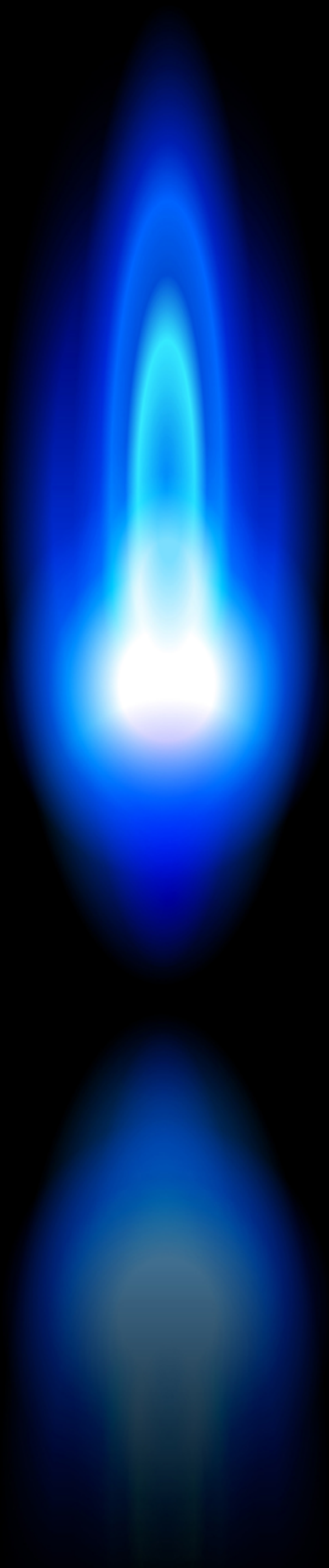
The future of gas



The future of gas is written in the present. Choices taken now, by investors and governments, will dictate supply and demand over the next 10 years.

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ADDLESHAW GODDARD

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The future of gas

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WHAT, WHY AND WHAT NEXT

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On the horizon

The role of gas is changing and the key determinants will be a combination of market forces and governmental intervention

ON April 21, 2017 the UK celebrated its first full day without using coal to generate electricity since 1882. That was the year in which the world's first public coal-fired generating plant was opened at Holborn Viaduct in London, Queen Victoria was on the throne and Gladstone was prime minister.

It was rightly hailed by the renewable energy industry and environmental groups alike as an important milestone in the long-term transition from fossil fuels to renewable energy. However, it would not have been possible without natural gas, which makes up just over half of the feedstock for electricity production. Furthermore, gas has a continuing role as the most widely used domestic heating fuel in the UK.

The "Energy Trilemma" of affordable, sustainable and secure energy supply is a continuing challenge to governments, energy companies and consumers all around the world. As such, the challenges and opportunities for gas in the UK and beyond have rarely been in sharper focus.

The very physical state of natural gas means that it is not a "quick fix" or drop-in energy source. For all involved in the gas value chain – from producers to pipeline and storage owners, distribution and transmission operators, and downstream offtakers and consumers – long-term planning, political consensus and robust economic logic are fundamental.

The future of gas is written in the present. Choices taken now, by investors and governments, will dictate supply and demand over the next 10 years. Prices have struggled in recent times, in part because of the deeply rooted link to oil, and this has reduced investments into grand projects, particularly greenfield LNG developments around the world.

As gas prices have fallen, though, new demand has emerged for the resource. This has come both in developed economies such as the US, where coal also faced regulatory pressure under the previous administration, in addition to emerging economies, such as Egypt and Pakistan. Jamaica began importing LNG in 2016, with Colombia and Malta following in 2017.

The spread of new technologies to allow easier LNG imports, most notably floating storage and regasification units (FSRUs), has reduced the cost of entry to this previously exclusive club. This has helped mop up excess LNG supplies, which have stemmed from new production centres in Australia and the US.

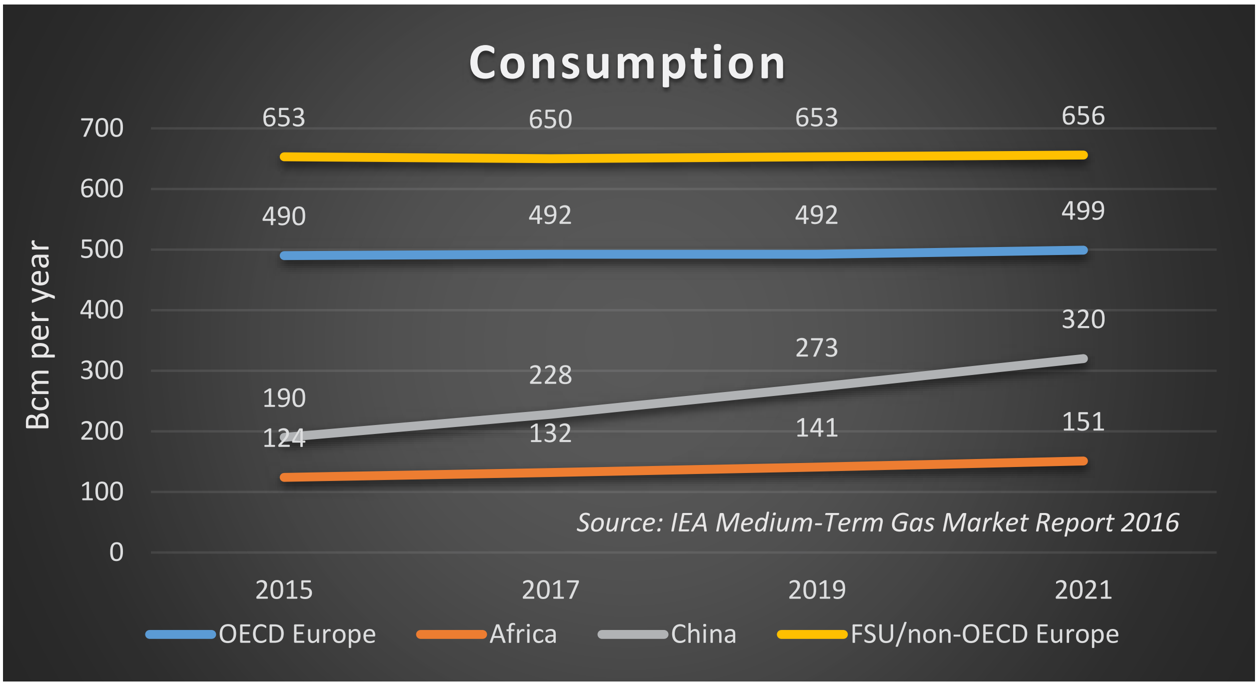
Shale

Additional supply from US shale has been perhaps the most important change of the last 10 years. Before 2008, the US had expected to be a major LNG importer but the surfeit of shale has turned this expectation on its head, with the shale-fed Sabine Pass project, on the Gulf Coast, shipping its first cargo in 2016.

The rise of shale has crushed gas prices in North America and has had an impact on global LNG supplies that will increase as more plants come online. The rise of flexible US supplies may, in fact, create a global Henry Hub-linked LNG price, given the wide range of export destinations available.

The next question for shale will be where else may such resources be developed? Substantial investments are going in to Argentina's Vaca Muerta formation, while China has also expressed a desire to seek its own reserves in a bid for energy security. In Europe, opposition to hydraulic fracturing and a high population density have deterred investments, although the UK may be able to make progress on this front once it has left the European Union.

> "As gas prices have fallen, though, new demand has emerged for the resource



LNG

Australia has played a critical role in the current LNG boom, with a number of projects in the midst of starting up, and the country is destined to overtake Qatar in terms of liquefaction capacity before 2020. However, the rise of Australian production has come at a high cost. Gorgon LNG, which started up in 2016, has a price tag of US$53 billion, making it perhaps the most expensive hydrocarbon project in the world. Ichthys LNG and Wheatstone LNG are anticipated to come in at around US$34 billion each.

Such is the cost of Australian developments that new projects seem extremely unlikely, unless substantial progress can be made in bringing these down. One way in which this might be achieved is through the use of floating LNG (FLNG) units, which can be built in Asian shipyards and moved into place. The technology is largely untested as yet and there are no guarantees of low costs – Royal Dutch Shell's Prelude FLNG may cost around US$11 billion – but it is being considered in a number of regions.

The leading destination for FLNG is in sub-Saharan Africa, where major deepwater gas finds have been made. The most advanced plan is in Cameroon, with a small-scale project by Perenco. Other areas under consideration are in Mozambique, backed by Eni, in addition to Equatorial Guinea and Senegal-Mauritania.

Given the strain on new projects, with companies and banks unnerved by low prices, changes are coming to the way in which the LNG business is done. Upstream costs must come down but there are also opportunities in how offtake contracts are drafted. Changes are already under way with buyers seeking shorter-term periods for supplies, a move from 20-year terms to five years.

Such moves will allow deals to be done but whether banks are willing to provide project finance on projects backed by such deals remains unclear.

Pipelines

LNG is expensive but flexible, while pipelines are cheap but lock suppliers and producers into a fixed relationship, for better and for worse. Russia's role as the world's largest gas exporter is based on its deliveries to Europe, although both sides have concerns about this link. Europe seeks diversity of supply, amid worries of over-reliance on Siberian gas, while Russia is seeking new markets to spread its risk, looking to China.

The question of security of supply looms large over pipeline issues. Turkmenistan, for instance, after falling out with its historic offtakers Russia and Iran, has increased its hopes for Chinese demand. Beijing, wary of too much reliance on one source, has backed out of building an additional pipeline from Turkmenistan and is seeking diversity through the Power of Siberia link, from Russia.

Pipelines are also central to concerns over the UK's position in terms of future European gas supplies. Exiting the EU may bring new pressures to bear on supplies, such as additional tariffs, in addition to concerns around the future availability of production from Groningen. The UK will not run out of gas – if nothing else, LNG can be imported from flexible suppliers around the world – but it may well be that prices must rise in order to secure volumes.

Gas is central to the idea of energy security, but the market – particularly the supply side – is dominated by private investment. Governments must navigate how to support energy ventures without trying to pick winners, which typically ends poorly. While it is market forces that drive investments, it is countries and consumers that will pick up the tab.❖

Edited by: Ed Reed
Written by: Jeremy Bowden, Joe Murphy, Ed Reed

European upstream gas looks to the south-east

Europe's gas sector is under pressure but some bright spots are emerging

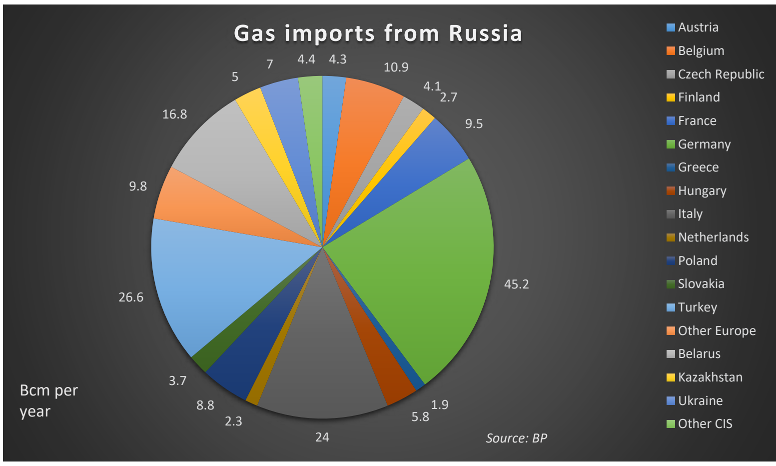
EUROPE

THERE is a distinct downward trend to European gas production, which is driving a rapid rise in imports, largely from Russia, with additional volumes coming in the form of LNG from destinations across the world, including the US. The exceptions to the European decline come from a temporary rise in UK production and continued strength in Norway.

Output from Europe's anchor field, Groningen in the Netherlands, is being cut sharply to avoid earth tremors, while Germany saw an 8.1% fall in its already meagre production, to 7.9 bcm, in 2016. What is more, German (and EU) demand rose in 2016 – reversing a multi-year decline, and making the continent ever more dependent on mostly Russian imports.

Low oil prices and higher demand helped Russian sales across Europe last year, but recent crude price rises may reverse that advantage this year, just as large volumes of new LNG production come on stream. This new output should maintain downward pressure on gas benchmarks and limit the incentive for domestic European shale development – especially in the face of strong and widespread political opposition.

Despite the increased dependence on Russian gas in 2016, Wintershall, Germany's biggest gas producer, was forced to abandon its research at two shale fields in North Rhine-Westphalia in February. So European supply is expected to keep falling, apart from another year or two of growth from the UK's offshore, Norway and potential new output in the Eastern Mediterranean. The only real prospect of shale gas is limited to a possible trickle from the UK post-Brexit.

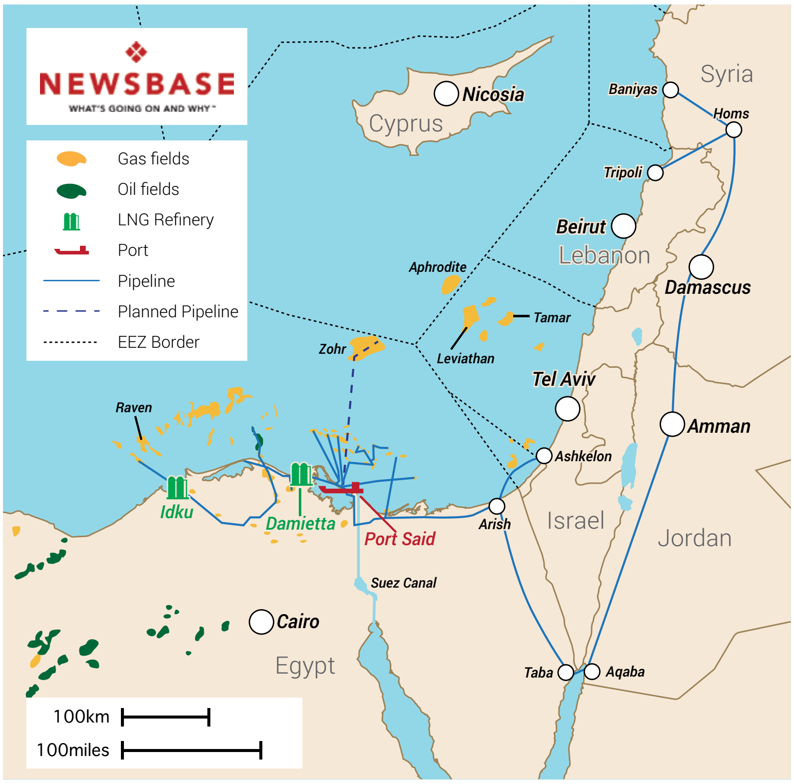


UK rebound

The UK offshore is doing well. The country's output in the third quarter of 2016 was up 10.8% on the previous year, at 10.9 bcm, helped by production from the new Laggan gas field and continued strength from across much of the UK Continental Shelf (UKCS). Falling costs are helping to improve the prospects for further additions, although these are likely to be overtaken by decreasing output from mature fields again in 2018.

"The rise, combined with warm weather and problems injecting gas into Rough storage, meant [UK] imports fell by 35% compared to the third quarter of 2015," said Gneiss Energy's Jon Fitzpatrick. "Imports from Norway were down 19.7%, and exports increased by 4.6%, with exports to Belgium up 18.8%," he added.

UK demand for natural gas in the third quarter of last year was up 3.5% year on year. Within this, there has been a significant increase in gas used for electricity generation, which is up 23% owing to a switch away from coal. The focus of European upstream attention is no longer on the North Sea, though. ▸▸



Gas finds in the Eastern Mediterranean represent the opening of a new major source of supply

Bigger fish

The brightest and biggest upstream prospect for the European market is undoubtedly Eni's 850 bcm Zohr offshore gas field, which is undergoing an US$11 billion development in Egyptian waters in the eastern Mediterranean – one of the biggest of its kind in the world. Much of the initial gas output will go to Egypt, which should free up gas for LNG export in winter and back out the need for Egyptian LNG imports in the summer peak demand season. Later phases of the project include plans for deliveries to Italy, and the project could mark the start of a larger upstream province in the area.

Cost is key

Eni is aiming to bring the field on stream by December 2017, less than three years after it was discovered. That would be the fastest a project of its size has started production in industry history. This speed is combined with the efforts by major oil and gas companies to reduce development costs – a response to the need for new production to be profitable at current low prices. Furthermore, conventional projects must compete for funds with shale oil and gas developments. Eni appears to be one of the most successful in this respect, with techniques for saving money including the use of standardised designs for rigs and other assets and equipment.

"To develop deepwater projects, ultimately it is always a question of price," said former BG Group executive turned consultant Mark Simmons, now at Energy Flux.

The other element of cost cuts come in asset and equipment rates, in addition to service costs. However, a return to spending may trigger oilfield service costs to rise quickly. A recent rash of deals among service and equipment companies, including Wood Group-Amec, Technip-FMC, GE and Baker Hughes – in addition to rumours of Halliburton's interest in Aker – would suggest a growing concentration and market power in the service sector, relative to its customers in the upstream operator sector.

Big boys move in

Driven by Eni's success, big oil is rethinking the Eastern Mediterranean region's gas potential. The ranks of larger companies in the region have now swelled to include Total, ExxonMobil and Rosneft, in addition to the established players – Eni, Royal Dutch Shell and BP – indicating the potential significance and scale of the basin.

In Cyprus' December 2016 offshore licensing round, Eni extended its acreage in the region with partner Total, while ExxonMobil won the bid for Cyprus' offshore Block 10, which Total had relinquished before the Zohr find.

More recently, Russia's Rosneft has shown interest in an offshore concession in Egypt, acquiring a stake of up to 35% in Egypt's offshore Shorouk concession, which includes the Zohr discovery. BP acquired a 10% stake – with an option for a further 5% – in the field early this year. BP holds a 19.75% stake in Rosneft, so the purchases are likely to be co-ordinated. The BP deal values the licence at US$5.25 billion. BP already holds many assets nearby in Egypt's Nile Delta Basin, where it dominates along with Eni and Shell.

Further north, development of Leviathan, Israel's largest gas field, has been approved under a US$3.75 billion three-year plan. The partners, led by Delek Group and Houston-based Noble Energy, have taken a final investment decision (FID) and production is due to start in 2019. Output is intended for both the Israeli market and regional sales. Leviathan's partners are in negotiations to sell gas to Turkey or to Shell's LNG plant in Egypt. The phase one investment decision will produce 12 bcm per year, followed by a second phase of 9 bcm per year, which is earmarked for export.

Deep gas pool

There may be more to come. This year all eyes are on Total's exploration well in its deepwater Block 11 located offshore Cyprus. Zohr's success encouraged Total to re-examine the potential of the block – which lies adjacent to the carbonate Zohr discovery. Geologists are intensely interested in the potential of Block 11 and the well results could change the competitive landscape – and future development trajectory – of the hydrocarbon sector in the Eastern Mediterranean. Another big find would begin to create a major upstream gas hub, bringing development

> "To develop deepwater projects, ultimately it is always a question of price

costs down and providing gas for export to Turkey, Greece and elsewhere in Europe, and price competition for the other finds.

Opportune's EMEA transaction services leader, Mauro Fiorucci, described Total's planned well in Cyprus' Block 11 as "one of the most significant this year. It can change the competitive landscape and development of the Eastern Mediterranean region. Zohr proved a carbonate reef play very different from the turbidite sand-play discoveries in the Israeli Levantine Basin and the Egyptian Nile Delta Basin. If the Zohr carbonate play extends northward into Total's Block 11, then there is potential for a significant discovery in Block 11."

A find, he continued, would provide competition for offshore fields in Israel and might even provide scope for exports to Turkey.

There is the potential for competition between Cyprus and Israel for gas sales to Egypt. A substantial new gas find would also provide additional options for Cyprus to commercialise its Aphrodite discovery, since infrastructure investments could support multiple discoveries. Territorial difficulties may hamstring hub plans, though, given deep-rooted enmities between a number of the Eastern Mediterranean states. In particular, Egypt's disagreements with Israel – related to the stoppage of gas supplies via a cross-border pipeline in 2011 – makes an agreement unlikely in the near term.❖

Balancing supply and demand in Azerbaijan

Baku is struggling to increase exports and meet domestic demand – something will have to give

FSU

EVEN while it prepares to launch substantial exports of natural gas to Europe, Azerbaijan is struggling with domestic fuel shortages. The former Soviet state, which emerged as a net exporter of gas in 2007, is now having to rely on imports to cope with rising demand in the power sector.

Azerbaijan's Shah Deniz, one of the world's largest gas fields, is aiming to ramp up output by 16 bcm per year, although these volumes are already pre-sold to Turkey, Italy and other markets in Southern Europe. Meanwhile, production from other smaller fields, which cater for the domestic market, has slipped in recent years owing to a lack of investment.

The country consumed 12 bcm of gas in 2016, but suffered from a shortage of around 1.4 bcm. Baku has sought to curb exports where it can to ease the problem, although shortages are likely to persist unless meaningful progress can be made in developing new deposits besides Shah Deniz. As such, ambitions export plans being touted by officials in Baku are unlikely to materialise.

There is little growth potential in overseas sales beyond the 16 bcm per year that will be provided by the Shah Deniz expansion by 2025.

Sales over security

Azerbaijan relies on the hydrocarbon sector for over 90% of its exports, and thus government policy has prioritised ensuring this revenue stream over the country's own energy security.

Shah Deniz, which came on stream in 2007, currently yields just under 10 bcm per year of gas, with the bulk of this fuel pumped to Turkey and Georgia under long-term contracts. Total Azeri exports climbed from 6.2 bcm in 2010 to 8.15 bcm in 2015 on the back of increased demand in these two markets. During the same period, deposits operated by state-owned SOCAR, which market their gas domestically, saw output slump from 6.4 bcm to 5.8 bcm.

Production is likely to have fallen further last year as a result of a platform fire at the shallow-water Guneshli field in December 2015.

The offshore Azeri-Chirag-Guneshli (ACG) oilfield complex is another major source of gas in the country, although much of its output is pumped back into reservoirs to sustain faltering oil production. All the while, Azeri consumption has climbed on the back of higher power generation, rising from 9.4 bcm in 2010 to 11 bcm in 2014.

The current situation has arisen largely because of Baku's eagerness to boost export revenues at the expense of domestic gas security. The government's drive to retain artificially low gas tariffs on the home market has compounded the problem. State-controlled wholesale gas prices slid to US$28 per 1,000 cubic metres in 2016 from US$40 a year earlier, largely because of the devaluation of the Azeri manat. However, SOCAR paid UAE-based field operator Bahar Energy almost US$140 per 1,000 cubic metres for gas at the well head in 2016.

The Azeri firm has to offer rates high enough for operators to cover costs but is unwilling to pass these burdens on to consumers, which has led it to incur heavy losses on domestic sales. Naturally, this has made it harder for Baku to settle on development terms with international investors.

"Lifting domestic gas prices can accelerate the investments in the Absheron field and anticipate first gas, which is now expected for 2021. In addition, these can incentivise SOCAR to develop its own fields and partially remedy domestic shortages," Opportune's EMEA transaction services leader, Mauro Fiorucci, said.

For instance, development of the offshore Absheron deposit has been delayed because France's Total and SOCAR have struggled to agree a suitable price for an offtake agreement. Total is now aiming to reach a final investment decision (FID) later in 2017 on a scaled-down plan, which would involve Absheron yielding 1.5 bcm of gas per year.

Hands tied

SOCAR has responded to shortages by curbing exports where it can, mostly notably to Russia, which did not take any Azeri gas in 2015. However, contractual obligations with Georgia and Turkey prevent the firm from reducing sales abroad any further. Indeed, even if Baku could reduce these sales, it would be unlikely to do so because of the resulting loss of revenues.

SOCAR's vice president, Khoshbakht Usifzade, was quoted as saying by Reuters recently that the firm had imported 286 mcm from Iran last year to cover the supply shortfall at home. The news agency noted, however, that this gas had actually originated from Turkmenistan. Iran would be unable to send large quantities of its own gas to Azerbaijan, as its northern regions are not adequately connected with its major gas fields in the south.

Baku has recently expressed renewed interest in a trans-Caspian pipeline to Turkmenistan, which would allow it to import perhaps 3-5 bcm per year from an offshore block operated by Malaysia's

> "SOCAR has responded to shortages by curbing exports where it can, mostly notably to Russia, which did not take any Azeri gas in 2015

BP's Shah Deniz platform, in Azerbaijan

Source: BP

Petronas. This project faces major political hurdles, with opposition from Russia and Iran, two of the Caspian Sea's other littoral states.

A potential gas swap involving Turkmenistan, Iran and Azerbaijan is a far more feasible option. However, in the short term this would require Tehran and Ashgabat to settle a dispute over gas debts and pricing. In the medium term, all three states would need to invest more in cross-border pipeline infrastructure.

SOCAR is also looking to purchase more gas from Russia, although they have thus far failed to see eye to eye on pricing.

Amid gas scarcity, energy producers in Azerbaijan have also turned to fuel oil as a solution. In August 2015, state-owned utility Azernerji began using residual fuel oil as a substitute for gas in power generation, causing demand for the product to more than double to 887,400 tonnes last year. This is not ideal, though, as domestic supplies of fuel oil are also becoming scarce, leaving Azerbaijan increasingly reliant on imports.

According to reports, SOCAR raised its gas tariffs for residential users in January in a bid to reduce its losses on the domestic market. The downturn in the Azeri economy has prevented the government from raising rates too much, as the population is already coping with high costs for other basic goods.

As such, complete liberalisation of gas prices would be politically unfeasible for Baku. The government would also need to carry out similar reforms to electricity tariffs to prevent power producers from booking hefty losses.

Consequences

Government officials have claimed that the launch of new fields such as Umid and Babek as well as rising output at the Bulla Deniz will help curb the gas supply shortfall. SOCAR has said it is open to developing Umid and Babek with a foreign partner, but so far there has been lacklustre interest.

SOCAR's fields could in theory yield an extra 5 bcm per year by 2025, although bearish market conditions are likely to stall their development. Equally, it remains uncertain whether Total will reach an FID on Absheron before the end of this year as planned.

Azerbaijan's best option for alleviating gas shortages in the near term is increased purchases from Russia. The government will also need to advance plans for gas swaps with Iran and Turkmenistan.

The squeeze on the domestic gas market leaves little room for optimism about Azerbaijan's ability to raise exports above the extra 16 bcm per year that will be flowing from the Shah Deniz expansion by 2025.

In turn, this casts doubts over plans for a second-phase expansion of the Southern Gas Corridor (SGC) pipeline system to Europe, as it is unlikely Azerbaijan will be able to provide enough gas to fill its capacity.❖

Frontier hunting in Africa

Exploration spending in Africa may have slowed in recent times but substantial opportunities remain

AFRICA

AFRICA was lauded during the last commodity boom as a major frontier for oil exploration, but its real impact lies in its gas reserves. Wells in recent years have found world-class reservoirs around the continent, most notably in East Africa's Rovuma Basin. Given the scale of this resource, development is a challenge but there are a number of other fields – discovered but not yet developed – that can offer attractive options for explorers.

Frontiers

Kosmos Energy's efforts on the Senegal-Mauritania maritime border are probably the leading example of a company making progress on gas discoveries. The US company, which is also participating in projects off Ghana, struck a deal with BP in December 2016, with the UK super-major stumping up nearly US$1 billion.

Kosmos has found around 425 bcm of gas in the Tortue field, with estimates of as much as 1.4 tcm of gas in the wider licences.

Under the deal, BP agreed to provide funds for appraisal on the Tortue discovery, with a drill stem test expected to be carried out this year. Kosmos has predicted the planned floating LNG (FLNG) development on the area would break even at below US$5 per 1,000 cubic feet (US$142 per 1,000 cubic metres).

The companies agreed Kosmos would continue to operate the blocks, where it is aiming to drill three wells this year. It has drilled five wells in the area thus far, with a 100% success rate. In late March, it announced it had begun work on the Yakaar prospect, in Senegal's Cayar Offshore Profond block.

Aboveground risks

The problem that Nigeria faces is less about gas discoveries, but rather more about the aboveground challenges. Historically, exploration in the country focused solely on oil but, despite this, Nigeria has 5.1 tcm of reserves, giving it the seventh largest gas resources in the world.

Perhaps the greatest problem facing those seeking to develop gas in Nigeria is infrastructure. Securing fields from communities and militants is a task that can be navigated but providing security for pipelines is far harder. Exemplifying this, pipelines supplying Nigeria LNG were sabotaged in August, reducing supplies to the export facility.

Despite this, there are emerging opportunities for companies to produce gas onshore and sell it to the local market, even though gas prices remain low, at US$2.5 per 1,000 cubic feet (US$70.8 per 1,000 cubic metres). Prices have increased but there are still only limited opportunities for producers. Companies working in Nigeria require a substantial amount of local participation, as required both by law and political will.

Nigerian companies working in both oil and gas can benefit from reducing their risk. Seplat Petroleum, for instance, saw its oil production suffer in 2016 as a result of the suspension of exports from the Forcados terminal but made up some of the lost ground as a result of its gas interests.

While prices paid by Nigeria LNG are better, there is little political appetite for further exports – the focus is on domestic supply. While steps are being taken in the right direction, prices will likely need to move higher to attract more investment to the sector. Given the economic problems facing Nigeria at the moment, higher gas prices seem an outside chance.

Majors working in Gabon have reduced their investments in recent times, in addition to selling off mature fields to more specialised operators. There are upstream opportunities in the country, though, particularly in the offshore. Significantly, Royal Dutch Shell in its March sale to Carlyle Group chose to hold onto its offshore assets, which include its Leopard discovery, from 2014. Total also sold down mature assets in the country, while keeping hold of its exploration options.

Eni, too, has a major find in Gabon at the Nyonie Deep, while Total has the Diaman find. All three of these fields lie in the under-explored pre-salt reservoirs off Gabon. The West African country is in the process of planning for another licensing round, focused on its offshore.

Angola also holds offshore resources in the pre-salt. Exploration has focused on oil extraction, with what gas there is being produced via the Angola LNG plant, for export. However, Cobalt International Energy has found gas in its blocks, with the Lontra and Zalophus wells. Commenting on the former find, in 2013, the company said Lontra's gas could be commercialised by meeting domestic demand, given its proximity to Luanda.

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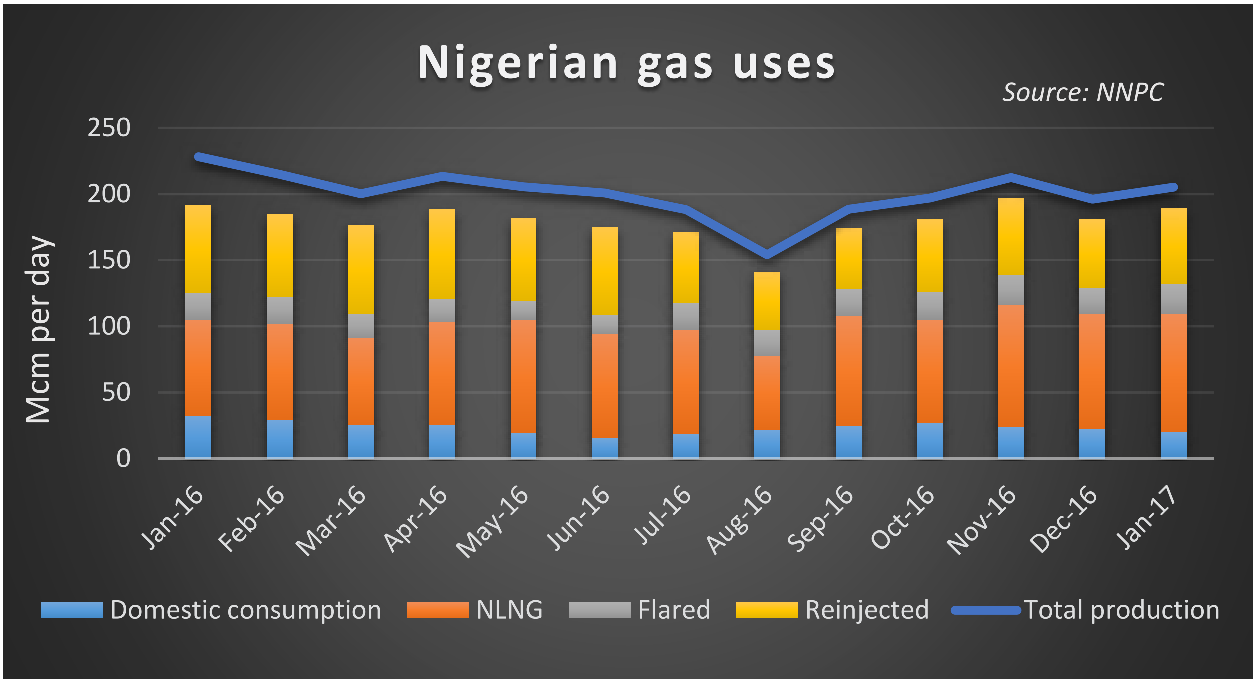


Technology

There has been some discussion of unconventional gas resources around Africa, but progress has been limited thus far. Algeria has made the most progress, with support from its traditional majors such as Eni, but it has also faced substantial opposition. Communities in the country's south have complained of a lack of local benefits from hydrocarbon resources for some time and discussion of hydraulic fracturing and shale gas has provided an outlet for this hostility.

South Africa is considered to have the greatest potential, with the US' Energy Information Administration (EIA) predicting there may be technically recoverable resources of 11 tcm in the Karoo Basin. While some companies had expressed interest in the region, including Shell and Chevron, in addition to the US' Chesapeake Energy, progress has been so slow that plans have been scrapped and delayed.

The South African government faces opposition from a number of pressure groups, which oppose fracking, particularly given the semi-arid nature of the Karoo, and has struggled to make headway. While there are some signs of progress, the candidate pool of interested companies has diminished. Some indications of activity emerged in March but extraction will not be quick, or cheap, and success is not assured.❖

TRANSMISSION & DISTRIBUTION

Gas networks at a crossroads

Changes in distribution pose a number of challenges that must be overcome

EUROPE

THE UK network sector is at a crossroads. Change must come in order to achieve the 2050 decarbonisation target, which will have an impact on both distribution and demand. "Progress on changing heat supply may come at a regional level: the Scottish Parliament, for instance, has issued a document on changing from natural gas to decarbonised gas. The future may come in a patchwork of solutions – perhaps including CNG, hydrogen networks and biogas, among others – while the challenge is how to stitch together such a network," said the National Grid's head of gas market change, Nicola Pitts.

Guidance is needed, though, from the UK government in how targets should be met. Pitts went on to call for direction to be given on heat transportation, carbon capture and storage (CCS) and the potential for regional responses. "To reach the 2050 decarbonisation target, we need technology to be deployed in the 2030s and 2040s. The next decade should be about trialling this technology and there is a price control window – and that window will close in the autumn of 2018," she said.

Brexit risks

While the NBP and TTF forward curves show no UK premium for the risk that Brexit poses, Simons believes there should be one. "There is a danger that both BBL and Interconnector pipelines will need to be decommissioned, [owing] to a lack of forward capacity bookings, just as Brexit becomes effective and the Rough storage facility is on its last legs," he said.

There is concern that cross-border trading will be made more difficult by the UK's departure from the EU, but arrangements are far from certain at this point. The interconnector is currently

> "To reach the 2050 decarbonisation target, we need technology to be deployed in the 2030s and 2040s

ramping up exports to Europe, after a winter when they flowed to the UK. "The impact of Brexit is still unclear. A 'hard Brexit' would suggest disruption but recent comments from the government have suggested it could attempt to preserve the single market in electricity and gas," said Pitts.

The UK's import capacity should be sufficient to overcome the immediate challenges that Brexit may pose to the commercial regimes for interconnectors.

The hydrogen option

At Davos this year it was no coincidence that super-majors chose to talk about hydrogen. It is zero carbon, and in the longer term provides the best option for them in terms of maintaining margins and making the most of their current positions.

Hydrogen makes use of existing infrastructure and works as a replacement for natural gas in heating and cooking – something which renewables are unable to do, apart from using biogas, which at scale presents its own set of environmental problems.

Hydrogen also offers an alternative fuel for electric cars, which would again make use of big energy companies' existing logistics and retail infrastructure.

Although the hydrogen itself can be made from water using electrolysis, it is cheaper to produce from natural gas, with the CO2 by-product sequestered centrally – which would continue to provide a market for proven hydrocarbon reserves.

Talking specifically about the situation in the UK, Northern Gas Networks' Dan Sadler said changes in the country would be driven by the climate change act, which requires an 80% reduction in carbon emissions by 2050.

"Smaller carbon savings can be achieved in the short term from resources such as biomethane, but in the longer term, to achieve the level of decarbonisation required, a move to hydrogen appears the most credible option."

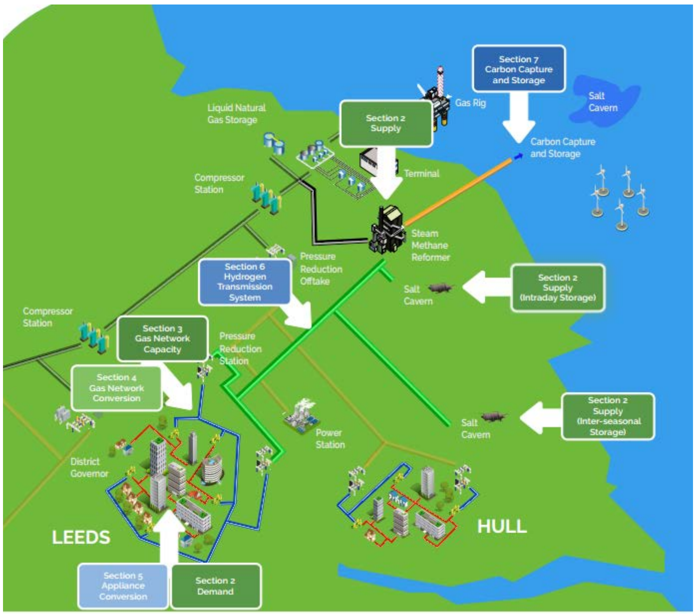
Large-scale hydrogen production also changes the economics for CCS, he said, "providing clear economies of scale and long-term certainty," he added.

This would make using natural gas with CCS cheaper than producing hydrogen from water, and would provide a revenue stream for natural gas production into the long term.

"Hydrogen is a destination fuel. We can get to clean energy through the use of steam methane reformers (SMRs) and CCS. Over a longer time, as a sustainable global hydrogen market develops, we can transition to entirely green energy utilising hydrogen as the central energy vector for balancing global green energy," Sadler said.

"Let's get to clean in a way that is technically achievable within the timescales available, then transition to green over a longer [post 2050] time horizon."

Leeds H21 hydrogen project



Source: Northern Gas Networks

Sadler concluded that Brexit could provide opportunities for the UK to move forward with this model, rather than act as an obstacle. "Brexit should not be a risk to hydrogen plans. Each country has different solutions to climate change based on a range of factors, including existing energy usage preferences, geography, geology, generation methods, population density, building stock and so on. Being out of the EU may improve the UK's ability to make its own decisions on energy based on its own opportunities. It can then use this expertise to support climate change requirements across the world."

CCS

CCS is an area where the UK may have an advantage, with depleted offshore oil and gas fields proving to be ideal candidates for storage sites, as illustrated by a number of examples along the east coast, including Royal Dutch Shell's abandoned plans to move CO2 from the Peterhead gas plant to the depleted Goldeneye field. There has been a recent tendency to focus on whether carbon reduction means the electrification of heating across the industrial, commercial and residential sectors – increasing electricity demand and reducing gas demand – or a renewed focus on CCS and decarbonisation of gas.

The "electricity vs gas" narrative seems too simplistic, though. There are questions about the intermittency of renewable energy power generation and the role for gas in energy – and carbon – intensive sectors such as aviation, heavy goods vehicles, marine transport and high temperature industrial processes. The future may lie in how gas and electricity interact and in ensuring that the flexibility of gas, ease of storage and energy content are used to complement the obvious advantages of renewable electricity. The challenge is to find not just an optimal mix, but an economic and regulatory basis for two very different markets to converge.

"Hydrogen is a destination fuel

Storage margins under pressure

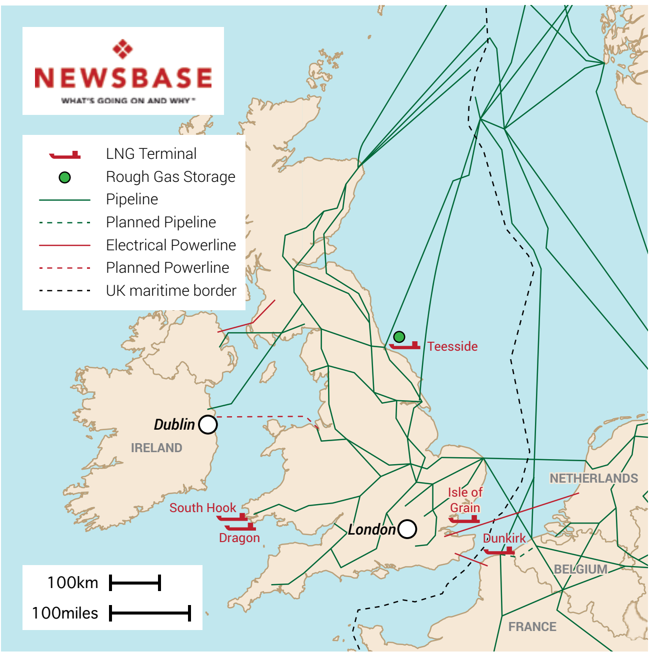
Europe faces a tough challenge in how to achieve security of supply, particularly in working out who will foot the bill

EUROPE

PRESSURE on storage margins dominates European midstream thinking, as a result of a sharp convergence in seasonal pricing. In addition, concern is growing over the possible impact of Brexit on cross-border pipeline trade.

Seasonal gas storage provides security and flexibility of supply, with gas traditionally injected when demand is low, in the summer, to take advantage of higher winter prices. But with both European seasonal and daily gas price spreads shrinking significantly, the practice is becoming increasingly unprofitable. The summer-winter differential at the NBP, for example, sank from US$8.6 per mmBtu (US$238 per 1,000 cubic metres) in 2005 to US$0.9 per mmBtu (US$25 per 1,000 cubic metres) in 2015, while daily price volatility dropped to US$0.1 per mmBtu (US$2.8 per 1,000 cubic metres) from US$0.6 per mmBtu (US$16.6 per 1,000 cubic metres).

As a result, the average price of storage has plunged sharply, as illustrated by prices obtained in The Netherland's capacity auctions, which fell from 9 euros (US$9.7) per MWh in 2012 to 3 euros (US$3.2) per MWh in 2016. The narrower seasonal spreads come as a result of increased pipeline supply flexibility, partly owing to lower demand, along with a rapid rise in LNG import capacity, which can act as storage itself and provides another conduit to deliver additional volumes during the winter.



"Project economics for storage do not look favourable but subsidies and government intervention are not the answer. There is a need for a market approach," said Energy Flux director Mark Simons. "The problem with energy security is that everyone wants it but no one wants to pay for it," he added – reflecting concerns over what might eventually happen if gas storage sites are closed and the market tightens again.

> "The problem with energy security is that everyone wants it but no one wants to pay for it

Consumers have been able to shift consumption from peak periods to avoid high prices, and this has reduced daily volatility. It is the high volatility levels of earlier years that have served as a major incentive for consumers to act. In addition, plentiful cheap renewables and, if necessary, old backup fossil fuel plant keep prices down most of the time – all made easier by advances in balancing, predictive and scheduling capabilities.

No sign of relief

The European market outlook is expected to remain challenging for the foreseeable future, despite a recovery in European seasonal gas consumption. This is anticipated to remain relatively stable – in contrast to the decline in demand of 20% since 2010. This contraction took place largely among residential and power consumers and was a major driver in the shrinking spreads.

Increased pipeline capacity from Russia and Norway, as well as LNG supplies, are the main factors responsible for eroding seasonal spreads in Europe. Pipeline flow and gas storage facilities will always be able to respond more quickly to a sudden rise in winter demand, but LNG can still dampen such spikes, especially as regasification terminals can also act as storage.

Storage's worst enemy is interconnectivity, as shortages are more easily covered given a wider range of options. Infrastructure interconnectivity grew by 3% between 2010 and 2015, partly fuelled by the EU initiative to incentivise a selected list of Projects of Common Interest (PCI). About 70 projects are expected to be commissioned over the next seven years, mainly in Central and Southeast Europe, which will keep pressure on storage margins there.

Competition between storage operators in Europe is also high, adding to the economic threat to individual companies. Some 3 bcm of gas storage capacity in Europe has been closed ▸▸

over the past five years, but about 12 bcm has been added, with a net 9 bcm gain.

Cold weather respite

The low margins have meant a number of other European gas storage facilities could face closure in the coming years, although the bleak outlook has been somewhat tempered by a strong use of storage across Europe earlier this year during a cold winter snap.

Very low prices in summer 2016 drove the record pre-winter stock levels to 100 bcm, but they ended the winter at their lowest ever, at under 11% of capacity. There had been extremely high withdrawals to counter the prolonged cold snap across much of Eastern and Southern Europe, making the season more lucrative than for some time.

Some support, but not enough

The collapse in spreads has also come despite supply constraints at Groningen, which are predicted to continue, possibly at even tougher levels. This has reduced capacity at Europe's most important swing supply source, which should put upward pressure on spreads. Groningen's restrictions led to output more than halving, with gas production falling to 26 bcm in 2015, down from 54 bcm in 2013. But this is outweighed by growing LNG regasification capacity and imports, as well as more pipeline import flexibility following the decline in demand in recent years.

In addition to Groningen, the biggest supporting factor to summer-winter spreads over recent months has been the decline of Britain's biggest gas storage site and the lack

of new facilities to replace it. Consequently, the UK will increase its dependency on swing imports over the next few years, intensifying wholesale market volatility and consumer gas prices. The inability to inject in the summer and reduced storage in the winter has widened the UK summer-winter differential. Rough, which accounts for 70% of the UK's storage capacity, can usually meet around 10% of Britain's peak daily gas demand.

Rough's operator, Centrica, has recently been granted approval to close the facility. A new storage is planned in northwest England, but will take many years to set up. ❖

Limited options for Central Asia

The Central Asian states are hamstrung by geography and finding new export markets is tough

FSU

CENTRAL Asia has been known to contain large deposits of natural gas since the Soviet era, but has suffered from chronic under-investment. Production in Turkmenistan, Uzbekistan and Kazakhstan pales in comparison to that of other countries with similar-sized reserves.

There are historical factors that explain this discrepancy – Soviet engineers prioritised development of large gas deposits in Western Siberia over those found in vassal states. Since the fall of communism, Central Asia is still struggling to make the best use of its resource potential.

Turkmenistan

Among the former Soviet States, Turkmenistan is second only to Russia in terms of gas exports, shipping out 37.5 bcm of the fuel in 2016.

This level falls far short of previous expectations by the government in Ashgabat, which once estimated that shipments overseas could climb to 100 bcm per year by 2015. Turkmenistan's problem is a lack of available markets.

During the Soviet era, excess gas produced in the country was delivered via pipeline to industrial centres in Russia, with some volumes being re-exported to Europe.

This trend continued even after the fall of the USSR, with exports to Russia peaking at 40 bcm in 2008. This arrangement was far from ideal for Ashgabat, which received only US$130 per 1,000 cubic metres of gas shipped northwards during that year. In comparison, Russia's

Gazprom was collecting an average of US$354 per 1,000 cubic metres from sales to Europe.

Turkmenistan lacked access to alternative markets and so had no choice but to accept Russia's terms. The situation got worse as Russia began dramatically cutting Turkmen gas purchases from 2009.

By 2015, sales had sunk to 4 bcm. At the start of last year, Moscow halted imports altogether, leading the two sides to lock horns in an arbitration court. Gazprom had little need for Turkmen supplies after the 2008 financial crisis, which caused gas demand in Europe to slump.

The state-owned firm had also invested heavily in expanding its own domestic production in the preceding years.

Russia's actions hastened Turkmenistan's pivot to the Chinese market, with 2009 marking the launch of the Trans-Asia Gas Pipeline's (TAGP) first string. The pipeline begins in eastern Turkmenistan, traverses Uzbekistan and eastern Kazakhstan, and terminates at the Chinese border. The launch of a second and third string in 2010 and 2013 respectively allowed Turkmenistan to pump up to 55 bcm per year of gas eastwards. However, Ashgabat has never been able to achieve this level, with deliveries under 28 bcm in 2015.

Beijing's reluctance to raise Turkmen deliveries is driven by its policy on import diversification. In recent years, China has expanded its LNG import capacity considerably, allowing it to tap seaborne supplies from a number of alternative producers.

Turkmenistan's only other customer is Iran, which bought 7.2 bcm of gas in 2015. Despite having considerable gas reserves of its own, Iran is unable to meet demand in its northern regions because of a lack of domestic pipeline infrastructure. Eventually, though, Ashgabat will lose this source of revenues as Iran makes improvements to its internal grid.

Naturally, Turkmenistan is pursuing alternative export options, such as pipeline projects to Europe and Asia. The proposed Trans-Caspian Pipeline (TCP) would allow the Central Asia republic to send its gas westwards via the Southern Gas Corridor (SGC), a network of pipelines under development that terminates in Italy.

While there is a strong commercial case for Turkmenistan joining the SGC project, political realities make it unlikely.

Russia would undoubtedly seek to block a trans-Caspian pipeline project, as it would endanger its market share in Europe.

Progress has also been slow on another export scheme – the US$10 billion TAPI project. This involves the construction of a 33 bcm per year pipeline, connecting Turkmen fields with Afghanistan, Pakistan and India.

There are security risks along the pipeline's route through Afghanistan, where recent years have seen a spike in Taliban activity. As a result, TAPI has been unable to rope in the necessary private investment to get itself off the ground.

Uzbekistan

Uzbek gas production has remained relatively flat over the past decade, with output totalling 57.7 bcm last year. The country sells gas to Russia, Kazakhstan and China, although the growth potential in exports is difficult to discern.

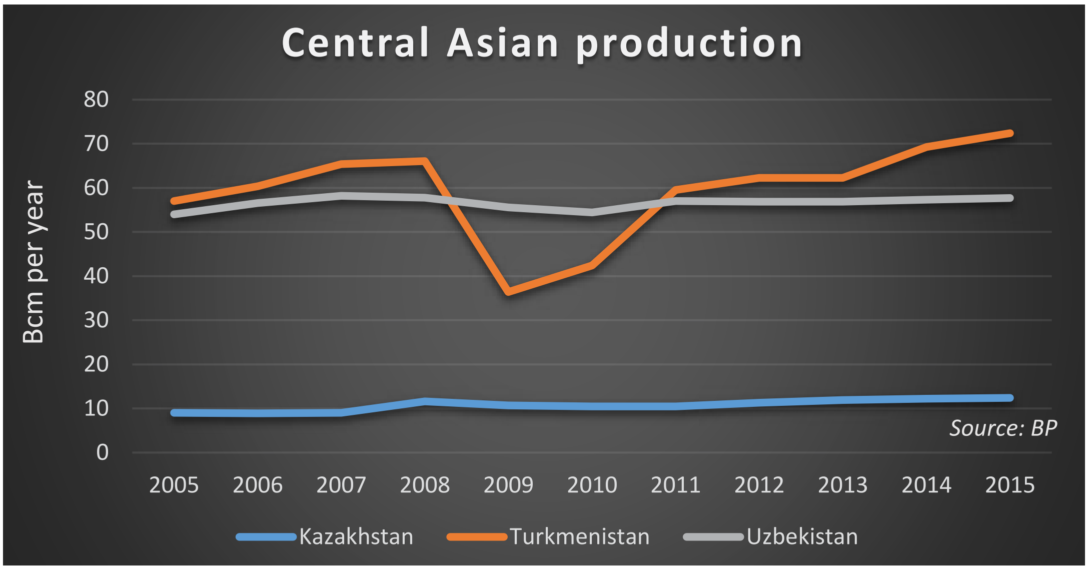
Russia's Gazprom is eager to resume importing large quantities of Uzbek gas, as demonstrated by a five-year supply deal it struck in April with Uzbekistan's state-owned Uzbekneftegaz. It reportedly increased purchases from Tashkent to 6.2 bcm last year, from 3.3 bcm in 2015. However, this growth largely came as Russia sought to make up for a shortfall in Turkmen imports. Given Russia's ready supply of untapped production capacity in Western Siberia, it is doubtful that its imports from Uzbekistan will expand much further.

Meanwhile, Kazakhstan is continuing with a grand gasification programme intended to eliminate the need for Uzbek supplies in its southern regions. Uzbekistan has also agreed to sell up to 10 bcm per year to China, although deliveries were only 1.5 bcm in 2015.

Whether exports will ever reach this level will depend on how quickly demand rises in

“Russia would undoubtedly seek to block a trans-Caspian pipeline project, as it would endanger its market share in Europe

RESERVES:
Turkmenistan is thought to have the fourth largest proven gas reserves in the world, estimated by BP at 17.5 tcm.
Uzbekistan and Kazakhstan have smaller, but nevertheless significant, reserves of 1.1 tcm and 900 bcm respectively.



Uzbekistan, the most populous republic in Central Asia. Meanwhile, recent delays to both Chinese and Russian upstream projects in the country have slashed production forecasts.

Kazakhstan

Kazakh gas production has steadily grown over the past decade, albeit at a slower pace than Astana has previously forecast. Output is slated to hit 48.1 bcm this year, up from 46.4 bcm in 2016 and 45.3 bcm in 2015.

These figures are somewhat misleading, as much of this gas is re-injected into oil reservoirs to maintain Kazakhstan's crude output.

BP estimates the country's production of marketable gas – which excludes volumes that are either re-injected or flared – at 12.4 bcm for 2015. The government wants to make greater use of its gas resources by expanding its domestic pipeline grid.

Despite reported delays in this gasification programme, progress is being made, with around 46.3% of the population now having access to gas supplies, up from 32% in 2014. The Kazakh government aims to lift this proportion to 56% by 2030.

Kazakhstan has a less diversified export mix than neighbouring Uzbekistan, with almost all exports going towards Russia.

Gazprom took 10.9 bcm of Kazakh gas in 2015, although it also delivered 5 bcm of its own gas to meet demand in isolated regions in northern Kazakhstan in return. Kazakhstan also sends around 400 mcm of gas to China.

The location of Kazakhstan's gas deposits in its western regions has complicated attempts to step up deliveries to China. Astana intends to increase Chinese exports this year, with the completion of the 10 bcm per year Benei-Bozoi-Shymkent (BBS) pipeline.

The pipeline will connect western gas fields with the TAGP system in the east. Beijing's interest in extra Kazakh gas was demonstrated in August 2015, when China Development Bank and Bank of China agreed to assign a loan of US$2.5 billion to fund the construction of the BBS line. According to the Kazakh government, all that remains is for the two sides to strike a binding agreement to allow supplies to start.

Looking east

China represents the most likely source of gas export growth in Central Asia, considering the lack of alternatives. However, Beijing is apparently reluctant to expand purchases quickly, much to the dissatisfaction of governments in the region. This was demonstrated in March when reports emerged that China's CNPC and Uzbekneftegaz had halted work on the Uzbek portion of a fourth gas string at TAGP indefinitely.

The 1,000-km line was due for launch before 2020 and would have increased TAGP's gas carrying capacity to 85 bcm per year.

China is expected to begin receiving Russian gas after 2020 via the planned Power of Siberia pipeline, adding competition to extra supplies from Central Asia. Power of Siberia should supply as much as 38 bcm per year of Siberian gas to China's eastern seaboard, although how quickly these deliveries will grow is unclear. Indeed, Beijing appears to be dragging its heels over the project, much to the frustration of Moscow.

At the same time, China's National Development and Reform Commission (NDRC) has unveiled plans to ramp up indigenous gas production by 220 bcm by 2020, up from 138 bcm last year. But Mauro Fiorucci, a consultant at Opportune, believes the potential of Chinese gas production is overstated. "I am not a believer in Chinese domestic production, which has historically been high cost and characterised by relatively small fields, remote from demand regions."

He also noted the higher cost of shale gas extraction in China compared to operations in the US, owing to complex geology, lack of water and limited available infrastructure. Strengthening the case for increased imports, the Chinese government is forecasting a rise in gas demand to 280-320 bcm per year by 2020, up from just over 197 bcm in 2015. The growth will come as China continues its drive to replace coal with gas-fired power generation.

Even if China's production targets are met, then, the country could need up to an extra 40 bcm of gas per year in imports by 2020, before Russian deliveries begin.

The prices of supply contracts between China and its Central Asian gas partners have not been disclosed. But it is reasonable to assume that pipelined gas from countries with few alternative exports will be cheaper than international rates for LNG cargoes.

This bodes well for Kazakhstan and Uzbekistan, but not necessarily for Turkmenistan. China's policy of maintaining a diverse import portfolio is likely to limit additional supplies from Turkmenistan, already its single largest gas supplier, meeting around 15% of national demand. Beijing, then, will prioritise extra supplies from Kazakhstan and Uzbekistan, with imports potentially rising to 10 bcm per year from each country. Further growth would require China to invest in additional import capacity, which is unlikely given the expected launch of Russian gas supplies post-2020.❖

"China represents the most likely source of gas export growth in Central Asia, considering the lack of alternatives

Africa's eyes on exports

In order to realise some of Africa's natural resource wealth, exports must kick up a notch – although financing conditions are looking tough

AFRICA

AFRICA'S gas resource is substantial. The problem is not one so much of exploration, but rather one of development. Industry sentiment has turned against megaprojects, which used to be the mainstay of super-majors' portfolios and the traditional means of exploiting major fields. Alternatives are emerging, including the use of early stage production hubs, but funds are scarce.

An offshore oilfield is relatively easy to develop. A company can build a facility in an Asian yard, for instance, tow it into position and then export to international markets via tankers – effectively being insulated from many of the political risk problems associated with onshore developments. Gas, though, is harder.

LNG

Deepwater resources carry a high price tag that often means they are too expensive for local markets. This disparity requires the resource be exported to a market that is willing to pay a price. Given the distances involved this requires the use of liquefaction, which adds a further premium needed to exploit such fields.

The economics of building LNG plants are demanding, particularly given the currently glutted market and low prices. Following the 2011 Fukushima disaster in Japan, LNG prices spiked and interest in building facilities soared. Now, as new Australian plants are coming online, with shale-backed US plants not far behind, the prospects for greenfield investments are looking slim.

Where gas is liquefied in sub-Saharan Africa it is often intended to allow oil to be produced. In Nigeria, for instance, the Akpo field produces condensate, which can be exported by tanker, but its gas is moved onshore, via the Amenam/Kpono platform, to Nigeria LNG. Similarly, Total's Ofon Phase 2 permitted gas to be moved onshore, ending flaring and also enabling oil production to increase.

Angola LNG also works along these lines. Feedstock for the development comes from associated gas resources offshore, which were previously flared or reinjected. The economics of the project change as a result: in cases such as these, gas can be seen to carry a negative price, or at least a far lower price than might be expected.

Where the distance to shore may be too great, or the volumes of gas too low, one alternative would be to install small-scale gas-to-liquids (GTL) facilities on board. This would allow associated gas to be converted into synthetic crude, which could be blended with conventional oil for export.

Stranded assets

Large gas discoveries in areas where infrastructure is minimal face challenges. Mozambique's Rovuma Basin development is the leading example of this inability to join up a major gas find with a development plan.

Anadarko Petroleum announced the Windjammer discovery in early 2010, with Eni celebrating the Mamba South find in October 2011. At the time, the prospects for developing such a resource – with Eni estimating Area 4 holds as much as 85 tcf (2.4 tcm) and Anadarko's Area 1 at 75 tcf (2.12 tcm) – must have appeared strong. Now, though, options do not seem so upbeat.

Given the scale of the resource, an onshore LNG plant is needed, with Anadarko having said the first phase would involve two trains with 6 million tpy of production, with an estimated investment of US$26 billion. The US company has struggled to secure financial backing for its plans owing to the uncertain outlook for LNG, leading to a final investment decision (FID) being delayed repeatedly. The arrival of ExxonMobil to Area 4, under a US$2.8 billion deal with Eni, will go some way to providing support for the project.

Bringing more partners into the project may well be the best way to make progress. "Companies need to learn from the mistakes of Australia,

> "Deepwater resources carry a high price tag that often means they are too expensive for local markets

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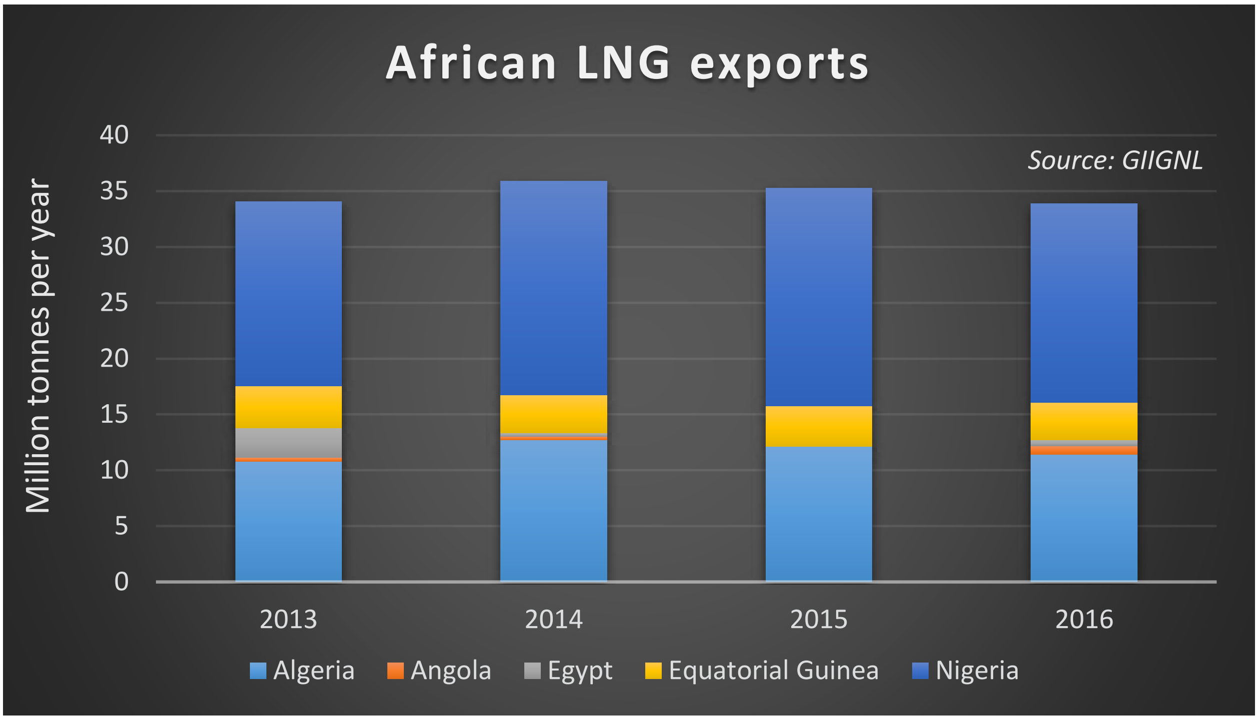


they need to collaborate and share the risk – alone it is unmanageable. If companies wait until prices rebound it will be too late," senior research fellow at the Oxford Institute for Energy Studies (OIES), Thierry Bros, said.

LNG construction costs, particularly at greenfield sites and in frontier regions, are likely to be higher than, for instance, converting a regasification terminal in the US.

"It's all about the return on investment metric and companies are unwilling to take risks at the moment.

The market may start to turn by 2021, at which point projects can get going. In the meantime, the task is to get projects as close to FID ready as possible," WorleyParsons' project director, Paul Hughes, said.

FLNG

While the onshore plant has languished, with an FID anticipated in 2018, the Italian company's offshore plans – with a floating LNG (FLNG) unit on the Coral field – have made much better progress. Various partners in the area have signalled their support for the 3.3 million tpy FLNG unit.

The FLNG plan appears appealing on a number of fronts. The project emulates the development path of an oil-based project, with the liquefaction vessel being constructed elsewhere and moved into place for hook-up. This should allow many of the challenges of a greenfield development to be moderated.

Other aspects of the Coral plan that have supported Eni's scheme include the speed at which first gas can be reached – which may be only three years after an FID is given. Furthermore, BP signed up to take the entirety of Coral FLNG's production for 20 years, providing a clear path to future cash flows.

Eni's Coral plan is not the only floating gas producing scheme in Africa. Perenco is expected to start up its Cameroon FLNG project this year, while Ophir Energy is close to an FID on its project in Equatorial Guinea.

A recent presentation from Kosmos Energy said it anticipated deploying two FLNG units to its gas development on the Senegal-Mauritania border. An FID is expected in 2018, with first gas from the first vessel due in 2021 and from the second vessel in 2023.

FLNG units can save time and money, Opportune's EMEA transaction services leader, Mauro Fiorucci, said, particularly in terms of accessing stranded resources and speeding up development.

"FLNG units, compared to onshore plants, require little construction and initial investment. However, they also have drawbacks and they are not always the best solution," Fiorucci continued.

Marathon Oil's liquefaction facilities in Equatorial Guinea

He cited relatively short leasing times and limited expansion opportunities. An FLNG unit can operate for 20 years, he continued, while onshore terminals are expected to be able to run for at least 25 years – with some having been in production for nearly 40 years. Finally, "FLNG has lower initial capex but significantly higher opex," the Opportune executive noted.

Cross-border pipes

While LNG is an attractive option for gas exports, given its ability to access any market, there are still some hopes for major gas pipelines in Africa. The model for such a project is the West African Gas Pipeline (WAGP). Unfortunately, this is a model for many of the wrong reasons. The link was built with a solid concept, exporting gas from the Niger Delta to Nigeria's western neighbours, allowing what would have been flared to be sold to meet local demand.

The reality, though, has been underwhelming. The pipeline has suffered from practical problems, such as being damaged by a ship during a pirate chase, and commercial issues, such as Ghana being unable to pay its bills.

Perhaps the most ambitious – and unlikely – is the Trans Sahara Gas Pipeline (TSGP). This would run from Nigeria through Niger and into Algeria. Gas moved via the TSGP could then feed into Algeria's existing export infrastructure, with pipelines going to Spain and Italy. The plan was launched in 2005 with a feasibility study but has made little progress since, although the Nigerian government did name the project as one of its medium-term objectives in 2016.

Another ambitious pipeline project is the African Renaissance Gas Pipeline, which would cost around US$6 billion and run for 2,600 km, from Mozambique's Rovuma Basin to Gauteng, in South Africa. The project is cheaper than the Eni-Anadarko LNG plant, but would still be tough to finance – while also preventing opportunistic sales to alternative markets.

Grand infrastructure projects require grand financial backing – and this appears thin on the ground at present, with banks wary of volatility in pricing. Smaller-scale plans are more likely to succeed but governmental support will be critical in making such plans happen.❖

CONSUMPTION

Superpower battleground again

The growing wave of LNG is challenging European consumption orthodoxies

EUROPE

FOR some time gas demand in Europe had been falling, with consumption undershooting forecasts. This is partly a consequence of higher than expected prices but also as a result of growing renewable capacity, which displaced gas use from the power sector more quickly than anticipated. Now, however, the tables are turned. The last two years have seen gas demand rise, beating forecasts. This comes as prices have dropped and coal prices have firmed. But the other factor has been a push by the EU and some nation states – notably the UK – to highlight gas' relatively positive environmental credentials when compared to coal and as a flexible balance to intermittent renewables. Carbon pricing, including the EU Emissions Trading System (EU ETS) and particularly the UK's coal penalty, makes gas much more attractive.

Remaining competitive

Russia is hoping to capitalise on Europe's gas demand growth and falling domestic output, using its huge reserves and lower production costs in Siberia to maintain

attractive prices.

Apart from the East Mediterranean, development of large-scale alternatives from Iran, Iraq or elsewhere will take a lot of time and money, leaving LNG imports – backed by additional Norwegian and possible Mediterranean supplies – as Russia's main competitor for the additional volumes.

Russia's monopoly exporter, Gazprom, supplied 34% of the European Union market in 2016 and it predicts its market share will rise slightly, to about 35% by 2025. Gazprom's exports to Europe reached a record last year at 179 bcm, up 12.5% on the 2015 figure of 159 bcm.

Non-CIS customers took delivery of 622 mcm of Russian gas on January 8, the highest daily figure ever reported for exports outside the former Soviet Republics.

"We have reached a totally new level of gas exports" as a result of "a cold snap, lower extraction volumes in Europe and higher demand for gas on the energy market," Gazprom's CEO, Alexei Miller, was quoted as saying mid-winter.

Gazprom has spare production capacity to tap and is expanding its gas transportation network, including through the Nord Stream II pipeline, which circumvents Ukraine. The pipeline looks likely to gain approval from the EU later this year, despite strong objections from Central European countries, principally Poland. Gazprom has also been blocked from fully utilising the Opal pipeline by European courts, which temporarily upheld a Polish complaint that its dominant user status hurt competition. "Blocking of Opal is giving us substantial financial damages," Gazprom complained earlier this year.

Earlier this year, Gazprom claimed that US LNG delivered to Europe cost about 30% more than gas supplied through its "most expensive" route, via Ukraine – but this might not be the case for long. Gazprom's prices in Europe, which fell to a 12-year low last year, are anticipated to go up over the next few months – reflecting the recent rise in crude prices – against a background of softening LNG prices. US exports are typically sold on a link with Henry Hub, which has remained persistently low.

Fragile demand growth

Demand will continue to remain firm only if gas prices stay competitive with coal as a generating fuel – as has been the case on and off over the last six to nine months. This could mean coal prices becoming a more important factor influencing Europe's gas prices than crude. So if Gazprom wants to go on seeing such high levels of exports,

it may be CIF ARA (Rotterdam) coal prices, in addition to US Henry Hub and UK NBP, on which it needs to keep a competitive eye.

Henry Hub-linked US exports may provide tough enough competition to reduce Russia's share on their own. Indeed, Vitol's head of LNG, Pablo Escobar, recently said the growing glut of LNG could create a "price war" between the US and Russia, which could drive UK prices below those in North America. He said growing exports of US shale gas would soon force Russia to slash prices to remain competitive in its main market.

"The next war in Europe will be a price war, and it will be LNG versus Russian pipeline gas," Escobar told the International Petroleum Week conference in London in February this year. "As ever, price will clear the market. We see NBP going below Henry Hub at points in the next five years."

Wood Mackenzie projects that 55% of US LNG volumes, or about 32 million tpy, could be sent to Europe by 2020, with the lower transportation costs mitigating the impact of higher spot prices in Asia.

Delayed reaction

The rise in oil prices from last summer onwards is now filtering through to Russian contract gas prices – making Russian gas less competitive and increasing the likelihood of large volumes of LNG moving to Europe.

Although Gazprom's export price increasingly reflects moves in gas-hub rates – as keenly demonstrated since last winter – a link with crude still predominates. Given the six- to nine-month delay in this, the firming of crude since OPEC's agreement to curb production in November will not be felt until the second and third quarters of this year.

Rates for Russian gas at the German border last month jumped the most in seven years, extending their gain since September to almost 50%, according to the International Monetary Fund (IMF). This is hitting utilities, which are already under pressure from low power prices, and undermining gas's competitive position against coal.

The price of gas supplied by state-owned Gazprom at Germany's border climbed 14% in February to US$5.88 per mmBtu (US$162.6 per 1,000 cubic metres), the IMF data show, while day-ahead gas on the UK's NBP fell 20% – although forward contracts were better supported.

Gazprom claims its prices will only rise to US$180-190 per 1,000 cubic metres this year, compared with US$167 in 2016 – but that may still not be low enough to compete with US prices or coal. However, Gazprom could probably go as low as US$3.50 per mmBtu (US$96.8 per 1,000 cubic metres) if it really thought its core markets were under threat.

Deluge begins

The additional LNG supplies are already having an impact on the market. LNG prices in Asia, the biggest and normally highest priced market, sank to US$5.85 per mmBtu (US$162 per 1,000 cubic metres) for April delivery – level with current Russian levels. Prices in the Atlantic basin are lower still. In a recent Argentine tender, where Royal Dutch Shell was awarded the bulk of deliveries, winning bids were estimated at just a US$0.1 premium to forward contracts on NBP. This would put US LNG around US$4-5 per mmBtu (US$110-138 per 1,000 cubic metres), which is enough to undercut Russian gas.

Despite the above, according to TASS, Gazprom expects revenue from its gas exports to grow to US$35 billion in 2017, compared with US$30 billion last year. If prices ascend quickly enough to achieve this revenue target, the company may start losing market share to LNG rather quickly.❖

> "The next war in Europe will be a price war, and it will be LNG versus Russian pipeline gas

Power hunting in Africa

Securing gas supplies for the generation of electricity can transform economies. The challenge is how to secure the investment

AFRICA

AFRICA has plentiful amounts of gas and a substantial under-supply of power. While companies have often been punished for finding gas by investors, the idea of supplying feedstock to a local market is gaining traction. In particular, small companies with relatively minor finds close to consumers can create a business focused on local supplies – although such a role requires navigating a range of commercial and political hurdles.

"Sub-Saharan Africa lacks infrastructure and local demand to support the development of its gas resources. The global LNG glut means that sub-Saharan Africa can't rely on export markets to develop and commercialise its gas," said Opportune's EMEA transaction services leader, Mauro Fiorucci. "Therefore, the development of a local gas market is becoming key to [supporting] a large-scale development of indigenous resources."

Gas-fired plans

Countries such as Nigeria, and the rising East African gas province in Tanzania and Mozambique, often hold resources that have been neglected. Providing a framework in which these stranded assets can be exploited and generate power would provide a double win. The company working on the asset would be able to generate revenues, generally at a relatively low cost. Meanwhile, host countries would receive the economic benefits of improved electricity supplies and taxes, both on the gas production and on increased manufacturing in the country.

Nigeria, in March, unveiled plans to invest US$15 billion in power plants over the next 10 years, with an eye on generating an additional 4,000 MW – effectively doubling the country's current capacity. Three power plants would be built on the Abuja-Kaduna-Kano (AKK) gas pipeline, which is under tender.

The country has also set out plans for a US$20 billion industrial park, with a gas focus, in Delta State. It will be home to fertiliser, methanol and petrochemicals plants, with support from Asian companies.

While oil-focused onshore operations in the Niger Delta have deterred super-majors in recent times, the latter have expressed continued interest in involvement in the gas sector.

ExxonMobil, for instance, is working on an integrated plan in the area, involving a 530-MW power plant.

Pitfalls

The concept is simple. The execution, though, is harder and often founders on efforts to achieve commercial rates for gas. Historically, governments have been unwilling to allow electricity prices to get too high, seeing cheap resources as part of the social contract, even to the point of allowing state-backed power producers to run up unsustainable debts.

Governments often see the provision of cheap energy as essential to maintaining their hold on power. Low prices deter private companies from trying to solve the supply problem. Governments have to choose whether to increase prices to their citizens or take on the losses themselves.

As such, payments for supplies can be squeezed, as can be seen in the difficulties between Tanzania's Tanesco and local gas supplier Orca Exploration. One way to avoid payment problems with wholesale suppliers is to strike deals direct with major consumers, such as factories or mines, which require a continuous supply of power and are prepared to pay for it.

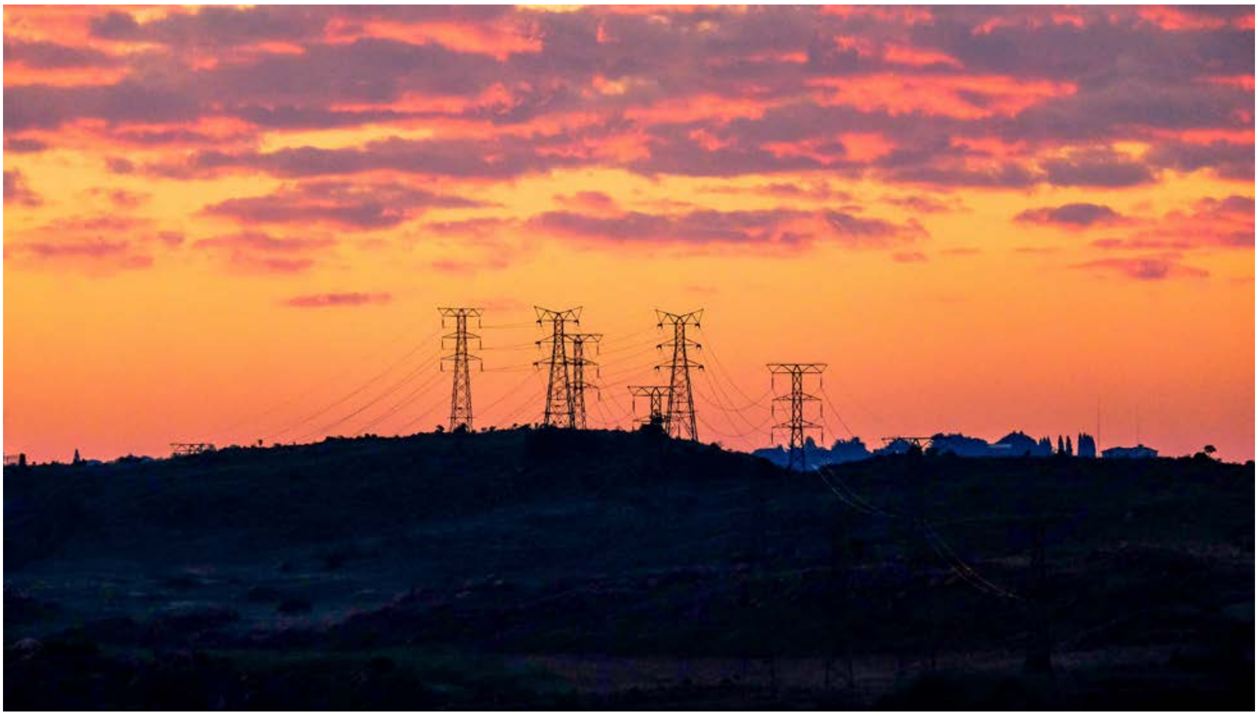
The cost savings of a secure gas stream, over an oil-fired generator, are substantial and can provide gas producers with impressive returns. Victoria Oil and Gas, for instance, working in Cameroon struck deals to sell gas at US$16 per mmBtu (US$443 per 1,000 cubic metres, versus US$22 per mmBtu (US$609 per 1,000 cubic metres) for kerosene or US$32 per mmBtu (US$885 per 1,000 cubic metres) for diesel.

Imports

There may be space for African power consumers to import gas, in the form of LNG. The fuel has historically been considered as too expensive to meet demand in the continent but there are signs that this is changing, with lower feedstock prices combined with new import methods, such as floating storage and regasification units (FSRUs).

"LNG has always been seen as an expensive resource but it is also flexible, producers can push it into new markets," senior research fellow at the Oxford Institute for Energy Studies (OIES), Thierry Bros, said.

"The development of a local gas market is becoming key to [supporting] a large-scale development of indigenous resources



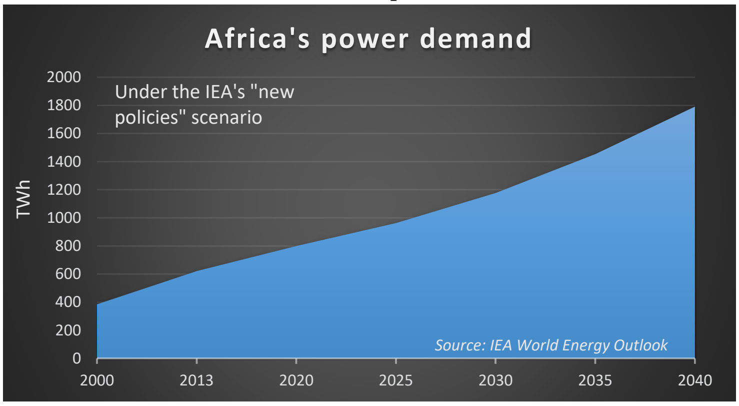
Power lines in Johannesburg

As such, a number of West African states are considering imports, including Cote d'Ivoire, with backing from Total, and Ghana, where an FSRU, the Golar Tundra, is in the country.

Major consumers are also considering imports. South Africa is the most plausible importer, given its gas shortage, but Nigeria's Lagos has also been mentioned as a potential LNG receiver – a stark demonstration of pipeline security concerns in the Niger Delta.

Financing

In order to be able to meet customers' demand, companies will need to build pipelines and facilities. This can be a challenge for smaller companies, which lack the financial depth to put together such projects. In Tanzania this problem was solved through a large company coming in to build the 530-km Mtwara-Dar es Salaam pipeline. This was made possible through a Chinese loan, from Exim Bank, with work being carried out by a Chinese construction company, the China Petroleum and Technology Development Co. (CPTDC), a subsidiary of China National Petroleum Corp. (CNPC).



While Chinese financing has come, over the last few years, to be seen as a panacea for Africa's infrastructure needs, other routes are also available. The Eni-backed Sankofa Gye-Nyame development offshore Ghana will cater to two audiences: oil will be exported while gas will be moved onshore for local consumption.

The International Finance Corp. (IFC) and Multilateral Investment Guarantee Agency (MIGA) signed off on a US$517 million support package for the project, which will provide up to 1,000 MW of new generation. As a result of this financing support, a number of commercial banks were also available to come onboard, from Europe and Asia.

The challenge of handling an integrated scheme can be daunting, given the need to tie up so many aspects into a flexible but durable relationship. Namibia's Kudu gas field had struggled under such a load, with long-time operator Tullow Oil being unable to make progress and, in early 2015, relinquishing its stake.

Vessel operator BW Offshore farmed in to the project in February this year, taking a majority stake. The move is unusual, in that it involves a company moving from the services sector into the operational side of things. BW has ready access to vessels and the ability to provide capital in order to secure long-term gains.

The deal will see the company move from securing its return on the vessel's provision, instead cashing in from supplying gas to an onshore power project, which will also supply electricity into South Africa. Securing development-ready projects is a clear benefit from the recent price crash, with a number of explorers unable or unwilling to commit to such investments. ❖

Global LNG market comes of age

LNG supply is booming, keeping a lid on prices and fuelling new demand, although pre-FID projects are under presssure

GLOBAL

AMPLE LNG supply over the coming years is expected to help the feedstock claim a global price independent of oil links. Demand may overshoot expectations as pressure grows to clean up city air in developing countries.

The start-up of Lower 48 US LNG exports in 2016, alongside a surge in supplies from Australia and other countries, should see LNG supplies soar almost 50% between 2015 and 2020. The surplus cargoes will help add liquidity to a market that has been dominated by crude-price linked contracts. This is anticipated to propel LNG trading towards independence from oil markets.

There are a number of ways in which pricing may develop. The US Energy Information Administration (EIA) has predicted an LNG benchmark price will develop in Asia, although alternatives would see a benchmark tracking European hub prices, where marginal demand is anticipated to be located, or Henry Hub.

"It is much more likely that a Henry Hub-driven gas market emerges, driven by Henry Hub-linked cargoes from US producers. This will mark a true globalisation of the gas market, a move away from the regional, oil-indexed contract approach we have at the moment," said Energy Flux director Mark Simons.

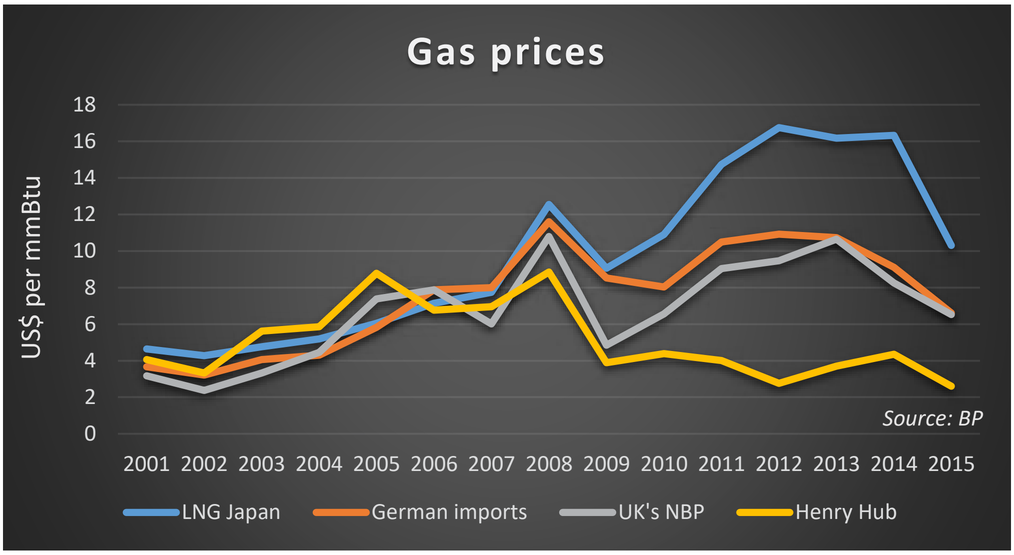
Oversupply, but for how long?

Australia is set to overtake Qatar as the world's biggest exporter by 2019 and the US will take second spot by the year after, leading to a surplus for several years. The head of Vitol's LNG trading, Pablo Escobar, recently said the market would likely be "significantly oversupplied" for the next five years, but that pressure on LNG prices was creating new markets, as well as raising demand among existing importers.

Looking at the supply outlook in more detail, even at the peak of the glut in 2019 the oversupply will only be around 2.2% of total global consumption – at 82 bcm of 3.7 tcm in 2019 – according to McKinsey figures. This may be enough to keep sentiment bearish, but it could also be relatively easily absorbed by any additional demand. Such demand is coming from increasingly wealthy developing cities that want to clean up their local air pollution.

At the same time some of the anticipated capacity may not be built, including planned floating (FLNG) projects in Australia such as Woodside's Browse and Sunrise facilities and ExxonMobil's Scarborough. Beyond 2024, additional final investment decisions (FIDs) for about 200 bcm per year of new supply will be needed to meet demand by 2030. But low oil ▸▸

> "Evidence of excess supply is initially appearing in a narrowing spread between Northeast Asian prices and the UK's NBP



prices and an oversupplied spot market could discourage long-term contracting and project FIDs, increasing the risk of market tightness from 2024.

Evidence of excess supply is initially appearing in a narrowing spread between Northeast Asian prices and the UK's NBP, which is resulting in a more uniform price for gas across the world than has been seen before, as surplus cargoes are backed out of Asian markets. The glut has driven Asian spot LNG prices down by over 70% since their 2014 peak to US$5.85 per mmBtu (US$161.8 per 1,000 cubic metres) for April 2017 delivery.

This shows sellers in Asia are having to compete for buyers, driving down the price. Producers are also selling to buyers with lower credit ratings, such as Egypt and Jordan – indicating a greater willingness to take payment risk. Buyers are also more able to dictate contract terms, reducing durations and increasing gas indexation, which all suggest that LNG producers are working hard to ensure that there is as little oversupply as possible.

"In 2016, we didn't see an oversupply … for the rest of the decade we expect strong supply growth but also strong demand growth and to the extent that there's an imbalance between the two, we believe Europe can easily absorb those volumes," a Royal Dutch Shell gas marketing and trading executive, Steve Hill, said at a recent event launching the company's market outlook.

> "US President Donald Trump's policies are likely to lead, if anything, to lower US gas prices and higher LNG exports

The Trump factor

Given substantial future supplies will come from the US, the recent change of government there may have an important impact on LNG flows. US President Donald Trump's policies are likely to lead, if anything, to lower US gas prices and higher LNG exports. His moves to scrap regulations are driving down costs and encouraging drilling, which is likely to add to supply. At the same time, any improvement in the terms for coal producers will displace gas from the power generation market, which is predicted to shrink over upcoming years as renewables claim market share.

Regarding foreign policy, so far he has done nothing to suggest that US sanctions would be imposed on Iran, reducing LNG development there – but equally there are no

Trading houses move in

Demand creation is also being helped by trading houses, which are expanding their presence in LNG, taking advantage of increasing spot sales, tenders and gas benchmark-linked trade, along with a rise in re-trades and destination swaps. Vitol's Escobar said his company was looking at spending money on LNG infrastructure to build up its clout in the sector, where it competes with traditional suppliers and other traders such as Trafigura and Gunvor. Furthermore, traditional super-majors are also beefing up their trading abilities.

In 2015, trading houses' share of the LNG market was just 3-5% of the overall traded volume. But that is anticipated to expand rapidly, with the bulk of the growth coming from up to 30 new smaller demand centres, mostly in Southeast Asia, Latin American and the Middle East, as well as China and India.

Trading houses bring greater risk appetite, or an ability to offset risk in a variety of markets. For example, traders will often have an established presence in other commodities in emerging or risky markets, which allows them to offset country and counterparty risk. Escobar said trading in LNG would grow, predicting that a larger derivatives market would soon develop, similar to that for oil, as the market became more global. Some traders have already used their wider product portfolio to experiment successfully with combining trading relationships.

Traders' presence and product portfolio allow them to talk to counterparties of various importance and size. This helps them to aggregate demand from several buyers and pursue large volume deals at better prices – with more choice on pricing link for customers than a conventional seller. Well developed in-house ship-chartering departments also provide additional flexibility.

signs of allowing US companies to carry out new work in the country.

"Trump's domestic policy encourages inward investment, and therefore US gas development and exports will increase," said Gneiss Energy's Jon Fitzpatrick.

Demand versus surplus

US exports are likely to be the most important supply-side factor for the world market for many years to come. But the demand side of the equation is just as important and price will play a key role in that – along with expanding infrastructure and flexibility.

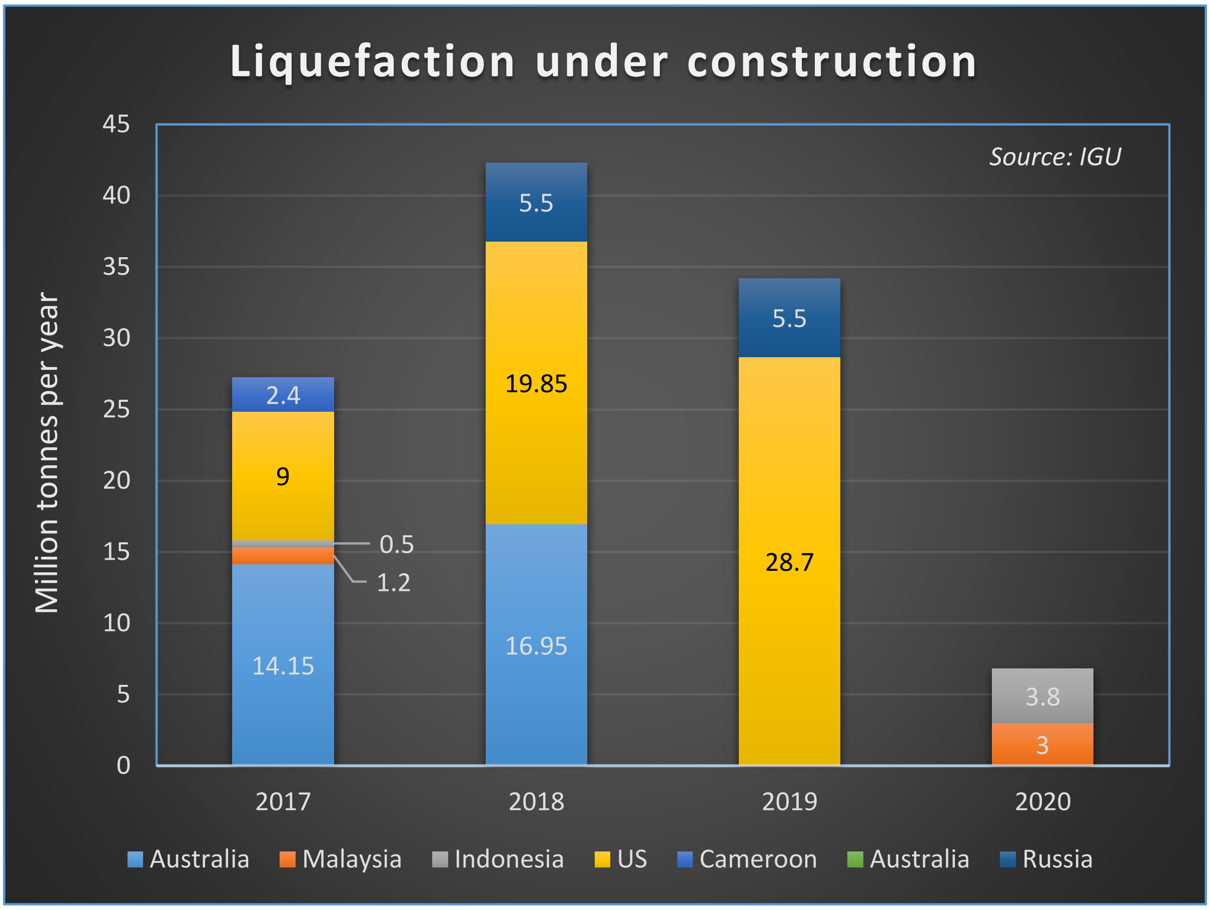
Demand has risen above expectations over the last six to 12 months, with China, India and many smaller countries speeding up buying to take advantage of low LNG prices, which has helped replace highly polluting coal. That and cold weather have pushed LNG prices up this winter, absorbing early surpluses and raising questions over some of the more price-sensitive incremental demand – although prices are retreating again now as the winter ends.

In China, imports of LNG in January were up almost 40% on a year ago, at 3.44 million tonnes, according to the General Administration of Customs (GAC) – outcompeting Europe for marginal cargoes, despite cold European weather and relatively high gas prices there.

Sharp growth in 2016 imports had already propelled China past South Korea to become the world's second biggest LNG importer, after Japan – above most analysts' forecasts. It could be that efforts to reduce city pollution in China are becoming such a priority that LNG demand will rise further above expectations as use of more polluting coal is reduced.

To decrease air pollution China has already set an ambitious target – in its Energy Development Strategy Action Plan for 2014-20 – for gas to reach a 10% share in the total primary energy consumption by 2020. This includes a substantial shale gas component, but so far Sinopec and others have enjoyed only limited success, increasing reliance on alternative sources including LNG. Australian producer, Woodside Petroleum, expects additional Chinese demand to bring the LNG market into balance by around 2021-22, about a year earlier than previously anticipated.

Beyond China, Shell has estimated Southeast Asian LNG demand will climb above 50 million tpy by 2035, up from 10 million tpy currently, while South Asia could add another 15 million tpy. Demand is also being created in the bunkering and transportation markets, as a means of reducing urban pollution. However, much of the new demand will be price sensitive, and so will only continue if the market is sufficiently oversupplied.❖



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