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Myanmar: drillers gear up in Asia's last frontier

The Yadana platform offshore Myanmar. IOCs are preparing to drill new acreage. (Total)

Damon Evans / Singapore

SEVERAL WILDCAT AND appraisal wells will be drilled off Myanmar this year as operators including Woodside Petroleum, Total and Shell start to mature blocks awarded from the hugely successful 2013 bid round.

Earlier this month Total announced it was farming into a 50% stake in Thai NOC PTTEP's deepwater Block MD-7 and that exploration drilling was a possibility.

The French major has already hired a jack-up rig from Vietnam's PV Drilling for a campaign this year in blocks M-5 and M-6, home to the producing Yadana field. Total aims to extend plateau gas production from Yadana, which started in 1998, beyond 2020. It is aiming for first gas from its Badamyar satellite field in Block M-5 this April.

A flurry of investment activity is also expected as companies farm down interest in exploration acreage to cut their risk and help manage the high costs of probing Myanmar's potentially gas-rich waters, which hold some of the last remaining frontier acreage in the otherwise mature Southeast Asia region.

"Shell will likely divest some interests due to their large number of blocks since acquiring BG Group," Adrian Pooh, a Southeast Asian upstream specialist at Wood Mackenzie, told *Interfax Natural Gas Daily*. The Anglo-Dutch supermajor has stakes in seven offshore exploration blocks and plans to take a drilling investment decision by the end of 2017.

Meanwhile "Chevron is looking to sell its stake in the Yadana field, but looks set to keep its very promising A-5 exploration block", Blair Miller, a Singapore-based energy trade and investment adviser at Scottish Development International, told *Interfax Natural Gas Daily*. "There has been a lot of investor interest because of the promising seismic. But it seems they will hang on to it unless they get a fair price, as it's a good asset."

The increased farm-in activity is a positive sign as the operators are thinking about upcoming exploration drilling and development, which will ramp up over the next two years, added Miller, who previously worked with Myanmar's Parami Energy.

But there is a point of contention. "Farm outs could attract a very high capital gains tax, ranging from 40-50%, so some operators may choose to go it alone," warned Miller.

Tricky drilling

Drilling off Myanmar is challenging, given its location far from offshore supply bases in Singapore and Thailand. Local weather, which features a cyclone season, also makes it an expensive business.

"Back in the day, China National Petroleum Corp. was quoting as much as $100 million for a very deep, remote and technically tricky well. But nowadays it's

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cheaper – from around $30 million for shallow waters to around $60 million for deepwater," said Miller.

Australia's Woodside starts its four-well campaign this month with Transocean's Dhirubhai Deepwater KG2 drillship in blocks AD-7 and A-6 in the Rakhine Basin.

The first two wells will appraise the Thalin discovery, made in early 2016 in Block AD-7, while two exploration wells will be drilled in each block. Woodside has an option for three more wells, which could see the drillship contracted for up to 375 days.

Water depths range from 800-1,300 metres in Block AD-7, and 2,000-2,500 metres in A-6. Woodside made a big discovery in each of the permits during its inaugural drilling campaign last year. The Shwe Yee Htun-1 find in Block A-6 and Thalin-1A in Block AD-7 hold 67.96 billion cubic metres of gas on a best-estimate gross basis.

Woodside and its partner Daewoo plan to define a development concept for Thalin, which was the seventh-biggest discovery in the world last year, by mid-2017. A tie-back to Daewoo's nearby producing Shwe field is considered a logical option, analysts say.

The Shwe Yee Htun-1 discovery, in which Total is a partner, could be tied back to the French major's producing Yadana gas facility, although a standalone development piping the gas to shore is also possible. Woodside said it has identified gas sales opportunities in the domestic market, as well as in other nearby Asian markets, including China and Thailand.

Domestic gas prices are quite competitive. They are based on a 10% discount to gas sold into Thailand and China, which ranged from $6.0-7.0/MMBtu in 2016, said Pooh.

State-owned Myanma Oil and Gas Enterprise has the right to buy up to 25% of new gas production for the expanding domestic market.

But "gas pricing aside, deepwater fiscal terms are tough. If we base on the Yadana or Shwe equivalent export gas prices, our analysis shows that companies need to find at least 4.5 trillion cubic feet [127.4 bcm] of gas with condensate, to generate a positive net present value using a 10% discount rate from a deepwater project," warned Pooh.

Myanmar, which was previously off limits to most IOCs because of international sanctions, could have a potential gas resource close to 849.6 bcm according to the government. Woodmac puts the country's remaining commercial gas reserves at 240.7 bcm, with the potential for another 237.8 bcm. ■

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Energy front-month futures

	Closing date	Close	High	Low	% change
Brent Crude, $/bbl	17 Feb	55.81	55.88	55.10	0.29
WTI Crude, $/bbl	17 Feb	53.40	53.52	52.88	0.07
Henry Hub, $/MMBtu	17 Feb	2.83	2.90	2.83	-0.70
NBP, p/th	17 Feb	48.47	49.50	48.00	-2.94
TTF, €/MWh	17 Feb	18.48	18.48	18.48	-2.69
Gaspool, €/MWh	17 Feb	18.03	–	–	-2.88
NCG, €/MWh	17 Feb	18.65	–	–	-2.71
CSX Coal, $/t	17 Feb	56.80	–	–	-2.41
Newcastle Coal, $/t	17 Feb	79.90	–	–	-0.12
South China Coal, $/t	17 Feb	66.65	–	–	-0.15

Prices provided by GlobalView.
GlobalView provides benchmark pricing, news and analytics for the commodities and energy sector. For more information, please contact sales.london@marketview.com.

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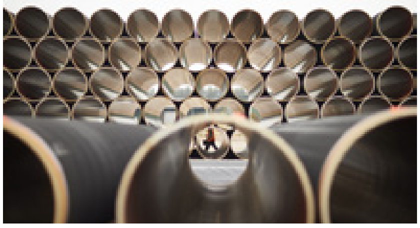
Editor's choice



Nord Stream 2 'a security threat' – US official

Russia's planned pipeline has come under scrutiny from the US, with a senior official opposing the project.

LNG bunkering gathers momentum

Europe's LNG bunkering market is looking hopeful, as companies turn to it to fill the region's gas consumption void.

Trending

1. Iran close to massive gas investments – ministry
2. Pertamina to build Indonesia's second land-based LNG terminal
3. Nord Stream 2 'a security threat' – US official
4. Japanese utilities agree to redirect LNG cargoes
5. CNPC and Gazprom agree to build Chinese gas storage

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EU ETS vote spurs optimism despite setbacks

Andreas Walstad / Brussels

The energy industry has broadly welcomed MEPs' vote to reform the EU Emissions Trading System, even though the changes fall short of expectations.

A coal power plant in Germany. The energy industry has applauded proposals to reform the EU ETS. (E.On)

LAST WEEK'S VOTE in the European Parliament on reforming the EU Emissions Trading System (ETS) has boosted optimism in the energy sector. Stakeholders are now hopeful the reforms will throw a lifeline to a system deemed a failure by many.

Despite some setbacks, the decision to double the intake rate under the Market Stability Reserve (MSR) to 24% in 2019-2022 and to cancel 800 million allowances from the reserve in 2021 is seen as significant. If the decision gets final approval from the Council of the EU, it could help boost carbon prices in the run-up to 2020.

"The doubling of the intake rate under the MSR is the main element that strengthens the ambition compared with the European Commission's original reform proposal. This will have a significant short-term impact since the MSR is set to start in early 2019," Milan Elkerbout, a Brussels-based researcher with the Centre for European Policy Studies, told *Interfax Natural Gas Daily*.

"This is not the final decision, as the council will still have to decide. However, the MSR amendment was carried by a huge majority in the parliament and it has support from key countries including Germany, France and the UK," Elkerbout added.

The surplus of allowances under the ETS is currently estimated at 1.7 billion, and has mainly accumulated as a result of lacklustre economic growth in many EU countries. Brussels decided last year the MSR will remove 12% of the allowances from the market each year if the surplus is above 833 million. Wednesday's vote to double that rate would set the upper boundary of surplus allowances to around 400 million.

However, exactly how this will affect prices is hard to predict because of external factors such as economic growth and sentiment as well as fluctuations in coal and gas prices.

Moreover, last week's vote in Strasbourg was also marred by a number of setbacks as MEPs voted against an increase in the linear reduction factor – the annual reduction in the supply of new allowances – from the current 1.74% to 2.40% after 2020. MEPs agreed instead to increase the reduction factor to 2.20% and that an annual 2.40% cut would only be considered by 2024 at the earliest.

"The vote [...] is an important step towards strengthening the EU ETS and delivering a stronger carbon price in the short and medium term," said Kristian Ruby, secretary general of Eurelectric, which represents Europe's largest utilities. "However, the decision to keep the linear reduction trajectory at 2.20% fails to ensure longer-term investor certainty and to signal higher EU decarbonisation ambition [for] 2050."

Elkerbout agreed that the linear reduction factor is more of a long-term measure to reduce the amount of allowances in the system and will not make much of a difference in the shorter term. "The linear reduction factor is something that is very powerful in the long run, but almost negligible in the short run. By not going for a sharper linear reduction factor, the parliament did not strengthen the long-term ambition of the system," he said.

One step closer

Klaus Schäfer, the president of Eurogas – which represents many of Europe's largest gas companies – welcomed the vote and said Phase 4 of the ETS directive, which will apply from 2021 onwards, was now closer to adoption.

"I am pleased that the vote in the parliament [...] is taking the new directive another step further towards adoption. It is important that the directive is now finalised speedily and strengthened in such a way that carbon markets regain confidence in the ETS," Schäfer told *Interfax Natural Gas Daily*. "This will enable the EU to achieve its climate and energy targets in the most cost-effective way and will reduce the risk that member states resort to national measures, which segregate rather than integrate the EU energy market."

Although significant, the reforms adopted in Wednesday's plenary vote fall short of the measures proposed in a committee vote on 15 December last year, when MEPs in the parliament's Committee on Environment, Public Health and Food Safety (ENVI) voted in favour of stronger carbon market reforms than originally proposed by the commission.

As well as a tighter reduction factor, ENVI had also voted to stop the free allocation of carbon allowances to the cement sector – a big emitter of carbon dioxide – but this proposal was not backed by the plenary. Moreover, the vote did little to immediately boost carbon prices, with the bellwether December 2017 contract trading slightly above €5 per ton ($5.30/ton) on the Intercontinental Exchange on Monday morning. Analysts say carbon prices may have to move at least four times higher to encourage fuel switching from coal to gas in power generation.

All eyes are now on the ministers in the council, whom have yet to reach a formal negotiating position on the ETS dossier. The picture may become clearer after a meeting of Europe's environment ministers in Brussels on 28 February. ■

We welcome your comments. Email us at comments@interfax.co.uk.

Russian energy minster talks plans and negotiations

Anna Gorshkova / Moscow

Russian Energy Minister Alexander Novak tells *Interfax* about the current state of his country's gas market and the plans for its future.

Russian Minister of Energy Alexander Novak (Russian Ministry of Energy)

ALEXANDER NOVAK WAS appointed as Russia's energy minister in 2012 under Prime Minister Dmitry Medvedev. Before this he served as deputy finance minister. In this interview with *Interfax* he discusses the country's plans for pipeline and LNG exports, as well as ongoing talks over supplies with customers – including Ukraine.

Interfax: *The Russian government has asked the Energy Ministry to adjust its Energy Strategy to 2035 to cater for various development scenarios for branches of the fuel and energy complex, reflecting, among other things, elements of government regulation. What does this mean? Also, what interests of independent producers must the revised Energy Strategy take into consideration?*

Alexander Novak: Government regulation [will cover] pipeline gas transport and services for the storage of gas in underground facilities used by independent gas producers. The method for setting tariffs for the use of underground gas storage services will be improved where this concerns increasing transparency and substantiating the calculations, the use of uniform approaches for all suppliers and raising the efficiency of the gas transmission system.

The Russian Energy Strategy to 2035 calls for retaining a single channel for exporting pipeline gas. But if the need arises to speed up growth and increase pipeline exports, then the issue of gas exports by independent producers via the single export channel will be considered.

I: *Poland recently blocked a portion of the capacity of the OPAL gas pipeline and prices in Europe soared. How critical is this situation for Russia and will the Energy Ministry attempt to take control of it by holding talks with Polish colleagues or the European Commission on this issue?*

AN: We are in contact with the commission and have already discussed this issue with European Commissioner for Energy Union Maroš Šefcovic.

The Russian side and the commission believe Poland has no legal grounds for cancelling the decision of the German regulator. The Polish side took the issue to court, but we believe that all the decisions that will be taken by the German regulator and the commission will adhere to European law. The commission has confirmed this.

Gazprom, for its part, has also filed for a consideration of this issue at the European Court in Luxembourg. Gazprom will defend its own interests during these proceedings.

I: *Have the arrangements for the participation of foreign partners in the Nord Stream 2 pipeline been defined?*

AN: This question is being discussed by the companies planning to participate in the project. All foreign partners have confirmed their interest and are now considering financing options.

I: *How is the issue of selling Sakhalin 1 gas being resolved? Which option does the Energy Ministry consider best – a third train of the Sakhalin 2 LNG plant or the construction of a Far East LNG plant? What are the costs of each option?*

AN: Strategically we are interested in both the construction of a third train of the Sakhalin 2 LNG plant and the realisation of the Rosneft and ExxonMobil Far East LNG plant project, which aims to use Sakhalin 1 gas. Sakhalin 1 is currently holding talks on the conditions of gas supply and prices.

I: *Does the Energy Ministry support the transfer of four Gazprom deposits on the Yamal Peninsula to Novatek to expand the resource base of future LNG projects?*

AN: This is a commercial issue, which is being resolved in agreements between the two companies.

Yamal is the most promising region for gas production, with significant gas supplies that can and must be monetised. Therefore, in the Energy Ministry's view, these four deposits need developing.

Due to the fact that infrastructure for liquefying gas has already been set up in the region – ports built, work on deepening the Gulf of Ob and so on – the use of these deposits as resource bases for LNG projects could be the most effective.

Various options are being discussed; all the talks are on a commercial level. Will these deposits be sold to Novatek, will Gazprom develop them independently, will a joint venture be established? It will depend on the economic benefits.

We hope the companies will find a mutually acceptable, win-win option.

I: *You recently held talks in Spain with the heads of Novatek, Gas Natural Fenosa and Repsol in attendance. We know Repsol expressed an interest in Yamal LNG, but did not join the project. Is the company*

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interested in Novatek's new LNG project, Arctic LNG 2? Is Gas Natural Fenosa interested in buying this project's LNG?

AN: Arctic LNG 2 is being discussed with companies from many countries: Spain, Japan, China and so on. But at this stage, [the focus of] talks is not on participation in the project but on financing it.

As for the Spanish companies, they are more interested in joint trading, including for Yamal LNG's liquefied gas. This is also of interest to Novatek as the company intends to increase its sphere of activity in the sale of LNG.

Allowing gas exports by independent producers would be considered if the need arises. (Gazprom)

I: *The latest trilateral gas talks with Ukraine and the EU ended with you handing a letter to the commission on Russia's concerns about the decision of Kiev Economic Court to fine Gazprom $6.6 billion for breaking Ukrainian antimonopoly laws. What was the response?*

AN: We received a response from Šefcovic. In this letter, he treats our objections attentively. He also wrote that he managed to discuss several questions with the Ukrainian side.

Notably, Šefcovic said the Ukrainian side assured him that it would not take any actions relative to Gazprom property, including gas supplied via Ukraine to Europe, under this court ruling.

We have taken this letter under advisement, because it lays out the commission's position to some extent. It is of course encouraging, but it has no force of law. We understand full well that the court's decision might be exercised at any moment.

We are currently insisting that this issue should be considered in the Stockholm Arbitration Court as this is what is specified in the contract between Gazprom and Naftogaz.

The decision taken by Kiev's Economic Court is unprecedented and has no logical explanation. The Ukrainian gas transport system belongs to Naftogaz Ukrainy. In this case it is Naftogaz that has a monopoly, not Gazprom, which is a user of these pipelines.

I: *Ukraine did not buy Russian gas in 2016-2017; however, it will be able to keep consuming because of reverse gas supplies in its underground gas storage facilities, which are essentially Russian. Does Russia have any levers or instruments to restrict reverse supplies?*

AN: It is clear to all that these reverse supplies are artificial. Gas doesn't arrive in Ukraine from Austria or Slovakia, but from the Velke Kapusany gas distribution station on the Slovakia-Ukraine border, through which Russian gas transits to Europe. This is our Russian gas, only purchased by Ukraine through European intermediaries.

Not only that, if the balance of supplies of Russian gas to Europe is analysed, it can be seen that exports to Slovakia and other European countries last year rose by roughly the amount by which gas supplies to Ukraine declined. That is, the balance of Russian exports has been maintained.

We cannot affect this process legally, as operation of gas pipelines in reverse mode is provided for in European law.

But perhaps, there is no pressing need for this. If Ukraine wants to pay a higher price to European intermediaries, then it's more of a problem for Ukraine itself. In the end, its consumers pay more for gas – significantly more.

It should also be taken into account that gas demand has fallen in Ukraine. [The country] consumed 50 billion cubic metres of gas before; it is now around 30-35 bcm. So we are observing a reduction in the Russian supply balance proportional to the fall in Ukrainian demand.

I: *Why have talks with Belarus on gas payments in 2016 reached a stalemate? How is communication between Russia and Belarus currently proceeding on this issue and what options for resolving it are being looked at?*

AN: The problem arose because Belarus unilaterally decided to stop paying the full amount for Russian gas, interpreting the intergovernmental agreement signed by the two countries in 2011 in its own way.

The Belarusian side is of the opinion that the gas price should be less than under the contract signed to the end of 2017. But the contract price is calculated according to a formula that has been used for many years.

We tried to find compromises for the whole of the second half of 2016. The talks concerned not just prices for 2016-2017 but also further supplies in the period to 2025, when a single Eurasian Economic Union gas market is supposed to be formed. The key aspect of the talks is the Belarusian commitment to pay off all debt for Russian gas supplied in 2016. This is necessary to support the status quo.

I wouldn't say that the talks have reached a stalemate. They are going quite enthusiastically, we are continuing to look for a solution jointly with colleagues.

I: *Which projects are Lukoil and Gazprom in line for following the first round of talks in Iran? When could a production-sharing agreement be concluded with Russian companies?*

AN: Work is currently ongoing between Russian companies and the National Iranian Oil Co. For our part we are offering to assist through the intergovernmental commission. This is a normal process, when companies meet, get information and stipulate the terms of a deal.

Gazprom Neft and Zarubezhneft have already signed memorandums on examining the possibilities of work on several deposits. Lukoil and Rosneft will hold their own talks on concrete projects. ■

We welcome your comments. Email us at comments@interfax.co.uk.

India awards licences for small oil and gas fields

Andrew Walker / London

Bharat PetroResources

5 blocks won

Karaikal (oil), Bakhri Tibba (gas), Sadewala (gas), B-15 Cluster (oil and gas) and B-127E Cluster (oil and gas)

Indian Oil Corp.

3 blocks won

Jeraipathar (oil), Nohta (gas) and KD (oil and gas)

PFH Oil and Gas

3 blocks won

Elao (gas), Achanta (gas) and Bhimanapalli Cluster (gas)

Prize Petroleum Co.

2 blocks won

Sanarudravaram (gas) and Hilara (oil and gas)

Megha Engineering & Infrastructure

2 blocks won

Laxmijan Cluster (oil and gas) and Khambel (oil and gas)

Nippon Power

2 blocks won

Kamboi (oil and gas) and West Bechraji (oil and gas)

Oilmax Energy

2 blocks won

Charaideo (oil and gas) and Duarama (oil and gas)

KEI-RSOS Petroleum & Energy

2 blocks won

Koravaka (oil and gas) and GS-KV1 Cluster (oil and gas)

Ramayana Ispat, Duggar Fiber, BDN Enterprises and Mahindra Infrastructure (consortium)

2 blocks won

Barsilla (oil and gas) and Dipling Cluster (oil and gas)

Vijayasri Bhaskar Industries

1 block won

Patharia Cluster (gas)

South Asia Consultancy

1 block won

South Patan (oil and gas)

Gem Laboratories

1 block won

Neduvasal (oil and gas)

Sun Petrochemicals

1 block won

B-37 Cluster (oil and gas)

Adani Welspun Exploration

1 block won

B-9 Cluster (oil and gas)

Hindustan Oil Exploration Co., Oil India Ltd, and Prize Petroleum Co. (consortium)

1 block won

Kherem (oil)

Hindustan Oil Exploration Co., and Adbhoot Estates (consortium)

1 block won

B-80 (oil and gas)

Enquest Drilling & SKN Haryana City Gas Distribution (consortium)

1 block won

D-18 (oil and gas)

Source: Noida Directorate General of Hydrocarbons

INDIA'S CABINET COMMITTEE on Economic Affairs gave its approval to award 31 contract areas of the discovered small fields licensing round last week.

The licensing round was successful for public sector companies, with around one-third of the contract areas going to state enterprises. Bharat PetroResources, a subsidiary of Bharat Petroleum, was awarded five of the eight contract areas it bid for. Indian Oil Corp. was awarded three of four it applied for and Prize Petroleum, a subsidiary of Hindustan Petroleum Corp., was awarded both areas it bid for.

PFH Oil and Gas was the most successful private company, being awarded three of the four contract areas it bid for. Most bids came from small Indian oil and gas companies, which were awarded just under half of all the contract areas.

However, the company that made the most bids – Indian start-up Akhil Teja Natural Resources – failed to win any areas, even in three blocks where it was the sole bidder.

International companies were less successful than local ones, with Nippon Power being one of the only firms to secure the two contract areas it bid for. UK-based producer Enquest Drilling was awarded a contract area in a joint venture with Haryana City Gas Distribution, which delivers gas to households via pipeline and to vehicles as CNG.

In-place resources of the fields awarded are expected to be around 40 mt of oil and 22 billion cubic metres of gas. This is expected to help boost domestic production over the next 15 years.

The directorate general for hydrocarbons received 134 bids from 42 companies for 34 of the areas made available in May.

AGL targeting Australia's first LNG imports by 2021

Sally Bogle / Perth

Australia's supply shortages mean the country could soon start importing LNG as well as exporting it, with AGL planning the country's first terminal.

The Gladstone LNG plant in Queensland. Australian gas producers are targeting the region's plants. (Santos)

GAS AND POWER supplier AGL is pressing ahead with plans to build eastern Australia's first LNG terminal in response to rising supply shortages in the domestic gas market, targeting first imports early next decade.

AGL told *Interfax Natural Gas Daily* the idea is one of several "strategic options" being considered as part of the group's "critical requirement" for security of supply.

"The gas supply picture will evolve but remains uncertain for several years at a minimum. The LNG terminal will provide a new source of supply and competition to existing domestic gas," the AGL spokesperson said, adding that there has been a "very positive" response to the concept from LNG suppliers and "solid interest" from AGL's customers.

Australia is better known as a growing LNG exporter. But as producers prioritise Queensland's LNG export market and the oil price downturn stalls upstream expenditure, gas buyers on the eastern seaboard are finding it increasingly tough to secure long-term supply contracts.

Initially derided when first floated, AGL's import proposal has gained traction following the state of Victoria's decision late last year to impose a moratorium on onshore fracking for unconventional gas. "The fracking moratorium potentially opens up the door to look at LNG imports," Martin Wilkes, principal adviser on LNG developments at consultancy RISC Advisory, told *Interfax Natural Gas Daily*.

"It seems odd that we have all this gas in the eastern states and yet it looks like we're heading for a critical shortage. A rational approach would be to divert some gas away from the LNG export facilities and make it available for domestic market, but I think commercially that's unlikely to happen," Wilkes said.

"So you either have to develop more gas fields, which doesn't look like happening given the moratorium or you have to start looking at imports. So you can see the rationale behind what AGL's saying," Wilkes added.

The specifics of the A$200-300 million (US$153.3-230.0 million) project have yet to be worked out, but AGL has set aside A$17 million for FEED this year and aims to select a site in mid-2017. Various import points are being considered in New South Wales, South Australia and Victoria, with an FID expected in 2018-2019 and imports from 2021.

AGL has yet to decide whether to opt for an FSRU or a land-based regasification facility. Wilkes said the flexibility and speed of installation afforded by an FSRU could make it the preferred option. "I see advantages in an FSRU approach because it could be temporary and flexible [...] In the long term, a fixed facility may be unnecessary and a waste of money," Wilkes said.

Flexible friend

"An FSRU could be used as a trading carrier for six months in the northern hemisphere winter and brought down as a temporary import facility for 5-6 months during Australia's winter. That sort of temporary, flexible type of arrangement means an importer wouldn't want to sign long-term contracts and may use the spot market and short-term contracting to fulfil their needs. If it was a fully fledged, land-based facility you'd be looking at something different," Wilkes added.

Whatever is chosen, importing gas to where it is needed has major logistical and cost advantages over pipelines in a country as large as Australia, where the network is patchy and has been built with a local rather than multi-regional approach in mind.

An FSRU can supply gas where it is needed at high volumes compared with a project such as the Northern Gas Pipeline – which is being built by Jemena to bring Northern Territory gas into Queensland – which has a modest capacity and is far from demand centres. "FSRUs generally have a send-out capacity of between [8.5-28.3 million cubic metres per day], which would have a fair impact on the east coast market," Wilkes said.

AGL is looking at a host of LNG sources including Australia, the United States, Asia and the Middle East. "LNG could be contracted from any available Australian or global LNG suppliers. We will source the lowest-cost competitive supply for its customers," the spokesperson said.

"Building LNG terminals is a natural progression for developing gas markets that outgrow domestic gas supplies. In countries such as the US, Indonesia, Malaysia, Egypt and the Netherlands, this has resulted in the simultaneous import and export of LNG and pipeline gas," the AGL spokesperson added.

Wilkes is confident AGL will not be alone in looking to imports to fulfil the tightening market. "It wouldn't surprise me if other companies are considering importing gas. They may not have announced it, but others will be looking at it," he said. ■

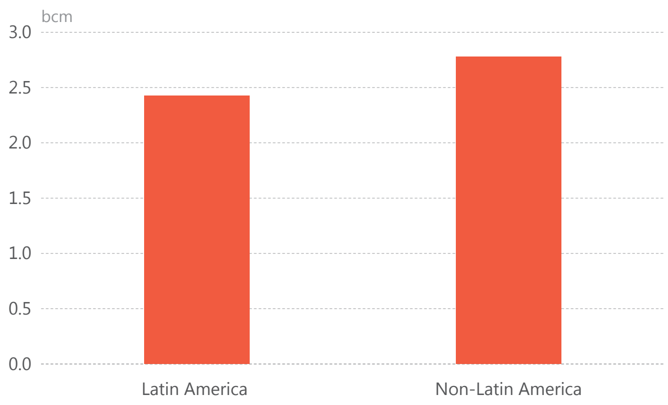
We welcome your comments. Email us at comments@interfax.co.uk.

Mexico swaps Peruvian LNG for US cargoes

Chris Noon / Barcelona

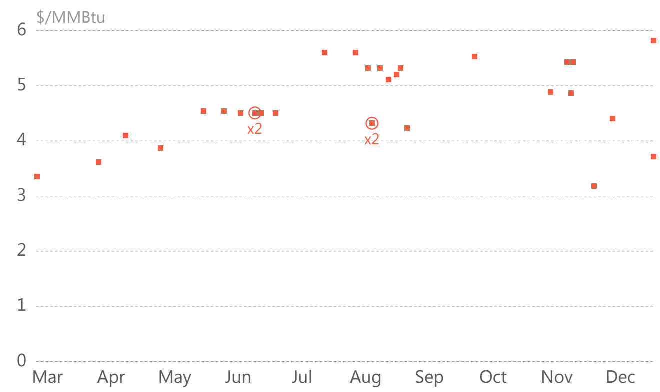
Cheap cargoes from the Cheniere Energy-operated Sabine Pass LNG plant in Louisiana continue to head south – with the demand void left by Brazil and Argentina instead being filled by Mexico.

US LNG EXPORTS TO DATE



Source: US Department of Energy

PRICE OF US LNG EXPORTS TO LATIN AMERICA



Source: US Department of Energy

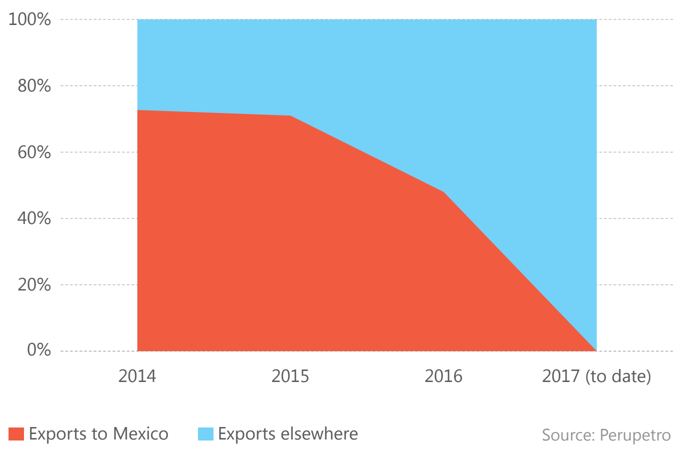
Latin America and the Caribbean provided a large share of demand during the first year of United States LNG exports. The region accounted for nearly 47% of US LNG exports by volume since February 2016, according to US Department of Energy data. Brazil, Argentina, Chile and Mexico have imported 30 of the 61 LNG cargoes to date. Barbados has also imported 33 shipping containers of the fuel since February 2016.

The price outlook for US LNG exports to Latin America is bearish. Spot LNG prices in Latin America could reach $4/MMBtu during the shoulder months because of the region's limp demand, according to *Interfax Global Gas Analytics*. LNG demand from Brazil, Argentina and Mexico is forecast to remain weak in the coming months, while LNG supplies will increase as the third train of Sabine Pass comes online in H1 2017. Latin America's spot LNG price for March delivery has averaged $7.6/MMBtu, down from $8.6/MMBtu for February.

BREAKDOWN OF US LNG EXPORTS TO LATIN AMERICA

Source: US Department of Energy

PERU'S LNG EXPORTS



Source: Perupetro

Argentina and Brazil initially provided strong demand for Sabine Pass cargoes, but neither country has imported any US-produced LNG since 14 August 2016. Mexico almost immediately filled the breach, importing nine US cargoes since 23 August 2016. Mexican state utility CFE appears to have replaced its Peruvian cargoes with US LNG. A pricing dispute between Peru, Mexico and Shell resulted in the South American country and the supermajor seeking higher-priced markets elsewhere.

Chile has also provided strong demand for US LNG, importing 10 cargoes to date. All but one of the cargoes was imported between May and August, during the southern hemisphere winter. The expansion of the Panama Canal, which has allowed larger ships to transit since June 2016, has been a boon for Chile-bound cargoes from Sabine Pass. The volume of LNG shipped through the canal on so-called 'southbound' journeys from the Atlantic to the Pacific was up by more than 35% in 2016 compared with 2015, according to the Panama Canal Authority.

Ukraine's gas stocks down by 41% so far this heating season

The amount of gas in Ukraine's underground storage facilities has declined by 41.6% from the beginning of the heating season to 18 February, to 8.61 billion cubic metres. Ukraine withdrew 45.99 million cubic metres (MMcm) from its underground storage on 18 February and a total of 1.28 bcm over the first 18 days of February (70.94 MMcm/d on average), Ukrtransgaz, which operates the country's pipelines and storage facilities, said in a statement. Ukraine is on track to have just over 8 bcm in its inventories at the beginning of March. Naftogaz Ukrainy officials believe stocks are sufficient to last the country until the end of the heating season and that Ukraine has the capacity to increase imports if the rest of the winter is more severe than expected. Naftogaz calculates that the country will have 7-8 bcm left in stock by the end of the heating season, which is above the minimum allowable level of 5 bcm.

A rig in Kazakhstan. The country aims to boost its gas output by 3.8% this year. (Tethys)

Kazakhstan targets 3.8% gas output increase in 2017

Kazakhstan is targeting a 3.8% increase in gas production in 2017, Energy Minister Kanat Bozumbayev said at an expanded meeting of the ministry's board on Thursday. "Production of up to 48.1 billion cubic metres of gas is expected in 2017, including up to 3.1 bcm at Kashagan, up to 18.0 bcm at Karachaganak and up to 14.0 bcm at Tengiz," Bozumbayev said. Gas production in 2016 amounted to 46.3 bcm. "The gas sector overall has a good development dynamic. Production of liquefied gas was above target in 2016. Commercial gas production will increase to 29.0 bcm in 2017. Consumption of liquefied gas in Kazakhstan increased by 65% over the last three years," he said.

Sound Energy acquires eastern Morocco assets

Sound Energy has signed a binding agreement to acquire all of Oil & Gas Investment Fund's oil and gas assets in eastern Morocco. Under the deal, Sound would acquire a further 20% interest in the Tendrara licence and a 75% stake in Meridja, as well as a possible 75% stake in the relinquished area near Tendrara. After the deal, Sound aill own 75% of Tendrara and 75% of Meridja. The purchase will be funded by shares in Sound Energy. A non-binding agreement for the deal was signed in January. Sound has started drilling a third well in the Tendrara permit. The well was spudded on 19 February.

Chariot wins 75% stake in Kenitra offshore permit

Chariot Oil & Gas has been awarded a 75% interest in the Kenitra offshore exploration permit in Morocco. The other 25% is held by Office National des Hydrocarbures et des Mines. Kenitra is also adjacent to the Mohammedia offshore exploration permits, in which Chariot has a 75% interest. Kenitra, which covers an area of approximately 140,000 hectares and lies at water depths of 200-1,500 metres, was formerly part of the Rabat Deep permits.

Three consortiums interested in building Iran LNG – NIOC

National Iranian Oil Co. (NIOC) is negotiating with three consortiums to complete construction of the Iran LNG project, Ali Amirani, acting head of NIOC's gas export division, told *Interfax Natural Gas Daily*. The groups have submitted technical and financial bids. "The first priority for negotiation is how the companies want to complete this project," said Amirani. "What is the cost and what would be the financing system? There are many issues to discuss." The winning bidder will be awarded an engineering, procurement, construction and finance contract. The companies' investment will be compensated through LNG sales and finance can be secured against international LNG sales agreements, said Amirani. For this reason, Iran will be looking to arrange long-term LNG supply agreements, rather than short-term deals or spot cargoes.

India considering 8% gas price hike in April

Gas prices in India are likely to be increased by 8% from the beginning of April driven by rising rates in reference markets including the United States Henry Hub, according to the *Economic Times of India*. The price is expected to rise to $2.70/MMBtu from April until the end of September from the current $2.50/MMBtu. It will be India's first increase in domestic gas prices for two years.

Solar power project auction yields record low tariffs

A competitive auction for a 750 MW solar power project in India has yielded the lowest-ever tariff for the industry, according to *Clean Technica*. The auction was held over 32 hours and yielded an average tariff of INR 2.97/kWh ($0.049/kWh) for the project, with three companies being awarded contracts. The three winners were ACME Cleantech Solutions, Mahindra Renewables and Solenergi.

Gas theft accounting for 83% of Balochistan's supply

Around 83% of the gas being delivered to the Balochistan region of Pakistan is going unbilled, according to the *Pakistan Observer*. Shahid Khaqan Abbasi, minister for petroleum and natural resources, recommended urgent action on the issue at a committee meeting over the weekend. The committee was told that 340 thousand

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cubic metres per day (Mcm/d) of gas was being delivered to the Qalat and Ziarat areas, but only 71 Mcm/d was actually reaching it. Illegal connections and theft were the reasons cited for the lack of gas and the low pressure in the network.

Su Tu Trang second phase will be developed in 2020-2025

PetroVietnam Gas and PetroVietnam Exploration Production Corp. will develop the second phase of the Su Tu Trang field off the country's southern coast between 2020 and 2025, according to the *VN Express*. The field will produce up to 300,000 tons of LPG per year and around 170,000 tons of condensate, according to a statement from the company. The field has been supplying 600 thousand cubic metres per year of gas under its first production phase, which began in 2012. Under the second phase it is expected to produce around 1.2 billion cubic metres per year for 20 years. This could help reverse the country's declining gas output and meet more of the country's demand over the coming years.

Petronas puts SK316 stake on sale

Malaysia's Petronas is looking to sell up to a 49% stake in the offshore SK316 gas block that feeds Train 9 of the Bintulu LNG plant to raise as much as $1 billion in cash and cut development costs, according to *The Star*. It is thought that the sale could interest other state enterprises in the region, including Indonesia's Pertamina and Thailand's PTT.

Chilly Argentina hopes for Chilean gas supplies

Argentina is again seeking to import gas and power from its neighbour Chile during the southern hemisphere winter, according to Argentine newspaper *El Cronista*. Chilean state-run company ENAP would offer Argentina "the same [gas] supply as last year", Chilean Energy Minister Andrés Rebolledo told journalists in Buenos Aires on Friday. Argentina topped up its gas imports during the winter months of 2016 with regasified fuel that arrived as six LNG cargoes at GNL Quintero and Mejillones, Chile's two terminals. The fuel was then exported to Argentina through the cross-border GasAndes and Norandino pipelines.

CNPC produces first gas from Peru's Block 58

China National Petroleum Corp. (CNPC) has produced its first gas from Peru's giant Block 58, state-run hydrocarbon agency Perupetro announced on Friday. Block 58 is in Peru's southern jungle zone, which accounts for more than 96% of the country's gas production. CNPC bought the rights to the licence from Brazilian state-run Petrobras in 2014. Lima said in November that CNPC had confirmed a discovery of 110.5 billion cubic metres of gas and condensate reserves in the block. The discovery would boost Peru's gas reserves by nearly 28%, according to Energy Minister Gonzalo Tamayo. ■

The Week Ahead

Tuesday 21 February

- International Petroleum Week, London, UK (until Thursday)
- Bruegel thinktank Nord Stream 2 event, Brussels, Belgium
- Eni after 6, Brussels, Belgium

Wednesday 22 February

- Petrofac, full-year results

Thursday 23 February

- Centrica full-year results

Monday 27 February

- Pemex full-year results

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