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This issue of the *Oxford Energy Forum* is dedicated to gas pricing. A mild 2013/14 winter in Europe and parts of Asia and a slowing of demand growth for LNG saw European hub prices and LNG spot prices begin to fall through the summer of 2014. The collapse of the oil price in late 2014 resulted in a lagged reduction in long-term contract prices (LNG and pipeline gas) to levels below $10/MMBtu in Europe and Asia. These events followed a period from 2011 to 2013 in which regional gas reference prices in the USA, Europe, and Asia appeared to be held within stable 'corridors' at levels which incentivized the progression of a long list of new LNG projects in North America, East Africa, Australia, and Russia. Many of these will likely be 'on hold' pending indications of a more supportive future price environment, but some 150 bcm/year of new LNG supply from the USA and Australia will have achieved start-up by 2020; this will add further pressure on prices and stimulate inter-regional arbitrage.

Our contributors cover different facets of the current and future gas pricing environment. Starting in Europe, *Beatrice Petrovich* reviews the rise in trading activity and liquidity of the European gas hubs and assesses the correlation of prices between them. Price de-linkages, where they occur, can be traced to periods of physical or contractual congestion but the general picture is positive – in terms of hubs providing reliable and linked-up price signals over much of the European gas geography.

While European hub prices may be well correlated, *Thierry Bros* argues that price level is affected by the market power of the two main suppliers: Russia and Norway. This influence is likely to be augmented by the recently announced production limits on the Dutch Groningen field. However, with a declining trend in European gas consumption, he anticipates periods of low prices to the end of the decade, as LNG flowing to Europe competes with pipeline suppliers who are likely to defend market share.

Jonathan Stern reviews the evolution of market-based pricing in Europe, including changes in the transformational period following the 2008 financial crisis, which saw the midstream buyers of long-term oil-indexed contract gas securing concessions, whether through negotiation or arbitration, to reduce their financial exposures. While Norwegian and Dutch suppliers have generally embraced hub-based pricing in their contracts, Russian gas remains subject to an ad hoc system of formulaic adjustment and rebates – and a seeming continual cycle of renegotiation and arbitration. He argues that the time has come for Gazprom to adjust its long-term contracts to hub prices.

CONTENTS

Gas Pricing

In addition, the DG COMP enquiry (concerning Gazprom's activities in the Baltic and south-east European markets) could have ramifications for oil indexation more generally.

The Russia–Ukraine situation has rarely been far from the headlines of late. *Simon Pirani* reprises the rocky road of post-Soviet gas supply and pricing arrangements between Ukraine and Russia. In parallel with the tortuous negotiations facilitated by the EU, the establishment of 'reverse flow' supply of essentially Russian gas molecules via Slovakia, Poland, and Hungary has played a decisive role in establishing more 'market reflective' prices in Ukraine. The emergence of this competitive dynamic likely marks the end of quasi-political gas price negotiations in this market.

Anupama Sen addresses the much heralded, but often delayed, reform of Indian gas pricing. The concept of this reform was to create a reference price high enough to incentivize new domestic exploration and development, but still affordable for Indian gas market sectors (especially that of fertilizer production, which is subsidized). The recent unforeseen decline in the KG-D6 field was expected to add impetus to this reform. The outcome, however, has been disappointing. The international benchmarks which comprise the Indian reference price appear to have been selected with the aim of producing a low price level rather than a rational price formation mechanism.

China's gas price reform, originally trialled in 2011 and adopted nationwide in 2013, is reviewed by *Michael Chen*. This represented a move away from wellhead cost-plus pricing towards a citygate benchmark based on LPG and fuel oil (but allowing for the addition of other competing fuel) prices. Each province has its own citygate price based on this principle. Challenges remain due to: the fall in oil product prices and the lack of success in translating this to gas prices in a timely fashion, and the specific pricing arrangements for different demand centres. However, the price mechanism is logical and momentum has been established; there also seems to be a desire to establish trading activity.

Having been faced with high oil-linked contract and spot prices, with its need to import significantly more LNG after the Fukushima disaster, Japan has identified the need for LNG procurement at more competitive prices as a national priority. *Ken Koyama* describes the debate within the Japanese LNG industry as it searches for alternatives to JCC pricing. Hybrid price formation mechanisms – with a mix of Henry Hub, European hubs, and some oil – appear likely pending the formation of an Asian hub or hubs.

James Henderson reviews the impact of falling oil and gas prices on non-US LNG producers. He concludes that projects which have not yet achieved FID in Australia, Canada, East Africa, and Russia are likely to face a two to three year delay pending a more encouraging view of market fundamentals for the early 2020s, a search for project cost savings, and the likely need to move away from oil indexation as a contract price formation mechanism.

Finally *Howard Rogers* reflects on the events leading to the advent of the USA as a large new LNG supplier with a business model based on sourcing gas from the US domestic market with a liquefaction plant 'tolling fee'. He addresses the likely impacts that this wave of new flexible LNG supply might have on regional markets.

We hope that this issue will provide readers with a comprehensive 'snapshot' of the rapidly evolving state of play in the world of gas pricing – and also a broader understanding of the dynamics through which growth in inter-regional trade is creating an ever more 'connected' global system.

The views expressed in this issue are solely those of the authors and do not necessarily represent the views of OIES, its members, or any other organization, company, or government

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The increasing hub pricing and market integration in Europe

Beatrice Petrovich

The growth of hub trading 2007–14

Since 2007, the sale and purchase of natural gas in Europe has been evolving from a 'traditional' model based on bilateral long-term contracts with prices (largely) linked to those of oil products, to trading by means of standardized contracts concluded between a large number of participants with prices set by supply and demand 'at the hub'. As of 2014, the main hubs where gas is delivered in Europe are:

- NBP in Great Britain;
- TTF in the Netherlands;
- NCG and Gaspool (GSL) in Germany;
- Zeebrugge (ZEE) in Belgium;
- PEG Nord (PEGN), PEG Sud (PEGS), and PEG TIGF (PEGT recently merged into PEGS) in France;
- PSV in Italy;
- CEGH in Austria.

Evidence used in this article relating to trading at these hubs is based on raw data from about four million trades recorded by the Tankard Parties (ICAP, Marex Spectron, and Tullett Prebon) over the period 2007–14. OIES accesses this database under licence for research purposes only and estimates that the database represents about 70–80 per cent of total European OTC hub-traded volumes.

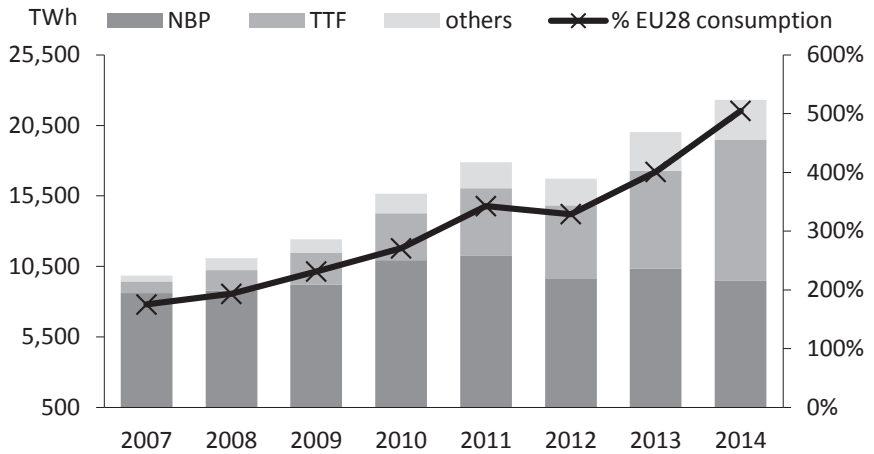

Figure 1.1. Total gross traded volumes, OTC market (TWh and % of total EU28 consumption)

Source: Tankard Parties, Eurostat, and Eurogas

Figure 1.1 shows that since 2008 gross traded volumes delivered at the main European hubs have steadily increased on the OTC market (which still accounts for the majority of trades). As the 'same' molecule may get traded within a specific (entry/exit) zone many times before delivery to final end users, total traded volumes may be several times greater than the figure for total demand in the corresponding area.

Hub trades are highly concentrated at the NBP and TTF, being almost an order of magnitude higher in volume

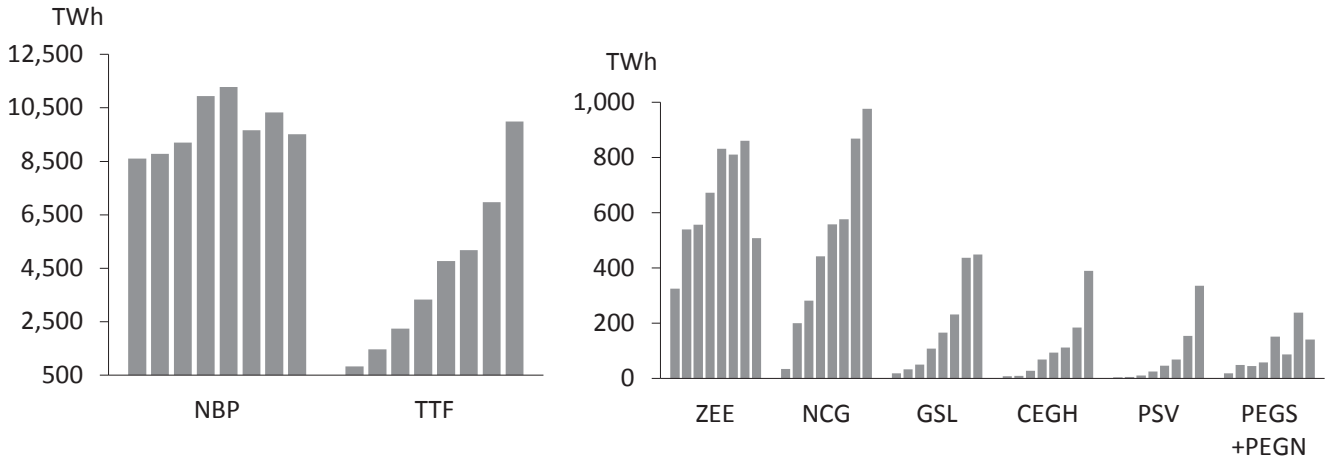

Figure 1.2. Total gross traded volumes, OTC market by hub (TWh)

Note: each bar represents a year in ascending order, starting from 2007.

Source: Tankard Parties

than those of France, Germany, Italy, Belgium, and Austria. However, the pace of growth (Figure 1.2) has been very fast for some of the less liquid hubs; CEGH volumes in 2014, for instance, were over 40 times larger than in 2007, while the NBP volume remained relatively stable. In 2014, only ZEE and the French hubs experienced a significant decline in traded volumes – possibly due to the creation of a new euro-quoted hub (ZTP), and players preferring to trade on the (French) Powernext exchange rather than OTC.

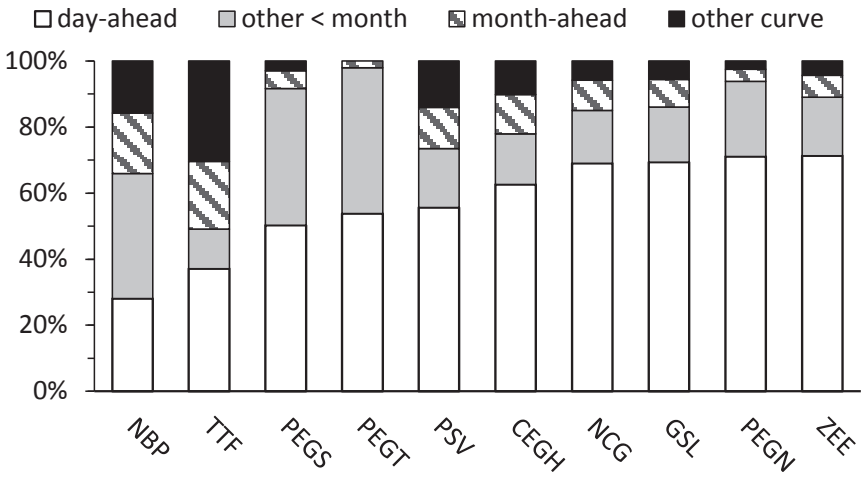

Figure 1.3. Breakdown of number of OTC trades by product in 2014 (% compared to total hub trades)

Source: Author's analysis of Tankard Parties data

Hub products and price correlation

Day-ahead is by far the most frequently traded product (Figure 1.3) on all European hubs, with the exception of TTF and NBP, at least 50 per cent of trades are for day-ahead delivery. Products for future delivery (quarterly, seasonal, calendar, and gas year products) are traded mostly on TTF and NBP, which account for almost 90 per cent of European curve trade.

Notwithstanding differences in traded volumes, European hub prices are broadly aligned (Figure 1.4), suggesting that they are spatially well integrated and competitive. In other words, parallel price movements suggest that there are no barriers to trade across borders, and no evidence of price manipulation or anticompetitive behaviour. When the prices of a commodity quoted in different interconnected markets move in tandem, and transportation costs can be considered constant over time, it indicates the fact that freedom to trade the commodity across borders is driving price differentials to zero (net of transportation costs). This supports the argument that hub prices are the result of supply and demand forces.

A simple metric to quantify the strength of price alignment ('correlation') between gas hubs is the Pearson correlation coefficient. A score close to 100 per cent indicates the strongest price alignment, meaning that when the price in market *A* goes up by *x* per cent, the price in market *B* also goes up by *x* per cent, and vice versa. The daily prices of the day-ahead product (the most liquid contract across all the hubs) in general feature good correlation scores over the 2007–14 period, with few exceptions.

The North West Europe core group (ZEE, TTF, the German hubs, and PEGN) stands out as it remains almost perfectly correlated over the whole period, with these hubs behaving as a single integrated market area. Periodic de-linkage occurs at the more peripheral hubs: NBP, PEGS, CEGH, and PSV. Drops in correlation scores signal that, at times, barriers prevented gas flows – and hence price correlation – between these markets and members of the core group. The nature of these barriers is mainly physical: de-linkages occur when there is physical congestion of the interconnecting infrastructure, whereas there is no evidence of other widespread non-physical barriers to trade. The origin of physical bottlenecks is related

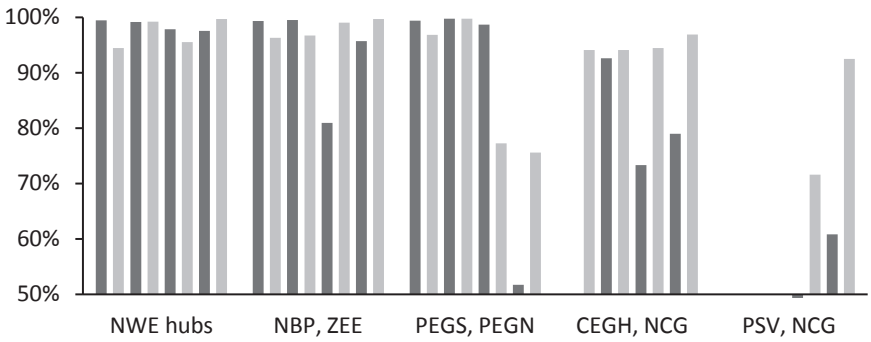

Figure 1.4. Average yearly correlation scores for OTC day-ahead prices, 2007–14 (%)

Note: each bar represents a year in ascending order, starting from 2007; PSV, NCG are for 2012–14 only.

Source: Analysis of Tankard Parties data

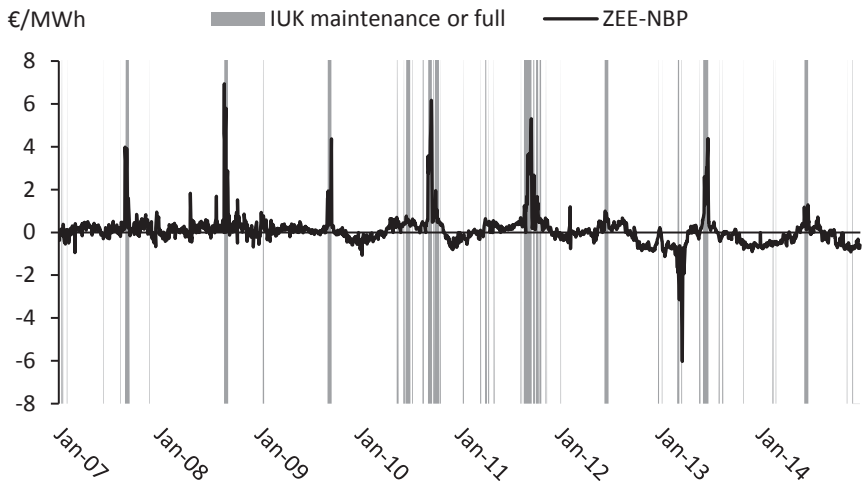

Figure 1.5. ZEE–NBP OTC day-ahead price spread (€/MWh) and periods when IUK is on maintenance or close to full capacity

Source: Tankard Parties, IUK

to periods of network maintenance (shutdown) and changes in flow patterns across Europe. The latter category involves changes in the use of European infrastructure – such as the 'LNG wave' hitting the UK in 2009–11, and the diversion of LNG flows from Europe to Asia during 2011–14.

Explaining price de-linkages

NBP de-linkage from other North West hubs can largely be explained by Interconnector (IUK) maintenance periods and occasions when the pipeline is close to full capacity. During these periods, the British market disconnects from the Continent and the resulting supply glut – supported by ample LNG imports – drives NBP below NW European prices (Figure 1.5). When import capacity from the Continent is physically congested, as happened during the cold spring of 2013, prices spike more at NBP than at ZEE, temporarily widening the spread. When there is spare capacity in the pipeline, prices at the two adjacent hubs are well aligned.

Similarly, PEGS delinks when physically separated from PEGN due to LNG supply being diverted, requiring consumption to be met by higher flows from the north, which in turn congests the N–S Link. Figure 1.6 illustrates events in 2014, showing that as soon as the LNG supply increases in the south of France, the spare transmission capacity between the two adjacent French zones restores price alignment within the country. The semi-permanent congestion of the French N–S link has already prompted a decision for investment in reinforcing the physical infrastructure, with the aim of creating a single French market by 2018.

Austrian hub de-linkages are related to physical congestion at Oberkappel (between NCG and CEGH); this tends to occur due to heavy exports from Germany to Austria during the summer and physical constraints on the German side (disparity between entry and exit capacity), which may be solved by additional investment.

However, PSV is a somewhat different story. Although the PSV premium increased significantly in H2 2013 and H2 2014, the route from the lower-priced NW European hubs to the Italian hub is not physically congested for most of the time. In 2014 at least 20 per cent of interconnecting capacity was normally available; it was fully utilized only for limited periods in September (Figure 1.7). This suggests that, due to non-physical barriers to trade (possibly relating to contractual congestion), market players did not fully exploit arbitrage opportunities.

The average correlation for the European hubs in 2014 was 96 per cent and only PEGS prices were substantially different from the other hubs, with minor de-linkages in Italy and Austria. However, these differences involve non-negligible costs due to the fact that (according to IGU/

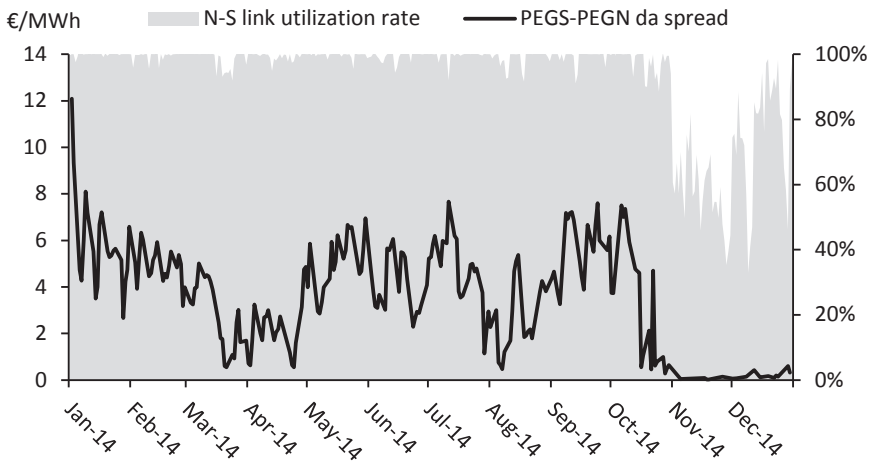

Figure 1.6. PEGS–PEGN OTC day-ahead price spread (€/MWh) and utilization rate of the N–S link (%)

Source: Tankard Parties, GRTgaz

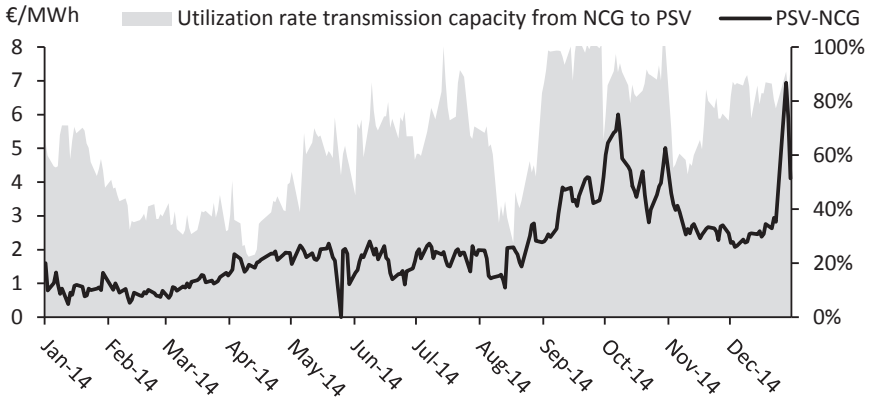

Figure 1.7. PSV–NCG OTC day-ahead price spread (€/MWh) and utilization rate of the transmission capacity from NCG to PSV (%)

Source: Tankard Parties, ENTSOG Transparency Platform, ENTSOG Capacity Map

Nexant data) more than 60 per cent of consumption in the countries with the less aligned hubs (France, Italy, and Austria) is priced on the basis of gas-on-gas competition.

Physical congestion between Germany and Austria resulted in an additional gas procurement cost in 2014 of about €60 million, most of which was accounted for by CEGH prices being higher than NCG in September and October 2014. Although the total volumes of gas sold at hub-based prices at PEGS are similar to those at CEGH, the wider de-linkage of prices in the south of France compared to those at the adjacent PEGN translated into a cost of €240 million. The size of the Italian market meant that, in 2014, barriers to flow into PSV resulted in an estimated increase in purchase costs of €330 million. These costs were incurred mostly in September–December, when the average premium over NCG exceeded €2/MWh (although for most of the time the cross border capacity was not fully utilized).

Summary and conclusions

In summary, it is increasingly difficult to deny the fact that hub prices represent market (supply–demand) prices in Europe. Price correlation across the North West hubs is almost perfect, and central Europe and Italy have improved significantly over the past five years. Some price disconnection still occurs in Austria, France and Italy for both physical and contractual reasons, but this issue is likely to be addressed by building new infrastructure and enforcing rules on congestion management procedures. However, it needs to be stressed that this article has focused on North West Europe, Central Europe, and Italy. In Spain and South East Europe, hub development is still at an early stage or absent. Once again, however, new infrastructure and, in particular, planned interconnections with markets further north, can be expected to align these markets with hub prices over the next several years.

Europe, prices and demand: key producers are maximizing rent

Thierry Bros

Russia and Norway both have market power in European gas. With more than a 50 per cent gas market share in Europe combined, they have theoretically more power in the European gas market than OPEC has in the oil market. The latter provides 32 per cent of the global oil supply (Figure 2.1).

'… IT IS INCREASINGLY DIFFICULT TO DENY THE FACT THAT HUB PRICES REPRESENT MARKET (SUPPLY–DEMAND) PRICES IN EUROPE.'

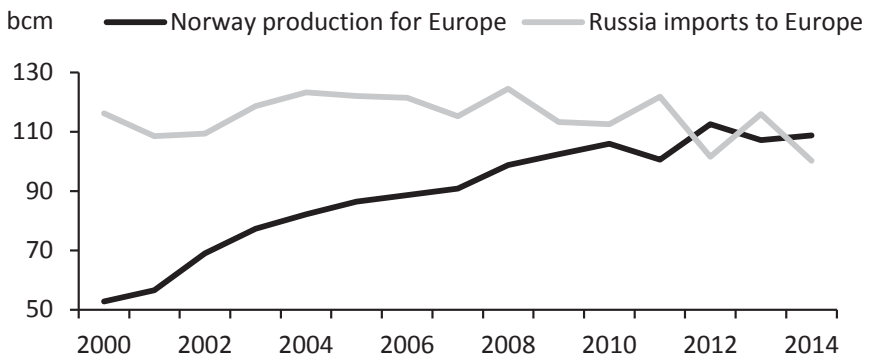

Figure 2.1. Russia and Norway gas supply to Europe, 2000–14

Source: SG Cross Asset Research/Commodities, IEA

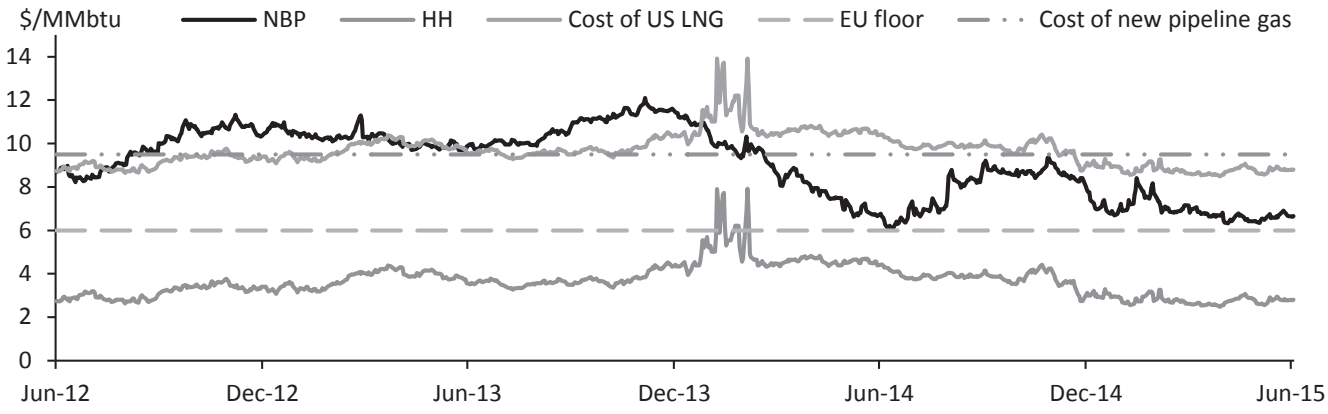

Figure 2.2. NBP to stay in a tunnel between the EU floor and the incentive price for new gas

Source: SG Cross Asset Research/Commodities, Datastream

By not pushing volumes too much, Gazprom (Russia) and Statoil (Norway) have not only avoided a price war but, since 2010, have managed to reset spot prices at a level acceptable to them, even if the move away from oil-indexation is continuing, with 61 per cent of European gas sold at hub-based prices in 2014 (IGU).

The author believes that both Russia and Norway have a vested interest in keeping gas prices in Europe between a floor estimated at $6/MMBtu and a ceiling that is either the cost of new gas (estimated at $9.5/MMBtu for pipeline gas from the Caspian Sea) or Henry Hub + $6/MMBtu for US LNG (Figure 2.2).

High Russian gas supplies in early 2014 demonstrated that new Final Investment Decisions for alternative supply were not needed. This allowed Europe to start the 2014/15 winter season with record storage levels, mitigating the potential risk of Russia–Ukraine-induced supply disruptions. As this risk didn't materialize, Gazprom reduced supply in Q4 2014 to a record low level to avoid a crash in hub prices.

With the fall in oil prices filtering through to long-term oil-indexed gas contracts, Gazprom has increased its export volume since March 2015. With Brent priced at around $60/bbl, some oil-indexed contracts with a low slope (around 10 per cent) will provide a cheaper price than the spot market this summer, hence Gazprom's forecast of increased Russian volumes for the remainder of 2015. The tricky question that remains is how to transport this gas to Europe, as Gazprom failed to get an exemption from the European Commission in December 2014 that would have allowed it to use 100 per cent of the capacity of the OPAL gas pipeline (35 bcm/year). Under the rules of the Third Energy Package, Gazprom is permitted to use only 50 per cent of the existing OPAL capacity and must reserve up to 50 per cent of pipeline capacity for gas transportation by independent gas suppliers. In April 2015, Gazprom started legal action in Germany (ongoing) to be allowed to use more than the permitted 50 per cent capacity of the OPAL pipeline.

Less Groningen gas means even more Russian gas and higher prices

In June 2015, Dutch Economy Minister Henk Kamp ordered a further tightening of production at Groningen, Europe's largest gas field, in response to a spate of earthquakes that have caused extensive property damage in this province. Output at the field will be capped at 30 bcm for the whole of 2015 (this figure was 42.5 bcm in 2014).

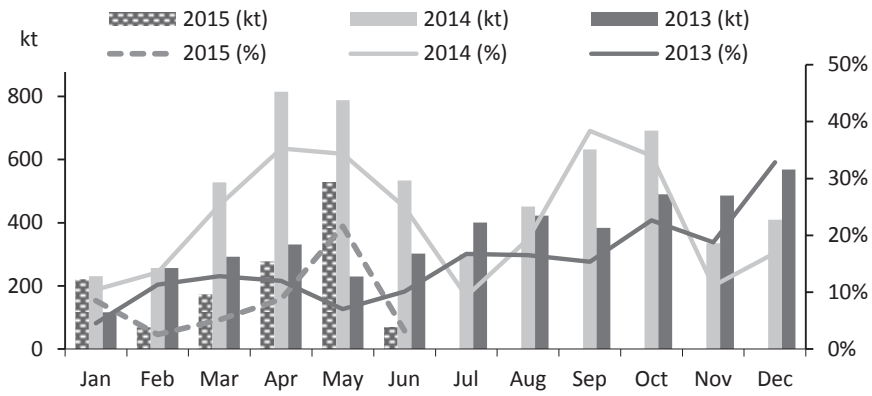

Figure 2.3. LNG re-exports from Europe, 2013–15 (% figures show reloading vs total LNG supply to Europe)

Source: SG Cross Asset Research, Waterborne

The direct beneficiary of lower European production is Russia, which has huge spare capacity and can respond to any unexpected impact on the supply–demand balance.

We will thus need more Russian gas year on year from Q3 15 to Q1 16 to mitigate the Groningen decision. However, the DG COMP restriction that Gazprom may not book more than 50 per cent of OPAL capacity means that more Russian gas will therefore need to transit via Ukraine at the end of the year. The current geopolitical stand-off between Ukraine and Russia is still tense, with renewed EU sanctions on Russia in place for another six months until the end of January 2016. Hence, the price outlook is bullish for winter 2015/16.

LNG back to Europe

Europe is, and will continue to be, the 'dumping' ground for excess LNG. Since February 2015 we have witnessed a severe drop in re-exports. With NBP and spot LNG in Asia being on par, we are also seeing an increase in LNG berthing in Europe (+27 per cent in January–June 2015 compared with the same period last year) (Figure 2.3).

This tendency of low re-export levels from Europe should become the new normal. The tightness of the LNG market following the Fukushima disaster is now history. But this extra LNG (8 bcm in 2015 vs 2014) represents only 64 per cent of the reduction of the Groningen cap (–12.5 bcm from 2014 to 2015) and will therefore not change the market power in Europe.

Prices are keeping European demand muted

Since 2006, European primary energy consumption has been reduced by 12.1 per cent and this trend is unlikely to change as Europe becomes more and more energy efficient (Figure 2.4).

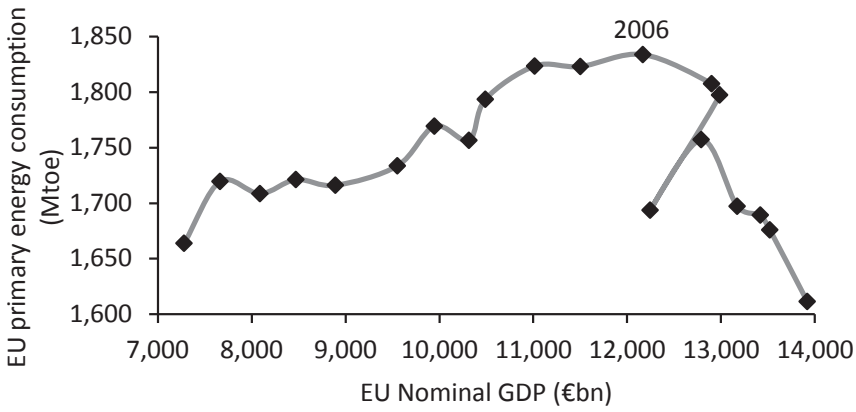

Figure 2.4. EU primary energy consumption vs nominal GDP, 1995–2014

Sources: SG Cross Asset Research/Commodities, BP Statistical Review, Eurostat

The strategic mistake made by European utilities was to disregard the 2007 political agreement that set the 2020 climate and energy objectives. By thinking that the secular energy growth trend was going to continue forever, their business model prompted them to overinvest in new power plants (in particular thermal). New thermal plants are a legacy of investment decisions dating back to the last decade, when companies denied the energy transition concept. Even with the closure of nuclear plants that happened overnight in Germany post Fukushima, the degree of over-capacity in generation was so significant that many plants needed, and still need, to be idled / mothballed / closed. This has hit gas-fired plants in particular, since gas was the higher-priced fossil fuel. If utilities had realized that energy transition would mean lower thermal generation demand, they would have invested less and would then have had to close fewer plants (and, in this case, perhaps the older coal plants would thus have been retired first).

As Europe is promoting renewables rather than fossil fuels, and as the floor for the gas price is too high to allow gas to compete with coal in power generation, European gas demand will be mostly weather-driven with an underlying downward trend driven by

Figure 2.5. Gas demand for Europe OECD excluding Turkey

Sources: SG Cross Asset Research, IEA for historical data

continued efficiencies (Figure 2.5). The estimated 2015 increase in demand is only due to an assumption of normal weather in comparison to an abnormally warm 2014. The increased UK carbon tax (£18/t from 1 April 2015 vs £9.55/t previously) could also marginally help gas used for power generation in the UK but, for the rest of Europe, coal is still the cheapest fossil fuel for power generation.

With more than 15 liquefaction plants in construction (mostly in Australia and the USA), an LNG supply surge will hit Europe, with imports forecast to double between 2014 and 2020. With demand and domestic production both declining, this wave of LNG is to be welcomed as Gazprom has no wish to renew its transit contract via Ukraine (expiring on 31 December 2019) while European institutions and companies will not accept taking delivery of these volumes at the Turkish border (an option suggested by Gazprom, which wants to build the Turkish Stream pipeline instead of the now cancelled South Stream). Gazprom will continue to be the swing supplier, while Norwegian production will stay flat for the 2016–20 period (Figure 2.6).

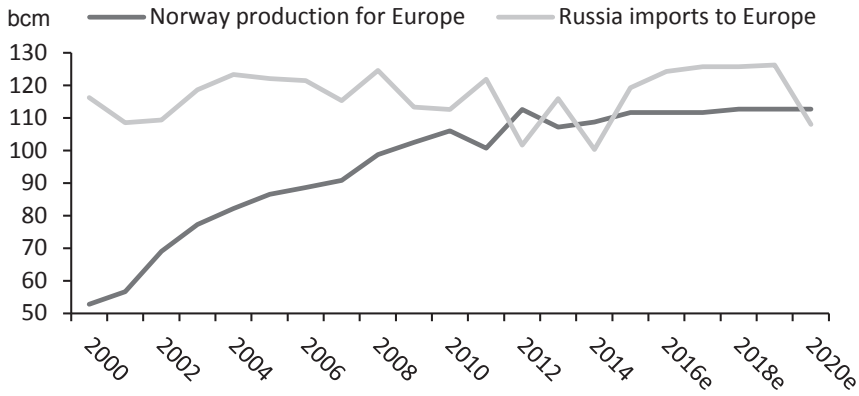

Figure 2.6. Russia and Norway supply to Europe, 2000 to 2020

Sources: SG Cross Asset Research/Commodities, IEA for historical data

However, if more LNG plants (above the five already in construction) go ahead in the USA in the next two years, this could lead to a price war in Europe as Gazprom will not accept a reduction in its export volumes below the 100 bcm level. European prices could then be reduced to a level at which US liquefaction plants could be mothballed.

Gazprom: a long march to market-based pricing in Europe?

Jonathan Stern

Europe: from oil-linked to hub-based gas pricing

For several decades up to the late 2000s, the netback market pricing formula – which links gas prices (principally) to oil product prices – dominated international gas transactions in Europe. This type of price formation is consistent with charging different prices to different national markets, as well as to different end-use sectors within the same market, depending on: their location, the fuels which compete with gas in their energy markets, and their ability to access alternative gas supplies (which was severely limited prior to the introduction of liberalization and competition). The formula institutionalized the practice of discriminating monopoly pricing – charging the highest possible price just short of a level which would cause customers to switch to other fuels and thereby maximizing the returns from sales to different markets – which was practised by all gas sellers (and European utility companies) prior to the arrival of competition.

When European gas demand crashed in the recession following the 2008 global financial crisis, many European utilities struggled to meet the minimum take-or-pay (ToP) commitments in their long-term contracts at oil product-linked prices, at a time when crude prices were rising to $100/bbl. The resulting surplus of gas was a key factor in creating a hub-priced gas market; this situation subsequently evolved to a point where the International Gas Union estimates that in 2014, more than 60 per cent of European gas was sold at hub-based prices, rising to nearly 90 per cent in the north-west of the Continent.

'… IN 2014, MORE THAN 60 PER CENT OF EUROPEAN GAS WAS SOLD AT HUB-BASED PRICES …'

The impact of these developments was of special significance for Gazprom because of the size and centrality of its supplies to the European gas market, and they resulted in renegotiations with buyers in its major markets. In

many cases, these renegotiations reduced ToP volumes to 70 per cent, with volumes taken in excess of that level being sold at hub-based prices for three years beginning in October 2009. Nevertheless, in 2009 and 2010, customers incurred take-or-pay liabilities of 5 bcm and 10 bcm respectively, although the reasons for these figures were different: in 2009 the take-or-pay shortfall was spread across a number of companies, while in 2009/10 it was concentrated on Italian and Turkish companies. By 2012 the ToP problem had been largely resolved, although export volumes remained around 10 per cent below the pre-recession highs of 2007/8, but Gazprom maintained oil-linked prices at the expense of volume sales.

Resistance to hub-based pricing

Gazprom's initial commercial reaction to the price problem was based on reasoning that by 2012 the recession would be over and pricing would have returned to normal. In other words, hub prices would return to oil-linked contract levels as gas demand recovered after the recession (and surplus LNG supplies were absorbed by fast-growing Asian economies).

'… DESPITE ITS PUBLIC STANCE, THE COMPANY [HAS] ADJUSTED TO HUB PRICES IN THOSE COUNTRIES WITH COMPETITIVE MARKETS.'

When, by 2012, hub prices had become established in many countries and were still 30 per cent below oil-linked long-term contract levels, arbitration proceedings (which had commenced with a number of buyers) forced Gazprom to agree a different type of price mechanism. The new mechanism retained the oil index but reduced the base price (the P0) in the formula – in effect bringing the price closer to hub levels. A rebate mechanism was added which guaranteed buyers a limit on their exposure to hub pricing: at the end of the (one or two year) price period, if the price paid by the buyer under the new P0 + oil indexation formula exceeded the hub price by more than a defined percentage (said to be in the range of 5–15 per cent), the buyer would receive a 'rebate' reflecting the difference. From 2012 to 2014 these rebates amounted in aggregate to several billion Euros annually, but nevertheless Gazprom could claim that it had not compromised on the principle of retaining oil-indexed prices. Figure 3.1 shows that, as a result of this new mechanism, Gazprom's realized export prices fell from more than 60 per cent above the NBP (UK hub) price in 2009, to parity in 2013, before rising again in 2014 (when European hub prices fell significantly ahead of the fall in oil prices), and then readjusting in early 2015. The result was that in 2013 Russian gas exports to Europe rose to record levels (before falling back in 2014). Therefore, despite its public stance, the company can be seen to have adjusted to hub prices in those countries with competitive markets.

The 2012 EU competition investigation

But in countries lacking competitive markets and significant alternative sources of gas, Gazprom's attitude was entirely different and has been the subject of a lengthy investigation for possible abuse of a dominant position by the European Commission's Competition Directorate (DG COMP) which (after two and a half years) issued a Statement of Objections in April 2015. A major conclusion was that in relation to Bulgaria, Estonia, Latvia, Lithuania, and Poland:

> *… the specific price formulae … which link the price of gas to the price of oil products have contributed to the unfairness of Gazprom's prices … [and] seem to have largely favoured Gazprom over its customers.*

Since the Commission's 'dawn raids' in September 2011, it has been reported that Lithuania (following the opening of its LNG import terminal) and Poland (with the ability to access hub-priced gas from Germany) have renegotiated more favourable prices with Gazprom (although in the Polish case arbitral proceedings restarted in 2015). In addition, some of the long-term contracts with Baltic countries expire in 2015/16, allowing for the possibility of renegotiation, or termination in the event of failure to agree new terms. However, in south-

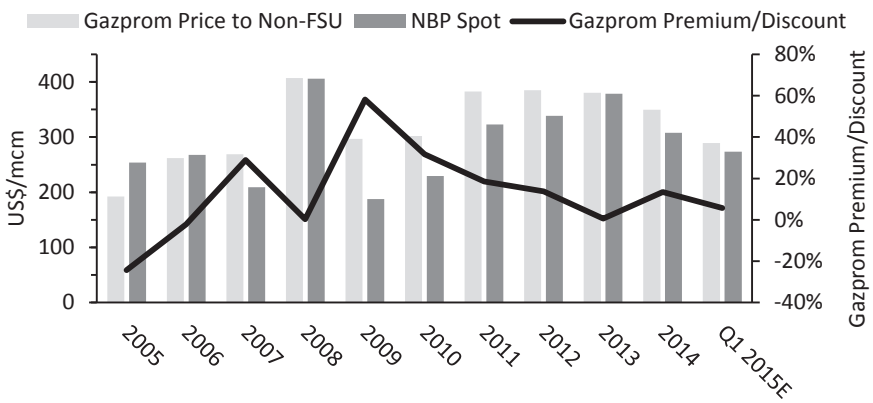

Figure 3.1. Gazprom prices to European customers compared with UK spot prices

Source: Henderson/OIES (from Gazprom financial statements)

east Europe (which involves a number of Balkan countries which are not EU member states) alternative gas supply and hub development (and hence price competition) has been slow to arrive, and oil linkage remains dominant.

How the DG COMP case will be resolved remains to be seen. The Commission apparently discovered territorial restrictions ('destination clauses') in some contracts which, together with the price findings, could constitute a case for imposing fines of up to 10 per cent of Gazprom's turnover for the relevant years. Should this happen, appeals to different European courts could delay a final judgment for several more years. But the price outcome is already clear: it will no longer be possible for Gazprom to continue traditional oil linkage, even in those countries which have not (yet) reformed their markets or connected to liquid hubs.

'Political' gas pricing: a variety of interpretations

In the minds of many European politicians, media commentators, and electorates, the principal concern about Russian gas supplies is the political and security threat which they appear to carry. While the pricing of Russian gas in the large, established European markets is becoming more market-related, in smaller markets further away from evolving north-west and central European hubs, it is very often referred to as 'political'. The term 'political pricing' is generally meant to refer to decisions by Gazprom – supported, or perhaps ordered, by the Russian government – to tie gas prices to decisions on gas infrastructure or investments (DG COMP has confirmed this in relation to Bulgaria and Poland), or to other non-gas bilateral issues between the Russian Federation and the country in question.

But while such views are widespread in Europe, they should be questioned – not simply because of regular denials by the Russian government that it uses either energy or Gazprom as a weapon, but because so much of Russian behaviour appears designed to extract maximum revenues rather than political concessions. Where political motives can be clearly identified (these cases are confined to CIS countries) they have involved the importer making a political concession in order to receive a price discount. Analysis of many political pricing claims suggests a confusion between 'political' motivation and the widespread practice of discriminating monopoly pricing (described above) prior to the introduction of competition in European gas markets. However, from the summer of 2014 to March 2015 Gazprom Export failed to meet nominations (daily volumes of gas requested) from a large number of European buyers. While this did not infringe contractual conditions, it seemed strange for a company with a huge surplus of shut-in production to pay penalties for under-delivery to European customers. The reasons for this policy were two-fold: an attempt to curtail volumes of 'reverse flow' gas (Russian gas being sold back) to Ukraine by Gazprom's European customers; and an attempt to support weakening hub prices by generally curtailing available supply. In the event, the action proved to be a failure in relation to reverse flow, its effects were unclear in relation to hub price support, and it was abandoned in March 2015. However, anecdotal evidence suggests that the policy was not instituted by Gazprom Export and may have originated directly from the Russian president which, if true, could be considered directly 'political', albeit with the commercial intentions of forcing Ukraine to buy more Russian gas and of attempting to support falling European hub prices.

The long march to market-based pricing – is the end of the road in sight?

Despite protestations to the contrary by the company and the Russian president, Gazprom has been forced by a combination of the spread of competition, development of liquid hubs, interconnection of markets, and litigation, to progressively adopt market pricing in its long-term contract sales to Europe. This is clearly evident in the case of Ukraine, where reverse flows from Europe have forced a reduction in prices in order to restore the competitiveness of direct sales to one of its major markets, rather than see its gas sold 'second hand' to that market by its European customers.

'… THE PRINCIPAL CONCERN ABOUT RUSSIAN GAS SUPPLIES IS THE POLITICAL AND SECURITY THREAT WHICH THEY APPEAR TO CARRY.'

By the third quarter of 2015, a move to market pricing makes absolute sense for the company when, due to the fall in oil prices, the gap between average long-term (oil-linked) contract and hub prices had narrowed to around 10 per cent (and in some markets to parity) compared with a figure of 50 per cent a year earlier. As a result of the significantly increased volumes of LNG which started to flow to Europe in 2015 (with more to follow as new projects start up and Asia is unable to absorb all of the new volumes), gas-to-gas competition could create the conditions for a 'price war' which Gazprom is equipped to win, should it choose to defend its European market share. But this would require unambiguous acceptance of hub-based pricing. Substantial Gazprom trading operations in the UK and Germany provide the corporate capacity for such a move, and this would bring an end to the seemingly endless cycle of renegotiations and

(threatened or actual) litigation with the majority of Gazprom's European clients. An alternative course of action has been taken in the Czech Republic where, after a disputed arbitral award, Russian deliveries fell from nearly 8 bcm to less than 1 bcm in 2014, suggesting that buyers have been able to access gas from alternative sources at lower prices. In non-competitive European markets, settlement of the DG COMP case could provide guidelines for pricing in these markets until interconnections bring them within reach of hub prices.

Ukraine: the end of post-Soviet gas pricing

Simon Pirani

In 2015, Ukraine's gas import prices have been pulled down by the effects of sustained low prices in Europe and the expanding reverse flow trade. The military crisis and soured relations with Russia have effectively finished off the post-Soviet method of setting prices by bilateral, politically influenced, negotiations. In the domestic market, shock therapy has been applied: households' gas tariffs were hiked by 280 per cent on average, in April. Whether and how such reforms will work remains to be seen.

'UKRAINE'S GAS MARKET HAS SHRUNK SUBSTANTIALLY IN RECENT YEARS …'

The background

Ukraine's gas market has shrunk substantially in recent years – from 70–75 bcm/year in the mid 2000s, to 50.4 bcm in 2013, 42.6 bcm in 2014, and down further in early 2015 – but even now it is one of Europe's largest. The country has steadily produced about 20 bcm/year, but otherwise has depended on Russian imports – payment (or non-payment) for which has long caused friction.

For several years up to 2005, Ukrainian import prices were fixed at $48–50/1000 cubic metres (mcm). After the Russo-Ukrainian 'gas war' in 2006 – when Gazprom responded to mounting debts by reducing supply, and flows to European destinations were interrupted – Russia argued that Ukraine's import prices should be linked to those in Europe. Kyiv agreed, but in subsequent years, rapidly rising oil prices made that target hard to achieve. Ukraine's import prices bounded up to $179.50/mcm by 2008 – but in that year they were still less than half the oil-linked prices Gazprom received in Germany.

After the second 'gas war' of 2009, a contract with European-style oil-linked prices was signed between Gazprom and the Ukrainian state importer, Naftogaz Ukrainy. But in Europe the economic recession, combined with market liberalization, resulted in a progressive move to hub-based prices, and a gap opened between the latter and Gazprom's oil-linked prices. European buyers demanded, and began to receive, discounts from Gazprom.

Ukraine got its discount ($100/mcm on import prices, from April 2010) not from Gazprom but from the Russian government, in exchange for extending the lease on the Black Sea naval base. But as oil prices rose remorselessly, prices in Ukraine's import contract followed them upwards, and in both 2012 and 2013, Ukraine's import prices, even with the discount, slightly exceeded the BAFA average German import price.

After the political crisis

In the spring of 2014, when the Yanukovich government fell, Russia annexed Crimea, and military conflict erupted in eastern Ukraine, the 2009 contract effectively ceased to function. (It is now subject to numerous arbitration cases, which will begin to be heard next year.) It has been replaced *de facto* by competition between Russian imports (prices of which have been agreed in trilateral political

Ukraine gas price vs European prices, 2006–14, $/mcm

	2006	2007	2008	2009	2010	2011	2012	2013	2014
Import price*	95.0	130.0	179.5	198.3	256.7	313.5	425.9	413.5	295.0
BAFA average German import price	295.5	300.0	435.3	320.2	301.2	393.7	410.2	402.5	341.6
TTF	275.2	223.7	402.7	183.6	252.8	346.2	363.7	395.3	310.3

* Russian import price 2006–13; average import price 2014.

Sources: German economy ministry; TTF; companies

Gas imports into Ukraine: prices and volumes

		From Russia		From Europe	
		Price, $/mcm	*Volume, bcm*	*Price, $/mcm*	*Volume, bcm*
2014	Q1	268.5	6.09	n/a	0
	Q2	485	7.84	282	0.6
	Q3	n/a	0	352	1.63
	Q4	378	0.52	353	2.84
2015	Q1	337	2.16	304	3.65
	Q2	247	1.54	280	2.65
	Q3	247	n/a	250–260	n/a

Sources: news reports, companies, author's estimates

negotiations between Russia, Ukraine, and the European Commission) and reverse flow gas imported to Ukraine via Slovakia, Poland, and Hungary.

In the second quarter of 2014, Russian imports under the Gazprom–Naftogaz contract, with discounts removed, cost $485/mcm, while small volumes of reverse flow gas were imported at a price of $282/mcm. Russian deliveries stopped, due to non-payment, in June (by the end of which there was 14.2 bcm in storage). In the third quarter, Ukraine sought more reverse flow gas.

In the six winter months (October 2014–March 2015), 6.5 bcm arrived in Ukraine from the west; its price fell from around $350/mcm to around $300/mcm. The trilateral negotiations noted above assured the restart of direct Russian deliveries, from November, but they were more expensive – $378/mcm in Q4 2014 and $337/mcm in Q1 2015 – and Ukraine bought as little as possible (about 2.7 bcm). Ukrainian imports were at a record low for post-Soviet times – but sufficed for the winter due to unusually warm weather and economic stagnation.

Reverse flow gas physically originates in Russia. It is bought and resold in central Europe (a practice that Gazprom frowns on but appears to have accepted that it is unable to stamp out). So the reverse flow trade cannot replace Russian imports – but it is compelling Russia to price direct imports competitively, and inducing Kyiv to buy from both sides (notwithstanding a political preference to stop direct imports completely).

This was demonstrated in the second quarter of 2015, when Gazprom priced gas for Ukraine at $247.18/mcm. By mid-May this offer – described by Ukrainian energy minister Volodymyr Demchishin as 'economically reasonable' – began to dislodge reverse flows. Ukrainian imports via 'reverse flow' fell, although they were still greater by volume than Russian imports. In the third quarter, Gazprom offered gas at a reduced discount, producing a price of $247/mcm that was again competitive with European hub prices. Naftogaz declined to buy directly imported gas at this price, and at the time of writing direct imports have stopped.

It remains to be seen whether, with both gas and oil prices depressed, the oil-linked prices of direct imports could be reduced sufficiently to erode the reverse flow trade further – and whether Gazprom will continue to compete on price. Moreover, it is difficult to calculate how much imported gas is enough for Ukraine. It will depend ultimately on the weather, the economy, and the level of storage (which in mid-June was 2 bcm lower than at the same time last year).

Another unresolved issue is: who will pay for gas delivered to the separatist-controlled areas of eastern Ukraine? Currently, it appears that no-one is paying. After Naftogaz briefly interrupted deliveries in February due to a pipeline accident, Gazprom began pumping gas directly to the area outside Ukraine's control. By late June these volumes totalled more than 0.7 bcm. Gazprom CEO Aleksei Miller proposed a separate contract with local distribution companies. This might be commercially logical for Naftogaz, which will otherwise be invoiced for the volumes, but not politically acceptable in Kyiv, as it would implicitly acknowledge the separatists' status.

The domestic market

Ukraine's military–political crisis has triggered economic collapse and near-bankruptcy for the state. The result has been a drastic fall in gas demand, and a programme of gas market reforms prescribed by the IMF, whose $17.5 billion loan programme stands between the government and sovereign default.

'UKRAINE'S MILITARY–POLITICAL CRISIS HAS TRIGGERED ECONOMIC COLLAPSE AND NEAR-BANKRUPTCY FOR THE STATE.'

Prices vary by sector. In 2014, gas consumed went to:

- industry and power (37 per cent),
- residential and public sector customers (37 per cent),
- district heating (16 per cent),
- fuel gas (9 per cent) and
- deliveries to separatist-controlled areas (1 per cent).

Industry and power customers pay for most of their gas at regulated import-related prices (currently $316/mcm), but their consumption has fallen furthest.

Gas consumption in Ukraine 2014

	bcm	%
Industry and power sector	15.7	37
Residential and public sector	15.8	37
District heating	7	16
Technical gas	3.7	9
'Uncontrolled territories'	0.4	1
Total consumption	42.6	100

Source: Naftogaz Ukrainy

Industry and power sector demand in 2014 was at 46 per cent of its 2007 level. This is not surprising given that: the separatist-controlled area includes the heaviest concentration of industry and accounts for an estimated 9 per cent of GDP; in 2014, trade with Russia was at one third of its 2013 level; and in 2014 industrial output and construction fell by 11 per cent and 22 per cent respectively year on year. (They were down a further 22 per cent and 31 per cent in Q1 2015.) All of this means that, notwithstanding emergency regulations over the winter months (compelling large industrial customers to buy from Naftogaz rather than private traders) the state company's income from these customers has fallen.

Residential customers pay for Ukrainian-produced gas at prices that have always been heavily discounted; an even greater loss has been borne by Naftogaz on sales to district heating companies, who buy imported gas at low prices. (This is not the end of the black hole in Naftogaz's finances: in 2014 the IMF reckoned that 'inability to collect domestic receivables' ($2.05 billion) and 'net sales shortfall' ($890 million) comprised about half of the company's total operational deficit of $5.5 billion.)

On 1 April the government, guided by the IMF towards classic 'shock therapy', raised regulated tariffs for residential customers by an average of 280 per cent (roughly – one group of customers now pays $333/mcm, and a larger group, entitled to discounts, pays $167/mcm). Tariffs for district heating companies rose by 129 per cent to $139/mcm. Naftogaz's team of reform-minded managers launched a feisty campaign against non-payment: they published a list of big non-payers among district heating companies (whose debts totalled $1 billion in late April); appealed a court ruling that prevented them cutting off non-payers; offered non-payers who own gas producing companies a swap deal; and secured parliamentary approval to sell on debts.

Tackling non-payment by residential customers will be much harder, mainly because protection for poor families (that good practice requires is arranged prior to increases) is patchy. Prime Minister Arseniy Yatseniuk says the number of families entitled to subsidies for gas will rise to 3 million. But past experience across the whole former Soviet Union shows that local authorities will probably take some time to put schemes in place, and that households will probably prioritize other necessities before they pay for gas.

Outlook

Ukrainian advocates of gas supply diversification have suggested that reverse flow gas, together with higher domestic output, could replace Russian imports completely; the government has instructed Naftogaz to limit imports to no more than 50 per cent from a single source (i.e. Russia). Like the analogous Russian claims – that new pipelines to Europe (Nord Stream, Turkish Stream, etc.) could reduce gas transit across Ukraine to zero – scenarios with no Russian imports at all would probably be relevant only in the unlikely event that political relationships deteriorate even further, for example if Russia and Ukraine declared war on each other.

The more likely outcome – a 'frozen conflict' in eastern Ukraine for many years, with Russian-supported separatism weakening the economy and government – will motivate both sides to reduce the Russo-Ukrainian gas trade to a minimum, but not to halt it completely. In this case, reverse flow deliveries will compete on price with direct Russian imports, as they have done this year. The benefit to Ukraine will be all the greater if, as it appears, we are entering a relatively long period of lower oil and gas prices.

'REVERSE FLOW DELIVERIES WILL COMPETE ON PRICE WITH DIRECT RUSSIAN IMPORTS …'

Domestically, market reforms are likely to continue. But only after the economy starts to recover from its collapse will it be possible to estimate how much gas demand will return at post shock-therapy prices.

Finally, Ukraine is likely to lose its status as a major gas transit country. Gazprom says that, once the current transit contract expires at the end of 2019, it intends to divert volumes for European customers via Turkey, Poland, or Nord Stream. Opinion as to whether some of those customers will wish, or be able, to buy Russian gas on Ukraine's eastern border and arrange transit themselves is divided. All that is sure is that the post-Soviet order, in which transit issues were always linked to Ukrainian import issues in quasi-political negotiations, is coming to an end.

Gas pricing reform in India: will it transform the gas landscape?

Anupama Sen

In November 2014, India implemented an unprecedented reform of domestic gas pricing. Under the reform, India's gas price (formerly controlled by the government at $4.20/MMBtu) became linked to a volume-weighted average of world gas prices – US Henry Hub, UK NBP, Alberta Gas Reference price, and the Russian domestic gas price. The price is to be reset every six months, based on a twelve month trailing average with a lag of one quarter.

Nearly a year on, India's gas sector (particularly upstream exploration), has failed to revive following a four-year period of decline. Rather than an anticipated rise in domestic prices (upon which upstream companies had based capital expenditure plans in an environment of rising costs) from the previously controlled levels, prices have been falling (down to $4.66/MMBtu between 1 April and 30 June, in comparison with $5.05/MMBtu for the preceding two quarters). While this is partially due to the global price downturn, it is also due to the benchmarks in the formula – such as the low Russian domestic gas price (amidst falling demand in the Russian economy) and Henry Hub/ Alberta prices (in an environment of plentiful supply) – which were arguably selected on the basis of their dampening impact on the price level rather than reflecting any sort of opportunity cost-based price formation mechanism for India.

One way in which the authorities are seeking to incentivize upstream explorers despite the low price is to allow a premium on the price for deep water areas, but the details of this have yet to be finalized. Furthermore, a policy consultation over whether the current profit-based fiscal regime for exploration should be replaced with a revenue-based regime has yet to be completed.

The lack of a clear price signal has made it difficult to make a confident and accurate assessment of India's market potential. This has led to diverging forecasts of demand for 2030 – ranging from roughly 100 bcm (EIA) to 400 bcm (government estimates) – and uncertainty over whether India – with its economic growth expected to overtake China's this year – is the global gas market's new 'wildcard'.

India's gas market

India experienced a brief renaissance in its upstream gas sector in the 2000s after the discovery of offshore KG-D6 gas by Reliance Industries Limited. Production began in 2009, briefly overtaking NOC production by 2010. But by 2013, this had fallen to a third of the original targets. Total production fell from a peak of 50 bcm in 2010 to just over 30 bcm in 2014 (as against a target of around 48 bcm in India's Twelfth Five Year Plan), and has thus far failed to recover. Along with investment uncertainty, there is ambiguity over India's resource potential, as 50 per cent of its sedimentary basin is classified as 'poorly explored' – most of this being offshore.

The inevitable shortage of domestic gas implies a greater need for LNG imports. However, demand-side constraints have prevented the expansion of gas in the economy. The most significant of these is India's 'Gas Utilisation Policy' under which the government rations gas. This has led to a two-tiered structure of demand, where domestic gas is first released in order of priority to fertilizers, power, and city gas for households and transportation (accounting for over 70 per cent of consumption); the remainder being released to a second tier comprising refineries, petrochemicals, merchant/ captive power plants, and city gas for commerce and industry. Some tier one consumers use imported LNG at lower prices (obtained by pooling it with domestic gas) as domestic supply is insufficient to meet demand, while tier two consumers are able to purchase LNG at import prices. In July 2014, city gas for households and transportation was moved to the top of the priority order.

Demand has therefore been determined until recently by fertilizers, where low-priced gas is used to manufacture roughly 22 million tonnes (Mt) of urea each year. A further 8 Mt is imported on the international market (roughly 6 Mt spot and 2 Mt on long-term contracts). Urea retails at around half of its cost price, and in 2013 a total subsidy of around $6 billion was provided for fertilizers. An impediment to gas price reform is therefore the impact of higher prices on fertilizers, and by extension, on agriculture.

'AN IMPEDIMENT TO GAS PRICE REFORM IS THEREFORE THE IMPACT OF HIGHER PRICES ON FERTILIZERS …'

These dynamics have created an incongruity in India's gas market, where there are two 'moving parts' – one has prices and quantities set by the government, and another utilizes gas at import prices. There is also some overlap, complicating attempts to assess these as separate markets. The potential for the reform to transform India's gas landscape is contingent upon whether it can reverse the decline in production and

incentivize new investments upstream, and whether consuming sectors can absorb gas at higher prices.

Impact of reform

A review of existing reserves shows that at current or marginally higher price levels the reform is unlikely to reverse the recent decline in domestic production before 2020. Any production increase would have to come from NOCs rather than the private sector in the absence of a new 'giant' discovery similar to KG-D6, as NOCs hold the largest proportion of India's gas reserves (of 1.4 tcm) as well as Exploration Licences (ONGC alone holds just over 50 per cent). Whilst a proportion of ONGC's marginal and offshore fields (3–5 bcm/year) can reportedly be brought into production by 2016 at prices of $6–7.15/MMBtu, higher prices of $10.72–12.63/MMBtu are reportedly required to commercialize the larger deep water fields. Existing studies on production costs and breakeven prices suggest that gas prices of at least $8/MMBtu are needed to develop roughly 30 Tcf of reserves, implying that the price level would have to rise substantially for the reform to have any sort of impact on existing and new production and exploration.

This leads to the question of how much high-priced gas could be realistically absorbed in the main consuming sectors. For fertilizers, one proposed solution has been to utilize the revenues that will accrue from royalty (around 10 per cent) and corporate income tax (around 34 per cent) on production valued at the higher gas price to finance the inevitable increase in fertilizer subsidies. An analysis of the cost of urea at different gas prices, when compared with government revenues (from royalty and taxes) based on 2014 gas production targets, suggests that the total subsidy bill could potentially be offset at prices of $9–11 per MMBtu ('Gas Pricing Reform in India: Implications for the Indian Gas Landscape', OIES Paper NG96). However, this is contingent upon private sector production targets, unless there is an equivalent increase in NOC production. A longer-term solution to the sustainable 'management' of the subsidy bill would involve a reorientation towards long-term contracted fertilizer imports. Any increase in the gas price would nevertheless reduce the net cost of the subsidy on urea through increases in tax and royalty receipts on producing gas fields, as these rise faster with the gas price than the subsidy.

In the power sector, where there is an estimated 14–24 Gigawatts of idle or suboptimal gas-fired capacity, higher prices would have a negative impact due to the absence of carbon pricing or equivalent incentive mechanisms encouraging the use of gas (to displace coal). An analysis of the cost of electricity at different gas prices reveals that gas is uncompetitive with domestic or imported coal at prices of between $5.20–6.20/MMBtu (at electricity prices of between 3–4 rupees per kWh on a variable cost basis for existing plant) under the current merit order dispatch system. Moreover, the heterogeneity of regulations on third-party access often prevents gas at higher prices from being sold to price-inelastic consumers. A goal of universal electrification by 2019 suggests that coal is unlikely to be discouraged, implying a limited role for gas in power.

The outlook for city gas is relatively more optimistic, especially since city gas for households and transportation recently displaced fertilizers in the Gas Utilisation Policy, implying that it now has the first right to domestic gas. The improved price competitiveness of city gas against diesel and LPG (on the back of recent petroleum product pricing reforms), along with the fact that city gas distribution entities are able to pass through upstream price increases, implies that investments in the expansion of city gas infrastructure should be forthcoming. However, there is uncertainty over how much gas this sector can realistically absorb in the next few years until infrastructure is built and pipeline use regulations are implemented.

'IN THE LONGER TERM, THE CITY GAS SECTOR APPEARS TO HOLD THE GREATEST OPPORTUNITY FOR EXPANSION …'

There is, theoretically, significant potential for LNG imports to bridge shortages. The fall in spot prices to $7–7.50/MMBtu implies marginally higher market potential for LNG imports in power and fertilizers – in March 2015, the government approved the pooling of domestic and import prices for supply to these sectors. At around the same time, India began negotiating a 10 per cent cut in its long-term contracted imports from Qatar, intending to substitute this with lower spot-priced imports. The market created through price pooling is, however, short term. In the longer term, the city gas sector appears to hold the greatest opportunity for expansion, although this will depend on the pace of infrastructure development. Recent analyst reports suggest that the sector grew at 21 per cent in the period 2010–14. Specifically, urban air quality is of growing public concern, reflected in conversions to gas of public transportation fleets in several cities; this could provide the necessary push to expand gas use in transportation.

Longer-term challenges

The domestic gas pricing reform is unlikely to transform India's gas landscape in the short term and the focus will continue to be on price level, unless there is a reorientation of policy towards a longer-term goal for the role

of gas in the Indian economy, relative to coal and oil. Three main conclusions can be drawn in this regard.

India lacks a clear roadmap for reform, and for gas in the economy relative to other energy sources. For instance: to make gas competitive with coal for environmental reasons, to replace other fuels for fiscal reasons, or to retain a proportion of gas as backup for renewables. This is different from the approach towards 'energy (supply) security' that has been pursued by governments – signifying the race to obtain adequate energy supplies to support economic growth.

India lacks a price formation mechanism which in some way reflects the dynamics of the Indian market. For instance: in China's reform process, gas prices have been determined by the fuels they are replacing in the domestic economy – fuel oil, LPG, and LNG imports. Similarly in India, the main substitute to domestic gas in fertilizers is imported LNG; in power it is coal; and in city gas it is LPG and imported LNG. In January 2015, an industry representation recommended linking the 'premium' on domestic gas prices to a discounted average of fuel oil, unsubsidized LPG, naphtha, and distillates in the domestic market.

The most likely outcome going forward is a continuation of the present system, potentially incorporating some elements of a market-based price formation mechanism. However, implicit price controls need to be recognized in order for any effective progress to be made. For instance: the calculation of a premium to the domestic price needs to recognize the capital constraints of the NOCs (whose capital outlays are influenced by their financing of subsidies). The problem with a continuation of the status quo, however, is that in the absence of a longer-term vision it fails to resolve the uncertainty that has deterred the development of the gas sector. 'Gas price pooling' could end up compounding the problem, as low prices are unlikely to incentivize new production, which could potentially lead to higher-priced LNG imports becoming the main source of incremental gas. This could create further disincentives to reform, as governments prefer to retain control over the domestic price in order to moderate the impact of higher-priced incremental LNG imports.

'… GAS PRICE REFORM SHOULD BE EASIER TO CARRY OUT IN A LOW "GLOBAL" GAS PRICE ENVIRONMENT.'

As was the case with the recent completion of petroleum product price reforms in parallel with the low international oil price, gas price reform should be easier to carry out in a low 'global' gas price environment. The current situation, however, could represent a missed opportunity, implying further difficulty in progressing with reforms in the event that LNG prices begin to rise. Without much more significant market-related reform (potentially involving much higher prices), gas is unlikely to become a significant source of energy for India.

China's pricing reform – how far and how fast?

Michael Chen

While China's consumption of natural gas grew dramatically in the 2000s, demand only began to outstrip domestic production by a significant amount in the second half of that decade, requiring pipeline and LNG import infrastructure to be put in place. High oil prices and emerging environmental problems, as a result of burning coal to fuel rapid economic growth, had increased the need for cleaner premium fuels such as gas.

'CHINA IS RAPIDLY BECOMING "CONNECTED" TO A PORTFOLIO OF INTERNATIONAL SUPPLIES.'

With pipeline imports secured from Myanmar and Central Asia, and more recently from East Siberia, as well as a range of LNG suppliers, China is rapidly becoming 'connected' to a portfolio of international supplies. As its demand growth increases, the scale of its import requirements will influence both regional and global trade flow dynamics.

However, a system of fragmented and uneven price regulation created tensions among producers and distributors, posing challenges to the encouragement of more investment in production and infrastructure to meet demand, and to the improvement of market access and connectivity between regions. Rapidly increasing import needs, widely dispersed domestic production, and the location of import pipelines and LNG terminals relative to consumption centres, called for the government to replace traditional cost-plus gas pricing with an alternative that would better reflect market fundamentals.

From wellhead cost-plus to citygate benchmark pricing

The netback pricing trial in 2011, and its eventual nationwide adoption for provincial citygate gas pricing for non-

residential sectors in 2013, partially ended more than 50 years of the general wellhead cost-plus ex-plant pricing model, and enabled gas prices to be indexed to the alternatives (LPG and fuel oil), allowing market forces to play a greater role than government decisions. It established a single citygate price ceiling for each province and applied this to all onshore piped gas supplies for non-residential gas use. In stark contrast to the cost-plus system, the new system moved the pricing point downstream from the wellhead to the city gate.

This reform has resulted in four types of ex-plant pricing:

1 The residential sector started to adopt end-use tiered pricing (the process should be completed by the end of 2015), but still uses the cost-plus ex-plant pricing model for onshore gas supplies.
2 Non-residential sectors apply netback citygate pricing for onshore supplies (both domestically produced piped gas and pipeline imports).
3 The imported LNG ex-plant price is determined by the LNG import and re-gasification costs of individual provinces. Due to differences in the timing of signing LNG contracts and lags in the contract pricing formulae, there are wide variations in the price of LNG imported through the same terminal.
4 For unconventional gas (shale, CBM, and Coal-to-Gas) and large industrial gas users, the gas price is determined directly between wholesalers and end users.

Challenges facing determination of price

However, in respect of the netback citygate pricing of non-residential gas, the lack of a transparent and frequent price review mechanism remains a key obstacle to market forces. The process also introduced both unpredictability and price risk for gas importers with oil-indexed contracts (subject to regular price adjustments) and failed to incentivize consumer demand by passing through lower prices. Due to a lack of proper implementation, the current netback system has not effectively reflected the price changes of alternative fuels. The citygate ceiling price is expected to be revised relative to oil price movements annually (but without a specific date for price revision) with a lag to accommodate similar lags in pipeline import contracts. In addition, the design of pricing by the NDRC is heavily dependent on consumer affordability rather than market fundamentals. For instance, calorific value and storage costs have yet to be factored into prices, which need to address heat content differences between various sources of gas and seasonal volatility. Diverse regional endowments also call for the inclusion of more alternative fuels (such as coal) to reflect competition in the power sector. Most importantly, netback pricing is holding back gas industry development and even, to some degree, price reform, as ex-plant prices and transmission tariffs are bundled, hindering third-party access and the independence of midstream operation. This prompted NDRC to announce a pilot programme in February 2015, allowing large industrial users to bypass the regulated city gates and negotiate directly with gas suppliers, allowing them access to cheaper gas. This mechanism has already been implemented – although only to a limited extent, as three NOCs still control most of the gas supply which gives them significant market power in negotiating prices.

'… NETBACK PRICING IS HOLDING BACK GAS INDUSTRY DEVELOPMENT AND EVEN, TO SOME DEGREE, PRICE REFORM …'

Falling oil prices – slow response of gas price

Given that the vast majority of China's gas import contract prices are linked to oil prices, the substantial decline in the Brent oil price since June 2014 implies that Chinese gas import bills in the coming year are likely to be much lower than previously expected. However, lower import prices may not be sufficient to stimulate Chinese consumer demand growth to a significant extent. In 2014, demand growth slowed to 8.6 per cent, the lowest figure seen in the past ten years. A range of underlying factors: weaker GDP, falling oil prices, mild winter weather, hydro outperformance, and high domestic gas prices all played a part in this slowdown.

With gas already a premium fuel, the economic slowdown constrained sectoral investment that would have expanded gas demand growth, which now faces challenges on multiple fronts. Lower crude prices narrowed the differential between oil products and gas used in transport. In addition, competition from rapidly developing nuclear power and the long-distance transmission of hydro and coal-fired power to coastal demand centres, have both significantly challenged gas-fired power use. The move towards oil-indexed citygate netback pricing for gas over the past three years, and the insufficiently rapid adjustment to reflect the oil price collapse (noted above), have also caused demand destruction.

Against this backdrop of economic slowdown, falling coal prices, rigid government pricing policies, limited consumer bargaining power, and reduced oil–gas price arbitrage opportunities, demand response to the lower import prices will be limited unless gas suppliers adopt voluntary measures to reduce wholesale prices before the netback citygate pricing adjustments are implemented.

Alternatively, government must revise citygate prices more frequently (to reflect oil price changes) and promote third-party access to pipelines and LNG terminals. Due to infrequent adjustment of netback pricing of pipeline imports (which have longer lag times compared with LNG contracts) and the high fixed cost of transmission from the interior to the coast, LNG imports became competitive with, or cheaper than, pipeline gas under regulated citygate prices in the coastal area. However, pipeline imports are harder to displace because of their scale, and any major rebound in oil prices could place LNG imports at a disadvantage to pipeline gas. Spot LNG cargos have become more competitive than small-scale land-based LNG serving the domestic market (which had been able to command a premium over citygate prices based mainly on pipeline gas).

Need for more widespread use of gas in China

In addition to an increase in market-based pricing, accessibility and speed of delivery will be crucial in promoting gas use in China. In addition to Shanghai, several gas trading platforms are being set up to create more liquidity. At this stage, their growth is constrained by lack of third-party access and the willingness of suppliers to provide gas to the platforms. The lower oil price environment is expected to reduce import bills and help China absorb the surge in contracted pipeline and LNG volumes. However, even with lower import prices, price pass-through and the development of new markets will take time. End users will have opportunities to negotiate better supply deals if third-party access to facilities is accelerated. One Chinese NOC has started to rent out part of its LNG facilities to non-NOC gas distributors and utilities. Nevertheless, relationships between NOCs that have an interest in protecting their traditional coastal markets, and non-NOCs that would like to import at a price which could undercut NOCs, remain delicate. Clear regulation to cater for third-party access to LNG terminals is needed to balance the interests of both parties with those of consumers.

'IN ADDITION TO SHANGHAI, SEVERAL GAS TRADING PLATFORMS ARE BEING SET UP TO CREATE MORE LIQUIDITY.'

As the implementation of the current netback pricing model gathers momentum and gas pipeline connectivity accelerates, prices for each province could start being developed on a 'differential cost of supply' basis, provided that rules and tariffs for third-party access and storage are developed and regulated effectively. At that point, China might gradually move to hub-based pricing (at least for a portion of its supplies and facilitated by regional exchanges) in order to allow gas to flow to regions that have the highest demand and the greatest ability to pay. The development of competitive domestic gas pricing for regions that depend on diverse gas sources with different costs of supply will be critical to fostering a sustainable level of demand and to reinforcing the drive to improve environmental quality, economic rebalancing, and fuel mix policies.

Japanese LNG import prices – are alternatives to JCC evolving?

Ken Koyama

The question of whether alternatives to JCC are evolving in the Japanese LNG market is important because the answer can make a fundamental difference not only in Japan but also elsewhere in Asia. This article discusses the problems of the current pricing regime and then examines LNG market conditions (including the supply–demand balance in Asia, and the benefits of, and constraints on, developing alternative pricing mechanisms). The conclusion assesses the possible future direction of LNG pricing in the Pacific Basin.

The problems of JCC

The rationale of current JCC indexation is being questioned by an increasingly large number of Japanese stakeholders which include: LNG importing companies (power and gas utilities), final consumers, government officials, politicians, and media sources. The rationale clearly existed in the 1970s and 1980s when LNG was introduced, as it was competing directly with crude oil in power generation. But in normal circumstances, oil-fired stations are used for peak shaving and account for only around 10 per cent of total power generation as power supply. Thus far, buyers and sellers of LNG have been unable to find a mutually acceptable alternative to JCC.

By definition, LNG prices determined by JCC indexation have nothing to

'… CURRENT JCC INDEXATION IS BEING QUESTIONED BY AN INCREASINGLY LARGE NUMBER OF JAPANESE STAKEHOLDERS …'

do with LNG or natural gas supply–demand fundamentals, but are solely related to global crude oil prices. A serious problem arose when crude oil prices shot up after 2011 and, as a result, Japan's LNG import price reached $16–18/MMBtu. This period coincided with the Fukushima accident, which had led to a large increase in LNG imports to offset the reduction in generation from nuclear stations. It also coincided with the US shale gas revolution, which resulted in Henry Hub prices falling to $2–4/MMBtu. High LNG prices caused by the oil price hike at a time of national energy security crisis, when contrasted with low US gas prices, attracted significant attention from public, industry, and policy domains in Japan. This led to a perception that there is a problem with the current price mechanism and that something has to be done about it.

The pressures on LNG buyers for competitive procurement

Post 2011, the procurement of LNG at more competitive prices has become a national priority. This is because high LNG prices have emerged as being an important factor in Japan's trade deficit and in its rising energy and power generation costs. In FY 2010 (before the nuclear accident) Japan had a trade surplus of 5.4 trillion yen, but recorded a 14 trillion yen trade deficit in FY 2013, while power generation costs rose by 4.4 yen/kWh during this period – a 43 per cent increase in industrial electricity prices. These changes were caused partly by significant increases in the volumes of LNG and other fuels imported to compensate for the loss of nuclear power, but LNG price increases also played an important role. Thus, together with nuclear restart efforts, competitive procurement of LNG has become an energy policy priority for Japan.

'POST 2011, THE PROCUREMENT OF LNG AT MORE COMPETITIVE PRICES HAS BECOME A NATIONAL PRIORITY.'

For LNG importers, competitive procurement has become a real and serious challenge for their survival. Success (or failure) of competitive procurement will have a direct impact on the financial performance of electric utility companies, which account for about 70 per cent of total LNG imports. Substantial increases in LNG and fuel import costs, combined with limitations on cost pass-through to customers by the government, have resulted in most of the utilities making historically high financial losses. At the same time, they have been under strong pressure from government, consumers, media, and the general public to make serious efforts to lower energy costs. For gas utility companies, the share of LNG purchase costs is much larger than for electric utilities, emphasizing the significance of competitive procurement and cost reduction.

Finally, ongoing electricity and gas market reform (liberalization) in Japan will increase competitive pressures on utility companies. The retail electricity market is scheduled to be fully liberalized in FY2016 (with legal unbundling to be introduced in FY 2018–20); gas sector liberalization is scheduled for FY 2017 (with legal unbundling for the three major gas utilities in FY2022). In a liberalized market, the development of a competitive advantage in fuel procurement will be an important key to survival and success, and modification of existing JCC-based contracts and the introduction of alternative pricing mechanisms have become a priority for electric and gas utilities.

Changing LNG market conditions in Asia

Supply–demand conditions in Asian LNG markets will be the key determinant of improved procurement (specifically price) conditions. In 2015, the Asian LNG market is over-supplied and favours buyers due to a combination of: weak demand growth in major consuming countries such as China, Korea, and Japan, and increased LNG supplies from the start-up of new projects in Australia. As a result, Asian spot prices declined substantially from over $15/MMBtu in Q1/2014 to around $7/MMBtu by Q2/2015, a five year low and similar to European price levels.

Many market observers believe these conditions are likely to continue at least for the next four to five years, because the expected supply additions from US and Australian projects will be more than sufficient to meet demand growth. On the demand side, Japan's nuclear restarts will further weaken the LNG appetite of the world's largest LNG importer and affect the supply–demand balance in the market.

Of course, there are many uncertainties in this outlook. Demand in Asia may pick up unexpectedly due to the effects of possible delay in nuclear restarts in Japan, and/or any slowdown in nuclear power generation elsewhere in the region. Any accidents and operational problems would also reduce LNG supply. But more importantly, lower LNG contract prices (because of indexation to crude oil) are beginning to impact the LNG supply–demand balance. Lower spot and contract LNG prices may stimulate LNG demand, particularly in emerging markets, but may also negatively impact the economic viability of, particularly, 'greenfield projects'. In short, the current low oil and LNG price environment may lead to a tighter supply–demand balance beyond 2020.

Buyers of LNG in Japan and elsewhere in Asia are struggling to explore any opportunity to improve the competitiveness of LNG procurement

under current market conditions. While there are uncertainties over the long run market conditions, buyers are now embarking on various procurement initiatives, including new ideas for pricing mechanisms.

Current situation and prospects for alternative pricing

But the fact remains that almost all of the existing long-term LNG contracts in Japan (and Asia) have JCC indexation and the traditional sellers of LNG have no incentive to change the current pricing regime. Therefore, buyer–seller negotiations on pricing may focus on indexation adjustment – for example by changing the 'slope' or reintroducing an 'S-curve'. This may assist buyers in securing lower prices, but will be of no help in addressing the 'rationality' of the price in relation to LNG (or natural gas) market supply–demand fundamentals.

'BUYERS HAVE CONTINUED TO EXPLORE NEW OR ALTERNATIVE PRICE MECHANISMS, WITH HENRY HUB-BASED PRICING EMERGING AS A FRONT RUNNER.'

Despite these drawbacks, buyers have continued to explore new or alternative price mechanisms, with Henry Hub-based pricing emerging as a 'front runner'. This is based on the widely shared expectation in Japan that US LNG exports will have many advantages: a lower price than JCC-indexed LNG, diversification of import sources, diversification of price mechanism, and greater supply flexibility (specifically destination-free delivery). US LNG import contracts signed by utilities, trading houses, and others, based on Henry Hub pricing, could reach 17 million tonnes around 2020, accounting for around one fifth of Japanese imports.

But with oil prices around $50–60/bbl the competitiveness of Henry Hub pricing against JCC is being questioned. As US LNG import requires fixed transportation and liquefaction costs of some $6–7/MMBtu, landed costs of US LNG to Japan are expected to be in the range of $11–12/MMBtu. While this is cheaper than actual import prices in the period 2011–14, it is significantly higher than the mid-2015 spot price, and contract prices are falling below $10/MMBtu. Thus buyers in Japan have started to take a more cautious stance toward imports based on Henry Hub pricing. The latter reflects natural gas supply–demand fundamentals in the USA, not in Asia, limiting its advantages as an alternative to JCC. Despite these problems, however, US LNG imports are still regarded as valuable for Japan because of other advantages (mentioned above) such as supply and price diversification and flexibility.

Spot LNG pricing presents another potential alternative to JCC. Several price reporting agencies (PRAs) publish regular spot price assessments, based on their own information and intelligence. By definition, spot prices reflect supply–demand conditions and can be regarded as a market reference, but there are issues related to reliability and transparency of prices. Though LNG spot trade has increased steadily and now accounts for about 10 per cent of global LNG trade (based on 407 cargoes in 2014, estimated by ICIS Heren, multiplied by 60,000 tonnes average cargo volume and divided by total LNG trade), the liquidity and depth of the market is not sufficient to be regarded as a reliable benchmark by many traditional buyers, who also tend to be wary of price volatility. But there is an expectation in the industry that further growth in trading will create greater liquidity and flexibility, and spot prices will eventually become a reliable benchmark for contract prices. In this regard, market participants have expectations that US LNG imports combined with the removal of destination clauses, will create conditions for greater spot trade.

The creation of an Asian gas hub is a longer-term measure for an alternative price mechanism. Asian hub-based pricing could be seen as the most desirable solution, in that it would genuinely reflect Asian gas market fundamentals. The success of US/European hubs, such as Henry Hub and NBP, as well as an observed ongoing shift to gas hub-based pricing in Continental Europe, has created the momentum to promote the establishment of gas hubs in Asia. In Japan and China, the creation of gas hubs is being considered, but current market conditions in these countries suggest that it will take longer to create well-functioning Asian gas hubs. Market liberalization, along the lines of the reforms currently under way in Japan, will be key to this approach, but the extent and timing of its impact is difficult to predict.

Corporate strategies for LNG procurement

Given current developments and expectations, Japanese and Asian LNG buyers are now trying to take a 'portfolio' (diversification) approach to pricing. Understanding that there is no perfect solution, buyers are exploring all available price mechanisms – such as Henry Hub, NBP, spot LNG, hybrids of these mechanisms, and JCC. The purpose of this approach is to reduce dependence on traditional JCC pricing and to promote risk diversification in the face of market uncertainties, until a viable alternative emerges which can fully replace JCC indexation.

For example, Chubu Electric, the second largest LNG importer in Japan after TEPCO, is reported to have a target to reduce traditional JCC pricing to less than 50 per cent of total imports. Chubu and TEPCO have

established JERA, a comprehensive alliance company which will be responsible for power generation and fuel (including LNG) procurement. JERA's LNG procurement policy will be very important for the future of Japan's pricing regime as its annual purchases may be as high as 40 million tonnes, accounting for almost half of the country's total imports. It is believed that JERA will use alternative mechanisms (discussed above) to reduce dependence on JCC. Other major importers such as Tokyo Gas, Osaka Gas, and Kansai Electric are known to be adopting similar approaches.

Conclusion

Given the dominance of existing contracts, it is highly likely that JCC pricing will remain the principal mechanism in Japan and Asia up to at least the early 2020s. Even in the longer run, JCC can remain an important part of Asian LNG pricing, depending on future negotiations between buyers and sellers.

'EVEN IN THE LONGER RUN, JCC CAN REMAIN AN IMPORTANT PART OF ASIAN LNG PRICING …'

But the market environment is changing rapidly. The prevailing over-supplied market, expected growth in LNG supply flexibility, and buyers' pursuit of competitive LNG, all point to a gradual shift towards a pricing regime which better reflects market fundamentals.

The answer to the question posed in this article is, therefore, that alternatives to JCC are indeed evolving in the Japanese LNG market; buyers are searching for alternatives and the share of JCC-based LNG is likely to decline. Currently, there is no clear answer as to what will be the single most promising alternative to JCC, but options that will better reflect market conditions are being introduced and will be tested.

The impact of falling oil and gas prices on non-US LNG producers

James Henderson

The fall in the oil price from a high of $115 per barrel in mid-2014 to around $65 per barrel in May 2015 has clearly impacted the revenues and commercial outlook of LNG producers and consumers, given the strong historic link between LNG contract prices and oil. The LNG contract price is generally negotiated in relation to a slope, which captures the link in percentage terms between the oil price in US$ per barrel and the LNG price in US$ per MMBtu. On an energy-equivalent basis, the LNG price would be 17.5 per cent of the oil price, but in order to ensure the competitiveness of gas the slope is normally negotiated within a 13–16 per cent range, depending on the market conditions at the time and the consequent bargaining positions of buyer and seller. A standard assumption is that the average slope is 14.85 per cent (plus a fixed element of $0.5/MMBtu), meaning that at an oil price of $115 the LNG price would be just over $17.50/MMBtu, while at $65 it would fall to around $10.00/MMBtu. LNG contracts generally also include 'kink points' which limit the upside and downside for both buyers and sellers (creating what is known as an 'S curve'), but even with this modification it is obvious that a $50 fall in the oil price will have had a significant impact on LNG suppliers. However, there is a broad range of outcomes across the LNG supply chain due to the differing economics of projects in various countries.

Qatar

Qatar has existing infrastructure that can produce and sell 77 million tonnes a year into the global LNG market, and although its pricing strategy has been based on a strong link to oil prices in Asia, its low cost of supply means that its projects are very robust even at a low price. The 'liquids credit' brought by the condensate it produces alongside its gas output dramatically reduces the breakeven cost of its LNG supply, allowing a 10 per cent rate of return to be generated at a gas price of below $0.50/MMBtu when the oil price is $80 per barrel. The most important issue for Qatar in the current global gas market, therefore, has less to do with managing costs and more to do with a concern over how to maximize revenues in a world where gas prices have fallen – not only due to lower oil prices, but also because global LNG supply is starting to rise, while at the same time demand in Europe is falling, and rising less quickly than anticipated in Asia. As a result, Qatar is unlikely to end its moratorium on increasing LNG supply above 77 Mt in the near future, even though expansion of its facilities would have very robust economics; its main goal therefore will be to optimize the balance between sales to Asia and

'THE MOST IMPORTANT ISSUE FOR QATAR [IS] … HOW TO MAXIMIZE REVENUES IN A WORLD WHERE GAS PRICES HAVE FALLEN.'

Europe, given the changing dynamics in both markets.

Australia

Most other LNG producers outside the USA are not in as fortunate a position as Qatar; the capital cost of new liquefaction plant has been rising over the past few years, meaning that the breakeven cost of many new projects is high at a time when prices have dropped sharply. The starkest example of this trend can be seen in Australia, where the rapid expansion of the LNG industry has led to a shortage of labour and equipment that has caused dramatic cost inflation. Examples of cost overruns and delays include the Gorgon project in Western Australia (where an initial cost estimate of $37 billion has risen to $54 billion, while first LNG has also been delayed by 2–3 years), and the three coal seam gas projects in Queensland (where costs have risen on average by around 25 per cent, accompanied by a one-year delay in first production). As a result, the long run marginal cost breakeven price for Australian gas is in the range $10–14/MMBtu, well above the current LNG price, meaning that all the new projects risk losing money for their sponsors.

'… THE BREAKEVEN COST OF MANY NEW PROJECTS IS HIGH AT A TIME WHEN PRICES HAVE DROPPED SHARPLY.'

However, despite these problems, Australian LNG output from six new projects is set to rise by a combined 58 million tonnes a year by 2018, as the new schemes were committed to long before the oil price decline and will therefore proceed as the majority of the capital cost has been sunk. Furthermore, approximately 80 per cent of the new gas has been sold under long-term contracts, meaning that the lower oil-linked price now being received could have three major consequences:

1 Project sponsors will be desperate to generate extra revenues by selling their remaining 'traded' gas at any price above short-run marginal cost, meaning that further pressure will be brought to LNG spot prices.

2 Some companies may come under pressure as they struggle to meet their commitments to repay project financing, meaning that industry consolidation and/or asset sales are a possibility. (The example of Shell's acquisition of BG, which is a major player in the Queensland Curtis LNG project, is one example of this trend.)

3 The deterioration in project economics could actually encourage the more robust Australian project sponsors to accelerate plans for brownfield expansion of their schemes. While this is somewhat counter-intuitive, brownfield development would allow the generation of cost synergies that can improve overall project economics, even at lower oil and gas prices, and could therefore be attractive if and when the global gas supply and demand balance starts to tighten in the 2020s.

If Qatar and Australia can ultimately benefit from new brownfield development over the longer term, countries and companies planning to develop brand new greenfield projects are set to be hit hardest by the current low-price environment. Two particular examples of this issue are Canada and East Africa (Mozambique and Tanzania).

Canada

As of March 2015, applications had been made for 25 LNG export projects in Canada, with four of these on the East Coast, two for supply to US plants in Oregon, and 19 for plants in British Columbia. This last group has been the main focus of attention for foreign investors who have been keen to exploit the country's large conventional and unconventional resources at a time when demand for pipeline exports to the USA has been in sharp decline. As a result the national government and the relevant provincial authorities have been keen to encourage an alternative route for exports to the growing Asian market, which is only 8–11 days away from Canada's west coast. However, this proximity is offset by the operational and political difficulties inherent in bringing gas an average distance of around 1500 km over the Rocky Mountains to LNG plants on the coast, also traversing land owned by First Nations peoples who are keen to extract value from the process. These logistical and operational difficulties have caused the average breakeven price for Canadian LNG to be around $11.50–12.00/MMBtu, meaning that project sponsors have been keen to price the gas under oil-linked contracts assuming an oil price of $100 or more. In consequence, the fall in the oil price over the past 12 months has led to most Canadian projects being postponed, officially or unofficially, until market conditions improve after 2020, despite the best efforts of the government to improve the fiscal conditions.

'… THE FALL IN THE OIL PRICE OVER THE PAST 12 MONTHS HAS LED TO MOST CANADIAN PROJECTS BEING POSTPONED …'

East Africa

A similar story is also unfolding in East Africa, although with slightly different drivers. Huge gas discoveries have been made offshore Mozambique and Tanzania that could support multi-train

LNG projects, and the large resource base located close to the planned liquefaction facilities can provide a relatively low upstream cost for the projects. However, the legal, political, and logistical issues involved in developing a huge greenfield project from scratch in a country where new regulatory and legislative regimes will need to be put in place before any major investment takes place, had created issues for project sponsors even before the oil price declined. In addition, the establishment of brand new service and supply bases, as well as the cost of importing all the necessary equipment and manpower, means that the breakeven price of East African LNG delivered to Japan is around $10.50/MMBtu, again encouraging the operators to seek oil-linked contracts (on the assumption that these would result in a high price) and thus undermining their hopes of rapid development at a time of global LNG surplus and lower prices.

Russia

One other country where LNG projects have also been postponed is Russia, although here it is a combination of lower oil price plus US and EU sanctions that have led to a re-think of strategy. Gazprom and Rosneft have both effectively pushed back projects in the Far East that were targeted at the Asian market (Vladivostok LNG and Sakhalin 1 LNG respectively), while the one Russian project that is progressing (Novatek's Yamal LNG) is still awaiting final project financing agreements. Sanctions have undermined the ability of all Russian companies to access capital markets, whether the companies themselves are sanctioned or not, and the risk of LNG equipment being added to a future sanctions extension has also put off potential customers who were already hesitant to commit to Russia during a time of geopolitical uncertainty. When this impact of sanctions has been combined with a lower oil price environment, which has limited the ability of Russian companies to go it alone, the outlook for Russian LNG has been sharply reduced over the past 12 months.

'… THE OUTLOOK FOR RUSSIAN LNG HAS BEEN SHARPLY REDUCED OVER THE PAST 12 MONTHS.'

Conclusion

In conclusion, it is no surprise that all LNG producers have been significantly affected by the decline in the oil price. Worst hit have been those companies with greenfield projects yet to take FID decisions, many of which are now likely to be postponed for at least two to three years. Although the owners of brownfield sites and new projects about to come on stream have also been hit, their competitive position is stronger as costs have already been sunk, with the result that the point-forward economic prospects are more robust, as long as the project sponsors can still afford the financing costs. For those that cannot, consolidation or asset sales will be the likely outcome. From a pricing perspective, two other outcomes are worth noting. Firstly, any un-contracted output from projects already in production or set to come on stream will put further pressure on an already saturated market. And secondly, the pressure from consumers to shift away from oil-linked contracts is likely to recede for a time; nevertheless the new lower oil price environment (combined with the convergence of global LNG spot prices on a netback basis across Europe, Asia, and the USA) could continue to catalyse a debate about the future of price formation mechanisms in LNG contracts. Indeed consensus between consumers and producers on a hybrid formula based on a basket of oil and market prices may now be achievable given the closing of the disparity between the various alternatives.

The impact of US LNG exports on global markets

Howard Rogers

Despite its relative maturity as a gas producing province, the USA has defied the expectations of market participants and observers over the past two decades. Figure 9.1 shows the make-up of supply to the US market comprising: US gas production, Canadian pipeline imports (net), net LNG imports, and pipeline exports to Mexico (net).

'DESPITE ITS RELATIVE MATURITY AS A GAS PRODUCING PROVINCE, THE USA HAS DEFIED THE EXPECTATIONS OF MARKET PARTICIPANTS …'

Increasing demand for natural gas in the 1990s was supplied by growing US production but also required an increasing contribution from Canadian pipeline gas imports. US gas production going into decline from 2001 came as something of a shock; the Henry Hub price rose accordingly and served to 'ration' supply for much of the early to mid-2000s (Figure 9.2).

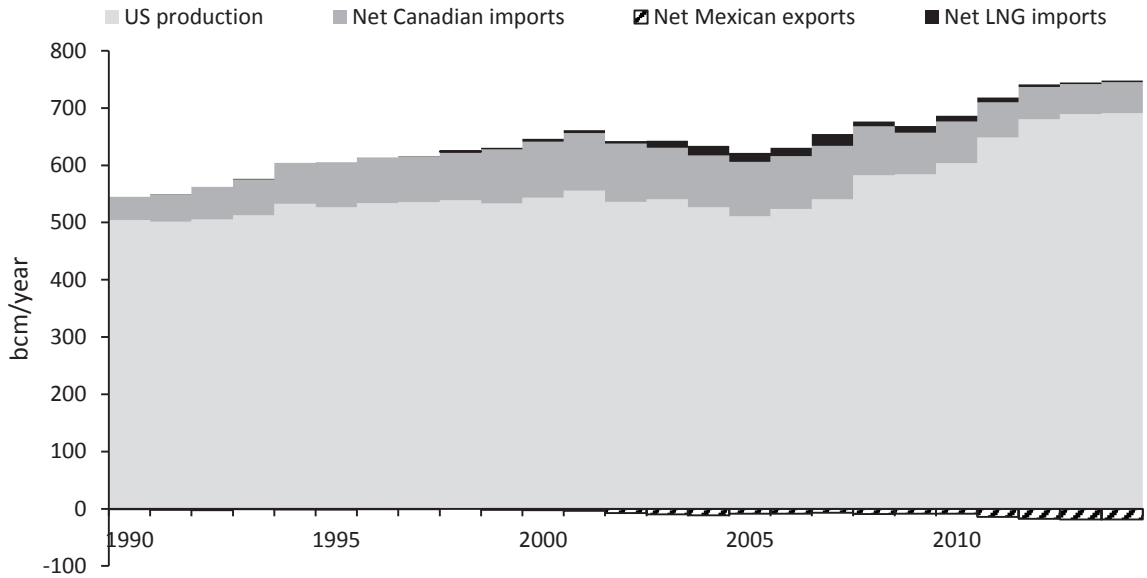

Figure 9.1. US gas production, imports and exports, 1990–2014

Source: US Energy Information Administration

In the early 2000s, the prospect of an apparent future US burgeoning import requirement catalysed the development of new LNG supply projects, notably in Qatar, with the USA as a destination market. US LNG re-gasification import terminal capacity grew from 49.2 bcm/year in 2006 to 186 bcm/year by 2013, equating to some 25 per cent of the gas demand of the USA in 2014.

Unexpected development of US gas production

Meanwhile, back at the ranch – literally – US Independents, spurred by the high mid-2000s US gas price, combined the technologies of horizontal drilling and fracking to exploit the numerous US shale gas plays, with increasing success. Their combined efforts account for the unforeseen, but no less dramatic, increase in US gas production from 2007 onwards. Although US gas demand increased, especially in the power sector where gas at lower prices was able to displace coal, the surge in shale gas production was sufficient to markedly reduce LNG and Canadian pipeline gas import requirements. In a reverse of the situation of the early 2000s, low prices placed higher-cost producers under huge financial pressure. Operators

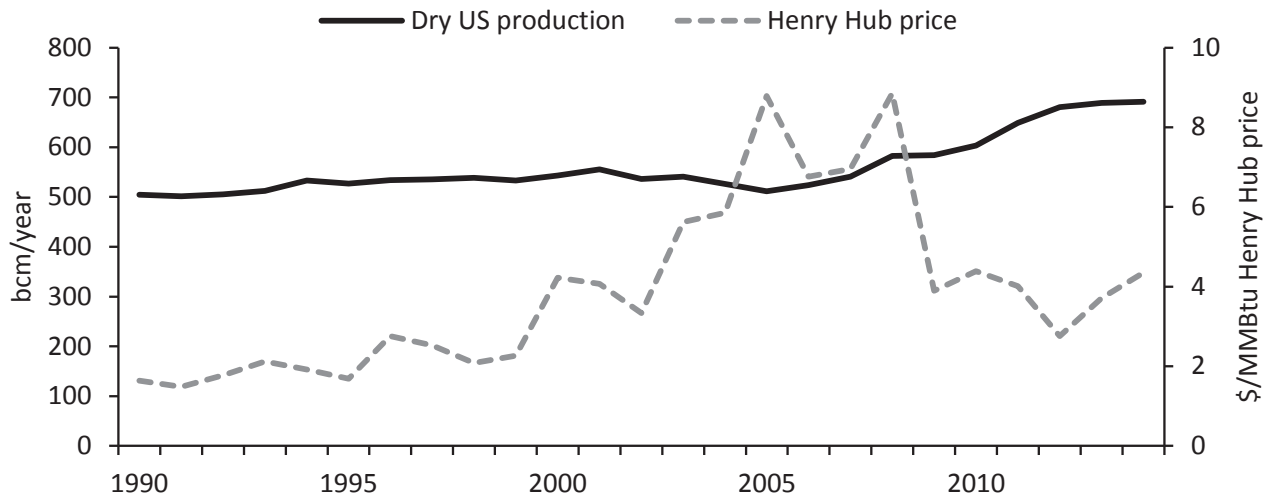

Figure 9.2. US gas production and Henry Hub price, 1990–2014

Source: US Energy Information Administration

tended to focus on plays with NGL co-production and hence more favourable investment economics. The commercial pressure to stay in business created a dynamic of technological innovation and cost reduction – possibly the only example in this era within the international upstream industry in general.

Switch from LNG imports to exports

Cheniere Energy are generally acknowledged as the 'first mover' in the race to gain government approvals and secure volume commitments to convert the ('built in haste' but subsequently under-utilized) LNG re-gasification import terminals to LNG export terminals. While this requires, in the case of Sabine Pass Trains 1 to 4, some $9 to $10 billion dollars of incremental investment to add liquefaction facilities to the existing import terminal, this figure is still significantly cheaper (per unit of output) than an international greenfield LNG project. The US Gulf Coast, in contrast to other potential LNG project locations, is also advantaged in terms of accessibility and availability of skilled, reasonably priced labour.

Sabine Pass is one of five US projects which have taken FID to convert re-gas terminals to export facilities, with an aggregate capacity of some 85 bcm/year. While the first Sabine Pass trains will start up in late 2015 and 2016, the later projects (Freeport, Dominion Cove Point, Cameron, and Corpus Christi) will commence production towards the end of the 2010s.

Utilization of gas from US domestic market for export

The US LNG projects are differentiated from their competitors in East Africa, Australia, Canada, and Russia in that they are essentially taking feed gas from the US transmission grid, rather than from a dedicated upstream field developed as an integrated element of the LNG project.

'THE US LNG PROJECTS ARE … TAKING FEED GAS FROM THE US TRANSMISSION GRID, RATHER THAN FROM A DEDICATED UPSTREAM FIELD …'

The offtake agreements generally take the form of a fixed 'take-or-pay' tolling fee of typically $2.25 to $3.50/MMBtu (to remunerate the capital cost of the liquefaction investment) plus a charge of 115 per cent of the Henry Hub price, for the procurement of feed gas. Marine transportation and re-gas fees are the responsibility of the off-taker and/or downstream counterparties. This contrasts with the 'traditional' Asian LNG contract where the buyer pays a price for LNG linked to Japanese Customs Cleared crude price or (in the case of north-west Europe) a price related to a gas hub in the importing market.

US LNG is, therefore, attractive to midstream portfolio players or end-user market wholesalers who believe that future destination market reference or alternative prices (whether Asia, Europe, or South America) will have a spread to Henry Hub in excess of the 15 per cent procurement markup, tolling fee, and cost of transportation and re-gasification. This looked like a safe bet prior to the slump in European hub prices and Asian LNG spot prices in early 2014, and the collapse in the oil price (and hence Asian LNG contract prices) in late 2014. In mid to late 2015, however, it looks more questionable.

Effects on regional markets

With doubts around Chinese (and more generally Asian) future LNG requirements and at best tepid demand growth for gas in Europe, the LNG market at present looks markedly less bullish than it did in the early 2010s, especially with 85 bcm/year of new Australian LNG projects adding to an equivalent US LNG volume coming onstream by 2020. The 170 bcm/year of new Australian and US LNG exports represent a 50 per cent increase over 2014 global LNG trade.

With this as context, in order to understand the market dynamics of the next five to ten years, we also have to jettison some traditional mental gas industry 'baggage', specifically:

- Flexible LNG trade flows have created, and will continue to create, a more 'connected' global system. As previously anticipated regional demand paths change, this will accelerate the need for LNG destination flexibility.
- Oil-indexed LNG (and pipeline gas) contracts, once regarded as the 'gold standard' of the gas world, will increasingly be seen as an absurd indicator of gas market dynamics and, as oil prices recover, as a liability for midstream utilities who are encumbered with them.
- Erstwhile 'comfortable' regional oligopoly positions will come under attack as LNG volumes, seeking customers, undermine what were previously regarded as 'captive' markets.

The above points contrast with the comforting platitudes frequently aired at LNG conferences; but with justification. The 85 bcm/year of Australian LNG projects currently starting up or nearing completion have very high capital costs (especially in light of adverse exchange rate movements and cost overruns) and very low variable costs (specifically any uncontracted shipping costs). Even if Asian buyers renege on contract volumes, these projects will produce to their maximum capability in order to recoup capital outlays.

The 85 bcm/year of US projects under construction will similarly operate to maximum capacity, although with different dynamics. The tolling fee for the US LNG export facilities is a 'fixed' or sunk cost. Once these plants are built, exports will proceed providing that destination market prices exceed US prices by a figure representing at least the 15 per cent procurement fee, variable shipping costs, and re-gas costs. In plain terms, these US LNG volumes will move to market, provided European Hub and Asian LNG spot prices are at least some $2 and $4/MMBtu, respectively, above Henry Hub.

With 200 bcm/year of re-gas capacity (utilized at less than 25 per cent in the period 2012–14), Europe is the obvious destination for LNG which is 'unwanted' in other markets. However, this will create problems for other European supply sources; with UK and Dutch production in decline, declining future pipeline export volumes from North Africa, and Norwegian production in all likelihood declining post 2020, the player with most to lose is Russia and, by association, those of its buyers still committed to long-term oil-indexed contracts.

Over the next five years we are likely to see LNG imports in Europe which lead to lower hub prices and which threaten the ability of buyers of Russian gas under long-term contracts to meet their contractual take-or-pay requirements. As the world's largest gas exporter, Russia could choose to take control of the emerging situation by moving to a position whereby:

- It moves its long-term contract delivery points to the established European hubs.
- It meets buyers' nominations with a planned mixture of physical gas transported from its West Siberian Fields and gas purchased from trading hubs by its Marketing and Trading subsidiary in London.
- In this way it can effectively set European hub and (by arbitrage) Asian spot prices.

Once rising demand has absorbed the current slate of new LNG projects, Russia could decide:

- whether to deter new LNG FIDs by demonstrating its willingness to maintain European and (by arbitrage) Asian spot prices below those necessary for future LNG project FIDs, or
- whether to maximize revenues in the short term by withholding physical volumes from the European market, raising prices but thereby encouraging competing supplies in the form of Canadian, East African, and new Australian LNG projects.

'WE APPEAR TO BE APPROACHING AN ERA WHERE THE NORMAL LAWS OF COMMODITY MARKETS ARE BEGINNING TO APPLY TO GAS AND LNG …'

In summary, the outlook for gas internationally has never been so 'interesting'. We appear to be approaching an era where the normal laws of commodity markets are beginning to apply to gas and LNG – long regarded as 'different and special'. This status has not served gas, as the lowest carbon intensity fossil fuel, particularly well to date in the minds of policy makers, especially in Europe. The challenge, albeit late in the day, is to demonstrate that gas is indeed a plentiful, low-carbon fuel, which global markets can supply, with low security of supply risk, through 'normal' market forces.

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