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King Abdullah Petroleum Studies and Research Center

How Will Natural Gas Adapt to the New Price Environment?

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About KAPSARC

The King Abdullah Petroleum Studies and Research Center (KAPSARC) is a non-profit global institution dedicated to independent research into energy economics, policy, technology, and the environment across all types of energy. KAPSARC's mandate is to advance the understanding of energy challenges and opportunities facing the world today and tomorrow, through unbiased, independent, and high-caliber research for the benefit of society. KAPSARC is located in Riyadh, Saudi Arabia.

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Key Points

During the period 2011-14, buyers – particularly in Europe and Asia – argued that high natural gas prices had been the main obstacle preventing the fuel from fulfilling its promise and increasing its share in the primary energy mix. Key gas price indices have dropped across the world in tandem with oil and the previous situation no longer prevails. Perhaps it is time for new perspectives for gas markets.

Demand for gas has yet to be boosted by the fall in prices over the last two years, though some regions show promise.

Gas faces competition not only from coal but, more recently, from cheap oil as well. Meanwhile, policies promote renewables and energy efficiency. Consequently, the prospects for natural gas would stand a greater chance once policymakers begin to account properly for coal's externalities.

The rapid change in gas prices will force investors to operate assets on the basis of variable costs. Some players, notably those holding U.S. liquefied natural gas (LNG) export capacity, may not be able to sustain financial difficulties for long, especially if a price war emerges in Europe.

The current reduced upstream investment climate could lead to a slower gas production recovery. If demand picks up in a few years' time, production rates could prove insufficient.

The need for flexibility and divergences between term and spot prices could favor the earlier emergence of another trading hub in Asia, although its specificities and location remain unclear.

Summary for Policymakers

In our previous workshop brief 'Natural Gas: Entering the New Dark Age?' we explored the discrepancies between forecasts of a growing longer-term role for gas in the energy mix and the current reality of a slow growing fuel, facing competition from cheap coal and policy-supported renewables. Two key factors were identified as obstacles to a bright future for natural gas: it costs more than coal and policymakers do not promote it because it is a carbon dioxide emitter.

The lower gas prices that have been observed since mid-2014 might appear to have taken care of the price issue, but market realities continue to cloud the outcome for gas as the prices of competing fuels have also fallen. Gas consumption increased in countries where prices were low enough to make gas-fired plants more competitive than coal-fired plants and where ample supply was available, such as North America. Usage also rose in countries such as the U.K. where governments implemented a carbon tax to improve the competitiveness of gas-fired plants and where environmental measures led to the decommissioning of old coal-fired plants, leaving more room for gas. It has also increased due to higher supply in developing countries. In contrast, Chinese gas demand slowed down while Japanese and Korean consumption fell due to increased competition from coal and nuclear. Finally, while prices have declined in some markets, they have increased in many regulated markets. This raises questions as to how gas demand will react if subsidies are removed and prices start to reflect the cost of supply.

With a more ambitious global warming target of 1.5°C, the implications of COP21 – the United Nations Framework Convention on Climate Change held in Paris in 2015 – are still uncertain for natural gas. The inevitable growth in demand for coal in many Asian countries conflicts with the resolutions passed at COP21. To achieve its long-term positioning, gas needs political backing to replace coal. This requires altering policymakers' perception of gas as a costly resource while domestically produced coal and renewables are seen as preferable environmentally or economically to gas, especially shale gas or imported gas.

It also requires the gas industry to deliver gas at an affordable price and to limit boom and bust cycles, which are detrimental to consumers. However, the industry will likely face a serious boom and bust cycle when 150 mtpa of LNG capacity comes on stream over 2015-20. This large oversupply, estimated to arrive when LNG demand is weakening, combined with low oil prices at about $30-40 per barrel is likely to set back the next generation of LNG projects as investors await improved oil and gas prices and try to trim costs.

Beyond making sure that sufficient gas supply remains if and when demand rebounds, lower gas prices create another challenge. Most recent LNG projects were built on the premise of rapidly growing gas demand, with their economics underpinned by high prices. Both elements of this projection are now gone. By contrast, LNG projects will now have to sell their gas on the basis of their variable costs. In particular, the U.S. tolling fee model and take-or-pay agreements mean that many off-takers may consider liquefaction fees as a sunk cost. For example, for a company that has contracted to take 1 mtpa of LNG, a $3/MMBtu liquefaction fee implies an annual sunk cost of about $150 million. The extent to which U.S. LNG off-takers could face large losses – and potentially default – will also depend on how much LNG will be uncontracted and head toward Europe beyond 2017. If large volumes of U.S. LNG target Europe, and Russia decides to fight for its market share by letting gas prices fall, this could cause real difficulties for U.S. LNG exporters.

In this context, the question of price and indexation is more relevant than ever. Asian buyers were previously pushed for a move to hub indexation in order to lower prices. By contrast, now they see this as an indispensable tool to achieve flexible supply. But they need to clearly define the type and location of the hub desired. As in Europe and North America, the financial distress of key players – either sellers or buyers – could accelerate the formation of such a hub.

Low Gas Prices Fail to Boost Global Gas Demand

Until recently, the relatively high price of natural gas compared with competing fuels was seen as the reason for slower than projected growth in demand. Oil indexation remains a substantial part of natural gas pricing in international trade and, during the past two years, natural gas prices fell sharply in most of the main markets. This was partly due to the collapse of oil prices and a looming oversupply in LNG. Yet gas demand growth has been weak, except in the U.S. Gas has struggled to compete with other fossil fuels that are going through the same down cycle and it remains largely uncompetitive in most regions. An uncomfortable combination of cheap coal and policies supporting renewables and energy efficiency is squeezing gas out of global power generation, previously its main market. The battle between coal and gas remains hard fought, now both are priced lower, and they continue to jostle for the power generation market. In emerging markets, the devaluation of local currencies has incentivized the exploitation of domestic resources, predominantly coal, over more expensive imported fuels. KAPSARC addressed this issue in a previous publication, highlighting how imported gas, specifically LNG, is inherently more expensive than coal.

The significant rebound in gas use that took place in Europe in 2015 was due more to colder weather in the early part of the year than the increasing competitiveness of gas against coal. However, the further drop in gas prices to $4.3/MMBtu in February 2016, against around $6.6/MMBtu in summer 2015, pushed spark spreads above dark spreads in the U.K., implying that gas-fired plants had become more competitive than coal-fired. This was because the U.K. government increased its carbon floor price to £18 ($26) per ton of carbon which, combined with the effect of decommissioning old coal-fired plants, created more space in the market for gas. The U.S. and the U.K. thus appear to be the only countries where low gas prices, supported by strong government policy, have gone some way to make gas-fired power competitive again. In the U.S., stringent regulation on mercury and other toxic emissions, which took effect in 2015, has forced utilities to shut old and inefficient coal plants. However, in the rest of Europe coal power plant economics still trump those using gas when adjusted for carbon and efficiency. Low prices alone may not be enough to boost demand for gas, so policy must be in place to strongly encourage utilities to switch to gas.

In Europe, consumption of coal increased due to its price (advantage) relative to gas despite policy efforts to rely on cleaner sources of energy… The limits of policy are stark when trying to compete with market fundamentals.

In Asia, demand for gas fell in Japan and Korea and demand growth slowed down considerably in China, in sharp contrast to the projected strong growth. China's natural gas consumption in 2015 increased by an estimated 8.4 bcm to about 190 bcm, the lowest incremental growth since 2006 and well below the targeted gas consumption of 230 bcm planned in the country's 12th Five Year Plan. While demand increased in Beijing due to environmental constraints, it fell in a number of regions as a result of lower industrial activity. In India, coal-fired power keeps growing due to the fuel's abundance and the extensive infrastructure that exists to deliver it to power plants. In regulated markets in the Middle East, Africa and parts of Southeast Asia, widening budget deficits have pushed some governments to raise wholesale gas prices over the period of 2014-16.

Lower oil prices meant that fuel oil has also joined the battle to compete directly with gas in power generation. Although the global share of oil as a fuel in electricity is small, in specific countries in Latin America, the Middle East and Asia the share of fuel oil in power generation can range from 15 percent to as high as 91 percent. Liquefied petroleum gas (LPG) is also presenting itself as a cheaper option for cooking, heating and transportation in developing markets, compared with natural gas. The massive increase in U.S. LPG exporting capability will exert downward pressure on global prices and make these gases attractive to end-users. Low oil prices are also indirectly competing with gas by providing low cost diesel, which is extensively used in the mining of coal, thus lowering coal supply costs as well as reducing the cost of transporting it to power plants.

What are the Long-term Global Prospects for Gas?

The arguments in favor of a larger share for gas in the energy mix seem quite straightforward. Gas is the cleanest burning fossil fuel and relatively abundant and so was projected to meet an essential share of our growing need for energy – or, at the very least, to play the role of a bridging fuel, which would lead us to a truly carbon neutral future. But, in practice, obstacles were strewn on the path for gas: namely, its competition with coal, support of policymakers for renewables and opposition from environmentalists. In addition, the costs of renewable energy technology continue to decline and their rate of deployment is increasing, making the share of gas in power generation vulnerable, especially where power demand growth has been modest to weak. Meanwhile, gas is still exploring new applications – like transport or micro CHP – but even here the competition is fierce. In the industrial sector, for example, oil use is more widespread, while coal dominates in Asia. Clearly, the market share of gas is at risk when oil and coal prices are low.

However, some regions still demonstrate potential. North America, with cheap gas resources, is certainly a bright spot for potential future gas demand. In Europe, an impending price war between U.S. LNG and Russian pipeline supplies could perhaps lead to gas demand recovery and, in the medium term at least, partly reverse the lost decade for gas in Europe. However, it is questionable whether this will be sustainable in the long term. The main impediments to an increase in gas demand in Europe are slow economic growth, energy efficiency measures and the rise of renewable energy. There could still be potential, however, for European gas demand growth in the transport sector due to existing and potential environmental policy constraints.

Asian markets could perhaps come to the rescue. China is a “wild card”: the country has the largest demand potential – over 600 bcm in the long term, given its low gas use per capita – but much is uncertain. Gas demand in China is expected to grow moderately by 2020 and to fall to between 269 and 360 bcm. To emphasize the uncertainty, the difference between the top and bottom of this range is comparable to Qatar’s LNG exports. It is increasingly difficult to forecast China’s gas demand growth because of the decoupling of economic and energy demand growth that has resulted from the ongoing structural reorientation of the economy away from manufacturing and industry. The competition between coal and gas could also deliver widely different outcomes. Gas is currently struggling to compete with coal, since the price of Pacific Basin coal has crashed due to lower Chinese (import) demand.

But environmental issues and air pollution strongly suggest a larger role for gas in China beyond 2020. Growth for gas is mainly dependent on China’s switch away from coal in the heating and power sectors and on a rise in demand in the transport sector. The government has adopted a National Action Plan for the Control of Air Pollution, a key measure of which was to implement lower city gate prices to promote gas use. This also includes policy support to limit the use of coal in key consuming regions by 2017. Industrial coal consumption amounts to about 1 billion (short) tons and there could also be significant switching potential. Demand is also expected to increase from rapid urbanization, as well as from increased availability arising from unconventional output – such as shale gas, coal bed methane and coal-to-gas – even though this, will be partially offset by a slump in conventional natural gas production. However, the two greatest risks are that China's gas demand growth continues to be limited by its greater use of coal and renewables in power generation and by lower oil prices that weaken the prospects for gas in the transport sector.

In India, coal will probably remain the fuel of choice in the longer term, although, like China, it has concerns over air quality. Gas suffers from India's lack of critical infrastructure, such as pipelines and LNG import terminals, and from coal-promotion policies. Coal, rather than gas, reaches all parts of India by means of an extensive railway network. It is also cheaper than gas. In India, gas is mainly seen as a niche fuel in power generation and the fertilizer industry, with coal the primary choice for baseload electric generation. The power sector offers significant potential, but this would require the government to recognize the positive role of gas in order to bring about a change. For example, gas could play a mid-merit role through an efficient dispatch mechanism. Meanwhile, India's policies favor renewable energy, with 100 GW of solar capacity planned by 2022.

That leaves Southeast Asia, a region that is forecast to see its gas demand increase by about two-thirds to 265 bcm by 2040, driven predominantly by industrial sector expansion. Floating storage regasification units (FSRUs) seem to be an increasingly attractive supply option for this region. Coal consumption growth is also outpacing gas because coal-fired plants are more competitive in Southeast Asia. The region has been experiencing a rise in regulated gas prices similar to those in Africa and the Middle East. These areas are expected to be the main supporters of future gas consumption growth. The long-term implications of a price rise are double-edged. In most regions, gas demand has so far been considered as having a stronger correlation to gross domestic product and population growth than to price, but this may change if gas prices increase considerably compared with the cost of living. However, while many countries face supply shortages, higher prices will likely improve the availability of supply – either domestic or imported.

India is a typical example of a market where domestic coal and renewables trump gas. A gas-fired plant was recently reconverted to coal in Mumbai on the grounds that coal from Indonesia was more environmentally sound, while gas was costly and not available.

Although natural gas faces an uphill battle for relevance in the future energy mix, the major companies remain positive when analyzing the fundamentals. Growing populations, rising economic growth, abundant gas supplies and an increasing need to tackle environmental issues – such as the tighter global warming targets of COP21 – all seem to suggest that gas demand must pick up in the coming years and decades. However, for policymakers, natural gas is only the third preferred option after renewables and demand side management. The downside of government policy that lacks a carefully thought out long-term focus is that it risks giving inaccurate signals to incumbents, which may choose to invest capital into one source of energy over another just in time for policy to change again. Pragmatic policy reflects externalities related to the respective fuel sources and allows the market to decide what is most cost effective.

Meanwhile, the natural gas industry will have to rehabilitate its public image, addressing its reputational issues and highlighting its most attractive features, if it wants the support of policymakers. It is not clear whether the North American shale gas success story – enabled by its abundance and low production costs, among other factors – can be repeated elsewhere. A final difficulty for gas lies in higher costs of liquefaction, which over the past decade have raised the cost of delivering gas from LNG suppliers to the market.

Will Greater Global Competition Mean Cheaper Sources of Gas?

Significant additional gas liquefaction capacity is scheduled to come online in the next four years, leading to more intense competition between supply sources. But will this provide the cheap gas that the market is waiting for? Global oil and gas prices are now significantly lower than the LNG industry's expectations when these projects were originally sanctioned, and existing players must adapt to this new environment or go out of business. By 2020 the global LNG picture will be significantly different from what it is now, with new and existing players operating in innovative and different ways and the destination markets for LNG frequently not as originally anticipated. As buyers' needs for flexibility increases, it is likely that the market share of spot and short-term LNG could reach 50 percent by 2020, up from 29 percent in 2014.

The LNG industry is discovering competition, not only between different LNG supply sources but also between LNG and pipeline gas and even domestic gas production.

The low oil and gas price environment, which could potentially continue beyond 2020, poses an immediate threat. When the U.S. LNG projects were built they were attractive compared to oil-linked gas prices, even based on full-cycle costs. With prices at the U.K. National Balancing Point (NBP) close to \$4.2/MMBtu and Asian spot prices at about \$4.5/MMBtu, as of March 2016, these LNG projects will have to compete on their variable costs. In the case of those in the U.S., this means only the cost of the commodity, shipping and regasification will be recovered, while the liquefaction fee will have to be partly considered as a sunk cost. While it is not unusual for companies to operate on the basis of variable costs, it is unclear how long some companies will be able to stay in business while doing so.

The next uncertainty is how LNG trade flows will evolve between now and 2020 as capacity builds up. If Asian incremental demand is lower than the additional Australian supply coming on stream, then Middle East (Qatar) LNG that previously went to Asia will be displaced toward the Atlantic Basin, where it will face U.S. and Atlantic LNG in Europe and potentially also in Latin America. Depending on the quantities at stake, there is a risk that a price war could start in Europe as Norway and Russia fight for market share. In such a battle, Norway could be the first to shut-in production if prices are too low compared to its production costs, whereas Russian gas is quite cheap and could be delivered to Europe at prices as low as \$3/MMBtu. If U.S. Henry Hub prices are significantly above \$2/MMBtu, U.S. LNG projects would have to price their gas below their variable costs and those companies with LNG capacity may just choose not to use it. This is a house of cards – and a very fragile one at that. Should one company with U.S. LNG capacity decide that it cannot afford to pay a liquefaction fee of \$3/MMBtu and consequently negotiates a lower fee, the house will collapse. In such a scenario, the position of lenders will be interesting: will they turn against LNG project sponsors or against companies with capacity? This would be a huge legal headache in the absence of any renegotiation or price review clause in those LNG contracts that are currently in the public domain.

Will Lower Prices Kill off New LNG Projects?

Looking further into the future, low oil and gas prices threaten planned LNG projects as they will probably not be high enough for them to be sanctioned. Planned projects such as onshore greenfield or new-build floating LNG (FLNG) are unlikely to proceed. Brownfield projects, as well as some FLNG from conversion such as the Cameroon FLNG, may stand a better chance. Projects based on relatively small plants also seem to be advancing more quickly. But geopolitical factors, not just the ability to finance and find the right sponsors, will be critical for projects to move ahead. There could also be cases when LNG projects are sanctioned due to the strategic involvement of key consuming countries – such as Japan, Korea or China – on grounds of securing gas supplies. Meanwhile, it may take until 2023 for global LNG markets to be balanced; but even beyond that the demand increase is projected to be no more than moderate, around 25 mtpa between 2020 and 2025. Many projects considered to be close to final investment decision (FID) are targeting this small increase in global LNG demand. One glimmer of hope for the LNG sector lies in the fact that additional LNG requirements may, in fact, prove to be higher as LNG output from existing projects decline.

A possible lack of investment in either the upstream or in gas liquefaction in the future is a real concern. The reputation of natural gas as a reliable fuel could be dealt a blow should there be insufficient supplies at the moment when demand finally picks up. In the current low oil and gas price environment, companies are slashing their investment capital. This could mean the gas industry may face challenges in meeting future demand since LNG projects typically involve long construction times.

Could the Push for Flexibility Promote the Emergence of a Hub?

Another question currently being debated is price formation, and specifically the likelihood of a trading hub being set up in Asia. While creating such a hub was previously motivated by what is known as the Asian premium, the subsequent drop in oil prices and global LNG oversupply have meant that this premium has now disappeared. Buyers are now looking for more flexible LNG supply and think that the creation of a more reliable benchmark will bring this about. For example, Japanese buyers face considerable demand uncertainty. This stems from the vague timetable for the restart of the country's nuclear plants, the liberalization of its power and gas markets, the growth in renewables, and competition from coal and energy efficiency. The same applies to many other buyers in the region, though the uncertainty factors vary.

Meanwhile other players, such as traders, are taking greater roles in LNG trading – and they are interested in the creation of liquidity and forward curves. But unlike Europe, where trading hubs have been created based on domestic production and pipeline gas, LNG plays the determining role in Asia as a supply source. The only exception is China, which has significant domestic production and pipeline imports. As in Europe, some specific conditions on the market side must be fulfilled for a hub to be created: third-party access to infrastructure, both LNG and pipeline; a functional balancing mechanism, which often requires storage – rare in Asia; competition between multiple buyers and sellers including financial institutions and non-physical market players; and, of course, the deregulation of wholesale gas prices. Shanghai, Singapore and Japan are the leading potential hub candidates, but none of them fulfill all the necessary criteria.

A key question is what kind of hub Asian players want. Would this be a natural gas hub where gas can be bought, sold and traded? Or an LNG hub? A hub can be physical, like Henry Hub in the U.S., or virtual like the U.K. NBP. It seems that a physical hub would be better adapted to the Chinese gas market, while an LNG hub could be a virtual point where an LNG spot price could be set. An LNG hub would require certain conditions to be met: most importantly, sufficiently liquid LNG trading – which obviously depends on developments in the global LNG markets. Greater liquidity can be achieved by having a range of market players, removing destination clauses in LNG contracts, standardizing contracts and permitting the possibility of reloading. Transparency on price information would be ensured by the existing price reporting agencies, for example.

As Europe and the U.S. have already provided two different roadmaps for the creation of a liquid and transparent trading hub, it could take considerably less than 10-15 years for Asia to create one. The importance of the role of the government in promoting and accelerating the creation of hubs and growth of liquidity is a subject for debate. The fact that a government wants liberalization is a necessary, but not sufficient, condition. While regulators cannot impose hubs, they have in the past played an important role by indexing end-users' tariffs to spot prices and triggering a renegotiation of long-term contracts, since price re-openers – mostly found in European contracts – are linked to the end-user market.

However, the key factors in the creation of any new hub will be the role and support of the gas industry. In the case of LNG, it is difficult to see how this could be achieved without support from the sellers.

Unlike the Federal Energy Regulatory Commission (FERC) in the U.S., or the European Commission, there is no global regulator for LNG that could take the measures necessary to increase liquidity. This tends to be boosted by the disconnection between term and spot gas prices – as was seen in the U.S. in the 1980s and in Europe in 2009-10. Sellers may become interested in setting up a hub given a scenario with lower oil prices and higher spot gas prices, which would encourage them to sell spot. But this situation appears implausible in current market conditions. Buyers would push for a switch to spot prices if term prices were to become significantly higher than spot – for example, if oil prices recover while an LNG oversupply persists. The existing risk-sharing mechanism represents a further hurdle, since buyers usually take the quantity risk through volume commitments and destination clauses while sellers take the price risk. However, the creation of a hub would shift that risk back to the sellers.

Another consideration is that a hub could exist away from the market as a free on board (f.o.b.) hub close to supply. That is to say, it would be an LNG index, based on supply out of an open market location such as the Gulf of Mexico. There are potentially many f.o.b. cargoes from the large new U.S. LNG exports set to commence in 2016 and expand rapidly to 2020 that could create liquidity at that point. Volumes would represent around 50 mtpa of supply, on an annual basis, contracted by a variety of market players and shippers. The coal industry developed a similar index with the globalCOAL NEWC Index, the benchmark price for seaborne thermal coal in the Asia-Pacific region. Experience with the Brent crude benchmark shows that such a hub/index could reach sufficient liquidity within 18 months because it is created at the source of supply.

Developing an LNG hub could have positive aspects for the industry. It would increase price transparency, reflecting supply and demand fundamentals, but also provide an indication of the expected future value of LNG through the forward curve and represent a step toward industry commoditization. However, developing a hub will not mean lower prices if the LNG price derives from the marginal supply.

Though these changes could eventually lead to the eradication of existing long-term contracts in the LNG industry, it seems too far-fetched to believe that new projects could move ahead in the short term without the support of long-term contracts, as lenders will still need some sort of commitment. However, it is plausible that the rise of flexibility will reduce the number of long-term contracts. In addition, low gas prices will put pressure on margins, which will trigger the need to optimize shipping and potentially break up the contracts through the shipping element in the value chain.

Conclusion

Low gas prices have not improved the outlook for natural gas in any obvious way. On their own, they appear to be insufficient to boost consumption. Policy measures such as carbon pricing and forced decommissioning of old coal-fired plants will need to be put in place in order to strongly encourage utilities to make that switch. As the prices of competing commodities – oil and coal – have also declined, these fuels remain competitive with gas in both the industrial and the power generation sectors. Lower oil prices have also made the case for switching from oil to gas in the transport sector less appealing from an economic perspective, even though the environmental reasons remain. Finally, regulated gas prices are increasing in developing markets. These imperceptible moves, less widely reported than the daily variation in oil prices, are nevertheless changing the outlook for gas. The long-term implications of such price variations are still difficult to capture at this stage, as these markets have always been considered price inelastic.

Natural gas has an intrinsic public image issue, as it is a fossil fuel. However, it seems odd that a mix of coal and renewables is in some countries perceived as environmentally acceptable, while outside North America shale gas is regarded as largely unacceptable. In developing countries, part of the reason for a lower acceptance of gas lies in its higher cost compared with domestic coal. Costs have increased tremendously in some parts of the value chain, such as gas liquefaction, over the past 10 years. The gas industry has to deal with the reputational issues it currently suffers from and to take action to avoid creating a boom-and-bust cycle that would mean gas supply could be absent or insufficient when gas demand eventually rebounds.

Low oil and gas prices have created a competitive environment that is markedly different from expected, especially for LNG supplies arriving to the market. If Asian demand fails to absorb enough of the incremental LNG supplies, these volumes will go instead to Europe as a market of last resort. Until now, Russia has been accommodating the swings of European supply and demand, but recent declarations indicate that, this time, Russia is ready to fight for its market share. It remains to be seen whether this move could trigger defaults among some players that have contracted U.S. LNG, unless China's appetite for LNG proves substantial enough to rescue American LNG.

About the Workshop

KAPSARC convened a workshop in February 2016 with some 30 international experts to discuss the impact of lower oil and gas prices on global gas markets. The workshop was held under the rule of summarizing the discussion on a non-attribution basis. Participants comprised:

Samer AlAshgar – President, KAPSARC

Marie-Claire Aoun – Director of the Center for Energy, Institut Français des Relations Internationales (IFRI)

Marco Arcelli – Head of Upstream Gas, Enel

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Luca Franza – Researcher, Clingendael International Energy Programme (CIEP)

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Steve Griffith – Vice President for Research, Masdar Institute of Science and Technology

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About the Team

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Anne-Sophie Corbeau is a research fellow specializing in global gas markets. Before joining KAPSARC, she worked for the International Energy Agency and IHS CERA.

Rami Shabaneh

Rami Shabaneh is a research associate focusing on natural gas market fundamentals. He holds a master's degree in sustainable energy development from the University of Calgary.

Sammy Six

Sammy Six is a research associate studying oil and gas markets. He holds a master's degree in international relations from Ghent University, Belgium.

About the Project

KAPSARC is analyzing the shifting dynamics of the global gas markets. Global gas markets have turned upside down during the past five years: North America has emerged as a large potential future LNG exporter while gas demand growth has been slowing down as natural gas gets squeezed between coal and renewables. While the coming years will witness the fastest LNG export capacity expansion ever seen, many questions are raised on the next generation of LNG supply, the impact of low oil and gas prices on supply and demand patterns and how pricing and contractual structure may be affected by both the arrival of US LNG on global gas markets and the desire of Asian buyers for cheaper gas.

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