



# RUSSIAN GIANTS TO *FIGHT* IT OUT

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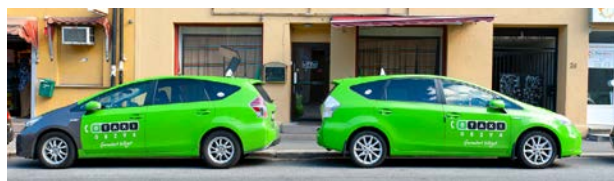
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# WASHINGTON CEDES CLIMATE LEADERSHIP

The US president, Donald Trump, fulfilled a campaign promise against the advice of some of his family and key advisers and announced June 1 that the US would withdraw from the Paris Climate Agreement. He opposed its \$100bn/yr Green Climate Fund and the different rules that it imposed on different countries and called it a bad deal for Americans.

US withdrawal from what, under Barack Obama, was a position of US strength, could have dramatic effects on the patterns of global trade and existing alliances. The lure of the political capital that could be derived from delivering the ambitious deal could be strong enough to unite other blocs. The European Union for example might otherwise have taken its cue from Washington but now will have to rethink its strategy, no doubt in partnership with other blocs.

Because without Washington to provide the solidarity that such an aspirational and expensive goal requires to keep everyone moving in the same direction, the immediate future of the agreement itself is less certain. After all, it has taken some 25 years to get where it is today.

Some politicians and observers doubt if the looser alliance of US states and industries, that has been suggested as the natural way ahead, could substitute for a committed government in Washington, if only because of the vast amounts of money that will be needed. The deal therefore might not survive.

The deal relies on national promises to reform that are not legally enforceable but with US government backing it would have been an important step towards a cooler planet that could gather momentum. Now, some European Union (EU) politicians say, it is just a shell, with nobody now in the driving-seat.

As emotions cool, the EU's categorical rejection of Trump's offer to renegotiate a 'fairer' deal might be tempered over the coming years as they find they need US government money – although that will have strings attached. China, too, will prove to be a tough negotiator.

But for now the EU is uncompromising on further talks. The US decision represents a rejection of shared values in favour of its own interests, encapsulated by the 'America first' slogan – which, along with Trump's comments in late May on the member countries' unequal division of Nato funding, has made it harder for either side to contemplate working together for shared goals.

That approach has put the EU in the unusual position of having to welcome the opportunities for co-operation presented by China, whose own style of government – opaque, no supporter of the rule of law and a major headache for European heavy

industry, such as steel manufacturers – is very different from the EU's. There has been much suspicion of Chinese ownership of EU infrastructure, such as energy grids, too.

Optimists however believe that it is now the destiny of the EU and others to fulfil the leadership role in the climate change fight, moving the centre of economic gravity decisively eastwards. Seizing the initiative, China's premier, Li Keqiang, visiting Brussels to promote the major Chinese trade initiative, Belt and Road, told reporters that China supports international rules.

"There have been changes in the international situation and there have been rising uncertainties and destabilizing factors and in such circumstances it is important for China-EU relations to become more stable," he said, within hours of Trump's announcement.

And Wood Mackenzie sees Trump's decision as triggering a major shift in one area of global business: "The US withdrawal of the Paris accord will offer an unprecedented opportunity for China, the biggest carbon emitter and the biggest renewable energy supplier, to ascend in leading global climate affairs," it said.

From this perspective, Trump has precipitated not only close co-operation between China and the EU; but also the flight of US companies eastwards as they relocate their renewable technology research and development centres to Asia, to the detriment of the US treasury. "By leveraging the strong manufacturing value chain in China and other Asian countries, the cost of renewables could fall even faster and penetrate more rapidly to displace dirty, fossil fuel such as coal in key Asian markets," it said.

The US agreed to reduce its emissions by 26-28% below 2005 levels by 2025, China only committed to peaking its carbon dioxide emissions by 2030 and to use "best efforts" to meet this goal earlier. Trump pointed out that China "will be able to increase emissions for 13 more years." And India conditioned its participation on foreign aid.

According to a study by NERA Economic Consulting, the total potential emissions reductions from existing policies together with planned policies announced by the Obama Administration are insufficient to achieve the US's INDC pledge. While the projected size of the INDC emissions "gap" varies somewhat among various analyses, the study concluded that such a gap cannot be filled without contributions from the industrial sector, such as iron, steel, coal and natural gas.

# RUSSIAN GIANTS TO FIGHT IT OUT

Privately-owned Novatek is expected in June to bid for more Yamal reserves to supply a second LNG project, leaving state-run Gazprom exposed to competition in Europe.

Russia's LNG export strategy could go in one of two directions, depending on whether or not the government decides to accelerate it. Russia started its LNG exports almost 15 years after today's leaders in LNG trade. The present market leader, Qatar, exported LNG to 25 countries last year, and its share of global LNG was more than 31.8 %. Russia by contrast has been selling LNG to four countries and its share was about 4.5 %.

One of the reasons why Russia waited so long before exporting LNG may be that it was focused on its big pipeline projects in Europe and Asia. Regardless of the disagreements concerning the North Stream 2 project, Europe will remain the most important buyer of Russian gas.

According to a document by the Energy Research Institute of the Russian Academy of Sciences (ERI RAS), titled *Energy Outlook. The World and Russia 2016*, by 2040 gas exports to Europe will constitute 52-56% of the total amount of Russian gas intended for export and even in the best case scenario, all of Russia's LNG exports will constitute only 40% of the whole amount of gas at present exported to Europe. Some of this LNG will be delivered to European countries. In 2016 Russia exported 178.3bn m<sup>3</sup> of natural gas and plans to increase this to 368.8bn m<sup>3</sup> by 2035

For Russia LNG could be the most prospective and, in fact, the only new way to increase sales of gas. Many experts argue that the development of Russia's LNG sector might not only give it access to new remote niche markets, but also develop LNG as a motor fuel in Russia and diversify gas supplies to Europe.

## Three operators, two projects, one tussle

There are nine possible LNG projects in Russia with combined production of more than 120mn mt/yr, operated by Gazprom, Novatek and Rosneft. But bringing these on line is proving slow. Only Sakhalin 2 is finished although the Yamal LNG project, which also has foreign investors Total –itself a shareholder in Novatek – is at the final stage of construction.

At present, Sakhalin Energy Investment has the only working liquefaction plant. It has 11 contracts with China, Japan, Korea and Taiwan which enabled the final investment decision. Gazprom, the operator, also sells spot cargoes. Output is 10.92mn metric tons/yr, compared with nameplate capacity of 9.6mn mt/yr.

Many believe that Russia is able to fill the gaps in world LNG demand by developing LNG production in the first half of the next decade. According to ERI RAS, in one realistic scenario Russia will export less than 50bn m<sup>3</sup>/yr of gas as LNG whereas in a favourable one, it might be as much as 80-90bn m<sup>3</sup>/yr. These forecasts may underestimate the real potential, because Gazprom alone is planning to have 14%-15% share of the global LNG market by 2030, when the total volume is expected to be 490mn-580mn mt/yr.

Besides Sakhalin 2, Gazprom is working on two other parallel projects: Vladivostok LNG and Baltic LNG. Vladivostok LNG is a project with an annual capacity of 10mn mt/yr but Gazprom is not giving it a major priority.

The other, Baltic LNG, is a plant project with a capacity amount up to 10mn mt/yr that will cost \$11.5bn. The project is primarily targeted at Europe (especially Spain, Portugal and Great Britain), India and Latin America and its launch is planned for 2023-2024. The president of Shell Russia, Olivier Lazar, said in March 2017 that the project needed support from the government, in a similar way to Novatek's Yamal LNG, where sanctions prevented long-term finance from the west.

Gazprom is rescheduling the start of its projects: Baltic LNG was supposed to start in December 2021, the third phase of Sakhalin 2, which would boost output to 15mn mt/yr has been postponed to 2023-2024. The feasibility study has taken longer than expected and the final investment decision, due in the second half of this year, is likely to slip into 2018.

## Novatek needs lower costs for Arctic

Privately-owned Novatek has been making more aggressive progress with LNG than Gazprom. The company notionally has two LNG projects: Yamal LNG and Arctic LNG 2. The realisation of the first one is at an advanced stage and this is the first Russian LNG project inside the Arctic Circle. Its budget is about \$27bn although financing was delayed by US and Russian sanctions.

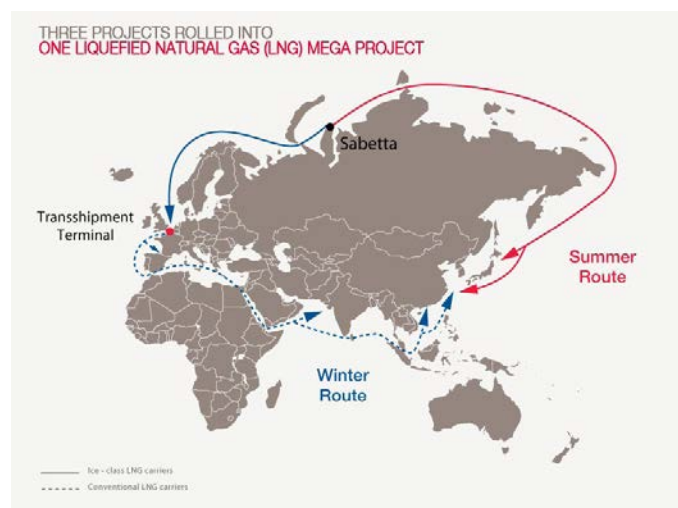
On 27 April 2017 Novatek held a presentation of the Yamal LNG project and said the implementation of the first phase is 91% complete and it will be finished in the second half of this year. Novatek's partners have been of invaluable assistance. China National Petroleum Corp has contracted to buy 3mn mt/yr of





LNG; French Total brought its experience and know-how and stuck with it even after US and EU sanctions were imposed on Novatek; Silk Road Fund paid \$1.207bn for its 9.9% stake and it helped it raise \$12bn from Chinese banks.

Yamal LNG has two routes, a summer route to Asia through the Arctic Sea, and a winter one to Europe where LNG will be offloaded in Zeebrugge LNG terminal and stored for transshipment. The contract with Fluxys LNG should last for 20 years and cover 8mn mt/yr. It underpins the building of a new large storage tank at Zeebrugge.



Yamal LNG (Map credit: Total)

The first dedicated icebreaker LNG carrier *Christophe de Margerie* – named after the previous CEO of Total, who developed the Yamal initiative with Novatek – was tested in extreme conditions during sea trials in 2016.

First volumes from Train 1 are expected in November 2017 and the start of long-term supplies is planned for 2018. If everything goes as planned, Yamal LNG will be the largest LNG project in Russia.



Christophe de Margerie (Photo credit: Novatek)

NOVATEK.RU

As for the second project named Arctic LNG 2 – Yamal LNG presumably being also known as Arctic LNG – for which pre-front-end engineering and design was completed in 2016 – Novatek has great ambitions and according to Novatek's CEO speech in March 2017 at a forum on "The Arctic – a territory of dialogue" the company expects to have it finished by 2022-2023. The month before, Novatek suggested it would be later, in 2022-2024. The project's budget is primarily \$10bn and will have a capacity of 12-18mn mt/yr but the company is trying to find ways to make it cheaper than its precursor, such as building a gravity-based system rather than sinking piles into the frozen sand that forms Yamal.

Additionally some observers say that Novatek could buy from Gazprom four fields close to Yamal LNG. If that went ahead, Novatek CEO Leonid Mikhelson said, the Yamal and Gydan peninsulas will produce over 75mn mt/yr – comparable to the present LNG production in Qatar. Furthermore, Novatek may become a foreign LNG investor and invest in regasification facilities in China.

### Moscow throws weight behind LNG

Yamal LNG proves that the Russian government is starting to think about LNG as a strategic market for its energy security, hence Moscow's financial support for it. The project is exempt from the LNG export tax; it will not have to pay the mineral extraction tax for 12 years; the government funded the Sabetta port and other construction projects and it received financial support from the Russian national wealth fund. These bonuses make Yamal LNG one of the most competitive LNG project in the world.

Novatek is also the only potential buyer of licence to develop the Gydansky gas field which will form part of the resource base of the second Novatek project Arctic LNG 2. In April the government announced an auction for the development of the field, in the Yamalo-Nenets autonomous region. The site area is 3,700 km<sup>2</sup> with gas reserves estimated at 58.4bn m<sup>3</sup> of C1 category, 57.7bn m<sup>3</sup> of category C2, 361.14bn m<sup>3</sup> of C3. Additionally there is condensate, which can transform the economics of an LNG project. The auction is planned to take place June 9 with the reserve price of roubles 2bn (\$35.35mn). No one apart from Novatek has satisfied the condition that the winner must liquefy the gas for marketing purposes.

### Rosneft, the also-ran

Rosneft has two LNG projects: Pechora LNG and Far East LNG. Pechora LNG is operated in cooperation with the little-known Alltech Group and has a capacity of 4-8mn mt/yr. The Far East LNG project is for 5mn mt/yr, headed by US major ExxonMobil. In distinction to Novatek, Rosneft sees LNG as only a part of its general development strategy rather than a priority.

The Russian government supports LNG projects but only Novatek benefits fully from it, perhaps owing to the relationship between the main Novatek shareholders Gennady Timchenko and Leonid Mikhelson and Russia's president, Vladimir Putin. The other possible variant is that Gazprom was preoccupied with other projects. These two companies will probably compete with each other and there could be a possible confrontation in Europe, where Gazprom remains the monopoly exporter of pipeline gas but where Novatek also trades gas and power. Among Yamal LNG's customers are Shell and Engie, both long-term customers of Gazprom.

Low-tonnage LNG production is the next market niche which has good growth prospects in Russia. Russia has seven facilities, producing in total 100,000 mt/year of LNG.

There are many obstacles blocking this segment of the LNG market, such as the lack of infrastructure enabling the supply of LNG as motor fuel, the necessary legal and regulatory frameworks, the high cost of foreign technology and a network of service centres for the maintenance of vehicles using LNG.

But while these limitations slow down the development of this segment, nevertheless it has good prospects because it creates a new source of gas demand. LNG as a motor fuel can be used in trucks, buses, trains, tractors and so on. Demand for LNG as a motor fuel will reach 1.156 mt/yr in 2020 and 5.208 mt/yr in 2040, according to some forecasts – in other words a 350% rise in demand if the forecast proves accurate.

Today it looks like Russian activity in LNG sector will keep a medium rate of development (except Novatek) and according to many experts, LNG for Russia will play only a supplementary

function. It would change if LNG became a bigger part of the Russian energy security strategy, which would mean government support for projects to pick up speed. There are already some promising signs: for example the deputy energy minister Kiryl Molodtsov said in May 2017 that by 2020-2022 Russia would create its own technology for LNG production. He said it was a strategic initiative in response to EU and US sanctions, although Novatek has used US Air Liquide technology.

The next step is to fully liberalize the LNG export and this is well understood in Russia. Its "General scheme of development of the gas sector to 2030" published by the energy ministry gives prominence to the liberalisation of LNG exports, which means that it is possible to introduce successive elements liberalizing the LNG market in Russia.

The big risk for Russian LNG is that today's gas market is a buyer's market. Russian LNG will have to compete with US LNG, more experienced LNG sellers like Qatar and Australia, plus probably within a decade, Iran which plans to become the next big LNG player with its LNG export capacity of 40mn mt/yr.

There are also low average spot prices, and for example, in Northern Asia from 2015 to 2016 the price fell by \$2.32/mn Btu to \$5.52/mn Btu. The future of Russian LNG depends to a very large extent on government support – tax exemptions and state involvement – and on exporters' sales capabilities. Nevertheless, Russian LNG projects have their future; and Novatek – a potential leader of LNG in Russia, with ambition to become a big player globally – could transform Russia's so-far monolithic gas export structure.

Kamil Sobczak

Yamal LNG (Photo credit: JSC Yamal LNG)





## US BUYERS TAKE A BREATH

The new Trump administration has focused on making it easier to sell US LNG to China and other Asian markets than permitting lots more export facilities.

In an atmosphere of LNG export oversupply and stalling projects, in mid-May the US Commerce Department announced that their Chinese counterparts agreed to give state-owned companies permission to enter into long-term contracts with US LNG exporters, sending companies scrambling.

The development came as part of the 'US - China Comprehensive Economic Dialogue', a framework for bilateral meetings set up in 2009 that deals with a variety of economic prospects.

While the agreement does not modify any current rules or regulations, experts say it clarifies and will accelerate LNG negotiations. Last year Cheniere Energy shipped nine LNG cargoes to five terminals in China from their Sabine Pass export facility; but these were sold on the basis of spot market pricing.

The new agreement will allow for discussions on long-term supply contracts, which has significant ramifications for infrastructure investment decisions. One analyst, Massimo Di-Odoardo at Wood Mackenzie, notes that "US LNG export terminal developers will now be able to target Chinese buyers directly, potentially helping the projects to secure financing ... the deal could also support direct Chinese investment in the terminals."

This agreement, while intriguing, is in essence a vague 100-day action plan and not a binding deal. Any co-operation between two economic behemoths like the US and China, however, is going to attract attention. China's LNG imports in 2016 were up 32.6% year on year, at 26.1mn metric tons, according to IHS Fairplay.

Meanwhile, Wood Mackenzie is forecasting Chinese demand will hit 75mn mt/yr by 2030. Given LNG price decline (prices in Asia as a whole, the premier market, are down 56% since 2014), these numbers are exciting for US producers.

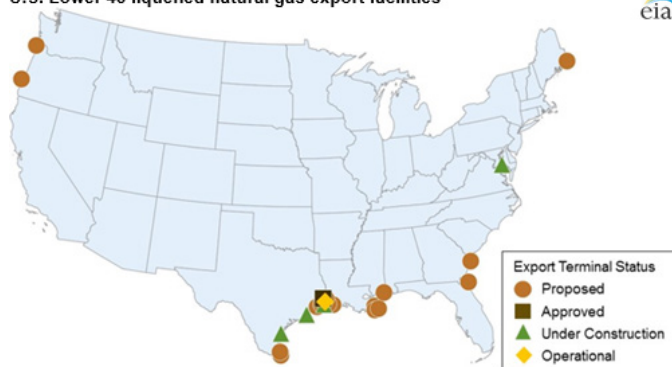
Currently the EIA predicts LNG export capacity between 2015 and 2020 will exceed demand growth by nearly 50% but new projects developed on the basis of long-term contracts could come online right at the time that glut is due to clear.

### US Supply Capacity Glut

When discussing the possibility of a new series of projects backed by long-term Chinese supply contracts, analysts frame it as the "second-generation wave." The first construction wave

is coming online now, with Cheniere and its Sabine Pass facility being the pioneer. One estimate says that the 'first generation' will yield about 64mn mt/yr of export capacity over the next few years.

U.S. Lower 48 liquefied natural gas export facilities



Map credit: U.S. EIA, based on Federal Energy Regulatory Commission

The significant projects are the fourth and fifth trains of Sabine Pass; two more Cheniere trains at Corpus Christi, Texas; three trains in Freeport, Texas; three in Cameron, Louisiana; and Dominion's Cove Point, the one project due to be finished soon on the east coast (Maryland).

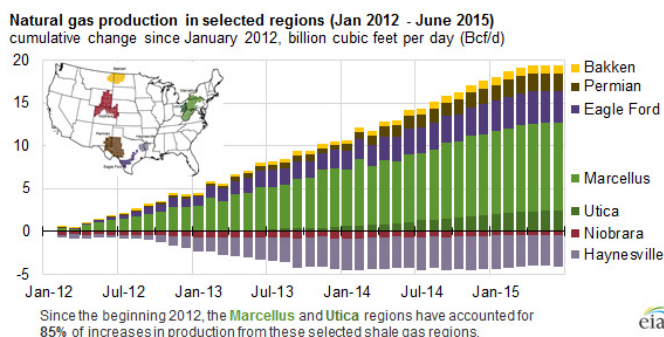
These projects are all due to come online in the near-term. Beyond them, the situation is murkier. Another set of projects have received US government approvals but are awaiting final investment decisions (FID) or notices to proceed. These include train 3 in Corpus Christi, train 6 in Sabine Pass, new projects in Lake Charles and Magnolia, Louisiana, and others.

As mentioned, LNG is a buyer's market, with depressed prices and more export capacity coming online than import. In addition to US projects, this includes new export capacity from Australia, Malaysia and Africa.

Of course, the US Gulf Coast is (and has been) the premier location for energy development. Only Pennsylvania comes close to the region when it comes to hydrocarbon history, and the Barnett Shale in Texas was the origin of the revolution, where Mitchell Energy & Development first successfully scaled the technology for commercial shale gas production in the 1990s.

However, it US gas production growth is not in Texas or the south. Since 2012, 85% of growth has instead come from the Marcellus and Utica formations, primarily in Pennsylvania, West





Virginia, and Ohio. A significant amount of this Marcellus and Utica supply is carried south through pipelines in Kentucky, Tennessee and Mississippi, to feed the Gulf export facilities.

As the sole non-Gulf Coast station, Dominion's Cove Point LNG terminal is an interesting case study. A milestone was hit on April 7, 2017, when Cove Point received US Federal Energy Regulatory Commission (Ferc) permission to begin accepting fuel gas into the facility. Commissioning should follow in a few months. The location could provide two benefits, as they are closer both to the booming fields in Pennsylvania, West Virginia, and Ohio, and also to markets in the European Union.

In practice, however, the location is proving to be of negligible benefit. Despite being closer to Marcellus/Utica, sourcing adequate amounts of gas could actually prove to be difficult for Cove Point over the next year. The intention was to purchase Transco's Atlantic Sunrise, a 200-mile, 1.7bn ft<sup>3</sup>/day project bringing gas from northern Pennsylvania southwards.

Unfortunately, that line has run into regulatory delays that are pushing the estimated completion date back a year, from mid-2017 to mid-2018. It gained Ferc approval in February, just before Ferc lost quorum and the ability to approve new projects, but is currently in the public comment phase with the Pennsylvania Department of Environmental Protection.

Ultimately, the often greater difficulty in permitting projects in the north, combined with the less developed infrastructure compared to that of the Gulf Coast, far overshadow the benefit of the shorter distance.

Likewise, the tantalising prospect of exports to the European Union is proving to be mostly political bluster. Many countries have expressed interest in cutting down on Russian gas supplies, particularly in eastern Europe, but deals fall through when people look at the economics. A milestone was hit this April when reports came that Poland's state-owned PGNiG bought a June delivery spot cargo from Cheniere's Sabine Pass, the first such heading to eastern Europe. A PGNiG spokesman even spoke of Poland turning into "a gateway for American LNG to central and eastern Europe."

However, these proposals ignore the harsh truth of pricing: it will be almost impossible for LNG imports to be competitive with Russian pipeline gas, and the import terminals that have been built in the region are running well under capacity (see separate feature on Lithuania). Their construction might help to depoliticise Russian supplies and secure discounts, but European demand will save US overcapacity.

## Gas for petchems

With these constraints in mind, the current situation could easily remain static. Recent gas price rebounds have given the industry some breathing room, after years of belt tightening and layoffs, but the oversupply of export capacity is putting the brakes on many intermediate-to-long-term LNG infrastructure projects.

With numerous US export terminal plans awaiting difficult FIDs or otherwise being delayed, it is unlikely that we will see another large development like Sabine Pass getting the green light soon. The Ferc approval process also remains a wildcard, as the agency has been without a quorum – and thus the ability to finalize regulatory approvals – for months. The Trump administration has recently announced two nominees to fill the gaps, but their confirmations will take more time.

The China announcement offers the possibility of committing to infrastructure investment that is backed by long-term contracts, but, given the vague nature of the agreement, time will tell whether this actually plays out in reality.

Further dampening expectations, cheap Russian gas will come into play there as well, as Gazprom recently announced that over 650 km of the Power of Siberia pipeline have been built. With an estimated in service date of 2019, this line will supply northeast China with gas from central Russia, and surely beat LNG prices. Finally, if one looks at infrastructure beyond LNG exports, natural gas production expansion has fueled a remarkable renaissance in the US chemical industry. While \$48.2bn is being spent on the 'first generation' of LNG terminals, chemical manufacturing investment from 2012 is around \$160bn. Of that, \$50bn have gone into projects are online or are scheduled to soon.

This includes Dow's billion-dollar propane dehydrogenation plant in Freeport, Texas; an ExxonMobil \$20bn program to expand Gulf Coast manufacturing capacity; and a large joint venture Occidental Petroleum-Mexichem ethylene plant. Pennsylvania is looking for investment as well, with Anglo-Dutch major Shell's ethylene plant under way and other proposals on the table.

The price dynamics regarding this new demand and LNG exports, which require cheap prices to be viable, will be a key factor to watch over the next few years.

Ben McPherson



# FLOATING REGAS: EASIER SAID THAN DONE

For all the size and promise of the global LNG market and the dramatic surge in floating storage and regasification projects, investors can still lose money.

The number of specialist owners of floating storage and regasification units (FSRUs) has only recently increased from a handful to a dozen or so. In part that is due to credit risks faced not only by such ship-owners but also by the sponsors of projects to which they charter their FSRUs.

International oil companies at times have talked about ordering their own FSRUs, but so far that's largely been just talk. Despite their appetite to create new markets for a structural global LNG glut that looks set to remain until at least 2023, so far the international majors – even LNG tanker owners such as Shell – have preferred to work with, rather than compete against, established FSRU owners.

## More than a tenth of global trade

Global LNG trade in 2016 increased by 7.5% to 263.6mn metric tons, according to the latest annual report by GIIGNL, the International Group of LNG Importers.

Egypt imported 7.5mn mt last year through its two FSRUs, but other FSRU-reliant markets such as Kuwait, Jordan, UAE, Argentina, Brazil and Pakistan each imported 3mn mt or more.

There were 24 FSRUs afloat at the end of last year, according to GIIGNL. Their 2016 throughput accounted for 30mn mt – or 11% of world trade – according to data compiled by WoodMac for Hoegh LNG, a leading operator with seven FSRUs now in operation and 3 under construction. Golar LNG is a similar-sized operator, while other established owners include Exceleerate, Exmar and BW Gas.

LNG demand meanwhile continued to rise year-on-year to around 75mn mt in 1Q 2017, according to data published May 24 by Hoegh LNG. The world's top 3 markets – Japan, South Korea and China – were among the greatest contributors to year-on-year demand growth – but so too were Egypt, Turkey and Pakistan where FSRUs were deployed to fill gas deficits with competitively-priced LNG.

Even southeast Australia, Poland and Hong Kong are thinking about deploying FSRUs for the first time for various reasons, said Hoegh in its 1Q results, adding that for LNG giant Australia the rationale is to fill a regional gas deficit – with cargoes from the west of the country.

Global overall LNG supply is growing rapidly on the back of expanding production capacity and could increase by another 100mn mt, or 35%, by 2020, forecasts Hoegh perhaps conservatively.

A recent blog by [London-based consultancy Timera Energy](#) suggests that figure could be even 150mn mt, as export projects like Wheatstone and Ichthys in Australia and Yamal in Russia are not expected to start until the second half of this year.

Hoegh says that floating regas is “key to opening up new markets for LNG” and it sees FSRU market activity reflecting the increase in global LNG supply: six new FSRU contracts awarded to shipyards in 2016, and a further 3 to 5 FSRUs likely to be awarded in 2017.

Market requirements can also be met by converting older LNG carriers to FSRUs – something which Hoegh itself began doing last year.

## FSRU project numbers could double by 2025, says Poten

There are 22 floating regasification terminals in operation worldwide, with a further nine under construction, shipping expert Amokeye Adede of LNG consultancy and brokerage Poten & Partners told an industry briefing in London, May 24.

That's a little more than the 24 FSRUs recorded by GIIGNL at end-2016, as some were not deployed as terminals, but rather working on short-term charters as LNG carriers.

Adede and her colleague, Jan Bruil, said the number of operational floating regas terminals could double to “more than 40” by 2025.

Acknowledging that Poten is “bullish” about FSRUs' prospects, Bruil said the high case for 2025 could be 50, with the low case in the low-30s.

They listed more than 30 FSRU projects at various stages of planning – including ones in South Africa, Namibia, Poland, Croatia, the UK, Benin and Curacao – not all of which would come to fruition. “Many of these projects come with a health warning,” said Bruil, a senior LNG consultant at Poten.





Map credit: Hoegh LNG (flag shows existing FSRU or is contracted to provide one)

### Small is beautiful and flexible

FSRUs can provide a fast solution to a country's scarcity of power generation feedstock, as was the case a decade ago in Argentina. In Egypt and, more recently, Colombia they were used because gas demand was outpacing domestic supply. In Kuwait, they have served to displace oil from power and desalination plants, and also provide cleaner air quality.

FSRU-based regas projects can also be developed very rapidly with the record being 6 months, but one year being not untypical, according to Poten, if the FSRU is already built. They also have low start-up costs for sponsor projects. Niche markets can be very small, and the typical 750mn ft<sup>3</sup>/d sendout of a standard FSRU tends to be lower than that of most onshore plants. They can also be chartered for a long fixed-term, or a short five-year term after which they can be taken elsewhere or the charter extended.

Such a newbuild FSRU today would cost \$130,000/day (\$47mn/yr) to charter, said Adede – down from a 2012 peak of \$170,000/day. Smaller and older FSRUs of 500mn ft<sup>3</sup>/d are sometimes available. The cost of ordering newbuild FSRUs has trended lower, and so too have charter costs.

But as well as converting existing LNG tankers to FSRUs, some proven FSRUs have come back into the market. Some earlier FSRUs on five-year charters in Brazil and China have been redeployed. Others will be removed in 2020 from Egypt, because of the discovery of giant offshore fields there like Zohr, and Kuwait, where a large onshore terminal will be built now given its long-term demand for LNG.

### More ship providers

Adding increased variety to the established quintet of Hoegh, Golar, Excelerate, Exmar and BW Gas are new providers that either already own one or two FSRUs or else have them under construction at Asian yards. They include Japan's NYK Line,

Malaysia's MISC, Monaco-based Gaslog, Canada's Teekay, Greece's TMS Cardiff and Maran Gas, and French utility Engie – although the latter is more a sub-charterer. Most are established owners of LNG carriers.

When a floating regas project is selected, there's no hazardous onshore site to deal, and permitting can be quick. Also the ownership of the FSRU asset can be structured separately from the sponsor project – which can be helpful when financing new ventures, and which is not really possible for land-based LNG import terminals.

### Credit risks in FSRU-ideal markets

At the Poten presentation, attended by gas company representatives, FSRU shipowners and lawyers, issues of credit risk in small developing economies, for example Ghana, were raised. With FSRUs, the owner has the option of taking the ship back into their portfolio if the charterer won't pay and the letter of credit has been used, as the ship is fully mobile.

"If you think you have problems as an FSRU sponsor, think of the guys who develop an onshore LNG terminal that may become a \$500mn-\$600mn stranded asset," said Poten senior adviser Jim Briggs.

### Ghana: Ghastly or Golden?

Fresh in most minds is the case of Golar Tundra, which arrived late May 2016 on schedule, ready to be connected to the Ghanaian gas grid. The FSRU was to have become the first to enter service in sub-Saharan Africa, but instead it became clear that the project sponsor, a joint venture of Nigeria's state NNPC and private partner Sahara Energy, had omitted to secure consent to import LNG first.

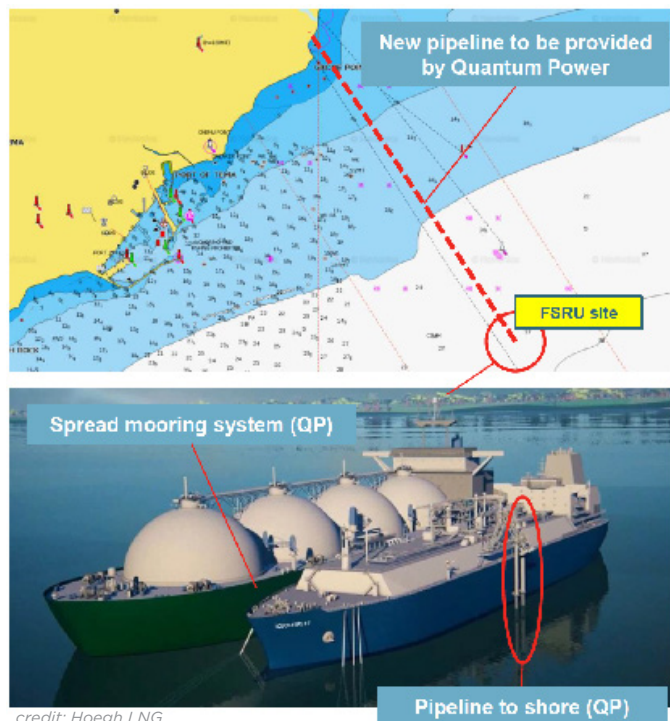
This has since happened, but the ship remains idle at anchor some 5 km offshore, with no pipe to connect it to the gas system. This is despite the country's latent demand for gas in its power generation plants. That demand, however, will not last indefinitely as new oil fields such as Eni's OCTP and Tullow's TEN oil will soon be supplying large volumes of associated gas to what is already supplied by the Tullow-operated Jubilee field. After initially refusing, the NNPC-Sahara joint venture – WAGL – began paying the charter fees due to Golar. It has gone to arbitration to recover \$45mn of unpaid charter fees from WAGL. But given the buoyant market for FSRU projects, Golar has said it has discussed an early release from the charter with WAGL.

That WAGL has not petitioned for this yet suggests it still holds some hope of making money in the Ghanaian market, with NNPC a co-owner in the 678-km West African Gas Pipeline (WAGP) that nowadays carries little if no spare gas exports from Nigeria into its western neighbours' markets.



The Golar Tundra saga has proved an ominous start to what should have been such a promising launch for LNG regas in West Africa. Yet two other FSRU projects are gearing to start up there – eyeing demand for electricity from the country's business sector, particularly mining. Hoegh expects a final investment decision mid-2017 on a Ghana project, sponsored by Israeli backed Quantum Power, that it expects to enter service mid-2018; Hoegh expects to earn \$36mn/yr Ebitda from the charter to Quantum.

Whereas WAGL expected to berth Golar's ship in the busy port of Tema, Quantum is relying on building a 12-mile pipe to where the Hoegh Giant will be stationed offshore. Hoegh already took delivery of the ship on April 27 and has it booked out on short-term LNG carrier jobs until mid-2018.



credit: Hoegh LNG

### Carrying the Sponsor Credit Risk

Ghana remains a risky place, where power generators aren't always paid by customers, and in turn ask for credit from gas suppliers who sometimes refuse – with the debt-laden government expected to step in with guarantees. But the government has guaranteed a price for Ghana's new OCTP gas.

In many of the unlikely success stories for making FSRUs work such as Egypt and Pakistan, governments have stepped into the breach to provide guarantees for LNG purchases. Argentina's state Enarsa has been the anchor customer since 2008 in that country, and likewise state Egas in Egypt and Petrobras in Brazil have provided this role – all seen as creditworthy. Many offtakers

in non-OECD markets though are not big utilities with high credit ratings, such as exist in more developed markets. Some of the 30 identified regas projects being planned worldwide are in places like Benin, Namibia, South Africa, and the Caribbean.

The issue of whether ship-owners may take more risk by going further downstream – by building pipelines themselves, or even taking equity in sponsor consortia – in order to ensure their projects succeed, was explored at the Poten briefing. There was less discussion though of whether majors, like Shell, Total and Eni, might do this. So far some have hinted at this, but not followed through.

In Cote d'Ivoire, the sponsor company for a FSRU-based project due for delivery 2018 is a seven-way consortium (CI-GNL) headed by Total, including Golar, Shell and Azerbaijan's state Socar, plus local Ivorian entities. But the mechanics of this planned 3mn mt/yr scheme remain somewhat opaque. Total though says it "illustrates Total's strategy to develop new gas markets by unlocking access to LNG for fast-growing economies."

### Brazil Offers a Template

Across the Atlantic in Brazil, one such case where Golar has joined a sponsor consortium – in a much more significant manner – is the Sergipe LNG-to-power venture in Brazil.

Golar Power – a joint venture owned 50-50 by Golar LNG and New York private equity fund Stonepeak Infrastructure Partners – took final investment decision in October 2016 on a 1.5-GW combined-cycle gas fired power plant to be built by 2020, with 26 committed offtakers for its power over 25 years under previously executed power purchase contracts awarded by the Brazilian government in 2015. Golar Power owns 50% of the CCGT and 100% of the FSRU earmarked to the project Golar Nanook. The ship will be delivered to Golar LNG later this year.

The Golar Power partners, who were advised by New York law firm Shearman & Sterling, moreover say they expect to deploy this investment template in other countries. The Sergipe venture will be supplied under a long-term LNG agreement by the Ocean LNG joint venture of Qatar Petroleum and ExxonMobil, the most significant large LNG supply contract yet for Brazil. The \$1.3bn CCGT will be the largest non-hydro power plant in South America and help meet Brazil's growing electricity needs particularly during dry seasons.

***LNG: Fuel for a Changing World** – A Nontechnical Guide (2nd Edition) by Michael D Tusiani and Gordon Shearer, pp594, was published 2016 by PennWell books. Tusiani is Poten's chairman emeritus while Shearer, a former CEO of Cabot LNG, rejoined Poten in 2015 as a senior adviser.*

Mark Smedley



# BALTICS ACCEPT GAZPROM'S GAS

The fate of Gazprom in the Baltics – first reviled for behaviour, now resignedly accepted as a supplier of reasonably-priced gas – shows diversification can be a luxury.

Russian gas monopoly Gazprom is flexing its muscles as never before in Europe, even though there are calls to dilute its power with US LNG and for it to be fined for its past anti-trust behaviour. The gas giant's supplies to Europe and Turkey reached an all-time record in 2016: deliveries of 179.3 bn m<sup>3</sup> were 19.9 bn m<sup>3</sup>, or 12.5%, more than the year before. As the company's share in Europe's gas consumption grew to a record high of 34% in 2016, the rouble-denominated profits soared by 21%, year-on-year.

Yet the more robust the pose that Gazprom strikes, the more uneasy the Baltics feel, especially with the green light to Nord Stream 2 which the region perceives as an arm of Russia's geopolitical influence and a primary danger to Ukraine.

"Indeed, it seems the notion we felt (in Europe) that Gazprom is Russia's geopolitical tool is waning. Commerce is taking over (fears)," Arvydas Sekmokas, a former energy minister of Lithuania, told *NGW*.

Russian oil and gas analyst Mikhail Krutikhin and a co-founder of the RusEnergy consultancy in Moscow, said more bluntly: "The politicisation of gas trade is over, we see the reverse trend now: its depoliticisation."

For the fearful Baltics, it means that the region will have to continue to deal, although reluctantly, with the Russian gas supplier for the foreseeable future – in Q1 2017, Gazprom sold Lithuania 2.5 times more than in the same period last year. Second, the company is keeping a foothold in the unbundled Latvian gas market – Gazprom boasts a 34.1% stake both in the Latvian gas company, Latvijas Gaze, and its demerged company, Conexus Baltic Grid, the transmission system operator – and the Russian monopoly is the only source for natural gas in Estonia.

"Considering that Gazprom was allowed to implement Nord Stream 2 project, the claims it has for Opal capacity and TurkStream, it's hard to argue that Europe is resisting Gazprom in its endeavors and or preventing it from implementing energy-based geopolitics," Romas Svedas, former deputy energy minister and now an independent energy expert, said.

Echoing this view is Virgilijus Poderys, the chairman of the energy committee in the Lithuanian parliament. He is convinced that TurkStream "purely" serves Russia's wish to pressurise southern Europe. "It is evident that TurkStream is a mirror image of the South Stream project that was supposed to cross Bulgaria. It seems to be aimed at bypassing gas transmission systems of

central and eastern European countries. With the project in place, Russia, will bypass not only them but also the European Union's Third Energy Package and its key requirements for the separation of gas supply and transmission activities," he said.

Speaking of the Baltics, after the exertion to drive Gazprom out of the region's gas market for good, especially so in Lithuania, the region – and Lithuania, a key plaintiff in the EU's Gazprom antitrust probe, too – is cosyng up with the increased flows of Russian gas.

To the surprise of some energy experts, Gazprom this year has recaptured 34% of Lithuania's gas market. Lithuania's state energy holding Lietuvos Energija (Lithuanian Energy), which supplies gas to households and industrial customers, is set to purchase around some 2.9 TWh or around 34% of its gas needs from Russia; and the fertilizer manufacturer Achema, the Baltics' single largest commercial gas consumer, plans to buy about 9 TWh, or two-thirds of its gas needs, from Gazprom. It has complained about the costs of the Lithuanian LNG terminal, which have been socialised across consumers and so made gas more expensive.

Meanwhile, Gazprom's total in the Lithuanian gas market this year is expected to hover at around 55%, up from one-third in 2016, but it is expected to remain below its 2015 market share of over 80%.

"Europe believes it has done much to rein in Gazprom, which has responded with some flexibility in the trade. To call on everyone now to put more pressure on the Russian company would not make much sense," Sekmokas, the former minister, admits. The EU antitrust settlement announced in March 2017 includes greater contractual freedom for countries dealing with Gazprom.

The remedies to tame the Russian behemoth also include removing restrictions on customers re-selling gas across borders, ensuring that gas prices are tied to competitive benchmarks. Gazprom will also be barred from taking undue advantage of infrastructure which it has obtained from customers by having leveraged its market position in gas supply. Under EU rules, if found liable for competition breaches, Gazprom can face a fine of up to 10% of annual sales.

In Gazprom's case this could be nearly €83bn (\$88.5 billion), cash it does not have. The one company to have published



its objection to Gazprom's settlement was the Polish former monopoly, PGNiG, which was given an extension of over a week to submit its lengthy response to the EC.

It fell short of specifying a figure that Gazprom should be fined but it did say that its own claims against Gazprom went back to when Poland joined the European Union in 2004 and thus became entitled to its protection from abuses of trade. The changed behavior of gas buyers has also contributed to the thaw in relations with the Russian company. The buyers no longer seem daunted by supply cuts and the security of supply issue is often deemed now of secondary importance, at least in the "mature" European markets.

A sign of this more relaxed attitude of European consumers is their enthusiasm for larger than ever quantities of Gazprom's gas – now comparatively cheap – and their lack of appetite for LNG. That shows rational, commercially-driven behavior, analysts say. Some of them believe that Europe's dependence on Russian gas supplies is relative and not critical for the 28-member bloc. Besides, the highly publicized LNG exports from the US are still very limited, another big setback for Gazprom's opponents.

The EC fine, if imposed, all agree would hurt Gazprom palpably, but the indications are Europe will not want to strain relations with the supplier, as its own reserves run down or production is capped. "I am sure Gazprom will get away largely unscathed. Europe is flirting with Russia as it always has (flirted). Although sanctions against Russia remain, the trade of gas is liberated,"

Sekmokas, of Lithuania, insisted. Svedas claims that both Nord Stream2 and TurkStream are redundant projects, and so

Gazprom's determination in pursuing them, in light of the EU's attempts at decarbonising, should make one concerned.

"The Gazprom expansion is not what the EU has aimed at," says Svedas. "Both projects are questionable from the standpoint of law, but, for some reasons, the legal intricacies have been solved in Gazprom's favor. The EC is too lenient to the Russian monopoly and furthermore it satisfies most of Gazprom's wishes," he said. He believes that, if Russia manages to implement all the planned gas projects, Europe will end up being in the noose of Gazprom's criss-crossing gas pipelines.

As many European companies eye the multimillion gas projects as an opportunity to rake in a lot of money, they stifle the grumblings of individual countries. "There is hardly anything Lithuania can do alone," Lithuania's observers say. Concurring with the Baltic pundits that Gazprom will evade an EU penalty, Krutikhin claims Gazprom is doing the right things. "If it showed even more flexibility to the European customers, its chances in the market would look even rosier," he said. "The politicisation of the market is now in the past and it is all about trade – the way it should be."

Agreeing, Dmitri Smirnov, a Latvian gas expert, says that replacing Gazprom is possible neither in Europe in general, nor in the Baltics in particular. "In the latter, I see its positions weakening, yet Gazprom's gas supply in the region's total gas demand will most likely hover above 50%. That's pretty impressive, considering the efforts to curb its activities here," he told *NGW*.

[Linas Jegelevicius](#)

## PUBLIC TIRES OF FUNDING LNG

Lithuania's energy minister Zygimantas Vaiciunas met with the vice president of the European Commission (EC) Maros Sefcovic responsible for the European Energy Union May 24. Discussions included the long-term security of gas supply in the region, the necessity to ensure further smooth financing of the decommissioning of Ignalina Nuclear Power Plant, and the linking of the Baltic States' power systems with that of Poland, the ministry said May 30. They also discussed the regional LNG import terminal question and long-term gas supply. Vaiciunas said that in May the prime ministers of the Baltic States would go on a tour of potential locations for additional LNG terminals in Estonia and Latvia as well as visit the sole functioning one at Klaipeda. There is also an LNG terminal functioning further down the coast to the west, in Poland, plus a small one to the north, on Finland's west coast at Pori.

While there is demand for more LNG bunkering, further LNG import terminals in the region are unlikely to receive funding from the EC, given the comparatively low use made of the present one, which is a floating regasification and storage vessel leased from Hoegh at a cost to Lithuania's industrial gas consumers. The EC has turned down one funding application from Estonia. Latvia also wants to have one. It was noted during the meeting that the EC supports the idea of regional terminals and encourages the Baltic States to seek the economically most rational solution to ensure security of supply for the entire region, the ministry said. The EC is co-funding the subsea BalticConnector pipe, expected to connect Estonia and Finland in 2020.

[William Powell](#)



# SECURITY OF SUPPLY, IGAs AND ENERGY UNION

Muddled thinking? The dividing line between European Commission law and aspirations has become blurred.

In April, a key piece of EU legislation concerning gas was revised: the decision on intergovernmental agreements (IGA decision). The end of the month also saw the Council and European Parliament reach an agreement on the amendment to another key piece of EU legislation concerning gas: the Security of Gas Supply Regulation ("Revised SOS Regulation"). Over the same period the discussions regarding Nord Stream 2 have intensified.

A lot of the discussion, especially amongst EU politicians, in respect of the above legislation and Nord Stream 2 centred on the concept of the Energy Union. Confusingly, many involved in the discussion seem to believe that Energy Union is a legal concept and a legal measuring rod for assessing projects, agreements and domestic laws and plans. So for example, gas infrastructure projects such as Nord Stream 2 are said to be "incompatible with the Energy Union".

But what does it mean for a project to be "incompatible with the Energy Union"? Such language may be taken to suggest that there are legal rules that define the Energy Union, but it is not even a legal concept. And furthermore, a project cannot be prevented from going ahead on the grounds that it is "incompatible with the Energy Union".

Nor can an agreement or a law or a national plan be legally assessed by reference to Energy Union objectives or principles. At present, it is merely a set of political objectives. In fact, there is not yet a consensus even about what the Energy Union means in political terms.

A misunderstanding over the concept of the Energy Union held up the adoption of the amendments to the IGA Decision. In its comments on the EC's proposal to amend the IGA Decision the European Parliament sought to have agreements between an EU states and third countries which concern oil and gas subject to

assessment by the EC as to their compatibility with the "Union's energy security objectives" and "Energy Union objectives" before they could be concluded.

Given that the reference to "Energy Union" is not to a legal term or concept, it is encouraging from a legal perspective that Recital 9 of the amended IGA Decision makes absolutely clear that "the relevant Union energy policy objectives, solidarity between member states and Union policy positions adopted in Council or European Council conclusions...should not form part of the legal assessment undertaken by the EC of IGAs before they are concluded".

Accordingly Article 5 of the revised IGA Decision provides that an IGA between a member state and a third country concerning oil and gas can only be signed after the EC has assessed whether it is compatible with EU law. Up until now such IGAs were subject to such an assessment by the EC only after they were concluded..

The decision not to include the references to the Energy Union in the IGA Decision as requested by the parliament, is therefore a very positive development since it reinforces legal certainty and clarity. And legal certainty and clarity are key to ensuring investment in new energy infrastructure in the EU.

We are now in the third round for listings of Projects of Common Interest. The next list will be drawn up by November of this year. Given low gas prices and the expected arrival of cheap LNG from the US, the stability, certainty and clarity of the EU regulatory framework is vital for the realisation of new gas infrastructure projects, be it for the construction of LNG terminals, inter-connectors or ambitious deep sea pipelines such as the East Med pipeline.

Lack of clarity and certainty as to the nature and scope of the





solidarity obligations imposed on states under the Revised SOS Regulation held up its adoption. The three key new provisions of the Revised SOS Regulation are: First, member states have to help their neighbours to ensure gas supply to households, essential services – other than educational and public administration – and district heating installations that deliver heat to households or essential services of its neighbour by prioritising the supply to such customers over the supply of consumers in its own jurisdiction that are not protected customers.

Importantly, the final version of the Revised SOS Regulation clarifies that this obligation is one of last resort; spells out the methodology for calculating fair compensation for such supply; provides that the payment for compensation shall be prompt; and ensures that supply to certain critical gas-fired power plants in the state(s) that provide the solidarity can continue if the lack of such supply would result in severe damages in the functioning of the electricity system or would hamper the production or transportation of gas.

Second, states are grouped in four risk groups at the regional level and are required to develop within these risk groups a common approach to security of gas supply by 1 September 2018 and thereafter every four years.

Third, gas companies are required to notify to the EC contracts which last for more than one year and which individually or cumulatively with contracts with the same supplier or its affiliates represent at least 28% of a state's gas demand. This

provision represents a significant victory for parliament since initially the EC proposed a 40% threshold for this reporting obligation.

Importantly, the EC's proposal to extend the solidarity obligation of a state to cover countries signatories to the Energy Community Treaty (including Ukraine and Georgia) was rejected by the Council after the Legal Service confirmed that it was incompatible with the provisions of the Lisbon Treaty. The final version of the Regulation makes clear that the EC cannot assess action and other plans by reference to the Energy Union or its objectives.

The attention of the gas sector will now turn to the Winter Package. Although this legislation concerns electricity the potential impact on gas is significant not least because it sets out the templates for national energy and climate change plans, contains references to the Energy Union, proposes to alter the decision making mechanism for the pan-EU energy regulation co-ordinator Acer; and seeks to introduce regional bodies which are not envisaged under the Lisbon Treaty. Moreover the EC as announced that it intends to mirror certain elements of the Electricity Market Design proposals in the package of proposals it plans to rollout to amend the Third Energy Package as it relates to the gas sector in spring next year.

Ana Stanic, E&A Law, London

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## ENERGY COMMUNITY EXTENDS A HAND TO UK

The UK would be welcome to apply to join the Energy Community, the director of its secretariat told the Flame conference on May 11. But every club has its rules.

Now in its 12th year, the Energy Community brings together the European Union and nine 'contracting party' nations in the Black Sea and former-Yugoslav regions to create an integrated, competitive energy market enabling cross-border trade and investment in gas and power. Ukraine is the largest such member while Georgia, another former Soviet republic, is the newest. Turkey and Norway are observers.

If in 2019, the UK leaves not only the EU – then, in 1973, still the EEC – but also its single market and customs union, it would be the first full member state to do so since the EEC came into being in 1957, and thus the first ex-EU country that might become a Community 'contracting party.'

As they go to the polls on June 8, UK politicians are split over Europe, with opposition (Labour, Scottish Nationalist Party, Liberal Democrats) parties arguing that – if the UK exits the EU in 2019 – it should secure a deal to stay in the EU Single Market, including for energy.

The ruling Conservatives though say that no agreement over the Single Market would be preferable to a 'bad deal'.

Janez Kopac became director of the Energy Community's secretariat in Vienna for four and a half years, having been director-general of energy at Slovenia's economy ministry from late 2008 until early 2012. Here he answers NGW's questions.

***How would you like the European Commission to improve its dealings with Energy Community countries?***

The Energy Community has been referred to as a wider Energy Union. And rightly so, as it extends the full set of EU energy policy and law to its neighbours, tying them to the internal energy market under the unique governance framework of the Energy Community Treaty. One of the goals of the current reform of that treaty is to provide for a true level playing field between the EU's member states and the participating non-EU countries based on full equality.

***You said at Flame that you would welcome a UK application to join the Energy Community, if it were to leave the EU and (unlike Norway) also exit the Single Market. Did you mean that ironically? May former EU states join the Energy Community?***

Any non-EU country in Europe can join the Energy Community if it considers that in its own best interests and the other parties to the treaty agree to an accession. For a long time, the Energy Community has been perceived as a “waiting room” for EU accession. This has not reflected the reality for years.

With the accession of Moldova, Ukraine and most recently Georgia, the Energy Community has turned into a long-term project of building a pan-European energy space. An objective assessment of a given non-EU country's best interest will take the nature and the particular features of the Energy Community into account, and not an outdated perception.

***What could the UK/GB offer the Energy Community, and what could it offer the UK - especially in terms of an area for resolving issues with the EU regarding gas trade, and an informal dispute resolution forum?***

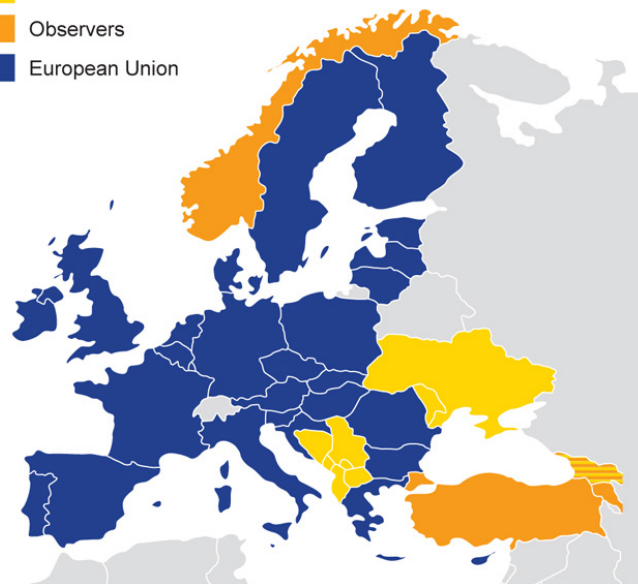
The UK has always strongly supported the Energy Community and has an excellent reputation in all its member countries. The Energy Community, on the other hand, has many interesting features including offering market access, fair and easy decision-making procedures, a functioning dispute resolution procedure and the possibility for flexible solutions.

***Many pro-Brexit politicians are strongly opposed to any jurisdiction 'post Brexit' by the European Court of Justice (ECJ) over the UK. But is acceptance of ECJ rulings an absolute precondition for membership of the Energy Community?***

The Energy Community does not have its own Court of Justice and thus does not issue judicial decisions which could be binding on a party. In their decision-making, the institutions are to follow the case law of the EU Court of Justice, but this obligation is part of homogeneity rules which govern any common market.

***The Flame traders' panel on May 11 - particularly TrailStone's head of gas Didier Magne - applauded what Ukraine has done***

■ Contracting Parties  
■ Candidate  
■ Observers  
■ European Union



Map credit: Energy Community

***to facilitate gas trading, to date, while noting that next steps depend on the Stockholm Arbitration (contrasting Ukraine's progress with Poland). Do you agree?***

The most urgent thing to be done in Ukraine's gas sector is the unbundling of the transmissions system operator in line with the EU's Third Energy Package. As long as this process – which the Secretariat initiated over a year ago – remains stuck, Ukraine is not compliant with the rules it wants others to apply.

## UKRAINE WINS ROUND I OF STOCKHOLM

The critical obstacle to unbundling is the lack of a ruling from the Stockholm arbitration tribunal, where the two companies, Naftogaz Ukrainy and Gazprom have been contending two contracts for three years this June. The ship-or-pay contract is with Naftogaz, not its transportation arm. NGW reported on issues relating to Ukraine in the run-up to the key Stockholm arbitration decisions in its [last issue on pages 4 to 7](#).

There was no update on unbundling as NGW went to press, but Naftogaz, the parent company of the transporter, UkrTransgaz, announced some positive news on May 31. The take-or-pay clause in its contract with Russian Gazprom has been greatly reduced and the penalty payment demand has been rejected and so has the ban on re-exports. Further, as of 2014, the gas price has been linked to the NetConnect Germany hub. However there is still the unresolved issue of whether Ukraine took Russian gas that it did not pay for in 2014.

Mark Smedley





# ROTTERDAM PORT GOES GREEN

Rotterdam, by far the largest European sea port, has ambitions for bunkering LNG – but not as we know it. Bio-LNG is the way forward, it says.

In collaboration with the Dutch National LNG Platform, the Port of Rotterdam Authority has started to study opportunities for developing LNG from renewable sources as a transport fuel in the port.

It is focusing on bio-LNG rather than on regular LNG, because the bio variant allows its users to drastically reduce their CO<sub>2</sub> emission levels. Dutch government authorities and companies share a common ambition that, by 2021, at least a tenth of the LNG supplied to end users, will be bio-LNG.

Electric transport options are expected to form a major means to cut back CO<sub>2</sub> emissions in passenger transport over the next few years. Today however, electric propulsion systems are not a viable alternative for inland shipping, maritime shipping or heavy road transport. LNG is already supplied as a transport fuel to shipping and heavy road transport from the Gate terminal – operated by Gasunie and Vopak – in the port of Rotterdam. It has three tanks, two jetties and one loading quay.

Compared with diesel and fuel oil, LNG is a far cleaner option, with a significantly smaller ecological footprint. On top of this, bio LNG offers another advantage: the emitted CO<sub>2</sub> is part of the so-called short cycle: CO<sub>2</sub> emissions are actually neutralised by the associated CO<sub>2</sub> uptake such as horticultural greenhouses. And today, 18% of the Dutch CO<sub>2</sub> is emitted in the port of Rotterdam.

Eight companies, all of them members of the National LNG Platform, will support the study with their technical, legal and financial expertise and market knowledge. The partners aim to have the study completed by the second half of 2017. Based on the research findings, it will be decided whether – and if so, how – Rotterdam will develop a bio-LNG programme.

## Market study

The researchers first will examine the existing and expected availability of production technologies and processes up to 2030. They also will perform a market study, including scenarios about the availability of sustainable feedstock and the future development of demand. Finally, they will look for business cases for the production, transport and transshipment of bio-LNG in the port area. But already today the Rotterdam port area is the largest bio based cluster in Europe. The largest investments will generally have to be made by private companies, but the port will offer support with attractive accommodation conditions,

connecting infrastructure and support in acquiring construction permits and finding financing. The port is also prepared to make its own risk-bearing investments or to take stakes in companies where investments are needed to bring about the energy transition.

## LNG fuelled ships

Energy companies cannot wait for detailed studies and political master plans to be completed. Recently the French energy firm Total acquired the Dutch Pitpoint Clean Fuels, with headquarters in Nieuwegein near Utrecht, about 40 km from Rotterdam. Pitpoint was a merger of several Dutch companies, involved in both CNG and LNG. In combination with Primagaz, it wants to develop at least 15 fuel and bunkering stations for LNG in the Netherlands. According to Pitpoint-director Erik Kemink, in the Netherlands there is room for at least 40 LNG filling stations.

Seven years ago the Dutch transport sector used almost no LNG. At the end of 2016, it was used by six ships and about 400 trucks. Today, Pitpoint uses about 100 CNG and/or LNG-stations in the Netherlands, Belgium and Germany. Its target is to have 350 stations operational in those countries by 2022. Buyers and retailers can specify green gas when they order it, in the same way they do green electricity: with a green certificate. Financial problems at the Korean ship builder STX Offshore & Shipbuilding have delayed the construction of the LNG bunkering ship ordered by Shell to use in Rotterdam. But as soon as it is operational, it will bunker four new Sovcomflot tank ships, chartered by Anglo-Dutch major Shell.

Those ships, with a length of 250 metres and a capacity of 141,000 metric tons, are the first LNG fuelled ship of this scale. The Gate Terminal is also contracted by Finnish Containerships to supply LNG to four new ‘short sea’ ships that are used for coastal navigation or between Netherlands and the UK. These will become operational in 2018. And in 2019, the American cruise line Carnival will bunker LNG in Rotterdam. Last year, shipping company Barkmeijer Shipyards ordered a dual fuel (LNG + diesel) dredging vessel. The Ecodelta is to be operational by 2018. It will be used mainly for dredging tasks in the port of Rotterdam, replacing a ship that is 30 years old ship.

## Remaining role for fossil resources

The port of Rotterdam also aspires to become a flagship as well as a laboratory for a low-carbon emission society. The German

Wuppertal Institute for Climate, Environment and Energy has been looking at the options available for Rotterdam if it is to align its industrial sector with the CO<sub>2</sub> targets set out in the Paris Agreement on climate change. Winding down specific industrial activities was not one of them, since the need for chemical products and fuels of all kinds will remain. Stopping making some sorts of products would only result in the same kinds of goods being imported.

According to the CEO of the Port of Rotterdam Authority, Allard Castelein, German research shows that it is possible to drastically reduce CO<sub>2</sub> emissions. He says in a document published by the port that the various projects that Rotterdam is working on align very well with the detailed transition pathways, in particular the use of residual heat; and the capture and storage of CO<sub>2</sub>.

The Port of Rotterdam Authority, the Rotterdam heat grid company, the province of South Holland, gas transport system operator Gasunie and energy company Eneco have signed an agreement to realise a 'heat rotund' in South Holland. This rotund has to become an open heat transport backbone. Any heat supplier can inject heat, as long as it does not generate heat from burning coal. Gas is one of the remaining options.

The energy transition however involves a large number of steps taken by a large number of companies and other parties over an extended period. "The study shows this transition is feasible. It can be seen mainly as a call to launch new initiatives," Castelein says.

### Combined pathways

The Wuppertal study shows four possible transition pathways, involving augmented use of biomass, the capture and storage of CO<sub>2</sub> and the almost entire recycling of fossil resources. Rotterdam is intended not to choose one of the proposed pathways, which each present their own challenges or bottlenecks. It would instead prefer a combination of the several options. A number of projects underway, such as the development of the regional heat transport grid, are already in line with these transition pathways.

Although the German study does not assign an important role to any methane conventional or otherwise, the 'combination' approach offers some leeway to involve it. The port is even thinking about building a pipeline to connect companies in the port area with depleted gas reservoirs in the North Sea, where the captured CO<sub>2</sub> may be stored.

An international research team, coordinated at the Radboud University in Nijmegen, is investigating the feasibility of this storage and its possible effects on employment in the Netherlands, Scotland and other areas that will be hit by the reduction in gas production and processing.

Koen Mortelmans

## BIOGAS: CLEANER THAN YOU THINK.

A new study published by the Natural Gas Vehicle Association (NGVA) shows that using natural or biogas as a fuel for passenger cars cuts greenhouse gas emissions (GHG) by 23% compared with petrol and by 7% compared with diesel.

NGVA commissioned life-cycle analysts Thinkstep an industry-wide assessment of the supply of natural gas to Europe and its use in the European Union, mainly in the transportation sector.

Thinkstep found, using thoroughly researched data to piece together the carbon footprint, that gas is not only cleaner than earlier studies have shown, when considered from the wellhead to the wheel, the wake, or the grid, depending on the application; but that it would become even cleaner when mixing with even small amounts of locally-produced biogas.

Greenhouse gas intensity of natural gas, intended for use as a reference study and using certified metrics to calculate its data, also says that using renewable gas provides additional benefits towards carbon-neutral mobility: by blending natural gas with just 20% renewable gas, GHG emissions are reduced by 40% compared with oil-derived fuels.

The reductions are greater in the heavy goods trucks sector, with both LNG and compressed natural gas (CNG) cutting emissions by about 15% compared with diesel. In the marine sector, the cuts are even bigger, at 21% compared with conventional heavy fuel oil.

In addition to the low GHG emissions, natural gas is the cleanest fuel to guarantee a particulate free combustion, aromatic free and close-to-zero non-methane hydrocarbons as well as dramatically reducing NOx emissions.

The study also highlighted the important role bio-gas (LNG and CNG) can play in the future fuel mix. Locally produced bio-fuels will contribute to local economic development in cities and regions across the EU, as well as providing increased security of energy supply to that region. These benefits can be realised as part of a comprehensive EU transport and stationary energy 'menu' of options.

Improvements in vehicle engine technology for gas and biomethane are also likely to be substantial, particularly for dedicated gas engines, the study concludes. Efficiency improvements are steadily reducing gas consumption and emissions. The production of bio-gas from renewables will further support the development of natural gas vehicles.

William Powell



## BELARUS EXTRACTS CONCESSIONS

In April, Moscow and Minsk agreed a new energy deal for this year, papering over the cracks in an ever less friendly relationship. Claiming some success, Minsk still clearly has some bargaining power.



*Russian President Vladimir Putin with Belorussian President Alexander Lukashenko on April 2, 2017 (Photo credit: The Kremlin)*

According to an April 2017 intergovernmental agreement between Moscow and Minsk, Belarus will pay Russia the present-day price – \$130/’000 m<sup>3</sup> for the rest of this year. Next year it will pay less than \$130/’000 m<sup>3</sup> although the price will be denominated in Belarusian roubles. It will also repay the debt it owes for gas, not far short of \$700mn.

For its part Russia will also send to Belarus 24mn mt of oil tax free, up from 18mn mt/yr, *Tass* reported. The Belarusian president Alexander Lukashenko said his country would compensate for the Russian gas price, which Minsk has been describing as too high, by re-exporting some of this Russian oil. The treasury could earn an additional \$500mn by re-exporting 6mn metric tons/yr.

The deal ends a stalemate. In 2016 Belarus paid \$107/’000 m<sup>3</sup> for Russian gas, whereas Gazprom had demanded \$132/’000 m<sup>3</sup>. Belarus had wanted to pay just \$72/’000 m<sup>3</sup> and to move to netback pricing – which would mean paying the equivalent of the Russian price plus the cost of any transport, which would be small given the countries share a border.

Moscow – acting as the main shareholder of Gazprom – demanded that Minsk should pay what Moscow regarded as Minsk’s debts. By the autumn of that year, Belarus owed

Russia between \$270mn and \$300mn so Moscow, according to newsagency *Tass*, cut the tax-free oil deliveries by a third.

By the spring of 2017, these debts had mounted to \$660mn. The stand-off continued until they did a deal in April, when the two leaders met, and presumably solved at least some of their problems, engaging in a mutually acceptable compromise, albeit later Lukashenko made it clear that the problems with Moscow were far from over.

Some Russian observers believe that Moscow’s decision to engage in the deal is purely geopolitical. One of them noted that the conflict between Russia and Belarus emerged when Russia was facing increasing problems with the west and this influenced Russia’s relationship with Belarus.

The other reason for the discount was the downward pressure on gas prices, and Moscow was genuinely worried that gas prices could fall even more. All of these factors explain Moscow’s desire to find compromise. Still the implication of the conflict is clear.

First, the recent clash with Belarus influenced Moscow’s approach to the country. Moscow increasingly sees Minsk as a foreign entity.



Second, and related, is the implication that Russia has now lost not just Ukraine, but even supposedly pro-Russian Belarus as reliable transit countries for deliveries westwards. That would explain Russia's need to speed up the building of Nord Stream II and Turkish Stream.

Both gas lines would bypass the unreliable former Soviet republics, as well as members of the former Warsaw Pact, and would deliver Russian gas directly to solvent markets customers in west and central Europe despite its 100% control of Beltransgaz, now known as Gazprom Transgaz Belarus.

### Difficult history

Belarus, a small Slavic republic of the former USSR, is officially one of the strongest Russian allies. It is in a "union" state with Russia, and in 2015 became one of the founding members of the Moscow-sponsored Eurasian Union. Still, Moscow looks at Belarus not so much as an ally as a vassal and it has used gas and oil supplies to impose its will on Minsk.

In the beginning of the post-Soviet era, Moscow tried to accommodate Minsk's needs; but as time progressed, Moscow's approach to Belarus changed and the pressure has increased recently. The implications of this could be manifold, and be both geopolitical and economic.

First, Belarus could continue to drift away, despite being formally a member of the union. Conflict with Belarus would also provide Russia with additional incentives to build Nord Stream II to send its gas directly to Europe, and bypass the republics of the former USSR, Belarus – the first transit country for Yamal Europe – among them.

Before Vladimir Putin's presidency, Boris Yeltsin's approach towards Belarus, and Moscow's policy in regard to gas supplies, were closely linked with Russia's internal politics. By the end of his presidency, Yeltsin was increasingly pressed by Nationalists and Communists who accused him of destroying the USSR and accelerating Russia's socio-economic decline. To demonstrate to the public that he was not a mere vandal but instead the founder of a new, multi-ethnic state, and indirectly restoring the USSR and some of the arrangements from the Soviet era, Yeltsin engaged the support of the Belarusian leader.

Lukashenko had his own reasons for moving closer to Russia. To start with, Belarus, so recently a part of the USSR and integrated in the Union economy, had a hard time surviving on its own. Minsk wanted the Russian market and especially Russia's oil and gas.

Second, Lukashenko saw how unpopular Yeltsin was, and thought that he could eventually replace him in the future. The





deal was cemented by the old Soviet provisions, which implied that Belarus would receive gas and oil much more cheaply than external customers outside the former USSR.

Yeltsin's Russia continued to provide a considerable discount for Belarus since the beginning of the post-Soviet era. But even in this new dawn the tension between Moscow and Minsk was visible. The conflict was due to Belarus' wish to receive much more than Russia was willing to offer.

According to some observers, there were six gas wars between Russia and Belarus although Belarus has been engaged in gas wars with Russia from the beginning of the post-Soviet era.

In 1995, Minsk paid only 27% of the price of the received gas; in 1996 it paid 64%, and in December of 1996. Minsk was not ready to pay and for the first time, Russia limited the delivery of gas for three days. Still these conflicts were brief and had no direct implication for Minsk's relationship with Moscow.

In 1999, Russia and Belarus became a union state. According to the new provisions, Russia sent Belarus as much oil as it needed without custom duties. According to the same agreement, Belarus could export products made from Russian oil. Russia would have received 85% of the export custom duties while Belarus paid less than Russian refineries were paying.

Still, problems emerged by the end of Putin's first term, and in 2004, there was a second gas war. As with the first one, it was comparatively short and Moscow struck a compromise with Minsk, possibly owing to the residual Soviet legacy and possibly because of Moscow's continuing hopes that a union with Belarus would lead to most of the post-Soviet republics around Russia seeing the advantages of such a union.

The arrangement held until the beginning of Putin's second term, and the change was related to evolution in the Russian elite's geopolitical designs and the general political culture.

### Imperial pragmatism

Putin increased the neo-imperialist drive that re-emerged during the late Yeltsin era, or even before. In this context, not everything was translated into cash, and broader geopolitical designs were taken into account. One could see this in Putin's behavior in Ukraine and Syria. In both cases, the Kremlin accepted financial losses as the price of its geopolitical goals.

Putin's administration is much more imperialistic and geopolitically oriented than its predecessor's. Still, the story is more complicated than it looks at first glance. Yeltsin, following Gorbachev, had been engaged in the process of continuous geopolitical retreat, and the Russian elite was interested only in cash in dealing with the West.



*Boris Yeltsin (Photo credit: The Kremlin)*

But in its dealings with the former USSR, Yeltsin continued with basically Soviet policies which implied a cheap gas and oil supply and he made no effort to block oil and gas producing countries of the former USSR from sending gas or oil to European markets. Yeltsin engaged in these policies to maintain control over the former USSR, even if the policy cost the Russian treasury considerable sums of money.

The policy was due to the existence of residual neo-Soviet arrangements, in which constituent republics of the USSR and even eastern Europe received gas and oil for a fraction of their cost, plainly because they were all part of the imperial commonwealth

The Putin era was clearly marked by the departure from the early approach to ex-Soviet republics. From now on they were not rebellious children who might at some point return to the family, but foreign countries in their own right.

While they could, and should, be under Moscow's sphere of influence, in Moscow's eyes they were considered foreign entities with no clear ties to Russia and who would never be fully blended with Russia in the Soviet fashion. Seen in this light it was not appropriate for Moscow to indulge their whims until some imaginary reunion should take place.

And this pragmatism influenced Moscow's views of Minsk. Moscow was willing to provide some limited support, but not to support the ally regardless of the cost. This behaviour is distinct from the USSR, which never argued with its allies and proxies about the price of oil, gas or any other raw material.

[Dmitry Shlapentokh, Indiana University](#)

## SWEET DEAL FOR TUBACEX

Spanish pipeline company Tubacex is exporting its acid-resistant technology to Iran in order to progress the development of the South Pars gas field.

National Iranian Oil Company (NIOC) signed a €550mn (\$630mn) deal with a 50-50 joint venture between Mobarakeh Steel Company and Tubacex May 24 to purchase 600 km of corrosion-resistant alloy (CRA) pipes, needed for the giant but sulphurous South Pars project.

So far, Iran has depended on imported CRA for laying the pipes for eight of the 24 phases. Currently, phases 11, 13, 14, 22-24 need purpose-built linepipe to transit sour gas to onshore refineries. Mobarakeh Steel Company and Spanish Tubacex will establish three firms, two of them in Isfahan city and another in Kish Island, to produce 600 km CRA pipelines over three years, NIOC announced.

Tubacex, along with Japanese JFE, is one of the few companies in the world licensed to produce the standard CRA and now it is obliged to deliver this technology to Iran's Mobarakeh Steel Company as well.

Until now there has been little information on the need for CRA pipes for South Pars, though Iran did once say that French Total, the operator of South Pars phases 2 and 3, had supplied CRA pipelines for them.

PHASES OF SOUTH PARS	STATUS AS OF JAN 2017	START DATE	NOMINAL SOUR GAS OUTPUT (Mn m <sup>3</sup> /d)	SULPHUR OUTPUT (Metric ton/d)
Phases 1-10	100%	Before 2010	280	2000
Phase 11	0%	Probably 2021	56	400
Phase 12	100%	2014	84	750
Phase 13	85%	2017	56	400
Phase 14	67.33%	2017 and 2018	56	400
Phases 15,16	100%	2015	56	400
Phases 17, 18	98%	2016 and 2017	56	400
Phase 19	96%	2016 and 2017	56	400
Phase 21, 21	92%	2016 and 2017	56	400
Phases 22-24	83.6%	2017 and 2018	56	400

NEW PHASES	CRA LINEPIPE NEEDED
PHASE 11	2 x 32" pipes, each 90 km
PHASE 13	2 x 32" pipes, each 136 km
PHASE 14	2 x 32" pipes, each 105 km
PHASE 22-24	2 x 32" pipes, each 105 km

*\* Based on official document*

South Pars, called North Field in Qatar, has about 40 trillion m<sup>3</sup> of recoverable reserves remaining, of which about a third are on Iran's side of the border. The field contains five layers (K1-5), of which the recoverable layers are K1-4; and Iran has started producing gas from the first. Iran started gas extraction from K2 and K3 in phases 1-10 2010 and then in new phases it extracted gas from K4, which was also the biggest reservoir.

Now it is extracting gas from K1, which Iran had thought contained too much hydrogen sulphide, although an engineer at South Pars told *NGW* that the sulphur content in all layers of South Pars is similar at 4,000 parts per million. An official document, prepared by oil ministry and seen by *NGW* also indicates that 26mn m<sup>3</sup>/d of sour gas – a standard phase – produces 200 metric tons of sulphur.

South Pars has been divided to 24 phases, some equal to two or three or 2/3 of standard phases. Phases 13 and 14 are close to onshore facilities, but other phases are further off. Iran plans to complete all phases of South Pars, except for phase 11, in the next three years. Official statistics indicate that 690 km of offshore pipeline are needed for completion of new phases by 2020. Then once it has the technology, Iran can produce CRA pipes for phase 11 and other projects by itself.

Iran and Qatar both produce gas from four layers of the field. Iran's output is still a little less than Qatar's, standing at 500mn m<sup>3</sup>/d, but Iran plans to bring it to 720mn m<sup>3</sup>/d after full completion of South Pars.

Dalga Khatinoglu





## JAPAN'S PRICE WAR STARTS

Liberalisation has reached Japan, sharpening the focus on importers' weighted average cost of gas. Greater co-operation could increase buyers' power.

Gas price wars are heating up in Japan as both the electricity markets and gas markets become liberalized, ushering in an era of cut-throat competition in the world's largest LNG importing country. Osaka Gas, Tokyo Gas, Toho Gas are Japan's largest retail natural gas companies accounting for about 70% of city gas sales. In addition, more than 200 city gas utilities operate in Japan. Japanese retail gas and electric companies participate directly in overseas upstream liquefied natural gas (LNG) projects to assure reliability of supply.

On May 9, Tokyo Electric Power (Tepco), Japan's largest electric utility, offered customers in the Tokyo metropolitan area gas prices up to 8% cheaper than those offered by rival Tokyo Gas, the country's largest gas utility. Tepco is also offering city retail customers a discount for electricity of around 1,200 yen (\$11)/yr if they apply for a bundled service along with gas.

Tepco's offer comes just two months before the company formally enters Japan's \$20bn/yr retail gas market which was fully liberalised on April 1, effectively opening up the remaining portion of the market.

Japanese households and other small-end gas users are now free to choose their city-gas suppliers. Customers had previously been allowed to purchase city gas from the gas utilities in their respective regions. The government fully liberalised the country's gas market to spur competition and offer lower rates and better services for customers.

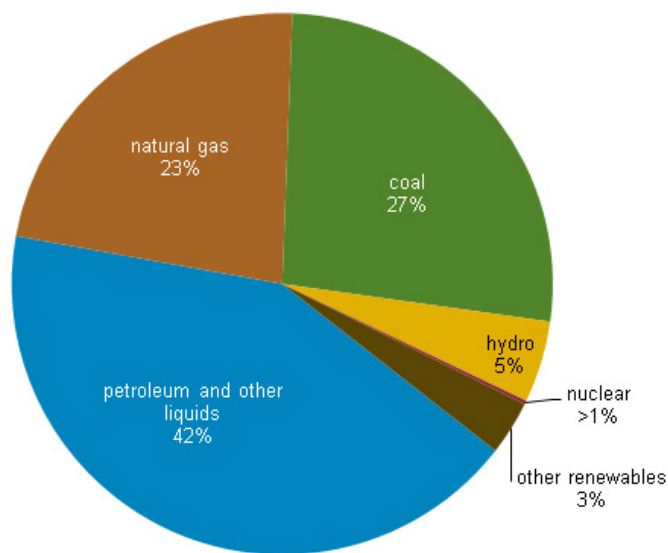
### Chasing market share

Tepco's discounted gas price offer comes after the company lost 1.81mn electricity customers last year when Japan's electricity market was liberalised. Around 760,000 of those customers were lost to Tokyo Gas, according to local media reports.

Former power monopolies will be pushing to capture a large part of Japan's city gas markets to compensate for the around 3mn (about 5%) retail power customers they lost to gas and other suppliers in the first 11 months since electricity markets were fully liberalised, *Reuters* said in a March 31 report.

Tepco lost a lot of retail power customers, but "can launch a hard strike (into the retail gas market)," said Michio Sato, managing director of Tepco's retail energy unit. "Both Tepco and Tokyo Gas will make their 120% effort to keep their market share, even if it requires a brutal price war," Keun-Wook Paik, a natural gas

Japan's total energy consumption, 2015



Source: EIA International Energy Statistics, BP Statistical Review of World Energy 2016

expert at the Oxford Institute for Energy Studies told *NGW*. "Losing or gaining market share is the upmost important criteria for their planning," he added.

Tepco's ambitions, however, will be curtailed, at least for now. The company has earmarked only 40,000 retail city gas customers in its first year of entry because of the limited availability of gas in the near-term – a disappointing figure to some analysts within the country.

Reiji Ogino, senior analyst at Mitsubishi UFJ Morgan Stanley Securities, told media that Tepco's goals are at the low end of expectations given that Tokyo Gas acquired more than 700,000 electricity customers from Tepco last year. However, by building a city gas-processing facility in the second half of 2018, Tepco hopes to boost the number of its gas customers to 1mn the following year. By way of comparison, Osaka-based Kansai Electric Power, Japan's second largest power utility, is looking to add 200,000 retail city gas customers in its first year of entry.

Tepco may best be known as the operator of the Fukushima Daiichi nuclear plant that was shut down in March 2011 after an earthquake-triggered tsunami caused a meltdown at the facility. A Japanese court ruled in a surprise verdict two months ago that Tepco and the government were responsible for failing to take preventive measures against the quake.

### Shaking things up

Several developments are unfolding from Japan's gas market liberalisation. Companies of all sizes are forging partnerships to capitalise on the change in gas markets to procure cheaper imported LNG and seek economies of scale.

Paik pointed to Jera, a joint venture formed between Tepco and Chubu Electric Power Co, as an example of the kind of partnerships that could be formed.

"The Jera joint venture is a kind of unusual alliance to make sure the leverage of big LNG buyers will be introduced," he said. "Kogas [Korea Gas Corp.] never enjoyed the leverage of single biggest LNG buyer, but JERA is determined to take advantage of the co-operation."

Formed in 2015, Jera is now one of the largest global LNG buyers and has also become a seller of LNG amid a supply overhang projected to last until the beginning of the next decade.

Last May, the JV agreed to sell as much as 1.5mn metric tons of LNG between June 2018 and December 2020 to a unit of France's Electricite de France, with the price linked to European gas market prices.

With as many as 16 nuclear reactors scheduled to become operational again in Japan by late 2022, based on several analysts' assumptions, more uncommitted excess LNG volumes will cause Japanese companies and utilities to unload these cargoes on the spot market, thus also becoming both buyers and sellers.

Meanwhile, Tokyo Gas said earlier this year it sees more than a dozen Japanese LNG importers possibly joining three large partnerships to secure cheaper fuel through increased bargaining power. Tokyo Gas and Kansai Electric Power said previously in a joint statement that they were considering co-operation in areas including fuel procurement and power plant development.

Japanese oil refiner JX Nippon Oil and Energy Co president, Tsutomu Sugimori, said in January that the company aims to expand its power and natural gas business. "Everyone who buys natural gas feels the same way. We want to get together as much as possible and buy cheap fuel," he said.

The company also said at the time that it was looking to team up with the owner of an LNG terminal near Tokyo where imports are dominated by Tepco and Tokyo Gas. In March, JX Nippon also joined forces with Japanese utility Hokkaido Gas to provide LNG to Hokkaido, Japan's northernmost island.

Tim Daiss

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## MAJORS DRAG FEET IN S AFRICA'S UPSTREAM

The low oil price has forced the majors to look elsewhere – although they might provide financial muscle later if the game proves worth the candle.

ExxonMobil and South Africa's Sasol are still engaged, but some large energy companies are getting cold feet about exploration offshore South Africa, a gas conference has been told. The warning came from Dave van der Spuy, who manages conventional resource evaluation at upstream regulator Petroleum Agency SA (Pasa).

Both Shell and Australia's BHP Billiton have recently relinquished licences for exploration off the west coast of South Africa, he told the recent Gas Africa 2017 conference in Johannesburg. "Offshore, some of the big boys have left. They get extremely aggressive when oil price is high, and then they leave (when it is low)," he said. "Shell has pulled out of licences they have held recently, as has BHP Billiton." He suggested this was due to the slump in oil prices and regulatory uncertainty. "Ultra-deep exploration is high risk. That may be the reason they have gone."

However, he said applications from other (unnamed) companies have been received for the same exploration blocks and "there is still a great deal of interest in the possibilities off our West Coast."

Larger oil firms might return when market conditions improve by acquiring projects being carried out by smaller players, he said. They would then be able to provide the capital needed to move a project to production.

He said that offshore there are currently six production licences, 16 exploration licences, one technical co-operation permit and three reconnaissance permits which exclude drilling. In addition, several applications or licence conversions are in process. He noted that SA's main offshore gas project at Mossel Bay still has 20 operating wells, but they are producing less than half of the feedstock the refinery can take.

The PetroSA refinery at Mossel Bay is being converted to use liquid feedstock, while PetroSA itself is embroiled in a scandal following massive losses, which have been attributed to poor management.

South Africa's Department of Energy is undertaking a restructuring so that it has better control over PetroSA. Van der Spuy said that there are "a number of interesting operators, including ExxonMobil, off South Africa's east coast. The last exploration was last year, for the acquisition of seismic data." He argued that challenges facing all gas explorers in South Africa

include a massive slump in the oil price since 2014, regulatory uncertainty, questions over the role of gas in the future energy mix, and environmental campaigns against fracking. He said that companies are adapting to the challenges by introducing risk-sharing mechanisms, with multi-client surveys, partnerships over licence areas, and the reprocessing of older data.

While some explorers are leaving, new explorers are taking up opportunities, with more focus on deep to ultra-deep water. He said it remains to be seen whether there as much gas on South Africa's east coast as has been found further up Africa's eastern seaboard.

ExxonMobil and Sasol have exploration blocks off the East Coast, and van der Spuy said that oil field services company Schlumberger last year completed a multi-client 3D survey, mostly over those Eni-Sasol and ExxonMobil blocks.

An ExxonMobil spokesman told NGW: "Evaluation of the Tugala South block (ExxonMobil interest, 40%) is ongoing - no wells drilled, and we haven't announced forward-looking plans. The co-venturers did acquire more than 700 square miles of 3D seismic data over the block in 2016." Statoil farmed into the 9,053km<sup>2</sup> Tugala South block in 2015, while the remaining 25% is retained by local privately-owned explorer Impact Africa.

Exxon's former CEO [\*Rex Tillerson said March 2016 that South Africa\*](#), plus Cote d'Ivoire in west Africa, are countries that present "moderately higher [exploration] risk but also much higher potential." The US major's focus since has been very much on big oil finds offshore Suriname, South America.

Impact Africa retains 100% of the 4,917km<sup>2</sup> Tugala North, adjoining the Exxon-operated south block. Its website also says it has 100% interests in the Orange Basin Deep, West Bredasdorp, plus Transkei and Algoa blocks – all sizeable offshore blocks – and has approached Exxon about becoming operator of the latter two.

The South African independent made headlines two months ago with an agreement to farm out a 65% stake to China's CNOOC of its 6,700 km<sup>2</sup> AGC Profond exploration block, in the offshore Senegal-Guinea Bissau joint development area, for an undisclosed sum or carry. Discoveries by Kosmos and Cairn off Senegal have turned that region into an exploration – and farm-in – hotspot.



## Onshore still attractive

Onshore South Africa, Van der Spuy said there is one production right, 33 exploration rights onshore, and three technical cooperation permits. Onshore activity is in natural gas, coal bed methane, and in shale gas requiring fracking – for the latter he expects new exploration licences to be issued soon.

The CEO of upstream industry group South African Oil and Gas Alliance Niall Kramer had earlier told the conference that he is positive about offshore exploration: “Offshore block activity is promising, given proximity to other large-scale gas finds in the region.” He noted that it is critical that careful, calibrated research and policy development, coherence as well as programme alignment informs South Africa’s gas industrialisation effort. It must involve a close collaborative effort by the government and the private sector. Van der Spuy also said that it is critical that

new regulations governing mineral producers in South Africa result in clear, stable, commercially attractive terms. Meanwhile of its offshore Mozambique interest, a Sasol spokesman said: “Sasol is presently in discussions with the [upstream regulator] Instituto Nacional de Petroleo with a view to finalise the exploration and production of Petroleum Concession Contract (EPCC) in respect of the A5-A Block in partnership with Eni (operator), ENH and Statoil.”

Eni operates Mozambique’s A5-A Block with 34%, partnered by Statoil and Sasol (25.5% each) and Mozambican state ENH with 15%. “Our objective is to execute the EPCC for the [Mozambican] PT5-C Block as soon as possible to be able to proceed with the proposed work programme and associated drilling campaign,” Sasol added.

John Fraser

## LINKING UP WITH MOZAMBIQUE

South Africa is in talks with Mozambique about a pipeline to import gas from the huge gas fields in the Rovuma Basin offshore northern Mozambique. South Africa’s new energy minister Mmamoloko Kubayi told parliament May 19 that the aim was to come up with an energy collaboration agreement.

The minister accepted the need to secure support from the energy multinationals for any new pipeline, but said that to date the discussions have been at a government-to government level. “In the coming few months we will engage with the gas industry,” she said. “Work with the Mozambicans has started. Technical teams have been engaging. There are concerns about regulations. We will make sure we comply but also ensure it is in the public interest,” she noted.

Eni, Anadarko and their co-venturers want to monetise their vast Rovuma basin offshore gas resources as LNG in the 2020s, once a current global LNG glut has eased. They have been wary about tying the resource into local markets until full-scale LNG projects are up, running, and earning their keep.

Eni has discovered more than 85 trillion ft<sup>3</sup> and Anadarko more than 75 trillion ft<sup>3</sup> of gas resources in the Rovuma offshore northern Mozambique and have agreed on a joint site where they could build onshore LNG trains. Separately, a proposed floating LNG project by Eni is pending a final investment decision.

South Africa’s Sasol has enough pipeline capacity to export from its onshore southern Mozambique production. Kubayi would not

say what overlap, if any, there might be between a new pipe and Sasol’s existing one. Meanwhile onshore exploration in northern Mozambique has been modest.

In early 2016 a proposal for a Chinese-sponsored 2,600km pipe costing \$6bn from Mozambique’s far north to South Africa’s industrial heartlands made little progress, with one partner SacOil dropping out soon after; the proposal to date has garnered no support to date from international oil companies.

Kubayi told MPs that “gas is an integral part our energy mix, notwithstanding that in the short to medium term, we do not have access to the indigenous gas promised by the shale gas exploitation program” in the Karoo basin.

She said the country’s gas programme is premised on LNG being imported from the world market within five years at Richards Bay in Kwazulu-Natal. But beyond that, gas piped from northern Mozambique held out the “possibility of being a more attractive option than LNG.” In the longer term, 10 to 15 years from now, shale gas [could be] sourced from the Karoo, she added.

In another development, Kubayi announced a shake-up in the chain of command between her department and ailing state energy company PetroSA, but expressed frustration that she is currently preventing her from talking direct action to deal effectively with the loss-making entity.

John Fraser



## BOLIVIA DISPUTE ADDS TO UNCERTAINTY

Bolivia has cancelled a \$149mn contract for the provision of drilling equipment, augmenting concerns over stable governance and attitudes towards foreign investment.

State-owned oil firm YPFB last month cancelled a contract with the Italian company Drillemec, which had been signed in February. The energy ministry said in a statement in April that it believed there had been irregularities in the bidding process for the contract. A total of 15 YPFB officials were subsequently suspended over their alleged connection with the deal.

Drillemec, which is owned by Italian oil services company Trevi Finanziaria Industriale, said at the time that the contracting process had been transparent and requested that the government honour the contract.

In response, YPFB said that Drillemec was not “telling the truth” about the manufacture of the drilling equipment.

YPFB’s senior leadership did not represent the firm during the contract signing and did not give any order for the manufacturing of the drilling equipment to begin, the Bolivian firm claimed.

Drillemec spokesman Gilberto Gallo told *NGW* that an audit of the tender is still ongoing but that the firm remains keen to help the Bolivian authorities “in order to demonstrate that it has fulfilled all requirements and complied with all procedures.”

Following participation in a public call for tender, the firm was awarded the construction of three drilling rig packages “in strict compliance with local legislation,” Gallo added.

He said that Drillemec has a strong presence in South America and is still keen to support growth of the “attractive market” in Bolivia, a country where it has already invested some of its resources.

Nonetheless, the dispute may add to concerns among potential investors over entering the Bolivian energy market. The Andean nation has been struggling to re-energise its oil and gas sector in the face of lower global oil prices in recent years. Its reserves are depleting at a rapid rate, putting pressure on YPFB to explore new areas.

### Red light for investors

However uncertainty over contracts along with concerns about political instability and potential corruption can deter foreign investors, while YPFB needs the help of foreign firms with more advanced techniques to take advantage of its resources – particularly those in challenging locations.

Plaza Murillo, LaPaz, Bolivia



In addition, the Bolivian economy is heavily dependent on oil and gas revenue, the two traditionally accounting for more than half of exports.

Around 70% of Bolivia's gas is transported via pipeline to neighbouring Argentina and Brazil, but there are mounting concerns that the country may not be able to keep up with contract commitments because of insufficient domestic production.

To add to investors' concerns, ratings agency Standard & Poor's revised Bolivia's sovereign credit outlook to negative from stable on May 25th citing low export prices for natural gas, combined with "only modest success in boosting prospects for gas production" to date.

Gas output fell by 4% in 2016, after falling by 1% in 2015, the agency said. The government has predicted that gas output could rise by 2% in 2017 but from 2019 onwards is projected to decline "more substantially", it added. "Uncertainty about future gas production could affect upcoming negotiations to renew long-term sales contracts with Brazil – due in 2019 – and Argentina, due in 2027."

Investment in the hydrocarbon sector amounted to \$725mn in 2016, down from \$1.15bn in 2015, the agency noted. The government is projecting about \$5.2bn in investment in exploration and exploitation in the sector between 2017 and 2020.

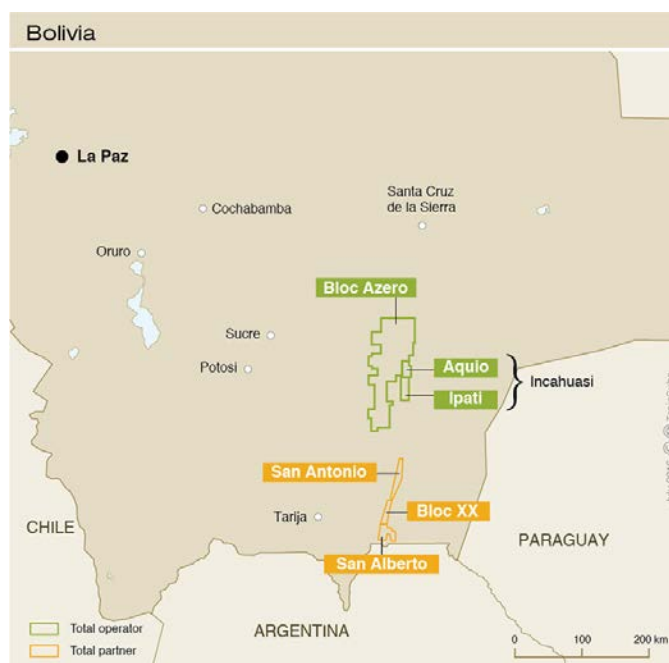
This is in spite of Bolivia's efforts of recent years to boost domestic oil and gas production. The government has pledged to invest \$30bn by 2025 to develop the oil and gas sector and has said it will concentrate on diversifying the market and providing companies with significant incentives.

Nonetheless even those projects that have already gained the support of international investors, like the \$1.2bn Incahuasi gas project, can be subject to delays in the current oil price environment. The field has recoverable reserves of 70.8bn m<sup>3</sup> of gas and 4.8mn metric tons of gas condensate.

French oil major Total has a 50% interest in the field, along with Argentina's Tecpetrol and Russia's Gazprom, which each have 20% stakes. Bolivia's YPFB Chaco, the E&P subsidiary of YPFB, has the remaining 10% stake.

The field is located across two blocks in southeastern Bolivia: the Aquio block and its larger neighbour, the Ipati block.

The companies formally launched commercial production at the field last September under the first phase of development, which comprised three wells, a gas treatment plant and 100 km of pipelines. The first phase took a total of three years to build.



Bolivian gas and condensate fields (Map credit: Total)

However, start-up of the second phase is still pending and is now nearly six months later than when company officials said it may start operating. Last September, Michel Hourcard, Total's director for the Americas, said that the second phase would be ready to start up in early 2017 if incentives for investment are established and the market conditions are right.

Total, which is thought to have committed around \$800mn to Phase 2 of the project, was unable to comment about when the next stage may now come online, when contacted by *NGW*. "There is no magic recipe. There is no hope for projects if we cannot control costs in everything especially with oil below \$50/barrel," he said, according to a *Reuters* report last September.

The French firm is hoping to negotiate the same conditions for the second phase that it got for the first phase of the project, Hourcard added.

Total told *NGW* May 31 that the company has no particular deadline for the start up of phase 2 of the Incahuasi field, and that the project is "currently under evaluation."

Suffice it to say, neither project delays at Incahuasi nor the ongoing dispute with Drillmec will do Bolivia any favours in terms of presenting an attractive image to investors. The clock is ticking if the country wants to avert a potentially serious decline in gas production after 2019 and the supply contract complications that could result.

Sophie Davies





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