Gas Industry

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Fuel rises to challenge oil industry's supremacy

Symbolic shift: supermajors once just pumped, refined and marketed oil. Today, gas plays a much bigger role Bloomberg

Plans to squeeze more value out of reserves are taking shape but not all companies have found ways to hedge their bets, says *Guy Chazan*

This year will be a landmark one for Royal Dutch Shell. For the first time in its 106-year history, the Anglo-Dutch giant will produce more natural gas than oil.

It is a historic shift that reflects an industry-wide trend. For decades, the supermajors just pumped, refined and marketed oil. But, today, gas plays a much bigger role in their business.

Nothing symbolised that change better than ExxonMobil's $41bn acquisition of XTO Energy, in 2010 one of the biggest companies in US unconventional gas. But the majors' eagerness to grab a slice of the North American shale gas industry is only part of the story. What is driving this "gassy" strategy is a conviction that it is the fuel of the future.

Its growing attractiveness is, in part, explained by the urgency of climate change. Though still a fossil fuel, using gas in power generation instead of coal can sharply reduce carbon emissions.

But gas is not just replacing coal. It is increasingly challenging the hegemony of oil, both as a transport fuel and as a feedstock in petrochemicals.

"Gas is being talked of as a 'transitional' fuel until truly clean sources of power are economically viable," says Steve Wardlaw, head of law firm Baker Botts' London office. "As long as the dream of cheap carbon-free generation remains a dream, and subject to suitable pricing, gas is the only logical substitute for truly dirty fuels."

Hence the widespread predictions of rising gas demand. Shell sees it growing by more than 60 per cent from 2010 to 2030, or by 2-3 per cent per year. Yet, it could grow even faster if the new uses of gas – especially as a transport fuel – take off.

"We're in the midst of both a demand and a supply revolution," says Maarten Wetselaar, head of integrated gas at Shell.

This process of substitution is having far-reaching consequences, not least for oil demand. For years, the consensus has been that demand for oil – and, by extension, the oil price – would rise inexorably, driven by factors such as the surge in Chinese car ownership.

> 'Gas is being talked of as a "transitional" fuel until truly clean sources of power are economically viable'

But analysts are now revising their forecasts. Take Citigroup, which recently put out a research note provocatively entitled "Global Oil Demand Growth – the End is Nigh". Seth Kleinman, one of its authors, says demand for crude could hit a plateau this decade – a view that would once have sounded eccentric to say the least.

The substitution wave is most pronounced in the US. There, the widespread use of techniques such as hydraulic fracturing, or fracking, in which rock is cracked open to recover hard-to-reach oil and gas, has unlocked vast reserves long considered uneconomic. Gas prices have fallen sharply as production has boomed, making gas much more attractive to utilities.

But substitution is happening elsewhere too. One striking example is Iran, where international sanctions have caused shortages of imported gasoline and triggered a switch to natural gas vehicles. The number of such cars has jumped from below 50,000 in 2005 to 2.9m in 2011, according to Citi.

Meanwhile, cities from New York to London are converting their taxi fleets to liquefied petroleum gas. And car companies such as GM, Ford and Chrysler now offer bi-fuel pickups that can run on compressed natural gas (CNG) and gasoline. UPS, FedEx, Walmart and Frito-Lay are just some of the companies to have switched

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Launchpads proffered for small-scale GTL plants

Gas to liquids

Ajay Makan finds an industry in search of a political solution

A process famed for keeping German tanks running during the second world war is set to revolutionise the fortunes of US natural gas producers, or so the evangelists of small-scale gas-to-liquids plants believe.

The Fischer-Tropsch process, which uses chemical reactions to alter the composition of gas molecules and yield a high-quality, oil-like liquid, has long been associated with isolated regimes desperate for access to oil.

The modern day adopters of the technology hope to bring it to the US, one of the most oil-rich countries in the world and where production is rising faster than at any time in history. The US is also in the throes of a shale boom and has an even bigger surfeit of natural gas, which has weighed on prices.

"In the US, a lot of gas is coming out of the ground at a declining price, so if you can convert it into oil you can get a step up in value," says Nicholas Gay, chief executive of CompactGTL, an Oxfordshire-based company that is developing small-scale gas-to-liquid plants.

The pitch of CompactGTL, its local rival Oxford Catalysts Group and others is that small-scale GTL plants can give US gas producers such as Chesapeake Energy exposure to higher oil prices.

A plant capable of producing 2,000 barrels of synthetic crude oil a day from 20m standard cubic feet of gas would cost about $200m to build, with an operating cost of about $15 to $25 per barrel, according to Oxford Catalysts.

At a Henry Hub price (the US benchmark price of gas) of $4 per million British thermal units (MBtu), that equates to about $68-$78 per barrel of finished diesel.

Such plants could be dotted across the US, producing oil from gas that would otherwise be shut in because of the low Henry Hub price or because of transport difficulties, according to the company.

Oxford Catalysts and CompactGTL say they are in talks with US gas producers. Lesa Adair, chief executive of Muse Stancil, a Houston-based energy consultancy, says the companies' technology may appeal to producers whose shares have fallen in tandem with US gas prices.

"GTL can transform smaller producers, with production portfolios heavily weighted to gas, from gas to [more valuable] liquid stocks," says Ms Adair.

But, as yet, there have been no firm orders from US oil and gas producers and some in the industry are sceptical of installing GTL plants in individual gas fields, operated by a single company.

Projects commissioned to take advantage of cheap US shale gas, such as Sundrop's gas to liquids plant in Louisiana – part-owned by Chesapeake – and an Oxford Catalysts plant for wax and solvent maker Calumet in Pennsylvania, are instead expected to tap into gas from a number of suppliers.

> 'If you look at what is going on with flaring in the US right now it is like the Wild West'

Another challenge to small-scale GTL may be rising gas prices in the future.

The Henry Hub price has doubled from a low of $2 per MBtu a year ago and the futures curve suggests prices could reach $6 within a decade. A $1 rise in Henry Hub prices adds approximately $9.50 to the cost of producing a barrel of finished diesel.

Low prices are an incentive for gas to be used as a transport fuel, which could erode the oil price premium in the long term.

Seth Kleinman, head of energy strategy at Citi, forecasts that gas will substitute for 3.5m barrels of oil a day by 2020, although he remains optimistic about GTL.

"We think the oil-gas spread has passed its peak, but even if US gas moves up to $6 that still leaves a healthy spread to make GTL work," says Mr Kleinman.

"The issue for GTL so far has been the massive [investment] and lead time that have been a function of the scale of the projects. The future for smaller scale GTL projects is very bright."

Proponents of small-scale GTL highlight environmental applications. The surge in shale oil production in the US has led to a huge jump in flaring – the burning of unwanted gas that comes to the surface with oil but cannot be transported to market.

Brazil, where the government has actively encouraged state oil company Petrobras to limit flaring, has provided the best incubator for small-scale GTL. Petrobras has staged trials for the applications of both CompactGTL and Oxford Catalysts technology.

The industry is hoping political pressure will provide a similar launchpad for small-scale GTL in the US.

"If you look at what is going on with flaring in the US right now, it is like the Wild West," says Roy Lipski, chief executive of Oxford Catalysts. "Things will take off much more quickly for us once you start seeing pressure from regulators and the government to stop flaring."

Continental shift may aid competition

Europe

Shale exploration is now a reality, says *Michael Kavanagh*

The jury is still out on whether the US shale gas revolution can be replicated in Europe.

But investors who took early positions in European shale gas explorers, during the initial euphoria at the prospects of quick profits, have been disappointed.

San Leon Energy and Aurelian Oil & Gas recently merged in a deal aimed at preserving cash after a string of disappointing drill tests for unconventional gas in Poland – a country that was once seen as the most likely in Europe to lead the continent's drive toward commercial shale gas production.

Fellow explorer 3Legs Resources has also suffered sharp falls in its share price since floating in London two years ago because of disappointing progress with its exploration acreage. Last month its chairman Tim Eggar, former UK energy minister in John Major's Conservative government, was forced to call on investors and return remaining funds to shareholders. But 3Legs intends to stagger on, albeit with reduced exploration spending, in partnership with US oil major ConocoPhillips.

US peer Chevron also remains committed to prospecting in Poland though ExxonMobil. But Chevron announced last June that it was abandoning its exploration activity in the country.

A combination of Poland's political determination to reduce its dependence on Russia for gas, combined with claims by the US Energy Information Administration that Poland might have 5.3tn cubic metres of shale gas – the largest reserves in Europe – fuelled demand for exploration licences in the country.

More recent estimates issued by the Polish Geological Institute present a more modest scenario of the country's shale gas reserves – now conservatively estimated at 346bn-768bn cubic metres. That, though, would still be enough to supply the country for 35-65 years.

Bulgaria and Romania have also been identified as countries in eastern Europe with the potential for commercial shale gas production. In western Europe, despite a range of moratoria that have held up appraisal of shale prospects, Germany, France, Spain and the UK are also on the list of countries experts argue are sitting on potentially lucrative sources of onshore shale gas supplies.

But questions over the eventual cost of production compared with conventional gas, overlaid with large levels of uncertainty over the scale of suitable gas-bearing rock contained in shale formations in these countries, continue to dampen predictions of a US-style boom.

In the UK at least, the government appears keen to face down opposition from environmental campaigners and encourage shale gas production in an attempt to counter the long-term depletion of Britain's conventional gas and oil reserves.

Last month, George Osborne, the UK chancellor, announced a range of tax incentives and proposals to ensure communities benefit from shale gas projects in their area as part of attempts to soften opposition to shale.

But a recent report by energy consultancy Wood Mackenzie suggests a combination of tax breaks and a move to calm public fears over the potential for fracking to cause earthquakes and pollution will not be enough to deliver a significant shale gas industry to the UK.

Success will demand rock that "is as good as the very best shale plays in North America", in part to cover the higher- than-expected production costs.

Niall Rowantree, one of the report's authors, says: "Until many, many more wells are drilled, fracture stimulated and flow-tested, it is not possible to accurately predict the ultimate recoverable volume of shale gas in the UK and, therefore, any estimates of the ultimate impact on UK gas supply are premature."

Yvonne Telford at Wood Mackenzie also suggests that the UK's dependency on gas imports could rise to 50bn-75bn cubic metres

> 'There's the will in Europe not to be left behind on the cost of energy'
> **Philip O'Quigley**

a year by the first half of the next decade. Delivering this scale of domestic shale gas in this timeframe would demand a world-class resource and a few thousand wells. Ms Telford says this is unlikely.

Shale Gas Europe, a lobby group that advocates exploitation of shale gas, tight gas and coal bed methane across the continent, concedes that potential operators face higher costs than in the US. There the cost of well development ranges from $3m-$11m, while in Europe costs range from $8m-$16m.

So far, major European energy groups appear to want to grab a slice of the US shale gas glut rather than scrabble for positions on their own doorstep.

Philip O'Quigley, chief executive of shale gas explorer Falcon Oil & Gas, suggests many in the industry are more attracted to prospects in Australia, South Africa and China than Europe, while Argentina is also seen as a potentially prolific producer if it could shrug off fears that it will expropriate foreign operators.

But he argues that fears of being at a competitive disadvantage will push European governments towards developing shale gas resources if they are proved to be economic.

"There's the will in Europe not to be left behind on the cost of energy – European energy costs are three times that of North America."

Risky business as billions invested in infant industries

East Africa Without transparency and clear regulations there is a prospect of increased discontent, reports *Michael Kavanagh*

When Mozambique's prime minister visited Rome last week, he called on the chief executive of Italian state-backed oil major Eni.

Talks between Alberto Vaquina and oil industry veteran Paolo Scaroni centred on the progress of plans to exploit the country's recently discovered offshore gas reserves, which could transform the economy of the impoverished country.

But getting gas from deep water in the Rovuma Basin off east Africa to market – most probably in the energy hungry economies of east Asia – will be no easy matter.

Eni and Anadarko of the US, which lead consortiums that have struck lucky in two adjoining blocks of Mozambique, are now considering plans to join forces for an initial development of four liquid natural gas liquefaction trains, each capable of producing 5m tonnes of LNG a year.

A final investment decision by Eni on how best to push ahead on exploiting discoveries estimated at 75tn cubic feet (tcf) is expected next year.

But, with the Mozambican hydrocarbon industry in its infancy, a range of engineering, legal and political risks face companies embarking on multibillion-dollar investments.

Last month, Eni announced it was selling a 20 per cent stake in its Block 4 offshore licence to China National Petroleum Corp, the country's largest oil company by production, for $4.2bn.

Mr Scaroni said this would dilute Eni's commitment to funding a project he estimated could require $50bn to allow LNG exports to Asia from Eni's and Anadarko's blocks by the end of the decade.

That deal was struck as Anadarko and Videocon, the Indian conglomerate, launched an auction for a 20 per cent stake in their Block 1 offshore licence that could raise more than $4.5bn.

The planned reshuffling of the Anadarko consortium comes within a year of the sale of an 8.5 per cent stake by Cove Energy to Thai oil and gas group PTT Exploration and Production for $1.9bn.

The sale to PTT, which saw off previously recommended offers from Royal Dutch Shell, was interrupted by the need to clarify the capital gains tax liability that would be levied by Mozambique on companies profiting from the sale of early stage exploration assets.

Further revisions to Mozambique's petroleum laws were approved by the country's cabinet last week. While stipulating that some revenues from developments would be allocated to local communities, they were also designed to "make the legal framework more clear and predictable for investors", according to a government spokesman.

In waters to the north, Tanzania also appears set to join the ranks of prominent LNG exporters.

In March, Statoil of Norway announced it was teaming up with BG Group of the UK and its partner Ophir Energy to develop plans for a $14bn liquefaction facility following further gas finds off the shore of Mozambique's northern neighbour.

Statoil, along with junior partner ExxonMobil, now claims up to 13 tcf of total recoverable reserves while BG

> Growing revenues from coal and oil have led to political arguments

Group and Ophir have also estimated recoverable resources for their Tanzanian blocks at 13 tcf.

Further drilling success at BG's Jodari field off Tanzania prompted chief executive Chris Finlayson last month to suggest that it took the company a step closer to developing an LNG export project, though Statoil warned that the speed of any development would be hindered by the country's current lack of infrastructure.

Nick Buckworth of international law firm Shearman & Sterling says that in Mozambique a number of interlocking issues must be tackled to allow LNG projects to proceed.

The requirement for a port, power plants and airstrip will also require substantial investment on top of the LNG trains themselves, he says, presenting both an opportunity and challenge to a country with modest GDP estimated at less than $15bn last year.

"There's lots of moving parts – there's the groups themselves where we are seeing the selling and buying of stakes. Then there's the role of the government in understanding what it needs to deliver in terms of investor security by tackling political risk and setting out tax regimes. And then there's the issue of how the two blocks themselves interact."

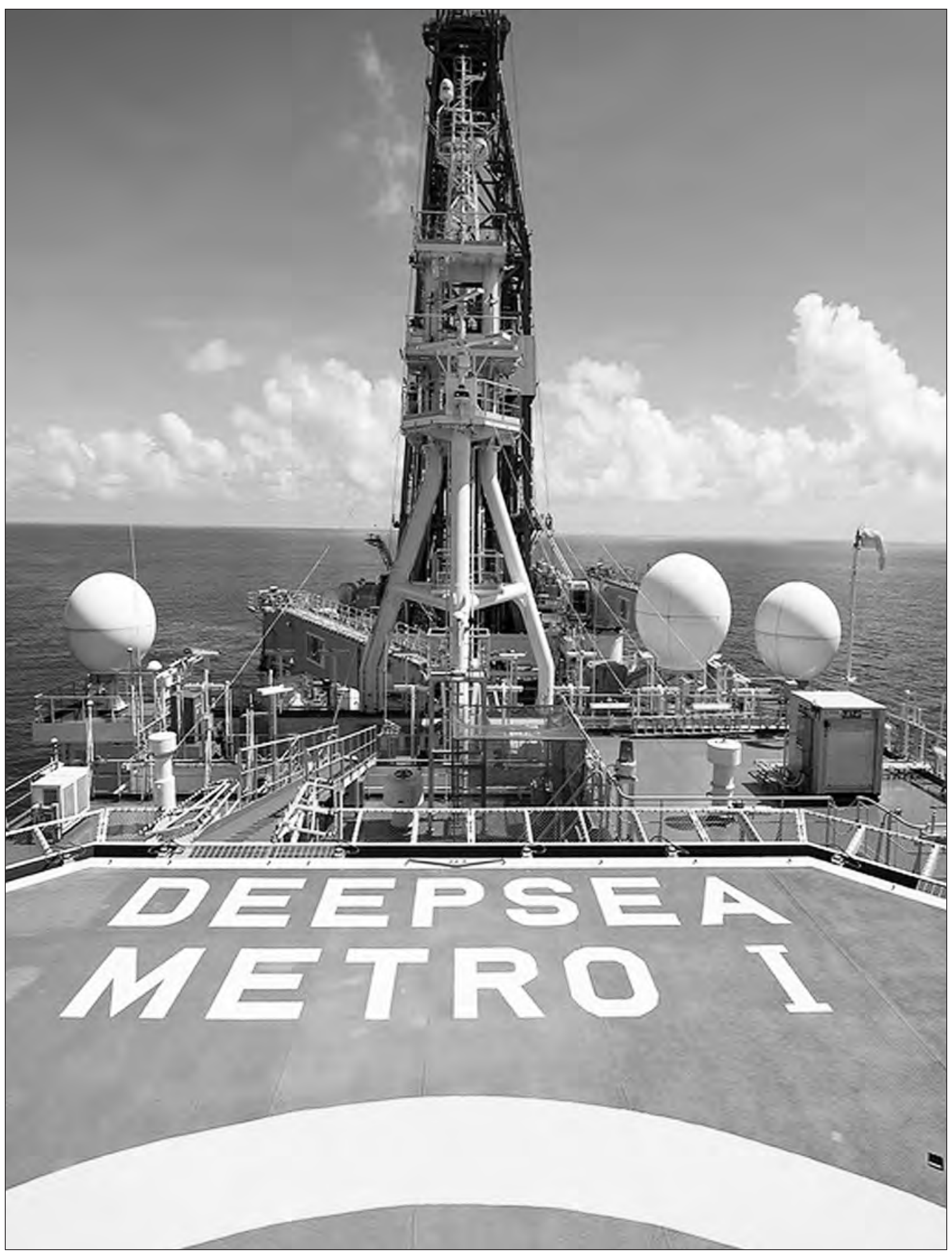
But Mr Buckworth, who advises one minority partner, an investor, on the Mozambican blocks, is relatively confident the investments will be made despite the potential for conflicts between the many companies involved.

"Mozambique wants the gas on stream, and it wants the power, petrochemical and other downstream activities," he says.

The prize for the successful development of LNG projects could be to overtake Qatar, the world's leading LNG exporter, through developing a combined production capacity of up to 100m tonnes a year, according to consultants at Wood Mackenzie.

But David Ledesma, an independent gas industry consultant, warns of dangers facing Mozambique and Tanzania in managing the transition to becoming large gas exporters. Both are relatively poor countries with limited institutional capability and capacity, he argued in a paper published last month through the Oxford Institute for Energy Studies.

Growing levels of revenues from coal and oil have already led to political arguments and urban unrest in an economy that, though growing fast, still suffers from extreme rates of poverty, he notes.



Digging deep: the Deepsea Metro can drill in water depths of 3,300m

Fuel rises to challenge oil industry's supremacy

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some of their fleets to CNG or liquefied natural gas (LNG). Citi forecasts some 30 per cent of carrier fleets and 50 per cent of rubbish trucks will be running on CNG in the US by the decade's end.

In the US, the main driver of oil-to-gas substitution is the huge discrepancy between the price of gas and oil. But in China, the motivation is environmental: the growing need to do something about air pollution. There, vast efforts are being made to replace gasoline with LNG. Already, Mr Wetselaar says, China has more than 20,000 LNG-powered vehicles on its roads, mainly buses and trucks.

Europe is also pushing hard to use more gas in transport. In its clean fuel strategy, published in January, the European Commission proposed that LNG refuelling stations be installed every 400km along Europe's main highway network by 2020.

The process of substitution is leading to strong growth in gas demand. Analysts at Goldman Sachs see domestic and export demand for US natural gas growing by 21bn cubic feet a day between now and 2020, from 69.5 bcf/d now. That is based on greater use of gas in power generation, fertiliser and petrochemical plants, transportation and in residential and commercial heating.

The growth of its gas business is having a big effect on Shell. The company has seen a 34 per cent rise in its gas production in the past three years. Integrated gas now accounts for about a quarter of its cash flow and 22 per cent of its production.

There is a danger lurking here. The more gas Shell produces, especially in the US, the more it is exposed to the problem of low gas prices. That is one reason its US upstream division made a loss last year.

It is a problem other majors are facing, too. Analysts at Bernstein have calculated the average revenue per barrel for the European majors fell last year from $73.8 to $73.5, despite a slight rise in oil prices. It suggested the main cause was the rising share of gas in the group's production mix. In 2000, gas made up 36 per cent of total volumes: by last year that had increased to 46 per cent.

Chevron has bucked the trend. It has traditionally favoured oil production over gas, with volumes split about 70:30 between the two, while rival Exxon last year saw a 52:48 split. As a result, the company now has the highest earnings per barrel of output of all five largest international oil companies and, in March, overtook Shell in terms of market capitalisation.

Mr Wetselaar says this problem will fade as Shell's plans for squeezing more value out of its gas reserves take shape. These range from a scheme to export gas in the form of LNG from a terminal near Savannah, Georgia, in the US, to a gas-to-liquids plant on the Gulf Coast that would transform gas into clean-burning transport fuels. Such schemes – still very much in their infancy – would harness the arbitrage opportunities that have been created by the gap between high Asian prices for LNG – and the high price of petroleum products – and the much lower Henry Hub, the US benchmark price of gas.

"Having the gas reserves and the conversion projects is a perfect hedge," says Mr Wetselaar.

"If you can do it in such a way that you don't produce the gas in the ground when Henry Hub prices are low but do when they are high, then you're in the money, whatever the price is."

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Swift decisions needed to gain second wave of investment

Australia Security of supply may not be enough to offset rising costs, says *Neil Hume*

Australia's liquid natural gas industry is coming of age. By 2018 the island continent should overtake Qatar as the world's largest exporter of LNG, as seven colossal projects reach full capacity and exports jump from 25m tonnes to an estimated 88m tonnes.

But there could be a price to pay for Australia's rapid growth. Analysts say a second wave of LNG developments and project extensions, worth more than A$100bn, are at risk from rising labour costs, infrastructure problems and the strong Australian dollar.

If these issues are not tackled, warn industry executives, then investment in Australia's LNG industry could dry up over the next four years and customers in Asia will turn to Canada, the US, east Africa, and the Mediterranean to satisfy growing gas needs.

"Projects in Australia have been hit with huge cost overruns, which has led to real reservations about whether Australia will see any more projects being sanctioned there this decade," says Tony Regan, LNG consultant at Tri-Zen International in Singapore.

The scale of the challenges facing Australia's LNG industry were recently underlined by Chevron, the US oil and gas company. In December it revealed that the budget for Gorgon, the largest single resource project in Australian history, had overrun by 40 per cent to US$52bn.

"The cost overruns have been huge," says Mr Regan. "We are talking about 25 per cent within 18 months of projects being sanctioned."

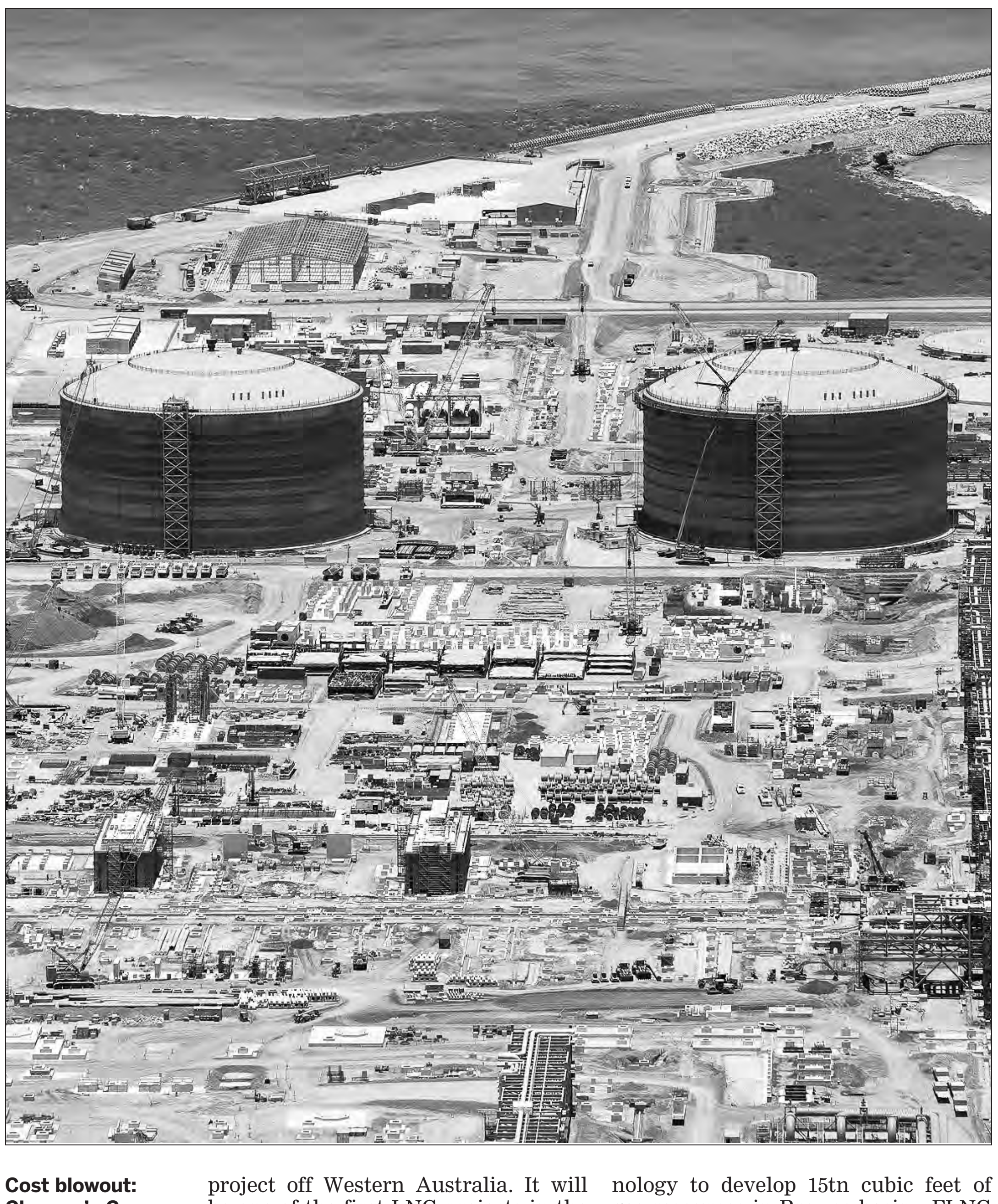
Australia is now the most expensive offshore exploration and production location in the world – three times as expensive as the US Gulf Cost, and slightly more expensive than Norway, says Santos, a major Australian oil and gas company. The biggest contributors to cost inflation are Australia's lack of skilled labour and experienced subcontractors, and the strength of the dollar, which continues to trade at parity with its US counterpart.

The strong Australian dollar increases the cost of imported goods and services, driving up already high project costs, says William Breeze, a senior associate at law firm Herbert Smith Freehills. "Costs as high as US$4bn per million tonnes of capacity have been reported for Australian projects, compared with US$1.9bn for Angola LNG."

Projects sponsors have got away with cost overruns in the past because oil prices, which help determine the price of LNG contracts in Asia, have risen. Chevron argues the Gorgon's economics remain attractive because, while investment requirements have risen, so too have oil prices – by approximately 80 per cent since the budget was set.

"But we are now in a period of almost static [growth] and forecast lower crude prices, and people are wondering if any of these projects will ever make an adequate return on their investment," says Mr Regan.

In an effort to bring down costs and bypass toughening environmental legislation, oil and gas companies are looking to technology. Royal Dutch Shell, for instance, is championing floating LNG at the US$12.6bn Prelude



Cost blowout: Chevron's Gorgon plant in Western Australia is the largest single resource project in the country's history

project off Western Australia. It will be one of the first LNG projects in the world to process gas at sea. This will be done on huge barges – six times the size of the largest aircraft carrier – moored directly over gasfields.

Floating LNG (FLNG) has several advantages over onshore LNG projects. The plant can be manufactured in more cost-effective locations overseas and there are no land access issues and fewer secondary costs, such as building housing for workers. Decommissioning is also less complex.

Mark Greenwood, analyst at Citigroup, estimates that the ExxonMobil-led Scarborough LNG project, which has selected FLNG as its preferred development concept, will sit at the bottom end of the industry cost curve if it goes ahead.

Analysts at JPMorgan estimate the US$40bn Woodside-led Browse LNG project could slice more than US$9bn from its budget by using FLNG. Last week, Woodside said it had scrapped plans to build an onshore processing facility near Broome in WA and was considering using floating LNG technology to develop 15tn cubic feet of gas resources in Browse basin. FLNG is one reason analysts believe Australia will see continued LNG investment. Another is the potential to add extra trains to existing projects, and there is also the possibility of collaboration. Shell has said its Arrow project in Queensland might be better served by tying up with one of three coal seam gas developments, worth A$70bn, already under construction.

There are also signs some of the cost pressures that resulted in the large cost overruns are easing.

"We think some of the heat has come out of the Australian market as projects in the mining sector have slowed," John Watson, chairman and chief executive of Chevron, has said.

But Australia will have to move quickly if it is to secure a second wave of LNG investment, says Mr Breeze. "If final investment decisions are not taken, and the LNG sale and purchase agreements are not signed in the relatively near future, it is possible that buyers will turn to other sources to satisfy their demands."

Companies push the boat offshore

Floating facilities

Innovative FLNG facilities offer a win-win solution, writes *Michael Kavanagh*

At the Geoje shipyard in South Korea, work has begun on the construction of Royal Dutch Shell's Prelude vessel.

The shipyard is one of the few globally to accommodate construction of Prelude that, when completed, ranks as the largest floating offshore facility in the world – longer than four football fields and displacing six times as much water as the largest aircraft carrier.

The prize for Shell is to tap potentially stranded gas deposits out at sea and transport this increasingly coveted energy source to customers without the need for local processing on shore before shipping.

Built by a consortium of Technip and Samsung Heavy Industries, Prelude will be towed and anchored on the Browse Basin, 200km off Australia's northwest coast. From 2017 it is expected to provide enough natural gas to more than meet the equivalent of Hong Kong's current needs.

Shell is scheduled to be the first to deliver a floating liquefied natural gas facility (FLNG) and is keen to exploit its first-mover advantage in the field.

But several other oil majors are also attempting to develop FLNG vessels to feed an anticipated boom in global demand for the fuel, which must first be cooled to below -162C to allow for economic transportation by ocean-going tanker.

Earlier this month, rival ExxonMobil also submitted an application to develop the Scarborough gasfield in the Carnarvon Basin off the northwest coast of Australia using floating LNG facilities.

At 495 metres long, Exxon's facility would be longer than New York's Empire State Building is tall. Though just seven metres longer than Prelude, this would establish it as the world's biggest offshore facility. A final investment decision on the project by Exxon and partner BHP Billiton will not be made until 2014 at the earliest. But, should it proceed, it will produce 6m-7m tonnes of LNG a year compared with the 3.6m tonnes of LNG – combined with a further 1.7m tonnes of liquid petroleum gas and gas condensate – expected to be processed at Prelude.

The engineering complexity of the developing and operating of FLNG units is still to be fully tested.

Prelude, for example, has been designed to take up a quarter of the space needed by conventional onshore LNG facilities. It has been designed to withstand the swells and strains created by a category five cyclone weighing on the structure and its stored liquids.

"This has never been done before," says Neil Gilmour, Shell's general manager for FLNG. "We had to find ways to adapt our technology for offshore."

In spite of the complexities and costs of Prelude – put at an unconfirmed $11.5bn and rising – both Shell and Exxon point to the potential cost savings and reduced environmental impact such technologies have over more conventional liquefaction onshore ahead of export.

According to Shell, FLNG bypasses the need for compression platforms and long pipelines to shore, while dredging and jetty construction to accommodate ocean-going LNG tankers is avoided – along with the onshore disruption of construction of liquefaction plants in remote areas.

Floating LNG facilities, whose main manufacturing investment is spent in lower-wage economies far from the vessel's eventual destination, can also help overcome the cost inflation that has blighted the development of several other Australian LNG and other natural resources projects in recent years.

The successful early execution of Shell's Prelude project could provide a welcome fillip to plans by it and rivals to switch towards floating LNG production facilities at a range of other proposed sites off the coast of Australia and other countries, including Indonesia, East Timor, Brazil and Mozambique.

The CSIRO, Australia's national science agency, estimates Australia alone has about 140tn cubic feet of stranded gas. According to Shell: "The Prelude

> The next destination for floating LNG projects could be Mozambique

FLNG project will demonstrate a means of developing some of Australia's 'stranded' offshore gas reserves – those considered uneconomic for development via an onshore plant because they are too small or remote".

Shell is proposing the use of floating LNG technologies at the Greater Sunrise gasfields planned for development by operator Woodside in seas close to East Timor. Chevron and ConocoPhillips of the US have also looked at the possibility of deploying FLNG facilities at projects off Australia and Indonesia.

But, in Brazil, partners Petrobras, BG Group, Galp and Repsol appear to have shelved plans to build floating LNG factories to allow for the exporting of gas.

The next destination for floating LNG projects could be Mozambique, where discoveries of prolific reserves and lack of existing onshore infrastructure could make the technology an option.

A position paper by Chevron notes that: FLNG offers the win-win potential to monetise stranded gas and also "overcome environmental, Nimby ('not in my backyard') and Banana ('build absolutely nothing anywhere near anyone') concerns".

Countries vie for a piece of the shale revolution

United States

Some companies have been very vocal in urging caution in awarding permits, discovers *Ed Crooks*

The shale boom – as with other revolutions that began in the US – has inspired many around the world to consider securing some of the benefits for themselves.

Before the shale revolution can overturn the ancien regimes of world energy markets, though, there are some powerful forces that will have to be overcome.

Starting up shale gas production outside North America faces many challenges, including shortages of skilled staff and equipment, the need to build pipelines and other infrastructure, and environmental concerns, the availability of water, and property rights that militate against fossil fuel development. So, for countries that want to benefit from the North American gas boom, the quickest way to do it will be to import liquefied natural gas. Many companies from Europe and Asia have been looking at doing that, and several have signed contracts with would-be exporters. With this route, too, however, there are some significant obstacles, both commercial and political.

The potential for US LNG exports is certainly very large. The Department of Energy (DoE) has received applications from 26 projects for licences to export gas, which are required under the 1938 Natural Gas Act.

If they all were to go ahead, they would have a huge impact on world gas markets. Their combined liquefaction capacity would be about 29.9bn cubic feet of gas per day – more than 40 per cent of last year's US gas production – and they would create about 230m tonnes of LNG per year: close to the size of the entire world market of 240m tonnes in 2011.

However, it is highly unlikely that all of those projects will go ahead. The political problem is the increasingly vocal lobby calling for a go-slow on awarding permits for gas exports, which argues that the gas glut that has created much lower prices in North America than in Europe or Asia is an important competitive advantage that should be retained for the benefit of US manufacturers.

US benchmark gas prices that are roughly a third of the price paid for LNG imports in Europe, and a quarter of the price paid in Asia, have already attracted tens of billions of dollars in investment, either planned or being considered – most of it in the petrochemicals industry.

George Biltz, vice-president of energy and climate change at Dow Chemical, a company that has been vocal in urging caution in awarding permits, says much of that investment could be at risk if unrestricted gas exports are allowed and US prices rise

George Biltz of Dow

towards world levels. "There is [a] huge amount at stake here: the US manufacturing renaissance, consumer prices, national security. And I think the DoE recognises that."

DoE consultants reported late last year that unrestricted LNG exports would benefit the US economy. Since then, however, the department has not awarded a single new licence for exports to countries that do not have a free-trade agreement with the US. Only one project so far has received such a permit: Cheniere Energy's Sabine Pass plant.

It has been suggested that licences might be awarded this summer, but the department has given no indication of its thinking. Ernest Moniz, President Barack Obama's nominee for energy secretary, gave little away at his recent confirmation hearing in the Senate.

Even if the politics eventually swings decisively in favour of US exports, there will still be commercial obstacles.

Dale Nijoka, global leader for oil and gas at Ernst & Young, the professional services firm, says customers' preferences will also set limits on US LNG exports. "Buyers like diversity of supply. They will want to source gas from the Middle East, from central Asia, Australia and Africa, as well as from America."

The potential for US LNG exports also depends on how much gas the country can produce.

The government's Energy Information Administration has warned there is still great uncertainty over the size of the ultimately recoverable gas reserves in the US. In 2035, production could be about 26tn cubic feet – very close to current levels – or as high as 34tn cu ft, the EIA says. Lower production will tend to mean higher prices and less gas being available for export.

"Not all of these proposed export projects will go ahead," Mr Nijoka argues. "Market pressures will force some out."

The ill-fated history of plans to import LNG to the US probably provides a precedent. There were 48 LNG import terminals permitted or proposed. Just 10 were completed.

Mr Nijoka suggests that, similarly, six to eight of the planned export plants will go ahead.

That is not insignificant: the US gas coming on to the market has already enabled Asian buyers to negotiate more attractive terms for their purchases. The American-style revolution, though, may have to wait.

Groups put pedal to the metal in dash to provide transport fuel

LNG

Legislation to reduce sulphur emissions is driving change, reports *Sylvia Pfeifer*

China has made no secret of its ambition to grab a piece of the shale gas boom that has gripped North America.

Several of the country's large energy groups have taken stakes in shale gas companies, including Sinopec, which earlier this year announced it would pay $1bn to buy a 50 per cent stake in gas and oilfields in Oklahoma and Kansas owned by Chesapeake Energy.

Yet, another company, ENN, China's largest nonstate owned gas distributor, has been quietly making progress on another front of the shale revolution: establishing a network of natural gas filling stations for trucks. The group, with CH4 Energy, a small Utah-based company, has formed Transfuels, which operates as Blu LNG.

"We think that, right now, the conditions are very good for developing this market, because America's natural gas is cheaper than gasoline or diesel," Jiang Yu, chief executive of ENN's international division, told the Financial Times in March.

ENN's vision is shared by others, including Clean Energy Fuels Corp, the largest provider of natural gas fuel for transportation in North America, and Royal Dutch Shell, the energy group. Shell plans to provide liquefied natural gas along a truck route in Alberta and also has plans for two small-scale liquefaction units to supply LNG transport "corridors" in the Great Lakes and Gulf Coast regions.

In Europe, the company is investing in barges powered solely by LNG.

BNSF Railway, a subsidiary of Berkshire Hathaway, and one of the biggest users of diesel fuel in the US, earlier this year said it would test using natural gas to power its locomotives. Such moves are part of a nascent industry using gas – in particular LNG – for commercial transport on land and at sea. Natural gas emits fewer greenhouse gases than diesel, for example, and is therefore seen as more environmentally friendly. In North America, where the shale gas phenomenon has seen natural gas prices drop to 10-year lows, it also offers a significant cost advantage.

Yet there are challenges, in particular the expense of building the infrastructure to supply and store the gas. Converting trucks, vans and ships to run on LNG is an added expense not every industry can afford.

Maurice Berns, partner at Boston Consulting Group, predicts the level of LNG penetration in each of the two potential markets will differ markedly.

In ground transportation, where LNG is being promoted for use initially by heavy-duty trucks or fleets, he thinks there will be some happy to invest ahead of the market. Entrepreneurs are also looking to enter this segment.

Colin Abraham, vice-president for downstream LNG business development at Shell, says LNG as a transport fuel has the potential "to make up a decent share of total road transport diesel demand" over the next decade. Analysts suggest it could be up to 10 per cent in certain markets.

Frost & Sullivan, a consultancy, predicts 8 per cent of all medium and heavy commercial vehicles in North America will run on natural gas, LNG or compressed natural gas, by 2018. Yet forecasts for the prospects of LNG's use in the marine industry are less bullish. Tough legislation – in particular a clamp down on sulphur emissions in

> 'It is very difficult to retrofit, so you would need to build new ships'
> Maurice Berns, BCG

Europe and North America – is being viewed as a driver for change. From January 2015, shipowners will have to cut sulphur content in bunker fuel from 1 per cent to 0.1 per cent in certain emission control areas, including the Baltic Sea and North Sea.

Some investment in infrastructure is already being made. The European Commission has set aside €2.1bn to equip 139 seaports and inland ports – about 10 per cent of its total – with LNG bunker stations by 2025. The plan forms part of the EU strategy for clean fuels.

Norway has been at the forefront of developing LNG-powered vessels for short-distance shipping, as well as the infrastructure to fuel these ships. Meanwhile, the Japanese government is backing the development of large, ocean-faring vessels powered by LNG.

But the main issue is cost. "It is very difficult to retrofit so you would need to build new ships," says BCG's Mr Berns.

Analysis by BCG suggests the maximum displacement of marine distillates by LNG would be just 0.6m tons by 2020. The estimate is based on the enabled ships using LNG only in the emission control areas and less expensive fuel oil elsewhere.

While Mr Berns says he sees potential for LNG in ground transportation, its take up by the marine industry will take time.

Headlong rush into pricing is a risky business

Benchmarks Oil-indexed contracts have developed a bad name largely as a result of poorly timed deals. *Ajay Makan* asks if the tide has turned

Trouble in the North Sea: Total's Elgin rig near Aberdeen in Scotland Getty

A new set of acronyms has entered the gas traders' lexicon, with potentially huge consequences for suppliers and consumers of natural gas, as well as the financiers who lubricate interaction between the two.

The Japan-Korea marker (JKM), a Platts assessment of the spot price paid for shipments of liquefied natural gas to Japanese and Korean ports, is the latest regional gas benchmark to gain traction. Traders privately acknowledge they now use JKM to price spot shipments of LNG not only to Japan and Korea, but throughout Asia, as well as the Pacific Rim of Latin America.

The rise of JKM follows the emergence in recent years of spot markets in Europe, such as Holland's TTF and the Netherland's ZEE, which complement the UK's National Balancing Point.

The wider use of spot prices, in Europe, as well as in Asia, reflects a hunger on the part of buyers to escape the rigidities of oil-indexed contracts, which require consumers to purchase fixed quantities of gas at prices linked to the oil price or pay a penalty. That hunger has increased as surging shale gas production in the US, has weighed on the domestic gas price and offered US industry access to cheap energy.

"In the current environment it is perfectly understandable that European buyers are pushing for indexation to regional spot-market-based gas prices," says Mark Lewis, European head of energy research at Deutsche Bank. "There's a lot of hope, and hype, about the ability of the US to export gas at prices that are below oil indexation."

Oil-indexed contracts have developed a bad name largely as a result of poorly timed deals. In 2005, with Brent prices topping $60 for the first time, and concern about underinvestment in Russian gas production, European governments encouraged their utilities to head to Moscow to secure long-term supplies.

With European gas consumption falling and the continent well supplied in the short term, the contracts that were signed do not appear so attractive today.

Oil-indexed contracts have long provided the bedrock for financing

The first transactions to move towards gas pricing have, unsurprisingly, been spot cargoes. But buyers are also looking to tie long-term contracts to gas prices.

In Europe, Norwegian producer Statoil has offered long-term gas price-linked contracts as a way of increasing market share at the expense of Gazprom. The Russian producer is steadfastly defending its oil-indexed contracts, but is slowly seeing its gas-price-linked volumes increase as European utilities take to arbitration courts to escape oil-indexed contracts.

Société Générale analysts believe more than 50 per cent of gas in Europe is now supplied on a spot basis. Asian buyers, meanwhile, are scrambling to sign contracts for US gas, although supplies are so far limited because of US government restrictions on exports.

But the headlong rush into gas pricing and regional benchmarks comes with clear risks.

Regional gas prices are closely tied to the local supply and demand dynamics that govern regional pipeline systems. This potentially makes them more volatile than oil prices, which are more aligned with global markets, because so much oil is traded between regions by tankers.

"The prevailing assumption is that moving away from oil indexation will lead to lower prices, but the unintended consequence will almost certainly be higher volatiliy in prices," says Thierry Bros, European gas analyst at Société Générale in Paris.

A prime example of this has been the volatility this year in the UK gas market, which was liberalised in the 1980s and is priced mainly off the National Balancing Point, the benchmark UK gas price. Prices have spiked repeatedly in recent months as problems with North Sea pipelines, and the Interconnector – a pipeline built to connect the UK and mainland European gas markets – created localised supply shortages.

A gas pricing regime would also pose a challenge to the financing of the capital intensive projects needed to guarantee future supplies of gas – from gas pipelines to upstream exploration and production and even large-scale storage. Oil-indexed contracts have long provided the bedrock for financing as oil prices can be hedged to provide banks with clarity about future cash flow from projects, and therefore certainty about loan repayments.

Project finance bankers acknowledge that Asian buyers of natural gas are pushing them to consider financing LNG projects with long-term contracts linked to the US Henry Hub Price – the US benchmark price of gas – or even the JKM, but offer only limited enthusiasm for development.

"It is quite possible that in future offtakers will purchase some of their gas at regional or Henry Hub prices, even if the gas is not coming from the US. In principle we do not have a problem with lending based on gas prices, as long as the market is deep and liquid enough to hedge exposure," says one banker. The Henry Hub market probably does offer the possibility to hedge long-term contracts, but a new benchmark such as the JKM is far from being able to.

In Europe, Carlo Malacarne, the chief executive of SNAM, the Italian utility, told the FT in March that European companies' unwillingness to sign oil-indexed contracts was holding back pipeline projects.

UK households and industry should prepare for higher bills

Storage

Increasing reliance on imports means prices could become more volatile, writes *Sylvia Pfeifer*

The North Sea has for decades been a source of fuel, jobs and tax revenues for the UK, but its bounty has also left the country with a less welcome legacy: a shortage of gas storage.

Unlike its continental neighbours, which have not had the benefit of the North Sea, Britain has just 4-5 per cent of its annual demand in storage. This compares with 20-25 per cent in many mainland European countries.

This was not an issue during the heyday of North Sea production but, with output in long-term decline and Britain increasingly relying on imports – energy imports exceeded UK production in 2011 for the first time since 1974 – concerns over the level of storage are increasing.

Two events earlier this year brought the issue to the fore among policy makers and consumers. At the start of March, a power cut at a Norwegian gas processing plant reduced supplies to an underground pipeline that feeds the UK. Gas prices in the UK rose to seven-year highs on the news. At the end of the month, a technical fault hit another import pipeline, the Interconnector, which brings gas into Britain from Belgium.

Prices once again rose because of increased concerns over gas supplies, especially with stores already depleted thanks to the prolonged wintry weather.

About 15 per cent of the UK's gas comes from storage and it is usual for stored supplies to run low early in the year. However, with few cargoes of liquefied natural gas (LNG) arriving in Britain in recent months – volumes have been diverted to Asia where prices being paid are higher – the country has been heavily dependent on pipeline gas from continental Europe and Norway. Hence the price spikes.

Coming at a time when ageing coal-fired plants are being retired and new nuclear power faces delays, it has raised concerns over energy security.

Alistair Buchanan, chief executive of Ofgem, the electricity regulator, warned of higher energy bills in February ahead of a "horrendous" gas supply crunch.

Ian Marchant, chief executive of SSE, one of the largest electricity suppliers, said in March that the government needed to take the risk of a power shortage seriously. "The government is significantly underestimating the scale of the capacity crunch facing the UK in the next three years," he said at the time, adding there was "a very real risk of the lights going out".

Britain's increasing reliance on imported gas has only heightened the pressure on the government to increase its capacity to store it. In the UK several companies, including SSE, Centrica and Italy's ENI, have plans for projects that would increase storage capacity, but have so far held off on developing them because of a lack of clarity on government policy. In addition, with gas prices relatively high compared with coal, for example, the market signals have not been there to encourage investment by utilities, which have been running their coal plants heavily instead.

Although the supply issues in March had no direct effect on consumers, Britain's increasing reliance

'The government is significantly underestimating the scale of the capacity crunch'

on imports means prices could become more volatile, and households and industrial users could be hit by higher bills.

Ann Robinson of uSwitch.com, the price comparison site, last month told utilities not to use the price spikes as an excuse to pass increases to consumers in the winter. "In many European countries where gas has been supplied mainly through imports, like Spain or Italy, the system has built-in requirements to secure strategic gas reserves to cope with scenarios of demand peaks or import disruptions," says Luis Barallat, partner at Boston Consulting Group.

"The costs arising from holding those reserves under storage is eventually passed on to the consumer, with a limited impact on their energy bill: strategic reserves costs represent less than 2 per cent of the energy bill of an average consumer. The UK could rethink its position towards strategic reserves, considering its increasing reliance on imports," he adds.

The government is considering whether to offer industry support to increase storage, but has repeatedly insisted the country will not run out of gas.

Another option, according to Nick Campbell at Inspired Energy, a consultancy, would be for the government, both at a local and national level, to free up the progression of domestic shale exploration.

"This would be a more economic and efficient option as it would be using market incentives rather than shaping the market."

The UK may be in the spotlight, but import dependency is rising among most OECD countries, with the exception of the US where the shale gas revolution has transformed its energy supplies. In Europe there is an increasing focus on imported LNG.

Today, import terminals are in operation in a handful of countries, such as Belgium, France, Italy and Spain. Norway has been operating a LNG export facility on the island of Meloya for the past six years.

The EU market is "increasingly focused on short-term transactions [and] reducing visibility over future gas deliveries," says Mr Barallat.

"The question is, who delivers the security of supply. There are no incentives to build more storage and the market signals are not there [to build storage]. Therefore, government policy is required to prompt storage to be built."

Pipe dream: Eon's UK gas-fired power station Bloomberg