Natural Gas Going Global? Potential and Pitfalls

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A Brave New Gas World

These are interesting times for international gas markets. Fueled by soaring unconventional gas production in North America, depressed demand in economically struggling consumer regions such as Europe, policies aimed at decarbonizing or denuclearizing the global energy mix, and strategic decisions taken by key gas producers, a perfect storm was created – an enormous liquidity in gas volumes available across the world. As a result, after decades of long term contracts (LTCs) firmly tying producers and consumers into bilateral relationships, markets have started to move toward new models. Gas-to-gas competition is in the making, and spot market trade has become a significant part of global gas arrangements, challenging oil indexation, the mechanism that traditionally pegged the price of gas to the price of oil. In short, we are starting to see the first serious signs of global gas prices based on actual gas fundamentals. As a corollary, the logic for international gas price parity has been set in motion across diverse geographic locations. What happens in one part of the world – be it the Arab Spring, nuclear catastrophes, new resource finds or intractable economic woes – has an influence on gas fundamentals, pricing, and outlook far beyond the immediate geographic region. In a nutshell, natural gas is about to “go global.” By some accounts, this comes close to a revolution and has the potential to fundamentally alter the geopolitics and geo-economics of natural gas (Butler 2011; Yergin and Inieson 2009).

Natural gas is widely considered the fuel of choice for the decades to come. As the IEA stresses, gas demand has grown at twice the pace of oil over the past decade, with further consumption growth of 50% expected over the next 20 years. If one was to believe the IEA’s analysts, the “golden age of gas” has just started (IEA 2011a). This is for various reasons. One, natural gas is a comparatively clean fossil fuel, whose carbon impact is some 50% lower than coal, the competitor fuel in the electricity and heating sector (Worldwatch and Deutsche Bank Climate Change Advisors 2011). Two, natural gas is abundant, with soaring unconventional gas production having recently boosted global reserves-to-production ratios to 200 years or more (EIA 2011; IEA 2011a; MIT...
The outlook therefore sounds promising: switching from coal to natural gas may simultaneously help decarbonize the global energy mix, serve as a bridge fuel to new and clean energy technologies, and provide for energy security, a key policy concern. Yet, while observers were quick to proclaim an all-too-bright future for global gas, we are not there yet. As anywhere else, transitions are bumpy processes, so also in natural gas markets. They are bound with uncertainty; they create winners and losers; and it may in fact take longer than expected to find a new and stable institutional equilibrium. In light of this, the current transition to new market structures will likely not be a quick or easy process for anyone concerned – neither producer states yearning for the “demand securities” of old, nor for consumers who will have to bear the heavy burden of high gas prices in some parts of the world, compared to cheap prices in others.

Furthermore, natural gas is not just another fuel. It is and has always been a strategic commodity, and its international trade is subject to state intervention. Whether gas is indeed going global is therefore not only a question of market fundamentals and technological progress, but equally depends on whether governments will eventually allow it to happen. If the world were to function according to the “iron law of economics,” gas trade should reflect price arbitrage opportunities. Liquefied natural gas (LNG) should therefore start linking regional markets in Europe, Asia, and the US. Physical assets should simply go from low price markets (in this case, the US at some $2.5/MMbtu) to high yield plays (Asian spot at some $20/MMbtu) (*Financial Times* 2012). Over time the $1bn a day arbitrage spread gets whittled down, with Europe occupying the middle (geographic and price) ground. Gas on gas competition would eventually morph the Atlantic and Pacific Basins into a single gas “Pangaea.” This would certainly mark a dramatic shift for a commodity previously deemed to hold insufficient “calorific clout” to make it worth sending halfway round the world and back (Stevens 2010). Yet the key question is what happens if gas fundamentals start to tighten and global liquidity literally dries up? Here, economic theory could easily crash on the harsh rocks of political preferences to keep gas as a regional, if not national affair based on oil fundamentals, rather than pushing toward efficient global allocation of the “blue stuff.” Russia, the biggest gas producer in the world, clearly aims at keeping prices tied to old formulas. In the US, a key future export market for LNG, a tortuous political debate has emerged as to how much gas it intends to put onto global markets, despite sitting on a vast oversupply of cheap domestic gas – coined the “American gas must stay here” debate by an author in this book (see Chapter 1). Political preferences may therefore severely impact on market developments.

This chapter discusses the political and economic drivers behind the current transition in international gas markets, and sketches the various contingencies characterizing this process. It starts by looking at the “climatic conditions” that have made global gas convergence a serious debate. What factors contributed to triggering a transition from old market structures to new – even if yet largely undefined – ones? As we will argue, reduced OECD demand and meteoric unconventional gains in the US has freed up vast tonnages of LNG tankers from the Middle East that should have hit US ports to find their way to European hubs instead. As a consequence, European utilities contracted to expensive Russian pipeline gas have been bleeding customers and cash ever since, constantly being undercut by new market entrants using spot purchases to good effect over term. As a result, Europe – more specifically European wholesale hub prices and Russo-German border prices – started to emerge as the main battleground for new pricing models, with as yet no conclusive winner, given the conflicting “fundamentals” in play. But the war over pricing models is not just being waged in Europe, it increasingly divides Asia as well.
We therefore turn to look at Asia, and particularly the China nexus. A key Asian growth market for natural gas (imports), China will have a crucial role to play in determining future pricing models. Here, the question emerges whether producers can continue to sell gas at oil indexed prices to China, or whether they have to shift toward gas prices based on gas fundamentals. As we argue, it is the “vital supply side relationship” between Russia and Qatar that will affect how these two worlds eventually play out.

To be sure, all upstream players will keep pushing for security of demand (and term prices) to sink significant capital investment into new upstream developments. Most producers still want long-term contracts to get fields developed, infrastructure built, pipes welded, and even LNG tankers filled to make sure someone covers the costs. This historical legacy is not going to lose contemporary resonance overnight – particularly as 90% of gas is still traded on a regional, pipeline basis. Hence the real question is not whether long-term bilateral supply contracts will be struck, but what is used as the pricing reference point within them: spot market prices based on supply and demand fundamentals or oil indexation. With this in mind, we next take a specific look at the options gas producers play in shaping the new international market landscape. Obviously, producer countries are not a coherent block. The mere prospect of additional North American LNG supplies hitting the market has the potential to create major pricing problems for other producer states trying to stick to incumbent formulas – not only Russia and Qatar but also Australia. Since US developments tend to retain links to Henry Hub, the main American trading spot, traditional oil indexation pricing methods could be additionally challenged. We therefore move on to discuss a much neglected aspect in this regard: political risk in developed markets. As we argue, the “US energy independence” narrative traditionally enjoys strong traction in America and may constitute a serious threat to large-scale LNG exports in the future. In Europe, regulatory (in addition to geological) risks are coupled with strong environmental concerns against domestic shale gas extraction. In addition, vested interests may play in favor of importing Russian gas rather than developing unconventional European reserves.

Turning to the future, we address a critical question during any transition and ponder: who would ultimately profit most from a globalized gas market? In the short run, we argue, gas on gas pricing should benefit consumers, driving competition and efficiency gains, not to mention far greater energy security by fostering diversification of supplies. But the long-term conclusion might actually tilt toward greater supply side collusion – a potential gas cartel in which producers coordinate prices and volumes. As we argue, a single price point could well lend itself to a core set of swing producers. That would certainly be an ironic twist in a fascinating gas convergence tale – out of a supposed existential crisis could come the biggest opportunity gas producers ever had. We conclude by drawing some implications for global energy policy.

**Perfect Storm: European Eye**

We first need to appreciate how the gas world has undergone a fundamental transformation in the past few years from a seller’s market to a buyer’s bonanza. As recently as 2008, producers found themselves in a comfortable market environment. Pricing preferences were under little pressure, oil prices were soaring, pipeline projects were signed off based on traditional models linking producers to consumers in regional markets, and those playing the emerging global LNG game were getting even better returns. Burgeoning demand and supply had producers dictating prices and politics to consumer states – all of whom were desperate to secure their gas supplies.
Two major trends significantly altered this environment by 2010. The first was that
global gas demand took a battering from the economic crisis that is still yet to fully
recover. Demand was cut by 3% in 2009, with the EU seeing a 7% slide in 2010/11 that
has since plummeted to 9.9% into 2011/12 (BP 2012). Furthermore, a swathe of new gas
was all coming onstream at exactly the wrong time for producers – be it pipeline gas, LNG
from Qatar or elsewhere, or more critically the breakthrough in unconventional gas pro-
duction in North America. In fact, the scale and impact of shale developments has been
widely underestimated. As with most “revolutions” this was not achieved by accident,
but by years of development spanning back to the 1970s, with fracking technologies tying
into deep and liquid US markets and lots of capital (ironically from high oil prices). The
result was the development of massive Marcellus, Haynesville, Barnett, and Utica plays
(unconventional gas “fields”), helping the US to catapult its production to 651 billion
cubic meters (bcm) in 2011 (EIA 2012). That makes the US the largest single gas pro-
ducer in the world, accounting for 20% of global share, while shale gas now makes up a
third of all US consumption. Shale developments and technological advances have been so
successful that they have driven gas prices to under $2/MMBtu (the standard unit of mea-
surement) in Henry Hub (the main US gas trading point) as the quintessential example of
gas on gas competition. What is more, the EIA’s latest estimate is that US unconventional
recoverable reserves now stand at some 13,65 trillion cubic meters (EIA 2012).

What happened in the domestic American market has had a profound global impact.
Most importantly, it has thrown existing international pricing regimes into turmoil.
Not only was global demand down, exporters also lost their “LNG banker of choice,”
the United States of America. Since the turn of the millennium, the US had been busy
building regasification terminals in anticipation of a tightening domestic market. But
with the shale boom, the US market closed down to LNG imports. This tilted the market
in favor of the consumers. To the surprise of unprepared producers, pesky consumers
started negotiating down long-term Gas Purchase Agreements toward lower spot prices
in flooded markets. All of a sudden, Russia, Central Asia, Africa, MENA (Middle East
and North Africa), and Australian suppliers all found themselves fiercely competing for
market share wherever they could. Expensive ($200m) tankers carrying “\(-162°C\) cargo”
literally had to find a new port in a pricing storm. And European hubs were the harbors
of choice.

As a consequence, a “hybrid” model has emerged in Europe, with oil indexed pipeline
gas averaging around $12–14/MMBtu against spot traded prices at $8–10/MMBtu
(Bloomberg 2012; see also Stern and Rogers 2011). In practical terms, that largely means
the UK National Balancing Point (NBP), as the most mature and liquid market, sets Euro-
pean wholesale benchmarks via its interconnection to the mainland (TTF, Zeebrugge).
LNG imports to the UK amounted to 22 bcm in 2011, 85% of which was unsurprisingly
sourced from Qatar, the largest single LNG producer in the world, responsible for 30%
of global supply. Smaller European markets increased spot deliveries as well (ironically
often for re-export purposes), which added to a raft of other suppliers ensured that close
to 50% of all physically traded gas in Europe was done so on a spot market basis in 2011
(Energy Intelligence 2011). For incumbent European utilities, these developments meant
trouble. They had hard times pushing into the market even the minimum quantities they
were obliged to buy according to their off-take agreements, given an uncompetitive price
determined by a relatively inflexible formula. They also found it hard to roll-over con-
tacted volumes as economic recovery in Europe was highly uncertain. It was particularly
the inability of incumbents to pass through costs to re-claw the weighted average cost
of gas from consumers – rather than the price per se – that has rendered the situation
rather dramatic for them. Soon, Germany’s E.ON Ruhrgas, Italy’s Eni or France’s GDF Suez saw their decade-old business model being fundamentally put in question, endangering margins and profits. In short, incumbent European utilities felt being left out of the money.

This, however, should not have come as a surprise to them. In fact, incumbent utilities failed to prepare for competition coming with market liberalization measures pushed through by Brussels. Several “energy packages” put together by the European Commission over the course of a good decade had opened the door for second tier players to take market share from incumbents, bypassing traditional wholesalers and going straight to large end users from spot (Talus 2012). Incumbents instead remained unable to retain market share by offering discounted supplies. As a consequence, and unsurprisingly, E.ON and its like started pushing for more flexibility in their LTCs with producers around 2010, triggering a wave of pricing disputes and arbitration cases (RBC 2010; Reuters 2010). Some eventually managed to renegotiate their contracts. E.ON now sources from Russia’s Gazprom by indexing a minority share of contracted volumes to a new formula (RBC 2012; see also Konoplyanik 2011). Likewise, Norway’s Statoil now sells up to 30% of its gas contracted to European utilities at spot prices (RIA Novosti 2010) and even signed supply contracts with Centrica directly linked to NBP prices. More cases are still pending across Europe, with virtually all major European utilities desperate to carve out a larger spot component.

As much as European utilities seek to add more flexibility to existing contracts, many gas producers aim at keeping the status quo at present. Particularly with regard to Russia’s Gazprom, it appears highly unlikely that some more flexible middle ground can be found on oil-indexed and independent spot benchmarks. For one, Gazprom has a vital interest in retaining its position as the main and often exclusive supplier of the European market, given the crucial margins the company makes through its European exports. By some estimates, and in addition to exports depressed by more than 10% in 2009 (Moscow Times 2010), Gazprom has already lost an estimated $2 billion in 2010 alone thanks to discounts granted to European utilities (RIA Novosti 2010). Second, as the major Eurasian resource holder, Russia seems to think it can sit through the current soft market environment, make minor tactical concessions, wait for fundamentals to tighten again, and eventually return to business as usual. Meanwhile, policy decisions such as Germany’s nuclear phase-out have certainly helped to give Russian pipeline projects such as the 55 bcm Nord Stream more hope, as have slower LNG developments in Qatar. But Russia also has indicated it has no problem playing rough to safeguard its perceived interests. Upstream asset sweating has been one argument on the Shtokman and Sakhalin developments; bypassing incumbent wholesalers and selling directly to traders, second tier players, and more end users is another. The idea of pegging gas to expensive European renewables has also been floated, more to “prove the point” that playing around with pricing formulas can “cut both ways” (UPI 2012). Gazprom also raised the structural reality that without Russian gas as the backbone to European supply, no spot market would ever be able to exist (Komlev 2012). Alexei Miller, Gazprom’s CEO, pondered over opportunities to look for attractive markets elsewhere. He allegedly quipped that he would get out of bed and decide which way to send his gas that day depending on price: to Europe or Asia. The logic behind this plain-spoken threat and Russia’s “Eastern Strategy” is very clearly to maintain the status quo – long-term contracts, oil price peg, and bilateralized business relationships.

In all, since 2010 Europe finds itself in the eye of a perfect storm in natural gas markets, with producers and consumers pulling toward opposite ends. Yet the question who will
win the ongoing price war will be not be answered in Europe. For this, we need to turn to China.

A (Very) Complex Pacific Game

The market that really matters in Asia is China. The Middle Kingdom already consumes 155 bcm/y of gas, a figure that many analysts think could easily double by 2030 given 15% year on year growth since 2000. LNG growth shot up 31% as soon as China’s fifth import terminal went online, with a dozen more terminals being planned. To put this into perspective, a 1% increase in Chinese gas consumption equates to around 25 bcm of gas, one quarter of Germany’s annual consumption, the largest European market (Economist 2012). China is the growth market that no producer can afford to miss. Past practice would almost certainly have seen Beijing put security of supply ahead of price and sign up for whatever it could get. But this dynamic is changing, precisely because China has opened up sufficient scope from strategic investments over the years to start hedging price risk far more effectively. Throughout the 2000s Beijing signed numerous governmental memoranda of understandings with major reserve holders for prospective supplies, while sourcing actual resources from Central Asia. Turkmenistan has been critical to this, with 30 bcm of Turkmen gas expected to flow into the Chinese mainland by 2015. Additional agreements toward 65 bcm are in place, with Uzbekistan and Kazakhstan added to China’s Caspian ranks (Downstream Today 2012). China has on its doorstep Australia, that could well become the largest LNG producer in the world by 2018 (80 mt/y) (Forster 2012). Burma also holds considerable resource potential, as do MENA states still actively seeking supply agreements with Beijing. Significant East Africa LNG plays currently developed in Tanzania, Mozambique, and Kenya will eventually plug into the Pacific Basin as well. On top, China’s own domestic unconventional potential could be enormous. Beijing extracted 10 bcm of coal bed methane in 2011 and has set ambitious shale gas targets for a 100 bcm expansion by 2020 (IEA 2011a, b). Whether they are reached is debatable, but China has brought Chevron and Shell in to provide technological edge, not to mention financing their own national champions to acquire shale assets (mainly in the US) to learn their “unconventional trade” and bring it back to the Chinese mainland. The upshot is hardly surprising; China is playing increasingly hard to get with core suppliers on oil-indexed pricing – both in liquid and pipeline form. On the important Chinese market the two worlds are increasingly blurring into one under a single rule: Beijing is not going to pay oil-indexed rates for either of them.

Let us take pipelines first. Russia initially signed a framework agreement to supply China with up to 70 bcm/y of gas in 2009 (China Daily 2009). Where the deal has since fallen down is Moscow’s insistence that gas is sold at oil-indexed rates at $350–400 per thousand cubic meters (roughly the European price), compared to China’s preference of $200–250 – more or less the domestic coal benchmarks. China can also handily point to independent (and in fact much lower) gas benchmarks in Europe as credible price points for “Sino-Soviet” deals. As a response to its failure to secure an oil-indexed LTC with Beijing, Moscow has voiced an inclination to develop gas to liquids in its eastern fields and sell LNG into jurisdictions such as Vietnam and Thailand, beyond Chinese markets. This however does not seem a viable strategy. In fact, Russia seemingly fell for its own press that it could sell expensive Siberian pipeline gas into China, which in turn would be used as leverage over other Asia-Pacific consumers for fringe LNG, and more importantly over its core European demand base. Russia currently does not have serious
LNG capacity. In addition, China has alternatives to Russian piped gas imports. In this, Moscow’s “Eastern Strategy” looks very much like an empty threat.

That brings us directly back to LNG, and more specifically to Qatar as the main primer of European liquidity. Tiny in size but a big player in natural gas, the Middle Eastern state is playing a very strategic game that is not just about maximizing receipts, but enhancing its long-term global potential. Qatar’s medium-term strategy is to keep feeding European spot markets as a transitional step toward an Asian future. It therefore stays in the European market despite netbacks on Qatari spot into Asian ports hovering about $14/MMBtu, twice the figure achieved on UK and Northwest Europe deliveries. Many industry insiders think Qatar would even need to see Asian spot prices hit $25/MMBtu before it comprehensively exited European markets. For Qatar, the step into Asian markets is both promising and risky. Qatar is trying to place up to 50 million tonnes of LNG into Asian markets over the next few years, ramping up the 34 million tonnes it already ships out east (under half its total 77 mt production), mainly to India, South Korea, Taiwan, and Japan, all relatively “easy” recipients. But for Qatar the real prize lies elsewhere: China. It is yet to reach conclusive agreements over contract duration and pricing formulas for full oil parity, providing a measly 2.1 mt/y to China. In total, Qatar has only sold around 2 mt/y at significant discounts into Asia, making clear that its vast riches (both in geological and paper form) do not need to instantly rake in the RMB to stay afloat. As long as it keeps feeding European markets, the underlying hedge is that China will have to pay a decent price on decent terms for Qatar to turn most of its tankers east. Yet this entails a very delicate balancing act for Qatar to get right, and it is one that ultimately points toward discounts on long-term gas agreements with Beijing. As much as Qatar wants a good price for its gas, it still needs to head off a full-scale Pacific Basin pricing war, with over 50 mt/y expected to come online in the region in the next few years (in effect, not that far off a new Qatar coming online). Leave things too late, and it risks losing out on the Beijing market altogether as others may serve it earlier and at lower prices. Beijing has a raft of supply options to draw on in the next five years, and would presumably not also take too much Qatari gas at premium prices. Rather, and closing the circle to Russia again, Beijing might try and keep Qatar involved in the European market. Allowing European spot prices to burgeon on the back of Qatari gas is in fact coming in remarkably handy for China, specifically because it knows in the longer term it will have to start sourcing large amounts of Russian gas. From a strategic point of view, China would much rather forego relatively small quantities of Qatari supplies to maintain spot prices on European hubs now, in order to drive a harder bargain for procuring larger quantities of Russian gas in future. It is telling that China refuses to touch Russian West Siberian supplies, precisely because it is worried Moscow could simultaneously supply Beijing and Brussels with the same fields. For Russia this means that if it wants entry to the Chinese markets, it has to develop fresh East Siberian fields – another blow to its Eastern Strategy.

Obviously, the Pacific part of the globalizing gas story is a complex one. What makes the Russia-Qatar-China nexus so important is the possible effect on future pricing models. Assuming Beijing forced Russia’s hand to agree to spot dynamics in their pricing, China will then place further downward pressure on future Central Asian supplies as a “domino” effect. It has already revised price offers downward to Turkmenistan (to around $200 per thousand cubic meters) in return for infrastructure loans (Energy Intelligence 2011). Such pressures would also be used against Australia for long-term Chinese contracts by using Qatar as a potential hedge to check Australian LNG price ambitions. Without us getting bogged down in any more price points, the bottom line is that Qatar
provides China far more arbitrage options with Central Asian, Russian, Australasian, and MENA producers by keeping them in the spot game rather than bringing them under Beijing’s wing. If there is a race to the bottom on price, soaking up European liquidity is a no brainer for China, at least at this stage.

Producer Competition over Markets and Models

In a nutshell, the Qatari-Russian intrigue rests on the same debate: can producers continue to sell gas at oil-indexed prices, or do they have to shift toward gas prices based on gas fundamentals? Clearly, a trend has already been set in motion. Of the 330 bcm of LNG gas shipped globally, 25% of it is now done on a genuinely spot basis. With another 250 mt/y of LNG potentially coming to market over the next decade from every point on the compass – Nigeria, Angola, Israel, PNG, Mozambique, Equatorial Guinea or other – LNG growth should continue to erode old market rules and structures. What will become a decisive factor, however, is how one key market will develop: North America. In fact, after having reached self-sufficiency by now, North America promises to emerge as one of the largest export markets of all (EIA 2012: 3). In Canada, Shell, PetroChina, Kogas, and Mitsubishi are lining up 12 mt/y exports from British Columbia for Asian markets. That follows export licenses already agreed for BG Group, and Apache through Kitimat LNG, as well as the Alaskan North Slope plumping for LNG to monetize its 706 million tonnes of recoverable reserves (EIA 2012). And since it can hardly place LNG into its neighboring US market, Canada is likely to aim at selling 30 mt/y of stranded gas to Asia to 2020. Likewise, US producers have started to look for export markets in Asia. Because of the phenomenal breakthroughs of its shale developments, the US now ironically risks becoming a victim of its own success in terms of Henry Hub prices dropping so low that full-cycle economics for US shale gas plays have become negative. Unless prices organically firm, or US producers artificially restrain supply, current output levels will be difficult to maintain or enhance for US consumers alone. Companies will fold, fields will be mothballed, with the woes of Chesapeake, arguably the front runner in unconventional gas, providing the best case study example. The quick fix option to get Henry Hub back at a sustainable $4–7/MMbtu level (and by far the most lucrative for some of the mid-cap players involved), is to sign up international LNG contracts and seek export markets. That is exactly what is being done, with some of the larger international oil companies such as Royal Dutch Shell and Exxon Mobil also aggressively pushing for LNG exports to capitalize on the huge spreads. In total, the US Federal Energy Regulatory Commission (exercising oversight over natural gas pricing and LNG terminals) has around 125 bcm/y of LNG applications currently awaiting approval; some 40–50 bcm exports should therefore be feasible by 2020. That would make the US the third largest LNG player in the world.

As a matter of fact, US LNG could be the straw that breaks oil indexation’s back. The mere prospect of North American LNG hitting the market is creating major pricing problems for producer states trying to stick to old formulas in Asia – and not just Russia and Qatar. Australia is facing serious cost inflation with coal bed plays (a form of unconventional gas) looking more costly than originally thought. International players are still investing down under (ironically as a double hedge against the risk of US LNG flopping), but given that Australian LNG docks into Asian ports for around $17–18/MMbtu any softening of prices could leave current (and prospective) LNG projects in the red. That might sound problematic for future supply prospects, but it is also extremely interesting when we consider how recent US supply agreements to Asia are being brokered:
Henry Hub is the underlying price point. Cheniere Energy’s export terminal at Sabine Pass, Louisiana, will sell LNG into South Korea at $9–10/MMBtu (Economist 2012). The “general” formula is to set a minimal $3/MMBtu (i.e., Henry Hub) capacity leasing charge as default payment if gas is not lifted, with a 115% mark-up to bridge differentials on actual deliveries over a 20-year period (3.5 mt/y). Indian outfit GAIL brokered a very similar deal, while European off-takers from Sabine Pass, most notably BG Group (5.5 mt/y) and Gas Natural Fenosa (3.5 mt/y), have pegged leasing charges even lower at $2.25–2.5/MMBtu. Other planned projects such as Excelerate Energy’s floating LNG plants off the Texas coast or ConocoPhilip’s 10 mt/y Freeport, Texas LNG project may work on similar pricing models.

Even if planned US LNG export terminals such as Cove Point (Maryland), Lake Charles (Louisiana) or Jordan Cove (Oregon) retain only notional links to underlying Henry Hub prices (plus mark-ups), then traditional oil-indexation pricing methods could be in deep trouble. Put simply, the fact that Cheniere Energy has inked Henry Hub deals with Japan’s Mitsui and Mitsubishi provides a very explicit price link between the cheapest market on earth and the most expensive. Given the enormous margins to play with between the US and Asia, shipping costs (with or without Panama Canal tariffs) all of a sudden become more of a “rounding error” rather than a core cost. US players will have no problem taking market share, providing far cheaper gas and more flexible contracts, a development that should create more space for excess LNG supplies to be placed onto wholesale hubs internationally. At the very least, long-term contracts will be far more dynamic in terms of pricing, while forcing the likes of Qatar, Russia, Australia, and even Canada to be more flexible on contractual terms if they want to secure Asian markets. It is still very early doors to call structural decoupling from indexation toward some future “Shanghai spot” driving competition between LNG, pipeline gas, and domestic production – the Shanghai Petroleum Exchange has launched a gas spot trading platform only very recently and is not a liquid trading spot as of now. But the fact that Singapore is eagerly expanding its LNG capacity in order to maintain its leading energy hub role in Asia gives a fair indication of where important market players may expect things to go.

Europe should be watching this space very closely as well, as European hub prices typically sit mid-way between the US and Asia. With new LNG plays predominantly eyeing high yield Asian markets to 2020, fierce price competition in the Pacific Basin might ironically leave Russia with a relatively free European hand until LNG tankers find their way back to European ports. The key question is: how quickly will Brussels see price convergence between Europe and Asia to make sure they don’t get dragged back down Russian indexation preferences? Until recently the answer would have been several years, but Japan has already filled most of its nuclear gaps, marking a dramatic 25% drop in Asian spot prices in one month to $13/MMBtu (June 2012). On that trajectory, it is very possible more and more spot cargoes could dock in Europe pretty soon. While an Asian premium on the gas price might persist given strong demand side fundamentals, analysts have already noted notional Henry Hub five-year curves look rather similar to the NBP plus liquefaction and shipment costs. In effect, the market seems to be preparing for the US to send tankers directly across the pond. Intra-Atlantic Basin spreads are on their way to glorious long-term convergence.

Headwinds: Grabbing Defeat from the Jaws of Victory?

Or are they? Overall, current trends seem to point toward truly globalizing gas markets, and fundamental shifts in contractual models and new pricing structures coming with
them. Yet, as dicey as things look for traditional pricing methods, our discussion so far fails to consider the big elephant in the room: political risk in developed markets. Unless that is addressed, the kind of liquidity needed for truly independent gas prices to become dominant is likely to remain absent. Arguably, the US is the number one risk to take the froth out of the spot market cappuccino. Despite the very clear economic logic of converting its shale plays into LNG, it is politics in Washington that will ultimately decide how much gas is allowed to leave US shores. As a matter of fact, a rather motley crew of actors in US energy debates has the potential to form a strange but effective alliance against LNG exports. On the one hand, the “energy independence” narrative has a strong voice and is traditionally represented by national security proponents (Jaffe 2011; Morse 2012). On the other hand, environmental campaigners happily rejoice in significant shifts from dirty coal to cheap gas – clipping US emissions by 450 million tonnes over the past five years. At the same time, industry is profiting immensely from low natural gas prices – the petrochemicals industry is getting its feedstock close to free by switching to gas – all of which is good news for broader US economic output. On top, a debate over gasification of the US transportation fleet has emerged recently. On paper this looks an interesting prospect, as gas at $2.5/MMbtu is about $15/b in oil terms and converting shale to compressed natural gas, or LNG, or putting it into gas to liquid form is all possible. Given only 3% of natural gas is being used in the US transport sector, there clearly is ample room for growth. Taken together, all of this provides for a neat argument to sell to the US electorate the idea of restricting LNG exports – at the expense of US companies suffering from low price environments and the 30 or so US States that currently benefit from hydrocarbon royalties. In short, if for political reasons the US gas market remains a dislocated island, with Washington “capping” Henry Hub prices to $5/MMbtu (Levi 2012), many of the pricing pressures in the Asia-Pacific region discussed above will rapidly abate.

Elsewhere, political risks characterize shale gas prospects from different ends. In Europe, regulatory risk couples with environmental concerns and a generally difficult business environment for shale gas (Stevens 2010). On most counts, Europe’s unconventional gas industry is at best a nascent sector: European rotary rig counts only number around 120 compared to 2,000 in the US, 700 in Canada, and 450 in Latin America; Europe has no serious in-house fracking expertise and generally a rather short history in mineral extraction on European soil; subsoil resource laws often remain unclear while fiscal regimes fail to capture unconventional gas altogether; and “nimbymania” is a widespread phenomenon on the densely populated European continent. Yet, it is in the political realm that most concern rests to get shale going across EU member states. Despite sitting on 5100 bcm of shale, France recently put a ban on shale. The Netherlands seems uninterested in shale given they still have conventional gas fields such as Groningen in operation. Germany decided to split its energy mix between beefing up wind and solar power and – at least in the medium term – even more lignite coal, using Russian gas to fill any residual gaps. That does not leave much room for North Rhine-Westphalia shale plays. In the UK political backing for shale gas rests with a few Conservative parliamentarians who think shale might offer a British version of the US shale revolution in Northwest England. Sweden has not shown inclination to pursue the prospects of some estimated 1162 bcm of reserves. Spain remains plugged into Algerian production, while Italy has been oversupplied with Russian and ongoing Libyan deliveries.

Central, Eastern, and Southeastern Europe (CEE/SEE) offers yet another lesson for the complex interplay between politics and economics in the natural gas sector. In most countries of the former communist bloc, import dependency on Russian gas fosters strong
political desire to develop domestic shale gas deposits. Poland or Hungary therefore made major political and fiscal efforts to enlist US majors to replicate the shale revolution in the US. Yet, as quickly as most of them came, many of them have since left. First, geology remains a challenge. While studies indeed suggest promising prospects, the overall technical and economic viability of shale plays remains deeply circumspect in Poland, Austria, Romania, Hungary, and Ukraine (EIA 2011). Second, Russia still casts a long geopolitical shadow over CEE and SEE states. As Gazprom has no interest in seeing domestic competition emerging in Europe, its traditional and most important export market, it will likely do everything in its power to prevent shale developments for those close to its borders. It is telling that no sooner had Exxon Mobil signed agreements to develop West Siberian tight oil plays in Russia, it exited from Polish shale exploration. Bulgaria has put a ban on any shale developments, officially due to domestic opposition. Bucharest has actually followed “Sofia’s suit” and imposed an outright moratorium on any further shale developments within its borders. Although Hungary remains open to shale exploration (with US Irish company Falcon maintaining its activities), the Carpathian-Balkan Basin (538 bcm) straddling joint reserves of Bulgaria, Hungary, and Romania is not likely to be tapped any time soon. In Prague, finally, the Czech upper house is in the process of pushing through a shale ban having canceled previous overseas contracts.

To be sure, the benefits of developing European domestic shale gas plays would certainly not lie in making the continent “energy independent” from Russian imports. Rather, by adding an additional (domestic) resource base, additional gas volumes would continue feeding spot market liquidity, enhance gas on gas competition, and reinforce the current process undermining incumbent pricing models. Developing indigenous shale could contribute to developing far deeper, liquid, and more mature wholesale hubs across Western Europe, reaching all the way to the Baumgarten hub in Austria and NCG in Germany. In conjunction with enhanced state-funded infrastructure to foster interconnections and back-flow capacity, CEE and SEE states would be in a better position to negotiate “cost reflective” contracts with Russia.

Overall, while much attention is placed on the geological potential of shale, it is very much the politics involved that matter (Butler 2012). IEA analysts suggest that if all goes well with shale, gas should take around 25% of the global fuel mix over the next 20 years (IEA 2011a). Shale has doubled the gas resource base and could potentially be five times larger than conventional supplies, leaving reserves-to-production ratios of 200 years or more of gas supplies. It has tilted the traditional 8:10 ratio (80% of oil and gas sitting in OPEC and Russia with 10% in OECD states and 10% in China) in favor of the OECD world. Yet, if politics in Europe and the US remain on the current track, the long-term supply outlook appears far less certain.

Who Gains? A Risky Transition

As stressed at the beginning, transitions are anything but smooth processes and create winners and losers. This leaves our discussion with a final question: who would ultimately profit most from a globalized gas market? Considering the contingencies first, it remains unclear whether shale is going to pan out on a global basis, either on geological or geopolitical grounds. Asia might develop its own domestic shale in India and China; Australia might come good on its LNG potential to make sure Qatari LNG can keep supplying European hubs. Europe might become home to liquid gas trading hubs thanks to developing its domestic resource base. East Africa might add extra depth to LNG supplies; West Africa might up its game directly in response. Latin America might pull
back from the resource nationalism abyss, a process that has gained strong traction again lately. The Southern Corridor might deliver more gas to Europe from the Caspian Basin than many currently think, and from multiple sources. The US might develop serious LNG export potential, sending tankers across the world to put gas benchmarks on a “fast track” convergence. And the enormous (private) capital required to make all this happen might come to the fore – possibly a function of how long the current economic crisis will last. If shale gas becomes a global play, earth is cracked, LNG trains loaded, then incumbent producers of unconventional gas may find themselves in deep commercial and political trouble. But there are too many mights to make a clear bet on unconventional plays, and by implication to make a definitive conclusion as to how price convergence does or does not play out – ultimately the determining factor of who wins and who loses.

Contingencies aside, gas market developments so far have clearly put traditional oil price indexation in question. In fact, it is highly questionable whether oil can be credibly deemed as a sensible way of pricing gas, a commodity no longer in direct competition. The principle that gas markets should be based on demand and supply fundamentals gains traction, and the “gas on gas” genie is clearly out of the bottle. True, the way to liquid international markets and global price convergence is not a straightforward one. We will probably continue to see a hybrid model playing out over the next decade until fundamentals tip the balance one way or the other. Many traders will continue to hedge gas price exposure against heavily traded oil markets, some might even point out the utility of long-term indexed contracts to renegotiate terms, just as upstream players will still demand long-term contracts to develop fields, build infrastructure, lay pipes, and even load LNG tankers. But if gas market liquidity continues to hold up, the contracts will probably not only be subject to far more dynamic price points, they could also be considerably shorter. The first conclusion to draw would therefore be that things do not look particularly good for traditional producers. Incumbents such as Russia might come under strong pressure to compete with newcomers such as Qatar on both their traditional European customer base and on emerging markets in Asia, or strike a deal on supply side cooperation. Under a “business as usual” scenario Russia will therefore have to make difficult decisions between what volume-to-price balances it is happy with. Consumers in the Atlantic and Pacific Basins, in turn, expect lots of LNG to keep coming their way at preferential prices. They would come out as the winners of globalizing gas markets and profit from suppliers being stuck in fierce competition over market shares.

On second thoughts, however, not all of this is bad news for producers. Most consumers (especially continental Europeans) seem to be laboring under the illusion that spot markets mean cheap prices, an assumption clearly also underpinning the European Commission’s energy packages (see European Commission 2011). Setting gas prices based on gas fundamentals however has got nothing to do with being cheap: it is purely about achieving a cost reflective price for whatever market fundamentals suggest. Gas on gas competition might well have positive medium-term effects on price, given that marginal costs of production are generally cheaper than oil. But there are never any guarantees. If anything, prices could initially be far more volatile than those associated with piped gas given the cyclical nature of the business, not to mention adapting to new upstream investment regimes unable to fall back on the oil “certainties” of old. The UK provides a vivid example of increased volatility during gas market liberalization and thereafter.

But even assuming these initial hurdles are jumped and gas markets are politically allowed to bed in, additional pitfalls may be looming. In short, an expanding market
share traded on spot rather than bound in LTCs also means an expanding market share open to cartelization. As much as import dependent consumers tend to think they have taken the political sting out of gas producers’ tails, spot markets could actually give producers far more leverage to manipulate prices, either on a collective or bilateral basis. A quick look at the map reveals that supply side dynamics are essentially oligopolistic in Europe, a position that Russia might decide to capitalize on. Much would depend on pricing pressures involved and how far convergence has gone, but the lower that prices go, the more compelling supply side collusion would become in order to recalibrate markets back toward producer interests. The emerging Gas Exporting Countries Forum (GECF) may become the organization of choice for this purpose. The GECF currently represents some 70% of world natural gas production. Major producers and reserve holders such as Russia or Iran have shown revived interest in the Forum, which has now moved toward a more formalized organizational structure (see Stern 2010: 4; Stern and Rogers 2011).

A gas cartel would obviously face similar challenges as OPEC, in that someone would have to shoulder initial opportunity costs and absorb likely free riding, enforce quotas, and restrict new market entry at the fringe. Moreover, the cartel would also need to find a swing producer, that many have long thought would be Qatar, but actually this may flag up an interesting opportunity for Russia. At present, and despite sitting on over 30% of global gas supplies, Russian LNG production accounts for less than 5% of global share. In short, Russia – the gas equivalent to Saudi Arabia for oil – has let itself become a fringe player in a global gas world. Developing Shtokman, Sakhalin, and indeed Bashenov and Achimov fields will undoubtedly not be to everyone’s liking, but given that Russia’s own unconventional reserves are estimated to be ten times larger than the whole of Europe, it still has the time and potential to take the lead back on volume to dictate long-term prices. If global gas benchmarks are the way of the future, then Russia has potential to play a pivotal role as the swing LNG producer of the world. Not only could Russia lean far heavier on Qatari, Australian, Algerian, East African, and burgeoning Latin American LNG production to align short-term prices, it would set the stage for a serious approach toward a gas cartel that would be the logical conclusion of independent global gas prices. On top of all, Russia’s swing status would be built on the shoulders of a well-supplied but largely isolated US market. If the US goes “energy independent,” Russia can start applying its own logic of gas on gas competition. Ironically, gas convergence – a supposed existential crisis for traditional producers – could eventually emerge as a tremendous opportunity to tilt the gas market in their favor.

Overall, the transition toward global price benchmarks should in the short run benefit consumers by driving competition and efficiency gains, in addition to diversifying supplies. In the long run, however, greater supply side collusion may be looming, both in terms of volumes and price. Ignoring a potential gas cartel could prove to be a costly mistake, just as it was to ignore the world’s largest oil producers aligning their interests in OPEC in the 1960s.

**Conclusion**

This chapter has covered a wide range of political and economic drivers characterizing an ongoing fundamental shift from the old world of natural gas (characterized by regionalized markets and oil-indexed LTCs) to a new and admittedly rather uncertain one (liquid spot trading replacing LTCs, and global price convergence). Whether that new gas world will be a brave and bright one will however depend on a number of things. One is economics. Overall liquidity is both the core driver and the core challenge in globalizing gas
markets, which means shale options need to be globally developed and LNG trains set in motion. This obviously comes with immense investment needs, which, according to IEA estimates, amount to some $8 trillion until 2035 (IEA 2011a: 8). Public funds will not do the trick here, and private capital will only find its way into upstream projects and infrastructure if the expected return on investment looks promising enough, if access is granted by reserve holders, and if risks can be hedged. As discussed, however, crucial markets in North America may fail to provide for an attractive pricing environment in the future, while geology may prevent shale plays from coming to fruition in Europe, in addition to non-business factors negatively impacting on investment decisions. Natural gas markets will keep on globalizing only if the underlying economics allows for it. This gets us to a second important insight: politics remains key in this process. Whether domestic reserves are made available to free up volumes for export, new plays are licensed out, and pricing mechanisms continue going global are, in the end, questions for political decision-making in key producer and consumer countries. Gas markets do not operate in a vacuum. More than other less politicized markets, they are created by states and ordered by institutions. Economics clearly do not trump politics in gas. To the contrary, the future direction natural gas markets take fundamentally depends on strategic decisions taken in Washington, Brussels, Beijing, Doha, and Moscow. Europe can shun domestic shale developments and bank on global gas fundamentals going their way. This, however, leaves them with a strategic supply game played out between Qatar and Russia, and makes them rule takers with regard to their own destiny. The US has a strategic decision to take on whether it becomes a self-sufficient island or continues shaping the new gas market order. Russia can stick to a failed “Eastern Strategy” or get to grips with the fact that US shale has made the energy heavyweight a price taker in Europe (and Asia) and start developing LNG prospects to reclaim control of global gas fundamentals. In fact, as discussed, the brave new gas world may have much to offer producers – a single price point could reduce price volatility, while far broader and flexible markets may offer better opportunity than a single consumer at the end of a pipeline where the price is set by oil, meaning OPEC. Markets will not take the decisions here, but governments.

One thing is for sure: gas is here to stay. It is widely regarded as key to fueling emerging markets, alleviating energy poverty, decarbonizing the fossil fuel energy mix, and building a bridge to a low carbon future. It simply is the fuel of choice for decades to come, and will claim higher shares in the global energy mix. While coming with adjustments costs for both producers and consumers, there is much to gain from globalizing gas markets, from greater liquidity to a pricing mechanism based on actual market fundamentals. The trend toward new, more market-based models in natural gas trade seems irreversible; status quo ante no longer seems an option. Producers and consumers had better get the policies right to make the inevitable transition a success.

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