best potential, but says their development needs the “indispensable” help of foreign companies. In contrast to Arctic uncertainties, Marvin Romanow of Nexen says that with Canada’s oil sands “we know exactly where the bitumen is, so the exploration costs are very low,” in contrast to high production costs which a lot of innovative effort is going into reducing.

New rules as well as new frontiers may also drive innovation. Michael Bromwich, the new regulator of the US offshore, spells out the new post-Macondo regime for the Gulf of Mexico. Among other things it requires operators to have far greater risk awareness that may only be possible through faster integration of information between surface and subsurface. John McDonald of Chevron calls it “ingenuity at speed.” But it’s not easy. As Ashok Belani of Schlumberger cautions, “reservoirs are becoming more complex, their production more difficult, their location more remote, and their environmental conditions in terms of temperature and pressure more extreme.”

Everyone is aware of the US revolution in shale gas, but Greg Hill of Hess Corporation reminds us that it also applies to shale oil in the US. If unconventional oil is developed on the low-cost business model he advocates, it could rise to 40 per cent of US liquids by 2015. However, the section focuses more on gas. This is because of shale gas prospects outside the US about which Peter Hughes of Ricardo is cautious but Stanislaw Rychlicki and Marek Karabula are more hopeful in Poland; because of the extra gas that Nobuo Seki says Japan will need after Fukushima; because of the relatively “green credentials” of gas as Dr Hashim of the IGU puts it; and because of the technical progress in its transformation and transport. Andrew Brown of Shell briefs us on his company’s ground-breaking Pearl gas to liquids plant in Qatar, and David Ledesma on bold projects for Floating LNG.

However, innovation may not just add to oil and gas supply. It could also subtract demand by providing alternative means of powering cars. Chris Borroni-Bird and Mary Beth Stanek of General Motors update us on development of electric urban cars and on biomass or hydrogen propulsion outside cities. Biofuel development will continue, say Anselm Eisentraut and Michael Waldron from the IEA, though taking over less of oil demand growth than before.
The need to train the innovators of tomorrow

BY REX W TILLERSON
CHAIRMAN AND CEO, EXXONMOBIL CORPORATION

The men and women of the energy industry have a long and proud history of overcoming challenges all over the world.

For more than 100 years, our industry has pioneered technological innovations that have unlocked new supplies of energy, increased safety and energy efficiency, and reduced environmental impacts. The result of these extraordinary advances has been an unparalleled contribution to global progress and prosperity.

As we look to the future, our industry’s scientific and technological breakthroughs will continue to be essential to meeting the world’s energy challenges. But we must remember that tomorrow’s innovations will not simply happen by themselves. They will require creative thinking, new ideas, and a bold and relentless commitment to scientific research and development.

In fact, it is no exaggeration to say that the future of our industry – and the aspirations of billions of people in developed and developing economies – will depend on the ingenuity and innovation of tomorrow’s scientists, engineers, and technology entrepreneurs as we seek to develop new sources of energy and new levels of energy efficiency.

That is why one of the most significant challenges we face as an industry is in working to increase the number of students pursuing degrees in science, technology, engineering, and mathematics (STEM).

At ExxonMobil, we believe now is the time for leaders from business and government to come together to promote education in these critical fields, so we can increase economic opportunity and the potential for progress in the future. Simply put, education today is the key to energy tomorrow.

The challenges of the future

The urgent case for new efforts to promote STEM education is clear when seen in the global context of the economic and energy challenges before us. In fact, as business and policymakers better understand the realities shaping our energy markets, it will become evident that we will need more citizens and workers who understand science and engineering than ever before.

While markets have been volatile in recent years, the fact remains that we are living in an era of tremendous economic development – development that is transforming nations and markets around the world. Reliable supplies of energy are needed to fuel this growth – especially for progress in areas such as Asia, Latin America, India, and Africa.

Even now, in the year 2011, 1.4 bn people, 20 per cent of the world’s population, live without access to electricity to heat their homes, cook their food, purify their drinking water, or power hospitals and schools in their area. For men, women, and children living in developing nations, the economic growth that flows from reliable energy supplies can be the difference between health and safety or sickness and death. For more developed nations, reliable energy enhances the robust trade, transportation, and technology that extend and enrich life.

This universal need for energy to support human progress is destined to drive energy demand for decades to come. Over the years 2010 to 2030, we project that global demand for energy will increase approximately 25 per cent.

Meeting this enormous demand will require human ingenuity, sustained investment, and teamwork to develop technological solutions that keep pace with our growing world.

Pivotal role of technology

Our industry can meet this challenge. We have proven it time and time again. With sound, unbiased, and reliable energy policies in place, all types of energy companies can engage in the long-term planning and make the disciplined investments that are needed. We have also proven that we can find and deploy integrated solutions that help us bring new supplies of energy to the market in a safe, secure, and environmentally responsible way.

But one lesson that is undeniable is that none of us can achieve these objectives alone. Over the last 30 years, our industry has proven the value of strong partnerships between national oil companies and international oil companies to recover the energy resources found in increasingly difficult-to-reach and remote places.

History also reminds us that new technologies require robust and sustained investment. This means in the years ahead we will need government leaders to play a role in establishing and sustaining energy policies that encourage investment, reward cooperation, and promote the rule of law.

And finally, as the importance of teamwork and technology increases we will need visionary leadership from business and government to build programmes that encourage the best and brightest in every nation to
pursue careers in science and engineering.
We cannot innovate without innovators.

The need for visionary leadership
Fortunately, there are proven ways to help encourage educational opportunity in mathematics and science.

Attendees at the World Petroleum Congress do not have to look far to see an example of what visionary leadership can accomplish in promoting education. Our host nation, the State of Qatar, is in the vanguard of such efforts.

In 2008, the Emir presented to his people the Qatar National Vision 2030 – a plan to transform his country into a knowledge-based economy, an educational leader, and a global technology pioneer. This commitment to the future is demonstrated by three particularly visible and significant projects – the creation of Qatar’s Education City by the Qatar Foundation, the establishment of the Qatar Science and Technology Park, and the construction of the world-class Sidra hospital complex.

Each one of these projects creates opportunities for Qataris to learn and excel, work and research. In addition, the Emir’s vision has provided a clear direction for government and business leaders to build long-range programmes that encourage the development of the next generation of scientists, engineers, and doctors.

At ExxonMobil, we are proud to be part of the Emir’s efforts to fully develop Qatar’s economic, social, environmental, and human potential. For the State of Qatar, the success of the National Vision is making the nation even more attractive to international business and investment.

The key to the Emir’s vision is its boldness and breadth. By involving both government and business, the National Vision supports science and engineering in schools and then helps graduates by providing a pro-investment climate that supports job creation.

In fact, such cooperation is a proven formula for success. Producing scientists and engineers requires discipline and time, so a comprehensive set of programmes are needed. Education in science and math must begin in primary schools and extend all the way to advanced degrees. In addition, business and academic institutions are valuable partners because their programmes can encourage government-run schools to use metrics to measure success, spread the use of proven curricula, and help teachers through training and scholarships.

As one example of what can be achieved through such partnerships, ExxonMobil in the United States is supporting two major programmes under the National Math and Science Initiative (NMSI). Through the UTeach programme, NMSI is working with universities to identify the most effective ways to recruit and support highly qualified teachers in mathematics and sciences. By encouraging teachers who have a mastery of these fields we can ensure more students are inspired by what science, math, and engineering have to offer.

A second and equally important part of NMSI is the Advanced Placement Training Incentive Programme. This is designed to dramatically increase the number of students taking and passing college-level exams in math, science, and English. Not only is this promoting STEM in US secondary schools, it also has a special focus on encouraging under-represented students to pursue these fields, which create tremendous career opportunities. Since their launch in 2007, the NMSI has helped US public school students and teachers achieve extraordinary results.

Conclusion
For more than a century, our industry has proven that we can meet the energy challenges of the future.

We have safely unlocked energy supplies beneath arctic tundra, ultra deepwater, and in remote locations across the globe. We have harnessed oil and natural gas resources – and then helped the world use them more efficiently. And as we look to the future, we see new technologies continuing to expand access to new supplies. A case in point is liquefied natural gas, which is helping enable abundant and affordable natural gas to be the fastest growing major fuel source in the world while its clean-burning properties also provide significant environmental advantages.

None of these milestones would have been possible without the creativity and ingenuity of scientists, engineers, and technology entrepreneurs.

As our industry meets at this year’s World Petroleum Congress, it is our duty to ensure that the world finds ways to develop new energy resources in a safe and secure way. It also falls to us to help the public and policymakers understand the importance of technology in achieving these goals and the role future generations of scientists and engineers will play in creating the innovations that will build a brighter future.
Brazil's 'pre-salt' reservoir is a layer of oil-bearing rock of carbonate composition, positioned under a thick layer of salt and located in the Santos and Campos basins (Figure 1). Lying under it are the source rocks, shale rich in organic matter. These sediments are the result of the evolving process of Brazil's southeast and eastern basin formation, due to the South America-Africa breakup around 120 million years ago.

The major exploration and production efforts are being applied on the Santos Basin Pre-Salt Cluster (SBPSC), that include six blocks operated by Petrobras with different partners: Galp (Caramba and Jupiter) Shell and Galp (Bem-Te-Vi), BG and Repsol (Carioca and Guará), BG and Partex (Parati), BG and Galp (Lula, Cernambi and Iara). The area is located 300 to 350 km away from the coast, with reservoir depths between 5,000 and 6,000 metres below the sea level, in ultra deep water (1,900 m to 2,400 m) under a thick salt layer (in some areas, up to 2,000 metres).

In the Lula and Cernambi fields, the total recoverable volume was estimated as 8.3 billion barrels of oil equivalent from carbonate reservoirs with highly variable geological properties. The oil has an API gravity between 28 and 30, gas-oil ratio between 200 and 350 m³/m³ and variable contents of CO₂ (8 to 15 per cent). The Brazilian government has transferred to Petrobras another 5 billion boe of potential reserves in other parts of the Santos Basin Pre-Salt Cluster.

**Development strategy**

A phased strategy will be applied to the SBPSC in order to allow exploration to be carried out with development. The immediate priority is to reduce uncertainties related to the reservoir – especially the basin’s geological character, hydrocarbon recovery methods, definition of the best well geometries, flow of oil through subsea pipelines, separation and use of CO₂ and design of the processing plant, risers and mooring systems. This acquisition of geological and production information is the priority of what is called ‘Phase 0’. This phase involves drilling and testing of appraisal and reservoir data acquisition wells and, since 2009, a series of Extended Well Tests (EWTs) performed with two small FPSO (floating production, storage and offloading) vessels. In all, this will lead to production of around 100,000 barrels a day.

The following phase - Phase 1A, aims to reach the production of 1 million barrels a day using using technologies developed in the Campos Basin:

- two anticipated spread moored FPSOs pilots in Guará and Lula NE, scheduled for 2013;
- two additional spread moored FPSOs to operate in Guará and Cernambi, scheduled for 2014 and;
- eight production systems, comprising new built FPSOs with similar engineering project, to be installed in order to support the following projects. For the gathering systems, flexible risers, decoupled rigid risers or coupled rigid risers can be applied. These eight FPSOs are scheduled to start operation gradually, from 2015 to 2017.

These units will operate with processing plants ranging from 120,000 to 150,000 barrels a day and 5 to 8 million cubic metres of gas capacities.

Definitive development of the fields will start in 2017 with Phase 1B. Further production systems will be required for the optimal exploitation of the fields, using technological and logistic solutions specially developed for the conditions of the SBPSC.

**Figure 1: Pre-salt cluster areas in the Santos Basin, Brazil**
Technological challenges

Due to the oil and reservoir characteristics as well as the environmental scenario, the development of the Pre-Salt in the Santos Basin raises technological challenges in several disciplines.

Reservoir characterisation

Pre-Salt reservoirs are Aptian rocks, mainly microbial, heterogeneous carbonates (Figure 2). The main challenge posed by the Pre-Salt reservoirs is to use the knowledge of the paleo-environment where these carbonates developed, as well as seismic attributes, in order to optimise drainage of the reservoir. The geological characteristics of the Pre-Salt raise some difficulties as to the quality of seismic data, because of the uneven surface of the top of salt, the internal variations within the salt layers which cause heterogeneous scattering of the seismic energy, and the limited vertical resolution in the reservoir which, due to the high velocity of the seismic waves in the carbonate, is very common in deep reservoirs.

Oil recovery

Secondary recovery must be implemented to improve oil recovery in the Pre-Salt carbonates. These rocks are usually oil wet, and this characteristic affects the performance of water injection, which will be tested in the Lula Pilot field.

Another complication in the case of water injection is related to rock-fluid interaction, which is more important in carbonate. To understand the phenomena and to assess the risks involved, as well as to define mitigation actions, rock-fluid interaction tests are being carried out with the reservoir rock and the salt cap rock. Alternative recovery methods will be implemented in the Pre-Salt reservoirs. Gas injection is already being tested in the Lula Pilot and the water alternating gas method (WAG) will also be tested in the field.

Well engineering

The main issue related to well engineering is the construction cost. Deep reservoirs in deepwater require special rigs and skilled people to improve the learning curve and reduce well construction duration. In order to reduce the overall cost, several initiatives are being carried out related to well design; control and constant improvement of rigs’ performance; using lighter rigs in the initial phases of the wells, well tests and deployment of ‘Christmas trees’ (often referred to as X-Mas trees, the equipment installed on the bottom of the sea that controls the production of the wells), and drilling of deviated wells.

The great depths of the reservoir and the great distance from shore add to well costs that represent approximately 50 per cent of the overall cost of a typical Pre-Salt development project. But there is room for improvement, such as: logistics, optimisation procedures for the construction of wells, simplifications in the design of wells and in the equipment being used in drilling.

The penetration both in salt and carbonate rocks has increased as wells have been built, with a significant reduction in the average cost of a well. By understanding the mechanical properties of salt and carbonate rocks and through close cooperation with the service companies, the average rate of current drilling of vertical wells is more than twice the rates obtained in the first wells. Different concepts and new technologies that could lead to further reduction are being tested.

Salt rock shows high creep strain rates, constituting a potential hazard to well drilling. The evolution of the well closure with time, caused by creep, can result in imprisonment of the drill string or successive operations to correct the diameter of the well. The low temperatures in the Santos Basin Pre-Salt reservoirs and the predominance of halite in the salt layer are favorable factors. At the opposite side the high stresses associated with great depths are concerns, even when dealing with halite. As mentioned, this challenge is being overcome, at least considering the salt characteristics in the Lula Pilot area.

Another focus is on materials to be deployed in the well, whose supply can add time and cost. Special resistant casing must be used to avoid well collapse due to the salt movement, and due to the presence of contaminants in the reservoir fluids and also characteristics of the formation water. Corrosion resistant alloys must be considered for completion of wells below the salt layer.

Expert cementing is also required in the Pre-Salt to guarantee a reliable isolation between the pay zones and also well integrity considering the cap salt rock. Special cement slurries are being applied in order to avoid risks of channeling and to guarantee that the cement properties will not be affected by the produced or injected fluids.

Another important issue is the definition of the best well geometry for each Pre-Salt area. Small scale reservoir simulation is used to quantify the benefits of different well geometries. Field results are encouraging. Three deviated wells have already been drilled in the Lula Pilot area, and ➔
the next step will be the construction of a high angle well in the Lula Pilot.

**Flow assurance**

The salt layer is a good heat conductor. So, the reservoir temperatures are lower than expected for rocks at great depths but more critical for wax deposition and hydrate blockages. Notwithstanding, with more than two years of production in the Lula Field, no significant problems were reported in pipes.

Wax deposits may occur in long flowlines or in the risers. The conventional solutions are to use thermal insulated flowlines, to manage heating and assure flow from the wellhead to the platform as well as frequent pigging the pipes to prevent wax accumulation. The high pressures involved in the flow, together with low temperatures, can result in a risk of blockages by hydrates. But the high values of gas-oil ratio (GOR) are a positive factor in operational procedures during shutdowns, because of the lower hydrostatic pressure.

Thermodynamic simulations have forecast the possibility of calcium carbonate, barium and strontium sulphate precipitation. Low sulphate sea water injection is an option to prevent sulphate scale formation. Chemical treatments may be required to prevent calcite precipitation in the perforations and subsea equipments. To cope with this challenge, Petrobras’ expertise in the Campos Basin, as well as support from international institutions, are being used to define the chemicals to be applied and investigate interaction that sea water or EOR methods may have with the reservoir rock.

The possibility of hydrates in the water-alternating gas injectors was thoroughly investigated. Among the improvements that are being considered are a special design for the standard Pre-Salt X-Mas tree, allowing the injection of hydrate inhibitors; the use of separate injection flowlines for gas and water; special procedures to be applied during fluid change; heating of the injection water, among others.

**Subsea technology**

The deeper the water, the higher the loads due to the weight of the mooring lines. The use of lighter materials with higher stiffness is necessary to limit the motion of the Production Unit. The higher loads due to the risers’ weight impact the platform structural engineering and possibly the riser lifetime, possibly requiring special materials. A good alternative solution, which is being applied, is to decouple the risers from the motions of the production floater.

The ongoing qualification process of flexible risers for the Pre-Salt environment deserves special attention. Coupled flexible risers have been applied in the Lula Pilot area, and no problems have been detected to date. For the Guará and Lula-North East Pilots, decoupled steel cathenary risers’ system were ordered.

**CO₂ – how to process it and what to do with it**

Petrobras has decided, for environmental reasons, it will not vent the naturally produced CO₂. But separating CO₂ from the natural gas is expensive and put huge space and weight requirements on the FPSOs. So designing low cost plants with reduced footprints and weight and low energy consumption has been a challenge.

The gas processing units have been designed to separate CO₂ from the natural gas after which the CO₂ rich stream is re-injected into the reservoir. The natural gas is exported through gas pipelines but can also be reinjected partially or entirely along with the CO₂ rich stream.

The sustainable hydrocarbon production from the Pre-Salt reservoirs will require, minimisation of emissions of its non-anthropogenic CO₂. Alternatives are under study for the CO₂ capture and storage: reinjection in the oil producing reservoirs, in salt caves, in salt water aquifers or in depleted gas reservoirs. Special attention was given to the gas processing plants in the floating production units. In this way, the process known as Carbon Capture and Storage will be applied.

The CO₂ capture is planned to be done with membranes technology, which is suitable for high CO₂ content. In the Lula Pilot the gas will be exported to the fixed platform of the Mexilhão field (located in shallow waters, 220 km from the Lula FPSO). Currently, the preferred storage option is to reinject the CO₂ in the reservoir, pure or with the treated gas current.

**Logistical challenges**

The Santos Basin is located around 290 km distant from Rio de Janeiro coast and 350 km from São Paulo coast, in ultra deep waters. This poses logistical challenges for the supply of bulk materials, transport of people (helicopters or boats), pipeline laying vessels, drilling & workover rigs, and terminals for oil export through commercial crude carriers.

As a result we are studying the selection of existing harbours and airports to be adapted, the design of offshore...
oil terminals, in deep and in shallow waters, floating hubs for fluids and materials, power generating offshore hubs, design of an auxiliary location for helicopter refuel/maintenance, and extensive automation to manage, control and supervise operations from onshore.

**Logistics challenges for the associated gas**

The deployment of large diameter gas pipelines is a technological challenge for installation vessels, due to the heavy loads involved. In ultra-deep water, the thickness of the pipe walls will be greater than 1.4 inches (3.6 cm), to withstand the high pressures at the seabed, resulting in huge weights. Additionally, the large wall thicknesses of the pipes require most accurate welding, as well as control techniques and inspection.

New technologies for exploitation of gas have potential to give more flexibility for evacuating the gas. In this sense, Petrobras and partners have been evaluating the potential application of technologies such as: FLNG (Floating Liquefied Natural Gas), CNG (Compressed Natural Gas), GTL (“Gas-to-Liquid”) and GTW (“Gas-to-Wire”).

**Boosting Brazilian economy**

Development of the Pre-Salt holds great potential for the petroleum industry and for Brazil. In shipbuilding, the opportunities include construction of several floating production units, offshore drilling rigs and supply boats; inspection and maintenance services for the fleet, and so on. The equipment industry stands to gain from the construction of salvage equipment, load transport equipment, compressors, turbines, pressure vases, special valves, equipment with special metallurgy to support high pressures and aggressive environments. For the service industry the opportunities will be enormous, not only due to the increasing demand for specialised services – drilling and completion offshore services, project and construction of oil and gas process units, handling of subsea equipments, subsea inspection services, project management – but also due to the logistics demands, such as different ways of transportation, load handling and transportation, facilities and supply technologies, management and technology for material stock.

The Brazilian government’s clear policy to promote increasing local content both in construction and design of all sorts of material, equipments and services offers an excellent opportunity for the international petroleum industry suppliers to set up in Brazil, especially when associated with Brazilian companies.

As for Petrobras, the company and its partners hope to follow the highly successful experience of the Campos Basin, where, through actions of synergy involving several areas of competence, Petrobras quickly managed to adapt technologies and arrange the logistics, in addition to critical resources, to place the fields discovered in production.

The next challenge is to develop the Pre-Salt cluster in the Santos Basin, with emphasis not only on Lula Field, but also on the other accumulations discovered, which will be operating by 2017. Both from the industrial technology and economic points of view, Petrobras and partners has all the conditions to explore for and produce oil and natural gas from the Pre-Salt cluster for a long time to come.

*Co-authored with Alberto de Almeida, Antonio Pinto, Celso Branco, José Filho and Ricardo de Azevedo.

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**Figure 2: Slices from Pre-Salt carbonates showing the high heterogeneity**
Brazil’s deepwater: A financial as well as a technical challenge

BY GARETH CHETWYND
SOUTH AMERICA CORRESPONDENT, UPSTREAM NEWSPAPER

When Petrobras first broke through the two-kilometre salt layer under Brazil’s Santos basin in 2006, few in the industry guessed the enormity of the find. The wildcat well, called Paraty, was almost stratigraphic in nature, designed to find the easiest passage through the salt rather than looking for the juiciest structures.

For years, a handful of Petrobras geologists had worked on somewhat unorthodox theories suggesting the presence of a potentially huge hydrocarbon system beneath salt deposits left behind when the South American and African continents began drifting apart more than 100m years ago. Their theories trickled down the ranks, generating rumours about a “new Campos basin” at deeper horizons, but not even Petrobras saw the pre-salt as the primary target on these ultra deepwater Santos basin blocks acquired in Brazil’s early bid rounds.

What Petrobras found in 2006 was an unfamiliar microbialite carbonate reservoir of light oil and gas, with carbon dioxide and sulphur dioxide showing up in unwelcome quantities. The three partners on the Paraty well – Brazil’s Petrobras, Britain’s BG Group, and Portuguese Gulbenkian Foundation offshoot Partex Oil & Gas – were cautious about the potential of their find. They had endured a difficult 672-day drilling operation, with another 200 days for open-hole and cased-hole tests and the Paraty well cost over US$200m.

The immense logistical and technological challenges for drilling or producing in the pre-salt environment were immediately clear. The targeted structures were located in water depths of around 2,220 metres, about 300 kilometres off the Brazilian coast and deep-buried beneath the salt layer. The Paraty well was drilled to 7,628 metres below the seabed. The most daunting challenge was posed by the reservoir itself. “There was a fundamental question mark about whether we could produce from this carbonate microbialite reservoir. It departed from all of our previous experience, which was mainly with sandstones,” recalls Ricardo Beltrão, general manager for production with the research and development arm of Petrobras.

Armed with information from the Paraty well, Petrobras went on to make some of the biggest discoveries for decades, including giants such as Lula, Guara and Franco. Estimates now point to at least 50bn barrels of recoverable oil and gas in the Santos basin pre-salt province. A strategy aimed at gathering information from these fields has put those early conceptual fears to rest. Extended well tests in the Santos and Campos basin showed that the pre-salt reservoirs can produce at prolific rates using systems that have been tried and tested in the Campos basin, including subsea completion and flexible risers and drilling optimisation. “An initial period of research under our Pro-sal programme and results out in the field showed that we were being cautious. The pre-salt fields are much more productive than we had imagined,” Beltrão reflects.

This is just the beginning of the pre-salt challenge, however, as there is immense scope for applying new technology and concepts to reduce costs and increase safety. Petrobras CEO José Sergio Gabrielli says improvements in drilling efficiency have helped push the break-even point down to an international crude price of US$35-US$40, compared with US$40-US$45 previously. Drilling through the salt is no longer the daunting challenge it was, and drill-string optimisation is starting to ease the difficulties of drilling into the hard carbonate rock. Petrobras expects to drill 1,000 pre-salt wells by 2020, when it will have 65 deepwater rigs at work, and activity is not likely to diminish before 2030.

The very scale of the pre-salt operation offers the chance for efficiency gains. Petrobras is working out how to use a mix of higher-end rigs, tophole rigs and specially-equipped intervention vessels to reduce drilling costs on each well, for instance. The company’s ‘Proinv’ drilling efficiency programme has already trimmed the costs of pre-salt wells to an average US$120m, down from US$180m two years ago, says Petrobras general manager for well engineering Luiz Felipe Bezerra. The company believes this sum can be trimmed back to US$80m. Such claims are impressive, but the pre-salt partners are still in the early stages of surmounting the difficulties.

These challenges can be divided into three main categories: the technological, the financial and the physical, which includes limitations on logistical or industrial capacity in Brazil. Extended well tests and pilot production system may have overcome the most fundamental technological challenge of getting these reservoirs to produce, but there is still tremendous scope for reducing production costs through the development and application of new technologies.

Ground-breaking projects are already taking shape, such as the tethered subsea buoys that will decouple risers from the huge loads to which they are subjected at these water depths, or the offshore gas-to-liquids project that promises to eliminate flaring on extended well tests. Petrobras is spending about US$1bn per year on research and development, and other operators are beginning to...
follow suit by virtue of a provision that earmarks one per cent of their royalties for this objective.

In the medium term Petrobras is aiming for a new era of highly-automated production and compact processing modules that allow production units to be “re-configured” during the life span of the fields. The company is also pursuing ground-breaking subsea processing projects, looking for ways of reducing the manning levels on offshore platforms and maximising output on the limited space available on production platforms. Subsea separation and compression technologies could eventually extend to the carbon dioxide that accounts for about 11 per cent of the gas in the pre-salt fields.

The financial challenge
The second great challenge Brazil faces in putting the pre-salt fields into production is a financial one. The pressures on Petrobras were in evidence in 2010 when the company carried out a US$70bn re-financing operation on global stock markets. Only about US$43bn of this sum was cash. The rest was payment-in-kind when the Brazilian government transferred production rights for up to 5bn barrels of pre-salt oil on unlicensed acreage.

This oil-for-shares mechanism left minority shareholders wary of another refinancing operation and fed perceptions that government objectives, such as increasing the federal stake to its current level of around 48 per cent of total capital, might be diverting Petrobras from its production targets. It also increased the capital expenditure commitments on Petrobras, imposing a tight production schedule and rigid local content requirements. The re-financing operation triggered a negative adjustment that has practically wiped out the increase in market capital for the time being. Petrobras has since overcome a budgetary impasse to approve a US$225bn five-year capital expenditure plan that slightly boosts upstream spending but included a market-pleasing US$14bn divestiture plan.

Petrobras CEO Jose Sergio Gabrielli insists that the stock price will bounce back over the long-term. Many analysts agree with him, enthralled by uncommonly attractive long-term fundamentals, especially burgeoning reserves and proven record as a top-notch deepwater operator. Gabrielli points out that debt requirements, estimated at between US$67bn and US$90bn through 2015, are easily fundable. This is based on oil price scenarios of US$95 to US$80 per barrel. Shorter term concerns are being eased by an exploration project called Varredura detecting more than 2bn barrels of pre-salt oil beneath existing Campos basin production infrastructure. These discoveries require investments to extend the life of older platforms. Combined with updated topside and subsea processing facilities they imply faster and more economic routes to higher production than the greenfield Santos basin discoveries.

More pressing financing concerns relate to a supply chain where the great majority of companies are small privately run outfits. “Petrobras currently has 5,500 registered suppliers, 60 per cent of which have a turnover of less than US$5m. This is not the ideal foundation for a US$224bn capex plan,” says John Michael Streithorst, head of private equity at Banco Modal. A study carried out by Brazilian national oil industries association (ONIP) and Booz & Co, concluded that the domestic supply chain will receive investments of US$400bn through 2020. This raises deeper concerns about possible bottlenecks or overheating.

This pressure has become more intense as Petrobras is asked to move swiftly to high levels of local content on a huge domestic rig-building programme. Hydrocarbons regulator ANP is beginning to enforce local content rules under oil and gas concessions more vigorously, affecting Petrobras but also the estimated US$33bn that international oil companies will invest in the Brazilian oil sector over the next five years. Brazilian authorities are working hard to meet the challenges. Flexible and cheaper new lines of credit are being made available to suppliers through the National Development Bank (BNDES) and an innovative online financing mechanism offered by five leading banks. A host of new private equity funds have been springing up in Brazil to help fill the gap. Brazil is already seeing a big expansion in supply chain investments, including new shipyards such as Estaleiro Atlantico Sul and Estaleiro Rio Grande.

Teething problems are not hard to detect, with delays affecting the construction of these yards and, as a consequence, the first wave of contracts. A chorus of complaints can be heard industry-wide about skills shortages and predatory hiring of technically-qualified professionals. Brazilian officials and optimistic industrialists insist that a combination of Petrobras’s contracting zeal, heavy investments in automated production and government coordinated training programmes will ensure that Brazil will build up toward the kind of productivity that will underpin long term survival. The extremely negative reaction to the Petrobras re-financing seems to have run its course and investors are harking back to the fundamentals that drew them so strongly to Petrobras three years ago.
Post-Macondo reforms: The new regime in US waters

BY MICHAEL R BROMWICH, DIRECTOR, US BUREAU OF OCEAN ENERGY MANAGEMENT, REGULATION AND ENFORCEMENT

In June 2010, President Barack Obama and Secretary of the Interior Ken Salazar asked me to serve as director of the US Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE), the agency responsible for regulating offshore drilling and production in US waters, and the successor to the Minerals Management service (MMS), which had been responsible for those functions since the early 1980s. Our mandate was challenging, ambitious and above all urgent – to reform offshore energy development and the agency responsible for overseeing it.

Two months earlier, the Deepwater Horizon drilling rig had exploded, taking the lives of 11 workers and unleashing nearly 5 million barrels of oil into the Gulf of Mexico. The tragic loss of life and the enormous environment damage resulting from the Deepwater Horizon tragedy transformed the unthinkable into the actual; it served as a wake-up call for industry and government alike.

Since that time, we have been working diligently and aggressively to make the changes necessary to restore confidence that offshore oil and gas drilling and production are being conducted safely and with appropriate protections for marine and coastal environments.

**Strengthening regulations**

One of the first challenges was to strengthen the rules and regulations governing offshore drilling in US waters. Those rules and regulations had not been adequately revised and updated to address some of the challenges of offshore drilling, especially in deep water. We promptly recognised the need to identify and examine improvements to drilling and workplace safety and to enhance protection of the marine environment.

BOEMRE swiftly developed and implemented a number of new rules to improve the effectiveness of government oversight of offshore energy drilling and production. The first rule, the Drilling Safety Rule, created tough new standards for well design, casing and cementing, and well control procedures and equipment, including blowout preventers. For the first time, operators are now required to obtain certification by a qualified engineer of their proposed drilling process. In addition, an engineer must certify that blowout preventers meet tough new standards for testing and maintenance and are capable of severing the drill pipe under anticipated well pressures.

A second rule, known as the Safety and Environmental Management Systems (SEMS) Rule, requires operators to systematically identify risks and establish barriers to those risks. It seeks to fundamentally reduce the human and organisational errors that lie at the heart of many accidents and oil spills. The SEMS Rule, sometimes referred to as the Workplace Safety Rule, introduced, for the first time in the US regulatory regime, performance-based standards similar to those used by regulators in the North Sea. US operators are now required to develop a comprehensive safety and environmental management programme that identifies the potential hazards and risk-reduction strategies for all phases of activity, from well design and construction, to operation and maintenance, and finally to the decommissioning of platforms.

A second proposed SEMS Rule will require third-party audits of operators’ mandatory SEMS programmes and addresses additional safety concerns that were not covered by the initial SEMS rule. The proposed rule will enhance safety for offshore workers and provide greater protection of the marine environment through additional safety procedures, training programmes, notification obligations and strengthened auditing procedures.

In addition to these important new rules, we have issued Notices to Lessees (or NTLs) that provide additional guidance to operators on how to comply with existing regulations. In June 2010, we issued NTL-06, which requires that operator’s oil spill response plans include a well-specific blowout and worst-case discharge scenario – and that operators provide the assumptions and calculations behind these scenarios. Our engineers and geologists then independently verify these worst case discharge calculations to ensure that we have an accurate picture of the spill potential of each well.

Following the lifting of the deepwater drilling moratorium in October 2010, we issued NTL-10, a document that establishes informational requirements, including a mandatory corporate statement from the operator that it will conduct drilling operations in compliance with all applicable agency regulations, including the new Drilling Safety Rule. For the first time, this includes a review of an operator’s subsea blowout containment resources for deepwater drilling.

We have also identified the need for the thoughtful consideration, development and implementation of additional rules designed to further enhance offshore drilling safety. This process will be broad and inclusive, with the goal of increasing drilling safety and diminishing the
risks of a major blowout. It will address improvements to blowout preventers, as well as many other issues.

By the time the World Petroleum Congress meets in Doha, we will have completed a top-to-bottom, comprehensive reorganisation of MMS, or Minerals Management Service which was the predecessor to BOEMRE. The reorganisation and internal reforms that we have implemented were designed to recognise the diverse and sometimes conflicting responsibilities of the former MMS by thoughtfully separating these missions into three new agencies and providing each of the new agencies with clear definitions of their respective missions and – for the first time – needed new resources to adequately fulfill those missions.

These functions will now be carried out by three separate agencies within the Department of the Interior. The Bureau of Ocean Energy Management (BOEM) will manage the development of the nation’s offshore resources in an environmentally and economically responsible way; the Bureau of Safety and Environmental Enforcement (BSEE) will enforce safety and environmental regulations offshore; and the Office of Natural Resources Revenue (ONRR), which has been operating separately from the rest of the agency since October 2010, will be responsible solely for collecting revenues from offshore leases.

Weaknesses of the past addressed
But organisational changes alone are not enough to address the institutional weaknesses of the past. That is why we have taken a large number of important steps to strengthen key functions. This includes our environmental enforcement function, our inspections programme, and the way the agency deals with conflicts of interest.

- Strengthening Environmental Enforcement: First, we have taken a number of steps to strengthen the role of environmental analysis and enforcement in the new regulatory framework. We have created the new position of Chief Environmental Officer in BOEM to provide institutional assurance that environmental considerations will be given adequate weight in resource development decisions. These decisions include five-year plans, leasing decisions, exploration and development plan reviews, and other decisions that bear on resource management. In BSEE, we are creating a dedicated environmental enforcement and compliance programme. Historically, with very limited resources, our personnel have attempted to determine whether operators have fulfilled their environmental commitments – in the form of stipulations and mitigations to minimise the adverse impact of operations to the environment. But the agency has never before had personnel specifically dedicated to that task.
- Improving Inspections: In addition to strengthening the role of environmental analysis and enforcement, we have also taken a number of steps to improve our inspections programme. We will begin to use multiple-person inspection teams for offshore oil and gas inspections. The new process will allow teams to inspect multiple operations simultaneously and thoroughly and will enhance the quality of inspections on larger facilities. In addition, we are creating for the first time a National Offshore Training Center led by a training director whom we selected after a nationwide search. The Director of the National Offshore Training Center will develop national training strategies, curricula and programmes to maintain and improve the technical capabilities of offshore inspections and compliance personnel throughout the bureau. This will be a dramatic improvement. In the past, our inspectors have learned how to do their jobs through a combination of on-the-job training and industry-sponsored courses aimed at teaching how certain types of equipment function. The agency has never had a training centre dedicated to training inspectors on how to do their jobs. Now we will.
- Addressing Conflicts of Interest: We are also taking steps to address conflicts of interest within the agency. We have issued a rigorous recusal policy that will reduce the potential for real or perceived conflicts of interest in our enforcement programmes. Under the policy, employees in our district offices, including our permitting engineers and inspectors, must notify their supervisors about any potential conflict of interest and request to be recused from performing any official duty where such a conflict exists. As a result, our inspectors are required to recuse themselves from performing inspections of the facilities of former employers. Also, our inspectors must report any attempt by industry or by other BOEMRE personnel to inappropriately influence, pressure or interfere with his or her official duties. A recent internal review demonstrated approximately 50 instances of our inspectors recognising a conflict barred by the policy and taking appropriate action to recuse themselves. That is an important step in assuring the public that our oversight and regulatory responsibilities are being carried out in a disinterested and objective manner.
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Promoting offshore safety through international collaboration

An important element of our long-term strategy is to maintain and strengthen collaboration with our international counterparts. Offshore regulators and senior policy officials have much to gain from collaborating with their counterparts in other countries to elevate the safety and environmental soundness of offshore operations around the world. To this end, in April 2011, the Department of the Interior hosted ministers and senior energy officials from twelve countries and the European Union for a Ministerial Forum on Offshore Drilling Containment. This was a historic meeting for the Department – and it led to a fruitful dialogue about best practices and how best to develop cutting edge, effective safety and containment technologies. The meeting concluded with the unanimous recognition that this dialogue should continue at the highest levels of government.

We also continue our work to strengthen existing channels for international cooperation and the sharing of best practices across different regulatory regimes. For example, we will continue our participation with the International Regulators Forum (IRF), an organisation that BOEMRE helped to found in 1994 to facilitate the cooperation and sharing of information among the leading offshore regulators. I attended the recent Forum in Norway, and am looking forward to the important role that BSEE will play in the IRF.

The United States will continue to participate in a number of government-to-government initiatives to share best practices and build regulatory capacity in countries trying to develop offshore drilling regulatory regimes. Our experts have participated in needs assessments and have conducted workshops in Suriname, Uganda, Papua New Guinea, and Liberia. We will also continue our long-term technical assistance with the governments of Iraq and India. This past summer, we hosted a delegation from Mexico for the first of a series of information exchange workshops to fulfil the Secretary’s mandate for developing the highest standards for operating in the Gulf of Mexico.

We will continue to collaborate with our foreign counterparts, both through bilateral government-to-government assistance programmes and through appropriate multilateral channels, in developing safer, more environmentally responsible drilling in the world’s oceans.

The Future of offshore drilling in US waters

Offshore drilling in the United States, and indeed around the world, will never be the same as it was a year ago. That much is clear. The changes that we have put in place will endure because they were urgent, necessary and appropriate. And more change will surely come, although not at the rapid pace of the past year. The process of making offshore energy development both safe and sufficient to help meet the nation’s and world’s energy demands will never be complete. It is – and must be – a continuing, ongoing, dynamic enterprise.

The central challenge that Deepwater Horizon highlighted is the need to establish the institutions and systems – and the processes of cultural change and improvement – necessary to ensure that neither government nor industry ever again become so complacent that they think no further change is necessary – because that sort of complacency set the stage for Deepwater Horizon.

Following Deepwater Horizon, a broad consensus quickly emerged – in government and industry – that there was an urgent need for upgrading safety rules and practices within the offshore oil and gas industry. As we move forward, we must do everything possible to keep the complacency from creeping back. We must have the discipline to continue pushing for improvements that will enhance the safety of offshore drilling. Both industry and government regulators must continue to use the memory of Deepwater Horizon as a constant reminder of the continued urgency of improving safety.
Russia is believed to be one of the richest countries in the world with its vast oil and gas resources. According to the recent data, its reserve base amounts to 96 billion tons of oil equivalent (btoe) which is nearly 700 billion barrels of oil equivalent. The offshore part of the reserves, defined as what is recoverable under current economic and technical conditions, is less than 10 per cent. Russia’s total resource base is several times larger and is estimated to be 259 btoe (1,890 bboe), and of this amount the offshore part is 96 btoe, or 37 per cent. This gives a total estimate of 355 btoe for so-called conventional hydrocarbons and as shown below.

The Russian Arctic is believed to be the area with the highest unexplored potential for oil and gas as well as unconventional resources such as natural gas hydrates. Despite a common view that the Arctic has plentiful hydrocarbon resources, there are ongoing debates regarding the potential of this region as a future energy supply base, raising issues of geopolitics and environmental concern as well as assessment and delineation of Arctic resources and the technology and market demand for developing them. However, scarce information and geological data create uncertainty about the Arctic as main base of Russia’s energy supply in the second half of this century. A further uncertainty is the pace at which production from northern areas including the Arctic, will be brought onstream – either because of national policy, infrastructure development or investment by the state and the oil companies. These areas embrace those where development has already been started (offshore Sakhalin, northern Timan Pechora) and those awaiting future development such as the Barents and Pechora seas, East Siberia, Yamal, Kara Sea and Kamchatka.

The following sections will briefly describe the status and future prospects in the exploration and development of these areas and challenges associated with them.

The Northwest of the Russian Arctic
There is a common view that shelves of the Barents, Kara and Pechora seas are considered as the most prospective areas for offshore oil and gas field development.

Barents and Pechora seas
With almost 31 btoe of oil and gas resources, the Barents and Pechora seas represent one of the most attractive areas of the petroleum resources development.

So far two gas-condensate fields – Shtokmanskoye and Ledovoye, and three gas fields – Ludlovskoye, Murmanskoye and North-Kildinskoye have been discovered in the Barents Sea. Potentially interesting structures have been detected in the Fersman-Demidov shoulder, Shatsky and Vernadsky swells, and also in the area of Medvezhy and Admiraletiskoy swells.

The former "Grey zone", which was disputed between Norway and Russia, has a high potential in the area of Fedynsky Swell and East-Barents foredeep where quite a number of structures are very prospective for both gas and oil.

Up to the present time oil has not been discovered in Arctic seas except the Pechora Sea, therefore these locations, including Admiraletisky swell, are of particular interest.

It is anticipated that development of the Barents Sea will start from the Shtokman field, which later will be accompanied by the satellite fields of Ledovoye, Ludovskoye and Terskoye and later by the fields of the Fersman and Demidov swells. This concept will enable utilisation of available infrastructure so as to reduce investment costs.

The 2010 Norwegian-Russian agreement on delimitation of the Barents Sea can spur a new round of active cooperation between two countries on the development of Arctic resources. The new agreement opens new opportunities for active cooperation in developing this strategically important
Possible large accumulations of petroleum resources in the delineated zone are located closer to the shoreline than the Shtokman field, and this may facilitate a new concept of the whole Barents region development.

The shelf of the Pechora Sea is the only one among all the Arctic shelves where the oil has been discovered. The main fields of this region are the Pirazlomnoye, Dolginskoye, Medyn-more, Varandey-more and Kolokomorskoye oil fields, the Severo-Gulyaevskoye oil-gas-condensate field and the Pomorskoye gas-condensate field. Besides these fields there are several large and prospective structures located in the south eastern part of Pechora Sea: Yuzhno-Russkaya, Pakhanchevskaya, Sakhaninskaya and Papaninskaya. According to the estimates, total resources of the Medyn-Varandey and Kolokomorsky structures amount to 410 million tons of oil with a recoverable volume of 80 million tons. It is planned that the Pirazlomnoye field will start the oil production in the Pechora Sea followed by development of other fields.

**Kara Sea**

The Kara Sea with its 37.4 btoe reserves, of which around 75 per cent is gas, is believed to be a sea with the largest petroleum resources. In the Kara Sea, shelf prospective locations are the Yamal shelf with its Leningradskoye and Rusanovskoye fields as well as offshore extension of the Kharasaveyskoye and Kruzenshternskoye fields. Another attractive location is Ob (Severo-Kamenomys-skye, Kamennomys-skye-more and Obskoye fields, aquatorial extension of Yurkharovskoye, Salekhatpskoye, Yuzhno-Tambeiskoye, Utreenne and Tasiiskoye fields) and Tazov (Chugoriaakhinskoye field and aquatic extension of Semakovskoye, Antipayutinskoye and Tota-Yakhinskoye fields) bays.

According to the estimates, gas production from the Kara Sea shelf area may reach up to 200 billion cubic metres (bcm) annually, which could compensate for the decline in production from fields in Yamal peninsula and enable utilisation of available infrastructure.

**Ob and Tazov bay areas**

The Ob and Tazov bays, now being actively explored, have emerged as another very attractive area of future petroleum production with a lot of already discovered fields and potential structures. According to the estimates, gas fields of the Ob and Tazov bay areas could produce gas with the annual rate of 75 bcm.

**Offshore Sakhalin and Caspian Sea areas**

According to Russia’s energy strategy, offshore fields should annually produce around 220–230 million tons of oil equivalent, and by 2030 up to almost 300 mtoe. It is anticipated that nearly half of that amount will come from the Sakhalin and Caspian offshore regions alone. Recoverable petroleum resources of the Sea of Okhotsk including offshore Sakhalin area amount to 8.9 billion tons of oil equivalent. Caspian recoverable resources comprise nearly 3.5 btoe. Active exploration programmes with dynamic production growth in both areas maintained by experienced and internationally recognised companies gives confidence that this target will be reached.

**Potential of West and East Siberia**

Is there an alternative to the development of oil and gas fields located in the untapped Arctic offshore areas? The development of Arctic resources is inevitable although there is no time pressure in doing that right away. Russia has abundant petroleum resources onshore with technology for safe and efficient development available now. There
are two regions, namely, Nadym-Tazov and Krasnoyarsk regions that could easily maintain production at required level on a mid-term and even on a long-term basis and thus, postpone development of the Arctic resources of the Yamal peninsula and the northern seas.

The Nadym-Tazov region is a new hub of hydrocarbon accumulations in West Siberia. Recent estimates showed that this region has potential gas resources up to 20 trillion cubic metres (tcm). Its proximity to the Yamburg gas condensate field with developed infrastructure and with gas pipeline exporting gas to Europe, makes development of this region very attractive both technologically and commercially. According to estimates made by VNIIGAZ (Gazprom’s R&D institute) a high level of production (up to 15 bcm per year) can be reached already in the third year of development.

The second potentially large centre of petroleum production is associated with the Baikal region of hydrocarbons accumulation, which is accessible for industrial development. According to resource evaluation reported in 2003, recoverable reserves of oil and gas in this region amount to 35-45 btoe (approximately 30 per cent of which are liquid hydrocarbons). The largest field of this region – the Kovyktinskoye gas condensate field with estimated in-place volume of two tcm (with an upside potential of up to 10 tcm) could serve as a starting point for such a development.

Although East Siberia is characterised by the highest reserve replacement ratio, capital investments in the area need to be almost twice as big as in traditional oil-producing regions, due to the lack of infrastructure and the distance to the market. For example, one of the key East Siberian projects, Vankor (developed by Rosneft) is located 1,500 km from Krasnoyarsk, the main transportation hub in this region. Severe climatic conditions limit construction to around 100 days per year.

One can conclude that these large scale projects in new oil and gas regions, like West and East Siberia, the Far East and Arctic offshore will provide the reserves to sustain Russian output. According to future planning by 2020 Russia should annually produce 1,300-1,350 mtoe, and by 2030 1,415-1,475 mtoe. The offshore share of Russian production will grow from around 17 per cent in 2020 to more than 20 per cent by 2030. It is anticipated that nearly half of that amount will come from the Sakhalin and Caspian offshore regions, while the other 50 per cent will be delivered by the Russian northern seas.

However, lack of infrastructure limits the attractiveness for companies. Development of resources of the northern seas is additionally complicated by the lack of technology and qualified personnel, operational and environmental problems and higher cost. In order to meet this challenge a state-coordinated exploration programme is required, with the close cooperation and participation of the international community.

A stable, transparent and predictable legal framework will be needed for the massive investments required in exploration and production, and for the active involvement of foreign companies, bringing with them indispensable competence, experience, technology and health, safety and environment principles. But Russia’s resources will be important to sustain oil and gas supplies to western Europe and the Asia-Pacific region.
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RWE Dea currently gives proof of this high standard upstream activities in Algeria, Denmark, Egypt, Germany, Ireland, Libya, Mauritania, Norway, Poland, Trinidad & Tobago, Turkmenistan and the United Kingdom – day-to-day. In light over ever-higher global demand and in an effort to expand its international upstream position, RWE Dea follows a distinctive growth strategy and is investigating further business opportunities worldwide.

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Environmentalists rail against it. Oil, gas and mining companies, shippers and some governments in the region insist on it happening. People who live there are in two minds about it all.

Resource development in the Arctic – whether it is oil and mining exploration or the expansion of shipping and other services – provokes widely differing emotions. The oil industry says with an estimated quarter of the world’s as yet undiscovered hydrocarbons likely to be in the Arctic region, the case for exploration is overwhelming. So also say the mining companies: whether it is uranium, iron ore, gold or rare earths, the Arctic has massive amounts of minerals the world urgently needs.

Shipping operators, particularly those in Russia, say routes through the Arctic seas represent a much shorter and ultimately cheaper way of shipping goods between the Americas, Europe and Asia. Governments in the region are busy staking claims to vast swathes of ice and ocean in the face of a regional race for resources.

The relatively small but widely diverse population living across what’s often referred to as “The High North” are well aware of both the positives and negatives of the rush for resources.

“Arctic peoples are caught in a bind” says Minik Rosing, a native Greenlander who is a professor of geology at the University of Copenhagen. “On one hand resource development offers the chance of more personal wealth and political independence. But it also threatens to overwhelm us and change our environment and culture for ever.”

Environmentalists show no such ambivalence. The exploitation of fossil fuels has led to changes in climate and the melting of Arctic ice. Exploration companies are now rushing in to the region to exploit yet more fossil fuels, only adding to climate change problems. “It’s madness” says a campaigner at Greenpeace, the environmental NGO. “You don’t put out a fire with gasoline.”

**Climate Change and the Arctic**

There appears to be little doubt that the pace of Arctic warming is speeding up: According to the latest report of the Arctic Monitoring and Assessment Programme, a working group of the Arctic Council, the warming trend in the Arctic has been twice the global average since 1988. Arctic winter ice seasons are becoming shorter while sea ice in the Arctic summer has retreated to its lowest levels since satellite measurements began in 1979.

“The clarity of that trend is very striking” says Sebastian Gerland, a sea ice expert and one of the report’s contributors.

The report also found that the Greenland ice sheet – covering an area of more than 650,000 square miles – is melting at a very fast rate. While this could mean rising sea levels and be bad news for much of the planet, it does, on the face of it, seem to be good news for the exploration industry.

**Oil and gas**

In the most comprehensive estimate of Arctic hydrocarbon reserves to date, in 2008 the US Geological Survey (USGS) said there were likely to be 90bn barrels of undiscovered and recoverable oil across the region along with more than 1,650 trillion cubic feet of natural gas – enough respectively to meet three and 14 years of world demand at present levels of consumption. More than 80 per cent of the hydrocarbons are offshore in waters of less than 500 metres, making them, said the USGS, accessible to drilling.

Longer Arctic summers and less
sea ice means more time and opportunity for offshore drilling activities. Cairn, the Scottish based exploration business, is the only company so far to have reported evidence of hydrocarbon findings offshore in the more westerly Arctic region. In summer 2010 it found indications of hydrocarbons off Greenland, and the company has been drilling again in 2011. Other companies including Shell, ConocoPhillips and Statoil of Norway have also been given offshore drilling licenses by the Greenland government. Elsewhere Shell, BP and other oil majors are busy applying for licenses to drill in offshore Alaska: Shell has submitted plans to the US authorities for drilling 10 exploration wells in the Chukchi and Beaufort seas in the summers of 2012 and 2013. In the Barents Sea off northern Norway – divided with Russia – Statoil has made what it says are commercial oil finds. A number of other international oil companies are now either already drilling or applying for licenses in the area.

Russia has been among the most bullish of the Arctic countries in wanting to press ahead with Arctic oil and gas exploration. With fields in western Siberia expected to contribute less to Moscow's oil revenues in future years, the big prize is considered to be oil and gas in Russia's far north – in the Kara and Barents seas. Moscow is making long term plans for exploration in the region. Eight floating nuclear power stations are at present under construction in St Petersburg: the plan is to position them along Russia's north coast in order to supply power to communities in the area and to onshore and offshore exploration activities.

Exploration obstacles

One of the main problems in the region relates to who owns what. When Artur Chilingarov, a veteran Russian polar explorer, placed a Russian flag on the sea bed beneath the North Pole in 2007, it caused considerable concern round the region. Though Vladimir Putin, Russia's prime minister, insists the Arctic should be a region "for cooperation and dialogue," Moscow claims sovereignty over vast tracts of the region's ocean bed. The US, Canada, Norway and Denmark – Copenhagen controls Greenland's foreign policy – also have competing claims in the region. Other countries and groupings – including China, India and the European Union – are trying to ensure their interests are safeguarded. Analysts point to evidence of a regional military build-up.

“For now, the disputes in the north have been dealt with peacefully” says Admiral James G Stavridis, NATO’s supreme allied commander for Europe. “But climate change could alter the equilibrium over the coming years in the race of temptation for exploitation of more readily accessible natural resources.” There are also great technical challenges. Equipment is severely tested in such extreme conditions. There is a lack of infrastructure – and lengthy supply lines. Recent rises in oil and gas prices have cushioned the expense of operating in the Arctic but the need for environmental safeguards is increasing costs. In the aftermath of the Gulf oil disaster it's not just environmentalists who are concerned about how an oil spill, possibly beneath the ice, could be contained in Arctic waters. There is a great deal of official nervousness as well: Shell and other oil companies have had their license applications for drilling offshore Alaska repeatedly scrutinised by US authorities.

Though Russia is considered to have less stringent conditions governing Arctic resource exploitation, its exploration ambitions are limited by a lack of expertise, particularly in offshore drilling operations. Russian exploration companies are keen to link up with overseas groups, as in the case of the proposed partnership between Rosneft and ExxonMobil.

Climate change also poses considerable challenges to the exploration industry: weather patterns are likely to become more unpredictable. More icebergs calving off glaciers are likely to pose increasing dangers to oil and gas rigs operating in the region. They will also threaten both existing and new shipping lanes.

Meanwhile environmental groups are mounting an increasingly militant campaign against the whole idea of drilling in the Arctic. Cairn's operations off Greenland have been a frequent target of protesters. Local groups in Canada and Norway are voicing concerns that drilling will adversely impact fisheries and threaten livelihoods.

The Arctic does hold out great resource exploitation possibilities. It is one of the last great untapped areas on earth – but it is also one of the most fragile of environments. The Arctic and its complex weather systems is often referred to as the world’s air conditioner, its waters and winds responsible for cooling down great swathes of land and ocean. Many exploration companies are learning that they have to tread carefully: if not, reputations and finances will suffer – and environmental disaster could follow.
Energy is the lifeblood of any economy. It’s what heats our homes, fuels our vehicles, powers our factories – and shapes the quality of our lives. As developing countries like China and India continue to evolve their economies, the global demand for energy is rapidly growing. And despite significant efforts to develop renewable energy sources, hydrocarbons – oil, gas and coal – are expected to play a dominant and critical role in meeting energy demands for decades to come.

More than ever, the world needs a plentiful supply of clean, secure and affordable energy. But meeting that demand has never been more challenging. Consider the example of oil, which currently supplies about a third of the world’s energy demand – and the vast majority of transportation fuels. The era of low-tech, easy-to-develop oil is drawing to a close in North America. Elsewhere, conventional oil supply remains abundant, but is increasingly difficult to access. Nearly 80 per cent of the world’s oil reserves are owned or controlled by state companies. That leaves just over 20 per cent of reserves on the open market.

And here is one of the most pertinent statistics of all: over half (52 per cent) of the world’s oil reserves still accessible to the private sector are found in Canada’s massive oil sands reserves.

Oil from sand
Buried beneath the boreal forest of northern Alberta, Canada’s oil sands contain 173 billion barrels of recoverable oil with current technology – the world’s third largest oil reserve after Saudi Arabia and Venezuela. Future technology breakthroughs could significantly increase the amount of recoverable oil, potentially making the oil sands the largest reserve of all.

About 20 per cent of oil sands reserves are close enough to the surface to be reached by traditional mining. The remaining 80 per cent can only be accessed by in-situ drilling, which injects steam into the deposit to thin the bitumen before pumping it to the surface (in-situ projects disturb less land than a typical mining project and do not produce tailings ponds). In-situ drilling is a relatively new innovation and one of many examples of how technology is helping to unlock this resource base.

As an independent Calgary-based upstream oil and gas company, Nexen is strategically focused on three key growth areas – conventional exploration and development in some of the world’s most abundant resource basins (the North Sea, the deepwater Gulf of Mexico, Yemen and offshore West Africa); shale gas; and Canada’s oil sands. Nexen has strong future prospects in the oil sands. We were proactive in assembling land in the oil sands region of northern Alberta to the point that we are now the largest landholder in the world’s third largest oil reserve. Our contingent recoverable oil sands resource is currently estimated at three to six billion barrels of oil equivalent (boe).

Nexen is ramping up production at our Long Lake in-situ oil sands facility, which has an expected capacity of 60,000 barrels per day (bpd) of high quality, ultra low sulphur, synthetic crude oil. At Long Lake, Nexen pioneered a patented OrCrude™ technology that takes a portion of the barrel other oil sands operations treat as a waste byproduct (asphaltenes) and transforms it into a source of energy and hydrogen for our operations, thereby reducing our reliance on natural gas. This
technology allows us to get the most energy out of every barrel of bitumen.

Our next oil sands project, known as Kinosis, is expected to develop a thick, superior quality reservoir starting with two smaller in-situ projects – each with a capacity of 40,000 bpd. We anticipate approving Kinosis in 2012. Nexen also holds a 7.23 per cent interest in the Syncrude Canada Ltd. joint venture that has been mining shallow oil sands deposits since the mid-1970s, and is Canada’s largest oil sands operation.

The economics of development
One of the great advantages of Canada’s oil sands is that the reserves are clearly identified and understood; we know exactly where the bitumen is, so exploration costs are very low. This allows the industry to approach production as a steady and reliable manufacturing process – and there is enough supply to keep the “oil sands factory” running for a century or more.

Another significant advantage is that the oil sands deposits are located in a province, and a country, that is very appealing to investors due to the combination of democratic traditions, an open economy and a strong record of regulatory and environmental oversight (Alberta is the only jurisdiction in North America to mandate industrial greenhouse gas emission reductions). Producers and governments alike remain focused on the goal of responsibly developing the oil sands to provide the energy our economy – and the world – requires.

All of this helps explain why the Canadian Energy Research Institute (CERI) recently projected that some US$ 2.07 trillion will be invested in building and maintaining the oil sands over the next 25 years. CERI also predicted industry-wide oil sands production will ramp up from the current 1.7 million bpd to 2.1 million bpd by 2015 and 4.9 million bpd by 2035.

Canada is already the largest energy supplier to the United States and close to half the crude exported is from the oil sands. With the right planning and infrastructure, oil sands crude also has the long-term potential to help supply energy-hungry Asian markets.

But oil sands development also faces some significant challenges. This is a very capital-intensive industry; a typical in-situ or mining project can take several years to move from conception to completion and requires billions of dollars in upfront investment. Success depends on superior planning and execution, and the ability to withstand inevitable fluctuations in commodity markets.

As a result, many companies have entered strategic partnerships. For example, the Syncrude joint venture allows the various owners to mitigate economic risks by cost sharing on infrastructure development as well as the technological expertise essential to achieving sustainable energy development.

Responsible development
The biggest challenge is managing the environmental impact of oil sands development. The industry is energy-intensive and water-intensive and involves significant land disturbance. But while some industry critics have been quite vocal in labeling oil sands crude as “dirty oil,” the reality is much less sensational. For example, independent studies show that oil sands crude is not significantly more carbon intensive than other North American crude oil.

Canada's GHG emissions by sector

<table>
<thead>
<tr>
<th>Sector</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>5.9%</td>
</tr>
<tr>
<td>Manufacturing, Commercial and Construction</td>
<td>11.5%</td>
</tr>
<tr>
<td>Agriculture and Forestry</td>
<td>8.4%</td>
</tr>
<tr>
<td>Electricity and Heat Generation</td>
<td>14.2%</td>
</tr>
<tr>
<td>Transport</td>
<td>27.5%</td>
</tr>
<tr>
<td>Industrial Processes and Waste</td>
<td>9.9%</td>
</tr>
<tr>
<td>Other Fossil Fuel</td>
<td>16.1%</td>
</tr>
<tr>
<td>Oil Sands</td>
<td>6.5%</td>
</tr>
<tr>
<td>Other Fossil Fuel</td>
<td>16.1%</td>
</tr>
</tbody>
</table>

imports on a “wells-to-wheels” life cycle basis. Similarly, the oil sands industry is currently responsible for 6.5 per cent of Canada’s total greenhouse gas (GHG) emissions – far less than the transportation (27.5 per cent), electricity (14.2 per cent) or manufacturing and heavy industry (11.5 per cent) sectors.

Moreover, whether it is emissions, water use or land disturbance, the oil sands industry has acted decisively to carry out continuous improvements in environmental performance. By harnessing technology, the industry has virtually eliminated sulphur dioxide emissions while reducing GHG emissions intensity (the amount of GHG emitted for each barrel of oil produced) by 39 per cent compared to 1990 levels. Oil sands producers recycle between 80 per cent to 95 per cent of water used and have invested billions of dollars in technology to significantly accelerate the pace of tailings ponds and land reclamation (companies are required to restore all disturbed lands to a sustainable landscape that is equal to, or better than, its original state).

As Canada’s oil sands industry grows, more must be done to manage the cumulative impacts of development. To address this, five like-minded oil sands operators, including Nexen, have teamed up to form the Oil Sands Leadership Initiative (OSLI). Each company is providing resources, sharing best practices and working together on potential technological breakthroughs to advance sustainable development. The other OSLI participants are ConocoPhillips Canada, Suncor, Statoil Canada and Total E&P Canada.

Recent initiatives undertaken by OSLI include advancing research into making in-situ oil recovery more energy-efficient (a key step to better managing GHG emissions); testing technologies to allow one oil sands operator to take another operator’s tailings wastewater, treat it, and then reuse it; and collectively planting new trees (600,000 to date) across the oil sands region to improve forest cover and better protect woodland caribou from predators.

Nexen, along with other oil sands developers, remains committed to working with all stakeholders – including governments, non-government organisations, academic researchers, communities and consumers – to seek long-term solutions to environmental and social challenges.

The oil sands industry is strongly positioned to deliver the energy our growing economies require in the years and decades ahead. It is no silver bullet for meeting global energy demands but – in tandem with the responsible development of a range of conventional and unconventional energy sources – Canada’s oil sands can play an important role in creating the sustainable energy future we all desire.

Total bitumen production (‘000 b/d)

Source: OCERI
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It **evolves** via nonstop innovation.

It **produces** far greater rewards for you.

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The ancient Greek mathematician Archimedes would have loved the modern energy industry. In oil fields dotted with pumpjacks, he would recognise familiar principles of leverage from his ingenious catapult designs. His water-lifting device, the Archimedes’ Screw, revolutionised irrigation and in a manner, evolved through the ages to ultimately give rise to an enormous variety of positive displacement pumps and compressors. Today, we depend on compression to do everything from pipeline transport to enhanced oil recovery – and more recently, hydraulic fracturing, a technology having demonstrated the potential to unlock significant new energy supplies.

Past generations of technologists, including Archimedes, have given our industry many gifts and have allowed us to achieve our present state – ingenuity at speed. Of course, they faced problems we can’t imagine – nor could they have imagined ours. For example, increasing and diversifying the world’s energy supply in support of 9 billion people will no doubt be a monumental challenge. The International Energy Agency forecasts that global demand will increase 40 per cent by 2035. Clearly, we’ll need more of every type of energy, especially oil and natural gas.

Ingenuity and integration

Throughout history, the inexhaustible resources of human energy and ingenuity have enabled us to do more, and to do it faster with less effort. The energy industry continues to build on this heritage of technology development and deployment. One of the greatest strengths of an international oil company (IOC) is integration: linking technologies, knowledge and worldwide experience to help create the reliable, safe, efficient and affordable energy supply that fuels human progress.

Today, digital technologies and new, efficient processes are transforming our workflows. They are empowering us to apply our best minds to the toughest challenges everywhere in the world, and to rapidly integrate information and innovate at speed. We connect surface to subsurface, past to present and present to future, predicting and optimising performance in reservoirs, wells and facilities measured and monitored in real time. This 21st century capability will ensure that IOCs and producing countries will continue to open new frontiers, raise performance to new levels and meet the world’s energy needs.

From ramps to robots

How do we know ingenuity will prevail in meeting the energy supply challenge?

Consider our evolutionary advance into the offshore: To monitor the first near-shore wells over 100 years ago, we walked on wooden piers, while today, we use robotic, remote, autonomous underwater vehicles to monitor subsea deepwater wells and facilities.

The evolution into the deep continues. Facing the incredible pressures inherent in deep water activities, we have found a way to remove water depth as a pressure-related issue. To improve safety and reliability under extreme deepwater conditions, we have been developing and will soon deploy “dual-gradient drilling.” This technology will significantly reduce deepwater drilling costs and improve outcome predictability. A dual gradient system, in effect, makes the deepwater well comparable to a land well.

Some of the tools we rely on today had their beginnings before recorded history. Without the innovations of metallurgists through the centuries, for example, the progression towards sophisticated alloys used in modern tubulars would not exist. Today, these materials make most of the world’s deepwater oil industry possible. During the next decade, deepwater production could grow to more than 10 million barrels per day, according to IHS CERA. Corrosion-resistant tubulars and components also make possible all of the world’s sour (high H₂S content) gas production, including growing output from Kazakhstan’s giant Tengiz Field and new energy from Chuandongbei, a gas project in China being developed by a partnership of Chevron and the Chinese National Petroleum Company.

It is unlikely that the first metallurgists could have envisioned the extension of their technologies to help enable the Gorgon liquefied natural gas (LNG) project in Western Australia. This project will significantly enhance Asia-Pacific LNG supplies while re-injecting much of its corrosive, produced CO₂ into the ground with the largest greenhouse gas storage project of its kind in the world – enabled by both metallurgy and compression.

Measuring time – simulating the future

One does not think of the hourglass, an ancient invention, and the seismic geophone as related, but in fact both record time. By continuously improving our ability to measure the time required for sound to travel through rock, we are finding new supplies and recovering more by optimising reservoir
management. Advances in seismic data processing using Gaussian Beam pre-stack depth migration have allowed us to "see" into the past, deep into the subsurface, often below volcanics and salt layers. Without this technology, Chevron and others might never have discovered many of the deepwater fields now contributing significantly to energy supplies around the world.

With “4D” or time-lapse seismic, we can measure change in reservoirs and predict behaviour and response. Our reservoir simulators and predictive tools allow us to travel “virtually” into the future, testing development scenarios and forecasting decades of potential performance. We can even simulate years of deepwater platform operations and optimise design before we invest – a game-changer in reducing risk and accelerating the time to peak performance.

The awesome power of integration
While applying a new technology can improve our work, integrating multiple technologies can create whole new sectors of our business. Evolving separately, horizontal drilling and hydraulic fracturing have enabled us to add new oil and gas reserves once thought unrecoverable. Now integrated, they have set off a phenomenal boom in shale gas development. In less than a decade, new output from shale has grown to 25 per cent of US gas production, according to the US Energy Information Administration (EIA). The industry is still assessing the global potential with exploration programmes, notably in Eastern Europe and China. One recent EIA study looked at 48 basins in 32 countries and found more than 6,000 trillion cubic feet of “technically recoverable” gas in 70 major shale formations. Time will tell how much resource we can reach. But IOCs by sharing the integrated technologies and best practices well proven in the United States can now help countries everywhere to evaluate the potential – and hopefully, grow their national energy supplies.

Steamflooding technology is another integrated solution poised for growth. After decades of improving this method in California and Indonesia, its application for developing heavy oil is now being piloted by Chevron in the giant Wafra Field located in the onshore Partitioned Zone between Saudi Arabia and Kuwait. If successful, the incremental upside potential for this one field could be 6 billion new barrels of recoverable oil. While steamflooding is a proven solution in sandstone reservoirs, the Wafra Field is a carbonate reservoir requiring the extension and integration of existing technologies applied in new ways, and the development of new technologies to meet the challenges not seen in sandstone. Additionally, with water being a scarce commodity in the region, our project is integrating a technology called “seeded slurry vapour compression” evaporation – to make pure water distillate for steam generators from reservoir brine. Successful integration of all of these technologies will help create opportunities for arid countries to unlock their heavy resources.

The renewables conundrum
We need to grow every form of energy, and renewables are forecasted to grow the fastest. But they must be
competitive at scale. By 2035 renewables are still expected to contribute only a small share of global energy supply. Solar, wind and biomass have been relied upon for energy since ancient times. But these energy sources lack the energy density of fossil fuels, which nature has pressure-cooked over millions of years to create natural energy cells packed with power.

Capturing and densifying renewable resources at scale represents a challenge that can only be met by extending, researching, developing and ultimately integrating technologies that improve our ability to concentrate and store energy from the resource to final product. To be cost effective without sustained subsidies, it is likely that technologies that can build on existing supply chain infrastructure to produce “drop-in” bio-hydrocarbon liquid fuels, for example, may succeed earlier than those that don’t. Elsewhere, the geothermal industry evolved by combining and extending technologies from the petroleum and the power-generation sectors. Chevron, the world’s largest producer of geothermal energy, is deploying this model at scale in Indonesia and the Philippines.

IOCs, including Chevron and many other companies, are working to commercialise and advance renewable energy. In California, our solar-to-steam demonstration project will employ more than 7,000 sun-tracking mirrors to make supplemental steam for enhanced oil recovery. And at the Qatar Science and Technology Park, we are helping test solar technologies in desert applications, where many large-scale solar projects are being considered.

**Connectivity - integration’s new wave**

One of the many uplifting stories in our industry’s history has been the way in which we have embraced information technology. The skyrocketing evolution of computing technology has made early calculating machines, such as the slide rule and the abacus, long forgotten. Today, high performance computing makes possible the miracle of reservoir modelling and high-speed simulation, integrating data, information technologies and mathematics to show us how best to develop oil and gas fields and extend their lives.

The next chapter in information technology promises to be even more exciting, because it is enabling connectivity and process improvements at an astonishing pace. This is driving integration on a whole new level, allowing us to create linked, global networks of experts in real-time without travel. A case in point are the visualisation rooms where top explorers and specialists gather to support the drilling of complex, deepwater wells while connected digitally to teams in control rooms on working rigs. Everyone sees the same data. We call ours the Well Decision and Execution Collaboration Center – and it ensures not just good decisions as drilling progresses, but the best possible decisions.

Meanwhile in the oil and gas fields, digital connectivity is allowing our industry to track operations much as a hospital monitors patients in surgery. Information from reservoirs, well and facilities feeds decision support centres in real time, guiding the management, well maintenance and fine tuning of every element of operations. With innovations such as continuous downhole sensors and wireless communications becoming common in the field, we are beyond automation and optimisation. We are transforming and integrating workflows with new operating behaviours and technology to enable new levels of performance.

**Human energy**

The combined potential for connectivity and integration to accelerate business insight seems endless. Our industry has been able to link geologic knowledge, geotechnical experience and human energy by integrating the best geoscientists and their tools. At Chevron, our rigorous process for rating, ranking, selecting and drilling exploration prospects worldwide has enabled us to achieve an exploration success rate approaching 50 per cent. Results like these tell us that with ingenuity at speed, IOCs have never been better equipped to add value, reserves and production. Everywhere partnerships take advantage of the global capability of this integrative mindset and human energy, new energy is sure to follow.

Consider again the compressor. Evolving throughout our industry’s history, it has taken many impressive forms and created new opportunities. With worldwide connectivity, we’ve found another way to capture value from this technology. We’ve long known that compressor reliability is a key to performance in individual fields and facilities. Now we’re going global, with a Chevron centre of expertise in Houston which digitally monitors every major compressor in the company – and serves as an on-line, 24 hours-per-day, seven-days-a-week consultant to field operations worldwide. Archimedes would have appreciated that.
n 1948, we opened our first research centre in Ridgefield, Connecticut. Located a short drive from New York City, the centre, over the years, became home to more than 140 scientists focused on challenges in formation evaluation. Perhaps the location encouraged creative thinking through its relaxed environment, or perhaps its early position on the world’s largest oil and gas producing continent made it the right place to be. Either way, as the company grew, so did our needs in research and a second centre was opened in Cambridge, UK in 1982. The intervening 35 years had seen considerable change in the industry with activity beginning to move east to follow the development of new oil and gas areas. The benefits of Cambridge, however, not only as a centre of academic excellence but also as a city close to hydrocarbon activity in the North Sea were apparent. Proximity to academia brought talent, being adjacent to growing business brought customers and investment. These two ideas remained as our world of research developed further and they lie behind the move of our first research laboratory from Ridgefield to Boston, Massachusetts in 2008.

At the same time the world of IT enabled communication around the world. Remote centres could exchange information more easily and more quickly. Partly as a consequence, our next research centre openings were much smaller – in Stavanger, Moscow, Dhahran and now Rio de Janeiro. In each case we were following the expansion of exploration and production activity while remaining close to customers and close to academic centres of excellence. It was as if the ideas of the laboratory could be tested in a customer field almost immediately.

Within any technical field, and certainly within oil and gas development, research is an essential activity. This is becoming more and more important as easier hydrocarbon supplies become exhausted. Reservoirs are becoming more complex, their production more difficult, their location more remote, and their environmental conditions in terms of temperature and pressure more extreme. So while research must address harder problems, its real purpose remains unchanged. And that purpose is perhaps twofold. First there must be a certain amount of fundamental work, where the question to be answered is often the question itself and where the impact on the business is difficult to measure. The potential of such a project is usually large, and failure to succeed should not be a surprise. Second, we must also engage on projects that consolidate earlier work. This sometimes becomes easier as enabling technologies are developed elsewhere. In this case, the question is known, the impact easier to measure, while potential and risk are much better known. We should still not be surprised by failure, however.

But above all, research must support new product development, and while this means solving hard problems and looking at new technologies, it is driven by needs from both inside and out. Advancement occurs by the creative solution of hard problems and our purpose is to develop technology for where the business is going to be in three to 10 years time.

This means that our research activity is characterised by three things.

First, taking such a long-term perspective allows us to make step changes in technology performance. At its best, research allows us to reduce and overcome scientific risk so we can direct our investment in areas of technology with higher confidence of substantial commercial success.

Second, the fundamental scientific understanding we develop gives us economies of scope. In other words, the science developed by research over our history can be applied to other oilfield businesses. And we can leverage this fundamental understanding to rapidly develop and deploy new differentiated products and services across our technology portfolio.

Third, no company has all the resources to overcome the technology challenges in the oil and gas industry all by itself. We must choose where we lead, and by effective networking and collaboration on a global basis gain access to complementary resources to extend our science and technology footprint to cover commercially valuable areas.

Within Schlumberger, the research and engineering organisation exists to deliver the new technologies needed by three product groups – Reservoir Characterisation, Drilling and Reservoir Production. These are aligned with the workflows of our customers as they move through the natural stages of exploration, development and production of oil and gas resources. Our six research centres cover a geographical and technical footprint that supports a worldwide engineering, manufacturing and sustaining organisation of 65 centres in 15 countries employing 15,000 people. Such geographical diversity offers a significant advantage beyond proximity to customers and academia in harnessing particular cultural strengths. Innovation for example is a key facet of engineering in France; Russia is renowned for its mathematical strength; China is one of the largest investors in nanotechnology while Singapore...
is developing expertise in project conception following its success as a manufacturing base.

The three factors that characterise our research guide almost all of our current research themes. Perhaps the best way to see this is to look a number of examples.

The first is the optimisation and control of the entire drilling process. While integration of the different components of the drilling system, both in the drillstring and with the drilling fluids, can considerably optimise that process, we are now seeking a step change that can best be described as safe, reproducible drilling performance. The goal is to achieve predictable consistency, assure repeatability, improve efficiency and reduce the cost of well construction.

This involves some fundamental science around the mechanics of drilling, as well as in the automatic algorithms that mirror how humans evaluate data and take steps to control. The area is sufficiently fertile to have broad application and the control and automation of the drilling system is only the first in what we see as the deployment of automation and control in reservoir management, particularly in completions and reservoir monitoring. It is particularly timely, since automation is becoming recognised as essential for the continuous observation and control in oil well drilling.

It also involves networking and collaboration. For example last December we conducted a test in Texas that compared a human driller against automatic methods for controlling a drillstring. Drillers control the rate of penetration through the weight on the bit and the speed of rotation. Humans can be conservative – too much weight stalls drilling, and too much rotation causes excessive shock and vibration. The experiment showed that with continuous measurements of downhole power and motor speed, an algorithm could optimise weight on bit and rotation to triple the rate of penetration. These are early signs of the potential we see to create step improvements in the drilling process. Although some integration of the drilling system components helped make this happen, we also need a network to access the components for drilling technology from a number of small start-ups and academic institutions.

A second example is the family of technologies that is driving sensor miniaturisation. This is aimed primarily at the needs of reservoir characterisation. Industries such as wireless telecommunications have profited from enormous strides in miniaturisation – the development of mobile phone handsets is one of the most striking examples as devices have become more sophisticated with ever expanding functionalities fitting into ever smaller packages at rapidly decreasing cost to the consumer.

The step change in performance will come from achieving comparable changes in oilfield sensors. This is driven by the need to characterise ever more complex reservoirs in

Modelling provides rapid-response testing of research theory
greater detail, yet we are currently hampered by practical engineering limitations of size and weight, and more challenging environmental conditions of pressure and temperature – all of which limit deployment – as well as the prohibitive cost of implementing more sophisticated measurements.

Miniaturisation makes possible several technology directions to address this. The obvious is packing more functionality into the same footprint, as well as by making completely new measurements enabled by physics and chemistry at these scales. One of our best examples, which has already reached commercial service, is an instrument that packs a grating spectrometer along with a number of other miniaturised sensors capable of measuring the downhole properties of reservoir fluids in situ. The tool is only a few inches in diameter but is capable of supplying real-time information from the bottom of a well to surface.

But more interesting is the fact that the same underlying technology can be deployed on several modes of conveyance – on wireline, logging-while-drilling, completions instrumentation, and perhaps even drill bits – meaning that downhole sensing has the potential to be far more pervasive than anything we’ve contemplated before. But most exciting is that our thinking on the architectures of the platforms for such sensors has fundamentally changed and that we now see the possibilities for proliferating measurement technologies across many different services.

Technologies from other industries
In terms of fundamental science, we are well-positioned to profit from the enormous advances in academic and industrial science in the fields of microfabrication in silicon and other materials, driven by electronics VLSI, of microfluidic lab-on-chip developments for the biomedical and life sciences, and of fiber optics and photonics for the telecom and instrumentation industries. But it’s not a straightforward transplant from those industries as there are key challenges in implementing these technologies in materials and forms robust and reliable enough to be practical and useful for the oilfield environment.

To make this happen we need to tap a wealth of external expertise via a network of contacts and collaborations with university partners and with other companies outside the oilfield. Over the last three years, we believe we have established leadership in the longer term science themes for the application of nanotechnology in the oilfield that we expect to have application in deepwater, in hydrocarbon recovery, and in unconventional resource development.

My last example concerns reservoir production for materials for applications in cementing and stimulation. Materials form a vast area where myriad needs exist in harsh environments – high pressure, high temperature, corrosive conditions. Above all we seek to make step changes in services for well integrity, pressure pumping and completions. For example for well integrity, we are interested in making a step change in the performance of cement by designing composites that can be used in extreme high temperature or extreme low temperature environments where appropriate products do not exist today. For stimulation and completions we are pursuing directions in so-called “smart materials”, materials which can change their mechanical and chemical behaviour in response to environmental triggers, expecting to achieve step changes in efficiency compared to the mechanical solutions available today. Our investigation into functional materials has many potential applications – a basic one is using such materials to cleverly place proppant to maximise productivity.

Like other step changes, this theme too requires some fundamental science. One major change in the last five years has been the ability of computer modelling to predict the macroscopic behaviour of materials. When married to experimental methods in characterisation this has allowed us to pursue a couple of major themes around functionalising new materials – the intelligent combination of material components to alter properties – in some cases mechanical, in others chemical. Indeed fundamental investigation into cement has allowed us to develop a more complete understanding of its setting under extreme conditions – leading us to believe we will be able to design superior cement materials in the future.

Each of these examples highlights the principles that guide research and engineering in Schlumberger today. Whether we are seeking to exact a step change in performance, gain a deeper understanding of fundamental science or develop knowledge through collaboration and partnership, a common organisational framework ensures that the necessary investment is correctly apportioned.

When Schlumberger published its first annual report in 1957, the report carried the subhead “First in the Field, Foremost in Research”. Today, Schlumberger remains consistent in that purpose and intent, although research has by necessity evolved in order to serve the future needs of the business.
Natural gas ready to meet the world’s energy challenges

BY DR ABDUL RAHIM HASHIM
PRESIDENT, INTERNATIONAL GAS UNION

Rising oil prices, the ongoing turmoil in the Middle East, and Japan’s continuing nuclear fallout, are helping to strengthen the case for natural gas. While natural gas has, in the past, played the role of the bridesmaid and has always been regarded as the discarded twin of oil, these recent events – along with the commodity’s inherent qualities – drive home the point that natural gas has what it takes to help the world address its energy and environmental challenges.

The natural gas industry is a phenomenal success story. Its beginnings can be traced back to more than two millennia ago when around 500 BC the Chinese used natural gas to boil sea water, separating the salt and making the water drinkable. However, it was only until the 1800s that the world began to realise the potential uses for natural gas, for lighting, cooking and heating. Over the centuries, what began as a fuel to provide mere lighting for homes and streets, has evolved into a powerful resource which would help countries across the globe meet their rising energy demand. Today, natural gas provides nearly a quarter of the world’s energy demand.

In the power sector, natural gas now accounts for 22 per cent of the world’s generation capacity and this share is poised to rise further due to the overall aging of power plants and the need for replacement worldwide. Natural gas is also expected to be the fastest growing major fuel through 2030. According to the International Energy Agency, global gas demand is projected to grow by an average of 1.5 per cent per annum through 2030. While demand is expected to rise across all regions of the world, growth will be strongest in non-OECD countries, particularly in China.

By 2030, China’s demand for natural gas is forecast to grow to six times more than the level in 2005, driven by the residential/commercial and industrial sectors where distribution lines are being expanded and the price of gas is competitive against other major fuels. In India, more than half the projected growth in gas demand is expected to come from the industrial sector, where gas provides the energy to produce steel and other products. Natural gas is also being used as raw material to produce paint, fertiliser and petrochemicals. In the Middle East, demand has been growing rapidly in both the power generation and industrial sectors.

However, despite being one of the world’s most important energy resources, in recent years, natural gas has been grouped together with the other fossil fuels, namely coal and oil, and they are viewed together as contributing to the world’s climate change problem. Today, climate change is considered one of mankind’s biggest challenges, and all efforts are being directed towards achieving a low-carbon energy mix. Climate researchers believe the only way to limit the rise in global temperatures by 2ºC is to halve global emissions of greenhouse gases in the long term. Natural gas can play a key role in helping to meet this objective.

With its low carbon emissions compared to other fossil fuels, natural gas is a solution to some of the world’s economic and environmental challenges. Cleaner than coal and oil, and more efficient and reliable than renewable energy, energy experts have rightly pointed out that natural gas should not be viewed as a bridge fuel, but is actually an answer to the world’s energy and environmental challenges.

While nuclear energy has long been regarded as the best choice for emerging economies like China and the Middle East, Japan’s nuclear fallout following the March 11 earthquake has spurred debate over the safety of nuclear power plants. China has announced that it is reviewing plans to add 27 reactors to the 13 it now has, while Japan, with 10 per cent of its nuclear power knocked out, will need to invest billions in new power generation capacity.

Green credentials
These developments serve to emphasise why natural gas should be the fuel of choice in a low carbon economy. When burned to heat homes or for industrial uses, it releases 25-30 per cent less CO2 than oil and 40-50 per cent less than coal per unit of energy produced. When used to generate electricity, natural gas can reduce CO2 emissions by up to 60 per cent compared to coal. Natural gas also produces little nitrogen oxide, sulphur oxide or particulates.

Other comparative environmental advantages include the fact that ten times more water is needed to produce the equivalent amount of energy from coal, while ethanol production can require as much as a thousand times more water to yield the same amount of energy.

Natural gas is also efficient - modern combined cycle gas turbine power plants are 40 per cent more efficient than coal plants, and also require only half the construction time needed to build a coal plant and less than a third of the time needed to build a nuclear plant. Apart from being quicker to construct, gas-fired power plants are also relatively easy to get regulatory approval for.
The Inter-governmental Panel on Climate Change has recognised that increasing gas use in power generation can have an immediate impact on emissions. In the US, for example, doubling utilisation rates at existing gas-fired power plants could displace enough coal to cut coal-related emissions by 20 per cent. And since coal-fired power generation accounts for 33 per cent of all US emissions, a reduction of that size is certainly no small matter.

Natural gas also supports the growth of renewable energy. Since gas turbines can be turned on and off relatively quickly, natural gas serves as a flexible partner for intermittent energy sources, such as wind and solar, in power generation.

In the transportation sector, natural gas can also make an immediate impact to reduce greenhouse gas emissions. The use of dedicated natural gas vehicles can lead to 20-25 per cent less CO₂ emissions compared to petroleum fuels. It is only logical that apart from fleet vehicles like buses, more and more passenger vehicles are now running on natural gas.

Recent development in the use of LNG as fuel for ships will further help reduce emission of greenhouse gases in the maritime sector. Since switching from diesel to natural gas can result in at least a 20 per cent CO₂ reduction measures are being explored to make it mandatory for inland ferries and offshore supply vessels to use LNG. In addition, increased use of natural gas in transport can reduce local pollution of, for example nitrogen oxide and sulphur oxide.

While natural gas has been widely acknowledged to be a cleaner alternative to other fossil fuels, the adoption of natural gas on environmental grounds has been limited to date. Amongst the possible reasons is the issue of affordability, but this may change as countries now strive to reduce their carbon emissions. One way is via the introduction of new environmental policies, such as carbon trading schemes.

**Game-changers for natural gas**

Natural gas has the means to meet the world’s growing energy needs. The world’s current proven reserves of conventional gas totals 187.49 trillion cubic metres, with a reserve production ratio of more than 60 years.

In addition, exploration of the world’s unconventional gas potential has provided significant boost to available reserves, extending current production life by a century or more. The US, for example, sits on a huge unconventional gas reserve, locked away in difficult-to-reach formations. While it has long been technically possible to recover unconventional natural gas – the term for gas that is not located in porous permeable reservoir rock and which includes coal bed methane, tight gas, shale gas, and methane hydrates – it has not always been economical.

Over the last five years, thanks to technological advances that have made it easier and cheaper to access these resources, more and more companies have been jumping.
on the unconventional gas bandwagon. Advances in drilling techniques and the hydraulic fracturing or fracking process have allowed North American shale gas players to increase production. According to a recent study from the American Clean Skies Foundation, the US now has 2,247 trillion cubic feet of proved natural gas reserves, enough to last 118 years at 2007 demand levels.

This windfall is not only confined to the US. According to Deloitte’s Energy Predictions Report 2011, by 2035, shale gas could make up 62 per cent of the total gas produced in China and 50 per cent in Australia. Canada too is looking to boost its reserves. While there is also shale gas in Europe, there are also greater challenges to its development because state ownership of mineral resources gives landowners little incentive to allow development on their land and because the region also does not yet have a robust oilfield service industry to support it. But some still see the potential of European shale gas resources as sufficiently robust to alter the energy supply scenario.

Technology also plays an important role in connecting gas supplies to markets. An example of such technology is Floating LNG (FLNG) that allows liquefaction at sea instead of having to build pipelines to the coast. This will open up resources previously considered too remote or expensive to exploit. Moreover, with FLNG, the facility can be re-deployed to another gas field once production at one field has been completed.

Advances in technology are also likely to affect the consumption of natural gas. There is an obvious economic incentive for energy-intensive industrial users to use energy-saving technology. But in the case of the residential sector, some form of government incentive, and probably also disincentives, may be needed to persuade households to adopt energy efficiency measures.

Advocacy initiative
Certainly, for all its merits natural gas is not the panacea for the world’s energy problems. Developing countries with abundant, low-cost coal reserves will continue to exploit and maximise those resources. And the progress of unconventional gas should not mask the challenges countries face in developing their potential shale resources. Open licensing, favourable regulations, and robust competition among many innovative firms were an integral part of the unconventional gas success story in North America, but those conditions are not yet in place in most regions.

The natural gas industry also has much work to do in convincing the public that natural gas extraction is safe and environmentally sound, and that natural gas has an important role to play in meeting energy challenges in a low carbon economy. The International Gas Union (IGU) has made natural gas advocacy one of its priorities. To that end, the IGU has developed a campaign – titled Natural gas CARES for the world – and a gas advocacy toolkit that has all the facts that support the argument for natural gas as a fuel of choice.

The IGU is also working with like-minded advocacy groups and gas associations such as the American Natural Gas Alliance (ANGA), the European Gas Advocacy Forum, and the Canadian Gas Association, to correct the perception of natural gas by policy makers, governments and the public.

In all our advocacy initiatives, the message is consistent: The natural gas industry is ready to take on a larger role in meeting global energy challenges, and it is time that policymakers and stakeholders recognised its potential and allow natural gas to step into the spotlight.
As the world knows, on March 11th of this year, a massive quake and tsunami of an unprecedented scale struck the Pacific coastal areas of East Japan leading to a serious accident at the Fukushima Daiichi Nuclear Power Plant. We, the people of Japan, are working diligently to recover and rebuild with generous help from the peoples and the countries of the world, to bounce back from the immense loss of life and damage. At the same time, the catastrophe has forced us to focus again on our selection of energy resources. Japan will have to redouble its efforts to save on energy use and diversify energy sources. The country has already made great efforts to develop energy conservation technology and put it to practical use. Japan has promoted nuclear power and LNG for diversification. Renewable energy is also increasing, though its ratio to the total is very small.

The nuclear accident at Fukushima Daiichi Nuclear Power Plant has given a big push for anti-nuclear power movements in Europe. Japan is also under pressure to weigh again the pros and cons of the use of nuclear power. But we also have to consider one important point we had overlooked – that it is no simple matter to quit nuclear power once you start. Nuclear fuel rods including the used ones must be safely stored in permanent locations and the plants must be safely brought to a close. What is more, unlike oil plants, the permanent shut down and mothballing of nuclear power plants is not so straightforward. As with Chernobyl and Three Mile Island, closing the Fukushima plant will present us with problems we have never experienced before that we must deal with head on.

On the other hand, many emerging and developing countries consider nuclear energy as an option when selecting the best energy mix for themselves, and Japan intends to provide technology and support to these countries. Moreover, the United States and Russia which have been the pioneers in nuclear power generation and have experienced their own nuclear accidents, maintain that they will continue to use nuclear power. France, too, which is number one in terms of relative use of nuclear power at home, intends to expand export of nuclear electricity to neighbouring countries.

Immediate withdrawal from nuclear power is not the way to go. Rather, we should engage more vigorously in the use of nuclear power. Of course, we should fully bear the responsibility of solving the problems that we are saddled with now. In Japan, power companies and major equipment manufacturers have led and coordinated nuclear power plant projects under the guidance of relevant government agencies. Future decisions on nuclear power will require more vigorous reexamination of safety. To that end, the International Atomic Energy Agency is working with the rest of the world and is calling for safety reviews and management based on harmonised global standards. I strongly recommend involving in these safety reviews experienced people from the oil, gas and chemical industries and the plant engineering industry which has long built and operated complex systems and equipment.

The other significant issue that needs to be reviewed when considering use of nuclear power generation is that of cost. It is argued that the cost of fossil fuels should reflect all their associated environmental damage. If you do the same for nuclear power, and add in the cost of used fuel disposal and plant dismantling, and the cost of paying compensation once a huge accident occurs, then it may no longer be feasible to fly the banner of “cheap electricity.” We need to conduct correct and accurate economic evaluation that takes all of these factors into account and we must do it in conjunction with value assessments including safety.

All of us, including the people in the disaster hit area who froze in wind and snow after their infrastructure was destroyed by disaster, and businesses and ordinary people who had to scramble to deal with the sudden electricity shortage after enjoying the benefits of the world’s most stable electricity supply, have had to admit once again what a blessing fossil fuel is as we began to receive emergency supply of kerosene oil and to hear the news of mothballed thermal power plants reopening. On the other hand, what has brought on the global warming and climate change is the accumulation of greenhouse gasses represented by CO₂, among others without regard for environmental balance. The basic policy that recognises the need for dealing with this particular problem will probably remain in place for the foreseeable future.

The current high price of oil is boosting development of shale oil and heavy oil, despite geographically difficult locations and high mining costs. Furthermore, improvements in mining technology are eagerly awaited as the producers aim to improve the recovery rate. But given the fact that its own demand of transportation fuel is in decline, Japan is looking into down-scaling its domestic refineries on the advice of the relevant government agencies. But while the domestic oil industry is on a downward trend, Japan still needs to secure a fixed amount of oil that includes backup.
supplies in case of emergencies. One possible solution is to deepen economic ties with Asian countries where energy demand is still rising, and where the most advanced large scale oil refineries could be jointly built. This kind of investment would help Japan’s neighbours and ensure redundancy of our domestic supply.

Natural gas is the cleanest fossil fuel. But the price of this precious resource seems a bargain compared to the price of oil. It has fallen over 8 per cent in the past year. One reason for the falling gas price is that gas has not been an object of speculative investment. Another reason is the recent increase in production of shale gas in the US. Gas is a clear-cut option as a wise use of resources in the future because gas, like oil, is a vital carbon/hydrocarbon element as raw material for chemical products. In recent years many Japanese have been opting for “the all-electric house” when choosing the energy mix for their homes. However, the Fukushima calamity has brought on black outs and power conservation mandates that the Japanese people had not experienced for several decades. This teaches us a lesson of how we need to prepare diverse energy supply chains and consider the best mix to use. The recent technological advances have improved the performance of equipment such as fuel cell batteries using municipal gas. Such effective uses of gas will expand even more. Either way, Japan remains the biggest importer of LNG and will continue to enjoy the benefits of this clean energy for a long time still to come.

As for renewable energy, the basis for renewable system operation is fundamentally local production and consumption. Therefore, the foundation of renewable energy will be individuals installing equipment in their homes to generate their own electricity, and communities jointly operating cluster-type facilities. Since investing in such systems will be made easier if all the excess power from these is purchased at a fixed price, Japanese Government is considering a bill to institutionalise such a scheme. Inevitably, there are challenges to be met including the quality of electricity generated, keeping the existing supply chain safe and intact, transporting power over long distances, and storing it in large amounts. When we consider optimising the use of renewable energy in Japan, we soon run into certain limitations because of local restrictions on siting and installation of equipment and facilities.

Another option for carbon-free energy is hydrogen. Large volumes of hydrogen have already been used in oil refining and petrochemical processes, but only recently has hydrogen been proposed as an energy source. Japan is promoting use of hydrogen by experimenting with small-scale electricity generation and automobiles that run on hydrogen fuel cell in specially designated areas.

Lack of safe and economical supply infrastructure is a big reason for the slow progress in promoting the use of hydrogen. The Chiyoda corporation has already completed the development of technology that allows for easy storage and transportation of large volumes of hydrogen under ambient temperature and pressure based on the chemical hydride method. Chiyoda has also completed the development of a technology for hydrogen separation and recovery, and is now preparing to construct a facility to demonstrate and eventually service these technologies. It is my hope that use of hydrogen for electricity generation and other usage will gain a big momentum once these infrastructures are completed.

It is vital that we all work together to achieve a sustainable society for future generations. For us to be able to do this, it is essential that we continue to develop technologies and nurture human resources to put these technologies to practical use.

Fukushima Daiichi nuclear power plant Number One reactor building
Global energy leaders and policymakers face a stark reality: world energy demand is forecast to grow sharply over the coming decades, greatly outpacing estimated production capacity. The danger is that supply will have to ration demand and prices will skyrocket, hobbling the world’s economy.

A chief constraint is that OPEC has limited spare capacity to meet this demand, and the overall share of non-OPEC crude is forecast to remain constant. Meanwhile, geopolitical issues, such as conflict in the Middle East, make access to traditional energy sources increasingly difficult.

As world energy leaders convene in Doha for the 20th World Petroleum Congress, we are all acutely aware of the challenges of meeting future energy demand – and averting a potential energy crisis. The US$140 per barrel oil price we witnessed three years ago was not an aberration – it was a warning.

In the United States, these realities pose significant challenges to our economy and to our energy security. Against this backdrop, and given the promising business prospects unfolding in the unconventional energy sector, key industry players like Hess Corporation are increasingly focused on the growing opportunities in that arena.

In the last three years in particular, there has been rapid growth in US unconventional liquids production, and there are strong indicators that the growth in US supplies of unconventional resources will play an important role in helping to meet future worldwide energy demand.

These new supplies have the potential to displace a growing portion of conventional production because of the competitive advantages which the unconventional projects possess: namely lower supply costs, easier accessibility and faster time to market. And while the United States will undoubtedly be a major supply source, the opportunities are global.

US unconventional development began to accelerate five years ago. Small E&P companies began leasing acreage in the Marcellus shale formation hoping to tap into shale gas to feed the underserved East Coast, and new technologies opened up opportunities in the North Dakota Bakken, where Hess had a legacy position.

Since 2008, the production of shale oil in the Bakken has tripled, and there are projections that oil production from the Bakken alone could be as much as 600,000 barrels per day (b/d) in just a few years. Looking ahead, un conventionals will likely account for up to 40 per cent of US liquids supply by 2015, up from 10 per cent to 15 per cent in 2008, according to Hess estimates.

The outlook for the industry is very bright, for both the unconventional oil and the natural gas base. Without a doubt, this has been a saviour for energy security in the United States. And the business prospects for this industry in the unconventional space are very significant.

But to be a successful player in the unconventional arena will require a different business model and unique capabilities – which is where independent oil and gas companies are particularly advantaged.

**Unconventionals: a different business**

The resources are much more challenging to produce than their conventional counterparts and require a different and, in particular, low-cost business model. While chances of success for unconventional wells are higher when compared, for example, to deepwater Gulf of Mexico fields, there are generally less hydrocarbons per well, decline rates are greater, and the drilling and completion capital expenditure per well as a percentage of total expenditures is significantly higher.

When one looks at the growth in US unconventional supplies over the last two decades, North America has been an incubator in which the independent oil and gas companies have been setting the pace, accounting for 70 per cent of total production in the 1990s, rising to an 80 per cent share over the last 10 years.

Independents are uniquely advantaged: they have the capabilities required in drilling and completions expertise, lean manufacturing approaches, fast-paced innovation and a low-cost philosophy that make them well suited to take advantage of these opportunities.

Independents are also more flexible, operating successfully as niche players with a corporate agility and a greater focus given that their opportunities may be a more material part of their portfolios. They are smaller, and they are often better networked.

Being able to continuously improve and rapidly innovate is a fundamental key to success. Advances, for example, in horizontal drilling and fracking have made unconventional development possible. Even more are needed, and continuing advances in other technology are needed to address concerns regarding fracturing fluid composition and water usage.

**Unconventionals: The world has and needs tight oil**

BY GREG HILL, PRESIDENT, WORLDWIDE EXPLORATION AND PRODUCTION AND EXECUTIVE VICE PRESIDENT, HESS
The importance of being lean

In the unconventional arena, we at Hess believe the company is uniquely positioned, and we have made it part of our core strategy to be a global leader. In particular, Hess is focused on leveraging its success in the Bakken in North Dakota across other unconventional projects in the US and abroad by being recognized as the partner of choice.

Last year the company completed two key acquisitions in the Bakken, where it now holds 900,000 net acres in this booming oil and gas play to become the largest acreage holder in North Dakota. It also acquired over 100,000 net acres in the Eagle Ford shale play in South Texas, where it has just begun producing oil. In October of this year, Hess acquired about 185,000 net acres in the Utica Shale, further strengthening its portfolio of unconventional resources in high-quality assets.

Hess' strategy in the Bakken has been to expand and upgrade its acreage, exploit its infrastructure advantage and execute through a lean manufacturing strategy. As Bakken has demonstrated, unconventional projects generally have faster time frames and higher success rates, but nevertheless, because of the fast pace and heavy manpower and resources involved, they require a leaner, lower-cost manufacturing approach to drilling and production.

Hess has been perfecting our capability in applying lean manufacturing principles to our unconventional business, and as a result our operations are becoming increasingly more efficient and profitable.

Toyota set the standard for this approach to manufacturing, but the methodologies and practices are directly applicable to the unconventional energy business, particularly since success is becoming increasingly dependent upon acquiring acreage early and executing swiftly, under conditions where infrastructure and resources are often constrained. In addition, while operating these large-scale drilling and fracturing and completions programme, there is a need for continuous learning and improvement. Finally, given the nature of large-scale drilling and completion programmes there are many gains to be had by standardising approaches.

Hess is employing the fundamental principles of lean manufacturing to get the most from our human and capital resources to achieve faster, more efficient, and lower-risk developments.

Lean manufacturing practices are also being leveraged to our overseas operations, where we are not only replicating our operating success in the Bakken, but are also leveraging our global scale and reputation for being a trusted energy partner. Unlike most other independents, Hess is an experienced global operator, doing business in 23 countries. We also pride ourselves on serving the communities in which we operate, investing heavily in social programmes such as education in Equatorial Guinea.

Those attributes have helped Hess to gain access and form partnerships in unconventional plays overseas. Specifically, we formed a partnership to explore for unconventional oil on 1m acres in the Paris Basin in France, a play that shares many of the Bakken’s attributes. We also signed three joint study agreements with Chinese national oil companies to evaluate unconventional oil opportunities in several million acres in China, and have farmed-in to over 6 million acres in the Beetaloo basin of Australia.

Improving stakeholder management

While the prospects for the unconventional business are bright in the US and abroad, there are significant stakeholder challenges in managing the above-ground risk and concerns of the many stakeholders involved, including policy makers, governments, lease holders, and citizens. This is where the industry can do a much better job.

Unconventionals are increasingly “in the news”, and highly publicised incidents and misinformation have heightened concern amongst citizens and communities located near unconventional plays.

Meeting the stakeholder challenges requires three imperatives. First, we need to communicate what we do and how we do it to address the safety and environmental concerns. Second, companies need to employ responsible practices – particularly in the areas of well control and casing and cementing practices. Finally, we need a consistent and predictable regulatory framework that also punishes poor performers. Most states do a good job at regulating our practices, but there is room for more standardisation and applying consequences to the violators, rather than the whole industry. The unconventional oil and gas business is not for the faint of heart. However, I remain optimistic that the oil industry will overcome all of these challenges and supply the world with affordable energy for prosperity – just as we have done for well over 100 years.
It is a remarkably short time since the outlook in the US and Canada was one of an irreversible decline in the domestic production of natural gas, and a corresponding steady increase in the need to import LNG in order to keep the market supplied. Significant investments were made in LNG import terminals, and in liquefaction capacity, particularly in Qatar, on the back of this, universally shared, outlook. However, one result of the move of the Henry Hub price into double digits occasioned by the tightening supply/demand balance was to motivate a number of independents to take another look at the shale gas resource that was known to exist but, with a few local exceptions, had been considered much too costly to exploit.

Those independents soon discovered that, by applying the latest that the industry had to offer in terms of drilling (horizontal/directional), imaging (3D seismic) and completion (hydraulic fracturing) technology, they could radically improve the production economics of shale gas. The rest is already history, in the shape of the spectacular surge in activity that has completely transformed the outlook for domestic gas supply, leading, amongst other things, to talk of Reserve/Production ratios heading for three figures, as compared to less than ten no more than a few years ago. In other words the prospect now is of self-sufficiency in gas for the foreseeable future, to the extent that there is now much talk of the possibility of building new liquefaction capacity to export, as LNG, those volumes surplus to domestic market requirements.

The North American supply surge has already been felt elsewhere in the global gas market, with the displacement of the LNG volumes originally destined for the US market having contributed to generalised over-supply over the last two to three years, at least until the boost to demand from Japan post-Fukushima. The key question now is whether, in a world where security of supply has become a preoccupation of increasing importance, the North American experience can be replicated elsewhere, generating significant new sources of domestic supply in the major consuming nations and thereby reducing their dependence on imported gas.

The answer has little to do with the existence or otherwise of a resource base – the geology in question is not limited to North America, and resources on a similarly impressive scale are known to exist elsewhere. Illustrating this is the study published earlier this year by the US Energy Information Agency (EIA), which provided an initial assessment of technically recoverable shale gas reserves in a total of 48 basins in 32 countries outside the USA. Table 1 reproduces some of these figures, and compares them with the current estimate of proven (conventional) gas reserves in the selected countries in question.

The figures are undoubtedly impressive. But “technically recoverable” does not mean the same thing as “economically recoverable”, and says nothing about the cost of developing and producing the resource in question. So the vital questions are to what extent the cost structure created in North America can be replicated elsewhere, and how does the resulting cost structure compare to that of alternative, imported sources of gas – remembering that the world overall is not running short of conventional gas.

An answer to these questions would start by considering the factors that came together to unleash the shale gas revolution in North America – the technology factors were clearly critical, but were...
by no means the only ones – and assess the extent to which these factors are present elsewhere.

- **Existing pipeline infrastructure.** Building up supply from shale gas involves the drilling of many wells one after the other (in a process that has been described as “gas farming”) and the ramp-up of production is accordingly a long, relatively slow process. Slow ramp-up rates depress the economics of new pipelines, and so the absence of need to create major new infrastructure, at least in the early stages of development, effectively removed one obstacle to its development in North America.

- **Proximity to end-use market.** This clearly relates to the availability or otherwise of existing infrastructure. Where no such infrastructure exists, the greater the distance of the shale resource from its intended market, the more challenging the economics will be.

- **Drilling cost.** This will, first and foremost, be a function of geology. A huge amount of work remains to be done in terms of deepening understanding of shale gas formations outside of North America, but initial indications in, for example, Europe and China are that the identified formations are in general likely to prove more challenging. Features such as greater depths and more complicated geology will mean that individual well costs will be higher, and often significantly so.

- **Liquid spot and forward market.** This factor has perhaps been under-appreciated, as it provided the independents in the US with both the signal and the confidence to look again at shale gas, in the knowledge that they would be able to monetise whatever gas they were able to produce, whether it be for one month or five years, into a fully fungible market and at a known price.

- **Supply side factors.** These refer in particular to the technical support industry that is a feature of the North American scene, and which is such an enabler of entrepreneurial behaviour. Drilling rigs available for hire in North America can be numbered in the hundreds, while in Europe only in the tens. Nor does Europe have anything like the oilfield service infrastructure that North America enjoys. Another supply side constraint is the availability of water, given that the hydrofracking technology that is so crucial to the economics of shale gas production requires such significant quantities. Much attention has focussed on the possible danger of hydrofracking contaminating ground water sources (though the evidence tends to suggest that the real issue lies with waste water handling and treatment). But it may be the absence of available water supplies in the first place that presents a significant impediment to development.

- **Favourable regulatory environment.** A large number of elements go to make up a favourable regulatory environment, and these for the most part remain to be defined outside North America. In Europe, the situation is likely to be far less favourable, as evidenced by the case of France, which has recently imposed a total ban on shale gas development involving the use of hydrofracking. In general, NIMBY (not in my back yard) factors are certain to be far more prevalent, especially in the absence of the mineral rights that American landowners tend to enjoy and which serve to incentivise their cooperation. Outside the US landowners generally do not own the minerals under their land.

An early assessment, therefore, is that whereas all these factors successfully came together in North America to enable the shale gas breakthrough, nowhere else has the same combination today. This may change over time. But one can conclude that it will in all probability take more money and time to develop shale gas outside North America than inside it.

A key question, then, is how will the cost of shale gas outside North America compare to the cost of conventional gas, even if imported from distant sources. While the security of domestic supply certainly has attractions, such attractions tend to diminish when they involve a significant price premium. This may be particularly pertinent in Europe, where the shift to a more “normal” traded commodity pricing structure suggests that prices will increasingly be set by fundamentals and therefore reflect the cost of supply. In such a scenario, with Gazprom in the role of marginal supplier, the market price target that unconventional gas would have to aim at would be the long run marginal cost of Russian gas, probably from the Yamal peninsula. With such a price likely to be in single digits, the target may prove a challenging one. In China, too, shale gas from the Tarim basin in the north-west of the country, relatively disadvantaged when compared to the shale resources existing in the Sichuan basin in the south-west, might find it hard to compete with imports of conventional gas from neighbouring Russia if that competition were purely cost-based.

The real challenge, then, facing the development of shale gas resources outside North America may be the fact that, unlike in North America, rival conventional gas should not be in short supply, even if not necessarily from a domestic source.
Shale gas: Poland starts prospecting

BY PROFESSOR STANISLAW RYCHLICKI, AGH UNIVERSITY OF SCIENCE AND TECHNOLOGY, KRAKOW AND MAREK KARABULA, VICE-PRESIDENT, PGNiG

In the light of America’s shale gas success, prospecting for shale gas has started in many parts of the world, including Poland. Drilling a shale gas well entails a greater technical risk than in the case of conventional gas. Those characteristics of rock mass considered to be useful in the case of conventional deposits can become an obstacle.

Among the most common technical challenges arising from geological conditions are the appearance of natural fissures that could cause captured gas to escape, the swelling of clay minerals under the influence of drilling liquids or materials used for hydraulic fracturing, and insufficient silica content resulting in poor fracturing efficiency, low total organic carbon content and thermal maturity, and possible local yield of nitrogen.

In Polish conditions, an additional difficulty is the lack of specialised and experienced companies on the European market able to perform all the necessary services. In Poland, the cost of a single shale gas well including stimulation treatment and well testing is estimated at US$15-20 million. Stimulation treatment requires large amounts of water. An average vertical well requires 2,000-4,000 cubic metres of water, while a horizontal well may need 8,000-20,000 cubic metres of water, as well as 2,500 metric tons of proppant.

There are many companies operating in the territory of Poland which altogether hold 87 exploration licenses primarily for shale gas, but also for tight gas (Table 1).

The Polish company, PGNiG, has been awarded 15 licenses in several oil provinces from Central Pomerania to the Lublin area. In the area of the Gdansk Petroleum Province, exploration work will be carried out by PGNiG SA in the Wejherowo, Kartuzy-Szemud and Stara Kiszewa within Ordovician and Lower Silurian formations.

PGNiG has started with a first exploration well within the Wejherowo license area. Drilling work was preceded by seismic acquisition. On this license area, the Lubocino-1 well was drilled up to depth of 3,000m. At present, the drilling results are being evaluated. The initial results are very promising.

On the other PGNiG licenses, geological analyses of Ordovician and Silurian shales progress. Geophysical surveys have also been started (magnetotelluric, gravimetric, seismic acquisition). In the Pionki – Kazimierz license area, the Markowola-1 well was drilled in 2010. The well tests have not confirmed the presence of unconventional gas deposits, however the tests were carried out in the Carboniferous and Devonian sediments. Parallel geological analyses of Silurian and Ordovician shales were performed. Additionally, a gravimetric and magnetotelluric survey has been started.

The target of the exploration for tight gas in the Rotliegendes formations is the Wielkopolska Petroleum Province, under the Szamotuly, Kórnik-Środa, Murowana Goślina-Klecko, Pydzyry, Gniezno and Ślesin licenses. In this area, seismic acquisition and exploration drilling are planned.

The challenges associated with the exploration of unconventional gas deposits in Poland include unknown geology, urbanisation of the area, restrictive environmental regulations, opposition of local authorities, especially in the case of attractive tourist destinations such as Pomorze and Roztocze, access to adequate water reserves, a very high capital cost (cost and number of wells, large production facilities), and the cost of appropriate technologies.

It was obvious from the beginning that exploration for unconventional...
natural gas deposits would not be easy, but one has to remember that it also creates opportunities for both Poland, and for companies which hold licenses in our country and have started the exploration work.

Among the potential benefits of shale gas exploration are possibly enormous natural gas resources, which will allow Poland to become independent from external gas sources, development of the PGNiG Group’s drilling companies, and the opportunity of significant profits for PGNiG and other licence-holders.

In the US, shale gas exploration has proved very successful in terms of documented in-place reserves and of financial returns. However, one has to keep in mind that exploration in Poland may be harder than in the US, not only because of different geological conditions, but also because of tougher fiscal conditions for unconventional gas projects, higher costs of drilling, more highly urbanised or cultivated agricultural license areas, and a higher percentage of environmentally protected areas.

Poland’s projected shale gas reserves have been variously evaluated as 1.4 trillion cubic metres by Wood Mackenzie, at 3 bn cubic metres by Advanced Resources, and at 5.29bn cubic metres by the US Energy Information Administration. But one has to remember that producible resources in the case of shale gas deposits are estimated at 10-20 per cent.

Unconventional sources of hydrocarbons – tight gas and shale gas – will play an increasingly important role in the planned exploration work in Poland and in the long term can result in a significant increase in resources, both geological and natural gas production. Cooperation of Polish companies, especially companies from the PGNiG Group, with foreign companies will ensure access to modern technologies, necessary for economically feasible shale gas production.

### Table 1: Polish exploration licenses

<table>
<thead>
<tr>
<th>Company</th>
<th>No. of licenses</th>
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<tr>
<td>PGNiG</td>
<td>15</td>
</tr>
<tr>
<td>Marathon Oil</td>
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<tr>
<td>San Leon TechnoLogy</td>
<td>9</td>
</tr>
<tr>
<td>3Legs Resources</td>
<td>9</td>
</tr>
<tr>
<td>ExxonMobil</td>
<td>6</td>
</tr>
<tr>
<td>BNK Petroleum</td>
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</tr>
<tr>
<td>Lotos</td>
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<tr>
<td>Orlen</td>
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</tr>
<tr>
<td>DPV Service</td>
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<tr>
<td>Chevron</td>
<td>4</td>
</tr>
<tr>
<td>Realm Energy International</td>
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</tr>
<tr>
<td>Eni</td>
<td>3</td>
</tr>
<tr>
<td>Cuadrilla Polska</td>
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<tr>
<td>Composite Energy</td>
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</tr>
<tr>
<td>Aurelian</td>
<td>1</td>
</tr>
<tr>
<td>Strzelecki Energia</td>
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</tr>
<tr>
<td>Ogólem</td>
<td>87</td>
</tr>
</tbody>
</table>

Source: EIA, Ministry of Environment
What is Sonatrach’s current policy on gas and oil production, and on investment in future capacity - upstream, midstream, downstream?

The primary production of hydrocarbons of Sonatrach and its partners reached about 214m tonnes of oil equivalent (toe) in 2010, of which 55.3m tonnes of crude oil and 145.8 billion cubic metres (bcm) of natural gas. Sonatrach plans to increase its production capacities given the significant potential of the Algerian subsoil yet to be developed. It should thus continue to meet the domestic market needs and maintain its position in international markets.

In order to do so, Sonatrach has launched an ambitious development plan in the medium term, involving a total investment of more than US$40 billion (bn) in the upstream. These investments should enable us to exceed a total production volume of over 1bn toe over the period 2011 to 2015.

Among the main elements of this plan, are development, starting in the last two years, of Gassi Touil by Sonatrach on its own, and of El Merk in association with Anadarko. To be launched in 2011 and 2012 are development of new deposits, including those of Hassi Tarfa and Hassi Dzabat, Touat Gas, as well as fields located to the south of In Salah and In Amenas satellite fields.

Sonatrach and its partners have also listed several projects to increase the production plateau of some fields, such as the oil rings of Alrar and Rhourde Nouss and In Amenas Gas deposit, and to optimise the recovery of products through projects such as water alternating gas injection in Ourhoud.

In addition, the new gas pole in the South West region continues to be developed, where at least six new projects of significant size are under development with production set from 2015. These projects, operated by Sonatrach alone or in association with its partners BG, Statoil, Total, Repsol and GDF Suez, will help guarantee the supply of Algeria’s markets. Sonatrach is also interested in developing unconventional resources in partnership, with the two first ‘shale gas’ pilot projects completed in 2011.

For the hydrocarbons pipelines transportation segment, the investment planned in the medium term is around US$6bn and mainly focuses on the development of transmission capacities to meet the commitments and on ensuring the security and reliability of facilities and infrastructures.

In the oil and gas downstream, the current portfolio of projects underway and new for the period 2011-2015 amounted to about US$8bn, most of which relate to the continuation and completion of the construction of the two new LNG trains at Skikda and Arzew, and to the programme of rehabilitation, modernisation and adaptation of the northern oil refineries that will contribute to raise the refining design capacity of 20m tonnes currently to around 24m tonnes in 2014, representing an increase of 18 per cent.

What should or will be the role of foreign partner companies, and their share in hydrocarbon production? Will this grow? Equally, what international presence does Sonatrach seek for itself in, for instance, regasification terminals?

Partnership is an integral part of Sonatrach’s strategy and is confirmed through the various hydrocarbons laws enacted by the Algerian State. The synergy between the national and international companies has enabled access to advanced technologies developed by the international majors, and sharing of financial and technical risks inherent in hydrocarbons exploration and production.

Results recorded so far are very positive, given the many partnership contracts entered into since 1986. Today, no less than 41 contracts signed by Sonatrach and its partners, 13 of which in the Exploration phase and 28 in the Development & Exploitation phase. These commit Sonatrach and its partners to an investment level exceeding US$6bn for 2011.

In 2010 production from fields operated by Sonatrach and its partners reached 59.1m toe, representing almost 28 per cent of total hydrocarbons primary production. I would like to underline that crude oil produced in partnership during 2010 represented more than half the total crude oil production, a fifth of which returns to partners. As for natural gas production in partnership, it is more than one-sixth of the total natural gas production.

These shares will grow in the medium and long term depending on partner’s activity and discovery potential.

Sonatrach continues its policy and ambition to become a global player particularly in the upstream and downstream. One may mention, for instance, the presence of Sonatrach in Peru (Camisea blocks 88 & 56) where it holds a 10 per cent share in the upstream and in Tunisia, with a 21 per cent interest in pipeline transportation through a mixed activity holding company called “Numhyd”. 
In the Sahel neighbour countries (Niger, Mauritania and Mali) Sonatrach operates alone and in partnership on exploration acreages located in one of the largest sedimentary basins of Africa – Taoudeni. Sonatrach is also present on the wholly-owned Kafra acreage, two exploration perimeters in Mauritania and two others in Mali.

In the downstream, the reservation of regasification terminal capacities in expanding markets may prove a productive strategy to maintain and even increase market shares in target countries.

Algeria has three pipelines for gas to Europe and is building a fourth, but is also building two more LNG trains because it was aiming to have raise the share of LNG to 50 per cent of all exports, in order to have more flexibility in choice of markets especially to export to the Atlantic basin and the US. Is Algeria still aiming at this 50/50 split between LNG and pipeline gas, or has saturation of the North American market because of shale gas there reduced Algeria’s interest in LNG? What about LNG exports to Asia?

Algeria has played an important role in the supply and the security of European energy markets for the past 40 years. Sonatrach has responded to the natural gas demand mainly from its natural market that is Europe, and has initiated the construction of three transcontinental pipelines, strengthening the ties between Algeria and its Mediterranean neighbours. These are essentially:

- The Enrico Mattei Pipeline (GEM), linking Algeria to Italy via Tunisia, came on stream in 1983 with an initial capacity of 8 bcm/year. This level has now reached the 32.5 bcm, thus following the changes in demand on the European market;
- The Pedro Duran Farell Pipeline (GPDF), commissioned in November 1996, is increasing volume every year to reach today a capacity of 11.6 bcm. The gas pipeline is now supplying the Iberian Peninsula via Morocco;
- And most recently, the Medgaz pipeline, with a capacity of 8 bcm/year, linking Algeria directly to Spain.

Drawing on its positive experience and strong relationships with its Mediterranean neighbours, Sonatrach today continues to work for the consolidation and development of its energy partnership especially through new pipeline projects such as:

- The Galsi project which will link Algeria directly to Italy will have a capacity of 8 bcm/year from 2014;
- The Trans-Sahara Gas Pipeline (TSGP) project that will link Nigeria to Algeria via Niger and will allow gas to be brought to Europe. The capacity of the pipeline will be between 20 and 30 bcm and its commissioning is expected from 2018.

In addition to the LNG capacities developed in Algeria over the years, reaching today a level of 26.7 bcm, two mega projects are under construction: the first one “GL2K”, in Skikda, with a capacity of 4.5m tonnes/year, expected to begin production in late 2011, the second one in Arzew, “GL3Z”, with a production capacity of 4.7m tonnes/year should start production in early 2013.

As you can see, beyond the 50/50 rule, the NG/LNG portfolio balance is motivated by various considerations including those of flexibility, security and opportunities to be seized. As for Asia, Sonatrach is firmly interested in this most dynamic market.

What is Sonatrach’s view of the decoupling of gas prices from oil, and of a move away from long-term contracts?

Let me remind you that since the petroleum crisis of the 1970s, natural gas has imposed itself as a first choice energy source. The breakthrough of natural gas has been spectacular thanks to the traditional contractual model which was developed by buyers and sellers. This has enabled consumer countries to provide for their gas supplies safely and almost continuously at very competitive prices on balance compared to other sources of energy. It also helped financing important investments to carry gas on thousands of kilometres and make it available to consumers. This model has been able to provide for a balance of the parties’ long-term interests.

The structure of these contracts provides for the sharing of risks between buyers and sellers: in broad outline, the former accept a volume-risk as they commit to pay for quantities that they will not need if demand is lower; the latter accept a price-risk as they commit to supply the contracted quantities even if the price falls.

Actually, take-or-pay clauses provide for important flexibility items. Hence, the buyer may carry forward, over several years, the quantities he does not wish to lift. Moreover, he is often given the opportunity to lift only 80 per cent of the contracted quantities. The buyer then bears only part of the volume-risk.

This “harmonious” and “balanced” relationship between producer and consumer countries, between buyers and sellers of natural gas, has led to the development of this industry.
Furthermore, indexing gas prices to petroleum products within long term contracts has been justified through the fact that these products could replace gas in its various uses – heavy fuel in industrial processes, domestic fuel for heating in households. Such a mechanism offers a protection to both buyers and sellers against different market risks. Although affected by the economic crisis, this situation has not changed basically. The relation between the prices of both energies should regain the proportions historically observed. Even if long-term contracts are momentarily more expensive than market prices, they should remain over the longer term, as the market trends should be reversed in a relatively short horizon around 2013.

According to the scenario drawn up by the International Energy Agency, gas natural consumption on a global scale should rise by 50 per cent by 2035. In the first position, we find emerging countries with soaring energy needs: China’s demand in natural gas should be equal to that of the entire European Union in 2035, whereas that of India should increase fourfold.

This spectacular boom lies in the fact that natural gas combines a series of unparalleled benefits. It has also been spared by the natural disasters that cast opprobrium on petroleum and nuclear – the Deepwater Horizon explosion and Fukushima nuclear disaster.

What is the policy in the domestic downstream, especially as regards subsidising the domestic cost of gas feedstock?
As far as we know, there is no subsidy applied to the natural gas price on the domestic market. The selling price used is regulated and supported by a legal framework. The gas selling price intended for the national market is calculated on the basis of the long-term gas economic cost for the domestic market and a premium to cover the needs to mobilize the required resources to meet the very long run demand.

The gas selling price for the domestic market includes production costs, costs of domestic infrastructure, operating costs of any export infrastructure used to meet the domestic market needs, and a reasonable margin.

Is Sonatrach interested in developing renewable sources of energy, such as in the Desertec solar initiative?
Sonatrach has created in 2002 the company New Energy Algeria (NEAL) in partnership. The company constructed in the gas field of Hassi R’Mel, with a Spanish partner, a power plant based on solar thermal CSP energy and natural gas, with a capacity of 150 MW including 25 MW from solar. The plant was commissioned on July 14, 2011. As regards the Desertec project, Sonatrach is not associated.
The Erhama Bin Jaber Al Jalahma Shipyard is Nakilat's new world-class ship repair and shipbuilding facilities in the Port of Ras Laffan and introduces a new era and capability in Qatar's Marine Industry sector.

Its partnerships with Nakilat-Keppel Offshore & Marine (N-KOM) and Nakilat Damen Shipyards Qatar (NDSQ) are positioned to provide superior repair, maintenance and conversion services for vessels of all types and sizes, and for the construction of high value ships of up to 165 meters in length.
Pearl GTL, the largest, fully integrated “gas to liquids” project, has risen from the sands of the Arabian desert under the Development and Production Sharing Agreement (DPSA) between the State of Qatar and Royal Dutch Shell. The project covers offshore and onshore development and operations, with Shell providing 100 per cent of the project’s US$18-19 billion funding – the largest equity investment made by Shell in a single project. Pearl GTL will add around 8 per cent to Shell’s production worldwide and will be a major contributor to growth for the company in 2012 and beyond. It will also provide the state of Qatar an opportunity to generate large quantities of high quality liquid fuels and products from its abundant gas resources for many decades to come.

From announcing Final Investment Decision (FID) on 27 July 2006, it has taken less than five years to see the first cargo leave the plant.

Pearl GTL is the largest and the most complex energy project launched in Qatar. At the height of construction, over 52,000 people were employed on site. Building QP and Shell’s biggest engineering project to date in Ras Laffan, a vast industrial zone on Qatar’s east coast, has been a major achievement. Around two million freight tonnes of equipment and materials have been imported to the site, some 800,000 cubic metres of concrete have been poured, and 13,000km of cables have been laid. At the peak, piping and steel equivalent to two and a half Eiffel Towers were being erected every month. The project is not only the largest GTL plant, it also features the largest oxygen plant ever built, the largest hydrocarbon industry process water treatment facility with zero liquid discharge capability and the largest high quality baseoil plant in the world.

KBR and JGC were the main contractors in a Joint Venture agreement. The JV was awarded contracts to provide the Basis of Design (BOD) / Basis Design Package (BDP), Front-End Engineering Design (FEED), project management and start-up support of the overall onshore complex, along with engineering, procurement and construction management of the GTL synthesis, utilities and infrastructure sections of the complex. But many other major contractors from the US, Europe and the Far East were also involved. During detailed design, 13 design offices in 10 different countries were designing different sections of the plant. By the end of 2010 major

The Pearl Gas-to-Liquids (GTL) plant in Qatar
construction was complete. On 23 March 2011 the wells, 60km offshore, were opened and gas began flowing into the plant. 13 June saw the first cargo of on-spec GTL gasoil sail away from Ras Laffan Port.

When fully operational, the integrated project will produce 1.6 billion cubic feet of gas per day from the North Field, considered to be the largest single non-associated gas reservoir in the world with estimated recoverable resources in excess of 900 trillion cubic feet.

Once onshore the gas will then be processed into 140,000 barrels a day (b/d) of GTL products, comprising mainly GTL gasoil which is clear, odourless, has low emissions and can be used in modern diesel engines; GTL kerosene for aviation fuel; high quality baseoils for advanced lubricants; GTL naphtha used in the production of plastics and normal paraffin for detergents. The plant will produce enough diesel fuel to fill over 160,000 cars a day and enough synthetic oil to make lubricants for more than 225 million cars every year. Additionally, Pearl will produce 120,000b/d of upstream products including ethane, sulphur, LPG and condensate.

The technology which supports the two train Pearl GTL plant is called Shell Middle Distillate Synthesis (SMDS). In the 1920’s, German scientists Franz Fischer and Hans Tropsch invented a chemical synthesis process to convert syngas into liquids. Some 50 years later, Shell developed this into an advanced proprietary version – SMDS. This technology was tested and proven at the SMDS GTL plant in Bintulu, Malaysia in 1993 and has evolved over three decades of research and development. The Bintulu plant has a capacity of 14,700b/d and is operating reliably and profitably.

Pearl GTL will use technology to limit its environmental impact. It features one of the largest steam systems in the oil and gas industry which will circulate 8,000 tonnes/hour of steam, capturing as much heat as possible from the chemical reactions to reuse the energy to drive the large quantity (1.2 GW) of rotating equipment on the plant. In addition, the water processing plant allows all the water produced to be recycled, giving it a zero liquid discharge capability.

The process on Pearl GTL begins with two 30 inch pipelines carrying the natural gas onshore from the two platforms standing in water up to 40 metres deep. On reaching the plant it enters the gas separation unit which extracts all the naturally occurring hydrocarbons such as natural gas, ethane and condensate. This separation process also removes contaminants like metals and sulphur.

The pure methane that remains will then flow to the GTL section of the plant where it will be converted to wax. Finally, the liquid hydrocarbon wax is upgraded using specially developed catalysts into a range of high quality gas to liquid products.

Making syngas: In the gasifier at around 1,300°C, methane and oxygen from the air separation unit are converted into a mixture of hydrogen and carbon monoxide called synthesis gas (syngas). The reaction →
produces heat which is recovered to produce steam which in turn powers the process via the large steam turbines.

**Making liquid waxy hydrocarbons:** The next stage in the process sees the synthesis gas entering one of 24 reactors in the plant. Each reactor holds tens of thousands of tubes containing a Shell proprietary cobalt synthesis catalyst. The surface area of the catalyst used in the plant would cover an area equivalent to 18 times the surface area of the State of Qatar, and if the tubes were laid end to end they would stretch from Qatar to Japan. The catalyst serves to speed up the chemical reaction in which the synthesis gas is converted into long chained waxy hydrocarbons and water. Shell has filed over 3,500 technical patents for its GTL process. For the Pearl GTL project, Shell will have spent approximately four years using dedicated facilities in full-time production to provide the thousands of tonnes of catalysts required.

**Making GTL Products:** Using another Shell proprietary catalyst, the long hydrocarbon molecules from the GTL reactor are fed into the hydrocracker where they are cut (cracked) into a range of smaller molecules of different lengths and shape. The process changes the molecular structure of the very heavy long chained hydrocarbons into products with lighter, shorter chains. They are then fed into a distillation column to separate the various components. In liquid form they are safe, ready to be used and easily distributed around the world.

**Safety**

Despite the massive number of workers involved and the complexity of the construction of Pearl GTL, a strong and focused safety culture has helped Qatar and Shell achieve a record-breaking 77 million hours onshore without injuries leading to time off work.

A benchmark for worker welfare has been set on Pearl with the introduction of Pearl Village, a 170 acre residential area that was specifically built to house construction workers. It was designed to meet rigorous standards in sanitation, health, safety, catering, recreation, IT, multi-faith worship, and banking facilities. Central to the Pearl Village is “Al Muntazah”, the Arabic word for park.

This recreation area forms the backbone of the village and provides extensive sports facilities including cricket, football and baseball pitches, an outdoor cinema, safety training centre and shaded seating areas.

The ethos of the facility is to create a “home away from home” where the welfare of each and every worker is looked after holistically. A community environment has been formed with a Mayor and a dedicated team who are responsible for welfare, cultural festivals and act as advocates within the community. To overcome communication barriers, courses have been given at the onsite training centre in seven languages including Hindi, Arabic and Tagalog. By early 2011, workers had participated in some 367,500 training sessions. At the peak of construction, it took a huge workforce of over 1,800, including 500 cleaners and over 1,000 kitchen staff, to ensure that the village ran smoothly.

Research demonstrates that this unique village community has greatly helped to consolidate, motivate and focus the workers and in doing so increase productivity, efficiency and output. Qatar Shell’s commitment and focus on safety was recognised by HE Dr Mohammed Al-Sada, Minister of Energy and Industry, on 16 May 2011, when it was awarded the inaugural Oil and Gas Industry Gold Award for Safety.

In terms of advances in new technologies, the number of new patents raised, the magnitude of the scale of construction, significant developments in worker welfare, outstanding health and safety records, Pearl GTL is a colossal and remarkable achievement by all those involved.
Floating Liquefaction (FLNG): How far will it go?

BY DAVID LEDESMA
SENIOR ASSOCIATE, OXFORD INSTITUTE FOR ENERGY STUDIES

The liquefaction of gas offshore utilising floating LNG (FLNG) has been the nirvana of LNG developers since the basic concept was developed in the 1990s. Companies saw the potential of FLNG as a means to access stranded gas fields that could not otherwise be economically developed, either because they are too far from shore, or too small to support an economic land-based liquefaction project. In May 2011, the FLNG project began to take shape as Shell took the final investment decision on its 3.5 million tonne Prelude project in Australia with start-up in 2016/7, a strategic move as the company aims to replicate the concept for other projects in a “build one build many” strategy. Other companies have also announced that they are planning to move ahead with FLNG projects. Flex and Hoegh have each claimed that they will launch rival projects in Papua New Guinea by 2014, though neither company has taken Final Investment Decision (FID), and no sooner had Shell announced its decision to move ahead with the project than Malaysia’s Petronas announced it was going ahead with Technip to develop a smaller 2 million tonne project to commercialise offshore Malaysian gas fields. FLNG projects are certainly gathering momentum, but which projects will go ahead and why?

Why FLNG?
Growing demand for clean energy, recent policy moves away from nuclear and a perception that gas pipelines may not necessarily give the assurance of security of supply that gas buyers seek, underpins a good growth story for LNG. Estimates are that LNG demand will double by 2025 and, in reality, if an economic project can be developed then buyers will be in place for the volume – but where are the projects that will supply this demand? Discovered offshore gas reserves, which have been defined by many developers as “stranded” due to their remoteness or location in deep water often cannot be developed commercially using onshore facilities. Where this is associated gas it is often re-injected or simply flared – thus foregoing the market value of the gas. Liquefying the gas offshore can access more reserves and stop flaring, thereby giving a low opportunity cost for the gas compared with liquefaction. Offshore LNG, therefore, saves building a sub-sea pipeline to move gas to shore, gives access to smaller reserves economically and theoretically the unit can be moved to a new location once the exploitation of the original field is completed.

Project promoters also argue that the costs of marine liquefaction and loading facilities are lower than those of onshore plants – some developers claim 20-30 per cent cheaper – and that construction time can be up to 25 per cent shorter than land-based projects, as the facilities can be built in yards that have purpose built facilities, not in the remote greenfield locations that are typical of many onshore projects. Permitting and approval processes are seen as easier than similar onshore projects as offshore projects are subject to different regulation requirements. Floating Storage and Re-gasification Unit (FSRU) projects potentially open up the business to newer smaller companies to participate in the LNG sector. In a business that, to date, has used economies of scale as a means to reduce unit costs, (which has meant that the absolute cost of the projects has increased), size and, therefore, high costs have acted as a barrier to entry. The involvement of new players can only be good news to a contractor capacity constrained business. Project developers also argue that the lack of onshore sites
for liquefaction plants means that they are being pushed offshore to develop new projects. FLNG thus removes a major obstacle to bringing these gas fields to market.

**Options**

There are two designs that are being considered by project developers:

- **Barge based facility that would carry the size of plant that could be built onshore**

  Under this design, the liquefaction facilities are mounted on a barge-like structure, with the LNG stored in the hull underneath. On 20th May 2011, Shell announced its intention to go ahead with this design concept in the world’s first FLNG project at the Prelude field 200km offshore Western Australia in 200-250 metres of water. The project has been designed to produce 3.6 million tonnes of LNG, 1.3 million tonnes of condensate and 0.4 million tonnes per annum of liquid petroleum gas (these liquids providing an important revenue to support the project’s economics). The vessel is being constructed in the Samsung yard in South Korea by a joint venture of Samsung Heavy Industries and Technip. The construction is scheduled to be completed in 2016 with start of production planned for late 2016 or early 2017. The liquefaction unit will be 488 metres long – the length of which is equivalent to four soccer pitches or the first hole at Augusta golf course, Georgia, USA (home of the annual US Masters golf) and weighs 600,000 tonnes. Shell is promoting a second FLNG vessel to be used for the development of the Sunrise field in the Timor Sea in the Joint Development Area between Australia and Timor Leste. This project is not currently proceeding, as the Timor Leste Government would prefer the project to be developed as an onshore plant. Until this is resolved, the project is unlikely to move forward.

  Petrobras has also been considering floating LNG as a means to evacuate gas from the huge pre-salt associated gas reserves offshore Brazil. Japan’s Inpex is planning an FLNG project to commercialise gas in the Masela block in Indonesia. In July 2011 it announced that Shell had taken a 30 per cent stake in the Masela block, and Inpex in its statement said that Shell’s expertise in large-scale offshore gas development activities and its FLNG experience were factors in its decision to involve Shell as a partner. At the same time, Inpex announced that it intends to award front-end engineering and design in the first half of 2012, which would suggest a 2013 FID and start-up in 2018.

- **Ship based design, where the liquefaction plant is built on a purpose built vessel that is sized as a conventional LNG ship**

  This design is being pursued by several companies including; Flex LNG; SBM/Linde/IHI; Hoegh LNG/Lummus (CB&I)/Aker; Teekay; Excelerate Energy; Malaysian International Shipping Company and GDF Suez. All these companies are looking at developing FLNG projects in the 1.5-3.00 million tonnes per annum range. Flex ordered four FLNG vessels from the Samsung yard in South Korea in 2007, and at that time announced that they would be producing LNG by 2011 - to date none have been delivered as the liquefaction projects are yet to be firmed up. No other production units have been ordered.

  Companies were initially looking at developing these FLNG units as offshore projects, but the focus of two companies, Flex and Hoegh, has moved to placing the FSRUs inside a harbour, therefore reducing some of the technical risks of operating in open water. Both companies have plans to use in-harbour FSRUs for the commercialisation of gas in

*Artist’s impression of Flex LNG Papua New Guinea proposed FLNG project*
Papua New Guinea. In April 2011, Flex LNG announced the signing of firm agreements with InterOil Corp, Pacific LNG, LNGL, and SHI to develop an inland FLNG jetty location for a 2.0 million tonnes FLNG facility with a condensate stripping plant to use gas from the Elk and Antelope Gas fields. In May 2011 Hoegh LNG announced that it had established a holding company "PNG Floating FPSO Ltd" with Petromin PNG Holdings Limited and DSME E&R Limited to develop a LNG FPSO project in Papua New Guinea and to develop a FLNG project, to be constructed at the DSME ship yard in South Korea, capable of producing up to 3 million tons of LNG annually, with a storage capacity of 220,000 cubic metres.

Other companies are developing FLNG projects; for example in February 2011 Malaysian state-run Petronas and Malaysian International Shipping Corporation awarded a front end engineering and design contract for an FLNG project to Technip and Daewoo for a project in Malaysia. GDF Suez is developing the Bonaparte FLNG project in North-Western Australia, targeting first LNG in 2018, and Excelerate is looking to develop a 3 million tonne facility, using three one million tonne LNG trains, and having completed front-end engineering and design (FEED), they are currently evaluating which project to proceed on.

**Challenges to development**
The list of challenges to the development of FLNG has been long discussed at LNG conferences and used by traditional LNG project developers to gain advantage over offshore projects. Yes, the challenges are many, but the industry needs change and access to new liquefaction capacity and certainly FLNG projects will be developed – the key question is when and how many?

All LNG projects, floating or land based, are capital intensive and structured around long-term, offtake agreements to provide the necessary revenue flow to support the project economics and, in many cases, the financing of the project. FLNG is a new technology and this means that lenders, who are often conservative in their approach, will seek support guarantees from project sponsors. Finance will, therefore, be difficult to obtain unless the shareholders are large creditworthy companies; indeed in such cases the companies will probably prefer to finance off their own balance sheets. This will mean that smaller companies without deep balance sheets will not be able to develop such projects or will have to bring larger companies or governments in as shareholders to give the necessary credit support.

FLNG also faces local in-country challenges – often governments see LNG projects as a means to develop their infrastructure and create jobs. Can FLNG projects achieve the local content requirements that governments seek, especially as a key advantage of FLNG is that the vessels can be constructed in specialised shipyards, thus avoiding local costs of development and potentially speeding up the project? Can the cost savings be achieved? Will there be cost overruns as developers start implementation?

Developers also face technological challenges. Can the facilities economically manage the treatment of liquids and impurities? Will the facilities have enough flexibility to manage changes in gas quality, in the feed gas either at the first location or, if moved to an alternative location, from new gas fields of a different quality? In such cases additional equipment may be required. But if so, will there...
be space on the FLNG for such changes? Will space on the vessel be a limiting factor? There has also been a lot of discussion by project developers about the operational challenges facing FLNG – will the workforce be safe? How to manage the transfer of LNG between two floating structures using flexible hoses? How will the liquefaction equipment perform when the vessels are in motion on the sea? All these challenges will have to be resolved and proven as manageable to the sponsors and financiers. And, finally a key point, how will they impact on the project economics. Developers are indicating unit costs in the range US$700m to US$1bn per million metric tonnes (the Shell Prelude project is reported to potentially be above this range), and at these costs, is FLNG still attractive to project developers? If costs were to be substantially above this range, it may move developers towards favouring land-based liquefaction projects.

**Commercial structures**

FLNG projects are likely to include a range of different stakeholders including upstream participants, national oil companies (or equivalent), FLNG vessel owners and/or operators, buyers of LNG (and natural gas liquids), vessel suppliers to move the liquids and suppliers of services to the FLNG and Federal/State/Local government bodies. Some of these stakeholders are new to the LNG liquefaction business and this could give rise to structuring complexities. Economic viability and cost of procuring the vessel and the allocation of risk for failure to perform across the LNG chain, as a result of the FLNG not operating correctly, will mean that lenders will seek extensive completion guarantees which may not fall away until a long time after start-up. For example, if an FLNG has been designed to withstand a specific strength of storm, lenders may insist that shareholder guarantees do not fall away until such a storm has been experienced, and this may only happen every 5 or 10 years, then the guarantees would have to remain in place for that period of time.

This would encourage the development of these new technology projects by large credit-worthy companies who can finance from their own balance sheet, without recourse to third party debt. This is what Shell has done with the Prelude FLNG project, keeping 100 per cent of the equity and using corporate debt to finance its construction. Shell will also take all the output into its LNG portfolio and the reported LNG sales of 0.8 million tonnes to Osaka Gas and 2 million tonnes to CPC will be supplied from this portfolio without a link to the Prelude project as a single supply source. This will mean that Shell can develop the project without “partner drag” and so focus on the technical aspects of the project without the distractions of marketing of the LNG and project financing. The LNG buyers also have the comfort that if Prelude is late for any reason, then they still get their LNG from the Shell portfolio of aggregated volumes. It will be difficult for smaller companies to structure a similar deal: their commercial structure would have to be established such that the risks are allocated specifically to give the buyer the necessary supply assurances that the LNG will be produced from the FLNG facility, while giving the developer the contractual and technical freedom to develop the project. These joint challenges may explain the delays in many FLNG projects to date.

**Conclusions**

Companies have been looking at FLNG as a means to produce LNG since the 1990s, and maybe earlier, with 2011 seeing the first FID. There are several other projects being considered with many companies seeking to succeed in this next frontier for LNG.

The key challenges are technology and financing, and these are inextricably linked. Once the first project has been successful the technology risk will reduce and bankers will be more pre-disposed to lend money, thus opening up the sector to smaller companies who aspire to be project developers. Projects with large backers, or other economic drivers (such as the Brazil pre-salt where the gas has to be moved to enable vast oil reserves to be tapped) will proceed; others where technological risks can be reduced (such as locating the FLNG facility in a harbour) may also proceed. But the number of “true” offshore FLNG units will be limited until the industry has seen a track record of successful operation.

The industry needs new technology to access and move remote deep water gas to market. FLNG is such a technology and is here, hopefully, to stay. That said, its impact on overall LNG production will be limited and by 2025 could represent only 5-10 per cent total LNG production globally.

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1. The industry compares liquefaction costs using an indices of $/metric tonne installed capacity (i.e. the capital cost of a project divided by its capacity). Whereas in the period up to 2005 liquefaction costs were $300-600/metric tonne installed capacity (MTIC), newer projects are proceeding at far higher costs. Over the period 2009-2011 projects have taken investment decisions on the basis of capacity costs in the region $1000-1800/MTIC or higher (with expansion projects $700-900/MTIC).
Often overlooked has been the petroleum industry’s own important role in developing carbon capture and storage, and deploying CCS in the future in order to stabilise carbon emissions in the atmosphere. The need for stabilisation of emissions has been starkly underlined by the Intergovernmental Panel on Climate Change’s (IPCC) Fourth Technical Assessment Report (2007). This contained three important findings about global warming:

- warming of the climate system is unequivocal;
- most of the observed increase in global average temperatures is very likely due to human-induced greenhouse gas (GHG) emission concentrations in the atmosphere and
- it is likely that there has been significant human-induced warming in the past 50 years.

The IPCC estimates the global temperature increase in the coming century could be between 1.8-4.0°C, which is much more rapid than any temperature changes known to have occurred during the past 10,000 years.

To limit climate change, GHG emissions need to be reduced significantly.

In 2010, the United Nations Framework Convention on Climate Change (UNFCCC) Conference of Parties 16 (COP16) adopted a non-legally binding goal to limit global temperature increases from pre-industrial levels to 2°C. This is equivalent to stabilising greenhouse gas concentrations in the atmosphere to about 450 parts per million of CO₂ equivalent by 2050 (with CO₂ concentrations stabilised at less than 400 parts per million). This compares to an estimated concentration of CO₂ in the atmosphere of around 395 parts per million in June 2011.

Achieving the degree of decarbonisation implied by the above statistics – no further growth in the concentration of CO₂ in the atmosphere over the course of a generation – is a challenge that can only be met by using a number of technologies in parallel.

Scenarios by the International Energy Agency (IEA) indicate that CCS could account for some 19 per cent of energy-related GHG emission reductions, on a par with the contribution from renewable energy and other efforts, if greenhouse gas concentrations in the atmosphere are to be stabilised by 2050. CCS is particularly important if this stabilisation is to be achieved at least cost.

CCS involves capturing bulk CO₂ from large stationary sources, transporting the CO₂ often via pipeline or other means (e.g. barge or tanker) and storing the CO₂ in a geological formation (for example, a depleted oil and gas reservoir, deep saline formation or an oil field suitable for enhanced oil recovery).

Much of the public policy discussion surrounding CCS in recent years has focussed on the power generation sector. This focus is understandable. It is prudent that governments take action to improve the costs and demonstrate the performance of CCS in the power generation sector, where future emissions will eclipse all other industrial sectors and where the application of capture technologies is considered to be immature and in need of “demonstration”. This is also the case in other high emitting industries such as iron and steel and cement.

The origins of CCS are found in the oil and gas sector

The same capture technologies considered not yet mature in power and many industrial applications have been commercially deployed by the gas processing and chemical industries for decades.

Substantial pipeline networks already exist for transporting CO₂. Most are in North America and are used to supply CO₂ for Enhanced Oil Recovery (EOR), with more than 5,900km of operating pipeline infrastructure.

In terms of storage applications, CO₂ use in EOR has a long history and represents an area of significant experience and expertise as well as an annual injection in the US of over 50 million tonnes per annum (Mtpa) of both natural and anthropogenic CO₂.

Through its annual survey of large-scale integrated CCS projects in 2010, the Global CCS Institute has identified eight operational projects. All of these projects have direct links to the oil and gas sector although the drivers for each are diverse.

One of the first operational projects was ExxonMobil’s Shute Creek Facility in 1986 in Wyoming. Using natural gas separation, today, this facility separates around 7 Mtpa of CO₂ and pipes it over 120 miles to a number of purchasers, including Chevron and Anadarko for EOR. The need to separate the CO₂ from the methane to create a marketable product, use of commercially available natural gas separation technology and significant EOR potential has made this project viable.

The same model applies to Occidental’s Century Plant and the ValVerde Gas Plants in Texas, both of which use CO₂ from natural gas separation to provide millions of tonnes of CO₂ each year for EOR. In addition, the Great Plains Synfuel Plant and the Enid Fertiliser plant both have similar models.
using CO₂ separated by commercially available technology (synfuel and fertiliser production respectively) for EOR.

In Norway, there are another two operational projects but the motivation for storing CO₂ is quite different to enhanced oil production. In 1991, the Norwegian government established a tax on GHG emissions. In response to the US$51 per tonne of CO₂ tax, the Sleipner and the Snøhvit projects have been injecting around 1 Mtpa and 0.7 Mtpa of CO₂ into offshore deep saline formations since 1996 and 2007 respectively. While they both use natural gas separation technology, the storage of CO₂ into deep saline formations has been prompted by having an adequate price on carbon.

Another operating project is In Salah in Algeria, which separates and injects around 1 Mtpa of CO₂ into a deep saline formation. This project has no external financial incentive driving the CO₂ storage component of the gas field operation. While there are subsurface lessons that can be transferred to other CCS projects, there is an expectation that this project could receive carbon credits through the UNFCCC’s Clean Development Mechanism (CDM). This is an important point for many potential CCS projects in developing countries. The CDM is meant to allow emission-reduction projects in developing countries to earn certified emission reduction (CER) credits. These CERs can be traded and sold, and used by industrialised countries to meet a part of their emission reduction targets under the Kyoto Protocol. While no CERs have been received to date for any CCS project, in 2010 at COP16 the Meeting of Parties agreed (subject to general recommendations from the Subsidiary Body for Scientific and Technological Advice which is advising the UN) to include CCS as an eligible project activity under the CDM. This may eventually provide a financial incentive for CCS projects in developing nations.

In addition, the four CCS projects currently in construction also have direct links to the oil and gas sector. Over the past year an important development has occurred in that →

<table>
<thead>
<tr>
<th>Name</th>
<th>Location</th>
<th>Capture type</th>
<th>Volume CO₂ (Mtpa)</th>
<th>Storage type</th>
<th>Key proponents</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sleipner CO₂ Injection</td>
<td>Norway</td>
<td>Gas processing</td>
<td>1 Mtpa</td>
<td>Deep saline formation</td>
<td>Statoil ASA</td>
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<tr>
<td>Snøhvit CO₂ Injection</td>
<td>Norway</td>
<td>Gas processing</td>
<td>0.7 Mtpa</td>
<td>Deep saline formation</td>
<td>Statoil ASA</td>
</tr>
<tr>
<td>In Salah CO₂ Injection</td>
<td>Algeria</td>
<td>Gas processing</td>
<td>1 Mtpa</td>
<td>Deep saline formation</td>
<td>BP, Sonatrach, Statoil ASA</td>
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<tr>
<td>Great Plains Synfuel Plant and Weyburn Midale Project</td>
<td>United States/Canada</td>
<td>Pre-combustion (synfuel)</td>
<td>3 Mtpa</td>
<td>EOR</td>
<td>Dakota Gasification, Chevron, Apache Canada</td>
</tr>
<tr>
<td>Shute Creek Gas Processing Facility</td>
<td>United States</td>
<td>Gas processing</td>
<td>7 Mtpa</td>
<td>EOR</td>
<td>ExxonMobil, Chevron, Anadarko</td>
</tr>
<tr>
<td>Enid Fertilizer Plant</td>
<td>United States</td>
<td>Pre-combustion (fertilizer)</td>
<td>0.68 Mtpa</td>
<td>EOR</td>
<td>Koch Industries, Anadarko</td>
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<tr>
<td>Occidental Gas Processing Plant</td>
<td>United States</td>
<td>Gas processing</td>
<td>5 Mtpa (and 3.5 Mtpa in construction)</td>
<td>EOR</td>
<td>Occidental Petroleum</td>
</tr>
<tr>
<td>Val Verde Natural Gas Plants</td>
<td>United States</td>
<td>Gas processing</td>
<td>1.3 Mtpa</td>
<td>EOR</td>
<td>Blue Source, PetroSource Energy</td>
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**Operation stage**

**Construction stage**

<table>
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<tr>
<th>Name</th>
<th>Location</th>
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<th>Storage type</th>
<th>Key proponents</th>
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<tr>
<td>Enhance Energy EOR Project</td>
<td>Canada</td>
<td>Pre-combustion (fertiliser and oil refining)</td>
<td>1.8 Mtpa</td>
<td>EOR</td>
<td>Agrium Fertiliser, North West Upgrading, Enhance Energy</td>
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<tr>
<td>Gorgon Carbon Dioxide Injection Project</td>
<td>Australia</td>
<td>Gas processing</td>
<td>3.4 - 4 Mtpa</td>
<td>Deep saline formation</td>
<td>Chevron, ExxonMobil, Shell</td>
</tr>
<tr>
<td>Plant Ratcliffe</td>
<td>United States</td>
<td>Pre-combustion (power)</td>
<td>2.5 Mtpa</td>
<td>EOR</td>
<td>Mississippi Power, Denbury Resources</td>
</tr>
<tr>
<td>Saskpower Boundary Dam 3 CCS Project</td>
<td>Canada</td>
<td>Post-combustion (power)</td>
<td>1 Mtpa</td>
<td>EOR</td>
<td>Saskpower</td>
</tr>
</tbody>
</table>

Large-scale integrated carbon capture and storage projects in operation and construction
the inclusion of captured CO₂ from power facilities is now a factor. The two projects of note are Mississippi Power’s Plant Ratcliffe and Saskpower’s Boundary Dam project in Saskatchewan. In both projects CO₂ captured from power plants will be injected for EOR.

These 12 projects, as well as the broader CO₂ EOR experience, highlight the extensive contribution of the oil and gas sector. This contribution includes:

- the commercial scale separation of bulk CO₂ to near purity;
- the compression, safe handling and transport of CO₂ over long distances at high pressure and extreme temperatures;
- the exploration and appraisal of suitable EOR injection sites and suitable storage sites in deep saline formations;
- CO₂ injection well design and development and
- reservoir management practices, including measurement, monitoring and validation.

All of these activities are central to the oil and gas sector and all of these will be required in demonstrating CCS today and deploying CCS into the future.

The future of CCS and the oil and gas sector

The above analysis of projects also provides a valuable stock of information that can be drawn upon to support the current demonstration of CCS. While this knowledge needs to be applied to a broad range of industries (power, cement, iron and steel, fertiliser production, refining, gas separation, ethanol production, etc), much of the effort, skills and expertise of developing CCS projects resides in the foundations of the oil and gas sector. By sharing this knowledge, the oil and gas sector can support accelerated technology diffusion, improved public understanding of CCS, cost and risk reduction and accelerated innovation. Overall, these active projects provide knowledge, insight, and lessons into developing CCS projects that can assist others to do so more effectively.

These projects also show that the drivers for CCS are diverse and growing. In some limited instances the application of CCS was commercial. In others, a price on carbon was sufficient and indicates that CCS can be more cost effective than paying to emit. Current studies similarly show that in some industries, for example, natural gas processing, fertiliser production and ethanol production, the cost of applying CCS could be as low as US$20 per tonne CO₂, according to a 2011 report by Worley Parsons, commissioned by my institute. This cost represents the cost of adding compression, transport and storage where a pure stream of CO₂ already exists.

Building on this, the CDM provides promise for the arrival of CCS projects in developing countries, especially in industries where the costs of applying CCS are lower and only a modest incentive is required. Ultimately a significant price on carbon will be required to see CCS deployed in future high emitting industries and countries. As governments move towards this, it is likely that new CCS projects will be developed, greater innovation will emerge and that the oil and gas sector will be heavily involved.

Since the beginning, the oil and gas sector has responded to incentives that apply to CCS. This has been shown through developing the first set of operational CCS projects and through the current suite of projects being developed to demonstrate CCS in industries such as the power sector. All of the current demonstration projects and those in the future that arise in response to new incentives will require a number of the core skills (individual and work practices) contained in the oil and gas sector. The past, present and future of CCS and the oil and gas sector are intertwined. Perhaps this combination can make significant inroads into the mountainous task of decarbonising the energy sector and reducing global warming.
The challenge of sustainable biofuels

BY ANSELM EISENTRAUT, RENEWABLE ENERGY DIVISION
AND MICHAEL WALDRON, OIL INDUSTRY AND MARKETS
DIVISION, INTERNATIONAL ENERGY AGENCY

Biofuels have a long history that tracks back to the late 19th century, but it was not until the 1970s that the sector witnessed some growth in Brazil and the US which both put support policies in place. In most other regions, a significant growth in biofuel production took place only in the last 10 years. Global biofuel production grew around five-fold during this period reaching 1.8 million barrel/day (mb/d), driven by concerns over energy security and climate change, as well as governments’ will to create new sources of income in rural areas.

Medium-term outlook

Dramatically rising oil prices in the first half of 2011 would appear to be a boon to biofuels production going forward. Indeed, from 2010-2016, the IEA’s Medium Term Oil & Gas Markets 2011 forecasts that biofuels output will rise by 0.5 mb/d, a near 30 per cent increase. Yet, market conditions and production economics have also become more challenging, even with high oil prices, undermining production in Brazil and Europe in particular. Difficult weather conditions, strong emerging market demand, increased energy costs, and to some extent usage from the biofuels industry itself have all tightened balances in many agricultural commodities. As such, biofuels production growth is expected to slow in 2011 after a strong 2010.

Over the medium term, biofuels will still help satisfy a significant part of oil demand growth, though less than before. From 2004-2010, biofuels supply growth, on an energy-adjusted basis, met 23 per cent of global incremental gasoline and gasoil demand, with ethanol at 48 per cent of gasoline and biodiesel at 10 per cent of gasoil growth. From 2010-2016, with combined gasoline and gasoil demand growing by 4.3 mb/d, biofuels supply growth should meet only 9 per cent, with ethanol constituting 24 per cent of gasoline and biodiesel accounting for 4 per cent of gasoil growth. By 2016, ethanol and biodiesel should displace 5.3 per cent and 1.5 per cent of total global gasoline and gasoil demand, respectively, on an energy content basis.

Feedstock prices and production economics for conventional biofuels will likely remain volatile in the medium term. Conventional biofuels, often referred to as first generation, are produced from starch, sugar or oil-burning crops. As such, government policies – blending mandates, production subsidies and blenders’ credits – will continue to serve as key production supports. In an environment of fiscal austerity, financial incentives are increasingly at risk, particularly in the US. However, mandated quotas and targets continue to rise, with EU Member States, Argentina, Canada, Thailand, Peru, and Malaysia all increasing required blending volumes. Notably, the fulfilment of government usage targets as they currently stand suggests production upside. Our 2010-2016 growth forecast of 520,000 b/d undershoots by 670,000 b/d the potential supply increases, were national level policy targets in major biofuels markets to be met.

Biofuels will face a number of challenges, including both economic as well as non-economic ones such as policy uncertainty, competitiveness of biofuels, sustainability requirements and consumer acceptance that might affect potential output. It is therefore important to identify these potential challenges and address them in the short term to achieve long-term targets. The IEA – in its recently launched technology roadmap Biofuels for Transport – assesses key actions and milestones that need to be taken to allow for a large-scale development of the biofuel sector to 2050 under an ambitious emission reduction scenario, cutting energy-related CO₂ emissions by 50 per cent in 2050 over 2005 levels. The roadmap analysis indicates that biofuels could provide up to 27 per cent of world transportation fuel by 2050 and thus avoid about 2.1 Gigatons (Gt) of CO₂ emissions in the transport sector when produced sustainably. Despite considerable potential for energy efficiency measures, and electrification of light duty vehicles, biofuels will play an important role to provide low-carbon fuel in particular for airplanes, marine vessels and other heavy transport modes.

The roadmap envisions an increase in global biofuel consumption from 55 million tonnes oil equivalent (Mtoe) today to 750 Mtoe in 2050 with demand for biofuels expected to pick up considerably in all world regions. Engaging developing and emerging economies in technology development and capacity building will therefore be crucial in meeting the roadmap targets.

Efficient technologies needed

Conventional biofuels have been criticised in recent years regarding their limited potential to save greenhouse gases, their high production costs and potential competition for land and grain for food production. It is important to note, however, that some biofuels perform well in terms of land-use efficiency, life-cycle greenhouse gas savings and production costs. Nonetheless, deployment of more energy- and land-efficient conversion technologies, in
particular advanced biofuels produced from lignocellulosic energy crops and residues, is required to achieve a significant contribution of biofuels to future transport fuel demand. Support for advanced biofuel research, development and demonstration is still needed in the short term. Most crucial, however are specific support measures that address the high investment risk associated with pre-commercial advanced biofuel technologies. Government action will be crucial to provide a stable, long-term policy framework for biofuels will be vital to trigger industry investments in first commercial plants and sustained investments in sustainable biofuel expansion.

Sustainable biomass supply
To produce the amount of biofuel envisaged in the IEA Biofuel Roadmap will require biomass feedstocks of more than 3 billion tonnes of dry biomass, in 2050. This feedstock demand could well be met with low-risk biomass sources, such as residues and wastes as well as sustainably grown energy crops. The latter still have great potential for yield improvements, in particular in developing countries, as many potential feedstock varieties have not yet been subject to commercial breeding efforts. This could limit the amount of land needed in 2050 to around 100 million hectares of land, a three-fold increase of the gross area under biofuels compared to the current level. In addition, better efficiency of biomass use, for instance through integrating biofuel and bio-material production in biorefineries, will also be vital to reduce land competition and associated negative land-use changes, and help improving the economics of biofuel production. Meeting the targets of the IEA biofuel roadmap will require substantial investments in crop breeding and large-scale field trials for promising biofuel feedstocks as well as the vigorous adoption of best agricultural practices to achieve sustainable yield improvements. Improved land-use mapping will also be vital to identify those areas with good potential for feedstock cultivation and little risk of food-competition and indirect land-use change.

Having a sound international policy framework in place is a prerequisite to ensure the required amounts of feedstock and land can be made available in a sustainable way, without compromising food security, threatening biodiversity or limiting smallholders’ access to land. Sustainability
certification of biofuels, following internationally agreed sustainability criteria, and involvement of all stakeholders along the production chain will be vital elements to ensure sustainability of the biofuel sector. Since many sustainability issues related to biofuels are in fact concerning the whole agricultural sector, biofuel policies should be aligned with those in agriculture, forestry and rural development. In the longer term, an overall sustainable land-use management strategy for all agricultural and forestry would help to avoid land-use changes with negative impacts on the environment and CO₂ emissions, and to support the wide range of demands in different sectors.

**Economics of biofuel production and use**

With substantial investments in place, most biofuel technologies could get close to cost-competitiveness with fossil fuels, or even be produced at lower costs in the longer term. Production costs for advanced biofuels could reach cost-competitiveness with gasoline or diesel around 2030 in optimal cases. However, future production costs will depend on the impact of oil price on feedstock and capital costs. Depending on the actual production costs, total expenditure on biofuels required to meet the roadmap targets is estimated between US$ 11-13 trillion over the next 40 years, representing a modest share of 11-12 per cent of total spending on transport fuels. Even with a strong correlation between rising oil prices and feedstock and capital costs, the additional costs of biofuel use compared to use of diesel/gasoline are in the order of 1 per cent of total costs of transport fuels over the next 40 years. With lower production costs, biofuels could even lead to actual fuel cost savings.

**International collaboration is vital**

International collaboration, to ensure technology transfer, capacity building and involvement of all stakeholder, in particular in developing countries, will be critical to realising the vision of a sustainable, large-scale biofuel deployment laid out in the IEA Biofuel Roadmap. In order to stimulate financing on the scale required to realise the deployment of sustainable biofuels envisioned in this roadmap, governments must take the lead role in the coming years to create a favourable climate for industry investments.

IEA Biofuel Roadmap is available at the IEA website: www.iea.org/roadmaps.

Brazil harvests sugarcane for biofuels
More than half the world’s population now lives in cities and, according to the United Nations, this fraction is expected to increase to 60 per cent by 2030. Moreover, 80 per cent of the world’s wealth is expected to be concentrated in urban areas in 2030 so that issues influenced by wealth (such as materials and energy consumption and greenhouse gas emissions) will be increasingly determined by urban dwellers. In short, it will not be possible to solve these global issues without addressing the challenges posed by urbanisation.

Mobility enhances our lives by allowing contact with others, offering new experiences and supporting the exchange of ideas and goods. Cities facilitate connecting people and goods but their roads are becoming increasingly crowded. This is particularly acute in emerging markets, with increased migration from rural to urban areas and with increasingly wealthy people aspiring to automobile ownership. Despite heavily congested roads, there is still a desire for personal mobility in urban centres because no other means of transport has so far offered the same mix of freedom, comfort, utility and security as the automobile.

However, to achieve sustainable urban mobility we will need to fundamentally reinvent the automobile to preserve the basic appeal of personal mobility (“go where you want, when you want with whom you want”) while addressing the societal challenges of congestion, land use for parking, air pollution, greenhouse gas emissions and road accidents.

A proposed solution from General Motors is the EN-V (Electric Networked Vehicle, pronounced “envy”) concept that was introduced at the 2010 Shanghai World Expo as a vision to support the Expo theme of “Better City, Better Life”. EN-V is a battery electric vehicle that can reduce energy consumption and environmental emissions. It uses a dedicated short range communications, sensing and Global Positioning System (GPS) platform to enable vehicle networking to reduce congestion and accidents. It is a small footprint, highly manoeuvrable vehicle that can reduce parking space requirements, energy consumption and ownership costs.

EN-V type vehicles could weigh around 500 kg and consume around 100 Wh of electricity per km (approximately 200 miles per gallon on a gasoline energy equivalent basis). This is possible because the vehicles may only need to have a range of 30 miles (not 300 miles), may only need to travel at speeds of up to 30 mph (not 100 mph) and may only need to accommodate 1 or 2 people (not 5 or 6). Compared with today’s vehicles, they can provide safe, convenient personal urban mobility at about one quarter the total cost per mile, and will need only one fifth of the land for parking. The same technology that allows them to network and sense each other to reduce collisions will also enable autonomous driving and help provide accessibility to address another megatrend – the increasingly aging population.

This new DNA for the automobile, based on electrification and connectivity, rather than today’s petroleum-fueled vehicles that operate as stand-alone transportation products, will also improve the integration of personal and public transport so that a new mobility system, offering the best features of both, can be realized. The convergence of electrification and connectivity, tied to the modest driving needs for urban dwellers, creates the opportunity to reinvent automobiles and fundamentally change how we move around. This quantum leap may be what is needed to meet the urgent sustainability challenges that face densely populated urban centres around the world, where the world’s population is increasingly living.

The situation outside the densely populated cities is different. Mobility needs for daily travel can be longer (more vehicle miles travelled), duty cycle requirements can be greater (more movement of goods over longer distances), and roads and terrain can be uneven and unpredictable. Electrically-driven vehicles could also play a significant role outside cities. However, to overcome range anxiety
and the limited recharging infrastructure, the source of electricity may need to come not only from a battery but also from an on-board range extender (as on the Chevrolet Volt or its European equivalent, the Opel/Vauxhall Ampera) or from a hydrogen fuel cell.

For most non-urban applications, other energy and propulsion options may be even more attractive than electric-drive. Where biomass is abundant, for example, liquid and gaseous bio-fuels may be more affordable than electrified options. Recent examples include bio-ethanol in Brazil and bio-diesel in Europe. For liquid fuels, a flex-fuel vehicle is preferred for early commercialisation. Advances in biomass conversion may allow future bio-fuels to have comparable energy density to gasoline and diesel. This would allow relatively affordable, local energy resources to be used without sacrificing vehicle utility in anyway.

Biomass can also be used to produce hydrogen. This conversion holds promise in supporting fuel cell vehicle commercialisation, enabling vehicles of all sizes to have zero tailpipe emissions and to be fuelled from renewable sources. Additional studies on biomass conversion are required, but because the fuel cell vehicle may have twice the efficiency compared to a similar sized gasoline engine equivalent the well–to-wheels greenhouse gas emissions for the fuel cell vehicle could be reduced.

Whether the biomass is used to make biofuels for use in an engine or to make hydrogen for fuel cells, “well-to-tank” energy conversion efficiency has to be combined with the vehicle’s “tank-to-wheels” efficiency to understand the most energy efficient solution.

There is also renewed interest towards using compressed natural gas and liquid petroleum gas in several regions of the world. This is likely due to recent discoveries of large reserves and new processes for extracting gaseous fuels from shale. It is generally accepted that there is approximately a 20 per cent reduction in greenhouse gas emissions, compared to gasoline, when internal combustion engines use natural gas. Although compressed natural gas has a lower energy density than gasoline, it is possible to develop vehicles having a range of hundreds of miles. In particular, medium and heavy duty vehicles that can accommodate the packaging of gaseous fuel tanks may be promising applications. In the long-term, as with biomass, these gaseous fuels could be converted into hydrogen and would support the development of zero emission fuel cell vehicles.

Lastly, the venerable internal combustion engine, with or without hybridisation, will continue to serve consumers around the world due to widespread fuel availability and relative affordability, especially for long-distance, high speed operation. Affordability will continue to drive consumers to this option although regulations could drive the market in terms of “carrots” (incentives for other alternatives, price controls, etc.) and “sticks” (feebates, penalties and taxes).

As shown below, it is expected that there will be an increase in the variety of energy and propulsion choices for vehicle usage outside densely populated centres because of consumer needs for range, performance and utility and governmental needs to promote energy diversity, domestic energy sources and cleaner environments. For urban centres, however, urban dwellers and cities may increasingly support a move towards small electric, networked vehicles that can address the energy, environment, safety, congestion, parking, affordability and accessibility challenges.
Trinidad and Tobago: First mover, still in the game

BY DAVID RENWICK
CARIBBEAN ENERGY CORRESPONDENT, WORLD PETROLEUM

Trinidad and Tobago’s entry into the World Petroleum Council (WPC) is long overdue – after all, it was the earliest country in the world to attempt to explore for oil.

In 1857, a well was drilled to a depth of 280 feet in the vicinity of the world-famous Pitch Lake in southwest Trinidad by the Merrimac Company.

Though no oil was found, this was two years before Colonel Edwin Drake sank the well in Titusville, Pennsylvania, which is generally credited with launching the international oil industry. This secured Trinidad and Tobago’s place firmly in the annals of the global hydrocarbon sector.

The small, 5,155 sq km, two-island state at the bottom of the Caribbean archipelago, with a population today of a mere 1.3 million, did achieve exploration success when Walter Darwent, an English mechanical engineer who had served in the Union forces in the American civil war and was later sent to Trinidad by the West Indies Petroleum Company, sank a well at Aripero, 6.5 km east of the Pitch Lake and encountered 20 feet of oil-bearing sands, which yielded two and a half barrels over a period of seven hours. But drilling difficulties and shareholder scepticism caused the operation there eventually to be wound up. Darwent himself died two years later but his descendants are still living in Trinidad and Tobago today.

Further productive wells were drilled in Guayaguayare in south east Trinidad between 1902 and 1907 by businessmen Randolph Rust and John Lee Lum, whose first hole, Guayaguayare 1, produced 300 barrels before it was shut in (apparently, the duo could find no shipping line willing to carry the low-flashpoint oil to markets overseas). Rust and Lee Lum drilled nine wells during the period, the third of which introduced rotary equipment to the country, an improvement over the cable tool method employed up to then.

Though Rust and Lee Lum are regarded as having put the oil industry on an operational footing for the first time, actual commercial production, when it began in 1908, took place near the site of the original 1857 well.

“Commercial” as used here means an oil strike that enables the exploration company to sell its product, recover all costs and declare a profit. The Trinidad Petroleum Company (TPC) qualifies as the first commercial producer, with its Guapo 3 well at the south west coastal town of Point Fortin. The New Trinidad Lake Asphalt Company was simultaneously drilling nearby and its Point Fortin West 4 well, completed in 1909, was demonstrably a major discovery, flowing at what was then the extraordinary rate of 12,000-15,000 barrels a day (b/d).

The first cargo of Trinidad crude (we'll call it that because no oil has ever been identified in Tobago) was shipped out the following year and by 1911, the country already had its own refinery, at Brighton, near Point Fortin, which possessed a functioning port.

As oil discoveries were made in other parts of south Trinidad, processing capacity grew and another refinery was established further up the west coast in 1917, at Pointe-a-Pierre, adjacent to the main southern town of San Fernando. This still survives today, as the only refinery left in the country.

Finding crude on land in Trinidad was never an easy task because of the island’s complex geology and, indeed, Trinidad was at one time, dubbed “the geologist’s graveyard” by frustrated practitioners of the art.

As the country’s Petroleum Association declared in a review of the industry in 1952: “Trinidad must be among the
most difficult places in which to find and produce oil in commercial quantities. All professional geologists may not agree that Trinidad is the grave of geological reputations but they will be the first to agree that geological conditions are highly complex and unpredictable.

Even so, by 1934, 26 years after commercial production of crude had commenced, Trinidad and Tobago had actually become the world’s eleventh biggest oil producer, ahead of Iraq, Canada, Ecuador, Egypt and Bahrain, among others. That eminence was to be short-lived, however.

Peak oil production on land reached 111,883 b/d in 1967 and then went downhill rapidly. Peak production in the Gulf of Paria, which separates Venezuela and Trinidad on the west and was the first offshore location for exploration, was 76,948 b/d in 1986 and then also declined. Peak production in the Columbus Basin off the east coast, attained the level of 139,163 b/d in 1978 and started to decrease thereafter.

It should be noted, however, that discoveries offshore gave the Trinidad oil industry a new lease of life in the early 1970s, just about the time that both land and west coast production was falling. The identification of three major oilfields – named Teak, Samaan and Poui – by the then Amoco Oil Company (subsequently absorbed by BP plc) sharply reversed the decline from land and Gulf of Paria sources, to the extent that Trinidad and Tobago’s overall oil output rose sharply to 240,000 b/d in 1978, six years after Amoco had commenced production.

Alas, this was the highest it has ever reached and today it is down to around 70,000 b/d (although the country’s Ministry of Energy and Energy Affairs – MEEA – has ambitious plans to address this situation, which we will come to later in this article).

Fortuitously, Amoco had also found natural gas reserves during its intensive exploration programme and that began laying the foundation for Trinidad and Tobago’s switch from an economy dominated by oil to one where gas has become dominant (indeed, if condensate is added to crude production, the liquids figure rises to around 90,000 b/d).

For example, whereas the oil refiners never seriously considered taking their product further down the value chain into petrochemicals, the gas sector has done precisely that, with gas being employed at the internationally renowned Point Lisas industrial estate in west-central Trinidad to produce methanol, ammonia, urea, gas liquids and other products further downstream. Indeed, Trinidad and Tobago today is one of the world’s largest producers of both methanol and ammonia, almost all of which is marketed abroad.

Liquefied natural gas (LNG) was added to the mix in 1999, when Trinidad and Tobago became the first country in Latin America and the Caribbean to produce LNG. The ground-breaking project was financed by BP, BG Group, Repsol, what is now GDF Suez and the local, state-owned National Gas Company (NGC). They called the company Atlantic, and train one, at 3 million tonnes of production a year, was then the largest, single-train LNG facility in the world. Three more trains have since been added, train four, at 5.2 million tonnes a year, itself, for a time, being the biggest in the world.

Though well over 160 companies have, in their time, shown keen interest in exploring in Trinidad, only the bigger names, such as BP, BG, BHPBilliton, Repsol and →

NGC ‘slug catcher’, Beachfield, south Trinidad

Photograph courtesy of NGC
Centrica are left today, along with a growing group of feisty Canadian independents and some small local upstream firms (of which more later).

Notable about the shift from oil to gas in Trinidad and Tobago (gas production is now at least eight times that of oil on a barrel-of-oil equivalent basis) is that it has been led, at least on the production side, by the international players, such as BP and BG.

BP produces about 2.5 billion cubic feet a day (bn cfd) and BG around one billion a day, out of total gas production now topping 4.1 bn cfd, 59 per cent of which is devoted to LNG and 41 per cent to the petrochemical and metals companies, electricity generation and smaller users.

BG, which opened up a new gas province off the north coast of Trinidad in 2003, has never shown much interest in finding oil in Trinidad (unlike its attitude to Brazil, where it is a partner with Petrobras in giant deep water discoveries).

BP, for its part, actually exited the oil business in Trinidad in 2005, preferring to focus all its attention on gas exploration and production.

BHP Billiton, which arrived in the late Nineties, departed from the international company norm in Trinidad and Tobago by actively seeking out oil, though it did also find some gas, which it began monetising in 2011. Its Angostura discovery in block 2c off Trinidad's north east coast, was, however, a disappointment, with the original estimate of recoverable reserves having to be downgraded to about 60 million barrels. Its output is now only about 15,000 b/d a day. Repsol took over BP’s Teak, Samaan and Poui fields in the mid-Nineties along with its state-owned partners, Petrotrin and NGC, but production there has never much risen beyond 15,000 b/d.

National companies

It is really the state-owned Petrotrin that has been obliged to carry responsibility for revitalising the oil industry in Trinidad and Tobago.

It now lifts around 40,000 b/d of crude from its land and Gulf of Paria fields, some 44 per cent of total liquids output.

Of course, the company has a vested interest in so doing: its refinery at Pointe-a-Pierre requires 160,000 b/d of crude to turn out the six different types of fuel it produces and local crude will always be cheaper than the imported variety.

So the role of state companies in the maintenance and growth of the energy sector in Trinidad and Tobago, 104 years after commercial oil production began, is a key one today.

Petrotrin is both the biggest crude oil producer and the only refiner, while NGC is the sole owner of onshore pipelines and only trader of domestic gas. Gas destined for LNG, in which NGC has no hand, travels through the company’s major east-west onshore pipeline. A third state company, NP, is the major petroleum products distributor and retailer in the country.

Free marketers may argue that the state should stay out of the oil and gas business but that thesis falls down in Trinidad and Tobago when it is considered that Petrotrin actually exists because foreign majors, like Texaco and Shell, decided of their own volition to quit the refining business and left the state with little choice but to step in.

NGC, for its part, has been the catalyst, through its wholly owned subsidiary, the National Energy Corporation (NEC), for the rapid development of the gas-based downstream industrial sector by deliberately promoting the country’s attractions as a site for modestly-priced gas.

NGC has been the intermediary between the gas producers, like BP and BG and the gas users, like Methanex, PCS Nitrogen, Methanol Holdings Trinidad Ltd. (MHTL) and ArcelorMittal. It negotiates the price to the producers and the price to the consumers and has structured the latter in such a way that a low base price is augmented for NGC when prices of the methanol and ammonia made from the gas rise on the international market (if vice versa, of course, the returns to NGC fall).

With BP having opted out of oil production in Trinidad and Tobago, BHP Billiton’s output having fallen far below expectations and Repsol not having done much with its TSP block, Petrotrin is the mainstay of the oil part of the country’s energy industry.

It is little wonder then that the Minister of Energy and Energy Affairs, Kevin Ramnarine, who took over that job in June, 2011, describes Petrotrin as “a company very near and dear to my heart” and has vested it with the task of turning around the country’s collapsing crude production, which, as earlier noted, now stands at around 70,000 b/d (another 20,000 b/d or so should be added for the condensate which comes with gas production and increases the liquids total).

Petrotrin is in the best position to do this, if only because it holds the vast majority of the onshore acreage in Trinidad and most of the offshore acreage in the Gulf of Paria as well. It is likely to receive strong support in this effort from the small local companies mentioned earlier, as well as from some of the Canadian independents now taking a renewed
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interest in Trinidad, such as Parex Resources, Niko and Touchstone, as well as a bullish UK arrival, Bayfield Energy.

As the minister admits, however, Petrotrin’s handicap has been that of cash flow, partly the fault of the government itself, which, as he says, “has built up a debt to the company in excess of TT$4 billion (about US$665 million) which arises because of money owed to it in relation to the petroleum subsidy that has crippled Petrotrin to the point where it is impacting even on its ability to pay its taxes.”

The minister is referring to the government’s policy of subsidising the price of gasoline and diesel at the pump and the state’s obligation to meet the real cost to Petrotrin of refining those products.

However, Petrotrin did manage to gather enough funds to support a recent 3D seismic survey over 312 sq km of its land acreage that is expected to lead to a major exploration programme which has not been undertaken on land for a long time. This is likely to commence in January, 2013.

Simultaneously, the state company will launch a re-activation effort in South West Soldado (SWS), one of its four fields in the Gulf of Paria. This area has great potential but has been neglected for some time. Minister Ramnarine himself describes SWS and the other fields in what is known as Petrotrin’s Trinmar unit as being “central” to the company’s resurgence. The Trinmar fields have yielded over 710 million barrels of crude since production began in 1955 and it is widely believed there is much more to come.

Trinmar also contains substantial reserves of heavy oil (API gravity 18 degrees or less), which Petrotrin has never seriously attempted to recover, along with the medium gravity oil it has traditionally extracted for decades.

The SWS campaign will pre-empt most of the US$1.2 billion Petrotrin intends to spend on its revival programme over the next five years, with the money going to upgrading ageing infrastructure, drilling many new wells, reactivating non-producing wells, undertaking workovers and replacing flow lines. Sixteen wells were to be sunk in Trinmar in 2011, most of them development wells.

Lindsay Gillette (pronounced with a hard “G”), the billionaire Trinidad and Tobago businessman who was appointed Petrotrin’s chairman when the People’s National Movement (PNM) government was replaced by the People’s Partnership (PP) coalition in the May 2010 general election, is confident that the company will make a significant contribution to the goal of raising crude oil production.

“We are most definitely up to the task,” he insists, “and Trinmar will be an important part of that process.”

Petrotrin has, for decades, brought in partners to help it maintain oil production, principally on land, where its joint ventures (JVs), fall into various categories, such as Lease Operatorships (LOs), Farm Out (FOs) and, most recently, Incremental Production Service Providers (IPSCs), all with local upstream firms (though some of these have been bought out by foreign independents recently).

Between them, LOs and FOs contribute about 5,500 b/d to the local refinery, while IPSCs currently provide about 400 b/d.

Petrotrin has also handed over operatorship of some of its fields to small companies from overseas, such as the UK’s Bayfield Energy, which has already succeeded in doubling production (to about 1,500 b/d) from the Galeota block nearshore the south east coast.

JVs initiated by Petrotrin (some have been mandated by the MEEA as part of the effort to maintain “local content” in larger land and offshore blocks) will continue, says chairman Gillette, “but we need better synergies and complementaries in the relationship.”

On the gas side, NGC and NEC will continue to pursue their respective role of gas transporter/trader and gas-based industry promoter, respectively.

Current developments

One of the big challenges ahead for NGC, as its president, Andrew McIntosh freely admits, is negotiating new contracts with the gas producers, as current agreements expire in the next five to six years.

Rising development drilling and production costs – Derek Hudson, president of BG Trinidad and Tobago, estimates it will require a minimum of US$750 million to develop the one trillion cubic feet plus of gas in the 5c block offshore south east Trinidad of which his company is the operator – mean that the sale of this gas to NGC will be more costly than has historically been the case.

But at the same time, the petrochemical companies are pressuring NGC to reduce its prices to them, because they sell methanol and ammonia principally in the United States, where bountiful shale gas production has driven down the gas price, thus giving their US competitors an advantage.

“In light of the competitiveness of US gas, NGC has to be very concerned about, and very sensitive to, how we structure our gas price regime going forward, so as to remain competitive in international markets,” McIntosh points out. Equally disconcerting is the strong possibility of all that gas enabling the US to turn the tables on Trinidad.
and Tobago and resume the export of LNG itself. Indeed, Cheniere Energy of Houston, which, up to now, has been an importer of LNG has already successfully applied to the US Department of Energy (DOE) to add exporting capacity to its Sabine Pass, Louisiana, terminal. It is also said to have signed up its first client, an electricity generator in the Dominican Republic called Basic Energy, which will require up to 600,000 tonnes a year of LNG from about 2015.

To accelerate this about-turn in its business model, Cheniere is preparing for as many as four LNG trains, each with a nominal capacity of up to four million tonnes a year and built in phases. Should all of that go ahead, it will mean that Sabine Pass will have more LNG capacity than Atlantic in Trinidad, an eventuality that would have been unthinkable only a year or two ago.

What’s more, both Dominion and BG Group, operators of the Cove Point, Maryland and Lake Charles, Louisiana LNG importing and re-gasification terminals respectively, have also applied for permission to become LNG exporters. Both will probably turn around imported LNG cargoes at the beginning and then establish new liquefaction plants after a while, using surplus US gas.

What all this means for Trinidad and Tobago and NGC in particular, since it is the only local company currently involved in the LNG business as 10 per cent shareholder in train one and 11.1 per cent shareholder in train four, which also carries with it the entitlement to a liquefaction quota of 88 million cubic feet a day (mmcf/d), is that the new US LNG exporters will want to target the nearest LNG markets in the first instance and that means, following Cheniere’s example, countries in the Caribbean and Central America.

Analysts in Trinidad feel that, having lost out on its gas processing venture in Ghana, NGC should be thinking of taking advantage of the smaller LNG markets that are likely to develop in its own backyard, as regional utilities move to replace heavy fuel oil and diesel with natural gas for power generation.

McIntosh is aware of the opportunities but cautious at this stage. “The small LNG market in the Caribbean is a possible thing,” he says. “However, the logistical and physical facilities required in Trinidad to achieve that, would not be easy.”

All of which may be true but many observers of the local energy scene fear that the market will be lost over time if NGC does not take it seriously, since delivery of the smaller LNG cargoes (say about 15,000-20,000 cubic metres) will then gradually slip into the hands of US exporters, maybe even some of the very companies, like BG, which are involved in the LNG industry in Trinidad itself.

Capturing small LNG markets would seem to fit neatly into minister Ramnarine’s vision for “internationalising” the state-owned energy companies.

The Ghana gas processing initiative was seen as the first move in that direction but now that China has apparently put in a more attractive bid for its construction, NGC has been left with only the offer of being hired to operate the plant after it has been built. Discussions on the matter were continuing up to late October, when this article was written, but insiders think that NGC will not want to operate a complex facility which it has had no hand in installing.

If neither Ghana nor the small gas trades work out in NGC’s favour, the internationalisation thrust will not be aborted. “The time has come for ‘Brand Trinidad and Tobago’ to go global,” the minister insists. “Instead of only seeking to attract investment to this country, we must become investors in energy projects around the region and in Africa. That is the idea and that is the vision.”

If it eventually gets the green light (and it has been stalled for several years), the Eastern Caribbean gas pipeline between Tobago and Barbados, in which NGC holds a 10 per cent share, will be one such project.

With offshore oil exploration about to re-commence in Guyana and the prospect of larger tankers eventually needing to call in, Rammarine sees prospects for NEC to become project manager, and operator, of a new port there, based on the expertise it has long acquired in port construction and management in Trinidad.

Grenada has also been examining the possibility of Trinidad helping it with oil exploration on its side of the maritime delimitation line in the Caribbean Sea and the minister has received this suggestion enthusiastically.

Further afield, in other countries of Africa, where Trinidad and Tobago’s success in gas monetisation is highly regarded, other initiatives are also possible.

Rammarine has in recent months entertained a delegation in Port of Spain from Mozambique and made a presentation to African leaders at the recent Commonwealth Heads of Government Meeting (CHOGM) in Perth, Australia. “Africa is looking to Trinidad and Tobago for help and guidance in establishing its own oil and gas industry,” he says. “This presents an opportunity to actualise South-South co-operation and the transfer of technology.”
Balancing the Energy Mix for a Sustainable Future

Trinidad and Tobago has been in the business of commercial hydrocarbon production for more than one hundred years. The country has produced in excess of three point five billion barrels of oil during this period, attaining a peak of 227,257 barrels of oil per day (bopd) in 1978. Since then oil production has consistently declined with production now at 85,000 bopd. In stark contrast (as seen in the chart below) as the oil fortunes have declined production of gas has gained momentum, and as of 2009 reached a peak of 4.2 billion cubic feet per day (bcf/d).

However, a major issue which concerns the Government of the Republic of Trinidad and Tobago (GORTT) is ensuring that the downstream demand for natural gas is met while attracting new industries to the country. It is with this in mind that the 2010 Competitive Bid Round offered mainly gas prone blocks.

The resulting work programme from the bid round will see nine seismic acquisition projects being undertaken; one processing project and six exploration wells being drilled within the next three to four years. Expected resource finds will be in the region of 4-8tcf of natural gas.

On examination of the global reality, the Minister of Energy and Energy Affairs, Senator The Honourable Kevin Ramnarine, is quite correct in enunciating that the money earned from a barrel of oil exceeds that from natural gas by a factor of 10. The chart below entitled, “Hydrocarbon Production in T&T” indicates that Trinidad and Tobago’s production is skewed in favour of natural gas. However, given the earning power of oil it would be to the country’s advantage to reverse this trend and the Minister has stated on numerous occasions that reversing the decline in oil production is one of his major priorities. Hence, the reason why the philosophy underpinning bid offerings has had different foci over time.

It is on the basis of the 2005/2006 bid round that eleven exploration wells are to be drilled in the 2011/2012 period, which include five wells onshore and six offshore. The onshore wells are all oil prospects and the offshore wells may be a combination of both oil and gas.

There are also short-to-medium-term projects in the Gulf of Paria which would address the decline in oil production. These are the East Brighton project being undertaken by SOOGL Antilles Trinidad Ltd (operator) and the Point Ligourie/Guapo Offshore/Brighton Marine project being undertaken by Ten Degrees.

Deep Water Exploration

The Trinidad and Tobago Deep Atlantic Area is located beyond the already producing oil and gas fields and has an area of 40,000 sq km. Water depths range between 1,000 to 3,500 metres. The area is divided into 39 blocks of approximately 1,000 sq km each. (See “Energy Map of Trinidad and Tobago” above.)

In the 2010/2011 bid round eleven blocks were offered and five bids were received for three blocks:

- Block 23(a) – 3bids, BPEOC, BHPB/Total/Repsol, Niko Resources
- Block 23(b) – BHPB/Repsol
- Block TTDAA 14 – BPEOC

BPEOC was awarded two blocks (23(a) and TTDAA 14) and with respect to Block 23(b), the Minister exercised his right to negotiate with BHPB/Repsol to arrive at a mutually acceptable arrangement. It is expected that exploration would be started in these areas by early 2012 – a very welcome start to our frontier exploration.

Additionally, another deep water competitive bid round will open in November 2011 with bids to be submitted in March 2012. A maximum of six blocks will be offered, based mainly on nominations by the companies. Companies are being asked, on the basis of the map to nominate a maximum of five blocks.

It is the stated desire of the GORTT that any exploration in the deep water of Trinidad and Tobago would discover commercial quantities of liquid hydrocarbon; from our reading of the reports and data this is highly likely. While some companies may not agree with that view based on their previous evaluation of the data, the Ministry is supplying some new data which should result in a more positive view by the sceptics and serve as reinforcement to those who are inclined to share our viewpoint.
In the meantime, the immediate priorities for minister Ramnarine’s four more years in office are unquestionably halting the haemorrhage in crude oil production by encouraging as much exploratory drilling as possible, especially in deeper water and deeper land horizons – as well as the determined application of enhanced oil recovery (EOR) methods.

A 20 per cent investment allowance for EOR in land fields was introduced in 2010, covering such applications as water flood, steam injection and carbon dioxide (CO₂) sequestration. Geologists feel there is potential for recovering another one billion barrels of oil this way.

The big prize for oil, however, may well lie in water depths between 1,700 to 2,000 metres out in the Atlantic Ocean to the east of Trinidad.

Two such blocks were awarded in 2010 – 23a and TTDAA 14 – both to BP plc, through a special purpose vehicle, BP Exploration Operating Company Ltd. A third, block 23b, is the subject of direct negotiations between the MEEA and BHP Billiton/Repsol, since the consortium’s bid did not meet the original ministry threshold.

Another deep water round is due in March 2012, at which six more blocks are to be offered for competitive bidding by companies, and the MEEA hopes to use its appearance at the WPC’s Doha congress to promote this.

There are 36 open deep water blocks currently in the MEEA’s inventory and Ramnarine has pledged continuous acreage auctions, both of deep and shallow water blocks as well as deep land blocks.

Extensive reprocessing of seismic data by MEEA and fiscal concessions, such as 60 per cent cost recovery and a reduction in petroleum profits tax (PPT) from 50 per cent to 35 per cent, are all expected to make deep water exploration more attractive to companies.

As for gas, while Trinidad and Tobago still has a fairly comfortable reserves and exploratory resources cushion of about 55 trillion cubic feet (tcf), the proven and probable components continue to fall and were down a combined 1.1 tcf in 2011, according to the annual natural gas audit by the Ryder Scott Company.

With the downstream gas based industrialisation programme now being revived – a second ammonia-to-melamine project is under construction and methanol-to-polypolyethylene, methanol-to-petrochemicals, bitumen upgrader and another direct reduction iron plant are all under consideration – it would be prudent to have more proven gas reserves.

Three major exploration initiatives in north coast offshore blocks 2, 3 (by Niko of Canada) and 4 (by Centrica of the UK) are considered to have a good chance of identifying new proven gas accumulations.

Yet another challenge for the minister in the near to medium term will be to get cross-border gas development between Trinidad and Tobago and Venezuela off the ground. The unitisation agreement for the reservoirs concerned – Manatee in block 6d in Trinidad and Loran in block 2 in Venezuela – has already been signed and reserves identified (2.1 tcf on the Trinidad side), so its only a matter of deciding how the gas will be monetised, before actual development can begin. Minister Ramnarine is due to hold discussions on the matter with his Venezuelan counterpart before the end of 2011.

If cross-border gas can be unlocked, it will make an important contribution to the maintenance of production, perhaps even provide the input for possible expansion of the LNG industry in Trinidad, though tilting the imbalance even more in favour of gas. But as the country enters its second century of uninterrupted petroleum production, it may well be on the verge of a revival of crude output and Minister Ramnarine will be hoping that his faith in Petrotrin, and others, to be able to achieve that objective is eventually shown to be justified.
The petroleum industry and resource holders can make huge profits, but they also need to make huge investments; this includes investing in the next generation of leaders as highlighted in our Special WPC Youth Magazine. According to Iain Brown of Wood Mackenzie, capital spending in the global upstream industry has strongly recovered from the trough of 2009 – possibly hitting an annual rate of US$ 500bn by 2013 – for a mix of reasons. There is growing confidence in a sustained high oil price putting value into unconventional projects, but also a return of cost inflation eating into profit. At the top spending league are ExxonMobil, Chevron and Petrobras, while most national oil companies with lower cost reserves are much lower down.

Fatih Birol of the IEA puts investment into a broader context with a warning that just to offset decline from existing fields, the world will need gross capacity additions of 47million barrels a day (mb/d), or twice current output of all OPEC countries in the Middle East. The IEA chief economist says almost all extra medium-term oil supply will have to come from Middle East and North Africa countries, which should cut domestic energy price subsidies to curb use and free more for export.

Sufficient investment stimulus should come from the oil price, suggests Amrita Sen of Barclays Capital. Growth in developing country demand will press up against the limits of global supply, and together with shrinking spare supply capacity and minimal buffer stocks, keep the oil price buoyant but volatile. Howard Rogers of the Oxford Institute for Energy Studies tackles the complex regional price differences for gas, but suggests these could narrow with bigger flows of LNG a around the world.

Where is the money for all this investment to come from is a question addressed by Peter Gaw of Standard Chartered Bank. He provides a relatively optimistic answer. Oil and gas companies, especially the majors, had no problem raising capital in the bond and equity markets through the 2009 recession. However, project financing has become harder, and banks are increasingly constrained by Basel III capital regulations and maybe now by new eurozone measures in what they can lend. Overall, however, “the favourable risk outlook for the industry combined with the positive market perception (flight to quality) place the oil and gas sector in an enviable position.”

The section ends with some prudent advice or rather advice about prudence. The explanation by Wilhelm Mohn of Norway’s finance ministry of his country’s ‘government pension fund’ shows why it is widely considered the gold standard among sovereign wealth funds. All Norway’s petroleum revenue goes first into the pension fund, and only then on a parliamentary vote can a portion be transferred to the budget. While acknowledging the somewhat special case of Norway being a developed democracy before it hit oil, he cautions countries with a perishable source of income “not to spend it all at once.”

Philip Daniel of the IMF echoes the same message to resource-rich governments, but also offers advice to companies negotiating with such governments. Contracts, he suggests, will not be durable unless governments get some revenue as extraction takes place and gain a share of any increase in a project’s profitability. Fiscal terms should also take account of the relative ability of companies and governments to bear risk. “A poor country with a limited portfolio may be less able to tolerate deferral of revenue than a major company.”
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Global upstream spending hits new heights

BY IAIN BROWN
HEAD OF REGIONAL UPSTREAM RESEARCH, WOOD MACKENZIE

As 2011 draws to a close, capital spending in the global upstream industry has fully emerged from the dark days of 2009. The recovery has kicked on strongly and global capital spending will reach a new record high. The annual total will be close to US$450bn (billion) – US$35bn higher than in 2010, and over US$25bn above the previous record in 2008. If this rate is maintained, annual upstream investment could reach US$500bn by 2013.

North America sets the pace

High levels of investment are being implemented across most of the world’s oil and gas sectors. Many sectors and companies are planning spectacular growth, whilst there are few countries where investment has slowed. There are many reasons for this restoration of investor confidence, although three are particularly strong:

• Growing confidence that the oil price will remain at or above US$80 a barrel (/bbl) in the medium and long term
• Improving value propositions for a range of unconventional resource plays, broadening the range of opportunities for international oil and gas companies
• Rapidly increasing demand for materials and services and the return of cost inflation

The onshore US Gulf Coast region, especially the liquids-rich Eagle Ford Shale in south Texas, is the largest single sector of activity, with planned upstream investment of around US$140bn over the next four years. And the Gulf Coast experience is repeated across most of North America. Total upstream capital investment in Canada and the US will be around US$600bn between 2011 and 2014 – up from US$480bn in our previous forecast. A key feature in this remarkable turnaround has been the restoration of Canadian Oil Sands to the prominence it enjoyed before the economic crisis. Several giant projects are under construction, in parallel with huge commitments to current production and facilities de-bottlenecking.

The rise of unconventionals

The major shift in industry spending trends in the past five years has been the rapid growth in a range of unconventional gas and oil resources, primarily in North America. Oil sands and coalbed methane have been prominent parts of the North American industry for many years, but shale gas and shale oil have taken centre stage more recently.

The huge impact of the unconventionals sector is illustrated by its share of global upstream spending. Ten years ago, the combined contribution from unconventional plays was less than 10 per cent of global expenditure, primarily in coal bed methane and oil sands. Now, in the period from 2011 to 2014, they will account for over a third of global upstream investment. And it is a pattern that looks set to continue, as the opportunity set for international companies in conventional, onshore and shallow-water reserves remains constrained by a range of political and economic factors.
Majors and NOCs lead the way

ExxonMobil has the largest capital spend of all oil and gas companies in 2011, at around US$22bn, and is planning to continue increasing investment over the next few years. Even so, it will be run close in 2012 and 2013, by Chevron and Petrobras. Chevron has several major projects under development in Australia, the Gulf of Mexico and US Lower 48. Its total upstream spending could exceed US$25bn by 2013. Several of Petrobras’ giant oil discoveries in the Santos Basin should be progressing through development in a similar timeframe and its annual capital expenditure could reach US$28bn by 2014.

Most of the larger oil and companies are planning high levels of capital spending in the next few years. This reflects an increased expectation that, whilst oil prices may fall back from current levels, they are likely to remain at or above US$80 per barrel. This outlook provides confidence in the value proposition for a wide range of unconventional developments, including oil sands, shale oil, shale gas and tight gas. Most major international companies have expanded their portfolios in the past three years to develop a higher representation in unconventional resource themes.

National oil companies (NOCs) and governments own around 67 per cent of the world’s oil and gas reserves and are responsible for over 55 per cent of production. Five of these (Saudi Aramco, Gazprom, Qatar Petroleum, NOIC and PDVSA) account for cumulative reserves of around 1.2 trillion barrels of oil equivalent (boe) – more than 40 per cent of the global total. Even the largest international companies fall far short of this scale – we estimate the combined reserves of ExxonMobil, Shell, BP, Chevron and Total at around 244 billion boe (on a working interest basis).

Despite this prominence in reserves and production, NOCs and governments proportionately spend far less on upstream development than the international industry – accounting for just over one-third of the global total. There are many reasons for this apparent inconsistency:

• Some of the most prolific NOCs (Saudi Aramco, Qatar Petroleum, Iraqi Government, and KPC) own the world’s lowest-cost oil and gas reserves. Their development costs are much lower on a unit basis than in other parts of the industry.

• Development costs for the international industry are getting higher; as the constraints on access to conventional reserves cause companies to increasingly pursue new reserves in deepwater or unconventional oil and gas.

• While many NOCs and governments continue to spend proactively to maintain or expand their production capacity, others have under-invested domestically for many years, with capital availability dictated by state budgets.

• Production capacities in some NOC territories are in terminal decline and the NOCs have not been able to replenish their investment options outside their domestic industry.

The highest-spending NOCs are those with the highest-cost reserves, in the early stages of development. Over the next five years, Petrobras and PetroChina have by far the highest capital budgets. Both companies have a significant international presence, but most of their development spending – 91 per cent and 95 per cent respectively – is on their domestic portfolios. Their assets are dominated by technically-challenging, high-cost reserves. These are deepwater reserves in the case of Petrobras, while...
PetroChina is developing a range of deep and difficult reservoirs in its home territory. The cost of new production capacity in the Middle East has been rising steadily over the past 20 years, as the shallower, higher quality reservoirs have been depleted and new developments focus on deeper, poorer quality reserves. We estimate that the capital cost of the next phase of developments in the major producing countries of Middle East OPEC will be between US$2/boe and US$10/boe. This is many times higher than in the past, but these are still amongst the lowest cost oil and gas reserves in the world today. This is confirmed by the low cost of new incremental production capacity for Saudi Aramco, NIOC, KPC and the Government of Iraq, even by comparison to their NOC peers.

Costs are on the rise again

There is growing evidence that the cost of services and manpower is increasing in response to the rapid growth in development activity. Renewed cost inflation is now evident in most producing areas, although there are significant sectoral and regional variations. The most obvious impact at this stage is in Australia and Canadian Oil Sands, where the proliferation of development approvals has placed unprecedented demands on fabrication capacity, materials and labour. Capital costs in these sectors have increased by at least 10 per cent in the past year, and by considerably more for specialist equipment and manpower.

Another area where demand is putting pressure on supply is deepwater. Activity is steadily recovering in the Gulf of Mexico, whilst aggressive development plans have been maintained over the past few years, in Australia, Latin America and West Africa. Demand for deepwater rigs, facilities and services remained high, despite the economic crisis and the post-Macondo moratorium. Current evidence suggests →

Figure 3: Global distribution of upstream capital spend* by resource theme

Figure 4: Top ten companies by planned capital investment† 2011-2014

* Cumulative upstream development spending for the period 2011-2014
† Upstream development spending, not including exploration and appraisal costs, capitalised interest, non-integrated LNG projects or investments in equity subsidiaries
that overall development costs for deepwater projects have risen by between 5 and 10 per cent in the past year. There is less evidence of extreme cost inflation in shallow-water and onshore provinces, where demand from new projects is lower. But some areas are particularly tight. In the US Lower 48, the flood of investment into tight oil plays has taken up all of the ‘slack’ that had developed in the service sector in the aftermath of the economic crisis. Equipment and personnel required for ‘fracking’ wells are back in high demand. These demands are unlikely to ease over the next few years and cost inflation for these services is expected to run above 5 per cent.

Clouds on the horizon
The economic crisis of late 2008 shook the foundations of the global upstream business. Many higher cost capital projects were delayed, shelved or abandoned, and annual spend dropped by US$50 bn. Now, just 30 months later, the industry has proven remarkably resilient. Plans have been restored and expanded and many new projects approved, in the presumption that demand and commodity prices will remain relatively robust over the longer term.

For many years, international companies have pursued ever more challenging and costly sources of oil and gas, in both conventional and unconventional sectors. Most of the major NOCs are now making greater demands on their state budgets, seeking to produce from deeper and poorer quality reservoirs, in progressively more challenging locations. As the industry strives to ensure that supply keeps pace with demand, upstream spending seems set on a relentless upward trajectory, producing more barrels and cubic feet every year, at a steadily increasing cost per barrel.

But there are significant risks and uncertainties which threaten this positive view. The macroeconomic outlook has deteriorated markedly since the summer of 2011. Europe could be on the brink of recession and the US is projected to enjoy only weak economic growth. This outlook could worsen further if European sovereign debt issues turn into a full blown banking crisis. The investment plans of the upstream industry are ambitious and encouraging, but they could yet be undermined by the fragility in the global economy.

Read more from Wood Mackenzie by visiting www.woodmac.com/wpc2011

Figure 5: Planned upstream capital spending* by country

* Cumulative upstream development spending for the period 2011-2014
Here for good

Can a bank really stand for something? Can it balance its ambition with its conscience? To do what it must. Not what it can. As not everything in life that counts can be counted. Can it not only look at the profit it makes but how it makes that profit? And stand beside people, not above them. Where every solution depends on each person. Simply by doing good, can a bank in fact be great? In the many places we call home, our purpose remains the same. To be here for people. Here for progress. Here for the long run. Here for good.

standardchartered.com
We have seen a recovery in oil and gas investment which seems to reflect confidence in the buoyancy of the long term oil price and of oil demand – is this confidence justified?

We expect global upstream oil and gas investment to continue to grow strongly in 2011, hitting a new record of over US$550 billion. Moving forward we will continue to need a substantial amount of investment in the oil and gas industry. There are two major drivers of this. One of them is significant growth in oil demand which in our new World Energy Outlook (WEO) for 2011 we project to rise from 87 million barrels a day (mb/d) in 2010 to 99 mb/d in 2035. Almost all of this new demand will come from the transport sector in emerging economies, as economic growth pushes up demand for personal mobility and freight. The total number of passenger cars is set to more than double to almost 1.7 billion in 2035. No doubt, alternative vehicle technologies will emerge that use oil much more efficiently or not at all, but it will take time for them to become commercially viable and penetrate markets. But, as important as investment to meet rising demand, we need a lot of investment just to compensate for the decline in production from existing fields as they mature. One of the major findings of our WEO is that between now and 2035 we will need gross capacity additions of 47 mb/d, to compensate for declining production at existing fields, twice the current total oil production of all OPEC countries in the Middle East.

Can the world achieve this?

I believe that oil prices will remain at levels sufficient to make most of these new projects that we expect to be developed profitable. Even at the end of 2008, when as a result of the financial crisis and the oil price was going down to US$40, I said the era of cheap oil was over. Today when the world economy is in a very shaky state, we still have the price of oil at around US$100/bbl for Brent. So from a project financing viewpoint, there will be enough incentive for those projects to be developed. However, I also see some challenges. One is whether the key producing countries will make, or can make the investments in a timely and adequate manner. According to our latest WEO, close to 90 per cent of the growth in global oil production over the next two decades will need to come from Middle East and North African (MENA) countries. In terms of physical resources, this does not represent a major challenge, theoretically. However, investments in these countries might be deferred. This could have far-reaching consequences for global energy markets. Such a shortfall could result from a variety of factors, including higher perceived investment risks, deliberate government policies to develop production capacity more slowly or constraints on upstream domestic capital flows because priority is given to spending on other public programmes.

What happens if Middle East and North African countries cannot deliver all this?

We have made a special investigation in our latest WEO around our projection that MENA countries need upstream investments of US$100bn a year over the next decade. We asked what would happen if this investment were one third lower? The results show that MENA production would be more than 6 mb/d lower by 2020 and we could face a substantial near-term rise in the oil price to US$150/barrel (in year-2010 dollars). This would not be good news for the global economy. Therefore it is in the interest of everyone that the investment in the key producing countries takes place in a timely manner. There is a significant responsibility here on the oil producers, but of course I also see they will face certain hurdles. Therefore it is very important that consumer countries should help – by for instance narrowing down the uncertainties on the oil markets – the producing countries to have the best possible investment framework to get the oil to the market.

What about production prospects elsewhere?

One of the trends we have highlighted in our latest WEO is the increase in US oil output. As a result of two major developments in the US we see a trend that is very different to most other countries in the OECD. With the recent efficiency measures taken by the Obama administration in the transportation sector, we expect a slowdown in US oil demand growth. This greater efficiency, together with the increase in new supplies, leads us to expect a substantial reduction in US oil imports in the decades ahead. One of the promising new sources of production in the US is light tight oil which we think may actually become a second American “revolution”, the first one being in shale gas. Light tight oil provides a great example of how the industry continues to innovate, developing new techniques and technologies to tap previously uneconomic resources. High oil prices would give very strong incentives to the further development of light tight oil in the US and may also result in production taking off in other plays or in other
parts of the world. This could have implications for the major oil producing countries by eating into their market share. I mention this to make the point that it is not always in the interest of the major oil producing countries to have very high oil prices.

**The IEA recently published a report called “Are we entering a golden age of gas?” Why the question-mark?**

It is true that there is much less uncertainty over the outlook for natural gas than there is for other fossil fuels. Factors both on the supply and demand sides point to a bright future, even a golden age, for natural gas. Gas consumption rises in all three scenarios presented in our new WEO, underlining how gas does well under a wide range of future policy directions. We now have gas reserves equal to around 120 years of current production; but adding unconventional recoverable resources brings this figure to nearly 250 years. And unlike oil, gas is widely dispersed around the world. You have the US and Canada, and of course the Middle East, North African and Russia, but China and Australia are also coming along very strongly. Based on currently operating and sanctioned projects, Australian LNG export capacity could exceed 70 bcm soon after 2015, making it the second largest global LNG exporter after Qatar.

But in terms of unconventional gas production, there are significant local environmental problems, due to the technology used, and this has raised a lot of questions in Europe and in the US which are well-justified. However, the good news is that with existing technologies these problems can be taken care of – though this will increase the cost of production for unconventional gas. So if we are to enter a golden age of gas, companies must apply golden standards to their extraction technologies. This will increase the cost of production somewhat, but it will open the door for gas to play a growing role in the global energy mix. This is why to the question of a golden age for gas my answer is yes so long as the gas industry is able to produce it in a sustainable manner.

**What is the prospect for gas price harmonisation around the world?**

I expect that the growing share of LNG in global gas supply and increasing opportunities for short-term trading of LNG will contribute to a degree of convergence in prices across the main markets in North America, Europe and Asia. Nonetheless, I still think we will see fairly significant price differentials, reflecting the relative isolation of these markets from one another and the cost of transport between regions.

**The IEA has expressed general concern about the impact of subsidised oil consumption on exports. Where is this particular concern?**

It is not only us who have expressed concern. Indeed in 2009, the G20 leaders actually agreed to phase out subsidies that “encourage wasteful consumption, reduce our energy security, impede investment in clean energy sources and undermine efforts to deal with the threat of climate change.” But progress on this worldwide is slow. Subsidies that artificially lower the prices of fossil fuels amounted to over US$400 bn in 2010 with around half for oil products. In many cases they were introduced with the well-intentioned objective of improving access to modern energy services for the poor. In practice, however, they have often proved to be an inefficient means of achieving this goal. Typically those who consume the most energy benefit the most from subsidies, such as those who can afford to own a vehicle or electrical appliances. The removal of these subsidies would improve energy security, reduce emissions of greenhouse gases and bring economic benefits.

**Light tight oil provides a great example of how the industry continues to innovate**

Although subsidies for oil exist in many parts of the world, they are particularly prevalent in the Middle East. At the same time, oil demand in the Middle East is increasing substantially. There are three reasons for this – two of which are justified, and one is not. Growth in economies and in population justifies an increase in energy consumption. But the third reason is not justified – the fact that retail energy prices are artificially low. This results in low efficiency in domestic energy use which leads to reduced availabilities for export. Over time, such subsidies may even threaten to curtail the exports that earn vital state revenue streams. At US$81 billion, Iran’s subsidies were the highest of any country in 2010, although this figure could fall significantly in the coming years if the sweeping energy-pricing reforms that commenced in late 2010 are implemented successfully and prove durable. I hope other countries in the region follow the example.
An increasing loss in confidence in global policymakers to deal with the sovereign debt situation, along with worries of global growth, have thrown oil markets into disarray. The recent worsening in conditions has led to a widespread and severe downwards lurch in risk appetite. Oil, like most markets, seems to be trading in a maelstrom of information, where any headline is immediately subjected to opposite and contradictory interpretations, with unpredictable consequences for prices. Indeed, much of the immediate action in oil is simply based on the same climate of economic fear that is battering equities.

For many, the key question is whether this is a repeat of the 2008-09 cycle, and what is the downside to prices. Despite the gloomy picture concerning sovereign debt in both Europe and the US, the corporate bond markets are functioning normally and most forms of credit remain broadly inexpensive – a key difference from 2008. Second, the backdrop of the oil market is significantly different from 2008. The supply side of the market is performing far more poorly now than three years ago. Libya still remains out of the market, with the cumulative loss of Libyan barrels now moving close to 350m barrels, and declarations of force majeure have reduced Nigerian supplies while oil embargoes are set to stymie Syrian exports. Moreover, the unrest in North Africa and the Middle East is leading to higher break even price requirements to balance vastly higher spending programmes in most of the Gulf countries. Thus, the threshold for active producer involvement in the market is some US$20 -25 higher, lending support to an oil price at around US$90-100 per barrel. Finally, the structure of the demand composition of the oil market is significantly different now than it was in 2008. In 2008, global oil demand was contracting, with the burden of OECD demand declines a large 1.7 million barrels a day (mb/d). So far, despite the revisions to current and projected US oil demand, the scale of decline in the OECD is a far more modest 0.5 mb/d.

But it is really the scale and speed of non-OECD demand increases that makes a significant difference to the global picture. The share of non-OECD demand has risen from about 44 per cent in 2008 to 48 per cent this year, and is en route to almost 50 per cent by next year. Within that, China’s share of global oil demand has increased by more than 2 per cent. In fact, Chinese oil demand growth averaged around 0.4 mb/d across 2008-09, half the level of growth seen across 2010-11. Thus, China and emerging markets are in general far more important for the oil demand trajectory, and while measures to tackle high inflation have undoubtedly tempered the growth profile in the short term, structural factors should keep economic and oil growth at elevated levels in these countries.

Perhaps most importantly, the main reason why we do not expect a repeat of the 2008-09 oil price cycle, short of a macroeconomic discontinuity, is what that cycle told us about the structure of the oil industry. Below US$90, investment dried up and was frozen; below US$70, the industry was visibly struggling, with unconventional oil – increasingly the marginal supply on the non-OPEC front – the worst affected. On the demand side, lower prices fed into a sharp global demand upswing, leading to the fastest demand growth for 30 years, with it running at least twice as fast in 2010, and perhaps three times as fast, as the maximum the supply side could cope with in the medium term. Spare capacity of 6.5 mb/d quickly became spare capacity of just 2.5 mb/d. The lesson of the last cycle is that the further prices are forced below US$90 and the longer they stay there, the faster the market tightens in the upswing.

Over the next five years, a steady annual growth rate corrected for distortionary base effects of 1.3-1.5 mb/d appears to us to be the status quo, short of a major macroeconomic discontinuity, and non-OECD countries are set to provide the bulk of that growth. Within that, China and other non-OECD countries have become the regular ones in recent years (i.e. China,

Global oil demand growth, mb/d

Source: Barclays Capital
India, Saudi Arabia and Brazil). Indeed, it appears 2012 will be no different. We project oil demand growth of 1.31 mb/d in 2012, marginally higher than the current 1.13 mb/d forecast for 2011, with the absolute level of demand averaging 90.2 mb/d, a record high and the first time global oil demand would achieve an annual average of above 90 mb/d. The oil demand profile is likely to continue to be dominated by non-OECD demand growth, which we expect to be 1.57 mb/d.

OECD demand, not surprisingly, is expected to slip back into negative territory this year and follow through next year, on the back of increased energy efficiency and oil demand suppression policies together with significantly higher price averages compared to the past decades. However, structural trends tend to dominate the profile of non-OECD demand growth, which now constitutes a far larger share of global oil demand and all of global oil demand growth. In fact, straight after the financial crisis of 2008-09, the sheer scale of non-OECD demand growth resulted in global oil demand surpassing 2007’s peaks by 1.7 mb/d last year, a good five to seven years earlier than consensus expectations. Indeed, in 2013, we expect non-OECD demand to overtake OECD demand in absolute levels for the first time. The marginal consumer in the oil market is increasingly showing reduced sensitivities to higher prices, evident in the robust growth in global oil demand even in the face of US$100+ average prices. At these price levels, it is not surprising that OECD oil demand is running lower, year on year, by over 200,000 b/d in the year-to-date, with elements of destocking having magnified the extent of that fall somewhat.

However, the fact that global oil demand is still running higher, year on year, by 7 mb/d underlines the shift in the marginal barrel of oil demand. While the blame for inflation, tighter policy response and patchier economic growth has often been laid at the door of high oil prices, the fact remains that we expect global economic growth to average a solid 3.8 per cent this year and 3.9 per cent next year (alongside an annual increase in oil prices of 39 per cent and 3 per cent, respectively). Have higher oil prices tempered economic growth in some parts of the world? Yes, we think they have. But have they been the sole factor for the recent softness in the macroeconomic data? No, they have not, with factors such as the earthquake in Japan, a patchier recovery in manufacturing and food inflation playing a hugely important part. While the jury is still out on this debate, in our view, given the bias of inelastic non-OECD demand in the global profile, the world can sustain a US$100 average oil price without necessarily suffering from negative economic growth in the short term. The juxtaposition of triple-digit oil prices and 3-5 per cent economic growth is likely to remain a debate that continues in policy circles through 2012.

The supply side of the market is performing far more poorly now than three years ago. We remain doubtful about the speedy re-incorporation of Libyan oil into the world market. The first task of a new Libyan government will be to repair the damage caused to the oilfields and other oil installations by a lack of investment funds, imported spare parts, and equipment and insufficient maintenance. The second task will be to negotiate with foreign oil companies the terms of production-sharing agreements for investments and operations in new and old oilfields. The new government will be in dire need of revenues and will not be in a position to give money away to foreign investors unnecessarily in our view. The problems of Libya will not necessarily be solved by the departure of Gaddafi; indeed, that might just be the start of some long-lived difficulties. The resumption of 250-500,000 b/d of production seems possible by year-end and into the first quarter of 2012, in our view, but extrapolating from this to the early restoration of full output volume of 1.7 mb/d from Libya would be a mistake.

### Annual changes in key demand centres in 2012

![Annual changes in key demand centres in 2012](source: IEA, EIA, Barclays Capital)
Non-OPEC supply growth, too, seems to have entered a turning point, after the upsurge in new projects start-ups in the past two years. We expect a slightly higher growth profile for non-OPEC supply in 2012, with a growth of 0.48 mb/d following a growth of 0.15 mb/d in 2011. The fall in North Sea production is expected to continue next year, as technical problems aggravate the already sharply declining mature oil fields. Former Soviet Union output, along with China, has faced considerable technical problems this year and poses downside risk to our forecasts for 2012, should the problems continue. Indeed, there is now a clear demarcation in non-OPEC supply, with growth largely concentrated in the Americas, and declines continuing elsewhere. The key theme going forward will be how much and how fast production in the Americas can grow to offset declines in other parts of the world as significant further increases from current levels remain a difficult enterprise for these non-OPEC supply countries.

Outside Latin America, most of the growth in American production involves what would largely be classified as unconventional oil. As with most unconventional oil plays, the break-even price required is significantly higher than the bigger, better behaved conventional oil fields, and thus, incrementally, non-OPEC growth is set to come from higher cost areas in 2012 and beyond. Further, while exploitation in reserves in ever deeper waters had in recent years been the key focus, there appears to be an emerging trend that is witnessing the cutting-edge of oil production techniques move back on-shore. Increased uncertainty about costs and regulation after the Macondo spill have imposed a pause on the growth in offshore drilling, and while we expect offshore drilling to continue off South America and Africa, we would expect onshore oil production to generate most of the incremental growth over the next two years.

Finally, the combination of persistent strong demand growth continuing to outpace the momentum in non-OPEC output increases is set to keep the pressure on OPEC, and in particular, Saudi Arabia, high. Thus, unilateral Saudi policy will remain key in 2012. Currently, the Kingdom, much like many OPEC countries, faces extremely challenging geopolitical situations and has been spending heavily. The already high level of spending is set to remain for next year at the very least (we expect a 5 per cent year-on-year increase), given the commitment to pay out extra cash for up to two years. We see little reduction in its defence spending, given the situation in neighbouring Yemen and Bahrain and its heightened tensions with Iran. Based on this planned new expenditure, we estimate that total government spending will increase to 48 per cent of GDP and 45 per cent in 2011 and 2012, respectively. Thus, in our view, current prices are roughly what Saudi Arabia is aiming for; we do not detect any wish to sustain prices at lower levels. The extra spending has pushed price aspirations up by some US$25 per barrel, with US$100 becoming the new US$75 in terms of the midpoint of producer expectations. Saudi Arabia will likely continue to try to prevent any explosive breakaway in prices, but given the chances of the global imbalance tightening to the extreme, this is likely to remain the biggest challenge for the Kingdom over the coming years.

All this has clear implications for oil prices. In general, the trend of steady growth in demand, with supply attempting to play catch-up at best, creates an environment for higher prices. This is aided further by changing producer aspirations and a heightened geopolitical backdrop. The growth in demand is rather rapidly likely to press against the limits of global supply, with most of the work needed to be done by prices in order to balance the market. In the more immediate term (i.e. 2012), eroding spare capacity and an almost non-existent inventory buffer is likely to keep prices infused with a large degree of dynamism and volatility.
At Sonangol, we're proud of our thirty-five year track record of no serious accidents or oil spills.

And because we plan to keep it that way, we've made a major investment into a Quality, Health, Safety and Environmental (QHSE) program to maintain high standards across all our business activities.

We've allocated $6m to implement the program across our operations - from production units and exploration sites to transport and distribution.

At Sonangol our determination to provide a safe, clean and environmentally-conscious workplace is good news for all our futures.
Oil and gas are both fluid hydrocarbons. Their exploration and development technologies are in general very similar and indeed in some circumstances they are both produced from the same well. With crude oil traded as a global commodity (albeit as benchmark regional blends) since the 1980s, one could be forgiven for assuming that natural gas would also have a global reference price. While this is not the case at present, this paper explores how a more ‘price connected’ future for gas may evolve in ways that will be the focus of detailed research by the Oxford Institute in 2012.

A world of difference in gas pricing

Natural gas suffers, however, from being, well, a gas, i.e. its energy per unit of volume (at atmospheric pressure) is only 0.1 per cent of that of liquid crude oil. Transporting and storing gas will involve higher infrastructure investment relative to oil. Liquefied Natural Gas (LNG) is gas that has been cryogenically cooled to minus 163 degrees Centigrade where it exists as a liquid at atmospheric pressure. In this state its energy per unit volume is 65 per cent of liquid crude oil and LNG can be shipped vast distances between the point of production and a destination market. This is only possible, however, through the construction and use of purpose-built liquefaction plant, loading and unloading facilities, insulated storage tanks and ocean going LNG tankers. At the destination market the LNG is re-gasified to enter the distribution grid. This supply chain is capital intensive and its construction confined to relatively few specialised contractors.

Given its relatively high cost of transportation and storage, it is unsurprising that historically, natural gas production has tended to grow to supply nearby national and regional markets. Accordingly each developed its own approach to natural gas price formation. A comprehensive review of regional policies is contained in ‘Wholesale Gas Price Formation – A global review of drivers and regional trends’ by the International Gas Union, as shown in Figure 1. While 52 per cent of global gas consumption is priced on the basis of gas on gas competition or by reference to oil or oil products prices, much of the remainder is regulated, often at levels significantly below those prevailing in the OECD markets of Europe and North America. This is illustrated dramatically in Figure 2 which shows that in 2009 gas prices in the Middle East, Latin America, Africa and the CIS were in the range US$0.80/mmbtu to US$2.50/mmbtu, levels significantly below the world average of US$4.00/mmbtu.

The rise of the long-distance gas trade

As growing regional gas markets outpaced the availability of indigenous and proximate supplies the growth of ‘long distance’ gas (trade-flows of pipeline gas and LNG) became established. This is shown in Figure 3. Long distance gas is classified as LNG (blue) and pipeline trade-flows from Russia, North Africa, Iran and Azerbaijan into Europe and pipeline flows within Asia and South America (red). In the period 1995-2010 both grew with LNG on a continuous trajectory. The recent economic recession resulted in a fall in global gas consumption and pipeline trade-flows in 2009. However, LNG consumption increased markedly over 2008 levels in 2009 and 2010.

The main regional markets impacted (or potentially impacted) by the growth in long-distance gas are North America (US, Canada and Mexico), Europe and the main LNG importing countries of Asia (Japan, South Korea, Taiwan, China and India). The intriguing question is ‘given the differing mechanisms of price formation in each region, what happens when you ‘plug them together’ with long distance gas?’

To explore this we need to understand how gas pricing is formulated in each of the regions and the nature and degree of flexibility of pipeline gas and LNG.
Regional price formation

North America
Gas prices in the US are in the first instance driven by gas on gas competition and are discoverable at the many regional trading hubs. The best known is Henry Hub (HH) which is viewed as the marker for US natural gas prices. The US has a ‘porous’ gas trade border with Canada and Mexico, both of which have prices influenced by the US market. Due to the potential for inter-fuel competition in the power generation sector, gas prices can at times be influenced by residual fuel oil. However, this has not been a factor since 2006. In the expectation that the US would require significant LNG imports some 125 bcm a year of LNG regasification capacity was built in the mid to late 2000s. With the dramatic growth in shale gas production since 2006, re-gas utilisation rates are extremely low and the industry is currently pursuing the conversion some of these facilities to LNG export facilities.

Europe
With the exception of the UK market which became liberalised in the 1990s, Europe began the 2000s with a market structure dominated by long-term oil indexed contracts for its pipeline and LNG imports and also its domestic production. Pipeline gas purchased under long term contracts from Russia and North Africa is priced according to formulae which include six to nine month rolling averages of gasoil and fuel oil prices. The pricing terms are subject to periodic review (typically every three years) and may be amended through negotiation. The buyer commits to buy at a minimum the ‘Take or Pay’ level (TOP) within a contract year running from October to September of the following calendar year. The take or pay level is typically 85 per cent of the Annual Contract Quantity (ACQ).

Gas market liberalisation in continental Europe has been a slow and tortuous process. However, the gas demand reduction caused by the economic recession coinciding with a rapid growth in LNG supply from Qatar has resulted in vigorous activity in the nascent gas trading hubs of Northern Europe and a growing challenge to the oil-indexed paradigm for gas pricing. A buyer of gas in Continental Europe can choose whether or not their requirements for gas above the oil-indexed contract Take or Pay level can be met by optional additional oil indexed contract gas or ‘spot’ gas purchased on a trading hub (much of which physically originated from the UK market via the UK-Belgium Interconnector pipeline). When conditions for arbitrage have been favourable this has resulted in period of price convergence between UK gas prices and those linked to oil products prices on the European continent.

Asian LNG markets
The majority of LNG trade flows in Asia are sold under long-term contracts with price related by formulae to a time-averaged value of crude oil. The coefficient linking LNG prices to oil prices differs between contracts and some contracts also contain price ceilings and floors or an ‘S’ curve which moderates the more extreme oil price impact on the LNG price. Asian importers also purchase spot LNG cargoes to supplement contracted supplies. Unlike the situation in Europe, there is no explicit provision in these contracts for a periodic price review. Each contract pricing formula is in effect ‘fossilised’ for the life of the contract – a ‘snapshot’ of the negotiated view of buyer and seller as to how the future LNG price should respond to oil price. Over time the differences in formulae relating LNG prices to oil price have led to a wide range of LNG contract prices. In 2004 contract prices were reasonably bounded but in 2011 the spread is between US$4/mmbtu to US$15/mmbtu.

The spread of Asian LNG contract prices also means that there is no obvious regional benchmark for spot

Figure 2: Average wholesale gas prices by region, 2009
Source: Mike Fulwood, 2009 IGU Survey of Wholesale Gas Prices
In the absence of an obvious alternative, Asian spot LNG cargoes are often priced relative to the UK gas price (National Balancing Point) plus a margin which presumably reflects a distance-related shipping cost and possibly, as the market becomes tighter, a further premium to attract cargoes.

The flexibility of LNG
In order to consider how the regional markets of North America, Europe and the Asian LNG importing markets might behave when ‘plugged together’ let us first consider the flexibility of LNG supply. The majority of LNG is sold under long term contracts. However, the trend has been towards more flexible arrangements.

Even LNG under long term contract can be diverted if the contract buyer and seller agree to divert cargoes for a higher sales price and share the proceeds. This is especially the case in European LNG supply contracts.

Interaction between regional gas markets
The schematic in Figure 4 is a depiction of the gas markets of North America, Europe and the Asian LNG importing markets in 2011. Global LNG supply is represented by the tap at the top of the diagram. The Asian markets are assumed to take whatever LNG they require to meet their demand (Japan, Korea and Taiwan having no other sources of natural gas). The remaining LNG is available for Europe and North America. At the moment however, due to the growth of shale gas production in the US, North America only takes minimal quantities of LNG. Europe is thus absorbing the balance by virtue of its ability to reduce pipeline imports of oil-indexed gas to Take or Pay levels.

What we have in this situation in mid-2011 is:
- North America as an isolated, self-sufficient gas market with prices around US$4.50/mmbtu.
- A ‘hybrid’ European market with traded hub spot prices at US$9/mmbtu and oil indexed contract prices at US$11/mmbtu to US$12/mmbtu, with buyers trying to satisfy their contract TOP commitments whilst maximising their take of cheaper spot gas.
- Asia with a range of LNG contract prices from US$4/mmbtu to US$15/mmbtu with supply supplemented by spot cargoes at a price of around US$12/mmbtu, apparently linked to European hub spot prices with a transport margin and premium.

The next stage of the evolution of the system depends crucially upon the US and the future trajectory of US shale gas production. Proponents of US shale gas see potential for supply growth well in excess of the country’s consumption requirements. A number of LNG export projects are under active consideration. The economics of exporting LNG from the US appear to require a price difference of some US$3.50/mmbtu between US natural gas prices and those of the destination market. In broad terms US$2.00/mmbtu for the cost of the liquefaction plant, US$1.00/mmbtu for shipping and US$0.50/mmbtu for regasification at the destination market. If enough LNG export capacity is built for the system to reach equilibrium, the outcome (probably around 2020) would be:

In Europe (if oil indexed contracts survive) gas prices
would be determined by the present two tier arrangement where hub spot prices are either below oil-indexed pipeline import contract prices (as they are in 2011) or above them (due to tight market conditions); or, in a balanced market, hub and oil-indexed prices converged through arbitrage. If long-term contracts transition to adopt hubs as their pricing basis, European prices would be driven in the first instance by supply-demand considerations.

Asia’s oil indexed LNG contracts would continue to exhibit a wide price range. The interesting question is whether the LNG spot market becomes deeper and more liquid. Whilst Asia might continue to use European hub prices as a reference, the competition between Europe and Asia for spot cargoes would in turn influence European hub prices.

In North America, assuming regulatory authorities do not limit the scale of LNG exports, US prices could be expected to stabilise at a level US$3.50/mmbtu below European hub prices.

If however, as some commentators expect, US shale production is unable to fulfil the potential described above, the US will at some point revert back to being an importer of LNG. The outcome (again probably around 2020) would entail active LNG arbitrage between Europe and North American. In this alternative view of 2020, US prices could converge with those of Europe in periods where Europe was able to close the price gap through arbitrage by optimising LNG and pipeline imports. In practice there would probably be a differential LNG transportation cost difference of between US$0.50/mmbtu and US$1.00/mmbtu. European pipeline import volume constraints and the need to meet Take or Pay commitments would at times, however, prevent arbitrage from closing the price gap. If oil-indexed contracts survive in Europe the net effect would be an arbitrage dynamic which would seek to bring US prices up to oil-indexed levels where physical factors permitted this.

Conclusions
The discussion of the potential for greater pricing linkage between regional gas markets broadly in the 2020 timeframe above is predicated upon the dynamic interaction between the liberalised markets of North America and the UK and the newly formed trading hubs of Continental Europe. The key medium-term uncertainty relates to the future performance of US shale gas and whether this results in North America becoming a net exporter or importer of LNG.

We are at present in the midst of an evolution in the nature of natural gas markets where, despite the inherent high costs of transporting and storing this commodity, differences in price level between regional markets provide a strong motivation for arbitrage via flexible LNG. As such arbitrage plays develop and intensify we may also expect to see a ‘Darwinian’ competition between oil indexation and hub-based pricing systems. For now such a competition is likely to be confined to Europe. However in time, through a deepening of its LNG spot market such changes may also influence the Asian market.
Three years have passed since the meltdown of the financial markets and the virtual collapse of the international banking system that continues to overshadow the global economic recovery to this day. The myriad of regulations and controls in the global banking system in 2008 failed to identify and rectify serious flaws inherent in the financial markets. Under the Basel II accord, in place during the run-up to the crisis, banks were discouraged from lending to risky enterprises and encouraged to hold apparently ‘risk-free’ assets that required minimal capital. In this lay the seeds of the crisis as many of the ‘risk-free’ assets banks held turned out to be packages of assets that were anything but risk-free. Unfortunately, the best of regulatory intentions appear to have been a contributing factor to the depth and duration of the 2008 financial crisis.

The crisis revealed deficiencies in financial regulations that have led to the development of the Basel III Accord, which aims to further strengthen bank capital requirements and introduce new regulatory obligations on bank liquidity and leverage. Basel III will come into effect in 2013 and will take many years to be fully implemented. However, the situation is further complicated by the fact that local regulators will likely have the flexibility to impose stricter measures as they deem necessary, although EU regulators, for instance, are trying to impose a single set of rules on their banks. The question we must ask is whether this new regulatory regime will prevent a repeat of the 2008 global financial crisis and more importantly, will the proposed ‘cure’ have the unintended consequence of stifling liquidity and hence future economic growth? In this article, I will examine the expected impact of Basel III on the financial markets as well as the impact on bank finance available to the oil and gas sector.

Post-crisis financing
Subsequent to the 2008 crisis, financial markets worldwide witnessed a severe shortage of liquidity and a significant jump in credit spreads despite the virtual collapse in interest rates.

The widening spread in rates between the US Fed Funds Target Rate and one-month USD Libor rate, exemplified the instability during the period of the crisis. Post-crisis, the absolute level of the rates decreased substantially and the gap closed with the US Fed Funds Target Rate at 0.25 per cent, and the one-month USD Libor rate has remained at a similar level with only slight deviations. The market has clearly stabilised and spreads have contracted from the peak of 2008-2009.

While central banks across the globe increased money supply and bank access to capital, the banking market significantly contracted, preserving excess liquidity to manage down their own, often toxic, portfolios. This had a severe dampening effect on economic growth and global demand which, combined with the collapse of the commodities market, reduced access to liquidity in the oil and gas sector.

Oil and gas companies fared rather better than...
other sectors due to their collective strong balance sheets and cash flows even though the industry was faced with constrained bank liquidity at significantly higher pricing.

Across all sectors, access to corporate credit will be a vital factor in the recovery of OECD countries but with bank lending still restricted, bonds have become increasingly important. The timing of bond issuance is critical, especially with market volatility being exacerbated by sovereign debt uncertainties.

Oil and gas companies were able to raise capital in the bond and equity markets during the crisis because the energy sector was perceived to be underpinned by strong demand growth from China and other emerging markets. The oil and gas sector successfully raised over US$200 billion in new bond issuances in 2009 alone, which was higher than in 2010 and 2011 to-date. It is interesting to note that there was varying ease of access to capital within the industry. While large oil and gas companies with sizeable balance sheets and cash flows witnessed no major problems, the smaller, more entrepreneurial players, with limited cash flow and large capital expenditure programmes, faced a more daunting challenge. A number of these smaller players faced severe liquidity shortages and in some cases were forced either to raise emergency equity, consolidate with other players or to restructure in order to fund relatively large expenditure programmes.

Stabilisation in 2011

The spreads on corporate debt of AAA and BB rated companies (across all industry sectors in the US and Europe) widened over a similar period but have stabilised in 2011. The implication is that the market now has significant differentiation in the loan pricing and access to capital being experienced by companies with different credit ratings. Large corporates with strong balance sheets and cash flows have ample access to capital in the current market.

Overall impact of Basel III

During the financial crisis, an over-leveraged banking system was unable to absorb the systemic trading and credit losses. The interconnectedness of the financial institutions caused the weakness in the banking sector to spread rapidly to the rest of the financial system and to the wider economy. As a result, the public sector had to step in with liquidity injections, guarantees and capital support that exposed taxpayers to significant burdens. The objective of the Basel III reforms is to improve the banking sector’s ability to absorb such shocks arising from financial and economic stress and hence reduce the potential spill-over from the financial sector to the real economy.

However, the likely net result of Basel III for the banks will be that they will be required to hold more capital and liquidity, and reduce their balance sheet leverage. Banks will be required to hold significantly more liquid, low-yielding assets, which will have a negative impact on their profitability. This has the potential to reduce banks’ investment.
lending ability. In addition, banks will also need to reduce their dependence on short dated funding and increased the proportion of their funding with a maturity of over a year. These two measures will lead to an increase in the cost of borrowing that could eventually feed through to the wider economy and world trade. Once again, the law of unintended consequences can be quite harsh. The realities of Basel III will likely be higher costs, more selective loan portfolios, shorter tenors and less structured financings. It is also possible that the banks may be required by the market and the rating agencies to maintain a lower degree of leverage than required by the regulator.

In such circumstances, weaker banks may find it difficult to raise the required capital and funding, leading to a reduction in competition. Investors may also be less attracted by bank debt or equity issuance given that dividends will likely be reduced to allow firms to re-build capital bases, and therefore the banks will have no option but to shrink their balance sheets.

Implications for the oil & gas industry
While we have seen that the oil and gas industry has weathered the financial crisis rather well, we should be aware that the situation can easily take a turn for the worse.

To illustrate how the acceptability of certain financings can change rapidly, the precipitous drop in project financing in the oil and gas sector during 2009 reflected the realities of the stress that the banks were under and, to some extent, the reduction in discretionary spend by the industry. During this period the number of project finance banks diminished due to the risk profile, longer tenors and greater complexity of the asset class. Many banks rejected structured deals, looking more to ‘plain vanilla’ financing in order to improve their respective loan portfolios.

The vast majority of oil and gas project financing deals were for assets located in emerging markets but many banks pulled back from such markets in order to reposition their portfolios. Moreover, regulatory requirements in these markets demanded increasing local bank participation in the financings. The shortage of liquidity in these smaller, local banks, led to higher pricing for borrowers than could be offered by international banks – something which may be exacerbated by the regulations under Basel III. The irony of this strategy of pull-back from emerging market risk is that the financial crisis of 2008 had nothing to do with emerging markets or the project finance asset class.
Regardless, liquidity has returned to the market and the influence pendulum between issuers and banks that had shifted to the banks during the crisis is now shifting back to the issuer side.

Despite concerns about the possible impact of Basel III it must be remembered that the pricing of financings will continue to be dependent on credit quality and the availability of alternative sources of financing such as export credit agency (‘ECA’) financing. Changes to treatment of risk-weighting under the Accord might increase the price of ECA-backed loans as it is proposed that certain assets, such as ECA-backed loans should be exempt from the calculation of the 100 per cent conversion factor leverage ratio. This might negatively impact banks’ ability to provide export credit facilities and trade finance. Recent history suggests however, that if the Basel III regulation had the effect of increasing corporate lending margins, we may see a shift from corporate lending to bond issuance.

**Conclusion**

The balance sheets and cash flow of the oil and gas industry are in very good shape following two years of robust commodity prices and the increasing non-OECD demand. This puts the industry in a positive position to raise capital, relative to many other sectors, as demonstrated by the rash of M&A activity over the past 18 months, increasing by 40 per cent after two consecutive years of decline.

Massive amounts of capital from multiple markets are required over the coming decade to meet the insatiable appetite of oil and gas development projects for both International Oil Companies (IOCs) and National Oil Companies (NOCs). With such high capital requirements (US$0.5 trillion of upstream expenditure is anticipated this year alone) it is possible that the banks’ increased capital and liquidity requirements might constrain credit lines and reduce country limits. The knock-on effect might be a reduction in banks’ lending capacity for the oil and gas sector overall or potentially in certain countries which will likely increase the overall cost of future capital (debt and equity).

Robust and relatively stable oil prices, underpinned by growing demand from emerging markets remain the dominant factors determining the financing appetite of the oil and gas industry. The impact of new financial sector regulation will likely have a greater impact on banks and less on the oil and gas sector as a whole.

Capital is unlikely to be a serious constraint for the industry over the medium term. The favourable risk outlook for the industry combined with the positive market perception (flight to quality) place the oil and gas sector in an enviable position. However, it is dangerous to assume that we are ‘out of the woods’ just yet. The fragile global economy, sovereign debt problems and anaemic Western economic growth, are clear warning signs for the future.
The history of modern Norway was altered by the discovery of oil during Christmas 1969. Norway had been a relative laggard in Western Europe in terms of industrialisation, and the economy was largely influenced by a geography favouring hydro-electric power, fisheries and shipping. The oil discovery roughly coincided with end of the post-war reconstruction period and the establishment of the welfare state. It was realised early on that the one-off monetisation of the nation’s resource wealth should also benefit future generations. Figure 1 illustrates the challenge faced by resource-rich countries in their management of resource windfalls: how to transform fluctuating and perishable revenues into a permanent increase in consumption? A financially motivated fund is one answer to this. By investing the fund solely in foreign assets, the threat of overheating the domestic economy can also be reduced.

The Government Pension Fund Global (GPFG) was established in 1990 as a fiscal policy tool to support a long-term management of the petroleum revenues. Due to the macroeconomic situation, the first transfer to the Fund happened six years later. The Fund has an important role in facilitating government savings to meet the rapid rise in future public pension expenditure (Figure 2). The Fund is, however, not earmarked for pension expenditures. The Fund’s objective is to maximise long-term international purchasing power. The Fund’s size at year end 2010 was some US$525bn, and it owns around one per cent of the world’s listed equities.

The Fund’s structure and governance
The Fund’s income consists of all state petroleum revenues, net financial transactions related to petroleum activities, as well as the return on the Fund’s investments. The Fund’s expenditure is the sum needed to cover the non-oil budget deficit. Transfers can only be made following a vote in the Norwegian parliament. Net allocations to the Fund reflect the total budget surplus (including petroleum revenues). The Fund cannot be earmarked for specific purposes and cannot be invested in Norway (and thus is not a secondary budget). Consequently, the allocation of fund liquidity forms part of an integrated budgetary process, and renders the State’s use of petroleum revenues visible. Fiscal policy is anchored in the guideline that over time the structural, non-oil budget deficit shall correspond to the real return on the Fund, estimated at 4 per cent. Whilst this is not a legal requirement, it enjoys broad political support. It is a transparent and simple rule, which should ensure that the Fund remains a permanent fund.

In the Government Pension Fund Act, the Norwegian Parliament made the Ministry of Finance responsible for the management of the GPFG. Key changes to investment guidelines are presented to Parliament before implemented. There is a clear division of roles and responsibilities between the the Ministry of Finance, and the operational management, which is carried out by Norges Bank (the Central Bank) based on a mandate given by the Ministry (see figure 3). In the mandate, the Ministry sets guidelines, including benchmark, provisions on responsible investment and risk limits. The Ministry reports yearly to Parliament on the management of the fund.

A sound governance structure is necessary for successful strategy implementation; it must ensure that important decisions relating to fund management risk have the support of the Fund’s owners, the Norwegian people as represented by the Parliament. There must also, however, be sufficient delegation of authority to allow day-to-day
decisions in the operational management to be made close to the markets. Efforts are made to achieve this balance by submitting decisions of material significance to the Fund’s risk level to the Storting before their implementation, while the mandate issued by the Ministry to Norges Bank is based, insofar as possible, on principles and frameworks. In this way, a necessary and high degree of delegation is combined with the “owner” having a good understanding of, and ultimate responsibility for, all major strategy decisions. Such a balance can only be achieved through a clear division of roles and responsibilities between all governance levels involved in the management. One needs to make every level of management responsible for the decisions delegated to them, and have good control and supervisory bodies in place.

Over time, there should be interaction between the governance system and the Fund’s investment strategy. The investment strategy must take into account the distinctive institutional features of the Fund. The need to secure the support of political bodies for important aspects of management means, for example, that it is difficult to design investment strategies based on taking quick, time-critical decisions. On the other hand, the strategy must also be able to exploit the Fund’s distinctive characteristics, in order to improve the trade-off between return and risk.

**Investment strategy**
The Ministry receives advice on the investment guidelines from Norges Bank, the Ministry’s advisory council on investment strategy and external consultants. The Ministry uses external consultants for controlling performance measurement and peer group benchmarking.

Investment strategy must be based on a combination of how the markets in which the Fund invests work, and what distinctive characteristics the Fund has as an investor. The most important characteristic of the Fund as a whole is probably its long horizon, size, state ownership and very diversified portfolio.

Avoiding risk is not an objective for the management of the Fund. On the contrary, risk-taking contributes to returns over time. The GPFG has considerable ability to bear fluctuations in the Fund’s returns from year to year. The investment strategy is therefore not aimed at minimising short-term value fluctuations.

Diversification is a powerful mechanism which allows one to realise better risk-adjusted returns. The power of diversification underlies the entire investment strategy, and also the motive behind the Fund; to reinvest the windfall gain from a perishable resource into a diversified portfolio of foreign assets which will provide a more stable and secure income stream. Developments in the investment strategy has meant the fund has become more diversified over time. A portfolio of property investments is currently being built up.

**The value of transparency**
The Fund is subject to a high degree of transparency and much public interest. The management of the petroleum revenues in general and the Fund in particular is characterised by a high level of disclosure. The Ministry of Finance emphasises transparency and public access to information. We see transparency as crucial to building trust and confidence in the management of the Fund – both domestically and internationally. Internationally, there has been considerable attention paid to the fact that some sovereign wealth funds (SWFs) have little transparency about their activities and to the possibility

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**Figure 2:** Pension expenditure and expected Fund real return as a share of mainland (excluding oil and shipping) GDP

![Pension expenditure and expected Fund real return as a share of mainland (excluding oil and shipping) GDP](image)
that they may have non-financial objectives for their investments. Domestically, transparency is a preconditon to secure public support for sound management of Norway’s petroleum wealth. Anchoring the strategy, and explaining the various sources of risk, has been a particular focus in public documentation.

The Ministry reports to Parliament on all important matters relating to the Fund, such as the size of petroleum revenues and the Fund; the outlook for fiscal sustainability; changes to the investment strategy; the Fund’s performance, risk and costs. The Ministry publishes advice and reports received from Norges Bank and external consultants. Norges Bank publishes quarterly reports on the management of the Fund, as well as an annual report, an annual listing of all investments and annual voting records. The reports include performance, risk and costs and is published on the website. In addition the asset manager publishes live simulated total assets under management on its website.

Whilst transparency is fundamental, there is probably also such a thing as “too much transparency”. On the strategic level this can lead to an excessively short-term focus or under-utilisation of financial risk limits. It can also threaten the efficiency of the GPFG’s ownership efforts, as it might reduce the topics NBIM, the fund managers, could engage in dialogues with companies, external managers and other stakeholders. Finally, specifically when it comes to regimes for rebalancing or transfers to the fund, too much transparency might lead to harmful “front-running,” where advance knowledge of transactions can lead to market share abuse.

External assessments
The Generally Accepted Principles and Practices (GAPP), or Santiago principles, for SWFs establish a set of sensible principles for the organisation and management that can build trust with recipient countries and in financial markets. The Ministry of Finance view the principles as a minimum standard which all SWFs should adhere to where applicable. The Ministry has published a self-assessment of the GPFG’s adherence to the principles. The Fund has been assessed by external bodies which address many of the same issues as the GAPP. The GPFG has consistently scored well in these assessments. Whilst not directly comparable to the recently published self-assessment, these correspond well with the conclusion that the Fund adheres satisfactorily to the GAPP. The transparency of the petroleum revenues before they reach the Fund has also been assessed externally by the Extractive Industries Transparency Initiative (EITI), of which Norway is a member.
The work of the International Forum for Sovereign Wealth Funds (IFSWF) and the continued implementation of the GAPP are important. At the same time, it is clear that the members of the forum are a very heterogenous group, and so the application of the principles will legitimately and necessarily differ from SWF to SWF – an obvious example is that some of the IFSWF members do not invest in equities, making equities related principles largely irrelevant. It is also clear that some of the issues that concern us as an investor, for example good corporate governance or other factors leading to well-functioning markets are not addressed through the principles.

Responsible investing and active ownership

The Pension Fund is managed on behalf of the Norwegian people. Shared ethical values therefore form the basis for the responsible management of the Fund. Generating good long-term returns is a fundamental obligation, and may depend on a sustainable development in economic, environmental and social terms, and on well-functioning financial markets. The Fund is a long-term owner with assets spread across a large number of companies in many industries and countries. In this way, the Fund indirectly owns a share of the world’s production capacity, it is what has been referred to as a “universal owner”. The Fund therefore has a comprehensive RI strategy which includes both exclusion (as a measure of last resort) and observation of companies, financially motivated mandates specifically targeting environmental investments, research and international collaboration. Perhaps the main and most appropriate RI tool for a diversified and long-term investor is active ownership. The overall purpose of active ownership is to safeguard the Fund’s financial values by contributing to good corporate governance and by striving to achieve higher ethical, social and environmental standards in the companies. Good corporate governance is important for the Fund’s returns over time and to ensure the owners real influence and dialogue with the companies in the portfolio.

Norges Bank has chosen to concentrate its ownership activities in certain key areas of significance to the portfolio. With relatively small individual holdings, such a strategy provides a better opportunity for making an impact. The manager has made it a priority that the areas should be relevant for investors generally and the Fund’s portfolio in particular. They should also be suitable for dialogue with companies and/or regulatory authorities, provide an opportunity for making a real impact and be justifiable financially, since the manager acts in the capacity of investor. The focus areas include the equal treatment of shareholders, shareholder influence and board accountability, well-functioning, legitimate and efficient markets, climate change, water management and children’s rights.

The NBIM has developed publicly available principles for voting, and aims to vote at all annual general meetings, currently around 10,000 a year. The manager votes on all issues, including those that fall outside the focus areas. The voting records are made public.

Conclusion

Large petroleum revenues have resulted in substantial financial assets in the GPFG, to the point where it is now amongst the largest SWFs in the world. In the more than 15 years that have elapsed since the first transfer to the former Government Petroleum Fund, there have been major changes to the Fund’s strategy. This seems likely to continue.

The Norwegian experience is rather unique. Norway has realised its resource wealth from an already enviable position, as a small, stable, democratic and economically developed country. This, and previous examples of economies overheating and succumbing to so-called dutch disease, has enabled the country to choose what is hopefully a more sustainable and long-term management of the country’s resource wealth. For this reason, while the Norwegian model has been well received in internationally, and to some extents inspired developments elsewhere, it is inappropriate to use any one country’s experience and set-up as a blueprint for developments elsewhere. The general principle probably holds for most countries, however; if you find yourself with substantial and perishable source of income, it might make both current economic and inter-generational sense not to spend it all at once.

The Fund is already a major owner in the global equity market. On average, the GPFG owns around one per cent of all listed equity in the world. In many companies it numbers amongst the largest individual owners. Projections for the Fund for the period to 2020 show that the Fund’s ownership shares will continue to grow. This, however, does not alter the Fund’s role as a financial investor. But it does strengthen the need for the exercise of ownership as a necessary effort to protect the Fund’s economic interests. The Fund’s management cannot be built on the assumption that this important work will be adequately taken care of by other owners.
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Potential for transformative new projects in the upstream petroleum sector (crude oil and natural gas) remains – notably in Africa, and also in Brazil. The last few years have also seen dramatic development in exploitation of shale gas. Despite concerns about “peak oil” and difficulties of access for international oil companies (IOCs) to new reserves, countries are emerging – new to the petroleum industry – where projects massive in relation to the size of the existing economy are in prospect. In Africa, these are reality in Ghana, Niger and Uganda, and possibility in Liberia, Mozambique, Sierra Leone, and Tanzania. Design and implementation of fiscal regimes for future petroleum exploration and extraction is a vital interest for these countries.

This article outlines these challenges from the perspective of countries seeking international investment, using tax and royalty schemes, or production-sharing contracts, or risk service contracts, under which companies take risks and share in rewards. More than half of world output, however, comes from wholly or substantially state-owned systems, where private companies participate, if at all only on fee for service terms, and different issues arise.

**What’s special about petroleum?**
Relative to most host economies, the sheer size of the petroleum sector, and of individual projects, distinguishes it. Government revenue is most often the central benefit, and stimulating ancillary economic development is a continuing challenge. The industry has high sunk costs prior to production, and long production periods, creating what economists term the “time-consistency” problem: terms that seem welfare-maximising when a project is negotiated are tempting for governments to change once investment is sunk and production started. Petroleum production has potential to generate substantial rents – in the sense of a surplus over all necessary costs of production including a minimum required return on capital. This is the public finance ideal of a non-distorting, immobile tax base. At the same time, however, international tax considerations loom large: not only the interaction of host country and corporate home systems, but also tax competition in attracting investment.

Uncertainty faces both governments and companies: uncertainty over geology, technology, price volatility, and – for companies – sovereign actions. Volatility in oil prices is well-known; less well-known is the enormous difficulty of making useful forecasts. Attempts to design fiscal terms on the basis of price forecasts will founder. Uncertainty faces the parties differently, however, under the problem of “asymmetric information” – typified by the likelihood that government will know less about a prospect at the time of award of a contract than a company does. Asymmetric information compounds the time-consistency problem – introducing potential for instability into fiscal terms.

Few of these features are unique to petroleum, though they often have bigger impact than in other sectors. Exhaustibility is unique to petroleum and minerals. What is extracted today cannot be extracted tomorrow (the opportunity cost of extraction includes future extraction foregone). Views differ on how important this is in practice, but the fiscal terms will probably affect the pace of extraction. Wise government regards petroleum revenues as transformation of a finite asset in the ground into financial, physical and social assets with enduring benefit.

**Fiscal terms for private investment**
Suitable fiscal terms will differ with prospectivity, cost conditions, or other factors – no one size is likely to fit all. Nevertheless, some principles can widely apply. Because of uncertainty, and price volatility, terms that are robust and flexible in the face of changing circumstances are likely to be more durable. A stream of revenue should accrue to government whenever extraction occurs – whether the rationale is the opportunity cost of extraction, or simply the political unacceptability of extraction without revenue. Terms also need to be progressive, in the sense that as project profitability increases the government’s share of it also increases.

Transparency calls for fiscal terms to be set in legislation or in published contracts; both can be combined with bidding over an initial bonus payment as a means of allocating rights. Sound tax policy requires avoidance of special incentives where possible, though cases where import duties or poorly-administered value-added tax systems bear heavily on investment costs may justify exceptions. The balance struck between companies and governments should be stable and credible.

Tax and royalty, production sharing, or state participation can all be made fiscally equivalent. A participation share assigned to the state without payment, for example, approximates a tax on profit distributions at the same rate. Different contract structures, however, apportion risks differently between the parties and thus affect stability and credibility. Whatever the scheme, the data for key assessments of fiscal instruments →
must be observable or verifiable, and opportunities for aggressive tax planning minimised.

The fiscal design should take account of the relative capacity of companies and governments to bear risk. A poor country with a limited portfolio of projects may be less able to tolerate deferral of revenue than a major company. The combination of requirements suggests that the fiscal scheme should have multiple instruments: the combination of a royalty, or its equivalent under production sharing, normal corporate income tax, and some form of additional rent taxation (or production sharing, or state participation) is thus common.

Issues for the future
How far should petroleum taxes be progressive? The question is the degree to which the government share should be rise, or fall, with prices or profits or lifetime project return. Progressive systems yield more volatile revenues and can therefore create problems for countries not able to bear that risk. Political pressures, however, may make progressive systems more robust and credible. The issue is how far to go. Angola or Azerbaijan, for example, introduced multi-tiered systems, while Norway operates a single rate of special petroleum tax.

What type of rent tax? Production sharing schemes geared to the daily rate of production have historically been popular, but the rate of production is an inadequate proxy for overall profitability. A matrix of production rates and prices is possible, though specifying the values is a challenge. In either case, costs must still be assessed, opening the way to consider more efficient forms of tax (sometimes implemented through production sharing). All rent taxes in cash flow form involve some “refund” of the tax value of losses – most clearly seen in the abandoned Australian proposal of 2010 for a Resource Super Profits Tax. In Norway, exploration losses are refunded and overall losses on one project offset against another. Perhaps the simplest scheme is the UK surcharge on corporate income tax, where no interest is deductible but capital expenditure is immediately deducted in full, The resource rent tax (RRT), where losses are uplifted at an accumulation rate until recovered, features in Australia, Angola, and other places. But setting that accumulation rate does not prove straightforward.

Capital gains on sales of rights
Taxation of gains became a big issue in Ghana, Uganda, and elsewhere, when large premiums were paid on transfers of rights or on indirect sales through shares of companies with interests in petroleum rights. The presence of large gains suggests the fiscal regime is not expected to tax rents sufficiently. One solution, therefore, is better fiscal regime design, but that does not solve an existing problem. The first question is whether domestic law and tax treaties permit taxation of gains on direct or indirect sales of petroleum rights (usually treated as immovable property). Secondly, what tax (income tax or capital gains tax) applies, and against what income or gains can the premium paid be deducted? Thirdly, how is the tax authority to learn about an indirect sale? Probably the only means will be a provision in a petroleum license that triggers default if a sale is not notified – but then, what size of sale qualifies?

International taxation and treaties
Border withholding is the main way to tax flows to non-residents (dividends, interest, service or management fees, royalties), which are significant in petroleum projects. Tax treaties have often eroded permissible rates – sometimes to zero. This phenomenon raises questions about the value of treaties to capital-importing countries, while at minimum it requires governments to have a strategy for negotiation of treaties that avoids erosion of the domestic tax base. An alternative answer is to focus on the domestic taxation of the underlying rents from petroleum extraction.

Pricing of infrastructure
Many petroleum projects (especially for gas) cannot develop without large ancillary investment in infrastructure. The fiscal regime usually deals with upstream production, valued at the field export point (or some similar concept). Where transport and processing infrastructure (midstream and downstream) requires establishment of a non-arm’s length transfer price, there is risk of diversion of rent to lower-taxed segments of the operation. New petroleum producers may need to invest as much effort in dealing with this issue as with the basic design of a fiscal regime.

This article has sketched principles and raised questions about design of petroleum fiscal regimes. Accelerating the pace of exploration and extraction requires mutually beneficial (to investors and governments) application of the principles, and answers to these outstanding questions.

Views expressed in this article are those of the author and should not be attributed to the International Monetary Fund, its Executive Board, or its management.

1. These ideas are distilled from The Taxation of Petroleum and Minerals: Principles, Problems and Practice, edited by Philip Daniel, Michael Keen, and Charles McPherson; Routledge/IMF, 2010, and from recent experience of IMF Fiscal Affairs Department technical assistance projects in member countries.
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