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Essential Interviews 2018

Perspectives from gas industry leaders

Gas Strategies

Editors' letter

"One doesn't discover new lands without consenting to lose sight of the shore for a very long time."

André Gide

The gas industry may have hoped for a steadier year in 2017, but once again events proved the energy landscape as unpredictable and uncertain as ever. The demise of the Clean Power Plan in the US threw policy conventions into disarray, while the uptick in crude oil prices called into question the "longer for lower" narrative the industry has spent three years learning to accept. In LNG, proposed, pre-FID liquefaction projects continued to grapple with a tough financing environment, as buyers held back from signing long-term contracts.

But gas and LNG players continue to innovate and adapt to this new reality. 2017 saw the gas industry's first foray into blockchain trading, which could revolutionise how our industry trades gas in the future, while the global LNG market readily absorbed around 30 mt of additional supply. FSRUs continued to play a crucial role in achieving this, while China spearheaded the growth in demand.

The following Essential Interviews bring together thought leadership from a range of industry participants and commentators, examining the gas industry's role in the future global energy mix, and the risks and opportunities in frontier exploration and technological innovation. If you too want to have your say, please get in touch – we are always keen to hear from readers eager to participate in a Gas Strategies interview.

Rachel Parkes, Editor, Gas Matters
Konstantinos Tsolakis, Editor, LNG Business Review

Gas Strategies Information Services

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Chris Schemers
Head of Gas and Power Origination

"Today the CO_2 price doesn't adequately incentive countries to make necessary switches. But it is better to go for gas and renewables, rather than coal, otherwise you may end up with investments that are going to be short-term, rather than economic in the long-term."

The global LNG industry is facing tumultuous times. A key uncertainty is the role of new LNG heading to Europe's markets, its impact on the global supply balance and its effect on gas prices on either side of the Atlantic. LNG Business Review talked to Chris Schemers, BP's head of European gas and power origination, about the state of play of the European energy market.

What is your view on Europe becoming a market of "last resort"?

The key point is how and where people manage their position. Sellers will fundamentally need somewhere with robust deep liquidity to manage their exposure. Henry Hub (HH) is a part of the equation and there is a lot of oil-indexed LNG in the water, but European indices offer a natural tool to manage risk. There are not that many alternatives in the global market.

My expectation is that many holders of US HH-linked LNG will sell it into Europe, but it does not mean that they will deliver those cargoes. Liquid indices, such as Dutch TTF and UK's NBP, will help them manage the spread risk inherent in this position. Many players will sell HH-indexed LNG to NBP or TTF-related markets to reoptimise their portfolios, as it is relatively easy to buy those positions back later. That is the beauty of the European market – it offers the ability to access a traded market for gas. The sellers retain a lot of flexibility with the underlying physical cargo, enabling them to limit their exposure as well as to access other markets. We are already seeing some evidence of this happening.

How likely is it that these volumes, albeit just financial, will trigger a price war between US LNG and Russian pipeline gas?

Europe is the key balancing point for the global gas market, but it is not obvious that we are going to see all new LNG arrive in Europe. Some of it will, but we have already seen tenders in Egypt, Argentina and Pakistan, as other demand centres start to be creative. There are other homes that will attract LNG, but Europe will play an important role in pricing and risk management.

Domestic supply into Europe has been on the decline. It bounces back from time to time when new fields come online in the North Sea, but Europe will fundamentally remain a large gas importer. The marginal cost of getting gas into the market will determine the price globally, not only in Europe. It is not impossible that there will be gas-on-LNG competition, because of the nature of the global market. But just the fact that US cargoes are pointed at Europe will not make much of a difference, because the physical supply/demand balance will ultimately decide the price formation.

Gazprom's deputy chairman Alexei Medvedev believes European gas demand will inevitably rebound. Do you see that happening?

There is potential for a gas renaissance in Europe. We are already seeing an increase of gas into power in the UK, essentially due to coal substitution. The carbon price floor in the UK, which augments the European Emissions Trading System (EU ETS) and encourages coal switching, is the biggest incentive for gas-fired generation.

France has also proposed a carbon tax directed at coal-fired generation. Those kind of mechanisms, if adopted by the European Union (EU) individual members, could lead to a significant increase in gas consumption. Increases in European gas demand could allow the market to balance at higher prices in the region and elsewhere in the world.

How do you see the spread between Henry Hub and NBP evolve in 2018-2019 when the bulk of US volumes hits the market?

There clearly is going to be an interconnection between those prices and to some extent we are seeing a correlation already.
The emergence of HH-linked merchant LNG acts as glue for different markets globally. It creates a band for European prices and I expect we will see more of that interaction in the future. NBP prices can go lower, but the key question is how much demand can be created in and outside of Europe.

The market has been intrigued by relatively large LNG tenders that we've seen over the last couple of quarters. We need a sign that non-OECD LNG demand is robust and growing its share globally, we also need to see traditional Asian buyers continue to purchase LNG. That will ultimately provide support for pricing in Europe.

How do you see the European indices, such as TTF, NBP, Zeebrugge and Baumgarten evolving? Will US LNG add liquidity and convergence to these hubs?

There are only a few true hubs for gas pricing globally – NBP, HH and TTF – others are just physical hubs. There have been other attempts to create contracts, but those are the choices when it comes to gas-on-gas pricing, with a liquid prompt and forward market. I expect that liquidity on NBP and TTF will continue to increase and I hope that the tenure of that liquidity will expand, so we would see more activity on the curve, as OECD sellers look to sell volumes into the European markets.

Within Europe, TTF and NBP are already strongly correlated, as are all other Western European hubs, albeit some more than others. The way the EU energy market has been created is unlikely to change. There is already significant interconnectivity between most markets, which means that the single energy market is finally coming together.

What is your view on LNG commoditisation? Are we likely to see it happen within the next five years?

Commoditisation is an inevitable by-product of standardisation in competitive markets. It is a natural tendency of all commodity markets to become commoditised as the underlying market forces tend to win in the long run.

There is an opportunity for buyers and sellers to differentiate their LNG products through innovative pricing, risk management and contractual structures, not just through the underlying commodity.

The services you offer and the point of differentiation you add to the commodity become more important as the underlying product becomes commoditised. You can look at a broad range of markets – metals, minerals, foreign exchange – and see the same tendency.

Over time, markets will become more liquid and standardised, bid-offer spreads will reduce, churn and trading will increase. Ultimately, it means that LNG will truly become a commodity.

There are several contenders for the title of the world's first LNG hub: Singapore, Beijing, Japan. Where do you see the first LNG hub emerging?

Creating a hub is challenging. A hub effectively needs standard cargoes, liquidity, a robust legal framework and a diversity of buyers and sellers. If you look at a market like WTI or Brent – two of the most liquid oil benchmarks – there is a whole set of conditions that allow for those markets to work.

It is more challenging for the LNG market and today it is not obvious that there is a LNG hub that will succeed. It is important for LNG players to have robust proxies they can use to manage their exposure, like HH, TTF, and JKM, if enough liquidity emerges. I think that the use of these proxies will continue to exist for a long time, before we see anything that resembles a true LNG price.

Chris Schemers, Head of Gas and Power Origination, BP

What will the emergence of an LNG hub mean for bilateral trading and long-term contracts that underpin new liquefaction plants?

The two can co-exist. A good robust liquid hub provides a tool to manage financial risk. There are certain financial risks that you might not be able to manage in the market, so you have to take a strategic view about whether you want those exposures, or you'll have to bilaterally negotiate with other counterparties to manage them. That's the case today and will be for a very long time to come. There are players out there who are willing to take on those longer-term exposures, which can only be managed through a portfolio, or through a strategic view, rather than through traded markets.

We have not seen the end of long-term contracts; I believe that long-term contracts and short-term trading can co-exist and complement each other. A key aspect is that long-term contracts are changing, as are price references, flexibility, features like destination clauses and so on. Long term contracts are becoming less and less about point-to-point virtual pipelines and more about finance and bankability of the project but with flexibility for buyers and sellers.

Will we see more hub-indexation globally?

You will inevitably see some more HH indexation. Buyers in the Asian market think that they can diversify their exposure by buying volumes portioned on HH index, TTF-indexed as well as oil index-linked. That gives buyers the diversification they are looking for.

There has clearly been a shift in the balance of supply and demand, which has also moved the negotiating position. The prices we see today seem to be acceptable to both buyers and sellers.

The industry opinion on the development of new markets seems to be divided – some believe that the markets that have the capacity to develop LNG regas facilities have already done so, while others argue that there is still plenty of latent demand out there. Where do you stand on this issue?

We will continue to see new markets. The world needs more energy and gas and LNG can provide it in a sustainable and affordable way. In the mobile phone industry, many countries skipped the wireline services and jumped straight into using mobile technology. I believe that emerging economies might follow the same trend and go for a mix of renewables and LNG. Given that we have just come out of a post-Fukushima era and Australian and US LNG has only just started to make it into the market, it is too early to say if we are maxed out on new demand.

You could argue that putting together a project and obtaining investment takes time. There is a lot of latent energy demand out there, but a big challenge for tapping into this demand is developing infrastructure as a country needs a regas terminal, power station or pipeline infrastructure for a functioning LNG value chain.

There are many opportunities in emerging economies to provide that solution, because nobody wants just LNG or gas. What customers want is power, heat or

industrial output, so you can't just bring in a cargo and hope for the best. There needs to be a solution, rather than just the offtake contract.

Despite global efforts to reduce carbon emissions, coal is still more competitive than gas in many countries. Do you think that gas will ever gain the competitive edge?

This is the big question. Converting coal to gas is the most obvious and economical route for reducing CO_2 and many governments have made official statements saying that they favour a reduction in emissions to keep global warming under control. It is better to go for gas and renewables, rather than coal, otherwise you may end up with investments that are going to be short-term, rather than economic in the long-term.

But today the CO_2 price doesn't adequately incentivise countries to make necessary switches, although they do it anyway in some cases. The market could look very different if policy makers put a meaningful price on carbon reduction.

Pretty much all the questions come back to it – fundamentally the market will look very different depending on the mix between coal and gas. It also makes a big difference on how the European market will price the imbalance.

Finally, is an easing of the global LNG supply glut likely by 2021-2023?

The LNG market historically tends to go through cycles. We had a period where the market was very tight, but now it is longer. It is possible to create a scenario where all the new LNG gets absorbed.

The size of the LNG market is increasing quite significantly in percentage terms, but still accounts for only a small percentage of the global gas market. If we create just a little bit of additional demand, we could probably be in a place where new projects can take FID.

The US projects will have an upper hand when that happens, as they benefit from the US legal and financial system and ultimately there are thousands of producers sitting behind a terminal, providing a secure source of supply.

Statoil

Stephen Bull
Senior Vice President, Carbon Capture & Storage

"When it comes to actual steel in the ground, our perspective is that smaller-scale, decentralised CO_2 capture units are the way to go. It's about replicating the success of the renewables business model through low-threshold investments and rapid deployment. Costs start to seriously fall through ultimate economies of scale."

Convincing energy industry players that carbon capture and storage (CCS) is essential to their long-term business models has been no mean feat. But the global ambition to lower carbon emissions, embodied by the Paris Agreement, has brought the nascent technology into stark relief: CCS is the only way to keep natural gas in the power mix long term, either as a destination fuel or as a partner to renewables, if carbon-reduction targets are to be taken seriously. Statoil is a key participant in the Oil and Gas Climate Initiative (OGCI), which, along with efforts to tackle gas flaring, highlights CCS as a vital tool for decarbonising global energy systems. Gas Matters speaks to Statoil's Stephen Bull, who is growing a commercial and future-fit CCS and wind portfolio in the company's New Energy Solutions business area.

Would you agree CCS is the only way to ensure that fossil fuels maintain their role in the energy mix long term, given binding global carbon reduction commitments?

Yes, especially in the electricity sector. And although I work for an oil and gas company, CCS is something that is included as a mitigation tool in our long-term scenarios. We've built our modern economy on the fossil fuel energy system, and even if everyone were to go out and buy a Tesla car tomorrow you'd still need oil and gas for decades to come.

We still need to produce a lot more; the global decline rates on oil and gas fields outside OPEC are 3-6% a year. In our Energy Perspectives 2016, we estimate

that we'll need another ten Norways to supply gas demand by 2040.

But I also think the justification or legitimacy of burning fossil fuels is going to be dependent on CCS, and when we turn the corner with peak demand – particularly for oil – regardless, the legitimacy of this need to be tackled. This is particularly the case for gas – it's not necessarily a transition fuel, it should be an end game as well, as it's highly complementary with renewables.

However, we should not forget that there are other tools to reduce emissions that will weigh more heavily. Switching from coal to gas in power generation is a cheaper and quicker way to realise reductions that, in size, are comparable to putting CCS on a gas-fired power plant.

We run a sizeable offshore wind business at Statoil and are fully aware of the need for peaking capacity; you need backup and you need energy security. In this respect, you can't look away from gas. I believe companies like Statoil need to lead with further investments to take up the slack on CCS.

Is there any alternative to CCS in reducing global emissions?

When it comes to industry, if you look at the chemical process of producing petrochemicals, plastics, cement, steel, paper – even if you completely electrified those processes, the byproduct of that business model is still to produce CO_2. It's probably unavoidable.

If we're still going to use steel and plastics in the world, which we need for renewables, then there's just no alternative. And that's the sweet spot for really getting CCS moving, because industrial CO_2 capture could be the ultimate deployable CCS business model – driving down costs and pushing innovation.

But CCS entails a double whammy on cost – there's R&D and then the additional cost implications of running power generation operations with CCS. How do you see companies shouldering and mitigating that cost burden?

In Europe, many of our peers have gone through the big existential discussion that CCS is essential to their long-term business model. A lot of other companies haven't. We have worked with many of our oil and gas partners to help convince them that CCS makes sense – that it's worth putting money behind R&D for utilisation and storage.

At Technology Centre Mongstad (TCM), the world's largest facility for testing and improving CO_2 capture, the last three campaigns have seen external vendors testing amine-based technologies to capture CO_2. Companies like Aker Solutions of Norway, Clean Carbon Solutions of India and ION Engineering of the US have tested their technologies, with great results.

The key improvements include reduced energy consumption, lower chemicals usage and more effective CO_2 absorption. Finding these sweet spots requires

continuous testing and deployment.

When it comes to actual steel in the ground, our perspective is that smaller-scale, decentralised CO_2 capture units are the way to go. It's about replicating the success of the renewables business model through low-threshold investments and rapid deployment. Costs start to seriously fall through ultimate economies of scale.

And that's where we see things moving – at a smaller scale. That's a key strategic push for us, also in our advocacy work in the UK and Europe, explaining Statoil's direction – namely "we're interested in CO_2 storage". You have to start with storage – the business model has to start at the back and work forwards, as storage is one of the most complicated aspects in terms of regulatory and technical capacity. But that's what we at Statoil are particularly good at with 20 years of safe CO_2 storage in Norway.

This seems to be resonating, as more focus on public-private partnerships are shaping serious policy discussions.

For example, the Dutch government recently said the cost of offshore wind had fallen so dramatically that its expectation for subsidising it had reduced, to the extent that a push towards focused support for CCS development was being discussed. Just as renewables helped bridge the 2020 EU climate goals, CCS must be part of this for the 2030+ perspective – as part of a national and international climate solution tool box.

But the full-scale industrial option is what we want to see pushed hard in the EU at the moment – to develop pilots in, for example, France, the Netherlands and UK, to complement a project the Norwegian government is piloting for a full CO_2 value chain in Norway. Internally, we call this the Northern Lights project.

What CCS projects is Statoil currently working on and what are your objectives?

The current one is Northern Lights. We put in a bid to the Norwegian government in early March for the storage part of the concept, which is a full value chain capture from three different industrial sites, transportation by ship and then offshore storage for the CO_2. We're expecting results to come back within about six weeks, followed by negotiations with government. This is a flagship project by the Norwegian government and one of the most exciting CCS projects in the world.

What we like about this project is that we think its scaleable, so we're looking to try and win this. But, we face stiff competition. Our goal, if we win, is to develop a broad partnering strategy and seek third-party CO_2 volumes on top of the Norwegian volumes, in particular around the North Sea Basin: Rotterdam, Grangemouth in the UK, and Teesside – key industrial centres seeking progressive CO_2 solutions to ensure a sustainable business model for the future.

We're looking at an area that could take at least 10 to 15 mtpa of CO_2, so that's considerable scale and there are lots of offshore possibilities. The surveys have

been done; the North Sea basin is well documented when it comes to storage opportunities, and we're talking about some serious tonnage here, which could really lift the EU's climate targets.

What are the key challenges for these kinds of projects?

On the fiscal side, without a proper tax on carbon, kick-starting deployment in CCS for industry is reliant on building public-private partnerships, and while widespread support mechanisms exist for new technologies, it is not without contention.

The other aspect is technical. Proper reservoir management is essential to avoid possible migration into gas reservoirs. Also, from a legal perspective, clarity around long-term liability for the stored CO_2 after the plug-and-abandon stage is essential for private developers.

Public opposition is a major factor. Who's going to want to pump CO_2 into the ground and risk the potential for a large-scale leak?

Having a proper discussion around CO_2 storage is essential. It's easier in Norway – where the whole discussion around CCS is based on experience compared to other countries – as we have a considerable offshore carbon tax and 20 years of successful storage.

Many of the key NGOs are also supportive of CCS because they know its necessary to make the deeper cuts in carbon emissions to get anywhere close to the Paris Agreement climate goals. And think about it – it's better to avoid all the CO_2 from combustion of fossil fuels "leaking" into the atmosphere, as is standard practice today.

Where do you see the best opportunity for a large-scale CCS pilot project globally?

There are 38 active large-scale projects today; 20 should be in operation by the end of 2017 and then the rest are all pre-FID. There are projects on every continent. We think Northern Lights in Norway is exciting because it has a very low threshold for taking industrial CO_2 via ship and into a major storage facility.

France and Germany have huge gas heating markets; there are heating markets all over Europe. Our biggest exposure at Statoil is not gas to power but gas to heating – we sell more on the industrial side into the heating sector than anything else.

What's different in the UK is that it's an easier PR discussion with the public about CCS or decarbonisation of heating than it would be in France or Germany. The UK has great prospects for it; there's been a lot of money invested in CCS research, but it's about putting in a lot of infrastructure.

The UK famously cancelled its GBP 1 billion competition to fund a CCS pilot project. Rather than monolithic large-scale projects, is the future more in small-scale distributed CCS?

There's a lot of EU funding that's still tied

up, which is supposed to be earmarked for carbon capture and transportation and local infrastructure, and Shell's Peterhead project obviously didn't happen. But it was a huge project and if the UK could at least look for some smaller-scale ones, such as the Teeside collective, it wouldn't take much to get some small-scale carbon capture developed.

Most of these industrial plants are close to the sea, implying less infrastructure requirements for transport and the option of using LPG ships. The threshold is low, but again it needs some funding and piloting beyond R&D and into industrial development.

There are always new developments at the Mongstad test centre. Are there any technological advancements in the pipeline that prove both the technical and economical sides of CCS?

The most expensive element of the CO_2 value chain is the capture part. It is also energy intensive. The transportation and storage parts become economies of scale and relatively predictable, so the capture costs are to be examined through further innovation.

I've seen several exciting developments including smaller, decentralised carbon-capture units – which are essentially housed in a couple of 40-foot shipping containers. These can be packed and shipped all over for deployment.

Major energy companies are pegging their futures on gas and putting out bullish statements about the outlook and role for gas, but not talking much about CCS – despite the fact it's key to keeping gas in the mix. Do they need to be doing something more and be more vocal?

We push it really hard. We have a USD 50/mt equivalent CO_2 offshore, so if you flare or emit CO_2 you're going to get taxed, so you build it into the system. We know taxes work as that is the regime we operate under in Norway. We also know the world isn't going to move to a global carbon tax overnight.

In cities, jurisdictions or states where there is one already, it starts to make a difference to investment, but where are we now? We've just come out of Paris, we've talked about these Nationally Determined Contributions, which people still feel rather unsure about, but when the EU in particular tightens these and says we need to see them more by 2019, I truly believe countries and regulators are going to look at CCS and say "we need this". And it will be driven by companies like Statoil, Total, Shell and others.

If you look at the Stern Review or the latest from global CCS analysis, we're seriously lacking some gigatonnes of carbon capture, but that's why we need to accelerate this business as much as possible. It's just one tool in the box though: there's decarbonisation of power; there's the transport and heat sectors, and there's shipping. And the farming sector

is a huge contributor to global emissions. It's not too little, too late, but it's definitely time for the industry and government to seriously be proactive.

What are the key outstanding challenges on the road to achieving widespread, commercial CCS?

The first is for the industry and NGOs to explain to the public why CCS is central to tackling climate change and ensuring long-term economic benefits for industrial jobs.

The other is to look at different types of regulatory support to try and get small-scale CCS moving, and get the deployment that the renewables sector has enjoyed for some time.

The last is for industry to scale up and step up its efforts on CCS so we can look at more global scale and share that learning across industrial actors. Watch this space!

Stephen Bull, Senior Vice President, Carbon Capture & Storage, Statoil

Pakistan LNG

Adnan Gilani
Chief Operating Officer

"What many people do not understand is, how did Pakistan come from nowhere with a projected demand of 20-30 mtpa? But we already had that demand. We just did not have the capacity to import the gas."

Pakistan's economy has been growing at a rate of 4.5% per year, but government estimates show that, were businesses not constrained by a chronic gas shortage, it could grow by 7-8% per year. The south Asian country pins its hope for achieving this on LNG. Pakistan could be importing up to 30 mtpa of LNG by 2025, but even that may not be enough to cover the country's yawning gulf between supply and demand, Adnan Gilani, the chief operating officer of Pakistan LNG, the state-backed company charged with managing the entire supply chain for LNG to solve Pakistan's energy crisis, tells LNG Business Review. In this interview Gilani explains why Pakistan could be the fastest growing LNG market ever, and how the government took an immense risk to underwrite more than USD 8 billion of infrastructure to support Pakistan's LNG import industry.

What is driving Pakistan's demand for LNG?

A high level of gas demand has always existed. We are not creating any new demand. Our local resources are depleting and we are basically replacing domestic gas with imported gas. The supply-demand gap is 57-113 MMcm/d, which equates to about 20-30 mtpa of LNG.

Power plants, industry and manufacturing all use gas in Pakistan, but no new industrial or commercial customers have been connected to the gas network since 2011 because domestic production is waning. Our biggest worry is that 20-30 mtpa of LNG imports will not be enough.

The huge gas deficit has knocked 2-3% from our economic growth rate over the past decade. Another 10-15 million jobs could have been created if we had ample gas supplies to drive economic expansion. So, the government came up with an emergency initiative to solve the energy crisis by fixing the gas one. The government set up Pakistan LNG, which manages the supply chain for the country's first two LNG import terminals.

How price-sensitive is Pakistan's demand for LNG?

Pakistan uses fuel oil to generate 35% of its power, but this is over two times more expensive than using LNG. As a result, the nation is less sensitive to pricing on LNG for power generation for its first 15 mtpa of imports. Our goal is to resolve the energy crisis and importing LNG is a very compelling argument based on all our estimates.

Once we are importing more than 15 mtpa, the price sensitivity will rise and we will need to rationalize local prices, which have been subsidized. We are ring-fencing the LNG supply chain from subsidies and political issues. Our policy is, whoever wants gas in Pakistan will get it – if they can pay for it. There will be no subsidies on LNG. We are trying to make the LNG business more robust with a solid foundation. Slowly we are starting to reform local gas prices with help from the World Bank.

Domestic gas prices at USD 2-4/MMBtu are cheap, as everything has been amortized. But domestic gas has been running out at an exponential rate. Domestic customers will continue to get local gas. But any new industrial or commercial users will pay market rates. We are not able to foot the bill anymore.

What is Pakistan's procurement strategy?

We have a diversification strategy and don't put all our eggs in one basket. We are looking for reliable cheap gas. Reliability is an important factor because LNG will actually power our baseload. As a result, we have a diverse procurement strategy. Firstly we are diversifying by suppliers, producers and traders. We are diversifying through geography. Some LNG will be sourced from Qatar, Indonesia, Malaysia, Australia, and even the US on various contract lengths. We are building a portfolio that will stand the test of time and that is more robust in a changing market. It will lead to reliable prices with some flexibility.

For our first 4.5 mtpa LNG import terminal we have a large supply contract with Qatar. But in the long run, I foresee Qatar supplying no more than 25% of the entire procurement. We also have two medium SPAs with Gunvor and a long-term SPA with Eni. By end of this year our two LNG terminals will be importing 9-10 mtpa, and that is already procured.

In July, Pakistan's petroleum minister predicted LNG imports could jump more than fivefold by 2022, up from 4.5 mtpa now. This would be faster growth than any LNG market has seen before. How

Adnan Gilani, Chief Operating Officer, Pakistan LNG

many LNG import projects are planned and how realistic is this forecast?

Pakistan, which relies on gas for 50% of its energy mix, will see its second 4.5 mtpa LNG terminal start operations by November. Pakistan received its first LNG cargo in 2015, when its maiden 4.5 mtpa LNG terminal opened. Four more LNG import projects are being proposed by the likes of ExxonMobil, Trafigura, Shell and various local companies, which will see Pakistan's imports jump more than fivefold by 2025. Our first two terminals are FSRUs and my understanding is the private sector will also bring in FSRUs as they are really cheap compared to onshore plants.

We had plans to build four or five LNG import terminals, as for the past 10-15 years the private sector did not step in. But we have invested a lot in infrastructure and now private investment is coming. The government is stopping at two LNG import projects as there are four more private projects proposed without sovereign guarantees.

Two years ago we guaranteed offtake, and developed new gas-fired power plants, but nobody came. Yet now investors are putting billions of dollars into Pakistan's LNG business because we have created a very attractive regulatory and economic environment. The private sector is coming in a big way.

Our economy should be growing at 7% every year, not 4.5%. In some areas half of our industry is shut down. We had no choice, and the government made a major commitment to support LNG imports. The government has also invested in transmission pipelines, two LNG terminals and new gas-fired power plants, at a cost of over USD 8 billion to the government. We created this superhighway and now the private sector is investing. The pipelines will be open to third-party access and that's why the private sector is coming in.

The country has invested USD 1.5 billion in a 34 MMcm/d pipeline that will come onstream in the third quarter of 2017. A second 34 MMcm/d pipeline will start up in the fourth quarter of 2018, while a third 34 MMcm/d pipeline, financed by Russia, will also start up six months later. Three 1.2 GW gas-fired power plants have also been commissioned this year as part of the strategy to replace fuel oil.

What many people do not understand is, how did Pakistan come from nowhere with a projected demand of 20-30 mtpa? But we already had that demand. We just did not have the capacity to import the gas. Building pipelines, terminals and power plants typically takes six to seven years. But the government took a huge risk and did it all in around two years. Now we are seeing the benefits.

Pakistan is considering inviting investors to build more small-scale gas-fired power plants that would add another 3,000-4,000 MW to the network. Why will investors come?

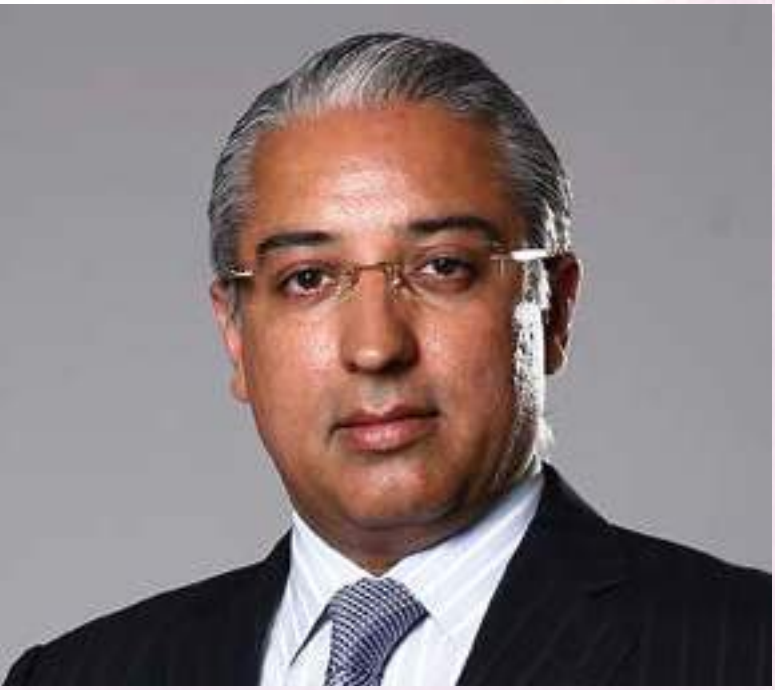
We have the most lucrative energy policy in the world. The IRR is anywhere from 16-18% so return on equity is 25-30%. We offer government and sovereign

guarantees on a dollar basis. We are wasting USD 2 billion year burning fuel oil, so we are happy to incentivize investors. The policy is very robust and is extremely investor-friendly.

How much gas fired capacity do you have now?

We had a few inefficient plants of around 4,000-5,000MW. We've set up another 3,600 MW that's already built and coming online within the next month. We have plans to convert 6,000-8,000 MW of fuel oil plants to gas-fired plants. That's not even factored in to my demand curve. We have total 8,000 MW fuel oil plants. We start by getting rid of least efficient ones first, then move on.

Green Dragon Gas



Randeep Grewal
Founder and Chairman

"With CBM we have been through the decades-long cycle of developing the right technology, we are now in the commercial period. We know how to drill the matrix, which way to drill, what type of drill to use and how to dewater quickly, and get the gas to market, including compression technology. The technology is mature today."

China plans to double domestic production of coal bed methane (CBM) to 40 Bcm by 2020 as a means of meeting its COP21 carbon reduction pledge. Last year the government increased subsidies by over 50%, in the hope of kickstarting then-sluggish development. Gas Matters speaks to Randeep Grewal, founder and chairman of Green Dragon Gas, a China-focused CBM producer, to find out whether the new support regime is bearing fruit.

China is clearly pushing clean energy at the moment, it must be a good time to be involved in the gas business in China?

Absolutely, the Chinese are very focused on gas. When I first went to China there was no gas, there was coal only. So, I think it's been an interesting journey since the mid-90s and to see how, regardless of who came to power in the central government, their commitment to gas has always been smack on. Since 2005, Beijing has offered unconventional gas producers preferential policies, including refunds on value-added tax collected from gas sales, exemption from equipment import duties, and free-market gas pricing.

You say there's been strong government support all the way, but hasn't there been a step change in Chinese policy more recently? What about the deals that finally seem to be coming through for you? Green Dragon Gas has just signed an agreement with CNPC to develop the Greka Chengzhuang block (GCZ), and there has been another key deal on production sharing with a subsidiary of

CNOOC. Isn't this related to the recent strong government push as part of their initiatives to improve air quality by replacing coal with gas and renewables?

Well, these supplementary deals that we've done [on production sharing agreements with CNOOC] are quantifying a carried interest/value from the wells CNOOC drilled five years ago. It's not related to government policy – that has been consistently spot on. They provide a subsidy of USD 1.65/MMscf for gas produced from coal, which is almost half the Henry Hub price. This gives you an indication of how firmly the government is behind it.

You said these deals this year would settle the upstream issues and allow you to get on with marketing the gas?

It will allow us to focus on selling more gas from the wells that are already drilled. We don't need to market the gas, the market is at the wellhead. We now need to connect the wells to the trunk-lines so gas sales can kick off. The numbers that we published at Interims show a rising net income and EBITDA, but our revenue is fairly flat. So, this year we have concluded agreements with our partners and focused on cutting costs to become more efficient, so now gross profit is almost 55%, and EBITDA 65%. That is the economics of doing what we do now in China.

As we go forward, we are selling from less than 10% of the wells we have drilled. Our capex is already in the ground, and capex is now being deployed by our partner to connect the wells so we can fully monetise the block.

What price do you get for the gas you sell?

We get USD 7.20/MMscf, which is a solid price, higher than in the UK at the moment.

Is that below landed LNG at the moment?

Yes, but that's effectively the well head price. You need to compare delivered prices. So, if you think about city-gate prices, they are around USD 10-12/MMscf today, and landed LNG closer to USD 9/MMscf. There's a bit more demand for LNG in the coastal provinces, but by the time you add on the transportation costs to get it to say, Beijing, then we are at parity. Most of the markets we serve are further from the coast, so there's no competition between the two.

And the main buyer is CNPC?

Because CBM is open to the market by law, we can sell to whoever we choose. So, we sell to CNPC, PetroChina, and local industry. We also compress some of our gas and sell it as transport fuel. Our CNG station sites are complementary to our operations in the Shizhuang South (GSS) in Shanxi, as well as to our distribution centre in Henan. And we take some of the gas and use it in a power plant. The national grid is very keen for us to expand our power plant capacity because of the stability of the gas flow, and the reliability of the plant. We have lots of outlets and we control where the gas goes.

So what sort of rise in production do you expect over the next few years, with all these gas wells already lined up?

Well, the growth rate might well look a bit odd. We have 1,339 wells in the ground at our GSS block [by far GDG's biggest venture], but of them only about 400 are currently selling gas. So, we're going to have another almost 1,000 wells coming onstream soon. This will mean a bit of a step change. There were many wells waiting for the agreements to be signed before coming onstream, and the agreement with CNOOC has just been signed. So, the next 12 months are going to be very exciting for us on this block alone.

Looking at the broader picture for CBM, official 2016 figures show CBM output up only slightly on 2015 at 4.5 Bcm, still not far behind shale gas, although that jumped 76% to 7.9 Bcm. Shale and CBM were running almost neck and neck unlike the US. Could CBM still be as significant as shale in China, or is shale gas now overtaking?

I've been investing in CBM and shale since the early 90s. CBM predated shale, but shale benefited from some important new technology. But I don't think there is another part of the world outside the US, apart from perhaps Africa, where shale can be successful. You need complete access to land, which in the States you can get by just signing a deal. Where there are large populations it doesn't work, as we've seen in the UK. The US is different. And remember shale wells decline very quickly, which means you need an active drilling plan to be successful, and that requires clear access to land, otherwise your decline curve is going to hit you.

You have another company in China though, Greka Drilling, that provides drilling services to the Chinese, including at shale formations. How is business there?

We don't frack, we are a pure drilling service provider. We provide services to CNPC, and shortly we'll be providing services in India to ONGC, which they may wish to frack. We promote our proprietary technology where you don't use chemicals and you don't have to frack the well. But we drill only in CBM, we don't drill in any other reservoir, but in some cases our client may wish to frack the well. But our track record now goes back to 2007, with our technology able to produce low decline output curves. It's a natural de-absorber of gas from the coal seams – no fracking, which gives you a peak and a trough. You allow for a natural release, permitting the fractures to naturally interconnect, and then drain the water over time.

So it's really focused around draining, that's the key, and most of that work has been done?

Yes, exactly. So today for example in GSS, one of our two commercial blocks [the other is GGZ, or the Baotian-Qingshan block] we look at the operation as a matrix production, not a well production. The matrix of wells has been drilled and the gas is migrating through the fractures; we

don't really care [which is the producing well]. It produces a stable consistent production curve that continues to go up as we further drain the coal strata.

The government appears to have a target for CBM production, but it keeps moving.

Yes, there's always been a target, but the targets have been continually revised. Gas rises from 7 to 11% of the mix and the targets for shale gas and CBM are roughly the same amount over the next 10-15 years. I'm biased… I think shale runs a bit quicker but won't be able to hold the production levels because there are a lot of people where the shale is. You are asking them to move aside while the work goes on. We operate on coal board land so people are not affected. China-wide it is Sichuan where the shale is and most of Sinopec's operations, but there are also a lot of people there. And while we hear of the odd successful shale operation, there are many unproductive wells we don't hear much about.

With CBM we have been through the decades-long cycle of developing the right technology, we are now in the commercial period. We know how to drill the matrix, which way to drill, what type of drill to use and how to dewater quickly, and get the gas to market, including compression technology. The technology is mature today.

What sort of cost levels are you getting now?

Our all-in cost is under USD 2/MMscf, so the government's USD 1.65 subsidy is envisioned to cover your costs. The government is saying it wants the gas so much it'll pay for the whole thing - here's the cash subsidy and you get paid for the gas sold. You have to sort out your carrying costs to get in, but once in and running your costs are paid for – it's a wonderful country to be in. Which other country would do that for you?

Do you expect the average costs to come down over time?

As volume grows and fixed cost gets spread you get some relief on that. But when we are already making a USD 5/MMscf margin, some cost spreading isn't going to make that much difference. The main priority is to get the volumes up and connected, there is plenty of demand for the gas.

So what are the major obstacles now, if there are any to your projects?

We've confronted many obstacles over the last 20 years, but knocked them out of the way one by one. If you haven't sorted it out after 20 years you never will, and I think two weeks ago [the agreements with CNOOC and CNPC] was the last item.

We are done with the commercial blocks that are working. Now we need to do the same with the other six blocks that we hold. They are currently under exploration and we will have to go through the same cycle as the first two, but hopefully we can do it a lot faster, because we are not going through a learning curve, it is more of an execution.

Do you have plans to develop CBM programmes outside China?

Yes. There's been an important upswing on CBM development in India, along with government policy changes last March. With the amount of development that CBM requires, government policy is key to supporting development, which has worked well for us in China. India's now doing the same – opening CBM gas prices to market this March, the first time it has done this in history. In addition, state-owned ONGC has come out with its first development plan, and our contractor, Greka Drilling, won the tender to develop the first asset for them from a field of 17 bidders earlier this year. So, India looks like following China.

The other countries with significant resources that ought to be getting behind it are the UK and Poland. Both countries have significant domestic resources, and both countries like India and China are major gas importers. It's far better to develop your domestic resources than to pay for imports of gas.

How do you see international oil and gas prices changing over the next few years and how might that impact your operations?

There continues to be a significant arbitrage between domestic and LNG production. I don't see any price spiking in LNG over the next ten years. It's a far more normalised price at this stage. And there will be more of a move towards pricing independent of Brent/crude. But anyhow, I don't see their movements affecting CBM. CBM is a provider of domestic gas for domestic consumption where you are not competing with LNG. Plus, we are developing CBM in inner China and is not going to compete with LNG from the coast brought inland. They are complimentary not competitors.

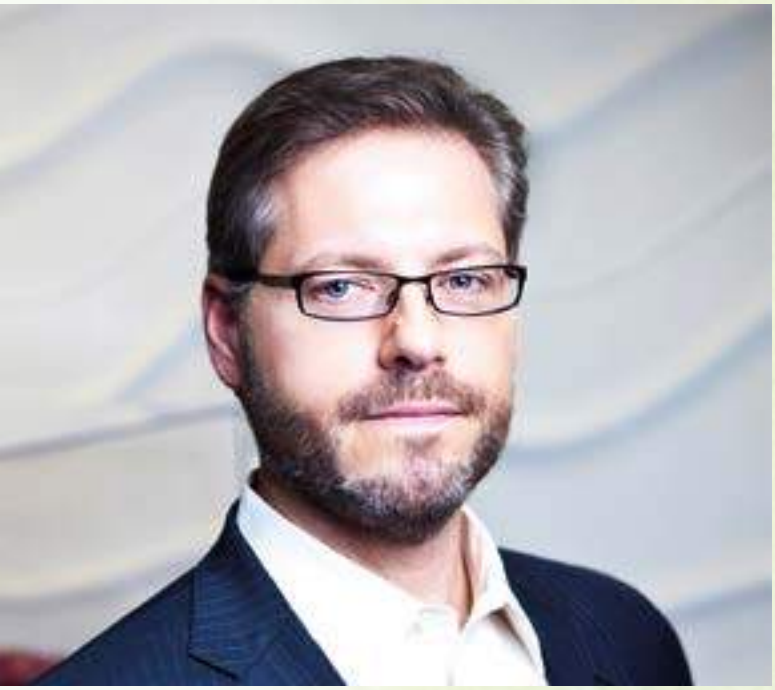
So basically, the investment you've made looks pretty risk free now?

That hasn't been the case for 20 years, but right now, yes.

Do you think the authorities may see that as an opportunity to take back some of the revenue you are getting, and what about contract risk?

Quite the contrary. The central government in China is consistently eager to support companies that are producing CBM. A recent ruling on our contracts went in our favour, underlining the strong position we now have. China doesn't have much conventional gas, but CBM reserves are large, [over 36 Tcm 2014], so the prospective prize for the Chinese government is huge. It's been tricky getting it out though.

Excelerate Energy



Rob Bryngelson
President and CEO

"The debate over the relative merits of floating regas versus onshore terminals has been settled. By 2016, FSRUs had captured 10% of the world market for regasification. At this point, nearly all new regasification projects are based on floating technology."

US-based Excelerate Energy was the trailblazer of floating regasification technology and today remains the largest player in this fast-growing industry, with nine FSRUs in its fleet.But competition is getting more intense. Established players Hoegh LNG and Golar LNG now have seven and six vessels respectively and more on order. Newcomers include BW Group, Mitsui OSK Lines and even Gazprom. Meanwhile, floating regasification projects are becoming more complex as customers seek new ways to exploit the opportunities that the technology opens up.In this exclusive interview, Excelerate Energy's CEO, Rob Bryngelson, explains how customer needs are evolving, his company's strategy to meet these changing needs, and how his company is responding to increasing competition.

Your company currently has the world's largest fleet of floating storage and regasification units (FSRUs). How is your fleet of nine FSRUs currently employed? And what plans do you have to expand the business?

All the vessels within Excelerate's fleet have been placed in term projects around the world. At present, we have two operating in Argentina, one in Brazil, one offshore Israel, two in the United Arab Emirates, and one in Pakistan. The remaining two vessels will be in Bangladesh, with one coming online in the first half of 2018 and the other in the first half of 2019.

Markets are evolving to both larger and smaller sized FSRUs, when compared with existing FSRU designs, so our plan is to continue to grow and expand our business

through a combination of conversions and new-build vessels.

Our focus is to develop long-term, highly integrated projects in markets with strong demand fundamentals to ensure our financial performance is stable going forward. In doing so, we plan to maintain our track record of on-time, on-budget delivery with highly reliable performance.

How do you see the floating regasification business evolving over the coming decade? What will be the likely impact of the new waves of supply from Australia, the US and Russia?

Floating regasification projects are becoming increasingly complex, with customers looking for integrated projects. By way of example, our first project in Bangladesh – Moheshkhali Floating LNG – is structured as a terminal use agreement (TUA).

What that means is that Excelerate is responsible for everything from the point at which the delivering LNG carrier arrives at the pilot station to the interconnection with Petrobangla's pipeline system onshore. As such, we will be providing not only the FSRU, but also full engineering, procurement and construction (EPC) services for the offshore pipeline, subsea mooring system, and all appurtenant infrastructure.

We will also be handling marine services including tug boats, supply vessels and pilots, as well as LNG ship-to-ship (STS) services, and providing operating and maintenance services for all the fixed and floating components of the terminal.

This means our customer has a single point of contact, and ensures that all the interfaces between the various project components are handled efficiently and effectively. It is the first project of its kind in the FSRU world, and Excelerate's ability to provide this level of service is a key differentiator for us.

Along with a more integrated approach, we see new markets looking at the ability of an FSRU provider to deliver reliable, consistent service throughout a project's life. The repercussions of unexpected downtime can be significant, so an FSRU provider must be able to deliver on its promises. To achieve this, all our vessels are built with reliability and maintainability in mind. This means redundancy of key systems to ensure nearly uninterrupted operation, while maintaining competitive economics.

The new supply coming online is adding to the overall length of LNG in the market, so it is a positive for the FSRU business. Customers in new FSRU markets are accelerating their projects in the knowledge that supply will be readily available, and on flexible terms that allow them to tailor purchases to meet their needs.

The FSRU is a small, but critical, part of the LNG supply chain. Having that ability to import in place provides a good position from which to negotiate supply.

Which countries do you see as the most promising markets?

We see continuing growth potential in our two largest markets: the Middle East and

South America. Along with that, we're seeing a number of new projects in southeast Asia gaining momentum. We see amazing potential on the horizon for Africa as the continent's nations move to develop cleaner electricity generation and spur economic growth.

That said, with the highly flexible, low-cost solution that FSRUs provide, if there's a coastline and an energy need, there's an opportunity.

How has your Puerto Rico project been affected by recent hurricanes?

Clearly, Puerto Rico has a tough road ahead rebuilding after the impacts of Hurricane Maria. Our Aguirre Offshore GasPort project is well advanced in the regulatory process, and can provide a quick solution to bring more natural gas to the island as the power system is rebuilt.

We continue to work with the Puerto Rico Electric Power Authority (PREPA) and the government of Puerto Rico to find a way to make this project a reality.

There has talk in recent years of developing LNG-to-power value chains as a way of encouraging LNG market development. Do you see that becoming a significant business?

Power generation is one of, if not the, largest drivers for new regasification projects. It can take the form of new electricity generation capacity or the re-powering of existing power plants away from oil or coal. Integrated gas-to-power projects present unique opportunities and challenges in their structuring, financing, and operation, but will be an increasingly large part of the business.

In February, you executed a Letter of Intent with South Korea's Daewoo Shipbuilding & Marine Engineering (DSME) for the delivery of up to seven FSRUs. What advantages does that LOI give you?

One of the key risks that an FSRU provider faces is timing uncertainty. Committing to a new-build vessel ahead of demand can put you in a good position to compete, but if a project doesn't materialise, the economic consequences can be severe. Improving our ability to time new-build vessel delivery with known shipyard slots helps reduce this risk – and our LOI with DSME does this.

The three main FSRU providers – yourselves, Hoegh LNG and Golar LNG – are being joined by a number of new entrants to the business, such as Singapore's BW Group, Japan's Mitsui OSK Lines (MOL) and even Russia's Gazprom. How are you responding to this increase in competition?

Our response is simple – we continue to deliver on our promises and provide the highest level of operating performance of any of our peers.

Excelerate doesn't look at a new opportunity as simply the provision of an FSRU. Instead we consider the project as a whole, and work with our customers to guarantee the level of service that they need.

What sets Excelerate apart from our peers is our depth of expertise coupled with the longest operating history in the industry. While new entrants are struggling to learn how to operate in difficult regasification environments, we're striving to improve and enhance the service we give our customers. This ensures that our projects grow and adapt to our customers' needs.

There has over the years been a lively debate over the relative merits of floating regas versus onshore terminals, with some commentators sceptical that FSRUs could ever be a true alternative to land-based terminals. What's the position today? Has the debate been settled?

The debate has been settled. Looking at the numbers, Excelerate's first FSRU – and the world's first – came on the scene in 2005. By 2016, FSRUs had captured 10% of the world market for regasification. At this point, nearly all new regasification projects are based on floating technology.

With our ability to deliver years earlier than land-based projects and at a fraction of the cost, the choice is an easy one.

The number of floating regasification projects has grown rapidly over the past decade, but floating liquefaction has not really lived up to the promise of, say, five years ago. You still promote the concept of FLNG on your website. How actively are you pursuing that?

The current pricing environment for LNG, due largely to the significant amount of new supply coming to market, simply doesn't support most floating liquefaction projects. Frankly, it doesn't support most land-based projects as well – except perhaps for brown-field expansions that can be executed at very competitive cost.

We still believe that floating liquefaction can be a viable solution, and we are keeping a lookout for projects that might be suitable. However, for the time being our focus remains on floating regasification.

The development of floating regas has been a story of innovation. What new technological or commercial developments can we expect to see as the business continues to grow?

Over the years, Excelerate has developed several proprietary technologies to increase the efficiency and performance of FSRUs. These include technical improvements to reduce fuel consumption and provide our customers with greater flexibility to manage load swings, but also include commercial enhancements such as gas-up cool-down services from an FSRU.

We've also led the market in regasification performance with two of the most capable FSRUs in the world, each having regasification capacity of more than 1 Bcf/d.

As a company, we remain closely engaged with our customers so that we can react to their needs and shape our offerings to best serve those markets. Saying much more than that would give away some of our best secrets that set us apart from the competition.

Nigeria Gas Association

Dada Thomas
President

"Government has no business running businesses. Government has no business running projects. They lack the requisite skills and the staff get paid whether they're productive or not. Whereas in the private sector you get paid for productivity, efficiency and performance. Today that plan is being re-modelled, with the objective of ensuring that the private sector takes the lead. This is the new thrust of the approved gas policy."

As the President of the Nigeria Gas Association and chief executive officer of Frontier Oil, one of the top five suppliers of gas to Nigeria's domestic market, Dada Thomas has a broad insight into the nation's energy crisis. In this exclusive interview, he outlines how the crisis has taken shape and what needs to be done to resolve it.

The government's recently approved national gas policy says Nigeria is experiencing a "full-blown energy crisis" in spite of its abundant gas resources. Why?

This is a cumulative problem dating back many years. Traditionally the pricing of gas in Nigeria has been regulated by the government. The international oil companies (IOCs), who hold the bulk of gas reserves, found the price far too low and so were not interested in producing for the domestic market.

The same IOCs were able to develop the successful Nigerian LNG (NLNG) project because the Nigerian LNG Fiscal Incentives, Guarantees & Assurance Decree of 1990 and Associated Gas Framework Agreement (AGFA) of 1991/92 provided sufficient fiscal incentives. And they were selling their product into the world market and getting paid for their product in US dollars.

For the domestic market it's not been the same. Traditionally, the largest consumer of gas domestically had been the government-owned National Electric Power Authority (NEPA). The NEPA would take gas and not pay for it. Over decades

a huge backlog of debt was built up by the NEPA, which was only recently cleared by the government.

Lately, however, indigenous operators such as us – Frontier Oil with our joint venture partner – have stepped into the fray, making investments in supplying domestic gas. But there are severe issues. Today is bleak. But there is a bright future, provided the gas policy is backed up by a fiscal policy that creates a win-win environment for everybody.

There is also a clamour by the gas suppliers for government to step out of commercial price regulation and stick to technical regulation. We urgently need a "willing buyer-willing seller" market now.

Going down the gas-to-power chain, the power sector is illiquid. The key reason is that the power privatisation undertaken [in 2013] under the previous [Goodluck Jonathan] regime hasn't succeeded because there isn't enough value in the pricing of power to provide for all the members of the gas-to-power value chain.

Something drastic needs to be done about the pricing of power, and something drastic needs to happen about the efficiency of bill collection by the distribution companies (Discos) because collection efficiency is as low as 28%. That's ludicrous.

On top of that, I understand that when the privatisation was being done the Discos did their economics on the basis of receiving about 5 GW of power. If you do your economics on receiving and selling 5 GW of power, and you're actually only receiving and selling half of that, there is simply not enough money. The Discos don't have enough capital to do all the things they promised, such as installing meters and upgrading the 33kv distribution infrastructure. They are practising estimated billing. Customer dissatisfaction has increased, customer resistance has increased, and so at any mention of increasing tariffs everybody goes crazy.

It's a self-perpetuating downward spiral. Something very bold needs to be done to break this self-destructive cycle.

What can be done in the short term to address the immediate crisis? And who should do it?

The government should increase the power tariff to make it market- and not cost-reflective. Market-reflective will promote efficiency while cost-reflective promotes inefficiency. This is the top priority because if the sector is not economically viable, anything you do is just putting Band-Aid across a huge gash.

The government must also ensure that Nigerian Bulk Electricity Trading (NBET) – which bridges the gap between the money remitted by the distribution companies and the money paid to the transmission, generation and gas suppliers – is sufficiently capitalised and funded and able to fulfil its role.

The government has instituted a NGN 701 billion (USD 1.95 billion) power sector intervention fund to pay for gas supplied and power generated from January 2017

for the next two years. That money has not yet been made available to NBET by the Central Bank of Nigeria. There is also the problem of the debt that accrued before January 2017, which is not being addressed at all. To restore confidence in the market, that intervention fund should be released to NBET and the government should repay the backlog of the debt.

To improve the ability to get power to the consumer, the Discos need to invest in their 33 kV local distribution infrastructure, in new transformers, and in metering. But they're reluctant to do so.

Does that mean there needs to be a recapitalisation of those discos? I think so. Does it mean that the existing shareholders should be diluted? Yes, they have to be, because they are insufficiently capitalised to undertake infrastructure upgrades. Other creative collaborative solutions between Discos and third-party investors by which new investments could be brought in should and must be explored.

What's your view of the final national gas policy as approved by the Federal Executive Council (Nigeria's Cabinet) in June. Are the targets the right ones?

The NGA and Frontier Oil engaged with the ministry team when they were formulating those documents. It was a good process.

The final document doesn't please everybody. There are members of our industry, especially those with substantial integrated oil and gas production operations, who are not happy about the segregation of the upstream, midstream and downstream because the gas policy has removed the AGFA fiscal incentive. AGFA meant that if you were doing a gas project you could write off all your gas costs against oil projects. The intention of the government is clear: to decouple the upstream, midstream and the downstream segments and to remove AGFA to create a level playing field and encourage new investors and players into the gas business.

We have to ensure that gas business is economic on a stand-alone basis. What we said to the ministry team was, "Please make sure that the fiscal policies are such that a dry, stand-alone stranded gas project, with no liquids, with no condensates or oil, is profitable and bankable in and by itself."

To assuage the fears of the IOCs and indigenous operators with substantial integrated oil and gas investments and operations, you have to grandfather existing agreements. You cannot cancel AGFA for investments that have already been made on the basis of AGFA.

The fiscal policy will be submitted to the Federal Executive Council by mid-September. We look forward to the approval of the policy by the Federal Executive Council (FEC). In encounters with the minister and his team, we have been assured that the fiscal policies will try to ensure that dry stand-alone gas projects are profitable. The minister has also said, "Look, we realise that a one-size-fits-all approach may not work. We are therefore ready to be flexible to look at projects on a stand-alone basis to ensure

that they clear the economic screening hurdle." That is encouraging.

When do you hope the FEC will approve the fiscal policy?

By the end of this year. They approved the oil and the gas policies pretty quickly, so I would assume they would treat the fiscal policy just as quickly.

Nigeria approved the implementation of a gas master plan in 2008. The gas policy document says, "the plan has not delivered on all its targets". What went wrong?

The project was very ambitious, it was not well funded, and project execution was not as effective as it could have been.

Let me tell you my fundamental belief: government has no business running businesses. Government has no business running projects. They lack the requisite skills and the staff get paid whether they're productive or not. Whereas in the private sector you get paid for productivity, efficiency and performance. Today that plan is being re-modelled, with the objective of ensuring that the private sector takes the lead. This is the new thrust of the approved gas policy.

Why is Nigeria's installed electricity generating capacity so tiny, given that you have a population of 180 million? And what can be done to speed things up?

We have 12.5 GW of installed grid utility generation, of which only 7-8 GW is technically available. And of that only about 5 GW is functional because of inadequate gas supply and technical problems such as wheeling capacity, grid system collapse etc. Why have people not been investing in generation capacity? For years there was simply no investment by the government and the NEPA in generating power or upgrading the backbone transmission and retail distribution infrastructure.

There was an attempt under the regime of President Olusegun Obasanjo – which was between 1999 and 2007 – to roll out around 19 new power plants but those plants were simply procured and placed in often the wrong places. There was no thought given to how would they get gas supply and how their power would be evacuated.

Putting generation aside, there is a bottleneck in the transmission system. Up to about last year the transmission capacity of Nigeria was a maximum of 5.5 GW. Above that the system was always collapsing because it could not handle the load. There's been a very good attempt by this current government to expand transmission capacity so we're just about between 6.5 GW and 7 GW of capacity now.

The reason why there is light in Nigeria today is because we are self generating power. We must be self-generating at least 20 GW of power.

Assuming that the Disco situation is resolved, transmission bottlenecks are resolved, and new generation gets built,

there will remain the problem upstream with gas supply. A major issue with that is the long-running security situation in the Niger Delta. Can the dissatisfactions in the region be effectively addressed?

The only long-term sustainable solution to general insecurity is good governance, at the local, state and federal government levels. But that's a long-term project. So let's look at the short term.

This government, under the leadership of the vice president and the minister of petroleum, has been heavily engaging with the Niger Delta. That has yielded the relative peace we have today, compared with 18 months ago.

Last year a 16-point agenda was agreed between the stakeholders and leadership of the Niger Delta and the federal government. Secondly, there are ongoing engagements to make sure that there's increased participation in the upstream oil and gas industry by Niger Delta communities. And you even have the fact that they've broken up the Petroleum Industry Bill (PIB) and there is now a whole bill entitled the Petroleum Host Community Bill. These are all good signs.

In our own [Frontier Oil] operations we form a symbiotic relationship in which we try to ensure we create and spread wealth within our operating area – that "if it's good for me, it's good for you". We're in it together. They have to have a stake in the business and therefore care for the well-being of the business such that they will not attack your facilities or blow up your pipelines.

This government is doing a much better job. It was rough at the start. The militancy brought oil production down to as low as about 1.5 million barrels/day from 2.2 million barrels b/d and it also affected gas supply to the nation because when you blow up oil pipelines a lot of the oil facilities use up all in-situ storage capacity and therefore have to shut down. Once you shut down oil production, you have to then shut down gas production because you no longer have storage space to store the condensate produced form the gas operations.

In 2015 less than 15% of the gas produced in Nigeria was sold in the domestic market, and more than 38% was exported as LNG. Should more gas be diverted from exports to the domestic market?

We're going to have to do both. We've seen wild fluctuations in oil prices, we've seen the double impact of low oil price and pipeline and facilities vandalisation. We need to diversify the source of foreign exchange. We already have commitments on LNG, and have to honour these agreements. Nigeria needs foreign exchange to industrialise, because we have to import capital equipment.

This means that we need to truly start the exploration, categorisation and classification of gas resources. The 182 Tcf of reserves we have is the result of exploring for oil not gas. There has been no active exploration for gas in Nigeria.

To meet our thirst for foreign exchange we have to move away from an oil-based economy to a gas-based industrialised

Dada Thomas, President of the Nigeria Gas Association

economy. This is the thrust of the new Petroleum Reform Programme and the newly approved gas policy. But that means that you need foreign exchange to buy your capital equipment, to start creating value locally to employ the tens of millions of young people that we have in this country.

So we need exports and more importantly we need to increase the local value addition of gas by using it for fertiliser, for methanol, for all kinds of gas-based industries, the way Trinidad has done, the way Qatar is doing.

How much of a help or a hindrance to the necessary reforms is the current political situation?

The problem in Nigeria has not been that we don't have good policies it's always been poor implementation, and continuity of implementation and of policy direction.

We have been saying to government that we have to stop what we call policy somersaults in Nigeria. There must be commitment to ensuring that policies and laws are consistently and transparently implemented. The indication that I get in all my interactions with this minister of petroleum and his team is that they want to ensure the success of these policies.

They understand that we can no longer depend on oil as a nation, we can no longer continue to export raw materials as a nation, there is a great appreciation that there needs to be local value addition, wealth creation, and therefore creation of employment opportunities for the huge number of Nigerian youths pouring out of our schools.

Now, this government has an election coming up in 2019. Will it win or will it not? I do not know. I'm praying that there will be policy implementation continuity, whoever takes over in 2019. The best thing really is to accelerate the pace of implementation of approved policies and pass the long-awaited Petroleum Industry Bill, which has now been split into four different bills, so that the train has already left the station.

Once you have a law then at least you have a framework for addressing any issue that comes along, whether it's a new government or not.

How optimistic are you that Nigeria will be able to resolve its energy crisis? Or will things will get worse before they get better?

They're going to get worse before they get better because the government has been slow in taking hard, fundamental decisions. They're reluctant to effectively implement the multi-year tariff order, which is the pricing mechanism for power in Nigeria and the politicisation of that has caused us great harm. If they don't take this hard decision before the end of 2017, it will be difficult to take it in 2018 because electioneering will start.

The government itself needs to respect sanctity of agreements, and set an example by paying its debt to the sector, and thereby saying to everybody: "It's a new day, it's a new age, we will honour our agreements, everybody pay your bills. If I the government am paying my bills why are you the consumers stealing electricity? Everybody pay your bills."

NextDecade

Kathleen Eisbrenner
Founder and CEO

"Organic LNG demand continues to grow. FSRU growth is dramatically underestimated. Traditional customers will have significant ability to re-contract existing volumes and the US will be the preferred choice."

Asked whether we are likely to see a second wave of LNG exports from the Lower 48 United States, Kathleen Eisbrenner, CEO of US LNG project developer NextDecade, is unequivocal. She believes that leading the second wave will be her company's proposed 27 mtpa Rio Grande LNG project, which she claims will be the world's most competitive. What's more, it will become the gateway for new gas resources in the Permian and Eagle Ford basins, large enough to make Texas "a stranded gas play" – larger than Qatar from a hydrocarbon resource standpoint. Eisbrenner is convinced there will be a second wave of multiple US export projects coming on stream in the next decade. If she's right, life is about to get even tougher for other proposed liquefaction projects around the world.

At a time when proposed new projects are being delayed and cancelled, you are aiming to reach final investment decision (FID) this year on your 27 mtpa Rio Grande LNG liquefaction project in the US. What's the business rationale behind what some might regard as a counter-cyclical investment?

I'm not sure why you're considering it counter-cyclical. There was a rush to FID and that's creating a bit of oversupply, potentially, for a while – although I think new markets will suck it up pretty quickly. A new tranche of long-lived asset-based LNG will be required in the early 2020s and so we're positioning ourselves to be the leader of the second wave of LNG out of the US.

The weird period of $26/barrel oil this time last year has given pause to a lot of things. It has not given pause to our investors, but it's given pause for us to revise our thoughts on how to be competitive. We worked really hard last year to get our capex down, to get our opex down, and to get our throughput up – and we are convinced we are the most competitive LNG project in the world.

Our EPC and marine costs will be $500 per tonne [per year of capacity] or lower. There's only one brown-field project, the original Cameron project, that will come in with a EPC-plus-marine dollars/tonne lower than us.

So that's what we're focused on: $500 a tonne for 27 mtpa. So $13.5 billion plus two pipes. It will be a phased build-out. Our base plan is two trains but if we can build three at one time that would be our preference – because each of the Rio Bravo pipelines can serve up to three trains. So I hope three, but we can take FID on two.

Which liquefaction technology are you using?

Air Products' propane pre-cooled mixed refrigerant (C3MR) – the technology that's used in 80% of LNG export facilities worldwide.

People are trying to suggest that diseconomies of scale by going to modular are going to make the LNG industry more economic. I tried and tried to find ways to do that and at the end of the day – maybe this is my three years at Shell – I became convinced that economies of scale are ultimately better on the export side of the business.

How did you achieve cost reductions of such magnitude?

We've had the luxury of a bit of time. Where before everybody was racing to meet schedule, we decided to take a breath and say "now wait a minute, we're at $26 oil, customers aren't dying to sign up more, what else can we do to be even more competitive in the future?" So, with our partners CB&I, we focused on what we could do to get our numbers to be the best possible.

Recent successes and announcements in the Permian and Eagle Ford basins further advantage our position. As these are mainly oil plays with associated gas resulting from them, the wells are profitable even at low – or even negative – gas prices.

Why are the resources in the Permian and Eagle Ford basins so important to you?

Over the last six months we've been gifted with an incredible position that we didn't plan for, but we now happen to be geographically ideal to monetise.

We've done a tonne of analysis on this and the Permian is now larger, from a hydrocarbon resource standpoint, than Qatar. It's incredible. Texas has gone from being a Henry Hub-denominated part of the United States where liquidity is assumed – and on any given day you

can buy, and any given day you can sell, at a competitive price – to one of being a stranded gas play. A lot of people don't realise it yet.

We had already planned to approach producers in the States about feedstock and gas supply. I have the privilege of sitting on the US National Petroleum Council along with many CEOs from oil and gas producers. In August last year I sent out letters to ten of them. Within two hours I had my first response; within 12 hours I had my second; and a couple of hours later I had my third – from CEOs of major Texas producers. And so I set up meetings with those three.

September 7 comes and Apache announces its Alpine High find in the Permian. Their public announcement was "we found 75 Tcf of gas within one county within the Permian".

The flight of capital to the Permian is phenomenal and is growing. So a big part of our agenda is to convey this message to the benefit of everyone – the producers, our projects, and our customers. Because we happen to be sitting, especially for Rio Grande, on the most proximate gateway to the world.

Think about the Alpine High Apache deal, just by itself – 75 Tcf. For these guys to conceive of producing their 75 Tcf, they have to compete with all the other producers, and they need markets that just don't exist in Texas, just don't exist in the United States. That's why last month we took our second lease, the Shoal Point lease in northern Texas. The state of Texas is the latest "a-ha" moment.

You've talked about having 30 mtpa of – as you describe it, "admittedly non-binding" – interest in Rio Grande offtake from buyers. What can you say about who and where the potential buyers are? And how much progress do you expect to make this year in converting those HOAs to binding SPAs?

Quite a bit. We've had several site visits by customers to Rio Grande. Our chief commercial officer Alfonso Puga is spending 150% of his time working on that, including with customers that aren't on the HOA list.

There are several groups that are driving LNG markets. Number one: new customers. At the top of this list might be China, might be India, might be the greater FSRU (floating storage and regasification unit) new customer list.

But there are two more groups of customers that we really focus on. Many traditional LNG customers, the largest group – such as Kogas, Tokyo Gas, Osaka Gas – have contract re-negotiations that roll in the early 2020s. There's more than 200 mtpa of contracts that need to be renewed or replaced.

So, the rule of law in the United States is great, our terminal is the cheapest in the world, and when we add in that we believe we can give them access to the cheapest feedstock in the world, we're very confident in lining up customers that allow us to take FID.

The third and final group is about half the size of the re-contracting group – and these are countries that have traditionally

been producers, but no longer have the reserves to extend contracts: Trinidad and Nigeria are in this camp. Yemen is effectively shut down, and Malaysia and Indonesia are adding imports in addition to continuing exports. Many Middle Eastern countries, UAE for example, are building import facilities. So there's going to be a reduction in supply availability and the US will be able to step up to compete for it.

You were the trailblazer for floating LNG regasification, with the founding of Excelerate Energy. FSRUs are now seen as crucial in the building of new markets. Yet in the early days you met with a lot of scepticism. How does it feel to have been so resoundingly vindicated?

It is with a great deal of pride that I see so much support for FSRUs – particularly since it was a tough beginning. The launch was indeed difficult. Even before I founded Excelerate, while at El Paso Corporation I faced serious pushback on the strategy. Fortunately, I found a greater number of advocates than naysayers and the rest is history!

I'm a firm believer that the FSRU is an enabler of new market development. At NextDecade we have a business unit, NextDecade Global Solutions, the main focus of which is to provide, advise, and support our customers that need natural gas and recognise LNG as the best solution, but need help to develop FSRU terminals. I'm thrilled to continue being involved in the development of this breakthrough technology.

You've spent much of your career in the LNG industry, so you've seen a lot of changes as the industry has developed. What do you make of the various transformations the industry is going through today? And what do you think the industry will look like, say a decade from now, in the mid-2020s?

I'm excited about the transformation, about the fact that the US is now in the mix as an exporter, and about the state of Texas – within the mix of exporters from the US – being the best positioned. The reason producers are producing in Texas is not so much to produce gas, it's to produce oil, and gas comes as a by-product. So it's associated gas. It is the cheapest production of gas supply because of the revenues that come from the oil.

You can't flare gas for any sustainable time in Texas, and you can't re-inject it because there is no reservoir to push it back into. So finding homes for gas from Texas is going to become paramount.

Texas is already the largest producer of gas in the United States and it's about to become substantially larger. The last time I looked, 45% of capital budgets for production in the US for 2017 were being allocated to the Permian. But where is that gas going to go?

For the last five years we've been into market pull, but for the 40 years before that it was monetising stranded gas that drove the growth of the LNG business. We're back to monetising stranded gas and there's plenty of headroom to look

at new commercial models. There are fundamental changes that we're going to live through and by selling this associated gas as LNG, returns can potentially improve dramatically.

From what you've said about the gas costs in the Permian, you'll be buying gas directly from producers rather than from the pipeline grid at Henry Hub prices?

We're looking at all of our options and considering ways to connect the pieces. One of those possibilities is directly linking Waha, the heart of the Permian, to Agua Dulce, the current liquidity point under permit as part of our FERC filing. So we are looking to increase infrastructure to make sure that Permian gas has an outlet to our plant.

So, yes, we or our customers will be buying gas directly from Permian producers. But there's another thought, which is: okay, if the Permian is moving to a stranded gas play, who is going to be selling gas and where? Is our plant an extension of the pipeline infrastructure necessary to monetise Permian gas?

And so our customers would traditionally be say Kogas, or Osaka Gas or Pakistan that might sign up for our tolling fee or FOB offer – we offer both by the way. Or maybe they will be, say, Exxon, Oxy, Chevron or Apache. We're fairly agnostic.

Your Rio Grande project is part of what you have described as the "second wave" of US LNG exports from the Lower 48 states. Will we see other projects aside from yours going ahead in the US?

Yes. Organic LNG demand continues to grow. FSRU growth is dramatically underestimated. Traditional customers will have significant ability to re-contract existing volumes and the US will be the preferred choice.

From a demand perspective I think the limitation is the credit quality of interested additional countries and incumbents who want to turn LNG largely into power but also grow grids around that. There are constraints, but they're all workable. So yes, multiple projects will move ahead in the US. That's why we've leased a further 994 acres for another facility in Texas City.

What about the prospects for proposed liquefaction projects elsewhere, in say East Africa, Russia and Australia?

They cannot compete with US export economics. With the possible exception of Papua New Guinea after the InterOil acquisition, any of the other ones that I have analysed cannot compete with what we can do in the States.

So, with what's happening in the Permian and the second wave of US LNG, life's looking even tougher for proposed liquefaction projects outside the US?

Absolutely. And let me give you another data point you may not have thought about that I'm going to be promoting to a great extent this year. Under a Trump administration, this is a huge opportunity for the US to start making changes in the

balance of trade. China's 2015 imbalance of trade is something like $342 billion. I don't think we can produce enough LNG to offset that in its entirety, but is it an incentive to get $100 billion done? Yes. South Korea and Japan have already acknowledged this.

So there's huge incentive for the United States to support developers' efforts to develop international markets and there's tremendous incentive for foreign countries to support American imports.

The Permian and this are the two things that other people aren't really focusing on.

This year will be a milestone for floating liquefaction as a number of new projects work towards the start-up of commercial operations. What are the prospects for floating LNG (FLNG) as far as you're concerned?

I started NextDecade with FLNG as our primary monetisation strategy. We started on the Tamar field in the Mediterranean offshore Israel. And I was part – when I was EVP Global LNG at Shell, responsible for Shell's Global LNG development portfolio and leader of LNG trading – of the FID team on Prelude.

However, when we focused on the fact that we had originally 500 acres and now 1,000 acres in Brownsville, Texas, and we thought about FLNGs and compared them to building land-based, we had to look each other in the eyes and say "why are we doing FLNG?"

Land-based can be extremely economic. It's very comfortable from a bank financing standpoint, comfortable from an EPC standpoint, comfortable from a technology standpoint. So I think FLNG will have niche applications, particularly for remote areas, but if you can do land-based it's hard for FLNG to compete. Which is the reverse, ironically, of land-based regas versus floating regas.

What type of liquefaction is also very dependent on your feedstock. If you have enough feedstock for 20-plus years of supply, land-based helps a lot. If you have only five or seven years, then you really should consider floating because then the asset can be moved.

Your company has recently signed a Heads of Agreement with Flex LNG "to create a full value chain solution" for customers looking to purchase LNG from Rio Grande. Is that what customers were asking for?

Flex's CEO and I have a long and successful working relationship – we know how to work together. And yes, it is what customers want. I don't see anybody else doing what I dreamt of when I envisaged FSRUs, which is linking the value chain, putting LNG in the FSRU so that you get gas out – because at the end of the day what customers want is gas.

The industry has morphed to become more of an infrastructure play – and there are tenders and shipowners, and all that's fine – but what I'd really like to do is… Look, we have the most economic LNG export terminal in the world, we have access to the most economic feedstock gas in the world, and Flex LNG are going

to have the most economic FSRUs in the world, let's work together and see if we can't put a bunch of them in place and bridge the gap that exists right now.

Would you consider going even further downstream and bolting a power station on the end?

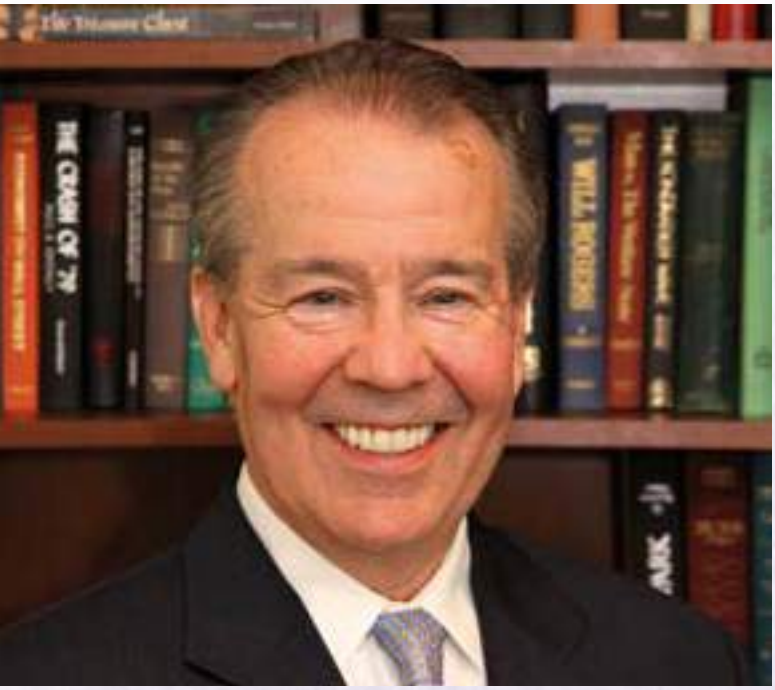
You'll have to stay tuned.

There is a lot of debate about the role of natural gas in an increasingly carbon-constrained world. Some see gas as part of the solution, others as part of the problem. What's your view about the future for natural gas?

I see natural gas as "the fuel for the foreseeable future". I hope for society's sake non-carbon solutions are found that are viable and economic, but when the wind doesn't blow, the sun is clouded, or there is a lack of rain, natural gas is the best back-up solution. It's hard to disassociate natural gas from renewables when you really understand how a grid works, how a plant works, and what's dispatchable.

Kathleen Eisbrenner, Founder and CEO, NextDecade

American Exploration & Production Council (AXPC)



The American Exploration & Production Council (AXPC) represents an influential group of independent E&P firms, including the US' second, third and fourth-largest gas producers – Chesapeake Energy, Southwestern Energy and Anadarko. Collectively, council members hold a quarter of the country's proven oil and gas reserves and account for nearly 30% of US gas output. Gas Matters speaks to AXPC president Bruce Thompson about the prevailing business environment during the early months of the Trump administration, and the hopes and potential pitfalls facing independents in the US upstream.

Bruce Thompson
President

"We want what's best for the country and the industry. We do not want to be anti-environment or anti-health or safety. We work hard to achieve good environmental and safety records and whatever we accomplish in business, we want to be seen and appreciated in that context."

How has the mood changed for AXPC members since Trump took office and started issuing executive orders?

AXPC members are extremely sensitive to the regulatory environment. Our 33 members are large independent E&P companies that carry out the bulk of well drilling onshore and on federal land in the US. We were right in the firing line of those affected by the Obama administration regulatory assault and, arguably, we have the most to gain by some rules being overturned.

For example, the Bureau of Land Management (BLM) waste minimisation rule on venting and flaring, which is being considered for a Congressional Review Act resolution. That practice is completely regulated by the EPA under the Clean Air Act. It's also regulated by states, so there is zero reason for BLM to be involved. This is not an environmental issue – it's

a matter of regulatory overreach. Finally, we have a White House and agencies willing to listen to our point of view. We're generally pleased and cautiously optimistic.

Has communication improved between AXPC members and government bodies such as the EPA?

Yes. We have good relationships with the folks in place. Some of the individuals that have joined various agencies were people I worked with when they held senior staff positions in Congress. But most federal agencies are not remotely staffed up yet, so we're a long away from having a full complement.

I don't think any deputies are in place yet, so as of now, there is no deputy secretary of defence or interior; no deputy administrator of the EPA. Names are rumoured, but no one has been nominated, much less confirmed. I don't think President Trump wants to fill every spot – that does not seem to be his MO – but some of these senior spots need to be filled.

Even if re-elected, Trump will leave office in 2025. His latest executive order aims to scrap the Clean Power Plan, but forecasts suggest that could remove a major driver for gas to power. With that in mind, how can his administration best support the US gas industry?

We want what's best for the country and the industry. We do not want to be anti-environment or anti-health or safety. We work hard to achieve good environmental and safety records and whatever we accomplish in business, we want to be seen and appreciated in that context.

That said, the Clean Power Plan needs to be done away with. It's a cap-and-trade system on CO_2 emissions on a state-by-state basis that is top-down and won't work well. In the short term it may raise demand, but in the long term it could become the regulatory hammer that squeezes out gas and forces renewables into the market. If renewables can be done on an economic basis we're happy to compete, but we're not thrilled about the deck being stacked against us.

Under Obama, regulatory overreach was a problem and his administration tried to incorporate the 'social cost' of carbon and methane as deeply as possible into the regulatory framework. President Trump will try and rip that out by the roots, so we can get back to a regulatory regime that makes sense and emphasises safety, health and free markets.

For years, environmental advocates and media outlets have claimed the government doles out subsidies and tax breaks to the fossil fuel industry. Does US gas receive federal subsidies – and if not, might you seek them in the next budget?

Oil and gas operations are not subsidised. If AXPC members spend money drilling a well, they can currently deduct a significant portion of those costs under the tax code as "intangible drilling costs". That's an unfortunate and confusing label, because these are

simply ordinary business expenses, just as pharmaceutical research and development is for a company like Pfizer, for example.

In a normal business environment, our members borrow money and spend around 130% of annual cashflow on drilling wells. If we couldn't currently deduct those costs, we wouldn't be able to drill nearly as many wells as we do now and the nation's supply of affordable, secure energy would decline. The current tax proposal under discussion in the House of Representatives recognises this and would allow all companies that do business in the US to expense 100% of their capital expenditures.

We are fine with the House tax blueprint, and are not looking for any additional provisions – rather, as discussed above, we're looking for less regulation. It's not in our interest to cut corners operationally, it's bad business and it's bad politics. But when mistakes happen – and they will happen – we fix them and move on.

Earlier this year, the EIA forecast that US gas output could rise by 45% between 2017 and 2050 under existing regulations, including the Clean Power Plan. Given that, can you really say that current rules are strangling US gas production?

I was recently at a series of meetings with our members in Texas and I have to say: the US truly is the Saudi Arabia of natural gas. Our technology has changed everything. We are so efficient that we continue to be our own worst enemy, and many people don't expect prices to get much above USD 3.50/MMBtu for the foreseeable future.

The issue now is reducing regulation that doesn't accomplish anything, i.e. has no benefit and makes life more expensive. AXPC members are generally financially strong enough to adapt within reason, but an unnecessarily burdensome regulatory environment really hurts the smaller operators and makes it difficult for them to survive.

Production can still be strong with the regulations. With less regulation, you may not necessarily see a huge jump in production, but there would be more opportunity for growth, lower costs and greater energy security for the US.

Trump has proposed 'devolving' regulatory power to states and opening up federal land. Is that the best way forward?

Our general view is that states know best. Each is unique, with different issues of geology and land ownership and they know what works in their particular state. Once upon a time, that is how the whole regulatory scheme was designed – states would govern themselves and the Feds would fill in when minimum standards weren't met.

Under the Obama administration, the unstated mission of the EPA and the BLM was to make it increasingly difficult for oil and gas operators to work on federal lands. And they succeeded. The number of wells drilled on federal land has fallen by two thirds since 2009. If we want

energy security in the US, we cannot afford a continuation of that trend.

Access to federal lands is one issue, but even if the leases become available, we have to look at the permitting process. Some AXPC member projects have been stuck in National Environmental Policy Act (NEPA) reviews for eight years without ever receiving a "yes" or "no". We need certainty as to what the rules are. And if you comply, you should be able to proceed with your operations instead of having the local or regional office sit on the application indefinitely.

US gas prices could be capped for some time and established plays like Marcellus still contain enormous proven reserves. Even if rules are simplified, what motive will E&P companies have to ramp up drilling anywhere in the country?

We have always been self-limiting. As I said earlier, we can at times be our own worst enemy. We keep going and going until there's too much supply, then the price drops and we do less drilling. Gradually the pendulum swings – that's the nature of this business. But compared to even ten years ago, technology has changed and we have unlocked staggering amounts of gas.

Several AXPC members that operate in the Marcellus shale believe that they have reached the 'sweet spot' in the rock, yet they will tell you that above and below those formations are still huge reserves.

A lot of US production will be price driven. If today's relatively low price environment continues, some of it will stay in the ground for the foreseeable future. That has always been a struggle for oil and gas operators and it will probably never change. The difference from 15-20 years ago is that companies can now hedge their positions and protect themselves financially. That smooths some of the ups and downs, but this is still a risky business, no matter how you slice it.

So new federal licences could sit undeveloped for say 20 years, even if regulations are eased and new areas are opened up?

That may be true, depending on the lease terms. Part of the reason companies drill wells is to hold acreage; in this lower price environment that's part of the business. Federal lands usually have longer-term leases and that works a bit better. Still, some companies can find themselves forced to drill just to hold the land.

Many US citizens will think of national parks when they hear the term 'federal land'. Doesn't an E&P firm making big profits from fracking on federal land pose a huge amount of negative PR potential for the industry?

This goes directly to the huge misconceptions about how we operate and the extraordinary efforts we make to protect and preserve the land and the environment. We came to that same conclusion and are putting together a stronger communications strategy. We're in 'sales mode', by which I mean we are trying to explain why our business is so

important to people in their daily lives. We want a smarter, more current, more 'millennial-considerate' message.

Most operations on federal lands are removed from towns, but that is not necessarily the case on private lands. A lot of the places we drill today are closer to cities than ever before. They're not on a 10,000-acre ranch anymore, we're next to neighbours on the outskirts of town. We have to be sensitive to their opinions and we want to be. We're also big fans of multiple use of federal lands.

I wish I could take everybody that's interested on the tour we organise for Congressional staff. Every year, we show a group around a field operated by an AXPC member, starting with a drilling rig and ending with a production facility – which is basically a few pipes coming out of the ground in a small grassy area behind a chain-link fence that you don't really see from the road.

By showing the policymakers how we operate, from soup to nuts, we are working to more effectively communicate our messages. That's the case all over the Marcellus shale. Our operational footprint is smaller and smaller every day. Pipes are buried, nobody sees anything, but the lights still go on and your house is heated and cooled. It's important to get that message out.

AXPC member list: Anadarko, Apache, Cabot Oil & Gas, Chesapeake Energy, Cimarex Energy, Concho Resources, Devon Energy, Diamondback Energy, EnCana, Energen Resources, EnerVest, Ltd. EOG Resources, EP Energy, Jonah Energy, Linn Energy, Marathon Oil, Newfield Exploration, Noble Energy, Oasis Petroleum, Occidental Oil & Gas, PDC Energy, Pioneer Natural Resources, QEP Resources, Range Resources, Rice Energy, Seneca Resources, SM Energy, Southwestern Energy, Synergy Resources, Ultra Petroleum, WPX Energy, Whiting Petroleum and XTO Energy.

Dresser-Rand

Michael Walhof
Sales Director of Distributed LNG

"All over the globe, there are gas fields that aren't connected to a pipeline, so the gas remains in the field. If you have a technology that can come in and convert that gas to LNG and truck it to customers, it will have a big positive effect."

Monetising stranded assets, expanding LNG as a transport fuel and bringing gas-fired electricity to remote towns and villages around the world are increasingly seen as gateways to maintaining profitability and securing a future role for the natural gas industry in the global energy mix. LNG Business Review speaks to Michael Walhof, sales director for distributed LNG at the Dresser-Rand business, part of Siemens Power & Gas, which is one of a handful of companies aiming to make micro-scale liquefaction deliver large, tangible benefits for upstream E&P activities, the environment and developing communities around the world.

Many companies define small-scale and micro-scale liquefaction differently. To start, how does Siemens define those in terms of plant capacity?

In general, there are no set guidelines, but the market is segmented. Small-scale liquefaction plants typically have 100,000-250,000 gallons/day, above that you start getting into mid-scale, then large-scale and mega-scale plants.

Siemens plays in all those spaces, but plants with less than 100,000 gallons/day are typically defined as micro-scale, which is what my group focuses on. The LNGo product line comes in two sizes: the LNGo-LP natural gas conversion system is very small – around 7,000 gallons/day of production, equal to roughly 10 tonnes/day or 0.0036 mtpa; the larger LNGo-HP system is around 30,000 gallons/day, or 48 tonnes/day or 0.017 mtpa. There is a market for both.

The Dresser-Rand business recently installed a modular micro-scale liquefaction plant in a stranded gas field in the Marcellus shale for US-based company Frontier Natural Resources. Aside from that unit, how many other micro-scale plants are there worldwide and how many might there be by 2020?

On the micro-scale, I would estimate that there are no more than 50 units installed globally. It truly is an emerging market and we're on the cutting edge of it. There are some in Latin America, the US and China, but especially speaking on the micro-scale, it's difficult to quantify.

Some companies use the LNG produced by their micro-LNG for internal consumption. It's not a commodity product. They may have a drilling fleet that needs LNG, so they produce their own. It may be a mining company that liquefies coalbed methane for private consumption.

We have multiple systems under contract, including one at Frontier Natural Resources in Pennsylvania; two low-pressure systems installed for public utility AGL Resources in New Jersey; a high-pressure system in northern Canada; and three additional units under contract also for sites in Canada, to name a few.

I would project that by 2020, you're going to see the number of micro-scale units installed globally increase to 200-250, but some market analysts are projecting up to 1,000.

Where do you predict that growth will happen?

Most growth will be defined by segment, but looking at the geography, we feel that besides the US and Canada, also Russia, Latin America, Africa, and Canada could become relevant markets. China will also continue to be an emerging market for this technology.

If you start looking at market segments, you can identify areas without connections to power infrastructure or to a natural gas source, where you start using micro-liquefaction by eliminating flares, accessing stranded gas assets or taking gas from pipelines to create a virtual pipeline and start providing power to underserved communities. They don't need 100,000 gallons/day of LNG; you bring in modularised systems like ours and you can install very quickly and produce enough LNG to power up to 20 MW of power for a community – it's a game changer for the community.

We see this happening in Latin America. There are also many remote communities in Canada that still use heavy fuel oil or diesel. If you are able to get them onto clean-burning natural gas, the environmental impacts are tremendous.

Looking at Asia, in Indonesia for example, many island communities are completely disconnected from any power source and don't have enough gas to supply a large-scale or mega-scale liquefaction plant. A distributed LNG model allows you to go where smaller amounts of gas are available and produce just enough LNG to power these communities.

In the US, the marine market is expected to move towards LNG as the Environmental Protection Agency's Tier 4 emissions standards come into effect. All the vessels along the Mississippi River would have the ability to switch from heavy fuel oil or diesel over to clean natural gas.

It's a very interesting time because the market is still trying to understand this technology and where it applies. As people understand how it can change the energy infrastructure, they will start finding new ways to use this technology.

Why would a client buy a micro LNG plant? How exactly would one of your plants or a virtual pipeline create a new value chain?

Modularised LNG systems allow us to come in with a very small footprint, a short installation period – often less than a year – and create virtual pipelines to communities that currently have no access to natural gas.

Any community disconnected from a nearby gas source – a stranded gas field, flares from an operating field or a pipeline, is a possibility. All over the globe, there are gas fields that aren't connected to a pipeline, so the gas remains in the field. If you have a technology that can come in and convert that gas to LNG and truck it to consumers, it will have a big positive effect.

For example, imagine a little town 500 km from a gas pipeline that brings in diesel or fuel oil to generate power. Attach one of our systems to an existing trunk line or a pipeline spur and you can deliver clean-burning natural gas to that same community. It not only benefits them economically, but it changes its entire environmental impact.

The US and Canada are huge countries with plenty of long-distance gas pipelines and proven resources. But if those are the only supply sources for micro-scale liquefaction, what business opportunities exist in growing demand centres like Indonesian islands, Latin America and Africa that lack infrastructure and active fields?

Let's look at Colombia. EcoPetrol owns a large amount of gas, but it's stranded because there are no pipeline connections from the field to the capital city, Bogota, or other communities. So they have an asset that cannot be monetised, and you can't economically run a pipeline through the mountains of Colombia. You have demand, you have supply, but how do you balance the two?

Why build a mega-scale LNG import terminal if demand is for only 50,000 gallons/day of LNG? In this case, a small-scale plant of 100,000 gallons/day or less makes better economic sense. Our LNGo-HP system is modularised so you can truck it through the mountains to the gas field efficiently, liquefy the gas that otherwise has no value and then transport the LNG via truck to Bogota or an outlying community. All of a sudden, you've monetised an indigenous energy supply with means to transport it to the consumer.

In Indonesia, there is flaring. They're burning off gas because it has no alternative. In that case, you can go in, clean up the gas, liquefy it, load it on a barge or small LNG transport vessel and deliver it to remote islands, which can then start generating 5-10 MW of electricity.

In Latin America, Peru and Argentina are very interesting and in North America we're looking at Mexico, which is building pipelines. However, if you look at a map, there are large areas in both of these regions that will not be covered. Again, if we go in where the lines are being built, the communities beyond the end of the line can use the gas as long as it can get there. A virtual pipeline can build a customer base in advance of the physical pipeline and as the pipeline extends to communities further down the line the LNGo system can then move to other points of use because of its modular design.

Shifting to Africa, the Nigerian National Petroleum Corporation (NNPC) has started publishing reports that show large amounts of flaring amid rising domestic demand. What are Siemens and the Dresser-Rand business doing to get micro-scale LNG into that market?

I recently spent three days in Lagos sitting face to face with great engineering and energy companies. It is certainly an emerging market because of the flaring, but also because it has gas pipelines in the south of the country. The problem is that the lines do not run far enough north. Eventually they will get there, but until then, installing an LNGo system at the end of the existing pipeline, then running a virtual pipeline up north could supply communities that currently don't have access to gas.

Also, as I've mentioned, the beauty of our LNGo systems is that they are modularised, so as the pipeline builds out, you can pick them up and move them. You can put it in one location for two years, five years or 10 years and when another 200 km of pipeline is finished, you can reinstall the micro-scale plant at the new end-point of the pipeline, and do the whole thing over again.

Would moving and reinstalling a modular plant affect its operation or shorten its operational life?

No. It has an estimated 20-year life and it's designed to be relocated. You can move it 50 times or not at all. That's what excites people – they can build out their pipeline infrastructure, and as they do, start preparing the potential new markets by creating gas demand to justify the cost of expanding the pipeline.

So you see modular micro-scale liquefaction as a means of opening markets and creating new gas demand?

That's exactly right. It also allows people to get off of a "dirty" fuel and onto a clean-burning one, which is going to help all of us in the global community. If we can help eliminate flares and monetise stranded assets, that will help the environment and small countries use their own resources. That said, micro-scale will suit some

emerging markets and small-scale will suit others. There are many different options and opportunities to grow. And Siemens covers the full range of LNG from micro- to mega-scale plants.

On the cost side, the whole purpose of 'modularity' is to take out cost, time and risk associated with field installation by doing most of the work in a controlled shop environment.

According to other players in the small-scale LNG sector, the one thing that would best support the spread of the technology is LNG having a better price spread versus competing oil products. However, futures curves and forecasts suggest that crude oil prices will not rise much over the next decade. Considering that, what makes micro-scale liquefaction an attractive investment?

Three things – increasing government regulations, growing energy demand and technology.

First, what is the global community going to do to eliminate flaring? We've been looking at that for many years now in the energy industry, but when action is finally taken, micro-scale LNG is going to be the solution that comes in. When companies feel the pain of not being able to produce oil until they stop flares – which we're already seeing in the US in some cases – we can provide the solution.

Second, the oil spread is a factor on a commodity basis for small-scale plants, which mainly aim to replace diesel with a clean alternate fuel. Micro-scale technology is completely different. We can come into a remote community and provide a better life to communities and enable energy to get there.

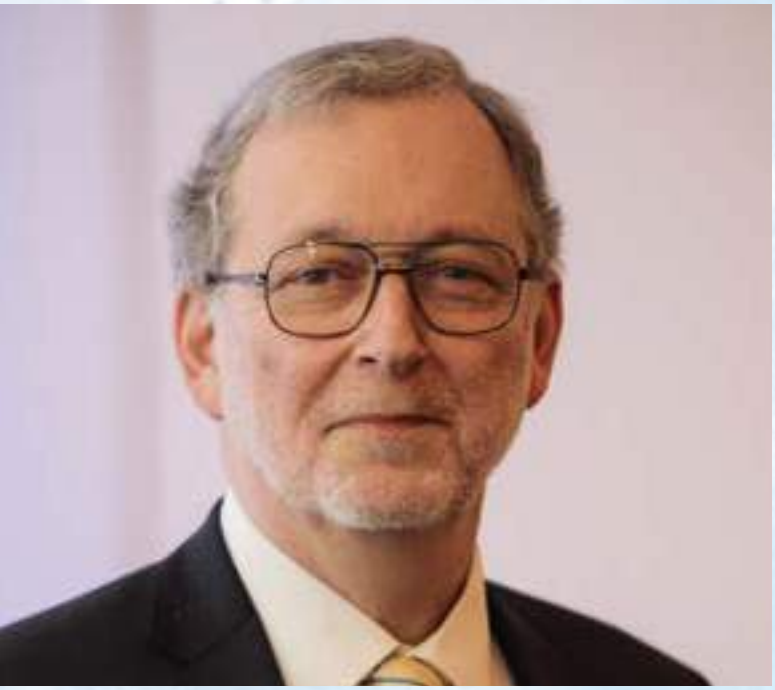
Last, our micro-scale liquefaction trains have cutting-edge technology and are connected to Siemens' digital technology that helps make systems more efficient. So even if we compete against diesel, we can offer a competitive micro-scale LNG solution because the investment is much less than a small-scale plant. We can come in at a fraction of that, which gives our customers an edge against diesel.

The micro market goes against the paradigm of other plants. There is space in the market for small-scale plants, but micro-scale is more flexible when the diesel price is down. The market has to find the technology to speed the conversion of high-horsepower vehicles to dual fuel using LNG as the gas source. Then when diesel does go up, it's a benefit to the customer. They're saving money.

We take the view that oil will stay lower for longer while in the meantime we continue to look for ways to further enhance the competitiveness of our LNGo solution. You have to look at micro LNG as a solution, not a commodity. But we're also not naive enough to think that price doesn't matter, because ultimately, it has to make sense for the customer. We have to provide the solution at a price that competes with other alternatives. That's not our main driver, but we have to do both of those things.

Michael Walhof, Sales Director of Distributed LNG, Dresser-Rand

Can gas decarbonise?



Jonathan Stern
Oxford Institute for Energy Studies

"What should be worrying the industry at the moment is that there are no really good scenarios for gas that anyone has come up with that are convincing and say "everybody builds gas, and it's a brilliant compromise solution" – even though the gas industry hopes for this outcome."

Gas is a clean, readily available and economically attractive fuel, which produces half the CO_2 emissions of coal. It has a proven track record of helping reduce atmospheric pollution, and has a key role to play in the transition to a low-carbon future by partnering with intermittent renewables. That, at least, is the way the gas industry would like the world to see things. But the message often presented by the media – and the one that policy makers mostly hear – is that gas is a major contributor to CO_2 emissions, and that its supposed carbon advantage over coal is to a large extent cancelled out by methane leakage – a far more potent greenhouse gas than CO_2. Moreover, the production of gas – whether by fracking or conventional means – is environmentally damaging, gas pricing is volatile and unpredictable, and gas is vulnerable to cut offs in supply for political reasons. Gas Matters speaks to Professor Jonathan Stern of the Oxford Institute for Energy Studies (OIES) and discusses how gas can be presented in a light that will gain the support of policy makers.

The competitive impact of renewables and coal on the European gas sector is powerful evidence that the industry has not been getting its message across, throwing into question the effectiveness of its 'gas advocacy' efforts.

The latest contribution to this debate has come from the OIES in the form of a paper by Professor Jonathan Stern, the respected gas industry researcher and commentator. Stern concludes that the industry urgently needs to up

its game, and proposes that it should align itself with a message that "gas can decarbonise".

The OIES analysis focuses on Europe – although Stern says further research will broaden the scope of this analysis – where gas has clearly lost out to other energy sources. EU gas consumption in 2015 was around 20% below its 2008 peak.

Gas has been impacted by three different factors. Firstly, the growth in renewables output; secondly, cheap coal and high gas prices; and thirdly, a reduction in overall energy consumption – particularly in the industrial sector – reflecting a persistent shift away from manufacturing industry.

It is also clear that policy has been the root cause of the fall in gas consumption, at least on the first two points, with renewables subsidised and politicians reluctant to reform the carbon pricing mechanism – the Emissions Trading System – which has been ineffective in disincentivising coal burn. Coal still provides 28% of EU power generation, compared with 23% for gas.

It is hard to judge how much the industry could have done to effectively promote the case for gas, given the strong vested interests of the coal industries – particularly in Germany and Poland – and the popularity of renewables. But it is also hard to deny that there is a great shortage of reasoned argument in the public domain that would cement opinion over the essential role of gas in reducing CO2 emissions.

In fact, the nature of public discourse has changed radically in recent years. The discussion has moved from reducing carbon emissions to the concept of decarbonisation. Complete decarbonisation of the energy sector is an extremely long-term goal, and arguably impossible to completely achieve.

Nevertheless, since natural gas is a carbon-based energy source it makes it more difficult to reconcile with the current agenda – in effect, gas risks being leap-frogged. It is in this context that the OIES paper makes the clear recommendation of the position – "gas can decarbonise" – that should be taken to bring gas back into the debate.

This may seem a paradoxical line to take, but it is based on three technological developments:

- Carbon capture and storage (CCS), which, if implemented would enable continued use of gas (and other fossil fuels) without emitting CO2.
- Power-to-gas (PtG), in which renewables-based electricity is used to produce hydrogen by electrolysis, which is then distributed using the gas network – either mixed with natural gas or alone.
- Biogas, produced from waste, and biomethane derived from biogas but upgraded to pipeline quality, and which is therefore part of the natural carbon cycle.

Each has its challenges. The lack of progress in launching industrial-scale CCS has been the subject of much comment, and it is far from clear whether the technology will improve to the level where it would be economic. Nevertheless, it is

notable that the group of companies that constitute the Oil and Gas Climate Initiative (OGCI) have hit upon CCS as one of the two key areas (the other being methane emission reductions) in which they intend to invest over the next ten years.

The other two possibilities do not promote the use of natural gas itself, but would allow a proportion of "renewable" gas to be blended with hydrocarbons and make use of existing infrastructure. PtG in particular is being piloted as a way to utilise excess renewable energy when, for example, wind power production is in excess of system needs. But totally decarbonising the gas stream would suppose baseload production of hydrogen from renewables, and this is hard to envisage.

Biomethane is already supplementing natural gas but in small volumes, and it is very hard to envisage biomethane production on a scale where it could truly substitute for natural gas. But despite these issues, the "gas can decarbonise" message is a strong one, and the OIES analysis is a clear call for the gas industry to find a way to align itself with the current policy agenda around CO2 reductions.

It could be argued that the issues addressed in Stern's paper are largely European, and that the gas situation is less serious elsewhere. Projections such as the central case in the IEA's World Energy Outlook show continuing, albeit modest, growth in global gas demand – a view echoed by BP in its recent Energy Outlook to 2035.

But there are warning signs that the future role of gas is coming under increasing pressure. BP devoted several slides in its Energy Outlook to the risks to its central case of continued gas growth. It noted in particular that it is also possible that "the growth of natural gas may be threatened if there is less government support encouraging a switch from coal to gas."

The BP view suggests that the position of gas is somewhat precarious on a global scale, and that some elements of what has happened in Europe could be played out on a wider scale. If this happens, the world would risk underplaying the ability of gas to impact CO2 emissions in a relatively short timescale – an ability that has been strikingly demonstrated in the case of the US, which has reduced emissions by around 9% compared with their peak in 2007, with coal-to-gas switching being the most important factor in achieving this.

Such concerns are a strong incentive for the gas industry to redouble its message – both to policy makers and the general public. The OIES paper should act as a spur to increased action in this area…

Gas Matters: What prompted you to write this paper at this time, and how has it been received?

Stern: The gas industry has been telling its advocacy story about gas as a transition fuel and a destination fuel for the last five to ten years. I have sat in large gas conferences and listened to the heads of very large companies give addresses about how, in their view, gas is complementary to renewables; is a

transition fuel etc. and I have seen heads nodding in the audience.

But, frankly, I couldn't help thinking "this is the industry just talking to itself – nobody outside the industry is listening to this."

So I decided to ask the question: how has the industry's gas advocacy strategy worked out? In my paper I examined the question on five dimensions: commercial, security, environment, business model and what I call fragmentation. And my conclusion is that actually it's been a pretty dismal time for gas, that really nobody outside the industry has accepted the advocacy arguments, and that things need to change fairly dramatically if gas is to have a decent future in a decarbonising world.

I realise that for a gas research programme to publish a paper saying that the future of gas in Europe doesn't look great, and that basically the industry has been putting out a message to which nobody has listened, is a pretty high-risk strategy – so I was prepared for some fairly significant pushback from the industry. To my absolute astonishment, the reaction from everyone I have met has been: "yes, that's about right".

Why do you think the gas advocacy arguments have been so ineffective? Do you think it's because they haven't been made well or because they aren't good arguments?

I think the things out there that the politicians and media listen to are fundamentally different from what the industry is saying. And the industry has not addressed issues such as the fact that, certainly between 2011 and 2014, gas was far too expensive – much more expensive than coal.

It has kept the line that renewables are too expensive when, in fact, the costs of renewables have been coming down: they're still not cheap but, especially in the case of solar and onshore wind, they are not wildly different from that of gas.

Also, the industry didn't address what I call the Putin/Russia phobia, and gas in Europe has been too closely identified with gas coming from Russia.

Another crucial point is that there really is no 'gas industry' any longer post-liberalisation: the different parts of the value chain have fundamentally different commercial interests, which can't really agree on a coherent message, and the more they think about the future the more they see they have different paths.

Oil majors are pinning their future on gas, and putting out what some consider optimistic forecasts. A recent Grantham Institute paper essentially said that upstream companies should stop basing their forecasts on 'business as usual' projections, which underestimate the evolution of the cost of renewables. Do you think these forecasts are not recognising the risks to gas?

If you look at the projections put out by fossil fuel companies, you have on the one hand ExxonMobil, which really is business as usual, but on the other BP,

which is much more thoughtful. BP has gas demand projections that are quite low in some scenarios, and show much lower consumption in two particular scenarios.

One is an extremely fast growth in renewables and the other is a reversal of climate change policies: I don't think anyone else has made this point of gas being under threat from two directions.

What should be worrying the industry at the moment is that there are no really good scenarios for gas that anyone has come up with that are convincing and say "everybody builds gas, and it's a brilliant compromise solution" – even though the gas industry hopes for this outcome.

With policy favouring renewables and cost favouring coal, isn't there another compromise, which is to build a combination of newly efficient coal and renewables? Is this an emerging threat to gas?

I think it is to a certain extent, but I don't think renewables and coal will get you to the targets. You see that in the case of Germany. People in Europe think the Germans have done wonderfully well with their renewables programme, but if you look at German CO2 emissions you see they've not been going down. And I'm fascinated by the idea of security of supply as an argument against gas.

Basically, renewables are not secure: you have to have a way to back them up when they're not generating. I am personally prepared to believe that in time there can be battery storage, but that's not going to be cheap and certainly not going to deal with seasonal storage issues.

I believe that gas has a story to tell in a number of countries – and this is where we get to the really complicated analytical problem, which is that this is not a subject that lends itself to regional generalisations. Basically everywhere is different; if you take a big country like the US or China, each region of the country is different.

Therefore, it may be that in certain countries or regions of countries there is a good gas story to tell, and in other countries there is no gas story to tell, and that makes analysis or trying to write a short paper very complicated!

And yet there are some countries in which gas has done well. If you look within Europe – you mentioned Germany – you could contrast with the UK, where gas last year made significant inroads into coal consumption.

Yes, and the reason that happened was that coal prices went up, gas prices came down and with the carbon support mechanism everybody wanted gas. But the UK has very specific properties that make it a good candidate for gas.

There aren't any other countries in Europe that have the same mix of old, inefficient coal stations and available gas plant, and where you can switch over from one to the other. What is happening in the UK is very interesting, but it doesn't help a lot in understanding what might happen outside of the UK.

Would you agree though that Europe could have reduced its carbon emissions more quickly and with a smaller financial impact on consumers if it had used more gas?

I think that's right, but I think you should say two more things – very loudly. Firstly, and it is one part of the advocacy argument that is right, is that you've got to have a higher carbon price. If you have a higher carbon price you will get switching away from coal, and the UK demonstrates this.

The second, which is much more fundamental, is that if you're in Europe and you're still using coal when you could be using gas, and you have gas-fired power stations that are not running, you are not really serious about reducing carbon emissions.

The topic of methane emissions has come up quite strongly in the last few years. This should be an easy win though for the gas industry, since there are obvious technical solutions that the industry can adopt?

It should be an easy win, but it's turned out to be a nightmare. The industry has said nothing convincing about methane emissions except that they are very low. It is crazy that the industry continues not to provide any convincing emissions data.

The only place we have methane emissions data from is the US, and this is somewhat contradictory: in some places emissions are low, in some places high. The industry has scored a massive own goal, but when I ask IOCs "where is the methane emissions data" they say, "Oh we're working on this" – but months go by and we see nothing.

In your paper you say that gas producers have to be concerned with the time limitations of sales. LNG, for example, is still based on investments backed up by 20-year contracts. Have we reached the point where this is already risky?

In Europe, yes, we have already reached that point, but not elsewhere. In Europe you only need look at what's going on in the Netherlands in terms of policy, where the plan is essentially to close the gas industry. One might say that this will not happen for a long while, and it may not happen if policy is reversed.

But if this gets followed through, the idea is that that they will disconnect residential customers and the gas grid will either be ripped out or will become defunct. Now that's an extreme example, but the fact is that in Europe this is something that is being openly spoken about – that gas will be phased out.

But there are a number of European gas advocacy organisations, such as the European Gas Advocacy Forum and Gas Naturally. Are they not doing a good job? What more should be done?

There are a number of these organisations but perhaps it's not really clear what they are doing, other than saying that gas is really good.

The industry has to stop *talking about*

things and start *doing* things. And the first action is to illustrate that the gas industry is serious about CCS, and for that you need a commercial-scale CCS project. People say it's not up to the industry to do this, that it's up to government, or that it's up to government to increase the carbon price to make CCS a commercially viable option, or that CCS will benefit coal as much (or possibly more than) gas.

Some of these opinions may be right, I'm not sure, but what I do know is that unless there are serious efforts to commercialise CCS it is going to be impossible to decarbonise gas. So the first thing is to make a decision about whether you want to make the claim that gas can decarbonise, and if you're going to make that claim, you have to back it up.

If you don't have an argument for gas with CCS, you don't have an argument for gas in a decarbonised energy market. And by the way, if it can be done, the UK is a very good place to do it. The UK has the onshore and offshore infrastructure and the storage structures that would enable decarbonisation of methane and conversion of the networks to hydrogen; very few other countries have those attributes.

So if it's going to be possible, it is going to be possible in the UK ahead of a lot of other places.

In your paper you mention two other possibilities that support the message that gas can decarbonise. One is PtG, where renewable-based electricity is used to generate hydrogen, and the other is biomethane. Neither of these would benefit the natural gas industry though, would they?

Perhaps not, but you have to consider the infrastructure. For network owners, it doesn't matter whether they are transporting natural gas or decarbonised gas – as long as somebody is paying them.

Your paper gives the impression that there will be more on this subject from the OIES in the near future, is that right?

Yes, this is going to be one of our themes this year and probably next year.
Are you in danger of being labelled as gas advocates yourselves?

That is a risk I'm prepared to take.

Society for Gas as Marine Fuel

Mark Bell
General Manager

"Gas as marine fuel is not a quick-fix, golden solution, but a step to the right direction when it comes to reducing carbon emissions. To not take that step forward simply because it is not the perfect energy solution, which is still 50 years away, would be a mistake for shipping."

The use of LNG as marine fuel has made considerable inroads in the passenger shipping segment in recent years but has yet to gain a solid foothold in the rest of the maritime industry, with only 0.2% of the world's fleet currently LNG-fuelled. However, public discourse on the merits of using LNG as bunker fuel is gaining momentum, especially since October 2016, when the International Maritime Organisation (IMO) – the shipping industry's regulator – announced it will impose a 0.5% global sulphur cap on marine emissions in 2020. LNG Business Review meets Mark Bell, general manager of the London-based Society for Gas as Marine Fuel (SGMF), to discuss what lies ahead for LNG bunkering.

At what stage is LNG bunkering as an industry?

It is starting to get going. There are more than 50,000 ships in the planet over 500 gross tons that could use gas as marine fuel, but right now we have just under 100 ships that are running on LNG. That's just 0.2% of the world fleet.

The target I can see in the foreseeable future – within five to seven years of a vessel generation change, going from an existing vessel to a new construction – is 2%, or 1,500 ships. What suppliers would like is 20% of the world fleet, but this is not going to happen in this timescale. LNG as marine fuel is not a silver bullet for the world's carbon emissions programme, but for shipping it is a giant step in the right direction.

The main hurdle LNG bunkering faces is its lack of a wide network of LNG bunkering stations. A wide distribution of LNG in marine ports does not exist now because the industry is not geared up for it. You have 50,000 ships for which you can pick up the phone and get fuel oil at the drop of a hat at most ports in the world. Can you do that with LNG? No. It is developing rapidly, but it will take time.

What role does SGMF play in this changing environment?

We were set up three years ago with the core principle of technical and operational excellence when it comes to LNG bunkering as the industry starts and gets going.

We've been set up as a membership-based NGO in the same framework as any of the other NGO. We have just over a hundred members, right across the industry: energy suppliers, shipowners, operators, shipyards, class societies, equipment manufacturers, academic institutions – the whole gamut, worldwide.

We operate in three main geographical areas. So far we have mostly focused on Europe, as there is a lot of activity there. We also are looking at North America and Asia, principally Southeast Asia, as it's home to Singapore, a major bunkering hub. Also, northeast Asia, which is the number one place to order, buy and procure ships. Of course, we also follow everything going on in the global socio-political environment that drives gas as marine fuel.

Many shipowners, in the dry bulk, tanker and container segments have been grappling with an exceptionally bearish freight environment and are finding it hard to make ends meet. Switching fuel may be the last thing on their mind.

If you're a shipowner and operator with a ship in the water and a negative freight environment, all you are thinking is where your next month's income will come from. Switching marine fuel is not even on the agenda.

However, bunker fuel will sometimes be 50-70% of the total operational costs. As we speak, oil prices are low, which means that marine fuel oil is relatively cheap – though returns from freight also are low. I believe that the oil price will go up and settle somewhere between USD 60-70/barrel at some point. Unless freight rates recover, it will make it more difficult for shipowners to cover their costs.

If I was in a shipowner's position with ships in the water but not earning money, I would be thinking carefully about what to do next – but not for too long. Typically, shipowners with an existing asset in the water will think twice about switching to LNG as bunker fuel. That's because the use of LNG itself has what I call a "gas factor" – pretty much anything you do for LNG will cost four to six times the price of what you have for a conventional fuel, largely because of the physical properties of the fuel being handled in a safe manner. It rarely makes sense to convert a vessel.

However, when it comes to the next vessel you buy, gas is being seriously considered by owners. The comparison is the car you

drive, which now may run on gasoline, or diesel, or perhaps is a hybrid. If I tell you to switch fuel, you will need to take the engine and tank out and rely on a small network of fuelling stations – you would think I were crazy. But next time you purchase a new car, you will consider a hybrid, or an electric car, or an alternative fuel vehicle. It's the same situation with ships running on gas.

Cruise liners were the first major segment to adopt LNG as bunkering fuel. Which segment comes next?

Cruise shipping is a relatively small but vital sector for gas as a marine fuel. Large, prestigious operators are procuring newbuildings running on LNG and everybody in the cruise sector looks at LNG as a chief marine fuel in the near future. When a large cruise ship docks in a city with "powered by LNG" on its side, it is a powerful, clean and green statement.

As far as suppliers are concerned, if you add up half that fleet in the next few years running on LNG, what sort of volumes are we talking about? Relatively small.

Deepsea container shipping is the next important sector. That's where you will find a lot of existing projects right now because container shipping works on a port-to-port liner basis. You can have LNG bunkering stations at most major ports they call at. If you're able to supply the right fuel at the right price at the right strategic ports – bearing in mind that container shipping is an extremely competitive market – this one little advantage that one may have over another would be very welcome indeed.

If you look at the LNG bunker fuel volumes that would be involved in container shipping – 20 times more than cruise for the established market – then suppliers start to get very interested, very quickly.

Small inroads in LNG bunkering are being made in sulphur control areas (SECAs) such as the Baltic Sea. What are your thoughts on this?

SECAs such as the Baltic will be a bit of a testing ground of how the world will look like when LNG takes off as bunker fuel.

In the North American ECA, where the US has gone from being a net importer to a net exporter of LNG, we have export terminals near port areas in the US Gulf. I believe we will see LNG bunkering develop there.

Already we are seeing LNG bunkering centres developing, or being suggested, near container ports – for example in Malta, Panama, the Dominican Republic, Gibraltar and the Canary Islands. Quite a few of them happen to be on shipping routes, in existing bunkering centres.

You mention Malta, which now imports LNG via a floating storage unit. Are we going to see LNG bunkering centres develop alongside floating LNG terminals?

We are already seeing a move in that direction. Bunkering stations are literally opening up alongside floating terminals. Dusup in Dubai already have their floating storage and regas unit (FSRU) with an

LNG bunkering station at the side of it. It is not operational yet, but it's there and I think we'll see a lot more of that happening.

Owners of FSUs and FSRUs can take the opportunity to put the bunkering station in place when they have a vessel in dry dock for repairs, ready for LNG bunkering demand, when it comes.

China could soon overtake Korea as the world's second biggest LNG buyer. Is LNG bunkering taking off there?

It is amazing how much LNG infrastructure is in place in China. Inland waterways are the most interesting sector. There are more LNG-fuelled vessels in the Yangtze River and Pearl River Delta than the rest of the world put together – but we just don't know about it. A lot of them are conversions.

Beijing is very keen on cleaning up China's air. From switching power stations to converting methods of transport. There is a lot of funding available from the government for sectors that wish to switch fuel. It is interesting that they are tackling inland waterways first and are trying that out as much as they can.

There are shipowners and operators who say LNG bunkering will not take off because the fuel takes up too much space on board.

They complain about needing a bigger tank on their vessels for burning LNG, which means less cargo. If that is your argument against LNG as marine fuel, think again. There are other ways to solve that problem. You can make the ship longer. Also, if you have a smaller fuel tank, your ship can make more calls, at ports that can bunker a vessel faster. But if you want to use that as an excuse at a time when a great percentage of containers on board your vessels are empty, it makes no sense. Already there are companies out that that are looking at new technology to resolve the issue of space.

How quickly is the shipping community moving toward a green future?

It has only just managed to get its act together in doing something about the sulphur content problem.

Punitive regulations have come along through the IMO to lower the sulphur content of marine fuel. But step out of shipping and look at other industries and sulphur content was cleared from the agenda a long time ago. It's all about carbon footprint, from emissions to carbon trading. That's the kind of thing you see discussed in the COP meetings.

Yet, in maritime, we still talk about sulphur naturally, as it is the industry near the end of the chain using what is left at the bottom of the barrel. If shipping does nothing about what it burns as fuel, while other industries such as automotive and industrial manufacturing do, then its proportion of carbon emissions relative to other industries will increase dramatically. If it does everything it possibly can to reduce its carbon footprint, it might just have a chance of keeping up.

How important are public perceptions when it comes to LNG bunkering taking off?

They are paramount. The move for a cleaner environment is what is pushing this forward. You see this in North America and Europe already.
But suppliers have been preoccupied with retaining long contracts and changing public perceptions on the use of gas.

We have witnessed strong, but naturally naive, opposition to LNG by the public. For example, one of our members had a project in Canada involving ferries. The operator spent a majority of its time appeasing the public. It took some convincing with people who were using these ferries for years daily. Now that is done, the door is open for much more widespread use.

There are myths out there about how good or bad LNG is. Gas is not a quick-fix, golden solution, but a step to the right direction when it comes to reducing carbon emissions. To not take that step forward simply because it is not the perfect energy solution, which is still 50 years away, would be a mistake for shipping.

Is there an end-all solution?

What we have at the end of the fuel evolution table is hydrogen. It has of course no carbon emission whatsoever. That's the golden goal. It's not going to happen in my lifetime for ship propulsion, but I can see it on the horizon and it's a fascinating prospect. There is a glimmer of hope when looking at fuels that have zero CO2 emissions, but we have an awfully long way to go before we get there and other problems to solve.

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