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Regulating the Arctic

In this quarter's guest commentary, legal firm DWF's Michael Kingston assesses what is being done to regulate oil and gas exploration in the Arctic while safeguarding investment and the environment.

- **As oil and gas E&P activity increases in the Arctic, more regulation is required, and steps have been taken to implement a Polar Code. However, much depends on individual countries.** *(Page 2)*

What lies beneath

The fortunes of deepwater E&P during the second quarter of 2014 have been a mixed bag.

- **Luanda has put its faith in hitting 2 million bpd of production by 2015 but this appears to be overly optimistic.** *(Page 5)*
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- **Mexico could follow Brazil and emerge as a vibrant deepwater exploration frontier, although a lot depends on the success of its ongoing energy reforms.** *(Page 21)*

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Edited by Ian Simm

Guest Commentary

Arctic regulations: tackling the White Elephant offshore

Deepwater Quarterly (DWQ) assesses what is being done to regulate oil and gas exploration in the Arctic while safeguarding investment and the environment

By Michael Kingston

- **As oil and gas E&P activity increase in the Arctic, more regulation is required**
- **Steps have been taken to implement a Polar Code. However, much depends on individual countries**
- **Maritime regulations have a history of being more reactive than preventative**

As we approach an era of expanded and more intensive oil and gas exploration within the Arctic Circle we must apply the lessons of history. The unique challenges presented by one of the world's last frontiers are significant, and are compounded by the shortage of skills, experience and equipment suited to this hostile environment.

The nexus of these factors should concern those beginning to work above 72°N – a single catastrophe could deal a fatal blow to the industry as a whole unless it works together to establish safeguards and best practice suited to the Arctic.

Not fit for purpose

At present there is no International Maritime Organisation (IMO) convention that governs operations in polar waters specifically. What is apparent is that the International Convention for the Safety of Life at Sea (SOLAS), as it stands, is not fit for this purpose.

Despite coming into existence in the aftermath of the Titanic sinking, the convention's life raft requirements are nowhere near the standard required in the harsh Arctic environment. It is also clear from the events of the Macondo spill that there is no coherent approach internationally to oil pollution and safety legislation.

While some individual countries such as Norway have stringent legislation in place that is fit for purpose, there is no cross-jurisdictional regulatory agreement in relation to Arctic operations.

For operations to flourish in this environment companies will have to lead to the way in creating and policing standards of safe operation.

This was highlighted in Lloyd's of London's 2012 report An Arctic Opening; Opportunity and risk in the high North.

The imaginatively named Convention on Civil Liability for Oil Pollution Damage Resulting from Exploration for and Exploitation of Seabed Mineral Resources, which was aimed at dealing with pollution from drilling operations on a worldwide basis, has been lying on government shelves gathering dust since 1977.

Drawing attention

A recent increase in activity has been highlighted by the seismic survey project undertaken by a group of companies in the southeast Barents Sea, demonstrating a firm commitment by Norway to open up the Arctic.

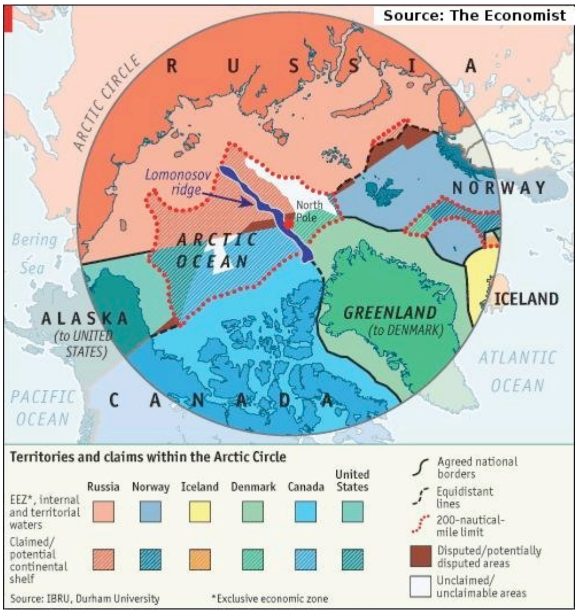
The seismic operations in the Barents Sea follow closely in the wake of another milestone in production activity. In April, Gazprom Neft, the oil arm of Russia's top gas producer Gazprom, shipped the first 70,000 tonnes (513,000 barrels) of oil by tanker from the Prirazlomnoye platform, the site of a high-profile protest by 30 Greenpeace activists who were arrested in 2013.

These developments coincided with an industry discussion held in May, organised by Lloyd's of London and hosted by the British Embassy in Oslo, addressing the question of deepwater drilling above 72°N in the Barents Sea. It is popularly accepted that as frontier fields draw the industry further north, this represents a paradigm shift in how operations should be managed: the Arctic is an atypical ocean, requiring very different preparation and management of operations.

Shifting patterns of ice flow, depth and density make the 'normal operational case' almost impossible to identify, compelling companies to approach the territory on a case-by-case basis. The concerns voiced were obvious, yet difficult to address by operators alone: ▸▸

- Accurate monitoring of ice formation and flows is not sufficient for commercial risk management
- Extreme cold can cause engine problems and make it difficult or impossible for equipment to work
- There is reduced coverage by modern navigation aids such as GPS
- Tradition maps are inaccurate and magnetic compasses are unreliable at such high latitudes
- There is some form of restricted visibility at almost all times
- A lack of commercial traffic has resulted in inadequate weather reporting infrastructure, and violent storms can occur at any time
- Salvage and spill-management capabilities are almost non-existent
- Remote operations at great distance from land

Guest Commentary



Out, on the ragged edge

Key amongst these concerns as operations approach the 'ice edge' is the new challenge of ice management. Effective management of the risks posed by ice requires information: about temperature; prevailing winds; wave patterns and currents; ice density; flow and dispersion rates.

In order for operators to cater for a 'worst case' scenario they need to know what the prevailing conditions are at a location, and to predict what they are likely to be over a sustained period, and what the implications are for their operations.

While the International Convention for the Prevention of Pollution from Ships (MARPOL) applies to ships it does not apply to oil rigs or floating production, storage and offloading (FPSO) units and there is still a legal question mark as to what can be defined as a ship, for the purposes of the convention.

This persistent gap in international law does not help with the management of risk in the Arctic.

The IMO is working on a draft Polar Code, with a particular focus on defining ice classes, and it is hoped that it will be agreed later this year. Agreement has been reached in principle on definitions for the different categories of ship and the requirements for safe operation in different ice areas in the Arctic.

Under the proposed Polar Code, ships will need a Polar Ship Certificate and a Polar Waters Operations Manual. These will include key operational capabilities and limitations, such as Polar Ship Category and ice class, an outline of an acceptable range of operating drafts, temperature parameters, and safe ice-going conditions capabilities. The crew of any ship that makes a polar voyage needs to be aware of the hazards that may be involved, and the operational procedures that will be needed to avoid these hazards, or to mitigate the risks that they may incur.

The knowledge and experience of the bridge crew is an essential element of ensuring safety, and training and manning requirements are incorporated in the Polar Code system. Voyage planning is also very important, and such plans need to be developed with an understanding of the ship's capabilities and limitations.

Additionally ships and mariners need to be adequately prepared for worst-case scenarios that go beyond what is to be normally expected in normal circumstances as envisaged. The Polar Waters Operation Manual is therefore intended to give guidance for a range of planned and possible situations.

However, the IMO Guidelines are merely recommendations at present. They are non-mandatory and to become legally binding would require either individual states to incorporate the Regulations into their national legislation, or the adoption of the Polar Code as a binding treaty, perhaps in the form of an amendment to either of the MARPOL or SOLAS conventions. The questions of whether the guidelines go far enough and whether the approach is too prescriptive have yet to be answered.

For the Polar Code to work it will require input from Arctic governments, industry and the research community as part of an integrated approach to create and apply best practice guidance by companies in the Arctic.

As a result, the shipowner must only satisfy the ship's Flag State that the content is appropriate – a very unsatisfactory position for tropically-flagged vessels. Concerns have also been raised as to how it will be enforced – by jurisdictions of operation, or through a ship's flagged port-state control? Operation in international waters raises further concerns as to enforcement mechanisms.

A polar ice regime

There is currently no ice regime applied to the Arctic or Antarctic Polar Regions, the absence of which will make it very difficult to complete the Polar Waters Operating Manual. If one cannot determine what the prevailing or periodic ice conditions are in a given area, then it is not possible to determine or mandate which consequent operating requirements should be enforced.

To determine the worst-case scenario and to plan for safe operations accordingly, companies will need to identify the ice that, as the Polar Code says, "may be encountered." Canada operates an ice regime with zones and ice classes depending on conditions. Russia also has an ice regime that has some principal similarities with that of Canada.

However, the US, Norway, Denmark/Greenland and Iceland all lack ice regimes. Sweden and Finland operate a Baltic system, but this is not applicable to the Arctic. In the high North, an Arctic ice regime should be established in order to allow for an effective application of the IMO Polar Code, enabling a universal application of the rules across the Arctic. In order for the Polar Certificate and Polar Waters Operation Manual to make sense, this is essential.
Recent examples have highlighted the dangers involved, with cruise ships carrying passengers having been seen in ice waters off the coast of Greenland. This is a nightmare for insurers and such incidents do not inspire confidence within the insurance industry. ▸▸

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Additionally in September 2013, Russian tanker Nordvik entered ice waters and punctured her hull in the Northern Sea Route, when she entered ice conditions that she was not capable of dealing with. Given that she was carrying a large cargo of diesel fuel, this could have had enormous environmental consequences. And in December 2013 we witnessed the well documented problem in the Antarctic with the Akademik Shokalskiy, which was not adequately prepared for the voyage in question, prompting an arguably unnecessary emergency rescue of passengers which, it is reported, cost the Australian Maritime Authorities US$1.6 million.

The way forward

It is clear that in order to make the Polar Code a relevant and useable tool to reduce the risk of exploration and production (E&P) operations on an Arctic-wide basis more work must be done to link the various elements together coherently, tying together ice regime, the Polar Code and Ice Class, research and industry best practice.

Essential to this is the integrated gathering and sharing of information, the research community working with industry being of critical importance.

It has been suggested by ice experts that the Arctic should be divided into distinct geographical areas – based on ice conditions with a number of seasons established in a year (perhaps three or four) – capturing ice seasons with ice coverage and hardness.

Each Arctic country can be responsible for rules in their 'sector' of the Arctic. The Arctic Council is essential in this process and its members can perhaps establish a central forum to be run by the research community, with industry and government making contributions.

Following the Sustainable Arctic Shipping and Marine Operations conference in March, the need to work together in an integrated approach, and to assist the IMO in their work, was deemed to be of paramount importance by industry. A subsequent workshop entitled 'Bridging the Arctic marine risk gap – The need for a cross-Arctic Ice Regime – linking ice conditions to ice class requirements' took place at Lloyd's of London, organised by the Swedish Polar Research Secretariat in conjunction with Lloyd's, the Swedish Club and the Nordic Association of marine insurers, after which the following recommendations were made to the Arctic Council:

- That the Arctic Council, or its working groups, is asked to assist in setting up a forum for the sharing of knowledge by industry, Government, the Research community and other parties in order to foster best practice
- That under that proposed forum a specific group be set up to build an ice data regime across the Arctic to encourage each member state to take responsibility for their section of the Arctic in order to ensure best practice that goes beyond current regulatory requirements in areas where it is lacking. This is similar to initiatives already in motion in relation to charting.
- That under that forum the issues of crew competence and training be nurtured in a systematic and harmonised way in order to foster and support best practice - similar to training in relation to dynamic positioning such as that provided by the Nautical Institute.
- That the Arctic States come to some agreement about the monitoring of operations outside their Exclusive Economic Zone that constitute international waters.
- That such a forum represents a cross section of interests that make it fit for purpose – operators, insurers, and representative bodies such as the International Association of Classification Societies, with representatives from each member state.
- That such a forum includes a mechanism for sharing of experience in a way that does not compromise competitive advantage, or confidentiality.
- That these recommendations be raised if possible at the meeting of the Senior Arctic Ambassadors, including participation by Koji Sekimizu, at Yellow Knife, Canada, March 25-27

The full reports from both these Conferences can be viewed here.

Such initiatives will either help to include further sensible requirements in the Polar code, or complement it.

Learning lessons from history

While the evolution of IMO regulation is welcome, it is clear that the marine and energy industries cannot afford another disaster of the scale of Macondo. Operating in more extreme environments, together with transits of vessel classes that are increasing in size, poses significant risks that must be addressed by industry and government alike. History has taught us that it usually takes a disaster to instil urgency in implementing previously suggested regulation.

How long will it take for the Polar Code to have legal effect regardless of its inadequacies?

The SOLAS convention was devised in response to the loss of life on the sinking of Titanic, and lives were nonetheless lost in the grounding of the Costa Concordia in safer and warmer waters than those of the Arctic.

In the 1970s SOLAS was amended to take into account the need to rectify inadequacies in oil tanker safety. But the amendments were not ratified until after the loss of 50 people when the Betelgeuse exploded at Whiddy Island in Bantry Bay, South West Ireland in 1979. The ratification in 1980 arrived too late to impose a simple requirement in relation to inert gas systems that would have prevented the disaster. Too often, the lessons of history are remembered too late.

Whilst the IMO has been working hard, in the interim industry has not always pushed for standards that will both assist the IMO's broad aims, or exerted pressure on states to ratify conventions which could go some way to preventing unnecessary disaster.

Recently, the International Union of Marine Insurers (IUMI) has backed an initiative for industry to show leadership and create its own standards of responsibility by signing up to the Arctic Marine Best Practice Declaration. ▸▸

Guest Commentary

This presents a significant opportunity for industry to create standards that are fit for the Arctic. The marine and energy industries need to demonstrate to the world that they are being responsible if public opinion is to support operations in the Arctic, particularly as impending operations represent a 'paradigm shift' at the ice edge, as described by Ake Rohlen of Arctic Marine Solutions.

Industry must work to bridge the legal divides between countries and operators, establishing the highest standards of safety and enforcing those as a measure of contract or insurance.

Until that responsible approach is demonstrated, organisations such as Greenpeace will continue with high-profile protests and public opinion will harden against operation in the Arctic, a perception that will be reinforced if one operator's irresponsible actions result in an environmental catastrophe.

It is in the interests of all parties to make sure that does not happen.

That possible set of events need not be considered an inevitability if individual governments, together with industry, mandate responsible standards that extend beyond IMO requirements and supplement the framework of the Polar Code.

It is the responsibility and indeed duty of those considering the Arctic as the next frontier to push for uniform, international regulation of the highest standards. If not, we risk the future of the industry, and the Arctic itself. ■

Michael Kingston is a partner of law firm DWF and a member of the firm's Marine, Trade & Energy Group. He has recently been invited to speak to representatives of NASA and the US Navy on the subject of safe marine operations in the Arctic.

Africa

Angola struggles to hit target

Luanda has put its faith in hitting 2 million bpd of production by 2015 but this is overly optimistic

By Kevin Godier

- **Angola produced 1.62 million bpd in March, down from 2013 levels**
- **Total has committed to the Kaombo project, with first oil expected for 2017**
- **Pre-salt exploration is gaining ground but will take years to come on line**

Despite continuing investment and some recent finds, Angola's goal of hitting the 2 million barrel per day of oil mark – and surpassing Nigeria as Africa's largest producer – remains elusive.

Oil is the main source of Angola's wealth and is responsible for almost all of its exports. Few would dispute the momentum behind the country's oil sector, after state-owned Sonangol scheduled an auction for May 30 of 10 new onshore exploration blocks in the Kwanza and Congo Basins. However, "expanding the hydrocarbon sector has proved more challenging [than] expected," ratings agency Fitch said, in a country outlook report on April 14. This reversed a May 2012 revision of Angola's outlook from stable to positive, and estimated that the country's output was declining every year at a rate of about 200,000 bpd, which many observers attribute to maturing shallow-water concessions. "Without substantial new investment, Angola's oil production will start to decline in 2016," said Fitch.

Angola is the second largest oil producer in sub-Saharan Africa after Nigeria, but has had a tough start to

2014, with output of 1.65 million bpd in January, 1.61 million bpd in February and 1.62 million bpd in March, according to International Energy Agency (IEA) statistics in April. Most of the country's oil production comes from offshore projects. The 1975-2002 civil war dampened interest in onshore operations but the industry grew subsequently and in 2008 it briefly held the title of Africa's largest producer. The country has just under 13 billion barrels of reserves, according to estimates. However, should pre-salt drilling be successful this amount could be doubled. In the near term, Sonangol plans to hike production to 2 million bpd by 2015, it said in a statement on May 5, and sustain this for five years. The reality, though, is that a combination of maintenance work, mechanical damage and delays in delivering technical equipment have all hindered the sector. ▸▸

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Foreign majors operating in the sector have often attributed the delays to Sonangol's insistence that it gives final approval to any construction or technical work.

Total boost

Expense is another obvious key factor. Companies have flagged up pressure on their spending in recent results and Angola's ultra-deep concessions are expensive to drill, while also being high-risk.

One positive note came from Total, which in mid-April announced it would spend US$16 billion to develop the deepwater Kaombo project offshore Angola, with a plan to bring this on stream by 2017. The development sounds expensive but the company managed to shave US$4 billion off the initial estimates.

Total is already the most productive operator in Angola, with equity production of 186,000 bpd, mainly down to its Girassol, Dalia and Pazflor deepwater fields in Block 17. The blocks it operates produce around 600,000 bpd, over one third of the country's output. Also in April, the French company said it was on track to start its CLOV project in Block 17 – covering the Cravo, Lirio, Orquidea and Violeta discoveries – in mid-2014, with capacity of 160,000 bpd.

Elsewhere, Eni, Statoil and ConocoPhillips are among other majors that have declared their intention to inject a greater level of resources into the country. Nonetheless, Angolan crude production fell by 1.1% to 1.71 million bpd in 2013, following a 4.5% jump in 2012.

Sonangol's CEO, Francisco de Lemos Jose Maria, set out the company's stall in February 2013, announcing that his company intended to launch a 10-year, US$8 billion investment programme and put several new concessions up for auction.

The investments, he predicted, would assist his company to support the goal of 7% per year production growth set by authorities in Luanda. Jose Maria subsequently demanded "explanations" from the heads of Chevron, Total, ExxonMobil and BP about a series of problems that contributed to the 2013 production drop.

Statoil sale

Norway's state-owned Statoil said on May 12 it was also selling its 5% stake in Block 15/06, which is operated by Eni. The sale carries a price tag of US$200 million, the company said, with Sonangol EP picking up the stake.

"This transaction is part of Statoil's continued optimisation process to maximise value and focus financial and organisational capabilities [on] core assets. The transaction will allow Statoil to unlock capital and contribute to improved financial flexibility going forward," said Statoil's sub-Saharan Africa head, Tove Stuhr Sjoblom. Total recently sold its stake in Block 15/06, with its 15% stake securing a US$750 million price tag from Sonangol EP in February.

Statoil also sold down stakes in Angola's pre-salt recently, farming down a 15% stake in Block 39 to Genel Energy and White Rose Energy.

Statoil's recent deal activity has not been restricted to Angola, with the company selling stakes in Azerbaijan's Shah Deniz and South Caucasus Pipeline for US$1.45 billion in early May.

Moody's positivity

One positive short-term view of Angolan production potential came in February from Moody's Investor Services, which projected in a credit rating report that the country's crude output would hit 2 million bpd by the end of 2015. This tallies with comments from Angolan Oil Minister Jose Botelho de Vasconcelos in October last year that 2 million bpd might be feasible by 2015.

The seven-page report affirmed Angola's rating at Ba3 with a positive outlook.

The report's authors estimated that in 2014 there would be a budget surplus of 2-3% of GDP.

Meanwhile, the deadline for bidding on the onshore blocks is nearing. Of the 10 blocks up for auction, seven are in the Kwanza Basin and the remaining three are in the Congo Basin. Proposals from interested companies were due in by April 30.

In October 2013, de Vasconcelos said oil could be extracted from the 10 blocks from 2015 onwards. In January of this year, Sonangol's head of exploration, Severino Cardoso, said in Luanda that the 10 blocks accounted for over half the known oil reserves in Angola.

Another upbeat note came on May 1, when Sonangol said that the US explorer Cobalt International Energy had discovered significant quantities of oil in Angola's deepwater offshore, calling the find the biggest so far in the promising pre-salt layer in the Kwanza Basin.

Drilling at the operator Cobalt's Orca-1 well in Block 20/11 reached a depth of 3,872 metres and successfully produced over 3,700 bpd of oil and 16.3 million cubic metres of gas per day, Sonangol said in a statement.

Cobalt – which counts Goldman Sachs and private equity firms Riverstone and First Reserve as investors – estimates the well may hold 400-700 million barrels of oil. Cobalt said the find was its fifth off Angola and followed the Lontra well in November, which it said at the time was "a discovery on a global scale". Cobalt also said it had started drilling the Cameia-3 well in the Cameia field in pre-salt offshore Block 21.

This year looks set to be critical for exploration and testing in Angola's pre-salt play, with up to 15 wells earmarked for drilling. It would not take much to surpass Nigeria, which, despite a crude production capacity of 2.5 million bpd, has seen its output drop below 2 million bpd for six consecutive months.

Luanda will be hoping for a cluster of pre-salt discoveries, allowing the medium- to long-term production picture in Angola to transform quickly, and the 2 million bpd milestone to come into view. Pre-salt production may have an impact in the longer term – with Cobalt saying recently that its Cameia project was intended to start up in 2017, the same year as Total's Kaombo – but reaching the planned target for 2015 is looking increasingly unlikely. ■

From AfrOil Week 19

Gabon's pre-salt prospects and the national interest

With the delivery of Gabon's long-overdue revised petroleum code promised for 2015, resource nationalism is already playing a part in shaping the country's policy

By Anne Edwards

- **Three bidders were ousted from the latest bid round**
- **Total's strong local links give it an advantage, despite a continuing tax row**
- **Early pre-salt disappointments are likely to be no barrier to broader prospects**

In December 2013, Gabonese Minister of Oil, Energy and Water Resources Etienne Ngoubou said the country's updated hydrocarbon regulations would not be published until 2015, breaking a promise to make the sector more transparent by the end of 2013. This followed Gabon's removal from the candidate list for the Extractive Industries Transparency Initiative (EITI), a global standard for natural resources revenue management, in February last year.

Work began on the code in 2011 to provide "a real framework" for the management and exploitation of the West African nation's resources.

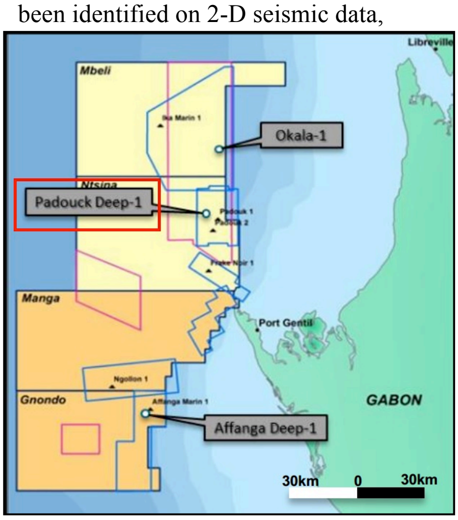
This includes the "valuation of undeveloped blocks, notably in the deep and very deep offshore" areas that were tipped to mirror Brazil's pre-salt resources. Until October of last year, the delay in drawing up the regulations was cited as a reason for postponing and cancelling licensing rounds. However, interest driven by Total's Diaman pre-salt gas discovery in the offshore Diaba block in August prompted an auction of 43 concessions.

A total of 13 blocks were awarded to 11 companies, with winners including Eni, ExxonMobil, Impact Oil and Gas, Marathon Oil, Ophir Energy, Perenco, Petronas and Repsol.

That offering was part of Gabon's ambitious plan to increase production to 500,000 barrels per day by bringing on line new offshore fields, hopes that are largely based on the country's pre-salt potential. Output from the former OPEC member peaked at around 370,000 barrels per day in 1997, dropping to 210,000 bpd in 2013. At the beginning of this month, Ngoubou told journalists at an industry event that he expected production to expand by at least 9% to 230,000-250,000 bpd.

There have been some mixed early exploration results from Gabon's pre-salt. In March, Ophir Energy announced results from its Padouck Deep-1 well in the Ntsina block offshore Gabon. The pre-salt well was disappointing, but the company said the failure was prospect-specific and did not reduce its enthusiasm for the broader play in the area. Ophir's next pre-salt target is the Okala prospect on the Mbeli block.

Harvest Natural Resources is expecting the results from the first 3-D coverage over the outboard area of the Dussafu licence, where pre-salt prospectivity has been identified on 2-D seismic data, during the second quarter of 2014.



Disinvited

In mid-May, Gabon said it had withdrawn the offshore licences it awarded to three companies in the October deepwater bid round, after they failed to meet necessary financial criteria. Two US-headquartered exploration and production companies – Cobalt International Energy and Noble Energy – and UK-headquartered Elenilto were dropped, according to a report published by Reuters on May 14. Elenilto was awarded the F-12 block in the round. Cobalt was part of the consortium working on Total's Diaman find.

Quoting Ngoubou, the news service said the firms had been turned down because they had failed to meet the "huge investment" criteria required for such work.

Ngoubou added that an approach had been made to Total, which, with fellow existing regional super-major producer Royal Dutch Shell, made an unsuccessful licence bid in 2013. "Total has been called in for discussions with the body in charge of negotiations," he was quoted as saying without providing any details and despite an ongoing row over tax.

Resource grab

In February, the Gabonese Ministry of Economy and Planning issued Total Gabon with a US$805 million tax assessment, including a notice of partial recovery following an audit of the years 2008 to 2010. ▸▸

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In its first-quarter 2014 results issued on May 15, Total Gabon said crude production had risen by 8% to 47,300 bpd, from the first quarter of 2013. The company said that the tax collection dispute had been suspended on March 5 and that discussions with the authorities were continuing.

In a statement issued on February 19, Total Gabon – which is 58.28% owned by Total, 25% by Gabon and the rest publicly held – said it considered the charge to be unfounded, having always followed Gabonese laws.

Meanwhile in January, Sinopec's Addax Petroleum resolved a US$1 billion dispute with Gabon concerning the transfer of the Obangue field to the state-owned company, signing three new production-sharing contracts (PSCs) for the Obangue, Tsiengui and Autour fields.

Gabon's activity bears all the hallmarks of resource nationalism. Risk analysts Maplecroft have defined the phenomenon as occurring when governments of countries that host large reserves of natural resources attempt to secure greater economic benefit from their exploitation, or to exert political gain, through restricting supplies. Such activity has operational and financial implications for companies operating in these countries.

In 2012, Gabon was ranked as a "high-risk" state – 42nd in Maplecroft's Resource Nationalism Index of 197 countries. This ranking was based on an evaluation of the stability, transparency and robustness of political and legal institutions, recent history of resource nationalism, including economic factors such as increasing debt and dependence on natural resources for revenue.

The Gabonese government must balance its need to extract the maximum possible value while not deterring investment – dollars must continue to flow into the country in order to sustain output. The country's pre-salt will attract bidders but the decision to cut Noble and Cobalt's involvement seems questionable, given both of those companies' substantial deepwater experience. Cobalt, in particular, has pioneered pre-salt exploration offshore Angola.

Gabon may have its reasons for dropping those three bidders and bumping up the government take, but neither of these actions looks likely to attract the fresh investment it needs from new companies. ■

From AfrOil Week 21

Tackling West Africa's piracy problems

The benefits of regional co-operation are being talked up to counter piracy in the Gulf of Guinea

By Aaron Ross

- **West African piracy appears to be falling, according to IMB numbers**
- **Under-reporting of attacks muddies the waters, though, and risks remain notable**

After a rapid increase in maritime attacks off the western coast of Africa, which led to the region overtaking Somalia as the epicentre of the continent's piracy in 2012, there appears to be some cause for tempered optimism in the oil-rich Gulf of Guinea. Attacks were down in 2013, and the trend appears to be holding in 2014.

In the first quarter of this year, the Gulf of Guinea, which stretches from Senegal to Angola, recorded 13 reported attacks, according to the International Maritime Bureau (IMB), down from 15 over the same period in 2013 and 19 in 2012. The decrease was most dramatic in Nigeria, which has been the hub of regional piracy, where first-quarter attacks fell from 11 in 2013 to six in 2014.

Meanwhile, West African governments have at last moved towards confronting the problem. In an April meeting in Yaounde, Cameroon, senior military officials from the Economic Community of West African States (ECOWAS), the Economic Community of Central African States (ECCAS) and the Gulf of Guinea Commission (GGC) agreed to create a centre in Cameroon to co-ordinate a regional response to the regional problem.

These are, though, small steps and are unlikely to turn the tide decisively against a threat that has swelled beyond all expectation in recent years. Though West African piracy has its origins in local grievances about oil revenue distribution and environmental destruction in the Niger Delta in the 1990s, large-scale piracy has only lately been recognised as a major problem.

In 2005, the International Monetary Fund (IMF) called the Gulf of Guinea "free" of the risk of pirate attacks. Since then, though, various armed gangs originating in the Niger Delta have expanded the scale and sophistication of their assaults on international shipping, especially as oil finds off the West African coast bring more and more traffic to local ports. Pirate attacks in the region are particularly violent, with assailants deploying heavy weaponry in snatch-and-grab operations targeting the ships' cargoes. ▸▸

Africa

One of the most disconcerting phenomena in recent years has been the increasing range of the pirates. In January, a gang attacked a tanker anchored in Luanda, Angola, before steering it some 1,200 nautical miles (2,222 km) to the Nigerian coast. In the process, they made off with large quantities of fuel. The incident marked the southernmost extension of Nigerian piracy.

Real risks

The assistant director of the IMB, Cyrus Mody, has said such attacks demonstrate the sustained nature of the threat in spite of what may appear to be encouraging statistics.

"There's still a lot of activity in the region. Ships tend to be still quite vulnerable going in," he said. "There is not a clear picture on exactly what is happening in the region because it is quite difficult to estimate the true risk. But the general feeling is that the risk in the region is still quite real." The IMB has estimated previously that perhaps only one third of the attacks go reported.

Mody, though, was encouraged by the early signs of regional co-operation. For years, many countries along the coast refused even to recognise the existence of a problem, rejecting initiatives aimed at greater intelligence sharing and joint operations.

"The first step is the acknowledgment that this crime exists and that it is a crime that needs to be addressed," he said. "A lot of this crime is obviously very Nigeria-focused. However, having regional co-operation can help and assist in the process of, say, a hot pursuit."

But the region remains far from reaching even that level of co-ordination. Sovereignty concerns have stood in the way of agreements to permit the pursuit of pirate vessels across international maritime boundaries.

Most of the coastal states have very limited naval capacities but are wary of ceding authority to regional powers, such as Nigeria, to operate in their waters. A joint naval operation between Nigeria and neighbour Benin in 2011 and some US and European Union-led training operations are notable exceptions.

A Western naval presence, similar to the one that has proved so successful in helping suppress piracy off the coast of Somalia, has been widely regarded as a non-starter. Furthermore, although the April meeting has been welcomed as a positive step, it mostly reiterated pledges made at a June 2013 summit in Yaounde of regional heads of state.

Most of the progress seen in West Africa, Alan Lambert, a former US Navy commander now with Salamanca Group investment bank, said is explained by measures taken by foreign companies and governments. Shipping companies have widely adopted a series of safety measures to make their vessels less susceptible to attack. Increasingly, they are carrying armed guards in international waters, swapping them over for local guards in territorial waters. In the absence of true inter-governmental co-operation, shippers are exchanging intelligence.

"[These measures] suppress the problem," argues Lambert. "It doesn't mean it goes away. If anything, with what's going on in Nigeria, it's becoming worse in the region."

The risks of operating in the region also entail tremendous costs. In the Oceans Beyond Piracy report, from 2012, the One Earth Future Foundation estimated the annual amount spent on insurance alone for "war risk" and "kidnapping and ransom" in the Gulf of Guinea was as high as US$427 million. The US' Africa Command (AFRICOM) has pegged the annual cost of maritime crime in West Africa at about US$2 billion.

Supply security

Some companies have abandoned the region entirely. Companies from Texas see Nigeria as unattractive, Lambert said. "People don't want to mess with it."

Most shippers and operators seem, though, to believe the risk is well worth the reward.

The Gulf of Guinea countries supply some 40% of Europe's oil and are becoming a new market to receive US petroleum product exports. Recent finds offshore Ghana and Cote d'Ivoire have only brought more attention to the region.

"The risk hasn't reached such a degree that would have such an impact that cargo vessels actually move away from that region," says Mody.

According to the US Department of Energy (DoE), oil production in the Gulf of Guinea is expected to increase by about one third by 2030 over 2010 levels, to more than 16 million barrels per day. Angola and Nigeria are two of the world's top 10 oil producers, with Angola being China's second largest crude oil supplier.

That convergence of Western and Chinese interest in the region should lead to ever more elaborate strategies for dealing with the region's pirates, whether or not local governments get their acts together.

While discussions continue about a regional co-ordination centre in Cameroon, oil and gas companies are said to be pouring money into a separate centre run by the Ghana Maritime Authority, with the support of International Maritime Organisation (IMO), a United Nations agency. ■

From AfrOil Week 23

More progress on methane hydrates in Japan, US

Both Japan and the US have announced new research into methane hydrate development, though commercial production of the resource is still years away

By Charles Coe

- **Japan leads the way towards commercial methane hydrate production, though it still has a lot of work to do**
- **Scientists are researching how methane hydrates emit gas, while the country is surveying offshore deposits**
- **The US government is soliciting interest in new methane hydrate research projects on Alaska's North Slope**

Japan and the US are planning new research projects designed to discover more about the potential of methane hydrates. The resource – also known as fire ice – consists of methane trapped in ice-like structures that exist beneath permafrost and along the edge of continental shelves, at low temperatures and high pressure.

According to a recent report in Japan's Asahi Shimbun newspaper, methane hydrate units can release roughly 170 times more gas than their own volume, leading the resource to be considered an abundant source of future energy.

Japan's progress

Japan, which imports practically all of its energy, is keen to examine methane hydrates as a potential source of domestic supply. However, extensive further research is needed before large-scale methane hydrate production can begin.

The Japanese government announced in mid-April that it had started a two-month survey to chart deposits in four areas in the Sea of Japan and in one area offshore Hokkaido in the Pacific Ocean. The study is being carried out by Japan's Natural Resources and Energy Agency, which is now in the second year of a three-year research programme.

Last year the agency confirmed the existence of methane hydrate deposits in an area of the Sea of Japan offshore Niigata Prefecture and the Noto Peninsula. The new survey is anticipated to provide a better idea of the extent of shallow methane hydrate resources within the research area.

The Natural Resources and Energy Agency plans to carry out a drilling survey in June and July that will take samples of geological layers that include methane hydrates, Kyodo News International reported last week.

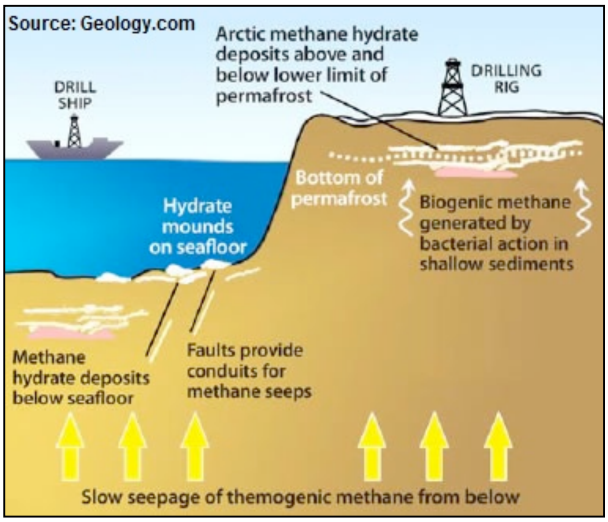
Kyodo said methane hydrates existed in both of their forms offshore Japan – with one type located near the surface of the seabed, and the second hundreds of metres below the seabed. The shallower deposits have been found in the Sea of Japan, while the deeper deposits have been discovered in the Pacific.

The agency, which operates under the Ministry of Economy, Trade and Industry (METI), intends to conduct another survey next year involving technological research on how to produce gas from methane hydrates. Japan is aiming to start offshore production by 2018-19. An initial production test was successfully carried out in the Nankai Trough offshore Japan last year.

In another step forward, a research team at Okayama University announced last week that it had discovered the process whereby methane hydrates emit gas, the Asahi Shimbun reported. The newspaper added that the discovery could lead to the development of technology to produce gas from methane hydrates.

Tests were carried out at the university, using a supercomputer to simulate changes that methane hydrates undergo when they are removed from their natural environment and exposed to normal atmospheric pressure. The process tracked the movements and reactions of crystallised methane hydrate molecules, simulating natural attraction and repulsion that occurs at the atomic level during the transition, the Asahi Shimbun reported. The results, according to the newspaper, showed that the rate of breakdown – slow at first – sped up over time. The researchers found that the speed abruptly increased once around 40 methane molecules had bonded together to make a microscopic gas bubble. It was also discovered that certain temperatures prolong the process. ■

From AsianOil Week 16



Indonesia grapples with energy balance

Falling production, rising domestic demand and stunted investor confidence are throttling the country's energy export options

By Sam Imphet

Overview

Indonesia is a major producer of crude oil and natural gas, but production of oil is in decline owing to a lack of upstream investment. The country was the world's fourth largest exporter of LNG in 2013, slipping one place from the year before as a result of growing domestic demand.

Despite more than 3 billion barrels of proven crude reserves, production has fallen since the mid-1990s, when it peaked at an average 1.6 million barrels per day. In 2013, crude and condensate production stood at 823,000 bpd.

Indonesia ended its membership of OPEC, of which it had been a member for more than 40 years, in 2008 after it became a net crude oil importer. In 2013, imports grew to average about 500,000 bpd.

However, exports remain an important part of the wider economy, with oil and gas amounting to 20% of all outward commodity trade in 2013 while making up nearly 25% of total state revenue.

Proven gas reserves at the beginning of 2014 were officially listed at 2.9 trillion cubic metres, which is 110 billion cubic metres lower than figures given by the Ministry of Energy in 2013, according to the US Energy Information Administration (EIA).

Regulatory environment

Since the constitutional court dissolved upstream regulator BPMigas at end of 2012, the Ministry of Energy and Mineral Resources became responsible for signing production-sharing contracts (PSCs). BPMigas was replaced by a temporary agency, SKK Migas, which manages PSCs and makes sure domestic energy needs are met.

The court disbanded BPMigas following a petition by political parties claiming the agency was not doing enough to cater for Indonesian oil and gas requirements. Observers said this was because it did not have the requisite authority to do so. These current regulatory arrangements are viewed by the government as temporary, but "temporary" in Indonesian politics can mean it will take a long time before a permanent solution is settled upon.

Indonesia's president has the authority to set new regulatory policies and the parliament has power to assess and approve or reject them.

The Indonesian Petroleum Association, representing oil and gas firms, has said the PSC system forces the developer to shoulder too much risk, as it makes the investor fully liable for costs until production begins. However, nearly 50% of the 750 oil and gas exploration wells drilled between 2002 and 2012 were dry and abandoned, according to SKK Migas figures.

At present, PSC operators can take 15% of oil and 30% of gas production, while the rest goes to the state. In addition, a domestic market obligation means operators have to sell up to 25% of their production on the domestic market to help satisfy local demand.

Political risk

Parliamentary and presidential elections are both being held in 2014. The year-long run-up has seen rising support for resource nationalism which, coupled with a lack of decision making, has impeded foreign investment. One victim of the indecisions has been the Mahakam offshore gas block operated by France's Total, which has been waiting to hear if its contract will be extended beyond 2017 before committing large-scale funding.

Parliamentary elections were held in April, with official results due in May. However, with widespread reports of 10 political parties winning seats a weak coalition government is anticipated, the Wall Street Journal has said. Presidential elections are to take place in July, as President Susilo Bambang Yudhoyono is retiring. Corruption is a serious problem. Indonesia ranks 114 out of 177 countries assessed in Transparency International's 2013 Corruption Index. Greater autonomy in regional government has led to conflicts over land access rights and production sharing on contracts awarded by the central government.

"The dissolution of BPMigas, which had enjoyed a certain degree of autonomy in its day-to-day operations, and its replacement by a unit under direct control of the Energy and Mineral Resources Ministry, suggests that the issuance and administration of PSCs could become a less pragmatic and more political affair," said Paris-based Global Business Guide in its 2014 assessment of Indonesia.

"While there was no visible shift in policies following the handover of control to SKK Migas, the situation fuelled concerns that the central government could become more susceptible to parliamentary lobbying and resource nationalism, which in turn could affect the issuance or extension of PSCs to foreign contractors." ▸▸

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Exploration

Three main areas of exploration are the Kutei Basin in Kalimantan in the west, the East Java Basin in the middle region and the Arafura and Bonaparte basins in the east. There is also an increase in exploratory drilling in the Natuna Basin which includes the Riau Islands in the southwest corner of the South China Sea west of peninsular Malaysia.

The 2013 bidding round offered 18 oil and gas blocks, mainly in under-explored eastern areas of the archipelago. Several deepwater prospects are pending in eastern Indonesia, where exploration data is still limited.

"Oil and gas reserves will most likely be on a downward trend in the coming decade," said Business Monitor International in its 2014 assessment of Indonesia. "Despite this outlook, Indonesia is a country where much below-ground potential continues to exist. If the country relaxes its nationalist stance on resources, there is considerable upside potential for both oil and gas reserves [through] greater drilling of its unexplored deepwater areas and its unconventional resources [of] coal-bed methane and shale gas."

NewsBase Research (NBR) also predicts an ongoing decline in production on the back of investor wariness and bureaucratic delays to upstream projects. Crude and condensate production is forecast to fall below 650,000 bpd by 2020.

Principle basins

Indonesia has 60 basins according to the energy ministry, but only half have been properly explored. Most of these lie in the western half of the archipelago and 14 are producing oil or gas. The eastern half of the country is under-explored.

The biggest operational plays are the South Sumatra Basin, which is home to the Minas and Duri oilfields, and the Central Sumatra Basin. The East Java Basin has also begun yielding oil.

The Barito and Kutei Basins mostly onshore in East Kalimantan are a source of gas, as well the East Natuna Basin offshore in the South China Sea.

In eastern Indonesia the Arafura Basin in Arafura Sea has been identified as a major gas prospect. This basin crosses the sea border between Indonesia and Australia.

Future prospects

Deepwater projects are under way in the Kutei Basin in western Indonesia and West Papua and the Bonaparte Basin of the Arafura Sea in the east.

The US' Chevron operates five of the eight deepwater fields at present, with development under way in the Kutei Basin along the east coast of Kalimantan. Estimated production prospects from 2015 are 11.3 bcm per year of gas and 55,000 bpd of oil.

The ExxonMobil-operated onshore Cepu block holds estimated reserves of 600 million barrels of oil and 48 bcm of gas. There have been delays in moving to maximum production owing to protracted negotiations between the investors and Pertamina.

SKK Migas has said Cepu will reach full capacity of 165,000 bpd by the first quarter of 2015. A longer-term prospect is the Natuna field in the Riau Islands of the South China Sea midway between Borneo and peninsular Malaysia. Preliminary exploration by a consortium including Pertamina, ExxonMobil, Total and Thailand's PTT Exploration and Production (PTTEP) has estimated gas reserves of 1.3 tcm. Production is not expected for another 10 years, according to the EIA. The Masela block in the Arafura Sea is estimated to hold more than 500 bcm of gas as well as oil. Japan's Inpex and Royal Dutch Shell are developing a floating LNG (FLNG) plant attached the block's Abadi field. Production is not due before 2018. In West Papua Province on the eastern edge of Indonesia's archipelago, meanwhile, BP is expanding its Tangguh LNG gasification terminal in Bintuni Bay.

"Many Indonesian basins have yet to be extensively explored for oil and gas deposits, making for potentially large additional reserves," said the Global Business Guide report for 2014. "It is believed that most of the discoverable hydrocarbon deposits lie in less explored eastern regions of the country. Finding and exploiting them will require heavy investment and a lot of deep-sea drilling."

Production

The energy ministry's official production target for 2014 is 870,000 bpd. However, there have been reports that this is likely to fall short, as in previous years, and might only reach 820,000 bpd.

The two largest and also oldest producing oilfields are in South Sumatra Basin. The Duri field delivers 140,000 bpd and the Minas field 190,000 bpd, according to a study by Fact Global Energy (FGE). The two fields are operated by Chevron, which has said it is using enhanced oil recovery (EOR) technology to boost declining production. The US firm is using steam injection techniques in the Duri. The East Java Basin is producing more than 40,000 bpd from a venture between Pertamina and PetroChina, which have said they hope to beef up output by 100,000 bpd before 2015. Cepu, in the onshore Northeast Java Basin, consists of three fields – Banyu Urip, Jambaran and Cendana. The development is led by ExxonMobil alongside Pertamina and several local firms. At the end of 2013, only Banu Urip field was producing oil, at 26,000 bpd. The biggest productive gas fields are in the South Sumatra and Kutei Basins. Mahakam in the Kutei Basin is producing about 20% of Indonesia's gas. Ongoing contract uncertainty for France's Total, however, is holding back new investment to maintain and expand production. Mahakam produced about 18.25 bcm in 2013, but Total said this might fall to 17.12 bcm in 2014.

Several blocks in the Natuna Basin in the South China Sea have started producing gas, with Pertamina in partnership with ConocoPhillips and separately PetroChina.

"Much of the reserves remaining under Pertamina's control require EOR techniques, currently beyond the technological capacity of domestic firms, or the development of basic infrastructure in remote areas of the country, mainly in the east," said a March 2014 report by the EIA. ▸▸

Trade balance

Declining oil production at a time of increasing demand at home is raising Indonesia's volumes of crude oil and fuel imports.

In 2013, the country imported an average of 506,000 bpd of crude oil, about 25% of this from Saudi Arabia. Other main suppliers were Azerbaijan and Nigeria, both delivering 15% of the total, while neighbouring Malaysia accounted for 4%.

Insufficient refining capacity has also led to an increase in fuel imports. In 2013, the volume climbed to 466,000 bpd compared with 435,000 bpd in 2012, said FGE. Gasoline accounted for more than 60% of these imports.

Indonesia also exports crude and fuel, mainly to regional markets such as Japan. In 2013, the combined export volume was 455,000 bpd.

Large domestic fuel subsidies, which cost the state US$20 billion in 2012, have been substantially reduced and since the middle of 2013 retail gasoline prices have gone up by 44% and diesel by 22%.

Indonesia is a major LNG exporter, but volumes have fallen in recent years. In 2013, exports totalled 23.1 bcm compared with 24.6 bcm in 2012 and were mainly sent under long-term contracts to South Korea, Taiwan, China and Japan. Indonesia now trails Qatar, Australia and Malaysia in terms of global exports.

Downstream

Eight refineries, all operated by Pertamina, have a combined capacity of almost 1.1 million bpd and domestic demand in 2013 was 1.6 million bpd.

No new refineries have been built since 1994 and recent plans between Pertamina and several major foreign oil firms to build at least two 300,000 bpd refineries have failed to reach development agreement.

These include: the 340,000 bpd Cilacap plant and 4,000 bpd Cepu refinery in Central Java; the 260,000 bpd Balikpapan facility in East Kalimantan; the 125,000 bpd Bolongan refinery in West Java; the 165,000 bpd Dumai and 47,000 bpd Sungai refineries in central Sumatra; the 135,000 bpd Musi-Plaju refinery in southern Sumatra and the 5,000 bpd Pangalan unit in northern Sumatra.

Logistics and fuel

Indonesia has very few oil pipelines for inter-province distribution, which is mainly done by sea tanker between islands and by road. The state-owned gas firm Perusahaan Gas Negara (PGN) controls gas distribution through more than 5,000 km of pipelines, although most of these are confined to western Indonesia in Java and Sumatra.

Industrial consumption has fallen, but residential use has risen. LPG consumption, meanwhile, is growing as a result of state subsidies and was more than 130,000 bpd in 2013.

While most gas exports take the form of LNG, 10 bcm per year is sold to neighbouring markets in Singapore and Malaysia by pipeline, according to BP's Statistical Review of World Energy 2013. About 7.9 bcm goes to Singapore under long-term contracts that expire in 2020. SKK Migas said these contracts would not be renewed.

Pertamina still dominates the retail fuels market even though the sector has been deregulated for a number of years. The state firm controls about 5,000 fuel stations, operated as franchises by individuals or small private firms.

Shell Indonesia, meanwhile, has 57 stations while Total has 13, mostly in the Jakarta region. In 2013, Malaysia's Petronas decided to quit fuel retailing in Indonesia where it operated 19 stations, and most of these have been bought by Pertamina. ■

From AsianOil Week 17

Bangladeshi bureaucracy draws foreign criticism

A group of IOC delegates has complained to the government over access restrictions to new onshore blocks as well as price restrictions on domestic gas production

By Sam Imphet

Bangladesh's efforts to win hydrocarbon investment have finally prompted a response from the international oil companies (IOCs) it has been seeking to woo – though not in the form Dhaka had hoped. Foreign investors have complained to the government over access restrictions to new onshore blocks, while also calling for a higher price to be applied to domestic natural gas production. A delegation from eight firms, including US super-majors Chevron and ConocoPhillips and Australia's Santos, presented their complaints through the Foreign Investors' Chamber of Commerce and Industry at a meeting with Bangladeshi Power and Energy Minister Nasrul Hamid earlier this month, reports have revealed. "They told him inadequate offshore fiscal terms and restrictive onshore access had limited their investment in the country," Platts reported, quoting a ministry source. ▸▸

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"They also asked for higher gas prices for producers, permission to market their share of supply and the flexibility to modify contract terms based on block location."

Energy needs

"The IOCs told the energy minister that inadequate offshore fiscal terms and restrictive onshore access had limited their investment in the country"

Bangladesh, which depends on domestic gas production to feed the majority of its power generation needs, has for many years suffered from severe power shortages owing to a lack of feedstock.

Given that industries, such as textiles, frequently experience black-outs because of inadequate power supplies, the government is desperately looking for energy supplies and is pushing to open an LNG import terminal.

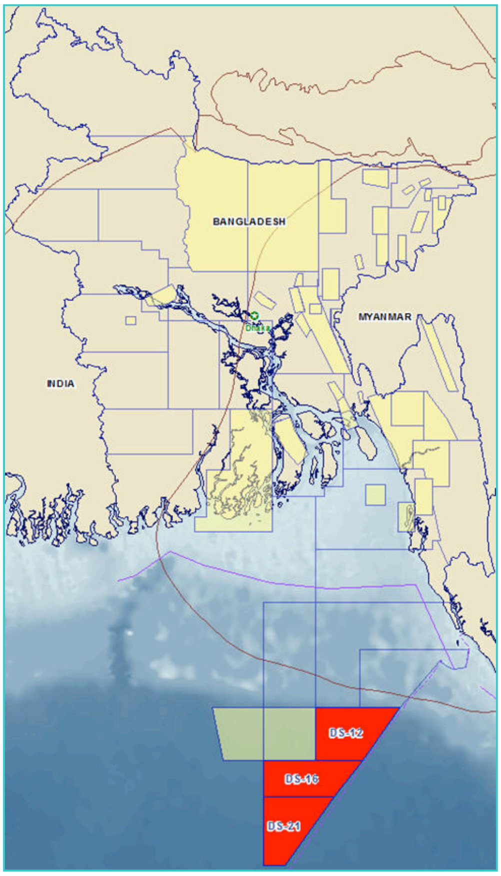
At the same time, however, access to much of the country's potentially productive onshore blocks has been restricted to state-owned Bangladesh Petroleum Exploration & Production (BAPEX), even though it has limited development capability.

Bangladesh has not offered any onshore oil and gas blocks for licensing since 1997, Platts quoted BAPEX's state-owned parent, Petrobangla, as saying.

While BAPEX recently announced the discovery 85-141 billion cubic metres of new gas reserves, it has been "plagued with constraints to funding, and human and technical resources," the IOCs' delegation reportedly told the energy minister.

The firms said they could help develop the new reserves more quickly, local news portal EnergyBangla reported. "The representatives of foreign firms said they have been facing many obstacles in implementing projects because of bureaucratic bottlenecks and urged the state minister to address the issue."

Foreign operators account for more than 50% of Bangladesh's domestic gas production, according to Petrobangla figures, and most of it is delivered by Chevron from three fields in the country's north.



Limited appeal

Bangladesh has had only very limited success in securing contracts for 12 offshore blocks first offered in 2012, and then re-tendered in October 2013 after supposedly offering sweeteners to make the licences more attractive.

The delays and confusion surrounding bids and final agreements involving these blocks illustrate the slow process in Bangladesh's state-controlled energy sector despite the urgent need for more production to meet domestic demand.

In February, local media reported that ConocoPhillips had teamed up with Norway's Statoil to make a joint bid for three deepwater blocks, but this has never been confirmed by either Statoil or ConocoPhillips.

India's ONGC Videsh Ltd (OVL), meanwhile, bid for two of the blocks but it remains unclear if production-sharing contracts (PSCs) have been finalised.

In April, ConocoPhillips declined to sign a PSC for shallow-water Block SS-07 in the Bay of Bengal, according to the Dhaka Financial Express.

The US firm has said nothing publicly since bidding for the block, but the daily said it had refrained from signing for two reasons: unfavourable financial terms and that it considered the block to be a deepwater prospect, requiring greater funding.

"This is for the first time that an [IOC] has refused to sign a PSC after being selected finally for a block," the paper said.

Additional complaints

The foreign delegation complained that existing PSCs offered by Bangladesh did "not reflect current risks or exploration and development costs", Platts said. It also criticised the slow approvals process that has held back exploration work stipulated by the government.

The delegation included Chevron Bangladesh's president, Geoffrey Strong, ConocoPhillips' managing director in Bangladesh, Tom Earley, Santos' country president, Andrew de Garis, and Kris Energy's general manager, Edwin Bowles, said EnergyBangla.

"[It's the] same old story with Bangladesh, where a combination of tight restrictions and lead-weighted bureaucracy has held back much potential exploration and production," independent energy analyst Collin Reynolds told *NewsBase*. "The only surprising thing in the latest developments is the public way in which the leading operators in Bangladesh have voiced their criticism."

Local media reported that state authorities were indeed surprised by the delegation's complaints but, given past examples, it seems too much to hope for that it will trigger a rapid response. Instead, further delays are likely as various government agencies debate endlessly over all manner of solutions and outcomes. ■

From AsianOil Week 20

China's gamble in the South China Sea

China's decision to send a drilling rig into contested South China Sea waters defies economic sense and instead suggests the move is a warning to Vietnam

By Sam Wright

- **The block is thought to have less than 1 million boe of 2P reserves**
- **China may want the rig to stand as a warning over mounting Vietnamese drilling activities**
- **The cost of the exercise could cost China hundreds of millions of dollars**

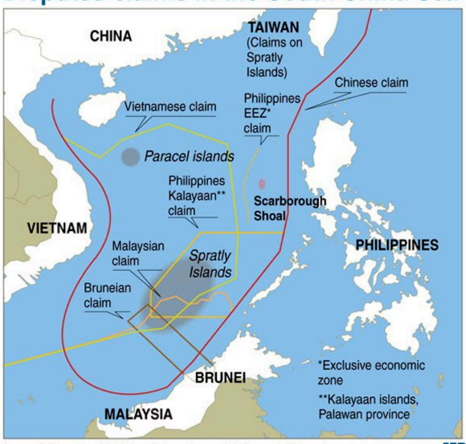
On May 1, CNOOC Ltd moved a US$1 billion drilling rig into waters in the South China Sea also claimed by Vietnam. Since then, the initial stand-off has escalated with violent protests in the latter causing Beijing to evacuate some of its citizens there, even as the reserve potential of the block itself has also been brought into question.

The South China Sea has long been a potential flashpoint. Given that China, the Philippines, Taiwan, Vietnam, Malaysia and Brunei all assert their ownership of various overlapping sections of a region that contains some of the world's busiest shipping routes and sizable estimated reserves of oil and gas, this should not be that surprising.

Yet the speed of the escalation of this latest conflict has still come as something of a shock. In 1974, China and Vietnam fought the Battle of the Paracel Islands, which ended in a Chinese victory. While this has been followed by years of barbed comments and antagonism over the ownership of the islands, known as Xisha in Vietnam, progress looked to have finally been made in recent months.

In October 2013, Chinese Premier Li Keqiang visited Hanoi as part of a three-day trip aimed at boosting bilateral ties. The talks appeared to have gone well, with both parties talking of the potential benefits of increased trade. This went as far as Li and his counterpart, Truong Tan Sang, openly stating that ways to develop jointly oil and gas fields in the South China Sea would be discussed. All this, however, has now changed.

Disputed claims in the South China Sea



Source: D.Rosenberg/MiddleburyCollege/HarvardAsiaQuarterly/Phil gov't AFP

Shifting tides

At first, it seems that Vietnam assumed the HD-981 rig was passing through Block 143 – which lies around 120 nautical miles (222 km) east of Vietnam's Ly Son Island and 180 nautical miles (333 km) from China's Hainan Island – on its way to drill at another location.

As soon as it became apparent that the rig intended to stay put, Hanoi sent vessels to try to stop its deployment. This move had been pre-empted by Beijing, which ensured that HD-981 was accompanied by a fleet of around 80 ships, including seven military vessels. The Chinese and Vietnamese boats have since been involved in numerous collisions, with each blaming responsibility on the other.

Soon after, the protests in Vietnam began. Initially, these were small-scale demonstrations sanctioned by the government in Hanoi. For a country that traditionally cracks down hard on street-level activism, this was seen as a sign of its irritation with Beijing. Yet things quickly escalated beyond the government's expectations.

Last week, a wave of attacks on Chinese-owned businesses and factories in Vietnam's industrial parks took place. As buildings were torched, at least 40 Chinese nationals are thought to have been killed and scores more injured.

Many Taiwanese companies, which the protesters believed were owned by mainland Chinese, were also targeted.

In response Beijing sent four ships to evacuate Chinese citizens from the country. So far, more than 3,000 have now left Vietnam with government assistance. Many more have found their own way home.

Vietnam, meanwhile, angered by the perceived damage the riots has done to its reputation as a safe place for foreign manufacturers and tourists, began blocking protests and arresting demonstrators.

Standing still

As it stands, the situation remains at a deadlock. The rig is still in place, with Beijing encircling it with a 10-km protection zone to ward off scores of Vietnamese vessels.

So far it remains unclear if drilling has begun. The costs of maintaining this status quo have been estimated at hundreds of thousands of dollars per day. ▸▸

With this in mind, the economics of China's move do not seem to stack up. Drilling in the South China Sea is already an expensive business – largely unexplored, a lack of quality data and the challenging conditions of the area mean that a single well can cost up to US$1 billion. CNOOC Ltd has frequently courted foreign partners for its projects in the region but interest has so far been sparse.

While there is undoubtedly huge potential in the South China Sea, Beijing's decision to drill Block 143 initially looks to be a puzzling one. According to the US Energy Information Administration (EIA), the area has less than 1 million barrels of oil equivalent (boe) in proven and probable reserves. Putting this into context, China consumed roughly 9.71 million barrels per day of oil in April.

Yet there could be much more to be gained. Speaking to NBC News, one Southeast Asia commentator with the Centre for Strategic and International Studies (CSIS), Ernest Bower, described the deployment as "less about practically developing that specific block, and more about the Chinese sending a calculated and pretty aggressive warning to the Vietnamese that they aren't OK with the Vietnamese developing there".

While Block 143 is seen as uninspiring, Vietnam is actively drilling in acreage nearby.

This includes a discovery made by ExxonMobil that state-owned Petrovietnam has said could hold 6-8 trillion cubic feet (169.92-226.56 billion cubic metres) of natural gas – one of the country's largest ever finds.

Calling the shots

As well as deterring Vietnam, Beijing is also sending a clear message to its other neighbours in the region.

In 2013, tensions flared between China and the Philippines over the former's activity in the South China Sea, which at the time prompted fears of a military conflict. Until recently, this looked to have eased, with the two countries – as with China and Vietnam in October 2013 – agreeing to discuss joint exploration projects.

In April, however, the US and the Philippines signed a 10-year military co-operation agreement – a deal that was widely seen as a move by Washington to offset Chinese influence in the South China Sea.

Publicly, this has been denied by the US, with President Barack Obama saying at the time that the goal was not to "counter" or "contain" China.

Instead, he said the two countries intended to "make sure international rules and norms are respected and that includes in the area of international disputes".

Previously, the US has backed Manila in its sovereignty claims ahead of China, as well as issuing public declarations of support for Japan and its administration of the Senkaku Islands.

Meanwhile, China has a clear path to saving face if its plan – whatever that may be – does not work out as expected. The rig is set to leave the block on August 15 after "completing its operations". Until then, the stalemate will continue unless something gives. ■

From ChinaOil Week 20

Developing win-win partnerships

BP and Maersk Drilling are designing a new ultra-deepwater rig that could reduce costs for the former while offering long-term options for the latter

By Amrit Sidhu

- **The rig is being designed to handle ultra-high pressure and temperature wells**
- **More than 350 design changes have already been made implemented based on client feedback**
- **Cost management is increasingly the focus of the offshore industry**

Maersk Drilling and BP are designing a new ultra-deepwater rig capable of handling up to 20,000 psi of pressure during drilling.

The new rig is being designed with reservoirs containing 10-20 billion barrels of oil reserves in mind.

In an interview with *NewsBase*, Maersk Drilling Singapore's managing director, Jan Holms, explained that the collaboration was a major step forward in the industry, with drilling contractors taking on more responsibilities in managing more efficient and productive rig operations.

"The collaboration gives us a very good understanding of what our clients require of a drilling rig from a contractor," said Holm, adding that more than 350 design changes had already been made based on client feedback for improved rig designs and operating efficiencies.

Tech savvy

BP is expected to make a final investment decision (FID) in 2015 on new US Gulf of Mexico reserves, after which a decision will be taken on building the new rig.

"It would be a big investment in building a rig to manage drilling of ultra-high pressure and ultra-high temperature wells," said Holm.

He added that such collaborations were leading the industry to drill in "[as] yet unknown and definitely very challenging environments". ▸▸

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Maersk's new rig is anticipated to give the company a competitive edge in a market where many of the latest high-tech ultra-deepwater rigs are designed and equipped to manage well pressures of up to 15,000 psi.

Cost management, Holm said, was "a challenge for any oil company seeking new reserves". He highlighted that drilling costs were on the rise, narrowing the oil producers' margins in the process. This has prompted developers, looking to ensure that future deepwater capital expenditure remains viable at oil priced around the US$100 per barrel level, to call on drilling contractors to deliver more efficient rig operations.

Holm said his firm was already in the lead, working with oil companies to provide rigs where time management was the top priority, from rig deployment through to the completion of the drilling campaign.

Time is money

"Our target is to reduce the time taken to drill a well," he said, adding that Maersk was looking to cut down on unproductive time, which can average 20-30% per drilling campaign, in some cases.

"We have clients asking us to take on more and more responsibilities in operating the rigs. We have full control on the rig operations and we have started offering integrated services – managing [the] drilling material supply chain for wells," he said. "We have developed a full concept of work with oil companies to optimise drill time. This has increased our drilling efficiency to 97% from about 92% previously."

He said the Maersk was looking to reduce the average 90-day drilling campaign by at least 10% through more efficient scheduling. While this could reduce charter contracts by as much as 10 days, he said, oil companies rewarded contractors by offering bonuses. He explained that collaborations between oil producers and drillers could reduce drilling costs while offering long-term options for contractors to deploy efficient rigs. This strategy of working closely with its clients will also help Maersk improve on its rig designs, given it is in the middle of building and taking delivery of eight new vessels.

Of rigs and men

The company has already received two drillships this year, which will be deployed in the Gulf of Mexico's ultra-deepwaters, as well as a single jack-up.

Maersk is working on new contracts, mostly long-term charters, for two more drillships. In total, it has committed US$2.6 billion for four drillships and another US$2.6 billion for four jack-ups. These drillships are designed to operate in up to 3,600 metres of water and drill wells to a depth of 40,000 feet (12,190 metres), with each unit designed to house up to 230 people. Holm said the company was investing heavily in collaborations with its clients because the drilling market was "very competitive, with day rates or chartering rates being challenged by some of the older rigs still drilling at lower rates".

He explained that some older rigs, around 20-30 years old, were still going to win contracts, especially in price-conscious markets, where oil companies are trying to manage their exploration costs. Adding to the challenge of remaining competitive is finding enough skilled workers to man Maersk's rigs. "Everyone is fighting for talent," Holm pointed out. "We have to train a pool of 3,000 skilled men for our planned 14-rig investment." He added that a training scheme was started in Denmark in 2011 and that Maersk had trained 841 of the crew of 1,450 needed for its eight rigs, of which six will be delivered this year, one in 2015 and one in 2016. "We have developed accelerated programmes for training rig managers among others. We need to hire people and train them, train them and train them," he stressed, before adding: "But training manpower is equally challenging."

With costs a serious concern for offshore prospectors, such industry collaborations are only likely to grow in number as oil companies and contractors look to develop win-win partnerships. ■

From AsianOil Week 24

Europe

Expensive exploration challenges

Increasing costs are squeezing exploration in Europe and diminishing discovery numbers

By Nnamdi Anyadike

Rising costs continue to thwart oil and gas exploration in Europe, delegates were told at the Global Hotspots conference in London last week.

Addressing the event, David Bamford of Petromall, a consultancy, said cash-strapped European companies were struggling to deal with soaring costs, which had forced many to look elsewhere in the world for more economical targets. "Exponential drilling costs are killing exploration, especially in deepwater," he said. Bamford noted that exploration results over the past 18-24 months had been especially poor. "There has been disappointment all over northwest Europe, including the North Sea, the Barents Sea and onshore." ▸▸

Europe

"Explorers should be deeply troubled by recent events, namely the general lack of success, especially in frontier plays, and the evident lack of new ideas."

North Sea

The North Sea in particular has struggled in terms of new exploration. For Malcolm Webb, the CEO of Oil & Gas UK, the problem is a perennial one. "We are just not drilling enough wells in UK offshore waters and those that we are drilling are not finding enough oil and gas. This worrying trend has been growing for some time. It started in 2011 with a 50% drop in the number of exploration wells drilled, [and] has since failed to recover," he said recently.

Webb reinforced Bamford's view that the industry in Europe was facing a crisis that required immediate action. "Our members tell us that drilling rig availability and the ability of smaller companies to secure equity capital are major hurdles. In any event, it is clear that we now face a crisis which demands urgent concerted action … if we are to maximise economic recovery of our offshore oil and gas resource and sustain future production."

The Oil & Gas UK chief said the situation was a strange one, given the record amounts of investment in offshore developments. "The paradox is that the UK continues to record annual levels of capital investment at over GBP13 billion [US$21.6 billion] … Meanwhile, production from existing fields has fallen significantly and the total number of exploration wells has dropped to just 15 in 2013, according to data just published by DECC."

For Webb, it is a problem with long-term exploration planning. "We are simply not putting enough reserves into the hopper for future development," he said. "Unless we do something about exploration now, we face a risk of a collapse in capital spend in a few years' time and hence lower future production."

A new report from Deloitte suggests drilling and deal activity on the UK Continental Shelf (UKCS) will remain at "a steady low" for at least the next 12 months. The report said a total of 12 exploration and appraisal wells were drilled on the UKCS in the first quarter of 2014, a year-on-year decrease of one well. The report notes there were also fewer deals completed than in the same period last year, with ten reported in the first quarter compared with 19 during the same three-month period a year ago. This is eight deals fewer than in the fourth quarter of 2013.

Graham Sadler, managing director of Deloitte's PSG, said the drop in deals could be because of a gap in price expectations between vendors and buyers, and explained that significant challenges remained in the region. He said: "It is very likely that what we're seeing is a result of the continuing higher operating costs and the ongoing challenges of a mature region. These could be having a knock-on effect on deal flow, since sellers might be seeking a higher price than buyers may be willing to pay."

New horizons

With problems in the North Sea well documented, other speakers at the Global Hotspots event said identifying new frontiers was key and that mounting costs would be partially offset by oil price increases.

Addressing the cost issue, Neil Hodgson, from oilfield services company Spectrum, asked delegates: "Is exploration getting more expensive? Yes, but so is the product price, which is soaring. Exploration may indeed be getting harder but the technology is also getting better."

Hodgson said explorers should be open-minded about where to look for new targets if they were struggling to keep a lid on costs in mature areas like the North Sea or challenging frontiers such as the Barents Sea. His company is active in Croatia, and Hodgson was upbeat about the country's prospects, which he described as one of the bright lights on the European oil and gas exploration map. "As an exploration arena, the Croatian Adriatic offers a number of significant attractions. First, there is the proven hydrocarbon system that looks more prospective than its Italian counterpart, but is much less explored. The basin is predominantly in shallow water, and there is sophisticated production experience and infrastructure in-country," he said.

Expanding on the advantageous aspects of the play, he continued: "Secondly, it is located in Europe, with a stable government, good economic terms, supportive energy authorities and it is close to hydrocarbon markets."

Croatia has moved swiftly to expedite exploration in the past year. In April 2013 the country introduced a new mining act before it was admitted into the European Union in July. It introduced its first hydrocarbon law that month.

The opening of the Croatian offshore licensing round on April 2, 2014 ushered in a new area for exploration in the Adriatic. Over 20 gas fields have already been found in the northern Adriatic offshore Italy, which has made Zagreb optimistic about the prospects of the current bid round. "The [Croatian] government feels that the first licensing round will be a success. Its 'take' will be in the region of 60-65%, which is attractive to investors, as it compares well to the 70% norm," Hodgson said.

Thus far, discoveries in the northern Adriatic have only been made in Italian waters. Previous attempts to identify carbonate margin oil plays in Croatian waters were significantly hampered by the lack of seismic data of a high enough quality. But new 2-D seismic acquired in 2013 offshore Croatia is likely to revitalise interest in the area. "The data bring a new light to the basin, heralding the dawn of a bright new day for Croatian exploration," Hodgson said.

The industry will watch with interest to see how things develop offshore Croatia. It could offer a slim glimmer of hope in what appears to be a rather bleak picture for exploration in Europe and the North Sea in particular. ■

From EurOil Week 17

Europe

Norway's offshore paradox

Major oil and gas projects are at risk as cost concerns bear down on the country's offshore sector, but the government appears unlikely to come to the rescue

By Tim Skelton

- **Oil and gas activities account for 22% of total Norwegian GDP, and for 66% of the country's exports**
- **The Norwegian Petroleum Directorate (NPD) expects oil investments to peak next year**
- **Oil Minister Tord Lien believes it is the private sector's responsibility to sort out the situation**

The economic juggling act between letting market forces prevail and offering state assistance to prop up essential but less profitable industries is nothing new. But recent comments from the Norwegian government have brought the issue back into the limelight.

In a normal capitalist scenario, countries helping out large companies that already make billions of dollars should not even come up for discussion. But the Norwegian example is slightly different, as the oil and gas sector there is vitally important to the national economy.

It accounts for 22% of total GDP, and for 66% of all exports. This has not only made the country one of the richest in Europe, but also raised hundreds of billions of dollars for the Norwegian sovereign wealth fund, which acts as a national pension scheme.

Waning interest

Exploring and drilling in the treacherous waters of the Norwegian Continental Shelf (NCS) have always been expensive. Yet production costs are said to have doubled in the past 10 years, owing to the increasing complexity and the higher costs of raw materials.

With faltering gas prices putting financial pressure on companies from the sales end of the spectrum, many have begun to downgrade their spending plans.

The Norwegian Petroleum Directorate (NPD) predicts that investments by oil companies in Norway will peak at around 214 billion kroner (US$36 billion) in 2015, and will tail off thereafter. This will do nothing to alleviate oil production that has fallen consistently for a decade as older North Sea fields mature.

Statoil announced in 2013 that it was delaying its Johan Castberg project in the Barents Sea, and that it had dropped US$15 billion in other investment plans. Elsewhere, Royal Dutch Shell has delayed plans for a gas-compression project at Ormen Lange in the Norwegian Sea, a field that supplies 20% of the UK's gas needs.

Politicking

The main bone of contention as far as the oil companies are concerned is that last year, despite their rising costs, the previous government in Oslo opted to increase tax revenues. It reduced the part of their investments that companies can deduct from income, and held the top tax rate at 78%.

The Norwegian Oil and Gas Association lobby group said this, along with new transition rules, had cast doubt over new projects valued at 80 billion kroner (US$13.5 billion), with marginal new developments being particularly at risk.

The new coalition government that came to power in September 2013 had hinted it might be prepared to help out. By the end of 2014 it was thought that the new administration could present a series of measures aimed at cutting costs, possibly including tax breaks. But speaking to Bloomberg last week, Norwegian Petroleum and Energy Minister Tord Lien dashed any immediate hopes for the sector, by effectively ruling out state intervention. "I don't really expect us to present a package of measures," he told the news agency. He said cost increases that were challenging offshore projects were partly because of "the fact that we're not smart enough in the way we work. The responsibility for that lies first and foremost with the operators and suppliers."

Whilst Lien said the government had not yet totally ruled out changes after it completes a study into the impact of last year's tax increase, he also added that the "overall picture is that petroleum taxation in Norway works well."

Erling Kvadsheim, the Norwegian Oil and Gas Association's manager for licensing policy, said he was both "surprised and disappointed" the group's criticisms were not being heeded. "It's clearly a move by authorities that conflicts with the intentions they've had to stimulate good resource management, increase recovery, and keep costs in check."

Norway's other dilemma is that one company – Statoil – is responsible for 70% of national production. And Statoil is majority-owned by the state, so it has a vested interest. Oslo has said it wants to scale back its 67% stake in the company, but while it intends to publish a white paper on state ownership in companies in June, no official sell-off plans have been announced.

So on those grounds, should the government have a responsibility to help out? Lien thinks not, and believes instead that there is great potential to cut costs as the industry moves to standardise its development solutions. "I want to leave this to operators and suppliers as much as possible," he said. ▸▸

"There's no point for a Progress Party minister to get involved in things that the private sector can solve on its own."

Lien said he expected oil and gas companies to continue developing new prospects regardless of the financial challenges. One way to achieve this would be to attract more companies into Norway able to compete with Statoil.

"We need to maintain the ambition of creating the conditions for more diversity among the players that have the financial and technological capacity to develop the really big projects on the Norwegian shelf," the minister said.

Although on the one hand operators will accept that working smarter would help to cut costs, on the other they might expect a bit more support from the government. After all, it is their offshore work that has generated US$500 billion for Norway's sovereign wealth fund and made the country one of the richest in the world. Time will tell whether the government's laissez faire approach is the correct course of action. ■

From EurOil Week 19

Irish tax tweaks could be turning point for offshore industry

Ireland's government is to unveil a new tax regime on June 18 with a view to spurring exploration of the country's offshore basins

By Nnamdi Anyadike

- **Ireland's offshore industry has lagged behind the UK and Norway**
- **Oil industry executives have urged the government to support exploration efforts**
- **There are fears the tax changes could impede rather than attract investment**

Ireland is to unveil a raft of changes to the tax regime for its offshore oil and gas industry on June 18.

The government hopes the amendments will kick-start the industry after 30 years of inertia. But there are concerns the proposals could actually impede development rather than speed it up.

Sources quoted by the Irish Times last week said that rather than liberalising the terms of the tax regime for oil and gas exploration, the government was in fact about to toughen them up, which could deter much-needed investment in the sector.

Irish Energy Minister Pat Rabitte's proposed changes will be based on recommendations in a report by energy consultants Wood MacKenzie that was handed over to the government at the start of June.

The Department of Energy, Communications and Natural Resources is currently assessing the report, the contents of which will be discussed by the Cabinet, prior to the expected announcement that is due to be made at a conference in Dublin next week.

Tax on profits in Ireland currently ranges from 25% to 40%, and there had been calls for these rates to be softened. However, one source told the newspaper: "From what I've heard about what's contained within the report, the industry won't like it."

Another source said that many within the industry were bracing themselves for an increase in the profit resource rent tax (PRRT), particularly for new licences. But there are also fears that any increase could be backdated to cover existing licences.

The government is expected to launch a new licensing round using the updated tax regime this summer. The country's last successful licensing round in 2011 resulted in 11 of 13 options being converted to full exploration licences.

The PRRT was introduced by former Green Party Energy Minister Eamon Ryan in 2007 as a top-up to the normal corporation tax on exploration profits of 25%. PRRT is only levied on the most profitable fields and ranges from an extra 5% up to 15%, giving a total possible tax rate of 40%.

Exploration lag

Oil executives at a recent conference considered the mooted changes and agreed action was required to build exploration momentum offshore.

Tony O'Reilly, CEO of Providence Resources, told the gathering there was an urgent need to attract more international oil companies (IOCs) to shoulder the cost of drilling off the Irish coast. Petrel Resources' CEO David Horgan concurred, saying: "The problem in Ireland has always been lack of exploration."

One reason Ireland has not succeeded, he said, is the "herd instinct of investors", which is currently concentrated on North Africa. Another reason is the fall in oil and gas prices after initial research was carried out in previous decades, which had also dissuaded explorers.

The result is that Ireland remains 100% dependent on imports for oil and 95% for gas, despite being surrounded by potential hydrocarbon riches. This high level of import dependence has injected a considerable amount of price uncertainty into the Irish economy. ▸▸

Europe

This has added impetus to develop assets in the Celtic Sea.

Speaking at the same event as O'Reilly and Horgan, Stephen Boldy of Lansdowne Resources, which owns rights to five exploration licences and one licensing option in the North Celtic Sea Basin (NCSB), described the Kinsale gas field as the "largest gas field ever" in the region. He argued that it should have received the same focus from explorers and investors as the Atlantic Margin. "The NCSB is under-explored, and there is a lot yet to find," he said.

Paul Griffiths, managing director of Fastnet, which has a 100% working interest in the East Mizzen Licensing Option off the southwest tip of Ireland, was also bullish about the potential of prospects in Irish waters. He described the area as "particularly under-explored, yet highly prospective".

Risky business

Despite the region's promise, there are real risks in exploring for oil and gas off Ireland. Bernard Looney, COO at BP, said that while the waters off Ireland could indeed prove lucrative, the sheer size, depth and hostility of some of the areas made it "exceptionally challenging".

Focusing on the three principal basins – the NCSB, the Porcupine Basin and the Rockall Trough – Looney said the latter alone was "one of the largest, unexplored basins in the planet. It is larger than the island of Ireland alone. These are no small facts … it's not easy. It's remote."

He went on to say: "The Rockall Trough is up to 400 km offshore. It's in water that's up to 1,500 metres and it's hostile … It's simply a question of whether the rewards justify the risks, and the reality is that given the track record in Ireland, exploration does carry real risk."

He added that BP left Ireland in 1989 after spending US$120 million on about 17 exploration projects, leaving "a whole lot wiser but with rather less money."

"The reality is that there is much more competition today for the investment dollar. Inevitably when we face choices of where we spend our exploration budget, we're drawn to conversations about above-the-ground factors and below-the-ground factors," Looney said.

As the industry ponders what the government's forthcoming tax changes could look like, some politicians have warned Ireland not to gift its oil and gas resources away by having too lax a regime.

Government opponents claim Ireland should never have dismantled its original Norwegian-style gas and oil policy in 1975. They point out that Norway now is one of the biggest exporters of oil and gas in the world and over the years has succeeded in using the revenue to build up a 620 billion euro (US$839 billion) sovereign wealth fund.

They also highlight a US government report that said Ireland currently had the second lowest tax take of 142 countries studied.

And they cited a report for the Department of Energy and Natural Resources, which said there was oil and gas worth about 540 billion euros (US$730 billion) in today's value off the west coast. But with companies able to write off 100% of costs against tax backdated up to 25 years, and a tax of just 25% on net profits, very little would go to the Irish state.

Juggling the competing interests will not be an easy task for the government and it could lead to further delays in bringing Ireland's offshore oil and gas resource on stream. With this in mind, the government's tax announcement on June 18 could be a pivotal moment for the country's oil industry. ■

From EurOil Week 23

Latin America

Mexico's deepwater exploration potential flagged up

Mexico could follow Brazil and emerge as a vibrant deepwater exploration frontier, although a lot depends on the success of its ongoing energy reforms

By Nnamdi Anyadike

- **Mexico is at a similar stage to where Brazil was in the 1990s in terms of opening up**
- **Deepwater areas in the Gulf of Mexico could attract investors**

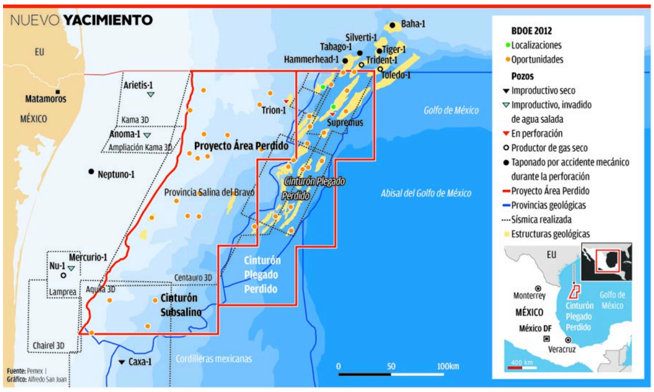
A general lack of exploration success should be of deep concern to explorers, delegates were told at a recent upstream event in London.

Global exploration results over the last 18-24 months have been disappointing, with the notable exception of several discoveries in Brazil's deepwater pre-salt acreage. Seven major oil finds have been made there, namely: Lula, Sapinhoa, Iracema, Carioca, Carcara, Jupiter and Iara. ▸▸

Latin America

Following in Brazil's slipstream, the next hotbed of exploration could be Mexico, which has estimated reserves of 150 billion barrels of oil equivalent, once its energy reforms go through.

Ivan Sandrea of the Oxford Institute for Energy Studies highlighted the potential investment opportunities the reforms would provide. "Mexico is at a similar stage to where Brazil was in the 1990s. It is definitely opening up."



He went on to say: "By mid-May, or at the latest June, we are expecting some 26 laws – eight of which will be new laws and 18 of which will be reforms – to be on the books. These 'secondary laws' will define exactly how the opening up of Mexico's energy sector will take place."

"We are looking at no less than US$83 billion in upstream potential capital expenditure [capex] over the next five years"

The reforms, which will affect all aspects of Mexico's energy sector, aim to reduce energy costs for consumers, increase inward investment, strengthen state-run companies Pemex and CFE, and also enhance the regulation.

In terms of new exploration, Sandrea said: "The core focus is the deepwater in the Gulf of Mexico [GoM], which is where the future lies." But he warned: "Pemex needs to be much better organised in order to take advantage of the GoM's offshore potential. We are looking at no less than US$83 billion in upstream potential capital expenditure [capex] over the next five years."

The total capex will be divided up between Mexico's mature fields, deepwater fields and shale prospects, he added.

A critical part of the negotiations regarding Pemex is the role of its potential partners. But while talks with investors will no doubt be "difficult", Sandrea expects them to be wrapped by September.

However, he conceded it was not clear if some aspects of the new reforms could be reversed after the 2015 mid-term elections.

"The treasury has traditionally always had a tight grip on Mexico's energy sector. And there is no guarantee that some of the changes will not be rolled back. Almost as bad, though, would be the poor execution of the present reforms," he said.

Brazil provides a salutary lesson to Mexico of what can go wrong if it does not execute its energy reform properly. The former's state-heavy strategy, the result of its nationalistic approach to energy since the pre-salt discoveries, has frightened off many potential investors and led to the over-politicisation of state-run Petrobras, which has created serious problems for the company.

High costs

Aside from the political risk inherent in the reform process, the question of cost is also a serious consideration. Deepwater drilling in areas like the GoM is now getting almost prohibitively expensive. Petromall's David Bamford said: "At the same time that exploration appears to be getting much, much harder, costs have been exponentiating."

This could be a problem for Mexico, given the government's plan to boost oil production by tapping into new deepwater fields in the GoM.

Pemex has already struck oil at its Maximino deepwater well close to Mexico's maritime border with the US.

The company also drilled the Supremus and Trion deepwater wells near to the Maximino site in 2012 and is developing a fourth well, PEP-1.

The wells are targeting the Perdido formation, which is already producing oil for Royal Dutch Shell on the US side of the border at the Great White, Tobago and Silvertip fields, which make up the Perdido project.

It is the world's deepest offshore oil drilling and production project, operating in 2,450 metres of water, with peak production from the three fields anticipated at 100,000 barrels of oil equivalent per day.

Once the reform goes through and the block on private investment is lifted, Mexico will hope to replicate those numbers on its side of the maritime border in the GoM.

Pemex's projections are that Maximino could produce as much as 40,000 bpd, rising up to 60,000 bpd when output from the other wells is factored in.

NewsBase Research (NBR) is confident that the reform process will catalyse significant investment and has projected output of around 170,000 barrels per day from Mexico's deepwater projects by 2020. But such output will only be possible if the reform process passes relatively smoothly and costs are within range.

In terms of the former, there have already been delays in the passage of the reform bills.

And in respect of the latter, rising costs remain a risk. As Bamford noted: "Exploration needs to become much more successful and at significantly lower cost than has been the norm over the last couple of years."

So while Mexico offers considerable promise as a future exploration hotspot, there is a long way to go before it becomes a reality. ■

From LatAmOil Week 17

Cuba reheats Russians relations as Caracas chaos continues

Cuba has struck deals with Russian companies as it looks to boost oil and gas production to hedge against the end of easy crude supplies from Venezuela

By Jon Stibbs

- **Havana is fearful a change of government in Venezuela will cause an oil shock for its economy**
- **Exploration in Cuban waters has been unsuccessful to date, but the arrival of Rosneft could boost efforts**
- **There is growing pressure in the US to end the embargo and let American companies explore off Cuba**

Cuba is gradually weaning itself off Venezuelan oil as it prepares to deal with a supply shock should there be sweeping political change in Caracas.

Venezuela's state-run PDVSA has been supplying Cuba with around 80,000 barrels per day for the past few years, or around 45% of the island's daily consumption. But deliveries have dropped by between 20% and 30% over the past 12 months, suggesting Havana is taking steps towards diversification.

It is sensible planning by Cuban President Raul Castro's administration, given the pressure his Venezuelan counterpart, Nicolas Maduro, is under. There have been months of protests against Maduro as Venezuela's economy falters and discontent spreads. Opposition parties have said they would scrap the preferential terms offered to Cuba for oil supplies.

The country currently receives oil from Venezuela in exchange for providing doctors and other services under a barter system set up and nurtured by the late Hugo Chavez when he was president. But it is an untenable scenario in the long term; hence Castro's contingency planning.

History repeating

The Cuban government has form when it comes to losing a benevolent energy provider to political change. The collapse of the Soviet Union in the early 1990s was disastrous for the country, cutting off oil flows and leaving it exposed to the vagaries of the global crude market. This in turn amplified the swingeing US sanctions imposed by the decades-old embargo on the island.

There is a sense of history repeating itself in the fact that it is Russia that Cuba is once more turning to in a bid to stave off disruption to its energy supplies.

Last week, Russian President Vladimir Putin oversaw the signing of two co-operation agreements between Cuba's national oil company Cupet and Russia's Rosneft and Zarubezhneft.

The deals, which were struck at the International Economic Forum of Saint Petersburg, establish the framework for future joint deepwater exploration projects in Cuba's Exclusive Economic Zone (EEZ). Rosneft has also committed to establishing a logistics base west of Havana.

In a return to Cold War-style collaboration, Cuban oil engineers will have the opportunity to train at Moscow's Gubkin Russian State University of Oil and Gas, which will be funded by Rosneft. "Since 1992, we have not trained Cuban citizens and today we are very pleased to renew that engagement," said the University's dean, Viktor Martynov.

Thwarted ambition

Reheating old ties with Moscow could prove beneficial to Castro's regime, especially given the involvement of Rosneft. But Cuba's possible emergence as an offshore oil and gas producer remains a distant prospect.

Several companies, including Spain's Repsol and Malaysia's Petronas, have invested in exploration efforts off the country's coast but with little success. This is despite the government's lofty claims that an estimated 5.5 billion barrels of oil and 9.8 trillion cubic feet (278 billion cubic metres) of natural gas lie beneath the ocean between Havana and Florida.

Such potential has yet to be converted into meaningful production because not only has exploration work proved technically demanding, but has also inevitably been hamstrung by regional geopolitics. Drilling for oil near the Florida coastline ruffles feathers in Washington and carries risk that a spillage would carry directly across to the US. In the wake of BP's Deepwater Horizon disaster in 2010 and the poor relations between Washington, Moscow and Havana, there is little confidence in Cuban safety procedures in the US. ▸▸

Latin America

Indeed, fears there could be a major oil spill have led to calls in America to ease sanctions on Cuba to allow it to buy US-made blowout preventers and rigs.8

There have also been calls in the US for Cuba to be allowed to join the 24-hour response capability established by oil companies in the Gulf since the Deepwater Horizon spill.

Dan Whittle, Cuban programme director for the US's Environmental Defense Fund, is a supporter of this approach, saying recently: "What we're shooting for is basically a world without the embargo with respect to offshore oil exploration."

Ending the embargo might not be such a distant prospect, despite the powerful Cuban exile lobby in Miami that continues to support it. Signs of a possible thaw in relations were apparent last week when the US Chamber of Commerce's president Thomas Donohue visited the island with a message of free enterprise. During his visit, Donohue met Castro and praised his economic reforms and said his chamber had consistently lobbied for an end to the economic embargo.

"Changes take time, but if [US President Barack] Obama wants to get it done before the end of his term, he's got two years," Donohue said in reference to lifting the embargo. "And it's going to take a while to do it, so he'll have to get busy."

If the chamber gets its way and the embargo is lifted, US companies could use their deepwater exploration skills from the Gulf of Mexico to explore offshore Cuba.

Until then, it seems unlikely that the island's offshore will emerge as a strong frontier play. Indeed *NewsBase Research (NBR)* does not envisage any meaningful increase in Cuba's current production of around 50,000 barrels per day in the near future, without a sea change in regional politics, which does not seem likely any time soon.

Given that Petronas and Repsol have recently failed in exploration efforts off Cuba, one might ask why state-run Rosneft is stepping into the fray. The timing of the deal announced by Putin in St. Petersburg last week is critical here. Cold War politics are back in vogue. Moscow is unhappy at the US over its support for Ukraine over the Crimea crisis and so is reverting to the old technique of sticking its finger in Washington's eye by supporting Cuba.

The motives for the new alliance between Russia and Cuba are purely geopolitical, driven by Putin's desire to unnerve Obama and Castro's need to hedge against Venezuela's inherent instability. ■

From LatAmOil Week 22

North America

Four years later: looking back at the impact of Macondo

The effects of the Macondo disaster in the Gulf of Mexico are still being felt, and BP's trial is ongoing, but there is growing optimism over the region's production prospects

By Michael Ashley

- **The final phase of the oil spill trial is set for January 2015**
- **The US government recently allowed BP to start bidding for federal contracts once again**
- **Activity is ramping up in the deepwater Gulf, with output forecast to reach 1.5 million boepd in 2014**

April 20 will mark the four-year anniversary of the largest offshore oil spill in US history. In 2010, BP's Macondo well blew out, causing an explosion on the Deepwater Horizon rig that claimed the lives of 11 workers, and led to the spill.

After several false starts, the gushing well was finally capped in July 2010, but by then it had unleashed an estimated 4.9 million barrels of crude oil into the US Gulf of Mexico over 87 days.

Roughly 16,000 miles (25,750 km) of coastline were affected, including in Texas, Louisiana, Mississippi and Florida. Reports indicate that oil is still washing up along the shore.

According to the National Wildlife Federation, over 8,000 animals – mammals, birds, turtles – were reported dead six months after the spill, including many endangered species.

The economic fallout in the region was far-reaching, hitting in particular the local fishing industry, which depends on the Gulf for its livelihood.

Interestingly, although an estimated US$700 million was lost in fishing and tourism revenue soon after the event, JPMorgan Chase suggested in 2010 that the disaster could actually boost the US economy.

The rationale was that up to US$6 billion could be generated by hiring 4,000 additional people to clean up the spill. ▸▸

North America

BP feels the financial pain

According to BP's own estimates, since May 2010 it has paid out roughly US$11 billion so far in claims to individuals and businesses for their economic damages and losses, as well as US$1.5 billion to the government.

Already, two phases of a civil trial have been held in the US District Court in New Orleans and a third is due to begin in January 2015.

This final phase will deal with matters of responsibility, negligence and the full extent of the damage caused, based on how much oil was actually spilled in the Gulf. The extent of the spill is still being disputed.

In 2012, BP and a committee representing numerous plaintiffs agreed to a settlement resolving most economic and property damage claims. However, a court-appointed administrator's interpretation of that settlement remains in dispute.

The company initially estimated the settlement would result in it paying US$7.8 billion in claims. Later, as it started to challenge the business payouts, BP said it could no longer give a reliable estimate for how much the deal would ultimately cost. However, based on the payments made so far and the current claim rate, it may be reasonable to expect the full payout to be closer to US$15 billion.

The company's bottom line was also hit by its strained relations with the US government in the wake of the Macondo disaster. In late 2012, the US Environmental Protection Agency (EPA) temporarily banned BP from bidding for new federal contracts, and leases in the Gulf. Once the Pentagon's top fuel provider, BP was reported last month to be the biggest loser among suppliers to the US government.

According to data compiled by Bloomberg, a lack of major contracts awarded, coupled with the withdrawal of promised military work, has cost BP US$654 million in net losses for federal contracts in the last fiscal year, which ended on September 30. This was compared to US$2.51 billion worth of awards during the previous fiscal year.

"I have never heard of a contractor falling in anything remotely like the distance from plus US$2 billion to minus US$600 million," a University of Baltimore law professor and former member of the US Commission on Wartime Contracting, Charles Tiefer, was reported by Bloomberg as saying. "The government has come down on BP because it needs to see that BP does not merely talk the talk of behaving responsibly but actually walks the walk."

The EPA subsequently lifted the ban in mid-March, and BP wasted no time in rejoining bidders for Gulf leases, winning 24 tracts worth US$41.6 million in a lease sale held several days later.

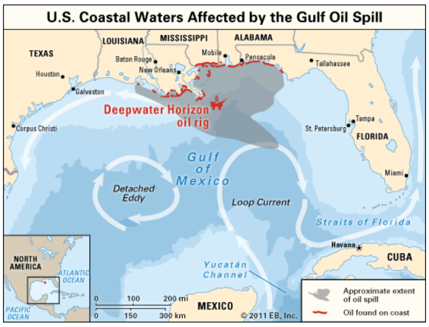
Impact on other drillers

The impact on drilling in the Gulf was almost immediate in the wake of the Macondo spill.

On April 30, 2010, US President Barack Obama ordered the federal government to cease issuing new offshore drilling leases and authorised the investigation of 29 oil rigs in the Gulf. Signalling an effort to tighten regulatory oversight, the government ordered environmental reviews for all new deepwater oil drilling proposals amid concerns that safety practices were not being followed properly.

A six-month offshore moratorium on drilling in water depths of over 500 feet (152 metres) of water was then enforced by the US Department of the Interior (DoI).

In response, a group of affected organisations, including the American Petroleum Institute (API), the Independent Petroleum Association of America (IPAA), and the US Gas and Oil Association formed the "Back to Work Coalition" to combat the ruling.



On June 22, 2010, a US Federal Judge overturned the moratorium, finding it "too broad, arbitrary and not adequately justified". The ban was officially lifted in October 2010. However, production from the Gulf took a hit, falling by 400,000 barrels per day between April 2010 and June 2012.

Production pick-up

Despite the increased regulations in the Gulf since the Macondo disaster, output from the region is rising, with optimistic forecasts for the future. At the end of 2013, Wood Mackenzie forecast that production from the deepwater Gulf would be equivalent to 1.5 million bpd this year, a 15% increase year on year, and 1.9 million bpd by 2020.

Billions of dollars are being invested in new projects offshore Texas and Louisiana, fuelling a resurrection that could set a production record this decade and marking an impressive recovery. A backlog of projects delayed by the moratorium is now being cleared as new fields start to come on stream.

Chevron is among those driving the revival. The company's US$7.5 billion Jack/St Malo platform is set to begin producing oil and gas later this year, with an eventual output target of 177,000 bpd. Other deepwater projects due to start up in the Gulf this year include Anadarko's Lucius and Hess' Tubular Bells. Earlier this year, BP started up Na Kika Phase 3, while Royal Dutch Shell brought the Mars B development on line. Several further projects – notably targeting the Lower Tertiary trend – are currently under development.

The Macondo disaster may have put the brakes on oil and gas development in the Gulf for a time but that situation is rapidly changing.

In a sign of continuing optimism over the US' production prospects, the DoI has estimated the Gulf could hold 48 billion barrels of oil yet to be discovered. If this proves to be accurate, the hope is that oil companies have learned from the mistakes made around the Macondo disaster as they explore in deeper, more challenging areas of the Gulf. ■

From NorthAmOil Week 15

North America

Illuminating the depths

Advances in seismic imaging are helping drillers to target the most challenging deepwater formations in the US Gulf of Mexico – and beyond

By Anna Kachkova

- **Technically challenging subsalt plays in the Gulf are increasingly important for deepwater production**
- **Seismic acquisition techniques have evolved but subsalt imaging remains extremely challenging**
- **PGS is in the middle of a multi-client survey in the Gulf, targeting subsalt formations**

Deepwater production is critical to maintaining the US Gulf of Mexico as an oil and gas hub and technology has allowed exploration to continue to develop. The evolution of seismic imaging has played a huge role in opening up the Lower Tertiary to exploration, allowing companies to identify resources underneath salt canopies.

In particular, wide-azimuth data acquisition techniques have been increasingly used on subsalt formations. Even with these advances, though, seismic imaging of the subsalt remains a challenge. Nonetheless, service companies are striving to make progress on developing their data acquisition and processing technologies as they target increasingly complex formations. The Lower Tertiary has been tipped by Wood Mackenzie as holding more than 15 billion barrels of oil, with the play's production increasing to 41% of regional output by 2028, from 8% in 2013.

Numerous firms are carrying out seismic surveys in the Gulf amid optimism that further deepwater discoveries can be made once more data with improved image quality have been acquired. Petroleum Geo-Services' (PGS) vice president of business development for the Gulf of Mexico, Steven Fishburn, spoke to *NewsBase* about his company's recent work in the Gulf, which he said moves seismic acquisition to the next stage of advancement in the use of technology and survey design.

Messenger of the sea

PGS is working on the Triton survey, which covers around 390 blocks – or 10,000 square km – in the Gulf. The multi-client survey is about 60% complete.

Acquisition started in November 2013, and is due to finish in August this year. The final processed data is set to be released in the summer of 2015, Fishburn said.

"We're bringing a number of unique things to the acquisition that we're conducting right now," he said. "The first thing is our GeoStreamer technology, which acquires data using multi-sensor streamers, so we're not only recording hydrophone data, but we're also recording velocity sensor data." This, he said, results in "a much broader bandwidth, as well as much better low frequency response".

It also allows for receiver ghost removal at the shot point.

PGS is using its GeoStreamer technology in a configuration known as PGS Orion, Fishburn added, which uses five vessels, of which two are high-capacity streamer – seismic signal receiver – vessels.

Each of these two vessels is towing 10 streamers, which are each 8 km long. The three independent source vessels then provide seismic energy from three different offsets in a simultaneous long-offset (SLO) configuration.

"This gives us a huge footprint as we acquire the data. We take the Orion configuration and sail it in multiple directions, which allows us to develop full azimuth, very long offset data – 16 km – resulting in coverage that's very high-fold."

"What's very interesting about this particular area is that there is a tremendous lease rollover coming in 2016-18"

Fishburn explained that PGS had designed its survey in this way because imaging in this area has historically been extremely challenging. "The salt structures are extremely complex. There's a lot of variability in the types of structures and so a normal-type acquisition or even a wide azimuth-type acquisition, we've been told by our clients, is not sufficient to get their prospects drill-ready."

While Fishburn was unable to name PGS' clients, he said the company's work had attracted significant interest and had received "very good feedback". He did note that a number of major players – including BP, Chevron and ConocoPhillips – were active within the area being covered by the survey.

"What's also very interesting about this particular area is that there is a tremendous lease rollover coming in 2016-18," he added.

"A vast majority of these blocks are going to expire and therefore come up for other companies to be able to lease, so we have a couple of goals with the survey."

Companies that are acquiring leases can be offered "a dataset that enables them to get ready to drill, so that they can retain the block with the discovery."

The second goal, he went on, was to offer something to "those other clients who are looking to come into this area but have never been able to, so that they can access a dataset that would allow them to justify coming here".

Challenges

The scale of the operation makes it extremely complex, as does the challenging deepwater environment, so there are major logistical considerations involved.

"There's actually a total of 10 vessels in the field – that's five support and five seismic vessels," Fishburn said. "It's quite an operation, with a couple of hundred people offshore."

Factors such as bad weather, he added, have the potential to present logistical challenges. "All of the technologies that we are employing here have been used elsewhere in the world by PGS, but have not all been used at one time on the same survey and so there's a lot of support that is going in from both our engineering teams and our [research and development] teams in support of the survey."

Beyond the Gulf

PGS believes that the survey design for Triton can be used anywhere that drillers are facing "complex salt challenges", which opens up a number of possibilities for the future.

"There are a number of other areas in the Gulf of Mexico where this same design could be used, as well as areas in West Africa, Angola and Brazil," Fishburn said.

The US data acquisition industry also recently received a boost following the announcement that the federal government was moving to allow seismic surveying off the US East Coast. A period of public comment on the issue is under way, although the move is opposed by environmental groups on the grounds that it could harm marine life in the region.

However, the US Department of the Interior's (DoI) recommendation that seismic surveying proceed in Atlantic waters is widely anticipated to be adopted. The industry is proceeding with caution, and is working to respond to any concerns relating to marine life issues raised by the DoI through the International Association of Geophysical Contractors (IAGC), an industry group.

Fishburn declined to comment on the development but said that the industry was "trying to speak with one voice" on this issue. Much remains unknown about the potential of the offshore East Coast region, with some drilling having been carried out up to the mid-1980s but no commercial production.

The Bureau of Ocean Energy Management (BOEM) estimates federal Atlantic Ocean waters hold only 3.3 billion barrels of undiscovered, technically recoverable oil, as well as 31.3 trillion cubic feet (885.8 billion cubic metres) of gas – comparatively little when considered alongside the potential of the Gulf.

Nonetheless, if exploration does proceed off the Atlantic Coast as anticipated, seismic data acquisition will be in even more demand in the US, and indeed, the estimates could rise based upon new findings once work is under way.

In the meantime, the Gulf will remain an area of major focus for both producers and companies that offer seismic surveying. The industry is working to address the remaining shortcomings in seismic imaging of subsalt formations, and while this remains a complex and challenging task, each technological advance helps to provide a clearer picture of the potential of frontier trends such as the Lower Tertiary. ■

From NorthAmOil Week 16

Shale vs the Gulf of Mexico

Investment has been flooding into North America's shales recently, with little interest in the US' offshore

By Tim Daiss

- **Apache has sold down its offshore assets, while Freeport has sold Eagle Ford developments**
- **Many analyses suggest shale production will peak around 2020 and then decline**
- **Deepwater spending is long-term and poses more regulatory hurdles**

Houston-based Apache is selling off various non-operated interests in the Gulf of Mexico, it said in May, under an agreement with Freeport McMoRan Oil & Gas, a subsidiary of McMoRan Copper & Gold, for US$1.4 billion.

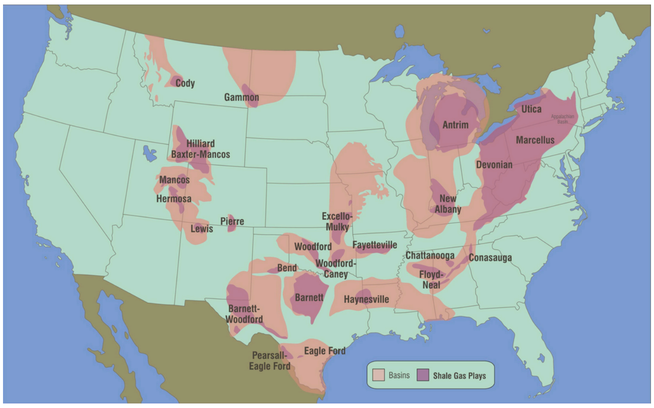
The move highlights the different strategies that companies are adopting, whether to chase the newer unconventional onshore plays or follow the more traditional offshore developments. Apache's executive vice president, Thomas Voytovich, said the company had combined its deepwater and shelf technical teams to focus on subsalt and other exploration opportunities in water depths less than 1,000 feet (305 metres), which have been relatively untested by industry.

"Discoveries on the shelf have quicker cycle times, require less capital and provide more options to bring oil and gas to market," he said.

Apache is selling its interest in Lucius and Heidelberg, in addition to 11 primary term deepwater exploration blocks. The sale is expected to close on June 30.

Lucius was discovered in December 2009, finding high-quality crude with 29 degrees API. ▸▸

North America



It is located offshore approximately 380 km (236 miles) southwest of Port Fourchon, Louisiana in approximately 2,165 metres (7,100 feet) of water and is estimated to contain reserves of more than 300 million barrels of high-quality crude.

The Heidelberg find was made in February 2009. The field is located 225 km (139 miles) offshore Louisiana in a water depth of 1,620 metres (5,314 feet) and is estimated to contain 200 million barrels of oil.

The Apache-Freeport deal is significant, since it shows increased interest in conventional developments in the deepwater Gulf by some companies, while others are focusing more on unconventional shale plays.

Apache is one of several companies – including Occidental Petroleum and Hess – that have also been selling their overseas assets to focus on domestic shale plays, which are considered to be more predictable. A 21% increase in liquids production from onshore fields helped Apache post a better than expected first-quarter profit.

While Apache is shedding a large portion of its deepwater Gulf assets to focus on unconventional plays and shallow-water projects, Freeport is doing the opposite. The Phoenix-based company, the world's largest publicly traded copper producer, said in a May 7 release that it would finance the Apache deal with proceeds from a US$3.1 billion sale of its assets in Eagle Ford shale in Texas – the premier shale play in the US – to a subsidiary of Calgary-based Encana to focus on its US Gulf coast operations.

In other words, Freeport exits unconventional for conventional, while Apache pares down its Gulf assets. A Freeport spokesman declined to comment when asked by *NewsBase* about his company's Eagle Ford sale and its subsequent purchase of Apache's deepwater assets.

An oil analyst at Energy Aspects, Virendra Chauhan, told *NewsBase* that one reason why companies such as Apache might choose to go for shale over Gulf projects was that shale required less by way of long-term planning and investment. "You can acquire land, for example, drill, produce and move on to the next spot, thereby propping up production growth," he said. "This would not certainly not be the case in the [Gulf] – particularly in the post-Macondo era."

Managing declines

A Motley Fool contributor, Matt DiLallo, offered a different analysis. Commenting on the Apache-Freeport deal, he said shale assets like the Eagle Ford decline quickly and "it wasn't likely that the company [Freeport] could continue to outperform unless it started adding more capital to the business".

Given the Gulf's potential, "Freeport-McMoRan can cash in on its Eagle Ford shale success and use that cash to pay down debt while it focuses its oil and gas cash flow to grow its operations in the Gulf," he said.

How companies choose to invest will also be based on their opinions about the longevity of the shale boom, with a number of projections – including the *NewsBase Research (NBR)* – predicting that production will drop by the end of the decade. *NBR* suggests US tight oil output will reach 4.9 million barrels per day in 2018 and then decline to 3.9 million bpd in 2028.

The Paris-based International Energy Agency (IEA) said earlier this week that the world would need more Middle Eastern oil as the US oil boom waned. In this light, the Gulf's resources could serve as a counterweight to impending drops in US shale production.

Chauhan said shale supplies "come off from the end of the decade – which is a combination of high declines kicking in and a saturation of drilling the sweet spots."

The Gulf's allure

In March, the Bureau of Ocean Energy Management (BOEM) offered almost 40 million acres (161,870 square km) in the Gulf of Mexico for bid, generating an estimated US$872 million in high bids for 329 tracts.

The oil and gas leases in the Central and Eastern planning areas of the GoM cover more than 1.7 million acres (6,880 square km). These bids could help fuel the resurgence of oil and gas development in the Gulf, which suffered as a result of the drilling moratorium after the 2010 Horizon Deepwater disaster.

According to the US Energy Information Administration (EIA), federal offshore Gulf oil operations account for 17% of the country's crude oil production – a 2% decline from 2012. Five states and the Gulf supplied more than 80%, or 6 million bpd, of the crude oil – including lease condensate – produced in the US in 2013, the EIA said in a March 31 release. In April, PennEnergy said that while production in the Gulf had decreased, leaders in the oil and gas industry were planning to inject billions in offshore exploration and production there.

Earlier this year, Forbes said that most of the potential from shale fields had already been identified, but a large portion of the Gulf remained untapped. The report said the area could hold a total of 48 billion barrels of oil, since much of these resources are in deep- and ultra-deepwaters. The EIA has put proven Gulf reserves at 5 billion barrels of oil.

Gulf hurdles

Despite renewed interest in GoM exploration and production there are still hurdles and challenges to overcome for producers.

North America

"The point about the deepwater Gulf is that whilst it is undoubtedly a high-margin business, it also requires large capex commitment over a prolonged period of time – more than five years – because drilling there is technically challenging, with drilling occurring at deeper well depths, in high-pressure and high-temperature environments," Chauhan said.

This complexity drives service costs upwards.

Other challenges for drilling in the Gulf include defining prospects, constructing wells, maintaining production and optimising recovery. Halliburton offered a succinct summary on the future of Gulf development. In a report, the oilfield services giant said that few provinces offered the rewards or the challenges of the deepwater Gulf.

"Success in this extreme environment requires a long-term perspective – one that systematically addresses return on investment over the life of the project, from exploration and prospect development to well planning and construction, completion and production," the contractor said.

Notwithstanding hurdles to both US shale and deepwater Gulf development, Chauhan said that the upstream sector was going through a period of transition, driven by investor focus on cash flow instead of on outright production growth. It is not yet clear what the long-term impact of this improved focus on profits will be, with very different tactics being pursued by the different companies.

Shale appears to be on the up for now but questions are being raised over its prospects, meaning one should not write off the deepwater developments just yet. ■

From NorthAmOil Week 22

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