THE OXFORD INSTITUTE FOR ENERGY STUDIES

December 2014

The Dynamics of a Liberalised European Gas Market:

Key determinants of hub prices, and roles and risks of major players

OIES PAPER: NG 94

Jonathan Stern & Howard V Rogers

ISBN 978-1-78467-018-4

Contents

Figures

Tables

Introduction

The OIES Gas Programme has published several papers on the transition from oil-indexation to hub-based pricing in the UK and Continental Europe, and in 2012 a book on 'The Pricing of Internationally Traded Gas'; earlier this year we published a study on the challenges for JCC pricing in Asian LNG markets.[1] The Programme has also published a paper showing how the arbitrage of flexible LNG supply has the potential to transmit price signals between regional gas markets.[2] We have also published papers on the future of gas demand in Europe, and the ongoing national and EU regulatory developments.[3]

This paper represents both a continuation of, and a departure from our previous publications on European gas. It is a continuation in respect of the focus on the determinants of European hub prices and how these have changed, and are likely to continue to change, over time. The departure from previous work is that for the first time we are attempting to understand the implications of the changing commercial landscape for the key market players themselves.

A challenge of such an approach is that stakeholder business models and strategies are influenced by drivers in a number of dimensions. These include ongoing supply and demand dynamics, physical supply chain configuration, evolving regulatory framework, competition with peers, price formation mechanisms and risk management. We have chosen to focus this paper on three specific questions about which major European gas industry players are seeking clarification:

- What are the key determinants of hub pricing?
- How have the roles of major players in the liberalised gas market changed and how may these evolve in the future? And, related to this.
- What are the new risks to which major players in the liberalised gas market are exposed, and how can they deal with these risks?

This paper aims to illuminate these aspects of market transition which can be viewed as a challenge, an opportunity, or a threat but certainly require changes of behaviour from all major market players. There is a temptation to characterise the historical and future development of European gas markets from monopoly to competition in terms of specific time periods. This is analytically problematic – because national and EU developments often refuse to fit into neat time periods. In this paper we have used only two time periods, before and after 2008. The reason for this is our proposition that 2008 can be viewed as the start of serious gas hub development in Continental Europe, and the point at which the EU authorities decided that more radical action needed to be taken to liberalise gas (and power) markets.

The paper is structured in three chapters. Chapter 1 looks at European price evolution and the key determinants of hub pricing. Chapter 2 examines the changing roles and risks facing the three key groups of gas market players: producers and exporters, midstream energy trading companies, and local distribution companies. Chapter 3 provides a summary of the arguments, and some conclusions on: the determinants of hub pricing; the roles of, and risks facing, the different groups of gas market players; and the implications for contractual frameworks and business models in the gas sector.

[1] Heather (2010) and (2012); Petrovich (2013); Stern (2007), (2009) and (2012); Stern and Rogers (2011); Rogers and Stern (2014).

[2] Rogers (2012).

[3] Honoré (2014), Haase (2008) and Yafimava (2013).

Chapter 1: European Gas Price Evolution: what are the key determinants of hub pricing?

1.1 The Historical Context

Town gas (or coal gas[4]) had been in domestic and industrial use since the mid to late 1800s, but the European natural gas industry was not effectively launched until the discovery of the giant Groningen gas field in northern Holland in 1959.[5] All other large-scale European gas imports from the Former Soviet Union (FSU), Algeria and Norway which followed in subsequent decades were strongly influenced by the commercial, specifically the pricing, framework for Dutch gas exports to neighbouring countries[6].

The emergence in the 1960s and 1970s of natural gas as a major new fuel/energy source in north west and central Europe, with advantages for the domestic consumer of convenience relative to coal and oil products, came some decades after its debut in North America earlier in the 20th century. Gas in Europe was different in other respects however. Markets were national, albeit with a high reliance on imported gas with flows often transiting neighbouring countries. In the development of national gas markets there was a requirement for large, creditworthy buyers to commit contractually to agreed volumes of gas in order to underwrite the development of upstream producing gas fields, the transportation infrastructure from those field locations to markets, and the storage and distribution infrastructure required to deliver to customers. The primary risk in those early days was that growth in gas consumption would be less than the volumes contracted, either due to uncompetitive price levels relative to alternative fuels, or that economic growth itself would be insufficient to lift demand for gas.

Due to its low energy density, gas is expensive to transport and store, compared with oil products and coal. Similarly from an institutional perspective, gas is a rather complex energy resource which gave rise to complicated industrial organisational arrangements throughout Europe. This was mainly due to the commercial and national interests at stake for both gas producing and consuming countries. Gas resources are valuable but only Norway, Britain, the Netherlands and Denmark have had (at different times and for different durations) sufficient resources to satisfy domestic consumption and produce an export surplus. It took significant investments in pipeline infrastructure to connect the few European production centres with all regional centres of consumption. These investments gave way to specific transactional relations between suppliers and consumers of gas in the form of long term contracts which were legally binding and subject to international arbitration.

In the Continental European context this was addressed by a long term gas contract in which pricing terms were related to oil products with periodic (usually three year) price reviews (or “re-openers”) and an Annual Contract Quantity (ACQ) with a minimum Take or Pay (TOP) level set typically at 80-90% of the ACQ level. In this way the ‘Seller took the Price Risk’ and the ‘Buyer took the Volume Risk’.[7] Price risk was reduced by a (three month) lag in applying the adjustment of (mainly) oil product prices averaged over the previous 6-9 months, to the gas price, hence largely eliminating volatility.

The dilemma posed by Groningen was that, being a large onshore discovery, its costs of development and production were low. Accordingly, instead of a ‘cost plus’ pricing approach, the ‘market value principle’ was adopted in which the price paid for the gas was negotiated based on the weighted average value of the gas in competition with other fuels, principally oil products, adjusted to allow for

[4] A mixture of hydrogen, carbon monoxide, methane and volatile hydrocarbons made by reacting coal or coke with air and steam at high temperature.

[5] Correlje et al. (2003) pp.26-37.

[6] Stern, (2012), p. 55.

[7] More details can be found in Stern (2012a), especially pp. 55-9.

transportation and storage costs. This allowed Shell, Exxon and the Dutch government to obtain much higher revenues than via a 'cost plus' approach, and also ensured a more gradual displacement of oil products in sectors where gas increased its market share.[8]

In contrast to the oil-related price mechanisms used in continental OECD Europe, from the 1970s pricing in Britain between diverse producers and the state monopoly British Gas Corporation (BGC) adopted various forms. All notable UK gas discoveries were situated offshore and the cost base was higher than that of the Dutch Groningen field. Negotiations therefore focussed on a price which left the producer with a 'reasonable' rate of return after taking into account a requirement (in the case of the early southern North Sea fields) to provide a high seasonal 'swing factor'. This required production facilities and transportation infrastructure to be sized for flows significantly higher than average offtakes. In this way, Britain avoided the need to build seasonal storage facilities in the early era of developing its natural gas business. The field-specific sales and purchase contracts signed between field producers and BGC (often termed 'depletion contracts') – similar to the Continental European long term take or pay contracts but without the periodic price reviews - included an initial price with provisions for indexation generally related to cost inflation rather than to competing fuels.[9] The cost plus mechanism, at least in the early days of 'North Sea Gas' development allowed gas a significant competitive advantage over oil products and was accompanied by a large scale programme of converting all domestic appliances from town gas or coal gas to natural gas.[10] This subsequently set the scene for growth in gas-fired domestic space heating as the rapid economic growth of the 1960s brought this within household affordability.

Despite initial uncertainties, the growth of the European natural gas industry was successful beyond the expectations of any demand forecast in the 1970s. Figure 1 shows that the industry enjoyed a near-continuous growth in demand to 2005 with a five-fold growth in gas consumption in the European region[11] from 1970 to 2008. In addition to general economic growth, this is largely accounted for by the displacement of coal and oil products in residential and commercial space heating and, post 1990, the displacement of coal and oil products in power generation. The growing reliance on pipeline and LNG imports throughout the period is apparent.

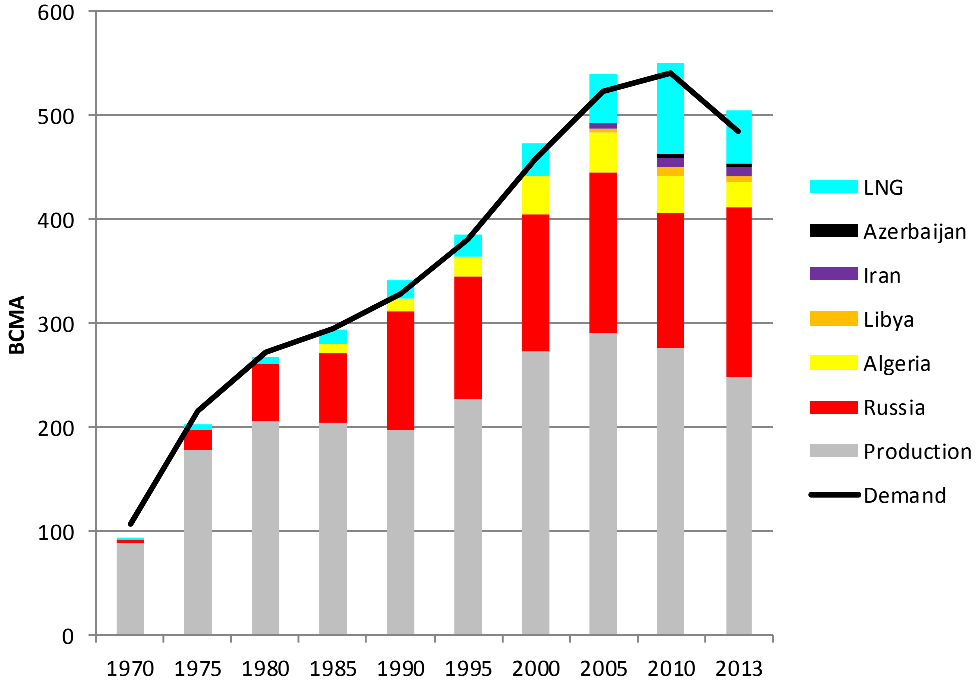
[8] For details of the history and evolution of the Dutch pricing regime see Correljé et al. (2003) pp.89-100.

[9] Stern (2012), p. 60.

[10] For details of UK pricing see Stern (2012), especially pp.59-61.

[11] The European region is here defined as 30 countries, see note to Figure 1.

Figure 1: European Demand and Supply Sources: 1970 – 2013



Notes: The European region is here defined as: Austria, Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey, UK.
Data inconsistencies account for balancing errors in some years, including lack of FSU individual country data before 1990.

Source: BP Statistical Review of World Energy

This was an industry which, by 2005, had enjoyed 35 years of growth and had prepared for similar – albeit perhaps not such strong – growth in the following two decades, although as Figure 1 shows and as we shall see below (Section 1.3), expectations that these trends would continue have been proved substantially wrong.

1.2 The Period Prior to Continental European Hub Pricing

European wholesale price dynamics

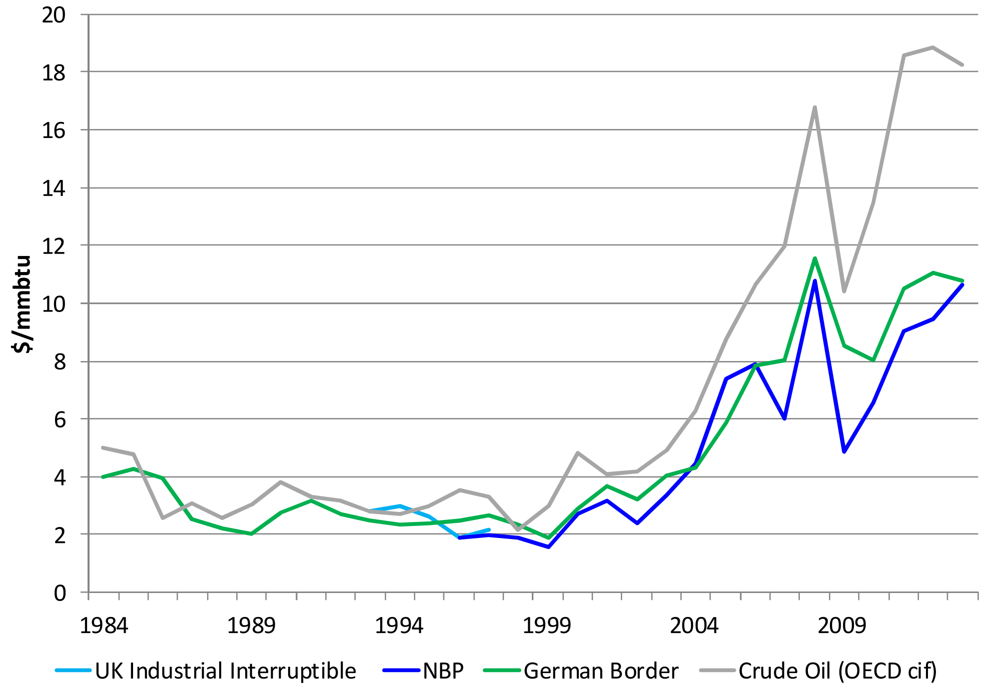
Taking Germany as a proxy for north west Continental Europe, and a point of comparison with Britain, Figure 2 shows four price series: the average German import (BAFA) gas price from 1983[12]; the British National Balancing Point (NBP) Heren index price from 1996 (when the hub was created); the price of BG's industrial interruptible contract (as a proxy for the lowest price available from the monopoly supplier) from 1993; and the Brent crude oil price.[13]

---

[12] Otherwise known as the German Border price. For many years BAFA was the only officially published data on gas prices in Continental Europe. See Glossary for more detail.

[13] This is the earliest data available from the DECC website.

Figure 2: British and German Wholesale Gas and Crude Oil Prices – 1984 to 2013



Sources: BP Statistical Review of World Energy 2014, p.27. 'Annual Prices of Fuel purchased by Manufacturing Industry', DECC, https://www.gov.uk/government/statistical-data-sets/prices-of-fuels-purchased-by-manufacturing-industry

With the liberalisation of the British market and the creation of the NBP as a trading hub in 1996 – more than a decade before Continental European hubs became a significant price setting mechanism - NBP prices were fundamentally driven by gas supply and demand.[14] But with the commissioning of the Interconnector (IUK) pipeline in 1998, Continental European oil-linked long term contact prices had an important influence on Britain. It should be noted that, up to the mid 2000s, in addition to gas traded on NBP, there was still a significant quantity of physical gas sold under 'legacy' contracts in which price was indexed to inflation and a variety of fuel and commodity indices.[15]

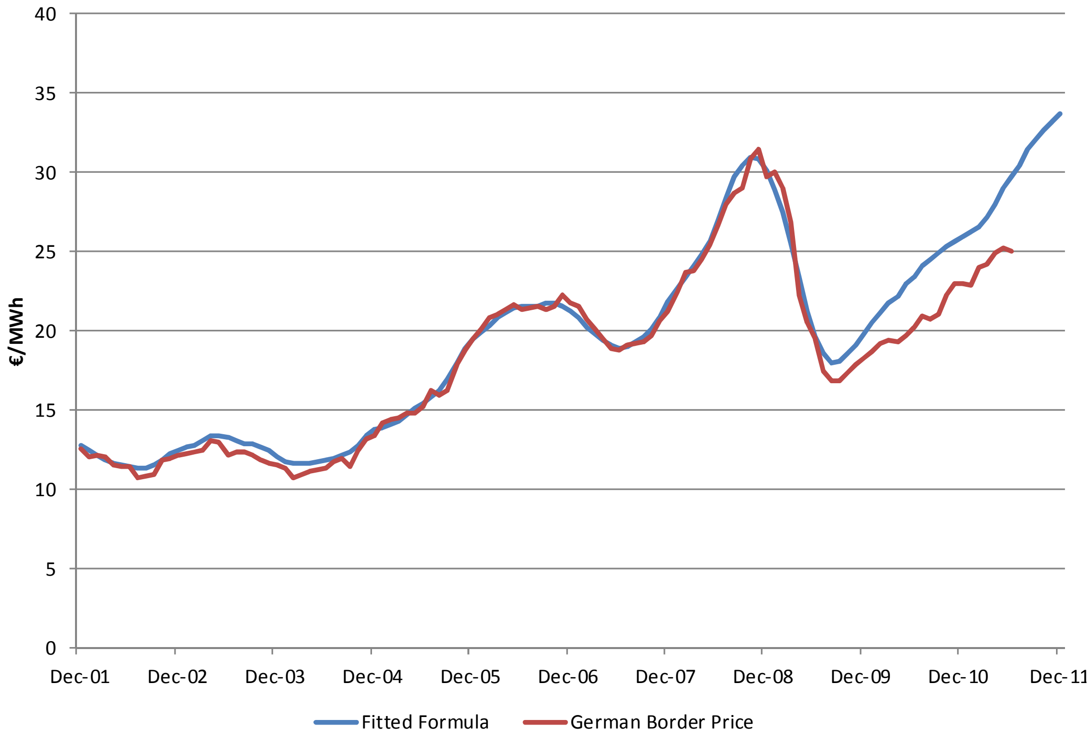
German import prices, in the period up to 2007, referred almost entirely to gas sold under long term contracts with Russia, Norway and the Netherlands in which the price formation mechanism was indexation to oil products. In Figure 2 the lagged relationship between crude oil (and by inference oil products prices) and border gas prices is evident, at least until 2009. Although the German border price was based on many individual contracts, with some variation in specific price formula variables, the linkage to oil product prices appears to have been reasonably consistent.

---

[14] For a full account of the evolution of hub pricing in Britain see: Wright (2006), Chapters 3 and 4; and Heather (2010).

[15] Heather (2010), p.30.

Figure 3: German Border Price and Fitted Formula: 2001-11



Source: BAFA, Platts, Author's Calculations

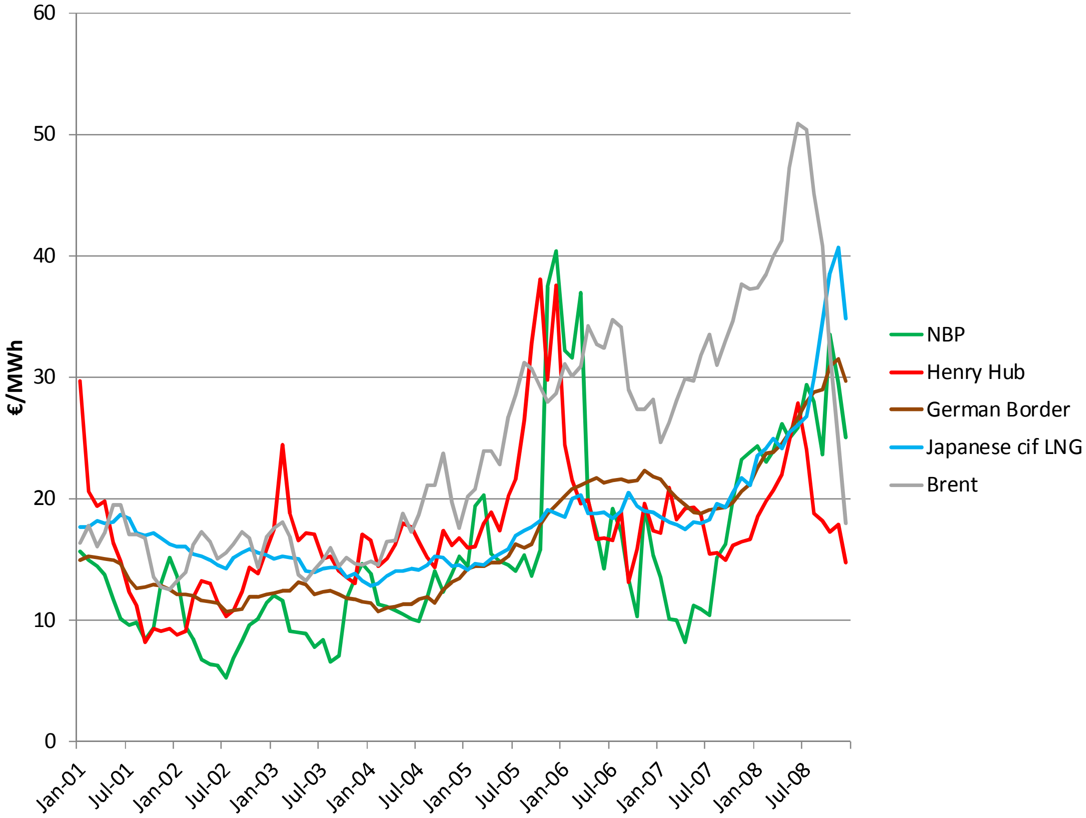
Figure 3 shows the comparison of the following 'best fit' formula with the official average German border price (BAFA): price in month (€/MWh) = 2.273 +0.025977*(average of previous 9 months gas oil prices in €/tonne) + 0.029224*(average of previous 9 months fuel oil prices in €/tonne).

The match is very good until early 2009, and the reasonable fit even over the 2008 peak confirms that the oil product price formula was a good approximation of the German gas price to the end of 2008. The reasons for the divergence post 2008 are discussed below.

European wholesale prices in an international context

Figure 4 shows European and other international gas prices with the (Brent) crude oil price for reference for the period 2001-08. During this period, crude prices (apart from a respite in the second half of 2006) trended upwards, prior to their peak and subsequent collapse in the second half of 2008. The gas prices linked formulaically to crude oil or oil product prices (Japanese LNG prices and German border prices respectively) followed the crude oil price trend with a lag.

Figure 4: Monthly International Gas and Brent Crude Oil Prices: 2001-08



Sources: Argus, EIA, Platts, BAFA

US Henry Hub prices exhibited different dynamics. During the early 2000s Henry Hub trended upwards due to a downward trend in domestic gas production, which at times led to inter-fuel competition between gas and fuel-oil in power generation – at a time when oil and oil products prices were rising. The mid-2005 peak in Henry Hub prices was caused by the temporary shut-down of offshore gas production due to hurricane Katrina, at a time when the market for flexible LNG tightened (due to Japanese nuclear shutdowns and the decline in Indonesian LNG production). The advent of US shale gas production on a large scale began to alleviate US domestic production concerns post 2006, although the pre-financial crisis 'commodities bull-run' served to raise Henry Hub price in the first half of 2008.[16]

Interactions between British and Continental European markets

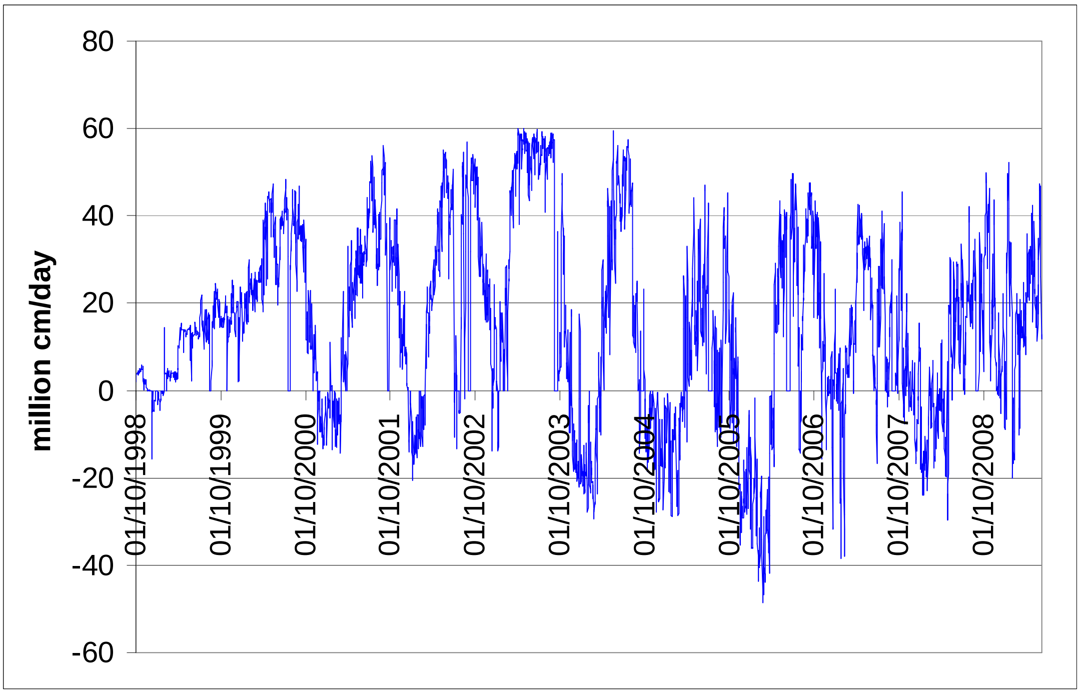
In October 1998 the Bacton Zeebrugge Interconnector pipeline (IUK) commenced operation, connecting the newly liberalised British gas market with Continental Europe.[17] The pipeline is able to switch its flow direction in response to the nominations of its capacity owners. Figure 5 shows the daily flows through this pipeline between October 1998 and June 2009.

---

[16] For details see Foss (2007) and Foss (2011).

[17] For a history of IUK see Futyan (2006).

Figure 5: Bacton-Zeebrugge Interconnector Daily Pipeline Flows 1998 - 2009 (+ = export from UK, = import to UK)



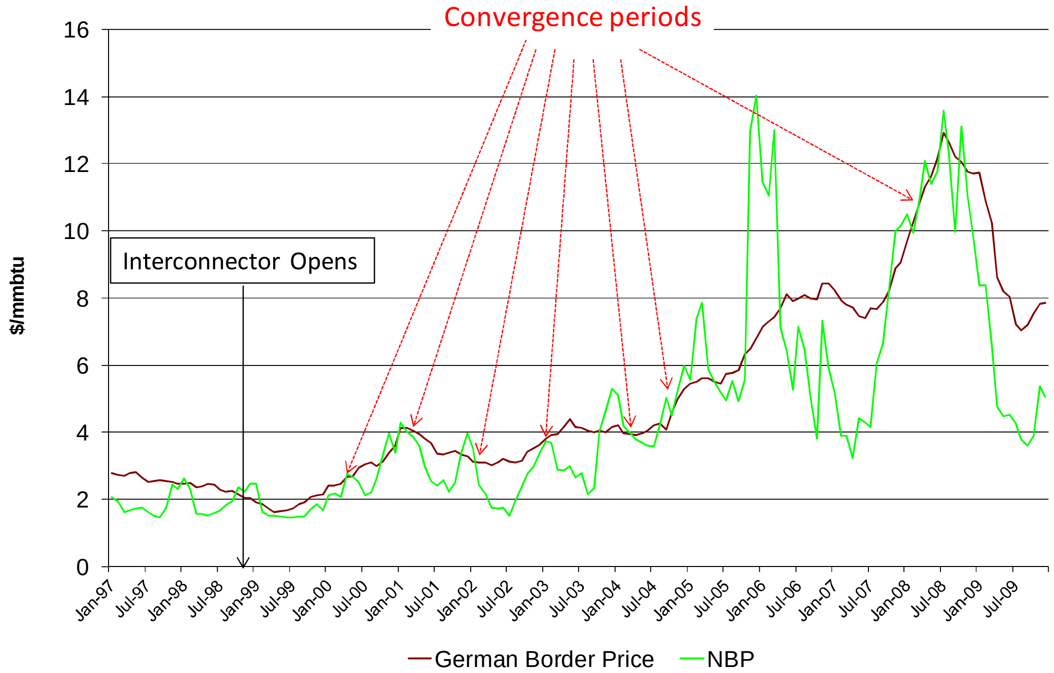
Source: IUK

The flow pattern is one of significant summer export from Britain during the summer periods from 1998 to 2006.[18] During the same period the winter seasons saw imports coming into Britain from Continental Europe. The underlying explanation for this dynamic was the relatively low provision of seasonal gas storage in Britain as its old 'swing' fields declined.

Following the opening of the IUK, NBP and Continental oil-indexed gas prices were reasonably well correlated through to the spring of 2001 (Figure 6). The years 2001-03 were characterised by reasonably close price correlation during the winter months but with NBP de-linking and falling during the summer. Summer export volumes peaked in 2003, with the decline in subsequent years driven by the reduction in UK domestic production. From 2004 onwards, evidence of increasing supply tightness is apparent, and winter imports increased through to the end of 2005. In 2004 and early 2005 there is close correlation between the NBP and continental prices, but in 4Q05 NBP de-links and soars to unprecedented price levels (also shown in Figure 4).

[18] The dip in summer 2002 was due to the pipeline being shut down due to operational problems.

Figure 6: NBP Day Ahead Spot Prices and German Average Import Gas (BAFA) Prices January 1997 – December 2009 (Monthly Averages)



Sources: Platts, BAFA

The NBP price peak in 2005/2006 was a consequence of the loss of the key Rough storage facility during winter months and the lack of sufficient IUK import flows in response to high British prices (partly as a consequence of Continental European storage operators being constrained by public service obligations and lack of availability of short term transportation capacity). The advent of higher Norwegian imports via the Langeled pipeline in 2007 reduced prices prior to the pre-crisis commodity bull-run dynamic in 2008. Additional supplies from Norway stabilized the trend of reducing summer exports and growing winter imports through the IUK.

The declining rationale of Continental European oil-indexed gas pricing[19]

The rationale for oil-linked gas pricing is that natural gas and oil are substitutable in both the short and the longer term. Price formulae were designed to ensure that the customer base continued to burn gas rather than returning to oil products since the majority of customers had switched from oil products to gas and, given a price incentive, retained the ability to switch back. If customers switched back to oil in large numbers, this would not only deprive gas importers of their market, but force them to incur take-or-pay penalties in their contracts with exporters. To argue that gas prices should continue to be indexed to oil products, it must be possible to demonstrate that:

- in the short term, customers have the capability and incentive to switch existing plant from gas to oil and back again in response to price signals;
- in the long term, customers building new plant (or replacing fuel burning equipment in old plant) will choose to install fuel burning equipment which is principally oil-fired, or equipment which is principally gas-fired but with the option of burning gas or oil products, or a plant with the capacity to switch between the two fuels.

[19] What follows is a brief summary of the arguments in Stern (2007) and Stern (2009).

Tables 1–3 show the share of gas and its two main competing oil products – gasoil and residual fuel oil – in the energy mix of the four main stationary energy markets in Europe in 2004.[20] The following features stand out from these tables:

- gasoil had been eliminated from power markets in all countries; in the industrial sector, the fuel's share was only significant in France (8%) with Germany being the next highest at just over 5% (see Table 1).
- household consumption of gasoil remained significant in all countries other than the Netherlands, ranging from 12% of residential energy demand in Italy to a surprising 34% in Belgium.
- in the commercial sector, the share of gasoil was higher than in the residential sector in all countries, other than Belgium and Italy, and was significant in all countries (other than Netherlands and Italy) ranging from 19 to 28% of fuel use.

Table 1: Share of Gasoil in Total Energy Consumption of Stationary Sectors, 2004 (%)

	INDUSTRY	*HOUSEHOLDS*	*COMMERCIAL*	*POWER*	*Total*
Germany	5.3	21.2	25.1	0.6	11.6
France	8.0	16.6	27.6	0.2	10.2
Netherlands	1.3	0.2	2.3	0.08	0.9
Belgium	2.6	33.8	27.9	0.06	14.6
Italy	3.1	11.7	3.0	0.7	4.8
Spain	5.1	17.4	20.6	0	7.5
TOTAL	4.9	17.7	18.9	0.4	9.0

Source: Stern (2007), Table 5.

Table 2: Share of Residual Fuel Oil in Total Energy Consumption of Stationary Sectors, 2004 (%)

	INDUSTRY	*HOUSEHOLDS*	*COMMERCIAL*	*POWER*	*Total*
Germany	7.1	0	0	2.5	2.4
France	4.7	0.5	0.6	1.2	2.0
Netherlands	0.1	0	0.2	0.1	0.1
Belgium	6.3	0	0.4	5.7	3.5
Italy	8.9	0.9	0	38.1	13.5
Spain	3.7	0.4	3.3	20.5	8.3
TOTAL	5.9	0.3	0.5	10.2	4.9

Source: Stern (2007), Table 6.

[20] Tables 1-3 are taken from Stern (2007); the data was updated in Stern (2009), Appendix A which demonstrated that the trend towards eliminating oil products from the stationary sectors was continuing.

Residual fuel oil had largely been driven out of all sectors other than power with the largest remaining shares being between 7 and 9% in the German and Italian industrial sectors (see Table 2). In the power sector, the only significant remaining shares were in Spain and Italy.

Table 3: Share of Gas in Total Energy Consumption of Stationary Sectors, 2004 (%)

	INDUSTRY	*HOUSEHOLDS*	*COMMERCIAL*	*POWER*	*Total*
Germany	35.9	37.2	30.9	19.2	30.7
France	38.7	36.1	..	3.2	..
Netherlands	44.4	75.7	53.3	67.6	59.7
Belgium	39.8	37.3	43.4	30.1	37.2
Italy	43.3	56.7	48.3	46.6	48.4
Spain	41.7	20.6	4.1	20.0	27.0
TOTAL	39.8	40.8	..	22.8	..

Source: Stern (2007), Table 7.

Gas had a very substantial share of all stationary sectors in all countries with the exception of power in France (because of the preponderance of nuclear power) and the commercial sector in Spain (Table 3). The share of power was relatively low at 20 percent in Germany (because of coal) and in Spain; likewise the share of gas in the Spanish household sector would rise as the network expanded. Elsewhere gas had a 30–45% share of stationary fuel demand with exceptionally high penetration in the Dutch household sector.

Thus, well before the arrival of hub pricing in Continental Europe , the rationale for pricing gas in relation to oil had become increasingly questionable as gas had displaced oil (on a virtually irreversible basis) in the domestic and power generation sectors. In Continental gas markets familiarity with, and profitability of, the oil-indexed pricing system created inertia which allowed for a continuation of the status quo; but this was to change post 2008.

1.3 The Arrival of Hub Pricing

Continental Europe - the 'Perfect Storm'

As the post-financial crisis hit economic activity towards the end of 2008, European gas demand fell. Demand in 2009 was 5.7% below its 2008 level and although it recovered in 2010, this was in large part due to abnormally cold weather.[21] By 2013, demand in 35 European countries was just over 528 Bcm, 66 Bcm and more than 11% below 2008 levels; demand in the seven major European gas markets (excepting Turkey) remained 5-26% below pre-recession levels. During 2008-13, despite a gradual improvement in economic growth, loss of market share to renewables and coal in the power sector continued to depress the outlook for gas demand, although the detailed reasons for, and relative importance of, these impacts varies by country.[22]

[21] For an account of gas demand in the immediate post-recession period see Honoré (2011a).

[22] Honoré (2014), p.71. This study contains an in-depth analysis of historical and future European gas demand.

New LNG supplies from Qatar, Yemen, Russia, Peru and Indonesia came on stream between 2009 - 12 adding some 100 Bcma to global supply. Some of this new supply had originally been intended for the US market, but the remarkable and unforeseen growth in shale gas production resulted in it becoming surplus to US requirements. Although much was absorbed by the robust rebound in Asian LNG demand from 2010 onwards, and by new markets in South America and the Middle East, some 30 Bcma of additional LNG flowed into Europe in 2010 and 2011. This surge of uncontracted gas supply, much of it flowing via Britain into the north west European trading hubs, substantially increased their liquidity. This coincided with sustained effort on the part of the Dutch regulator, system operator and main domestic gas producer to launch the TTF as a successful hub and the embodiment of the 'Dutch Gas Roundabout' concept in a newly liberalised market paradigm.[23] Also the north west European utility companies appeared to be undergoing a generational 'mind-set change' as younger staff, familiar and comfortable with traded markets, rose to senior positions.

The plight of the midstream utilities

Not only had demand fallen and available supply increased, but long term contract gas prices were rising rapidly driven by oil prices increasing to more than $100/bbl. These changes to European gas fundamentals were especially unwelcome to the midstream utilities in north west Europe who were caught in the unenviable position of being obliged to buy high-priced, oil-indexed gas under their long term contracts, but increasingly forced to sell at hub-based prices demanded by their customers. The rise of the north west European hubs, with transparent prices available on the internet, and legal rulings which freed customers from multi-year purchase agreements for gas at oil-indexed prices, heralded a fundamental challenge to the midstream utility business model (see Chapter 2).[24] With the progressive merger of gas and power utilities, management of the newly combined entities became increasingly influenced by concepts such as 'mark to market'[25] and, to this mind-set, long term oil-indexed contracts represented a potentially unbounded future liability. With some utilities losing around €1 billion/year in gas trading operations, their commercial position was rapidly becoming unsustainable.[26]

At the Offshore Northern Seas conference of 2010 the new CEO of E.ON Ruhrgas, Klaus Schafer announced that: 'Hubs are the reference point when customers talk to us …LTCs in their current form no longer reflect the market….We have to re-engineer the LTCs to anticipate the future needs of the market: price levels, indexation and review mechanism'[27] This was the starting point of a series of renegotiations of long term contract prices – many of which required international arbitration proceedings to resolve – which are still ongoing at the time of writing. Summarising a very complex (and still unfolding) picture, by 2013 Statoil and Gasterra had both appeared to embrace the new gas market paradigm in north west Europe by agreeing to move long term contracts to hub prices where competitive markets existed.[28] But the cases of Gazprom and Sonatrach were fundamentally different.

---

[23] The details of this are set out in Heather (2012), pp. 7-11.

[24] See for example in the case of Germany: German Energy Blog, 24th March 2010:'BGH Declares Oil Price Linkage in Gas Contracts Void': see article at: http://www.germanenergyblog.de/?p=2278. BGH ruling 61/2010, can be accessed at: http://juris.bundesgerichtshof.de/cgi-bin/rechtsprechung/document.py?Gericht=bgh&Art=pm&Datum=2010&Sort=3&nr=51371&pos=2&anz=63

[25] The accounting act of recording the price or value of a security, portfolio or account to reflect its current market value rather than its book value

[26] E.ON claimed that its long term contracts were responsible for its gas trading losing €1 billion in 2011. http://millicentmedia.com/2011/08/12/germanys-giant-utilities-are-posting-losses-and-slashing-jobs-what%E2%80%99s-going-on/

[27] The video of the presentation is unfortunately no longer on the ONS website, but see: `EON Ruhrgas seeks gas contract reform', Platts *European Gas Daily*, August 26, 2010, pp. 1-2.

[28] A detailed analysis can be found in Stern and Rogers (2011) and Stern and Rogers (2012).

Sonatrach, having won an earlier arbitral case against Gas Natural in 2010, felt justified in continuing to insist on the retention of oil indexation for customers in Spain and Italy.[29] However the company's failure to maintain gas production to keep pace with (heavily subsidised domestic downstream pricing and hence) burgeoning domestic demand has left the company short of gas supplies. As a result, it has shown willingness to relax take or pay obligations, but a reluctance to compromise on oil-linked prices in long term contracts. Algeria's price maximisation strategy in Europe reflects its lack of available gas to export, lack of pressing need for additional revenues, and ability to divert its LNG exports from Europe to higher priced markets in Asia.[30]

By contrast, Gazprom's price-volume strategy is one of the key determinants of the 'new world order' in global gas dynamics, and is not straightforward. The company had been in negotiations, often leading to arbitrations, with its European pipeline gas customers under long term oil-indexed contracts from 2010. Two stages of negotiations can be identified:[31]

- 2009-12 where customers were obliged to pay for minimum contract quantities at oil-linked price formulae but could purchase additional volumes at hub prices;
- 2012-14 where, although oil indexation remained in the price formula, the company agreed with individual buyers a complicated mix of base price (P zero) reductions and rebates on prices paid under the contract formula relative to hub prices.

In many contracts TOP levels were reduced from 85 to 70%.

Many of the arbitral decisions which were made public during 2012-13 found that the spot price (either at hubs or for LNG cargoes) should be considered at least part of the market price in existing long term contracts.[32] It may be a reasonable generalisation to say that arbitral decisions on long term contract gas prices in the post-2012 period, have ruled that at least some element of hub pricing should be included in the price formula, and that the share of hub pricing should increase with time.

The rise of the hubs and the spread of hub pricing

Following the creation of NBP in 1996, there were a number of `false starts' for Continental European hubs: the Zeebrugge hub in 2000, was followed by EuroHub and NWE-Hubco in 2002. All appeared to be intended by incumbents to frustrate gas trading rather than to promote it.[33] It was not until the creation of the Title Transfer Facility (TTF) by Gasunie in 2003, followed by Central European Gas Hub in 2005 and the two German hubs – Net Connect Germany (NCG in South Germany) and Gaspool (North Germany) in 2009 – that the incumbent European companies became serious about facilitating gas trading.[34]

As mentioned above, the rise of the Continental European hubs was catalysed by the arrival of spot-priced LNG overflowing from Britain into north west Europe. The volumes of gas traded have increased significantly during this period as shown in Figures 7-10.

---

[29] `Gas Natural loses Sonatrach dispute', Platts, *European Gas Daily*, August 18, 2010, p.2;

[30] For background see Darbouche (2011); for the more recent period see Stern ed. (2014), pp.17-21.

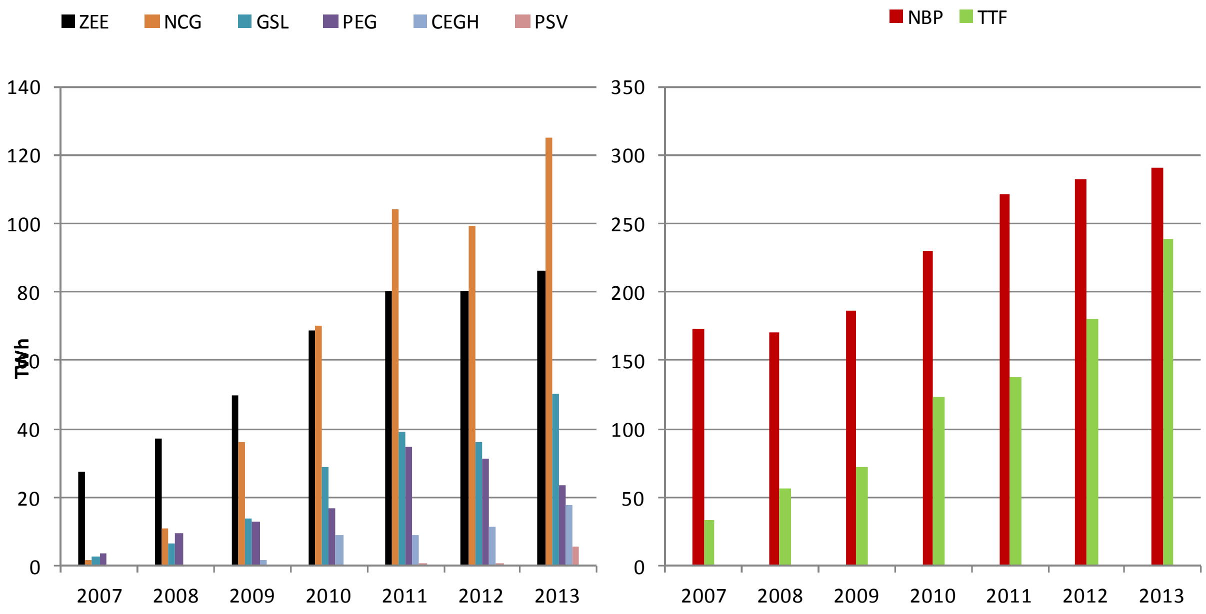
[31] This is explained in detail in Stern (2014).

[32] Arbitral decisions are confidential, so we cannot be certain. This information is from press reports which cannot be verified. But for example: Edison received €450 million from Rasgas (in relation to its long term LNG contract during 2010/11); in October 2012 Edison received €250 million from ENI (in relation to gas from ENI's long term contract with Libya); in May 2013, Edison received €200million from Sonatrach; in July 2013, a tribunal awarded RWE a payment of €1.6billion from Gazprom and a share of hub pricing in the long term contract formula.

[33] Eurohub was set up in 2002 by Gasunie to facilitate trade between the company's flanges at Bunde-Oude (on the Dutch-German border) and Emden (on the north German coast). NWE-Hubco was launched as a rival to Eurohub by Ruhrgas, BEB and Statoil. In 2004 the two agreed to merge but finally ceased trading in 2006.

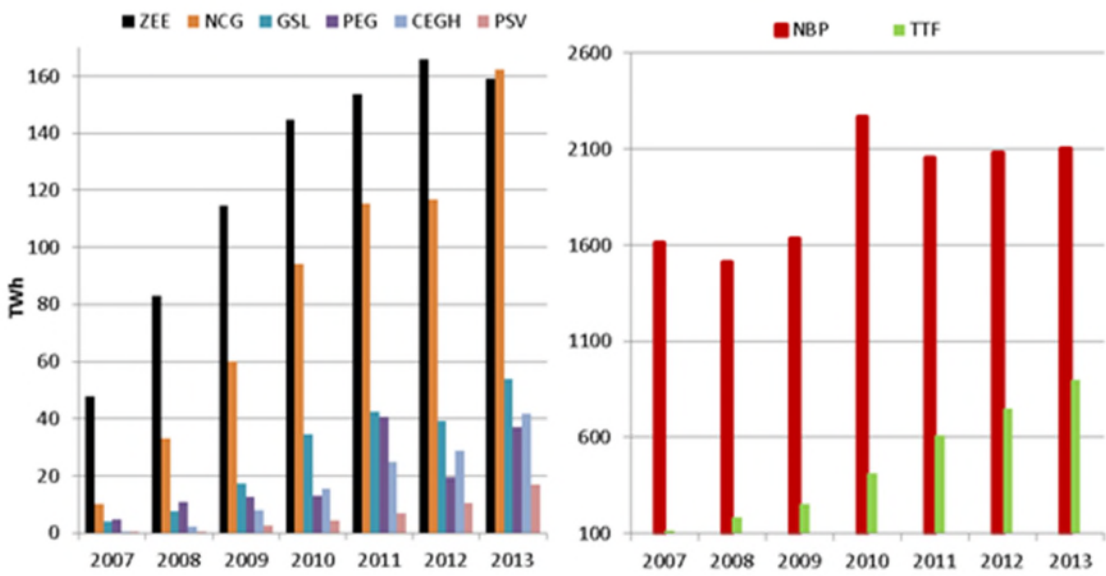
[34] For the history of how these hubs emerged see Heather (2012), Chapter 3. This source also covers the other major hubs, the French Points D'Échange de Gaz (PEGs) set up in 2003 and the Italian Punto di Scambio Virtuale (PSV) in 2004.

Figure 7: Gas Volumes Traded, OTC Day Ahead 2007 – October 2013 (TWh)



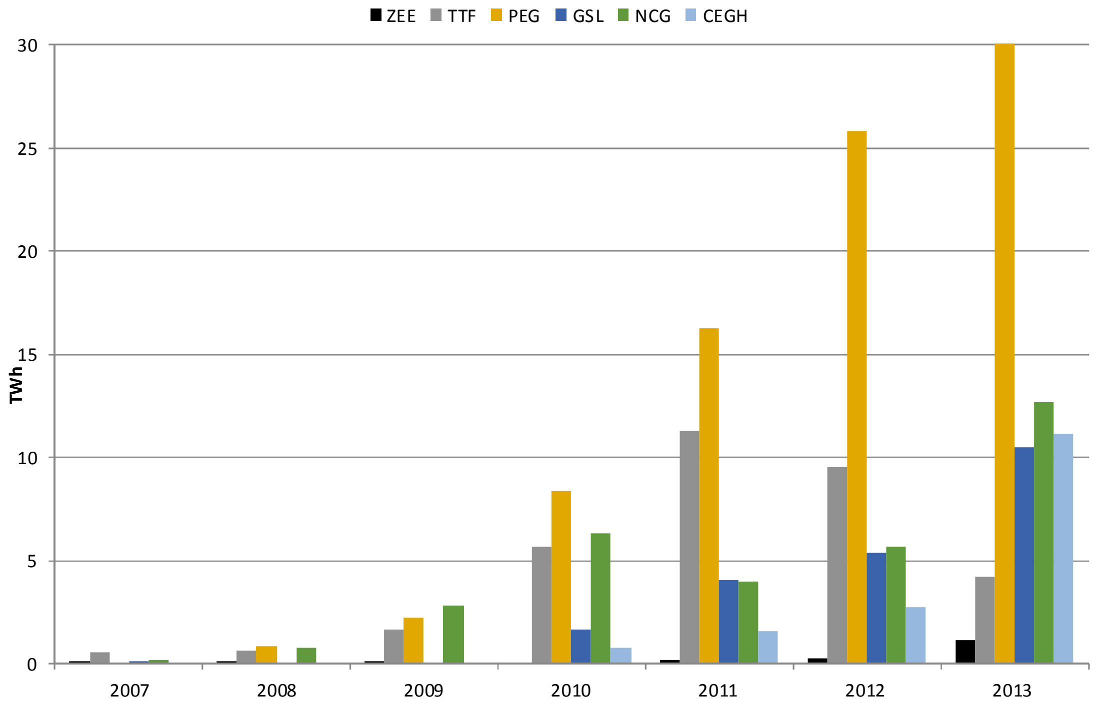
Source: Tankard Parties (ICAP Energy Limited, Tullett Prebon (Europe) Limited, Spectron Energy Services Limited)

Figure 8: Gas Volumes Traded, OTC, Month Ahead, 2007 – October 2013 (TWh)



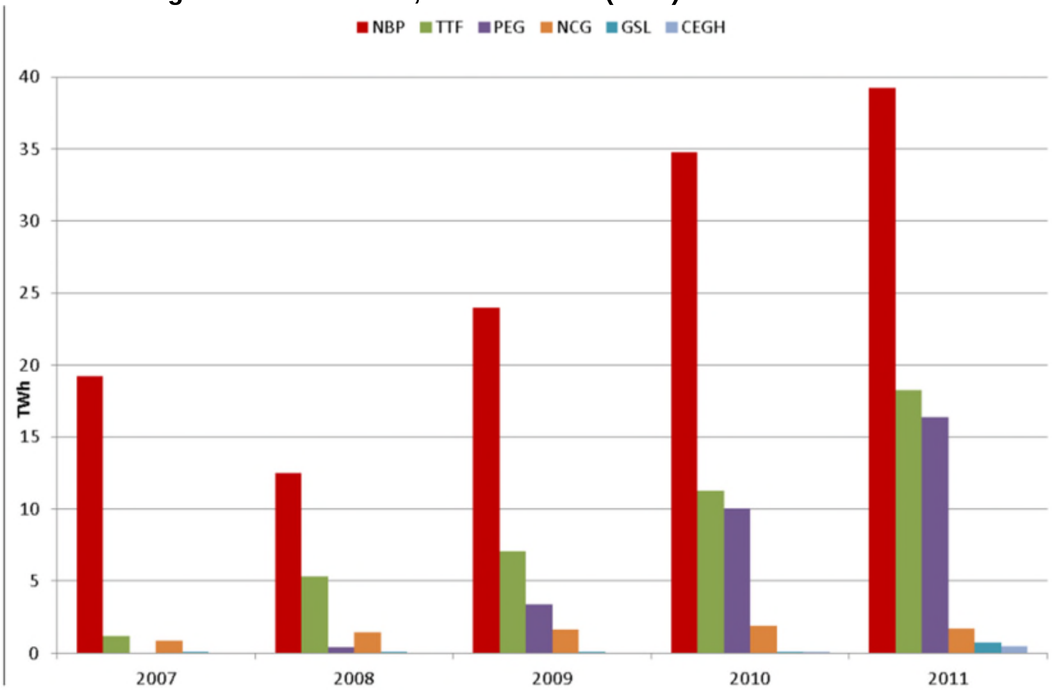
Source: Tankard Parties (ICAP Energy Limited, Tullett Prebon (Europe) Limited, Spectron Energy Services Limited)

Figure 9: Exchange Traded Volumes, Day Ahead, (TWh)



Source: ICE-ENDEX, EEX, Powernext, CEGH Gas Exchange

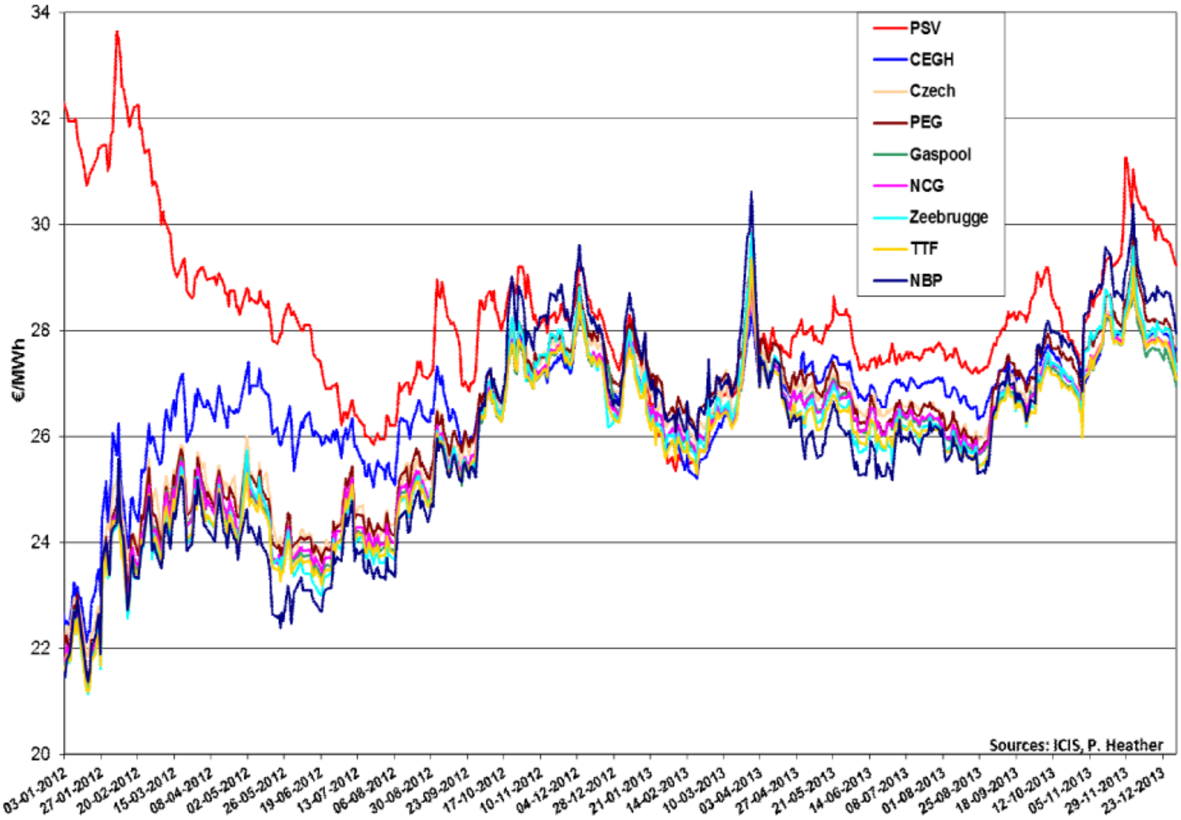
Figure 10: Exchange Traded Volumes, Month Ahead (TWh)



Source: ICE-ENDEX, EEX, Powernext, CEGH Gas exchange

As Petrovich (2013) and Heather (2012) have shown, traded volumes of gas on the main Continental European traded hubs have increased substantially since 2007 and both TTF and NBP can be regarded as mature liquid hubs. Although comparable data to that shown in Figure 10 is not available for 2012 and 2013, exchange-traded volumes for all contracts other than within day and day ahead in general increased strongly in 2012 compared with 2011. In 2013 however, NBP and TTF exchange-traded volumes were some 12.6% and 7.4% below those of 2012 respectively[35]. It is also of note that TTF OTC volumes for 2014 up to October have exceeded those of NBP[36].

Figure 11: European Hub Price Correlation Month Ahead Contracts January 2012 – December 2013



Source: ICIS, Heather (OIES)

Figure 11 shows the daily month-ahead contract prices for all the main European hubs for 2012 and 2013. Prices have generally been well correlated but it has been observed however that in some periods there has been significant price de-linkage when price correlations are assessed quantitatively. The most significant of these are:[37]

- In 2011 NBP at times de-linked from TTF and other NW European hubs. Further investigation revealed that this was overwhelmingly due to IUK capacity congestion and maintenance outages;
- PEG Sud and PEG Nord at times de-link from the other continental hubs. This is thought to be due to physical north – south pipeline capacity constraints in France (especially at times of low LNG delivery in the Fos area) and also possibly due to low liquidity at PEG Nord;

[35] For data and further analysis see Heather, P. (2015) forthcoming.

[36] London Energy Broker's Association Monthly OTC Energy Volume Report, October 2014.

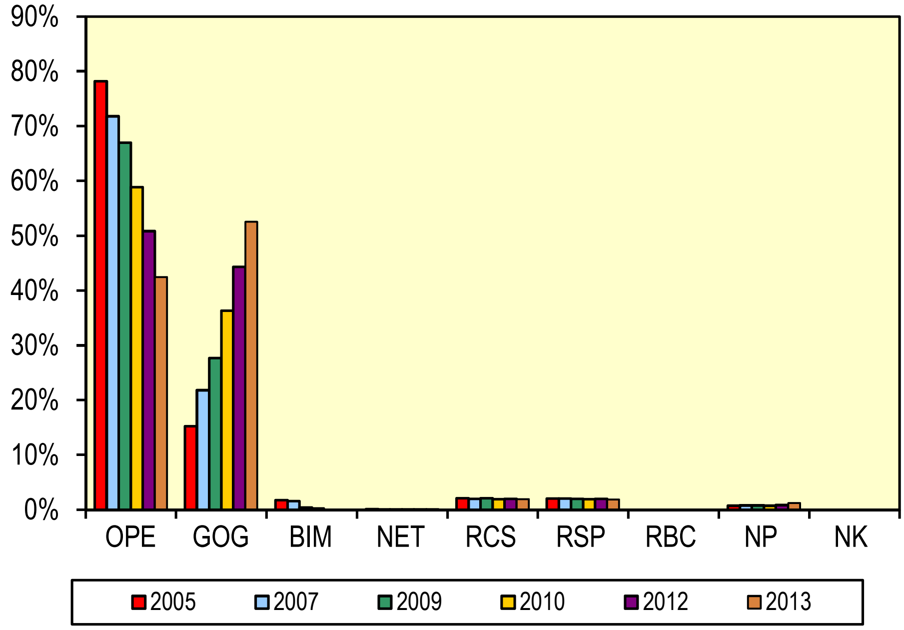
[37] These are conclusions from Petrovich (2013) and Petrovich (2014 forthcoming).

- PSV and at times CEGH have de-linked from the north west European hubs. This was certainly the case prior to 2012 when these hubs were at an early stage of development. Price correlation was good in late 2012, but in 2013 both hubs saw lower correlation metrics. This is thought to be due to physical and/or contractual congestion in infrastructure linking Italy and Austria to the NW European hubs.

Most importantly, Figure 11 shows no evidence of `manipulation' – defined as the ability of dominant players in national markets to impact prices over a long period of time – which had been one of the main reservations of those opposing a move to hub-based pricing.[38]

The increase in the importance of hub pricing at the expense of oil-linked pricing over the period 2005-13 is shown in Figure 12. In 2005, nearly 80% of the gas sold in Europe was priced in relation to oil (OPE), and only around 15% in relation to gas on gas competition (GOG), or market prices at hubs. By 2013, gas priced in relation to oil had fallen to just over 40% and more than 50% of gas was market priced. This is a remarkable transformation over an 8-year period and the trajectory of change in Figure 12 shows no signs of slowing down. It needs to be emphasised that the survey data are collected from the gas industries in individual countries; hence they are not based on models or estimates but on real data provided by gas companies.[39]

Figure 12: European Price Formation 2005-13



Note: a full description of the price formation mechanisms : OPE, GOG, RCS and RSP can be found on p.7 of the source.
Source: IGU (2014), Figure 1.3, p.8.

[38] This is different to the definition of that term in Article 2 of the EU REMIT Directive which states that a company or individual which, "gives, or is likely to give, false or misleading signals as to the supply of, demand for, or price of wholesale energy products", may be guilty of market manipulation. REMIT (2011).

[39] For information on data collection and analysis see IGU (2014), pp.10-13.

Table 4: European Wholesale Gas Pricing 2013 (%)

REGION (approximate % of total european demand)	Oil Price Escalation (OPE = oil-linked pricing in long term contracts)	Gas on Gas Competition Price (GOG = hub price)	Regulated Cost of Service Price (RCS)	Regulated Social Price (RSP)
NORTH WEST EUROPE (50%)	20	80		
CENTRAL EUROPE (10%)	35	50		15
MEDITERRANEAN EUROPE (30%)	85	15		
SOUTH EAST EUROPE (10%)	41		47	12

Note: A full description of the price formation mechanisms: OPE, GOG, RCS and RSP can be found on p.7 of the source. **North West Europe**: Belgium, Denmark, France, Germany, Ireland, Netherlands, UK. **Central Europe**: Austria, Czech Republic, Hungary, Poland, Slovakia, Switzerland. **Mediterranean Europe**: Greece, Italy, Portugal, Spain, Turkey. **South East Europe**: Bosnia, Bulgaria, Croatia, FYROM, Romania, Serbia, Slovenia.
Source: IGU (2014), pp. 26-27.

However, Table 4 demonstrates that very different price formation mechanisms operate across different European regions: north west Europe is clearly dominated by hub-pricing, but only 15% of gas is sold at hub prices in the Mediterranean region (virtually all of which is in Italy) and none in south east Europe. Half of central European gas is priced at hubs but still 35% in relation to oil.

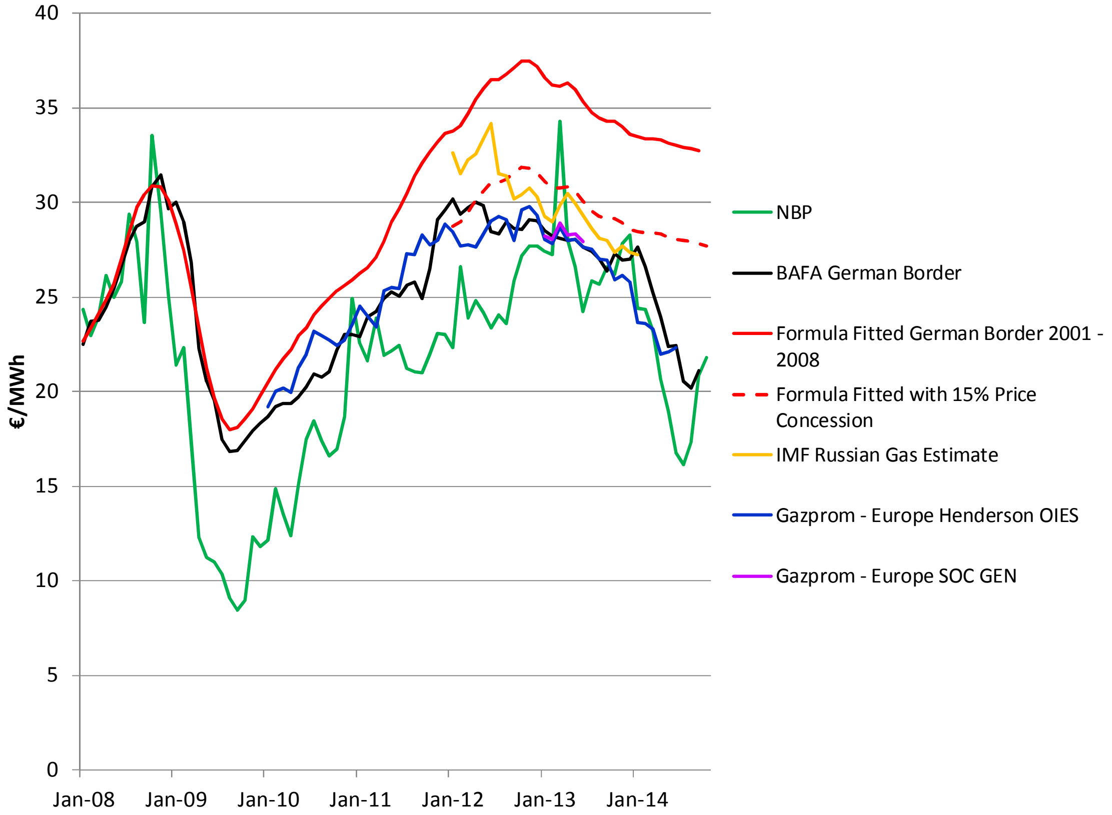
The evolving relationship between long term contract oil-indexed prices and hub prices

In Figure 3 it was shown that the predictable relationship between lagged prices of gasoil and fuel oil and the average border price of German gas imports broke down in early 2009. This might be explained by a combination of price concessions negotiated with Gazprom and Dutch and Norwegian sellers of gas under long term oil-indexed contracts; and the increasing impact of hub-priced gas imports into Germany – probably from TTF. As trust in the BAFA price as a benchmark of European oil-indexed prices waned, a number of different estimates emerged.

Figure 13 shows a range of these estimates. The green line is NBP (day ahead monthly average price). The black line is the BAFA (the average German import) price. The red line is an estimate of 'pure oil indexed pricing' (and therefore matches BAFA pre-2009) based on a formula including average gasoil and fuel oil prices (see Figure 3). The dashed red line is a 15% reduction of the solid red line and is used by some commentators as an estimate of the Russian long term contract price following the reductions described above. The yellow line is an estimate of Russian gas price at the European border used by the IMF.[40] The blue line is the quarterly price received by Gazprom for gas delivered to Europe (calculated by OIES) based on the company's financial information; and the pink line the results of a similar calculation by Société Générale.

[40] Available at http://www.indexmundi.com/commodities/?commodity=russian-natural-gas

Figure 13: NBP and Estimates of European Oil-Indexed Contract Prices 2008 – 2014



Sources: Platts, BAFA, IMF, Henderson (OIES), Bros (2014).

The first conclusion from Figure 13 is that, as we noted above, despite continued support for oil-indexed prices in public, Gazprom has made significant price concessions to its European contract customers and since early 2013 has been selling gas at close to hub prices.[41] The second conclusion is that the process of ceding price concessions may have started as early as 2010, and that the post-2009 divergence of BAFA from its strong historical relationship with gas oil and fuel oil prices may have been a truer reflection of prices than previously thought, given its strong agreement with prices derived from Gazprom's financial information. Two potentially important observations flowing from this analysis are that:

- it seems strange that Europe has no definitive measure (in the public domain) of the price it pays for 25-30% of its gas demand[42];
- it seems strange for Russia/Gazprom to vocally and publically state that it wishes to defend a higher (oil-linked) price level than it is actually charging its customers, given this is an obvious invitation to competing, lower cost suppliers.

[41] An exchange between Gazprom Export and the authors on this subject can be found in Stern and Rogers (2013).

[42] The exact figure depends on the specific year and number of European countries under consideration. In 2013, a record year for Russian gas exports, the latter accounted for 27% of EU (but not European) gas demand. For further discussion of how to interpret dependence on Russian gas, see Stern ed. (2014).

The emergence of dynamic arbitrage between hubs

We now examine the mechanics of the North West Europe hubs which are the physical interface between 'spot gas' and oil indexed pipeline gas.

Figure 14: North West European Hubs and Trading Flows around 2008

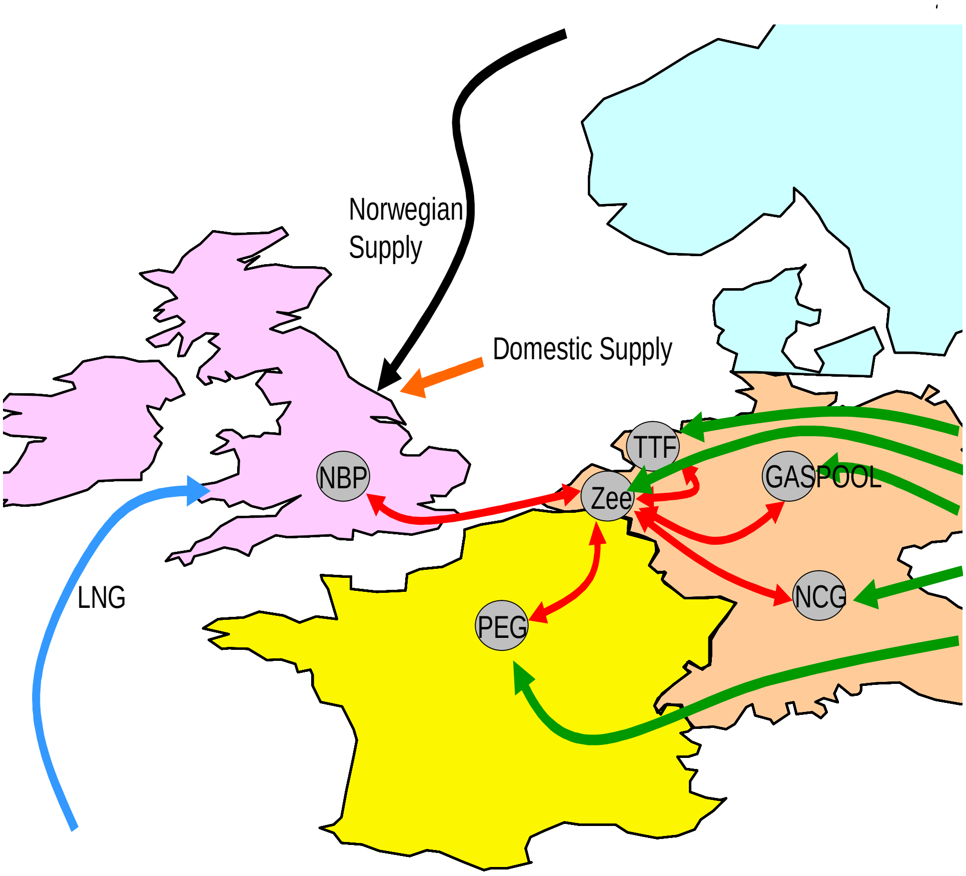
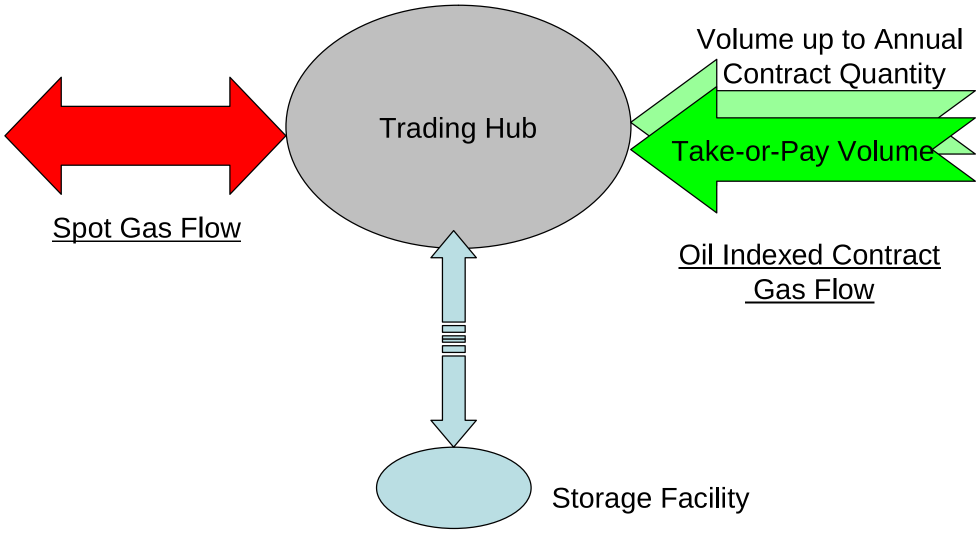


Figure 14 is a representation of the North West Europe gas trading arena as continental hubs were beginning to develop, i.e. around 2008. The interaction between UK spot-priced gas and oil-indexed gas, shown in Figures 14 and 15, gave rise to the formation of the Zeebrugge Hub at the continental European end of the Bacton-Zeebrugge Interconnector, and the PEGs, TTF, Gaspool and NCG hubs. All these Continental hubs were effectively embedded in 'oil-indexed gas territory', but they did provide a market place or platform to trade between oil-indexed gas (green arrows) and spot-priced gas (red arrows). As UK domestic production declined it was supplemented by Norwegian imports and by growth in LNG imports (both pricing off UK traded gas i.e. NBP). The British regas terminals looked set to establish the UK as North West Europe's 'offshore unloading jetty'; effectively enabling spot gas to overflow into the continental heartland markets and compete with oil-indexed gas at the trading hubs. Not shown in Figure 14, but enhancing this dynamic, is the ability of the Zeebrugge LNG regas terminal, and from 2012 the GATE terminal in the Netherlands, to receive spot cargoes.

Figure 15: Dynamics of North West Europe Trading Hubs



A hub is schematically represented in Figure 15. Arbitrage dynamics can be illustrated by considering two cases:

1. *The spot gas price is lower than the oil-indexed gas price:* in this situation, midstream gas players at the hubs will buy up more spot gas and buy less oil-indexed gas. This will have the effect of pulling more gas out of Britain and causing the NBP price to rise. As the demand for oil-indexed gas falls, buyers with long term contracts will reduce their nominations – effectively taking gas 'out of the system' (it remains in the gas field upstream). This process repeats itself until either:

- NBP price has risen to equal the continental oil-indexed price; or,
- The supply of oil-indexed gas has been reduced to its take-or-pay level and the process of arbitrage can proceed no further.

2. *The spot gas price is higher than the oil-indexed gas price*: in this situation, midstream gas players at the hubs will buy less spot gas and buy more oil-indexed gas. This will have the effect of pulling less gas out of Britain (and could send gas which was oil-indexed into Britain), causing that price to fall. As the demand for oil-indexed gas rises, buyers under these long term contracts will increase their nominations - effectively bringing extra gas 'into the system' through higher upstream production. This process repeats itself until either:

- NBP price has fallen to equal the continental oil-indexed price; or,
- The supply of oil-indexed gas has been increased to its annual contract quantity (ACQ) level and the process of arbitrage can proceed no further.

Three overlays on this central concept need to be noted:

- The arbitrage can be 'time parked'[43] by the use of gas storage facilities. Historically, storage usage in continental Europe has been driven by a conservative 'utility' mindset[44], however

[43] 'Time Parked' – shorthand for the action of trading entities injecting into storage gas purchased at low prices with the intention of withdrawing and selling this during periods when the hub price is higher.

[44] 'Utility Mindset' – with reference to storage this means only using storage to meet demand peaks and to provide supply security.

much of the current and future salt cavern storage development in North West Europe is driven by the prospect of spot vs. oil-indexed price arbitrage.[45]

- It is likely that arbitrage is restricted by pipeline infrastructure bottlenecks, ('connectivity'), as well as by contractual flexibility limits.
- The reference to take-or-pay and annual contract quantity levels as limitations at the monthly level is simplistic. In practice there is greater short term flexibility as long as these levels are adhered to on a cumulative basis by the end of the 'gas contract year' which runs from October 1st to September 30th.

This framework explains the recurrence of price convergence in Figure 6.

1.4 The Determinants of European Hub Prices: an analytical framework

We have discussed the 1990s development of the NBP hub, and how it has been influenced by arbitrage interaction with long term contract oil-indexed supplies. We have also seen how the apparent price reductions in long term contract prices, in large part as a consequence of a growth in Continental European gas hub development post 2008, resulted in the convergence of Russian gas prices towards hub levels.

In order to address the question 'what drives the pricing of gas at European hubs?' an approach developed by Timera Energy (and subsequently presented on their website blog) provides a good framework for understanding the key drivers.[46] The elements of this framework are summarised below, adapted by the authors.

An understanding of European hub price dynamics requires sources of supply with similar pricing and flow dynamics to be grouped according to flexibility, which is an important driver of hub pricing. This is helped by the fact that most sources of European supply are under long term contracts that use a similar structure and price formation mechanism. An important point is that only a relatively small volume of total European supply actually has the flexibility to respond to changes in hub prices. The traditional approach to understanding market dynamics is to use complex modelling requiring huge datasets covering the characteristics and costs of fields, contracts, import infrastructure, transmission, storage etc. However, two important characteristics of the European market question the validity of such an approach:

- Most gas comes into Europe under long term contracts. So contractual pricing and flexibility are key drivers of physical flows and hub pricing dynamics.
- A significant share of European gas is priced at an increasingly interconnected set of hubs across a complex range of physical infrastructure. Hubs are also increasingly influenced by global supply/demand dynamics, and by prices in other regions notably (at times) North America and Asia.

Trying to represent this complexity in a detailed bottom up model has two key flaws: the detail erodes transparency as to the real drivers of gas flows and pricing, and genuine insights are lost in the 'noise' created by trying to capture the complexity of detail.

The sources of supply

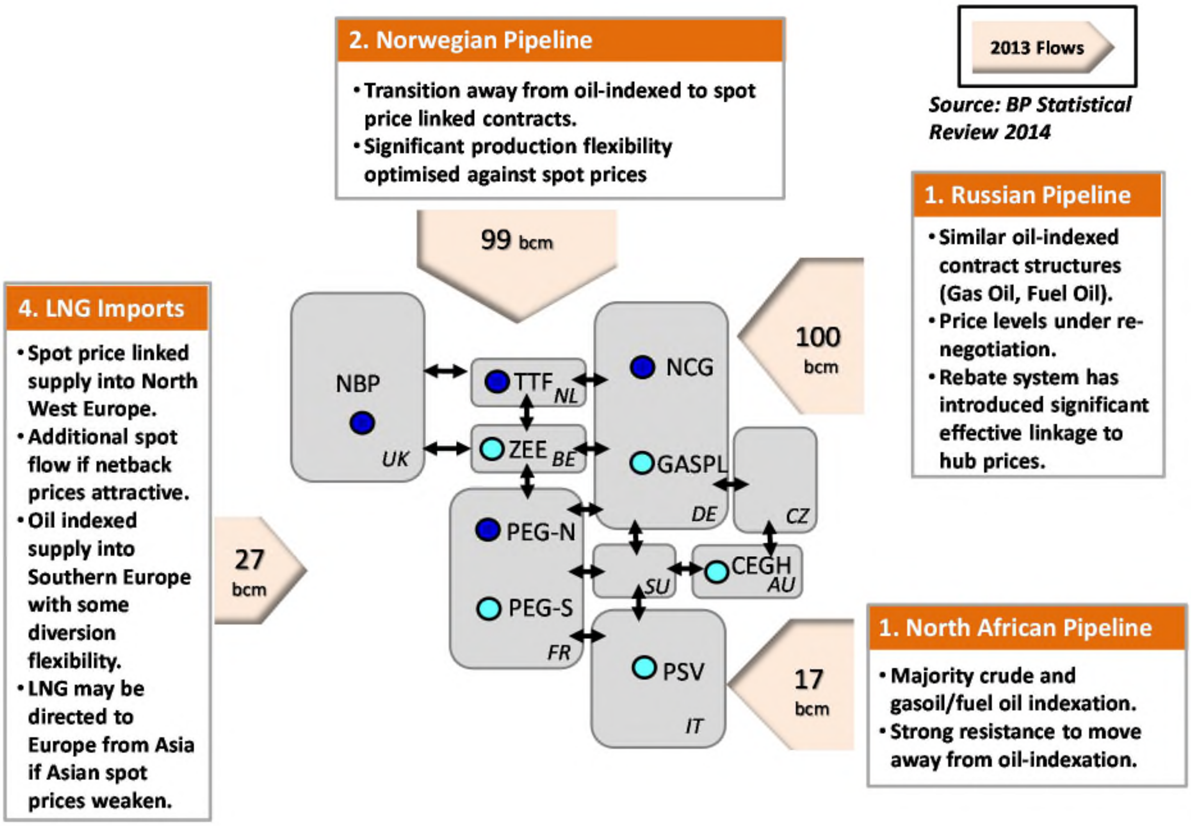
To understand hub pricing dynamics, it helps to draw a ring around the European countries that have direct access to hub liquidity. The boundaries of this ring broadly include north west, central and

[45] For an illustration of how these commercial mechanisms operate see Le Fevre (2013).

[46] Timera Energy is a specialist consultancy service focusing on value and risk in global LNG and European energy markets. Timera Energy (2013) and (2013a)

Southern Europe, excluding Spain which has limited physical pipeline connectivity with the rest of Continental Europe[47]. Within this boundary, European gas supply can be grouped into several key sources by geography as illustrated in Figure 16. The diagram illustrates volumes by supply source based on 2013 gas flows.

Figure 16: Sources of European Gas Imports



Note: Diagram and gas flows based on a European hub zone boundary that includes UK and Ireland, Belgium, Netherlands, France, Germany, Czech Republic, Austria, Switzerland and Italy.

Source: Adapted from an approach used in Timera Energy (2013).

The following is a brief summary of each source of supply:

1. Russian supply – imported under long term supply contracts of a relatively consistent structure, incorporating indexation to oil products with some volume flexibility but subject to a take or pay constraint. Price levels have been the subject of re-negotiation and the rebate system introduced from 2012 has brought prices closer to hub price levels.
2. Norwegian supply – which can be split into two components:
    - Long term supply contracts formerly indexed to oil product prices but now mainly hub-indexed.
    - Supply that flows based on spot price signals, mainly in response to seasonal variations.

[47] Southern France and Italy suffer from periodic periods of limited connectivity, which at times result in a de-linkage. See Petrovich (2014).

3. North African supply – primarily import contracts into Italy and Spain with prices indexed to crude oil and oil products.

4. LNG supply – which can be split into two components:

   - Long term oil-indexed supply contracts (primarily into Southern Europe).
   - Supply that is imported into North West Europe either on medium term contracts indexed to hubs or on a spot basis sold at hub prices.
   - Spot supply re-directed to Europe to maintain an Asian LNG spot price premium when market conditions allow this.

5. Domestic production – dominated by declining field production in the UK and Netherlands, sold at hub prices.

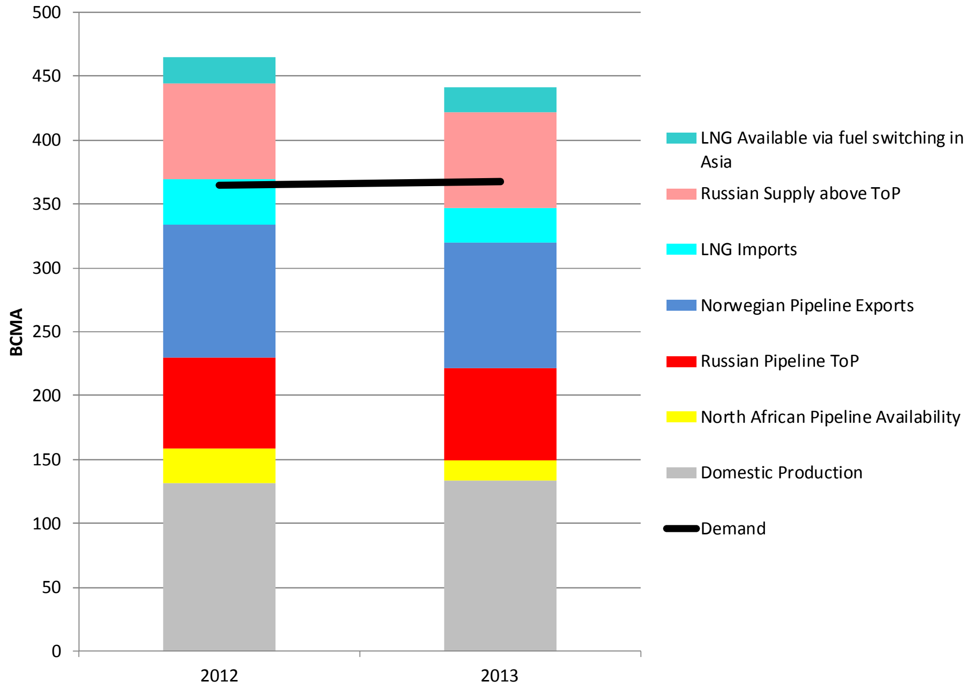
The other key supply dynamic that is not captured in these five categories is gas storage capacity. Storage capacity enables the movement of gas between time periods, rather than representing an outright source of supply. Seasonal storage acts to move gas from lower priced summer periods to higher priced winter periods. Fast cycle storage acts in a similar fashion but over a shorter time horizon.

The groupings of supply sources set out above enable us to focus on the commercial decisions that drive the pricing and flow of gas.

A European supply stack view- flexible and inflexible tranches

A supply stack for the market geography defined in Figure 16, is shown in Figure 17 with data for 2012 and 2013.

Figure 17: A Supply Stack for North and Central Europe, 2012 and 2013



Note 1: Diagram and gas flows based on the European hub zone boundary in Figure 16. Russian gas contract volumes are based on delivery into this zone (i.e. they do not include sales into Eastern Europe or the Balkans).

Note 2: The Russian pipeline supply tranche above take-or-pay levels includes contracted and uncontracted gas and is shown as a nominal quantity. The OIES estimate of available Russian production above recent delivered levels is around 100 Bcma but, prior to 2020, transportation capacity would limit Russian gas flows above ToP to some 70 Bcma.
Source: IEA Monthly Data Series, BP Statistical Review of World Energy, Author's assumptions and calculations

Inflexible supply tranches:

The supply tranches in the stack chart are broadly ranked from lowest to highest marginal cost. The inflexible supply sources include:

1. Russian pipeline contract take or pay volumes
2. North African pipeline gas take or pay volumes
3. Domestic Production
4. Norwegian Gas. Some of this will be sold under long term contracts (mainly hub- indexed), some on an un-contracted basis at hubs. While there is generally a seasonal pattern to this production, in aggregate, there is scant evidence that annual production deviates from planned field production other than due to field shut-downs.

These tranches can be effectively viewed as having no relevance to the level of hub pricing as the gas will flow regardless of hub price levels. In practice these tranches may contain some flexibility (e.g. the ability to bank gas across contract years) but this tends to have only a secondary impact on hub pricing.

Flexible supply tranches:

Much more important are the flexible tranches of supply that can respond to incremental changes in hub price levels. The key tranches of flexible supply are listed below. The first three tranches are the key drivers of marginal pricing across the hubs.

LNG Imports This tranche has three components:

- LNG delivered under long term contracts to buyers in Southern France and Italy based on oil-indexed formulae. In general such contracts have provisions for re-direction to higher priced markets if buyer and seller are in agreement[48].
- LNG delivered under medium or long term contracts to buyers in North West Europe priced in relation to hubs.
- LNG sold to Europe on a spot or uncontracted basis. This includes a managed volume of LNG that Qatar chooses to place into Europe rather than selling at higher Asian spot prices. It is a secondary outlet for Qatari production that could otherwise reduce Asian spot prices[49].

Russian Pipeline contract swing and uncontracted volumes

- Swing volumes (above take or pay) are optimised by buyers under long-term contracts based on contract vs hub price relationships. Russian contracts are a key provider of swing. As shown in Figure 13, during 2012 and 2013 Russian contract prices (post concessions) were estimated to be in the range €25 to €28/MWh. Gazprom rebates, to close the gap between contract prices and prevailing hub prices, has added a layer of complexity which will be further discussed below.
- In addition to swing volumes under Russian contracts, Russia also has the ability to sell additional supply, either to established contract buyers or on the hubs. Since 2008, Gazprom has a) developed upstream production capacity in excess of its European export volume growth and b) lost market share within Russia to non-Gazprom producers. While some estimates indicate that swing and un-contracted volumes combined could be up to 100 bcma, pipeline capacity would restrict this to 60 to 90 Bcma in 2015, growing to 85 to 110 Bcma by 2020.

LNG Available via fuel switching in Asia. This is shown as a nominal tranche in Figure 17 as its size is difficult to estimate. To attract such volumes from the Asian market would require a price sufficient to incentivise Asian utilities to backfill the LNG re-directed with another fuel (e.g. oil products) in the power sector. This would require a correspondingly high European hub price.

Gas storage capacity. Storage capacity is priced off the opportunity cost of alternative flexibility (typically pipeline swing). Storage is not shown in the supply stack as it has a limited net impact at an annual level (i.e. it is primarily used to move gas between different periods across the year).

How does flexible supply set hub prices?

The LNG and Russian pipeline supply tranches shown above interact to dominate European hub pricing dynamics. If the European market relies on Russian swing and/or uncontracted gas as the marginal supply trance to meet demand, then hub prices will be anchored by this price level. This dynamic also influences forward curve prices at the hub. If the expectation of market analysts/traders is that Europe will require Russian swing volumes, then forward curve prices will tend to converge on

---

[48] This component is arguably less flexible and could be included in the 'Inflexible Supply' category. However splitting this out from the total LNG import figure is difficult and in any case it is unlikely to constitute the marginal supply source.

[49] For a discussion on whether Qatar can be viewed as displaying 'discriminating monopolist behaviour' see Rogers and Stern (2014), pp 13 – 14.

the estimate of Russian contract prices (i.e. around the €25 to €28/mmbtu band at oil prices around $100 to $110/bbl)

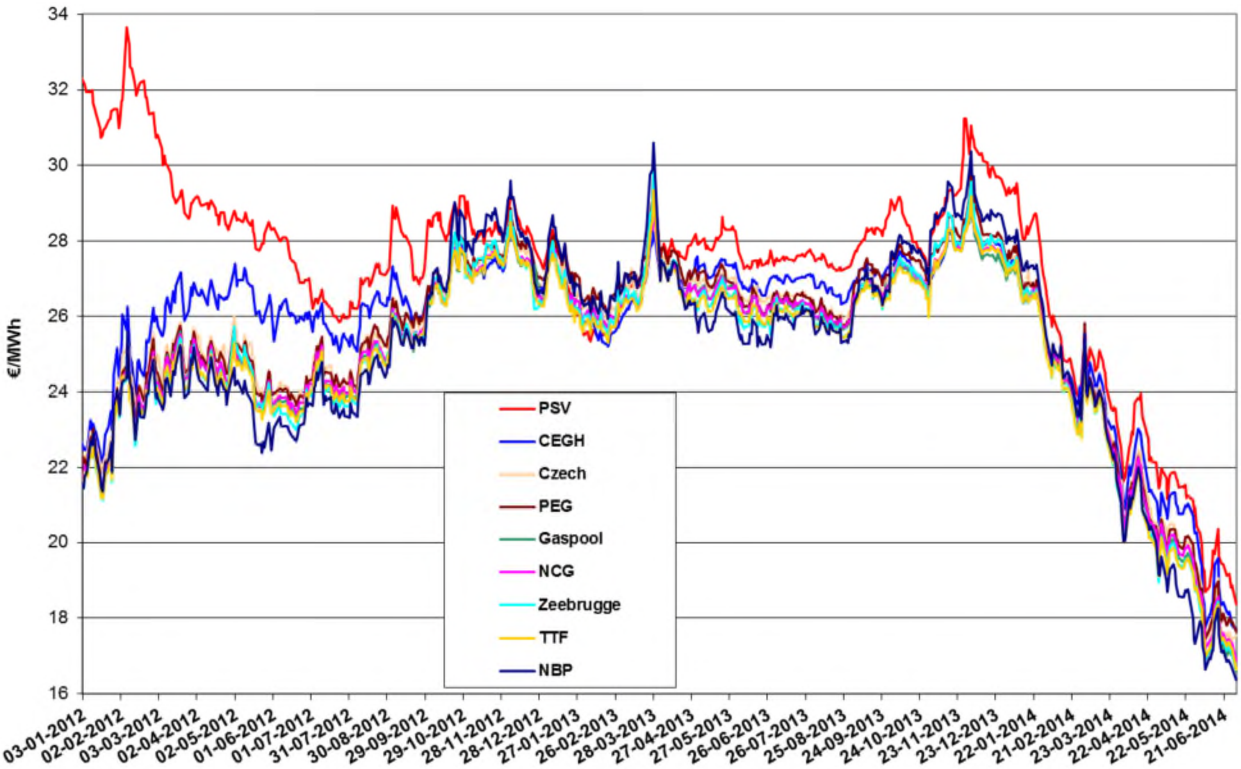
Figure 17 shows that in 2012 Europe's demand was met by LNG imports at the margin with little or no requirement for Russian swing supply. The average NBP price (which is representative of Continental European hub prices) for 2012 was €25.1/MWh ($9.46/mmbtu). In 2013, reduced supply availability from North Africa pipeline gas and LNG meant that Europe relied on Russian swing supply of some 20 bcma. The average NBP price in 2013 was €27.3/MWh ($10.63/mmbtu).

The extent to which Russian contract swing supply influences hub prices also depends on the decisions of LNG suppliers (notably Qatar). Depending on the level of demand for spot or flexible LNG in Asian markets, Qatar will place a portion of its LNG production into Europe so as not to depress Asian spot prices. In 2013, had Asian market demand for spot LNG been low, Qatar would have been able to re-direct some 20 Bcma of LNG into Europe without appreciably lowering European hub prices, at the expense of a loss of 20 Bcma of Russian swing volume. The future evolution of hub prices will depend crucially on the extent to which the balance of power currently exercised by Russia and LNG producers (chiefly Qatar) can be maintained.

European hub pricing in 2014

Europe has witnessed a dramatic and widespread fall in hub prices in 2014 as shown in Figure 18. In July and August 2014 European hub prices stabilised at a level of €17 to €19/MWh.

Figure 18: European Hub Prices January 2012 – June 2014, Month Ahead Contracts



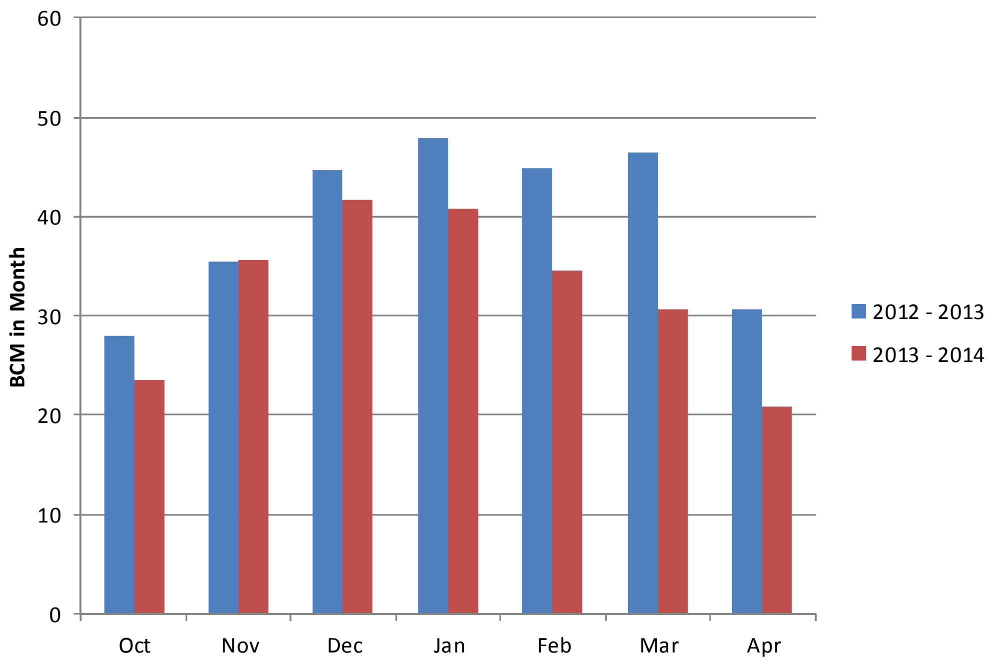
Source: ICIS, P. Heather OIES

This prompts two questions:

- What are the primary causes of such a price fall, and will it be maintained i.e. can we say that Europe had entered a new price band?
- How does this fit with our European price framework?

The primary cause was the mild winter of 2013-2014 which for the October to April period resulted in demand for the European countries represented in Figure 17 being 50.5 Bcm lower in 2014 compared to 2013. This is shown in Figure 19.

Figure 19: Monthly Gas Demand in North and Central Europe, October 2012–April 2014



Source: IEA Monthly Data Service.

In the first half of 2014 demand for spot LNG in Asia was lower than anticipated which resulted in a decline in the Asian JKM spot price[50], and in March and April 2014, a re-direction of spot cargoes to Europe in an attempt to limit such a price fall.

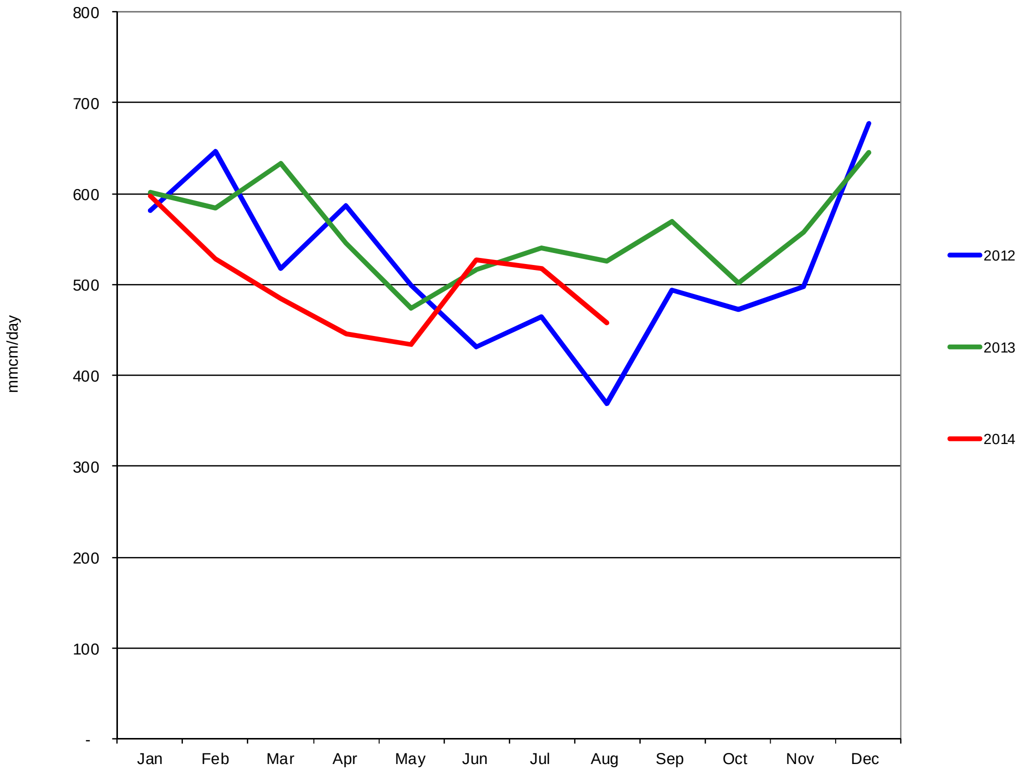
Although we cannot accurately break out monthly Russian pipeline gas imports for 2014 to date, Figure 20 shows total European pipeline imports from October 2013-August 2014 compared with corresponding months in 2012 and 2013.

The low pipeline import volumes in the first five months of 2014 suggest that Russian contract gas above Take or Pay was not required in Europe and consequently that hub prices were influenced by the forces of supply and demand, as the effective marginal supply tranche - spot LNG including LNG re-directed from Asia to protect Asian spot prices - is a hub-price taker. This may explain why prices fell steeply in 2014.

What remains to be seen is how Gazprom’s system of rebates, to compensate its buyers for the difference between contract price and hub price, will be adjusted in this lower hub price environment.

[50] Japan Korea Market: a price quoted by Platts for spot LNG cargoes.

Figure 20: European Pipeline Imports 2012 to August 2014



Source: Author's calculations from IEA Monthly Data Series.

The important issues for future price expectations are:

a) a) If the expectation is that Europe will not require Russian pipeline gas above take or pay levels for the remainder of 2014, then hub prices could remain below the erstwhile €25 to €28/MWh Russian contract 'flex volume' benchmark price; but

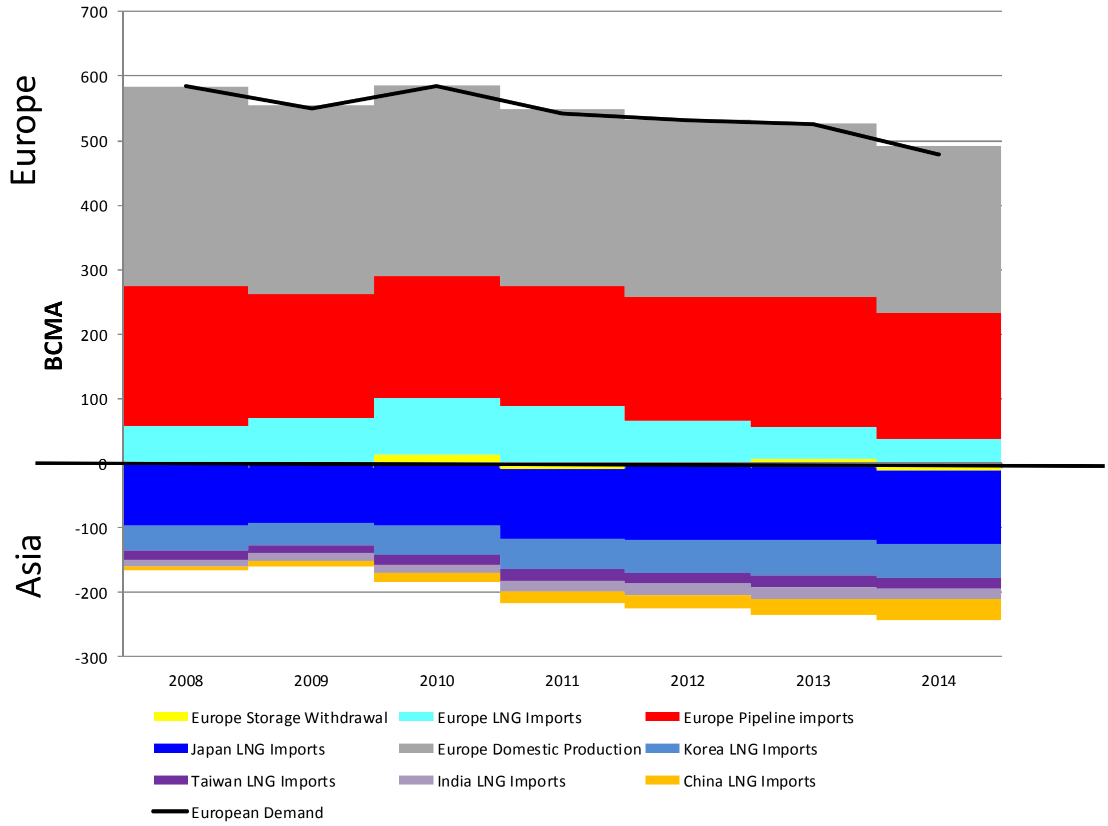
b) Even if Europe requires Russian flex volumes, the recent practice of rebates granted by Gazprom and its perceived shift to hub-indexation may significantly erode the importance of this former price band as a benchmark, to the extent that it no longer features in the considerations of trading analysts.

We may therefore witness a continuation of European hub prices responding to supply and demand fundamentals below the former Russian contract benchmark price level for a period. If, as is likely, such price levels are below Russia's preferred range, Gazprom may use its market power to rectify the situation. This would involve a managed reduction of physical volumes delivered to Europe, probably through buying gas on the hubs to be delivered to contract buyers as partial fulfilment of contract nomination volumes. The timing of such a move is uncertain but current European fundamentals, and the need on the part of Russia to exercise price-volume management in the light of future competition from US LNG supplies, makes this development inevitable at some stage.

1.5 The Impact of Global Dynamics

The surge in European LNG imports which occurred in 2010 and 2011, and the subsequent redirection of LNG to Asia were timely reminders that Europe has become linked to a more global gas arena. As discussed above, such linkages, through their 'disruptive' impact on existing contractual and price formation mechanisms, can catalyse significant changes in market structure. Figure 21 is a representation of the European[51] market (above the axis) and Asian LNG demand (below the axis). 2014 incorporates actual LNG data to June and other supply/demand data to April 2014.

Figure 21: Europe – Asia LNG Balance 2008 – 2014



Source: Platts, GIIGNL, IEA, EIA, Own Analysis

During 2009-12, pipeline imports (red) were squeezed between generally lower demand and higher LNG imports (light blue). As Asian LNG demand recovered post 2009, and significantly increased in the aftermath of the Fukushima nuclear disaster, LNG was 'pulled away from Europe' and pipeline imports (mainly Russian) increased. For the remainder of 2014 and beyond, the key issues determining the balance of LNG between Europe and Asia and, as a consequence, the supply make-up and pricing dynamics at European hubs are:

- The trend of European demand. Although variations will occur due to weather, the outlook is unlikely to include substantial growth.[52]

---

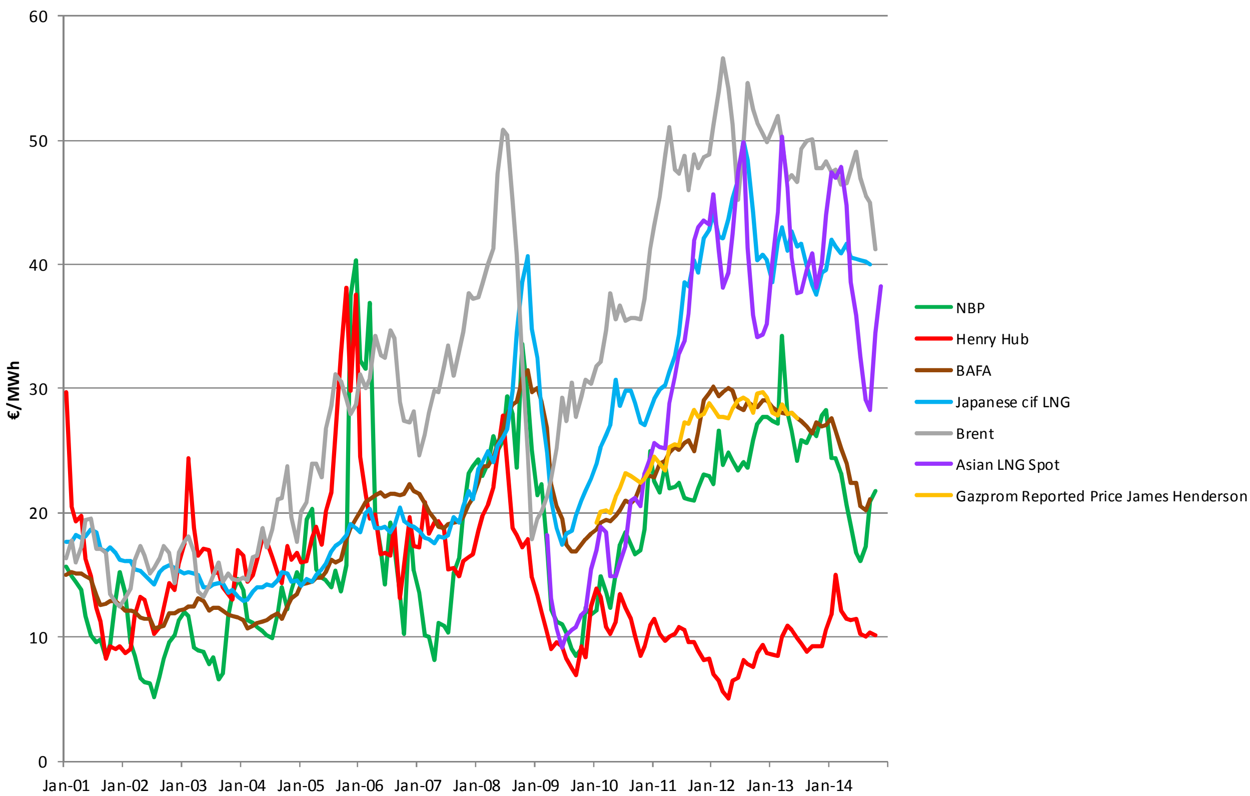
[51] In this Figure and subsequent analysis Europe is defined as Austria , Belgium, Bulgaria, Croatia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovakia, Slovenia, Spain, Sweden, Switzerland, Turkey and UK.

[52] See Honore (2014), Figure 45, p.64.

- The rate at which Japan successfully brings back on line a significant portion of its nuclear generation fleet.
- The rate at which new LNG projects, currently under construction, are commissioned; and,
- The future pace of LNG demand growth, especially that of China.

Figure 22 shows the key international gas prices for the period 2001-14. Since 2011 the unprecedented spread between US, European and Asian LNG prices has been reasonably consistent, apart from the weather-induced early 2014 European hub and Asian LNG spot price decline. How might this change as we move into the future?

Figure 22: International Gas Prices 2001 - 2014



Sources: EIA, Platts, Argus, BAFA, Henderson (OIES)

The global supply-side response to such regional price differences may well have further implications for European gas markets which:

- despite currently offering only modest long term gas demand growth prospects (as coal-fired and nuclear plant are retired and gas in transportation becomes a new potential growth area)[53];
- are set to progressively increase their gas import requirements due to the long term decline in domestic production, notably in Britain, the Netherlands, Denmark and Germany.

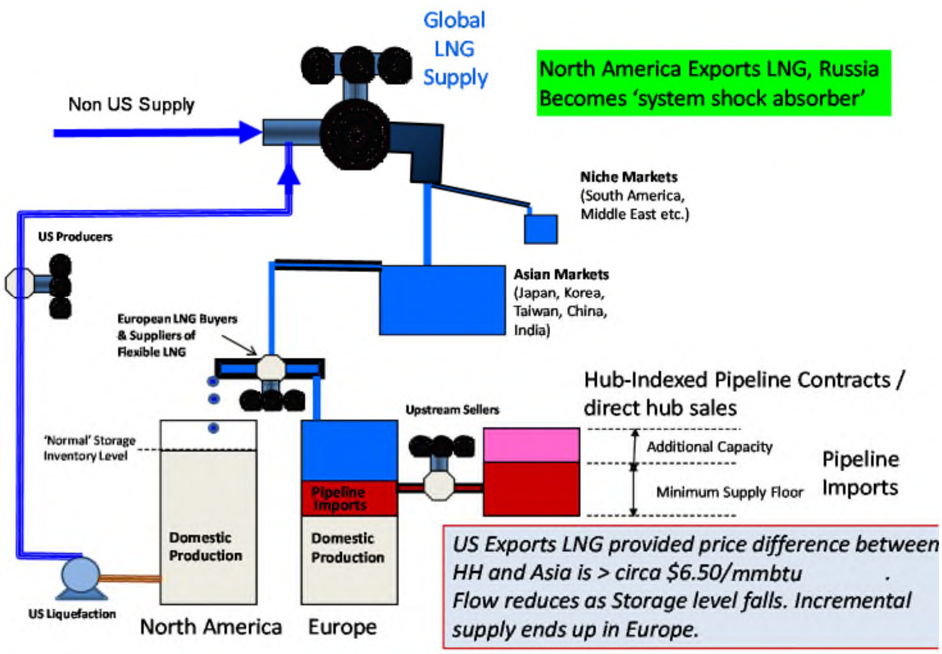
---

[53] See Honore (2014) and Le Fevre (2014).

And, given its newly liberalised structure, 199 Bcma of regas capacity[54] and Russian pipeline gas import capacity, the major European markets represent a 'battlefield' over which LNG and Russian pipeline gas are likely to compete strongly.

The post 2015 'Global System' is represented schematically in Figure 23.

Figure 23: Global LNG-Linked System Post 2015



In this representation, Global LNG supply (from US and non-US sources) is first taken by the Asian LNG markets (with Japan, Korea and Taiwan having no other source of natural gas). Also included here are the niche markets including South America.

What is left over is available for the markets of North America and Europe. North American requirements are limited to those of Mexico (due to pipeline bottleneck constraints in its ability to import US supplies) and isolated demand pockets on the US East coast which require LNG due to a dearth of pipeline supply. Europe will receive LNG volumes which are surplus to requirements from other markets. After domestic production and contracted pipeline imports, the balancing item tends to be Russian pipeline supply. As discussed earlier, Russian pipeline imports have risen as LNG has been diverted away to Asian markets, but this could change substantially if LNG supply grows in the future.

The 'Big Six' post-2015 uncertainties

In this increasingly 'connected' future system there is a surprisingly high degree of uncertainty in some key trends which will have a bearing on future supply and demand fundamentals. While it might reasonably be expected that connection via LNG to a wider market set would bring a degree of stability (the conventional portfolio risk diversification principle), the nature of the natural gas industry (given its high cost of transport and storage) tends more towards a 'just in time' supply philosophy – especially in relation to the fast growing Asian markets. The only major supplier with significant

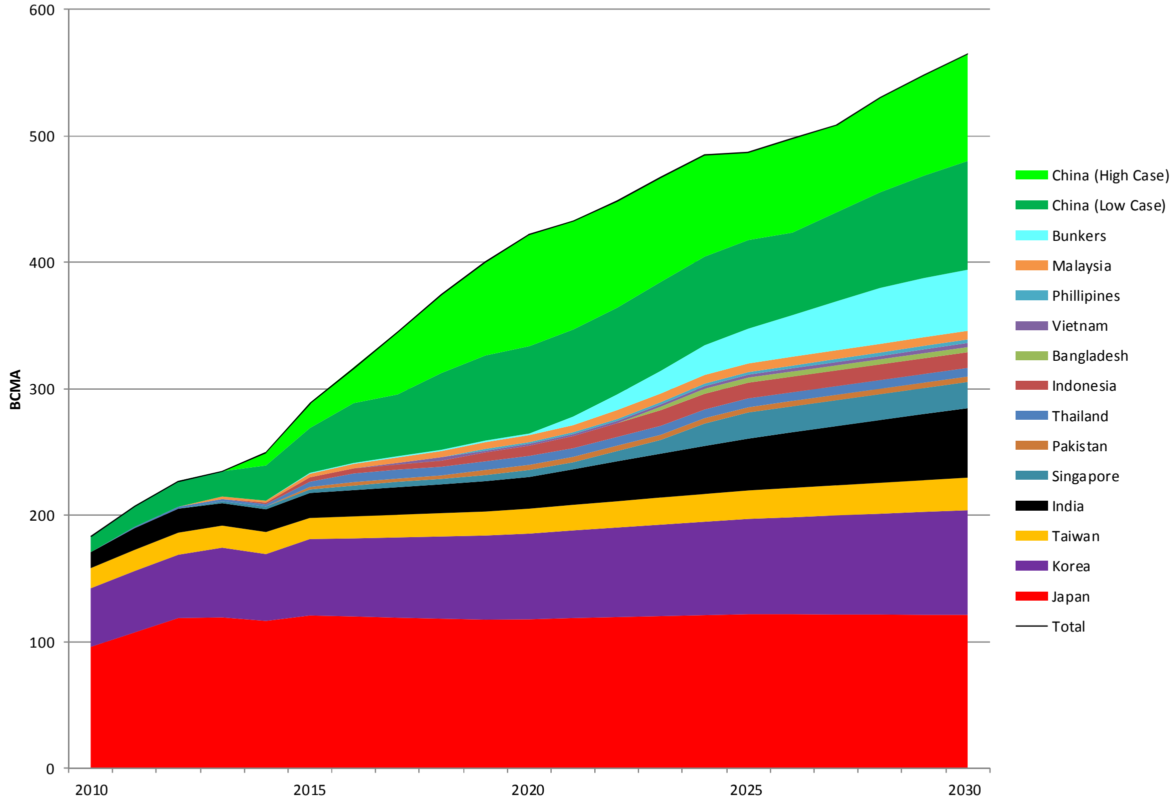
[54] GIIGNL (2013), p. 31.

upstream spare production capacity is Russia – which will increasingly emerge as the 'buffer' or shock absorber in the new global order.

Six of the most important uncertainties going forward are:

1. *Demand for natural gas and LNG in Asia*

Figure 24: Asian LNG Demand 2010 – 2030



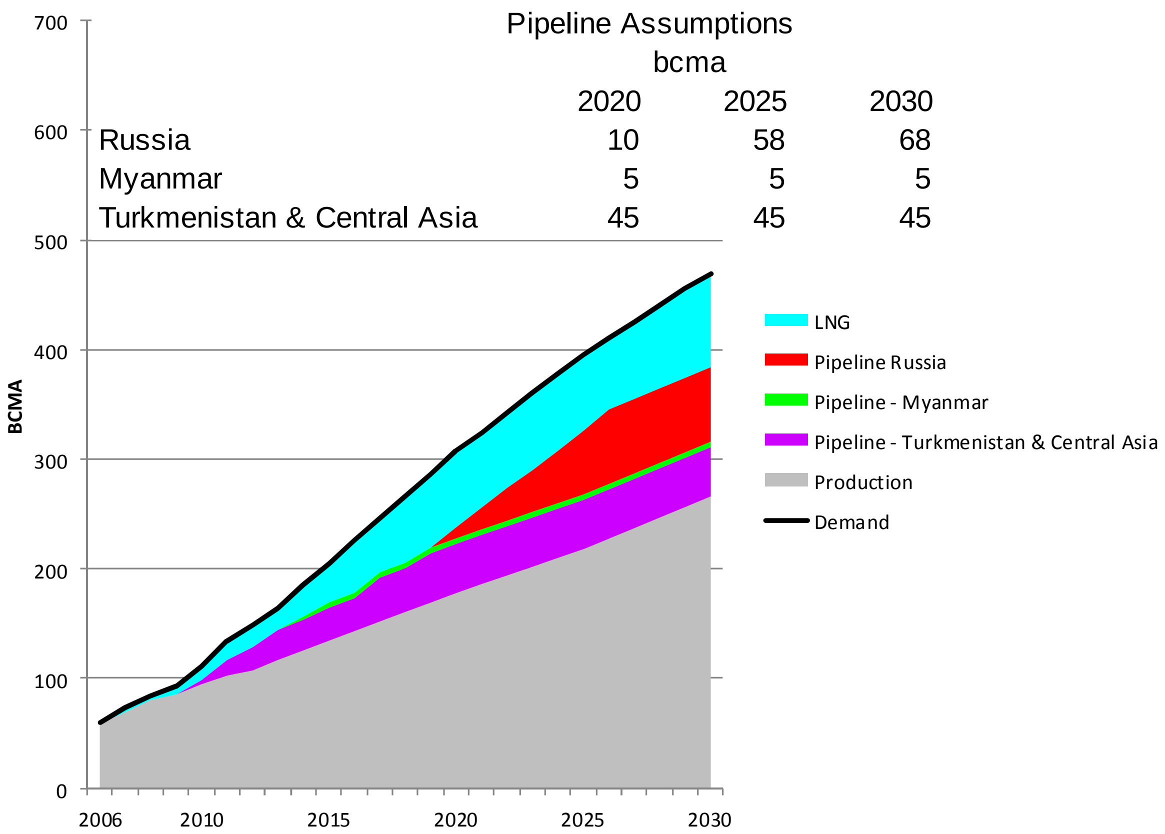
Sources: Source: Platts, GIIGNL, Ledesma/OIES, Chen (2014), IEA (2013), Author's Assumptions

Note: This outlook also includes the global marine bunker fuel market.

Asia is the most dynamic growth region for natural gas demand and its LNG requirements are shown in Figure 24. The key uncertainties in Asia's future LNG demand requirements are the pace of Japanese nuclear plant restarts in the 2014 – 2017 period; and beyond 2015 the growth rate of Chinese LNG demand. Chinese LNG demand will be a function of overall Chinese natural gas demand; domestic production (including shale gas and Coal Bed Methane); pipeline imports from Myanmar, Turkmenistan and other Central Asian countries, and Russia (East Siberia and potentially West Siberia via a possible future Altai pipeline); and gas price reform. All of these elements are difficult to forecast. Although the OIES Gas Programme will continue to focus research on 'de-mystifying' Chinese natural gas and LNG demand outlook, it is likely to remain a key 'known unknown' in the gas world for some time to come, and will indirectly impact market dynamics in Europe and North America.

The two (low and high) Chinese LNG demand outlooks shown in Figure 24 were based on distinct Chinese supply and demand cases. Figure 25 shows the Low Chinese Demand Case and its supply make-up.

Figure 25: Low Chinese Demand Case Supply Make-up 2006 - 2030



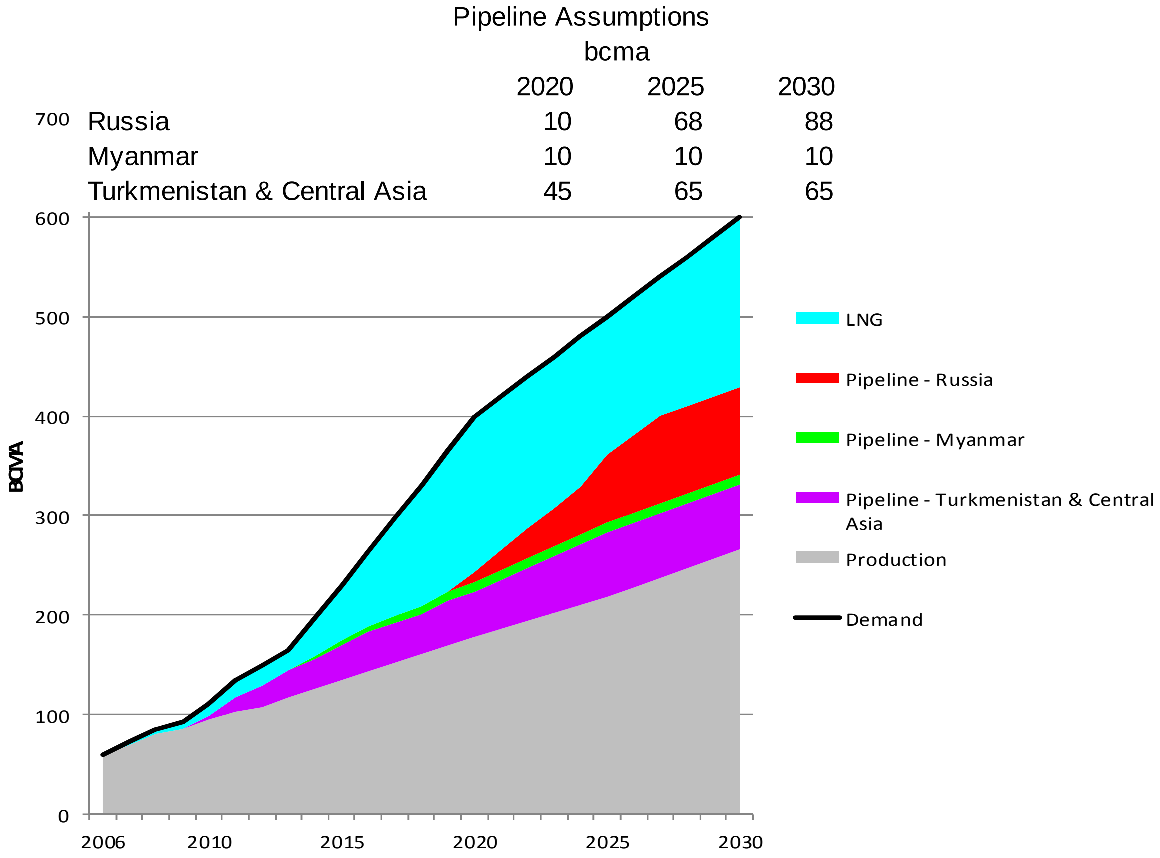
Source: IEA, Author's Assumptions

The Low Case incorporates gas demand and domestic production assumptions consistent with the IEA's 2013 World Energy Outlook New Policies Scenario. Pipeline import assumptions for Turkmenistan and Central Asia (as well as Myanmar), are below the 65 Bcma cited as a reasonable upside, but beyond 2025 Russian imports are assumed to expand beyond the recently announced 38 Bcma pipeline project to include the 30 Bcma Altai line. In this projection China's LNG import requirements are 69 Bcma in 2020, 70 Bcma in 2025 and 86 Bcma in 2030.

In 2014, CNPC predicted that by 2020 China's gas demand could reach 400 bcma. This was noted by the National Development and Reform Commission as a goal; Figure 26 reflects this higher 2020 demand level.[55]

[55] See Chen (2014), p.4.

Figure 26: High Chinese Demand Case Supply Make-up 2006 - 2030



Source: IEA, M Chen OIES, Author's Assumptions

The high case assumes greater use of Turkmenistan and Central Asian imports and in addition to the 'Low Case' assumption includes an additional 20 Bcma of Russian pipeline gas by 2030, potentially from Sakhalin. This results in LNG imports of 157 bcm, 139 Bcm and 171 Bcm in 2020, 2025 and 2030 respectively. These two LNG import cases will be used later to derive scenarios for European and global fundamentals and indicative price paths.

2. *Transition away from JCC pricing in Asian LNG markets*

The challenges faced by LNG suppliers in seeking to maintain JCC[56]- linked pricing in the Asian LNG market are addressed in Rogers and Stern (2014). If an Asian LNG hub was successfully formed, initially in Singapore but then later in Shanghai and/or Tokyo, this would provide a more rational basis for LNG pricing in Asia which would respond (in price terms) to Asian demand for LNG and the price at which flexible LNG was available from the global market. In addition to the obvious benefits for Asian buyers, this would improve the arbitrage and trade-flow dynamics between the European and Asian regional gas markets and reduce the potential for gaming by today's largest flexible LNG suppliers.

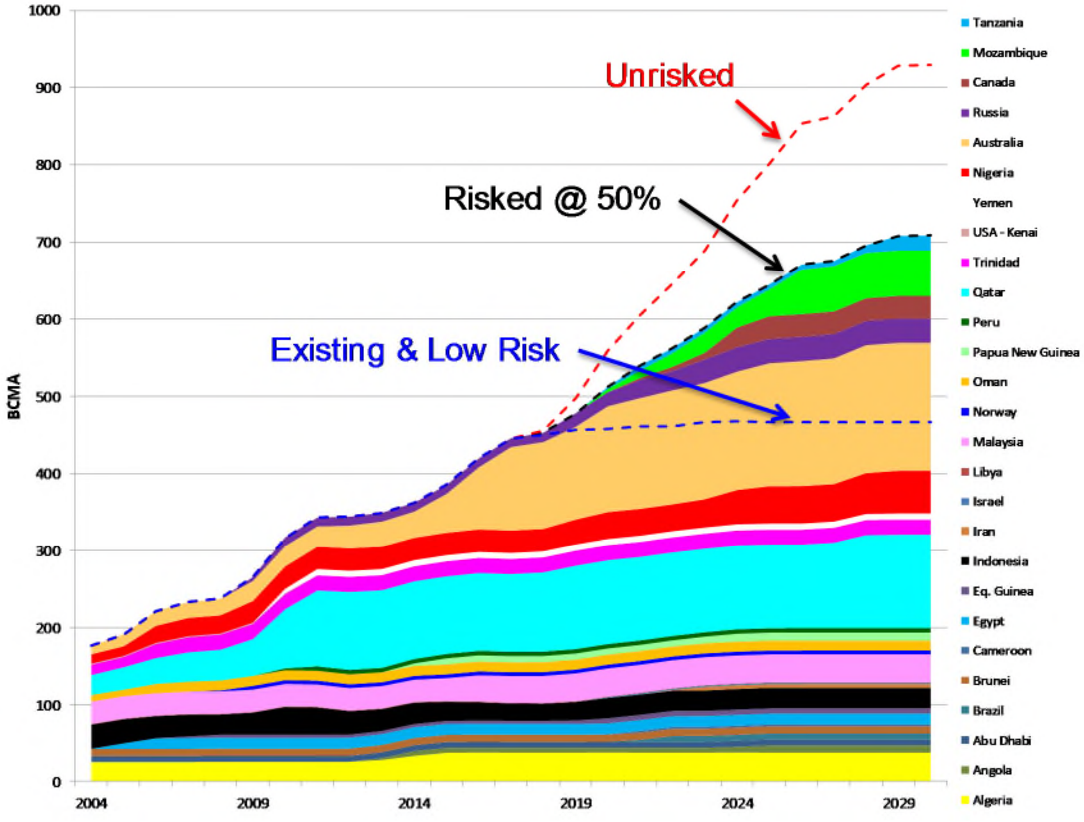
[56] JCC – Japanese Customs-cleared Crude Oil Prices – an internationally recognised crude oil price marker, sometimes referred to as the Japan Crude Cocktail.

3. *Scale and pace of US LNG export approvals and construction*

By mid 2014 some 99 Bcma of non-FTA [57]approvals had been granted for projects converting US regas terminals to become LNG export facilities, of which 40 Bcma has achieved FID. The Dominion Cove Point and Freeport projects (together representing some 27 bcma) have received FERC[58] approval to move to the construction phase. FIDs are expected in late 2014 or early 2015. Including these and additional trains and projects still awaiting non-FTA approval, the sum of volumes with offtake agreements (or Heads of Agreements) amounts to 121 bcma. While the Sabine Pass facility is expected to become operational at the end of 2015, given the time taken for approvals and subsequent facility construction, the major wave of US LNG exports is not expected to commence until 2018 at the earliest. Whilst confidence in the ability of US production to respond to higher prices and meet both domestic demand and LNG export volumes is the prevailing consensus, there is always the possibility this will fail to meet expectations. At an assumed 'sustainable' Henry Hub price of $5.50/mmbtu, US LNG could be economically viable for delivery to Europe at hub prices of $10.50/mmbtu ($5.50/mmbtu Henry Hub, plus $3.00 regas fee, plus $1.50/mmbtu shipping plus $0.50/mmbtu regas fee). The equivalent delivered price to Asia (before regas costs) would be $12.50/mmbtu. In order to address the uncertainty of future US production – price response, and hence the volume of US LNG exports - two LNG export trajectories have been incorporated into the scenarios below.

4. *Scale of LNG supply ramp-up from non-US suppliers*

Figure 27: Global LNG Supply (excluding US Projects) 2004 - 2030



Sources: Platts, Ledesma OIES, Author's Analysis and Assumptions

[57] FTA, Non-FTA – Relating to countries with which the US has (or has not) a Free Trade Agreement

[58] Federal Energy Regulatory Commission

Having witnessed a period with no material additions to global LNG supply since 2011, LNG supply projects under construction, notably in Australia, will begin to lift global supply significantly from 2015. Beyond 2019 however there is a range of uncertainty as to how many new projects – particularly in Australia, East Africa, Canada and Russia will come onstream. Global LNG supply, (excluding US projects addressed above) is shown in Figure 27.

Some of these projects may delay their investment commitment and start-dates in the light of further firming of US LNG export projects. For this reason a convenient (if simplistic) 50% probability has been applied to uncommitted projects in Figure 27.

5. Shale gas development outside North America

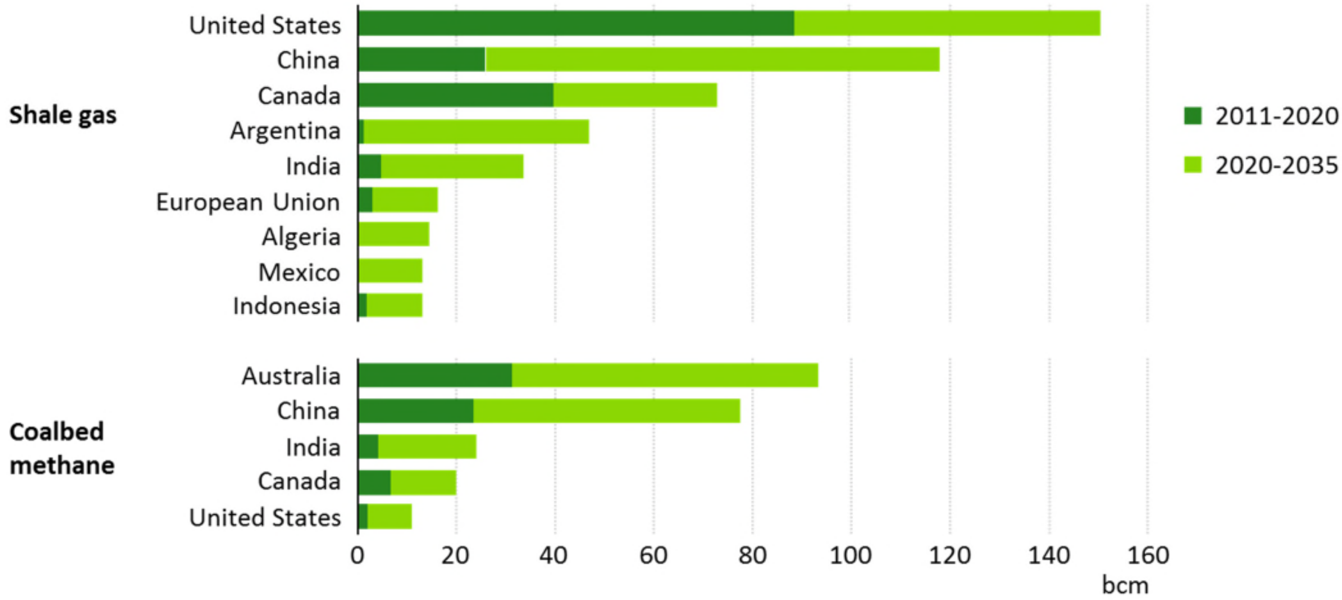
While shale gas potential exists in many world regions the North American shale gas phenomenon at present has not yet been witnessed elsewhere. The unique co-existence of many characteristics undoubtedly assisted the growth in US (and Canadian) shale gas development and production:

- An onshore industry presence and data accumulation of 100 years.
- A multiplicity of upstream players, access to risk capital and a competitive and entrepreneurial service sector.
- The ability to quickly conclude bi-lateral deals with landowners (who also own mineral rights) to drill shale gas wells.

The above factors have helped to create a 'multi-play gold-rush' in the US where rapid 'adaptive learning' has enabled the upstream players to home into the play 'sweet-spots' where well flow rates are most economic. It is questionable whether this dynamic can be replicated successfully in other geographies. China appears to be slowly building shale gas production, although the economic effectiveness of this is not yet apparent. Poland has faced bureaucratic and fiscal delays and many of the larger companies have withdrawn following disappointing drilling results. The UK's success or failure will depend on gaining positive exploration results in short order, but the ability to gain public acceptance for the number of wells required to be drilled on an ongoing basis to produce meaningful shale gas production is still highly questionable. Figure 28 shows the International Energy Agency's relatively pessimistic view for unconventional gas production outside North America up to 2035, from which it is clear that aside from shale gas in China, Argentina and perhaps India; and coalbed methane in Australia and China, very little can be expected elsewhere in the world. The prospects for Europe are particularly discouraging with production of less than 20 Bcm of shale gas in 2035; other studies come to similar albeit slightly less pessimistic conclusions for Europe.[59]

[59] For example: BP Energy Outlook 2014, http://www.bp.com/content/dam/bp/pdf/Energy-economics/Energy-Outlook/Energy_Outlook_2035_presentation.pdf; Gény (2010), JRC (2012).

Figure 28: Growth in Global Unconventional Gas Production to 2035



Source: IEA (2013), Figure 3.6, p.118

6. Russian response to 'overspill' of excess LNG into the European market

As shown in Figure 23 Russia, as the 'shock absorber' in this global system, is the upstream player most prone to uncertainty. Even if Russia, as one might logically expect, explicitly abandons oil-indexed pricing and adopts hub indexation in its contracts, (rather than obliquely accepting hub pricing through base price reductions and rebates), it still would have significant market power by virtue of supplying 25-30% of European physical gas demand, and could directly influence European hub prices by varying its delivery profile.[60]

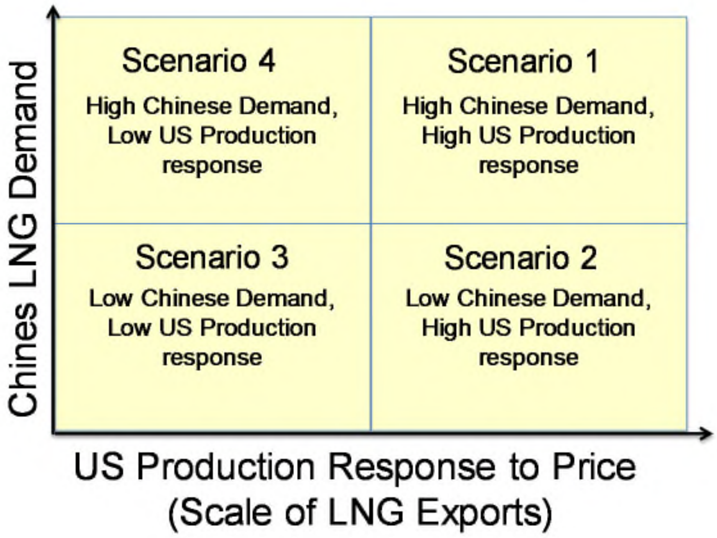
A strategy of maximising price at the expense of market share – which it followed in the 2009-12 period – creates problems for the choice of 'target' price level. If this price target is sufficiently high to support the building of more US LNG export capacity then it merely encourages a competing supplier. On the other hand, a choice of market share at the expense of price, may be ineffective once significant US LNG export capacity has been built and capital costs and tolling fee commitments are effectively a 'sunk cost'.

Scenarios arising from the six major uncertainties

The two key uncertainties - future Chinese LNG demand and US production-price response (and hence LNG export volumes) - were used in combination to define four scenarios, as depicted in Figure 29.

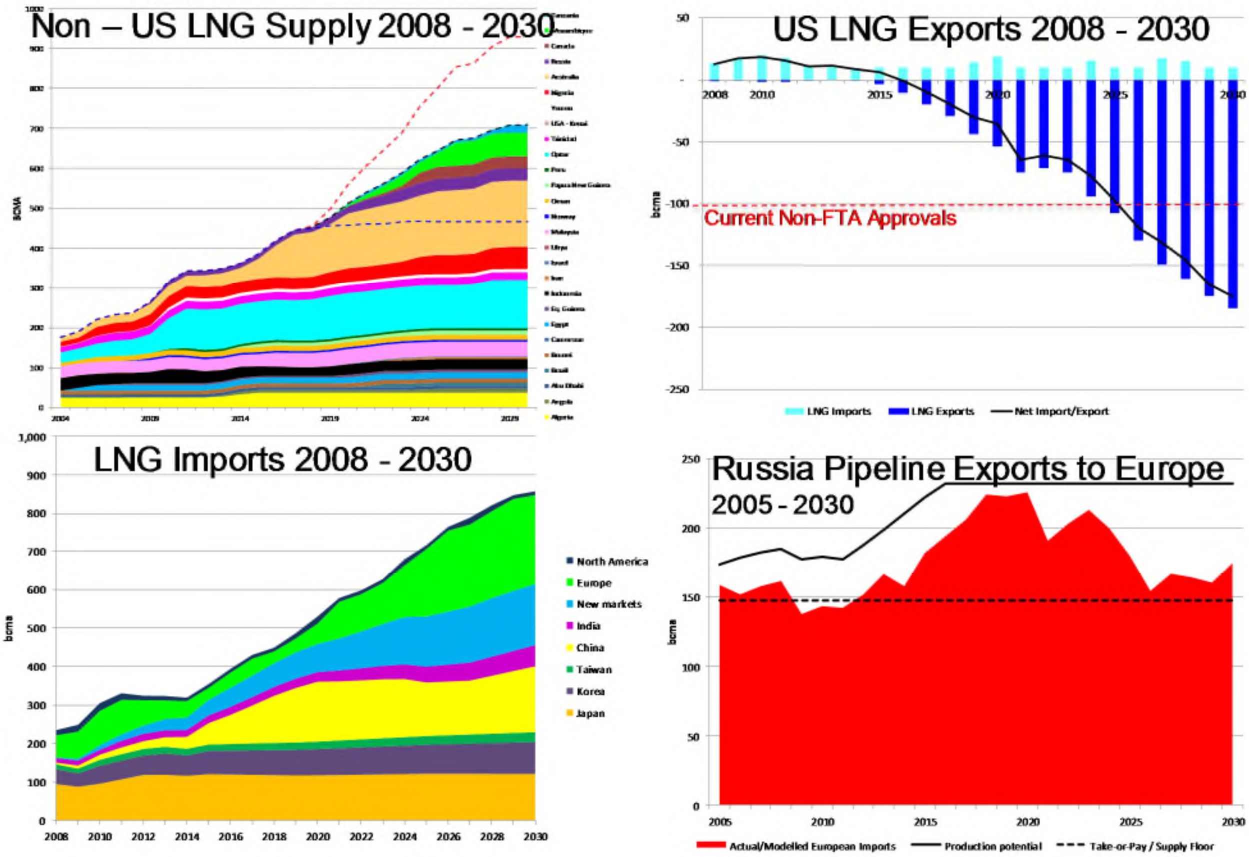
[60] Stern (ed) (2014) pp. 61 – 63.

Figure 29: Global Scenarios for a range of Chinese Demand and US Production Response



The assumptions on Asian LNG demand described above were combined with those of European demand and domestic production and a hypothetical relationship between future US production, demand and prices. Scenario 1 combines the high Chinese demand case with a high US production response. The key outcomes of modelling this scenario are shown in Figure 30.

Figure 30: Scenario 1 – High Chinese Demand, High US Production Response

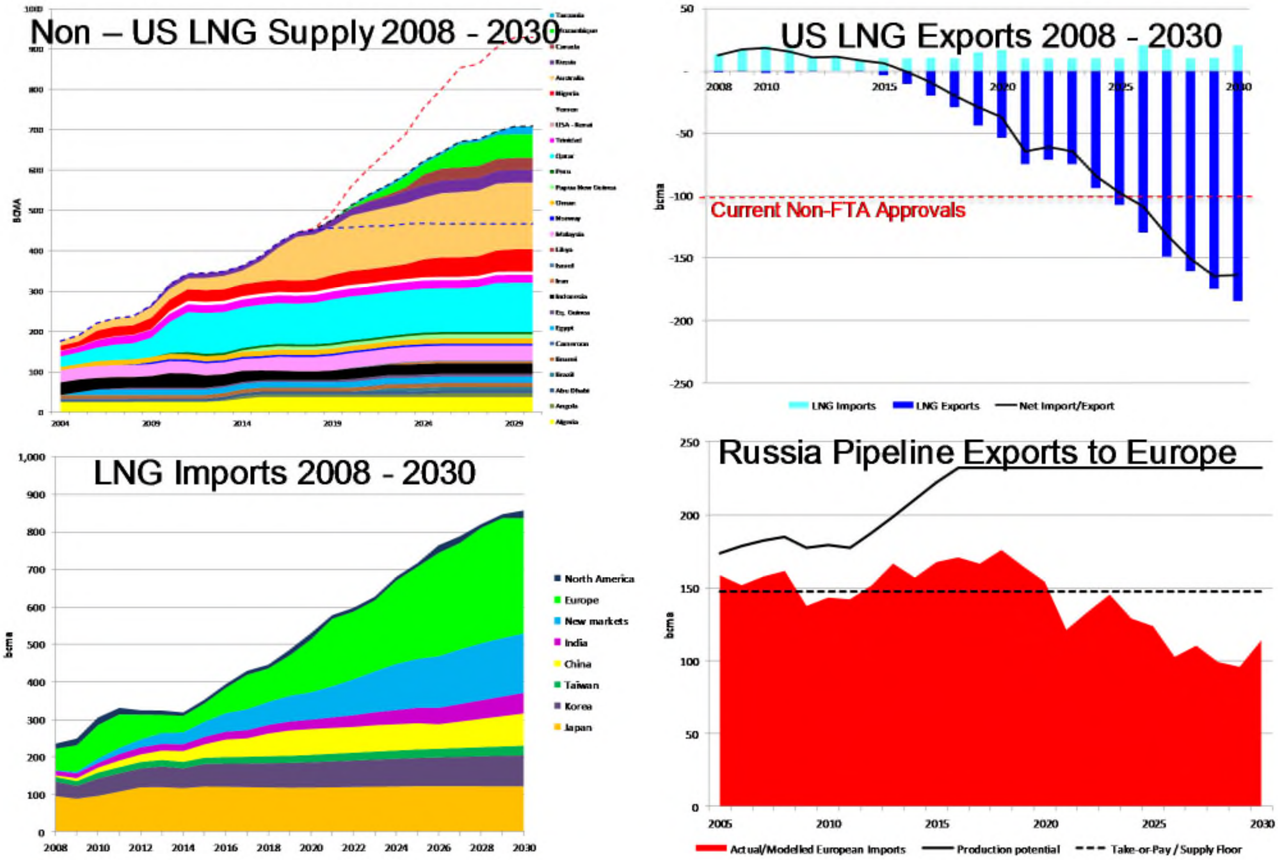


Source: Author's Analysis

In Figure 30, the top left hand graph shows risked non-US LNG supply as shown in Figure 27. In the top right hand graph US LNG exports are shown reaching some 100 Bcma by 2025 and 190 Bcma by 2030. The bottom left hand graph shows the destination markets for LNG with the majority absorbed in existing and new predominantly Asian markets. The green area represents European LNG imports which grow post 2020. The bottom right hand graph shows Russian pipeline exports to Europe. In this scenario there is strong growth to 2018 after which imports remain at a plateau level of around 200 - 230 bcma, before falling to around 160 Bcma post 2025. In this scenario Europe and the wider connected 'system' is balanced by Russia – using some (but not all) of its 'spare' production capacity. This has pricing implications which will be discussed below.

Scenario 2 combines Low Chinese Demand with a High US Production/Price response. The scenario outcome is shown in Figure 31.

Figure 31: Scenario 2 – Low Chinese Demand, High US Production Response

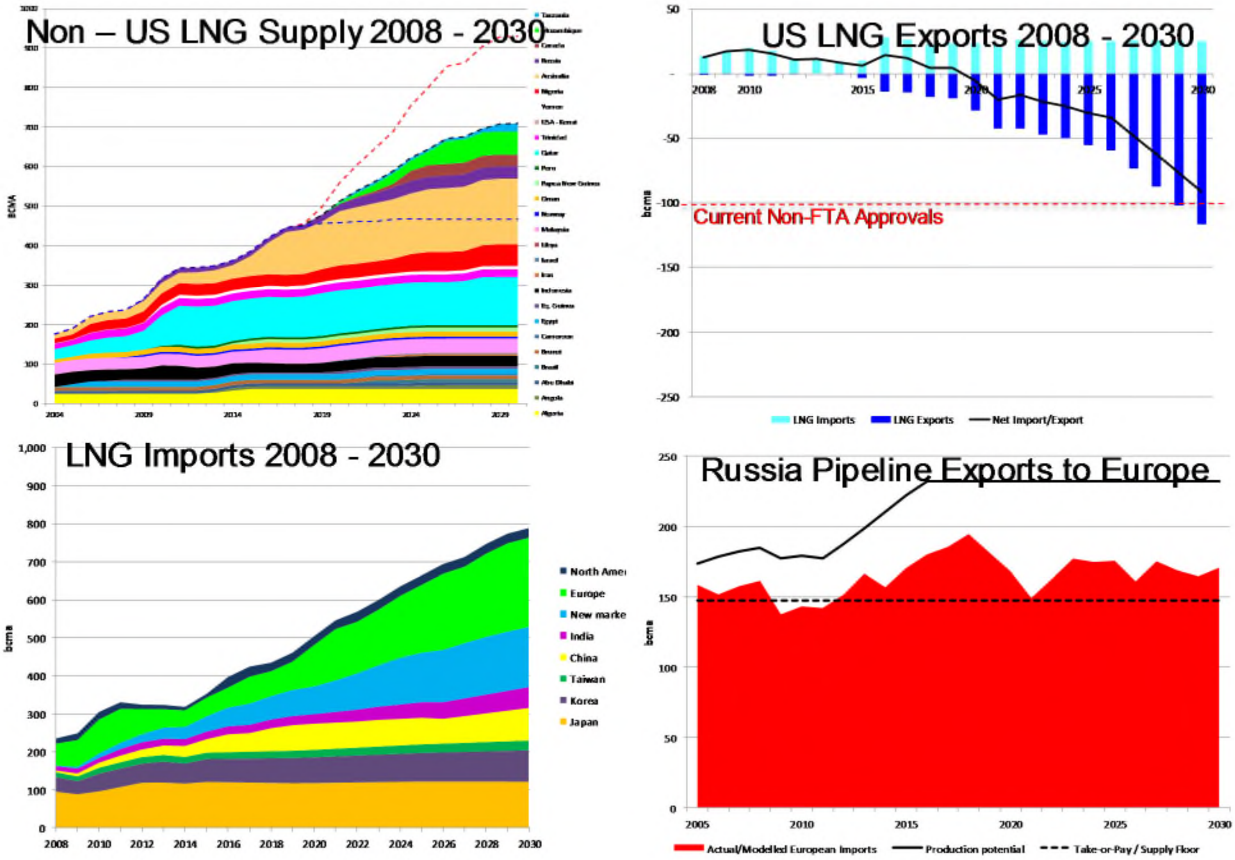


Source: Author's Analysis

In Figure 31, the top left hand graph showing risked non-US LNG supply and the top right hand graph showing US LNG exports are the same as those in Scenario 1 (Figure 30). The bottom left hand graph shows the destination markets for LNG with a significant proportion destined for Europe. The bottom right hand graph shows Russian pipeline exports to Europe exhibiting a marked reduction post 2018 and remaining below the estimated current ToP level for the remainder of the period. Clearly this is an outcome in which Russia loses significant market share in Europe to LNG. It is however, worth questioning whether such a scenario would be modified in the early part of the 2020s by the deferral of non-US LNG projects once it had become clear that China's future LNG demand growth was following a low trajectory.

Scenario 3 combines Low Chinese Demand with a Low US Production – Price response. The scenario outcome is shown in Figure 32.

Figure 32: Scenario 3 – Low Chinese Demand, Low US Production Response

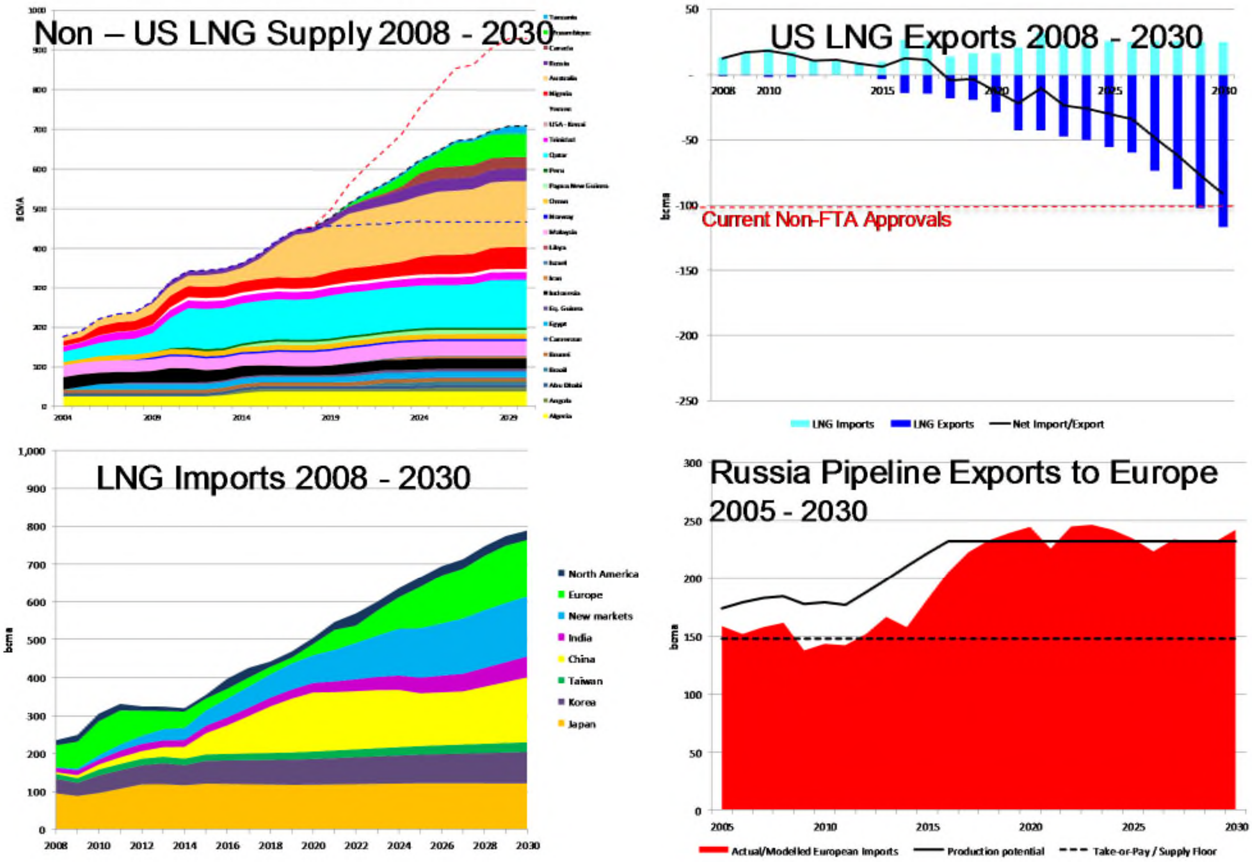


Source: Author's Analysis

In Figure 32, the top left hand graph showing risked non-US LNG supply is unchanged from Scenarios 1 and 2. The top right hand graph shows US LNG exports on a lower trajectory however, reaching 55 Bcma by 2025 and 112 Bcma by 2030. The bottom left hand graph shows the destination markets for LNG with still a significant proportion destined for Europe. The bottom right hand graph shows Russian pipeline exports to Europe. Although these remain above ToP levels, for the remainder of the period they are significantly lower than Russia's full export capability. In this scenario Europe and the wider connected 'system' is balanced by Russia – using some of its 'spare' production capacity, similar to the situation in Scenario 1.

Scenario 4 combines High Chinese Demand with a Low US Production/Price response. The scenario outcome is shown in Figure 33.

Figure 33: Scenario 4 – High Chinese Demand, Low US Production Response

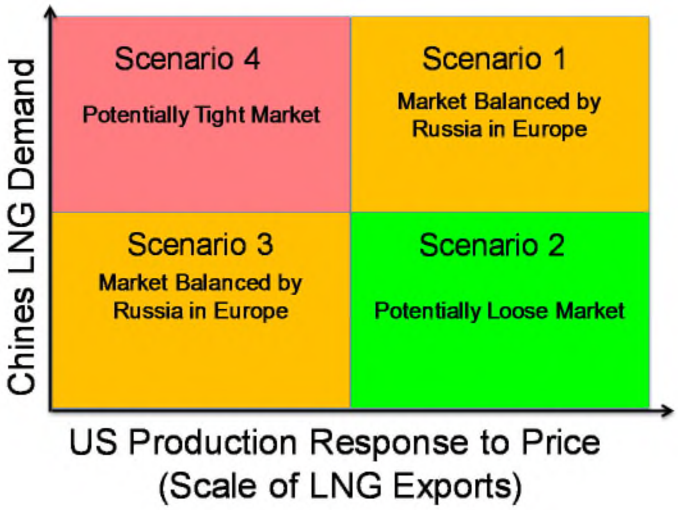


Source: Author's Analysis

In Figure 33, the top left hand graph showing risked non-US LNG supply is unchanged from Scenarios 1 - 3. The top right hand graph shows US LNG exports on a low trajectory as in Scenario 3, reaching 55 Bcma by 2025 and 110 Bcma by 2030. The bottom left hand graph shows the destination markets for LNG with significantly less destined for Europe compared with Scenarios 1 - 3. The bottom right hand graph shows Russian pipeline exports to Europe. With high Chinese LNG demand and lower US LNG exports, Russia significantly increases its exports of pipeline gas to Europe in order to balance the wider connected 'system' using much if not all of its 'spare' production capacity. Russia's market power is strongest in this scenario, with consequences for pricing, which will be discussed later. Clearly in this scenario, one might expect additional LNG projects to be undertaken (in addition to those shown here) in the 2025 to 2030 period should the continuing 'tight' market situation result in high price levels for LNG.

A summary of the scenario outcomes is provided in Figure 34.

Figure 34: Scenario Outcomes



Indicative Scenario Price Paths

Figure 35 illustrates indicative price paths commensurate with Scenario 1 in which Russia, balancing the European market and the wider connected system chooses, by export flow management, to maintain a European hub price level of €27/MWh (the 2013 hub price level). Henry hub prices of €14.50/MWh would co-exist with European hub prices of €27/MWh and Asian LNG spot/hub prices of €33/MWh. High Chinese LNG demand in this scenario limits LNG imports to Europe prior to 2019 (see Figure 30) which is likely to result in higher Asian LNG prices due to imperfect arbitrage of flexible LNG. The Asian JCC-linked LNG contract prices (assuming $100/bbl crude) are at a significant premium to spot prices, post 2020, in this scenario and further question their continuation, at least for new contracts. If late 2014 crude prices of $80/bbl continue however, new JCC contracts would produce prices similar to those based on the 'Henry Hub cost plus' formulation of contracts signed for US LNG export project offtake by Asian buyers.

Figure 35: Indicative Regional Price Paths 2010 – 2030, Scenario 1

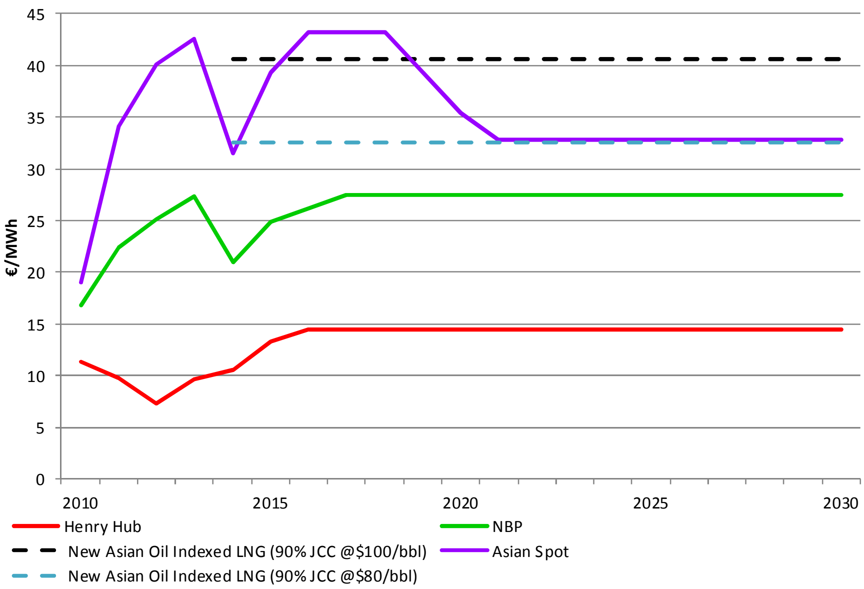
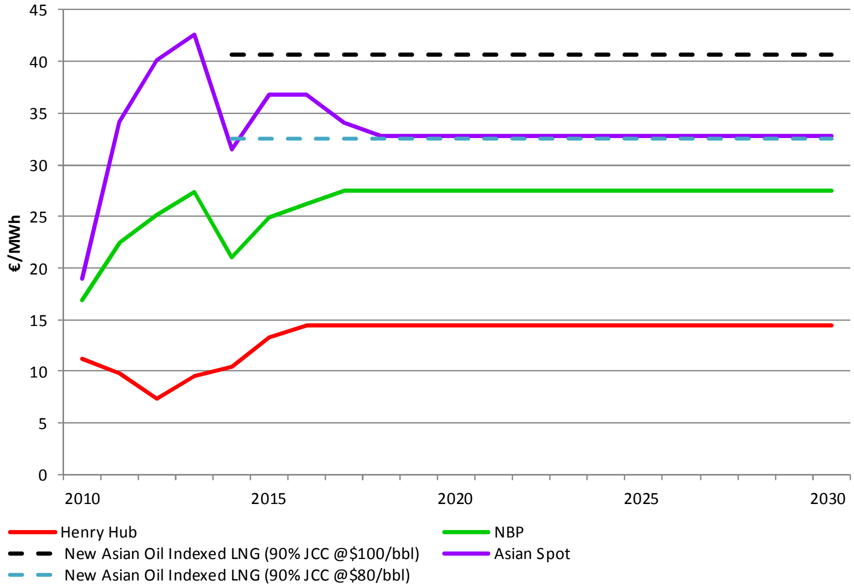


Figure 36: Indicative Regional Price Paths 2010 – 2030, Scenarios 2 and 3

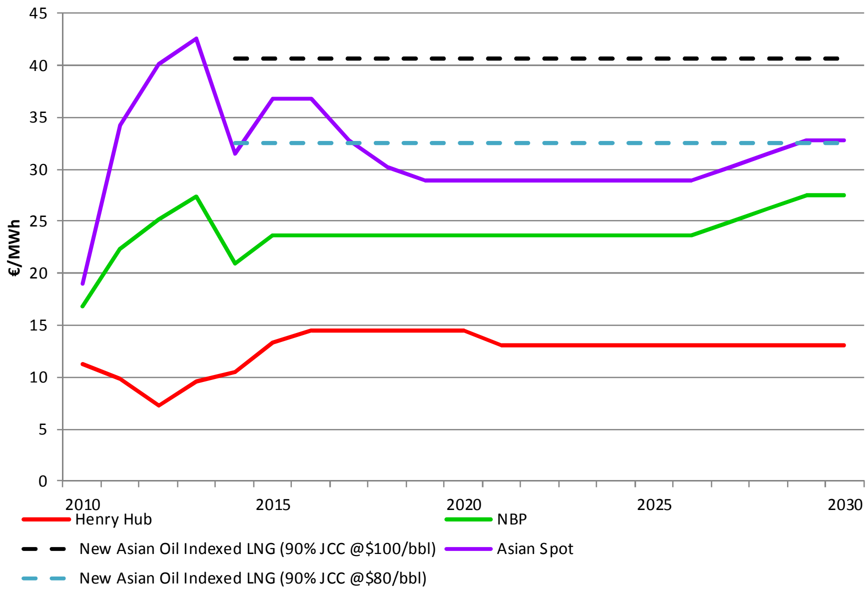


Source: EIA, Platts, Author's Calculations and Assumptions

Figure 36 illustrates indicative price paths commensurate with Scenarios 2 and 3 in which Russia, balancing the European market and the wider connected system chooses, by export flow management, to maintain a European hub price level of €27/MWh (broadly the 2013 hub price level). Henry Hub prices of €14.50/MWh would co-exist with European hub prices of €27/MWh and Asian LNG spot/hub prices of €33/MWh. With plentiful LNG supply to Europe post 2015 (see Figure 31) arbitrage should rapidly introduce a price relationship between European hub prices and Asian spot LNG prices based on differential transport costs for the marginal flexible LNG supplier, with competition from US LNG exports enforcing this. The Asian JCC-linked LNG contract prices (assuming $100/bbl crude) are at a significant premium to hub prices in this scenario and further question their continuation, at least for new contracts. At an $80/bbl oil price however, Asian spot LNG prices in this scenario are very similar to those under contracts based on JCC prices.

In Scenario 2 (Low Chinese Demand, High US Production Response), Russia's dilemma is that in order to maintain European hub prices at the notional target level of €27/MWh, its level of gas pipeline exports to Europe fall significantly below 2013 levels. If Russia followed a strategy of maintaining European Hub prices at a target level of around €27/MWh, this scenario would have regional price trends as shown in Figure 36. If, however, Russia decided to lower European hub prices in order to deter the construction of further US LNG export facilities, (i.e. by increasing physical pipeline export flows to Europe to maintain hubs at a level of €24/MWh) this would result in the regional price trends shown in Figure 37.

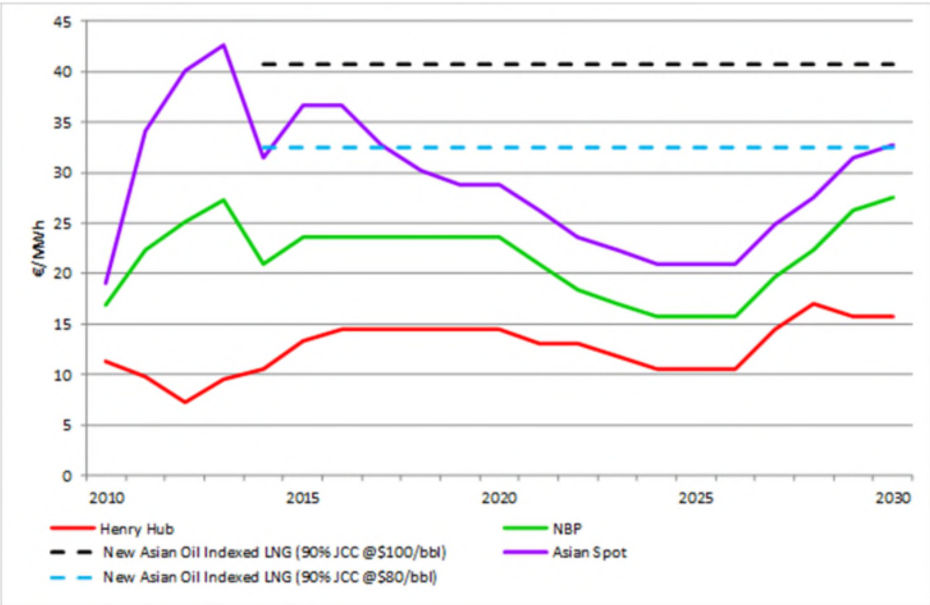
Figure 37: Indicative Regional Price Paths 2010 – 2030, Scenario 2 with Price War



Source: EIA, Platts, Author's Calculations and Assumptions

Given the number of US LNG export projects already under construction and, at the time of writing, about to take FID, it could be said that Russia has left it 'late in the day' to use its market power in the European gas market to deter this potentially significant competing supplier. Managing physical gas supplies to Europe to maintain European hub prices at around €24/MWh may deter future US LNG investment, but by end 2014 or early in 2015 we may already have some 70 Bcma of US LNG export capacity under construction after achieving FID. Using market power to reduce LNG exports once US export facilities have been built represents a more significant challenge for Russia – specifically in terms of the lost revenue incurred in reducing European hub price levels (through increasing physical flows from Russia) – in order to ensure that Europe (and through arbitrage, the Asian spot LNG market prices) are below the levels required to cover the variable costs of US LNG exports, i.e shipping and (where appropriate) regas fees. This dynamic is shown in Figure 38. This illustrative scenario suggests that Russia, in an attempt to reduce LNG exports from US facilities already constructed, may have to be prepared to reduce European hub prices to levels of around €15.50/MWh to reduce upstream shale gas drilling activity in the US and hence the volume of US gas production available for LNG export. After confirmation of such reduction in US upstream production Russia could, through managing physical flows to Europe, raise prices and enjoy the revenues of a higher European gas market share before the recovery of US production activity. In passing it is worth noting that in the price paths represented in Figures 37 and 38, Asian LNG buyers would have been better off 'trusting the market' and buying LNG at spot or Asian hub prices, rather than on a contractual 'Henry Hub plus costs' basis.

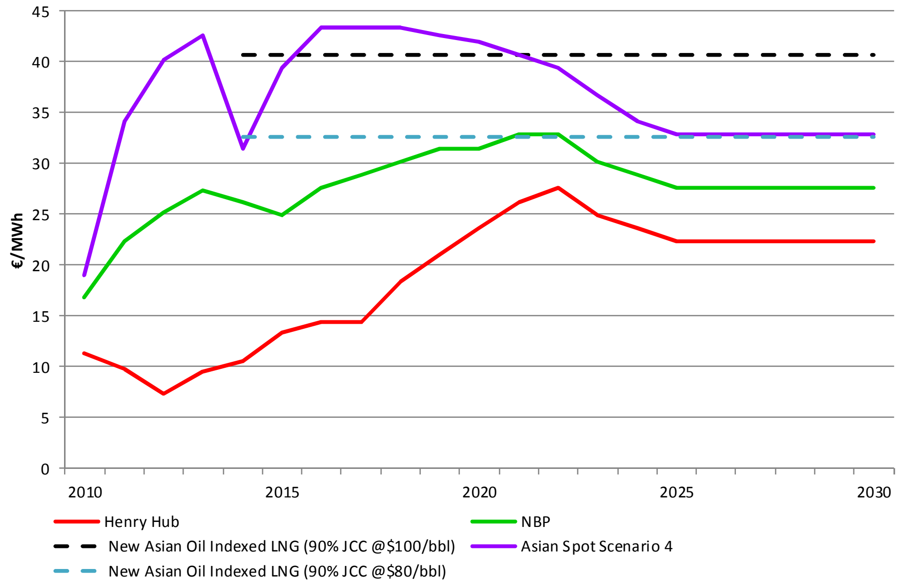
Figure 38: Indicative Regional Price Paths 2010 – 2030, Scenario 2 with Intense Price War



In Scenario 4 (High Chinese Demand, Low US Production Response) the indicative future price trends shown in Figure 39 are those of a 'tight' market. Despite rising Henry Hub prices, US gas production response is disappointing[61]. With Asia continuing to attract flexible LNG away from Europe, Russia's market power rises as its pipeline exports to Europe increase. It is therefore able to achieve a higher level for European hub prices by supply management. Asian LNG spot prices begin to rise above the arbitrage – related premium to European hubs in the early 2020s. However, this tight market of the late 2010s could evoke a response in terms of an acceleration of non-US LNG projects which leads to a price level for European hubs and Asian LNG spot by the second half of the 2020s similar to that of Scenarios 1 – 3. In this scenario however, Henry Hub is higher due to the continuation of LNG exports on the basis that they cover only the variable costs of shipping and regas.

[61] This could be due to, for example, higher than envisaged unit production costs for dry shale gas, a reluctance for players to re-direct drilling from tight oil/wet shale plays or a limitation imposed by skilled personnel/rig availability to do both.

Figure 39: Indicative Regional Price Paths 2010 – 2030, Scenario 4



Source: EIA, Platts, Author's Calculations and Assumptions

1.6 Summary and Conclusions: key determinants of European hub prices post-2014

Summarising the arguments in this chapter it is clear from the evidence of the 2008-14 period that hubs have progressively taken over from oil product prices as the main gas price formation mechanism in north west Europe, and are well advanced towards doing so in central Europe. Although (Italy excepted) progress in southern Europe has been much slower, there are strong aspirations everywhere to move away from oil and towards hubs as the preferred price formation mechanism for gas. This does not mean that by 2020 it will be impossible to find some European locations where gas remains priced in relation to oil, but it strongly suggests that hub pricing is an unstoppable force which will continue to spread south and east across the Continent. Persistence of crude oil prices at or above $110/bbl (the average during the period 2011-13) will support this trend.[62] At oil prices of $80/bbl the differential between hub price and 'contract formula' price, post adjustments, may be reduced, but this is more likely to be recognised in Russian contracts by a reduction in the 'rebate' cheque rather than any indication that low oil prices may result in a 'massaged' oil-indexed contract price which is materially below hub price levels.

There are a significant number of potentially important elements in terms of gas supply and demand which represent the key determinants of European hub prices at any particular point in time. Movements in these supply and demand elements are potentially constrained by infrastructure and by existing contractual obligations which require suppliers to deliver, and buyers to accept, certain volumes of gas albeit at prices which have been renegotiated in the 2010s, so that they track hub prices relatively closely.

In this chapter we have reviewed the evidence of the 2008-2014 period and found that:

- LNG supply has been a major determinant of the spread of hub pricing, demonstrated by the fact that prices fell during 2009-11 when supplies flowed into Europe; rose during 2011-13

[62] During 2011-13 Brent crude prices averaged $108-111/bbl. BP Statistical Review (2014) p.15.

after the Fukushima nuclear accident in Japan when LNG flowed out of Europe; and fell in 2014 as supply flowed back into Europe (although the extent to which this will continue through winter 2014/15 is uncertain);

- Russian price/volume policy has been another major determinant of hub pricing with the 2009-12 period demonstrating that refusal by Gazprom to adapt prices in its long term contracts to hub levels led to a dramatic reduction in Russian exports to Europe, followed by a recovery in exports in 2013 when Russian prices came into line with the hubs;
- Developments in North America have been important, with the arrival of shale gas freeing up North American gas supplies which would have been needed in the US, and leading to the construction of liquefaction facilities promising to add significantly to global LNG supply;
- Developments in Asia have been important, as Japan closed its nuclear plants post-Fukushima, and Chinese regasification capacity continues to expand rapidly.

A major conclusion to be drawn from the 2008-14 period is therefore that global market dynamics have played a bigger role in European gas price formation than in the past. Our proposition from this analysis is that these global dynamics promise to be more important in the future than domestic European energy and gas dynamics. While we have not extensively reviewed domestic developments in this chapter, we have done so in other published OIES research dealing with: gas demand (specifically in the power sector); weather events – e.g. the very cold spell of March/April 2013 followed by the very warm winter of 2013/14 – which impacted the need for gas to fill storage; security events – eg the Russian/Ukraine crisis of January 2009; and events involving both weather and security issues e.g. the February 2012 price spike caused by a combination of very cold weather and Russia/Ukraine problems.[63]

The decline in European gas demand has been a 5 year trend. Our projections (and those of others) show that gas demand will not recover to 2010 levels until (and possibly after) 2020. None of the weather and security events has had any *lasting* impact on hub dynamics beyond the duration of the event, and it is our view that this pattern will continue. We cannot see any major domestic development in the remainder of this decade which would impact that judgement.[64] The more important multi-year impacts on hub prices will come from global dynamics.

We have looked at different scenarios over the period up to 2020 and beyond – which rely on combinations of what we have called the `big 6 major uncertainties':

1. Demand for natural gas and LNG in Asia
2. Transition away from JCC pricing in Asian LNG markets
3. Scale and pace of US LNG export approvals and construction
4. Scale of LNG ramp-up from non-US suppliers
5. Shale gas development outside North America
6. Russian response to `overspill' of excess LNG into the European market

These six major uncertainties emphasise the importance of three key forces on European hub pricing:

- the supply and price policies of existing European suppliers – especially Russia, Qatar and possibly, but to a lesser extent, Norway;

[63] Honoré (2014), Pirani et al (2009), Henderson and Heather (2012).

[64] Perhaps the only events would be: an unanticipated collapse in gas production in Norway or the Netherlands, a very substantial increase in EU GDP growth, or the introduction of an EU ETS price regime or carbon tax in excess of €30/tonne. None of these looked likely at the time of writing.

- the availability of flexible supplies of pipeline gas (principally from Russia) but particularly LNG (particularly from Qatar but also from new suppliers in North America and Asia);
- the development of Asian LNG demand, particularly from China.

Having surveyed this landscape and its uncertainties, we think it likely that:

- to the end of 2015, Europe will rely to a greater extent on Russian pipeline imports (subject to weather trends) due to continued LNG diversion to Asia;
- in the period 2015-18 the LNG market should ease depending on the pace of Japanese nuclear re-starts, start-up of Australian LNG projects and Chinese demand growth;
- post-2018 the global market becomes very unpredictable with potentially large volumes of US LNG and new projects from Australia, Canada, East Africa and Russia. Overspill of 'excess LNG' into Europe could trigger Russia to utilise its considerable spare production and export capacity to lower hub prices to protect its future market share, but…
- should US shale production costs increase and higher project costs delay the introduction of new LNG projects this, especially if combined with higher Chinese LNG demand, would lead to the possibility of a tighter global LNG market in the early 2020s, with very significant consequences for European hub prices.

Predictability, volatility and market power

Another conclusion which can be drawn from this chapter is that, as the number of influences on European hub prices has grown, they have become less predictable. While background hub price volatility has declined since 2010, several supply or demand side events have triggered high volatility episodes[65]. These are two of the points most frequently made by those advocating the retention of traditional oil-linked pricing. While oil-linked pricing was not `predictable' (without the ability to predict oil price trends), the time lags in the price formula and averaging of prices over a period of several months provided early warning of prices changes (and generally eliminated short term volatility). Because hub pricing reflects supply and demand conditions in close to `real time', it will inevitably be more unpredictable and at certain times volatile and this is why price risk management skills become important for market players.[66]

A final important issue is the extent to which hub pricing may confer market power on suppliers with the ability to impact prices by withholding gas from, or releasing larger volumes into, the market. This paper has pointed to instances of major suppliers – notably Gazprom and Qatar – acting in this way, and the possibility that such power may increase in future. While our scenarios suggest severe limitations on any single supplier – even Gazprom – being able to exert market power over any protracted period, that possibility exists particularly under `tight' supply/demand conditions. This is yet another, but probably not the most important, determinant of future hub pricing in Europe.

---

[65] Petrovich (2014), Chapter 8

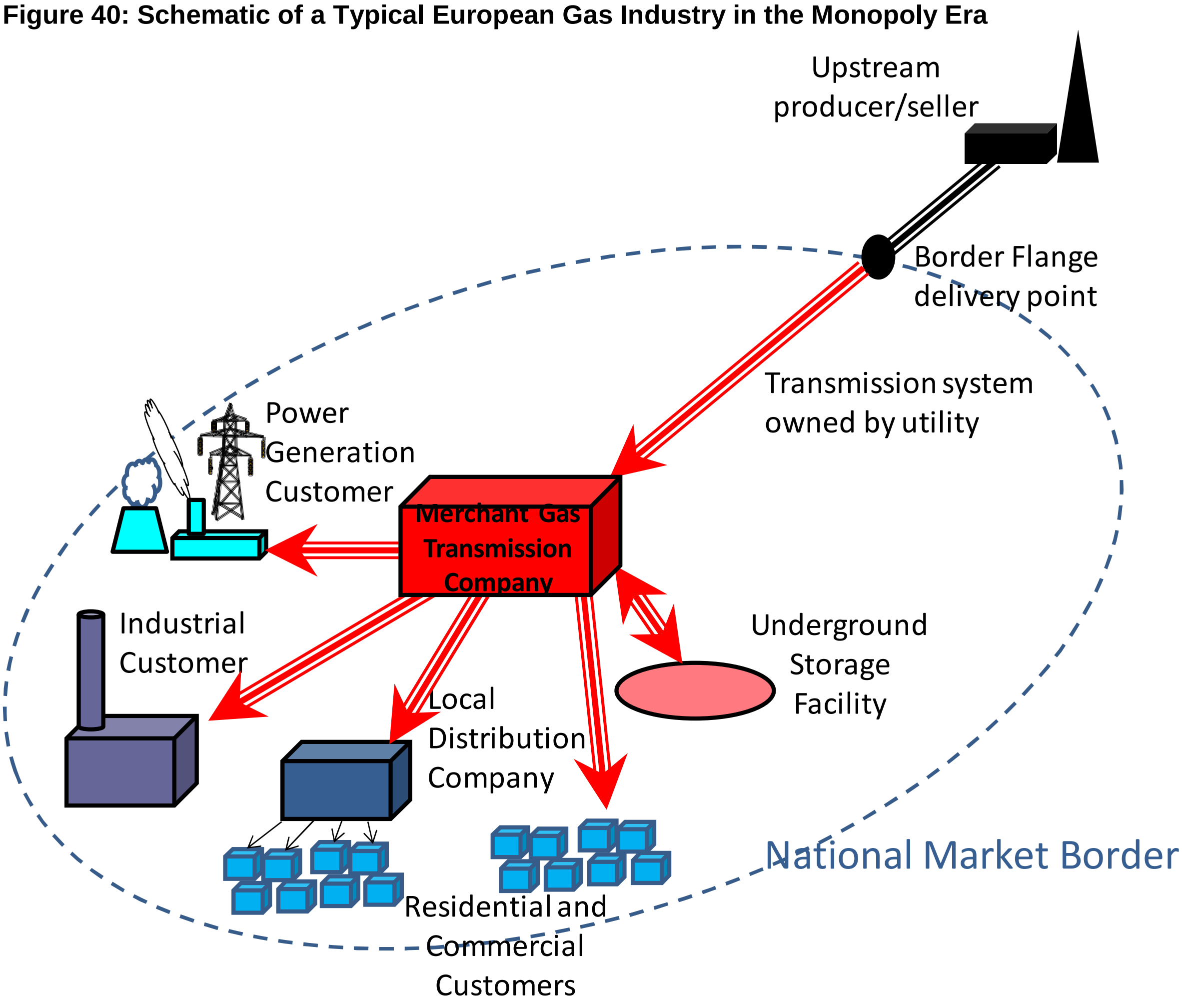
[66] For analysis of hub price volatility see Alterman (2012) and Petrovich (2014).

Chapter 2. European Gas Market Players: changing roles and risks

2.1 Historical Context: the monopoly era

In what can be called the "monopoly era" of European gas, the industry consisted of three groups of actors: producers and exporters, merchant transmission companies and local distribution companies (LDCs). A schematic representation of the monopoly market is shown in Figure 40. The general shape of the value chain was producers selling to a merchant transmission company, the latter reselling to local distribution companies and large (industrial and power generation) customers; with LDCs selling to smaller (residential, commercial and some industrial) customers.[67]

Figure 40: Schematic of a Typical European Gas Industry in the Monopoly Era



Source: Author

[67] This is discussed in detail in Estrada et al (1988), Chapters 2, 4, and 6.

Producers and exporters

In producing and exporting countries, a mixed state/private model became the standard for exploiting gas fields in Europe. International oil and gas companies (IOCs) - Shell, Exxon, BP and others - either in joint ventures with each other or with state-owned companies such as (the pre-privatised) British Gas, NAM (50% Shell/Exxon, 50% Dutch Government), Statoil and ENI, created a balance between the state's financial interest and the commercial interest of the private companies.[68] But although IOCs had ownership interests in transmission companies, they only began to move downstream in Britain during the 1990s, and later in Continental Europe, with the introduction of liberalisation and competition. They were subsequently joined by Gazprom, (to a much lesser extent) Sonatrach, and eventually in the 2000s by LNG exporters such as Qatargas, which were wholly or majority state-owned.[69]

Merchant transmission companies

With the exception of Germany, European countries created (largely) national companies responsible for co-ordinating national gas supply and demand. The `merchant transmission companies' (MTCs) – the largest of which were British Gas, Ruhrgas, Gaz de France, Gasunie, Distrigas, SNAM and Enagas - purchased (either from domestic producers or exporters), transported and sold virtually all of the gas used in their national markets. In order to achieve this, they created the long term contracts which supported the infrastructure investments needed to bring the gas to consumption centres. They were often referred to as `monopolies' which was correct in the sense that they had almost complete control of their national markets, but failed to recognise that in many countries substantial numbers of distribution companies owned low pressure networks and sold gas to small end-users.[70] Of the MTCs: British Gas was state-owned (until 1986) as were SNAM and Gaz de France; Gasunie and Distrigas were in joint private/state ownership); subsequently the gas industry was progressively privatised in most countries.

Germany was a structural and ownership exception to the rest of Europe, featuring a three-tier structure of multiple importing MTCs, regional companies and more than 700 distribution companies, mostly in private ownership, transporting either low or high calorific value gas.[71] Ruhrgas was the preeminent company in the German gas industry with control over very substantial parts of the market beyond its service area; and a significant pan-European influence due to its geographical location and purchases from all major suppliers of gas (other than Algeria). But there were other important German gas companies such as BEB and Thyssengas; and post-1990 the Wintershall/Gazprom joint venture Wingas.

Local distribution companies

Distinct from long distance transmission companies were the local (merchant) distribution companies which both owned the low pressure networks and supplied gas to (mostly) residential and small commercial end-users. In Britain there were no such local distribution companies (which had been abolished when the gas industry was nationalised) with the British Gas Corporation (BGC) as the sole transmission, distribution and sales organisation. In France, Gaz de France was in a similar position apart from in the south west of the country and a few major cities. But in countries such as Germany

---

[68] For detail on the early development of the Dutch and Norwegian gas sectors see: Peebles (1999) and Bartsch (1999). The official history of UK North Sea development is set out in Kemp (2012a), Chapter 4 and Kemp (2012b) Chapter 1.

[69] For detail on the early development of Algerian, Russian, and Qatari pipeline gas and LNG exports to Europe see Aissaoui (1999), Stern (1999) and Flower (2011).

[70] See below, the dividing line between small and larger commercial and industrial customers served by LDCs and merchant transmission companies varied from country to country.

[71] This structure is set out in detail in Lohmann (2006), Chapter 2.

and Italy there were hundreds of distribution companies mainly in municipal ownership (although some privately owned) with gas (and electricity) being just one of many services managed by towns, cities and local regions.[72]

Roles and risks of the major players

The role of producers (and exporters) is clear from their title: they needed to find gas, produce it and arrange for it to be delivered into the high pressure network of the purchasing company. For the upstream producer/seller the objective was to maximise revenue (volume multiplied by price) and generate adequate investment in upstream field development and transmission infrastructure. For private upstream companies, the overriding aim was to generate a return on investment in line with shareholder expectations. For a state-owned enterprise, additional goals relating to state budget contribution may be a higher priority. Their principal risk in the monopoly era was that the cost of producing and delivering the gas would exceed the oil-linked price in the long term contract. Clearly it is in the upstream producer/seller's long term interest to ensure that the price of gas under the contract remained below that of competing fuels. So that, having signed long term contracts, their principal commercial risk was to ensure that the cost of project development remained below the price they had agreed in their contracts, which was linked to international oil price levels.

Broadly speaking, the role of the merchant transmission companies in this era was to meet demand and to ensure absolute security of supply to the customers in the franchise area where they had a monopoly. In order to achieve this they:

- built a huge transmission infrastructure (including storages) in order to develop, and ensure they could serve the most profitable parts of, their market;
- developed long term relationships with their customers – local distribution, large industrial and power generation companies, which in any case had no access to other sources of gas and, even if they found an alternative supply, were not likely to persuade the transmission company to deliver it to their premises;
- signed long term contracts which involved legal obligations to purchase (or pay for) stated minimum annual volumes of gas (see Chapter 1).

The principal risks arising from these roles were that:

- they might fail to develop sufficient demand – by failing to persuade customers to convert from other fuels to gas;
- they might fail to build sufficient infrastructure to deliver this gas to customers;
- the infrastructure might not be sufficiently reliable to deliver secure supplies.

Failure to fulfil the first two of these tasks meant they risked not being able to meet their take or pay commitments i.e. that they would need to pay for gas which they could not take, due to lack of sufficient market. Security of supply failure meant that management risked being sacked by politicians – who for state-owned companies were their immediate bosses – fearful of the electoral consequences of jeopardising economic growth and the safety and comfort of citizens. It is important to stress here that in the monopoly era there was no competition risk, and relatively little price risk. National and regional franchises, and monopoly ownership of pipelines, protected merchant transmission companies from competition, which meant they could pass through their purchase costs to customers. Meanwhile oil-linked pricing ensured that gas prices remained below those of oil products – meaning that customers which had switched to gas would have no incentive to switch back

[72] For an overview of structure and ownership of LDCs in five major European gas markets (France, Belgium, Netherlands, Germany and Italy) see IEA (1998).

to oil. And long term contracts conferred obligations on the seller to deliver, which provided security of supply.

MTCs were highly successful in carrying out their role, as can be seen from the growth of demand during the 1970-2005 period shown in Figure 1. This demand growth meant that take or pay risks never materialised, while the cost pass-through mechanism in an era of (mostly) rising oil prices ensured substantial profitability.

The role of local distribution companies was to either build new low pressure networks or to convert existing `town gas' networks to natural gas. These companies mostly had city or municipal monopoly franchises. They purchased their gas from the transmission companies on contracts which ranged from 3-20 years and were automatically extended on expiry since (most) LDCs had no other supply option.[73] LDCs generally operated regional, sectoral and municipal cross subsidies. 'Postalised' prices meant that different regions of a country paid the same price irrespective of the cost of service. Sectoral cross-subsidies resulted in residential customers paying more or less than commercial or small industrial customers, depending on local political imperatives rather than cost of service. Municipalities, particularly in Germany, charged high gas and electricity prices in order to cross-subsidise many other services – public transportation, leisure and education – which were made available at very low prices, with the tacit acceptance of the customer base. Their risks were more related to local and municipal electoral politics than commercial exposure.[74]

Industrial customers and power generators - It is also appropriate here to consider major gas customers – large industrial customers and power generators – because although their customer roles were straightforward, their risks bear further examination.[75] In the monopoly era they purchased gas on multi-year contracts from the MTC, at prices based (usually) on an oil product-index. Industrial customers needed to manage the risk that they could absorb the cost of gas (and electricity) into their product prices and still remain competitive (especially if competing internationally). The power generation customer in this era may well have been a state monopoly, in which case its generation portfolio would have been based on a diversified fuel/technology mix with the ability to pass the blended cost of generation through to its customers. As such its risk would have been significantly less than for large industrials. Nevertheless, lack of choice and the fact that they were the captive customers of monopoly suppliers meant that, once they had switched their facilities to gas, they had limited control over an important commercial aspect of their business.

2.2 European Union Legislation and Regulation

Pre-2008: the First and Second Gas Directives and the Energy Sector Inquiry

In the late 1980s, the European Union (EU) began a quest to make the gas (and electricity) industry more competitive by including it in the Single European Market initiative. Over the next two decades the first legislative and regulatory steps towards the goal of achieving a pan-European liberalised gas market were:[76]

- *The First Gas Directive*: adopted in May 1998, set out the initial steps towards changing industry structure and network access conditions by introducing legal unbundling and negotiated and regulated third party access.

[73] IEA (1998), pp. 40-42.

[74] Ibid, pp. 44-54.

[75] In some gas markets they also played an important role in balancing gas demand, reducing the need for storage. Many of these customers operated on interruptible contracts – and paid a lower price for gas than `firm' gas customers – which allowed the merchant gas company to interrupt supply during periods of high demand.

[76] For details of this legislation and regulation see Haase (2009) especially Chapter 6.

- *The Second Gas Directive*: adopted in June 2003, sought to accelerate the process by calling for liberalised access for business consumers by 2004 and for all consumers by 2007. It required (at least) management unbundling (i.e. separate subsidiaries for transportation and supply) to be implemented, and regulation to be carried out by an independent authority.

- *Regulation 1775* of September 2005 laid down detailed guidelines for 3rd party access, principles for capacity allocation mechanisms, congestion management procedures and transparency requirements.

It would be an understatement to say that the strategy adopted by the large incumbents throughput this period was one of 'retreat at the slowest possible pace'. The lack of support for liberalisation from most Continental European governments prior to 2000 also served to reduce the pace of change. The 'tight' supply position, and consequent high and volatile prices, in the liberalised British and US gas markets during the middle of the 2000s, did little to promote market liberalisation. Fundamentally however, the combination of long term oil-indexed contracts providing a significant proportion of continental Europe's supply, and lack of progress of liberalisation of national gas markets, severely limited gas to gas competition – a phenomenon termed 'vertical foreclosure' in the lexicon of competition regulation.[77]

Despite this lack of progress, positive events did occur during the early to mid 2000s both upstream and downstream, principally due to the application of competition rules:

- The abolition of centralised gas sales organisations: In June 2001, after sustained pressure from the EU competition authorities, Norway abolished its centralised gas sales organisation (GFU) in response to the EU position that joint sale and purchase organisations thwarted competition. Individual equity holders in gas-producing fields took contractual responsibility for marketing and selling their own gas; similar restrictions were placed on Denmark's DUC sales consortium.[78]

- The abolition of destination clauses: provisions within many long term gas contracts within Europe prohibited the re-selling of gas to national markets outside the original destination market; and designated groups of customers within national markets. As a consequence of competition rules, such provisions were removed from contracts, including those of the Norwegian sellers, Gazprom, Sonatrach and LNG sellers.[79]

- Progressive moves towards third party access, regulation and competition in a number of Continental European countries: despite very slow progress in many countries, the 1990s and early 2000s did see at least some of the legislative and regulatory groundwork laid for liberalisation.[80] Particularly important were `release gas' programmes introduced to overcome inadequate access to gas supplies or pipeline capacity. Release gas programmes (previously used in Britain) were implemented in France, Austria, Germany and Italy. Given that the price paid by new entrants for release gas was inevitably linked to the price paid by the releasing incumbent, release programmes did not significantly increase end-user price competition in the markets where they were applied, but they were part of the story of encouraging new entrants by increasing the availability of gas supplies.[81]

---

[77] For an explanation of competition law in relation to gas contracts see Talus (2011) Chapter 4.

[78] Ibid, pp.157-9.

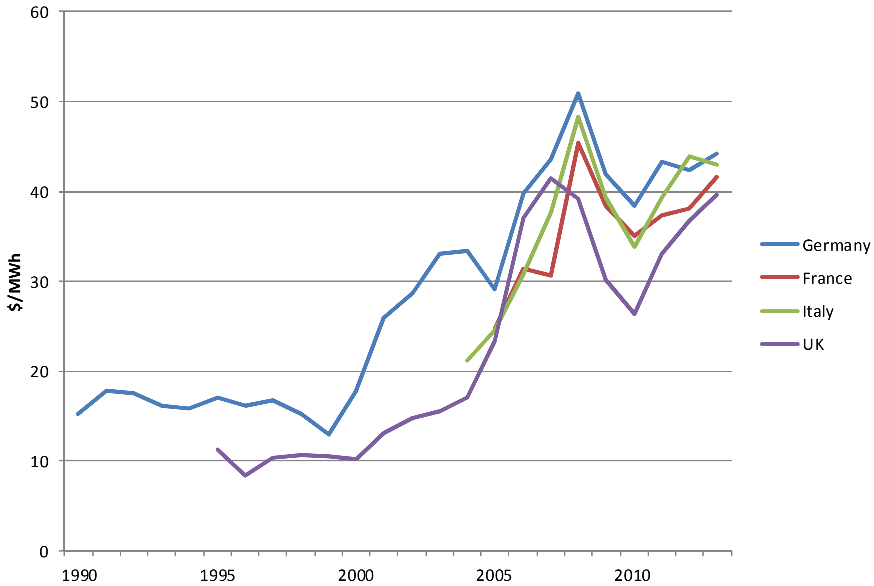
[79] For a complete account of the destination clause saga see Ibid, pp. 159-167.

[80] For a review of developments in the early to mid 1990s see Stern (1998), Chapter 5. For a review of progress in 12 countries in the early 2000s on parameters such as market opening, tariff structure, capacity booking and trading see Haase (2009), Chapter 8; details of national developments in Germany, France, Netherlands and southern Europe up to the early 2000s, can be found in Arentsen and Kunneke (2003).

[81] Haase (2009), pp. 221-2.

In January 2007, after a one and a half year investigation, the EU DG Competition report on the Energy Sector Inquiry was published. On virtually every measure which it examined – market concentration (market power), vertical foreclosure (inadequate unbundling), market integration (including regulatory oversight), transparency, price formation, downstream markets, balancing markets, and liquefied natural gas – DG COMP found competitive conditions in (electricity and) gas markets to be somewhere between inadequate and unsatisfactory.[82]

Figure 41: Prices Paid by Industrial Customers in Britain and Major Continental European Gas Markets 1990-2013, $/MWh



Source: Eurostat

This was crystallised by the differences in retail prices for customers in the liberalised and competitive British market and the still largely monopolised Continental European markets shown in Figures 41 and 42.

Collating 'like for like' end-user gas price data is difficult prior to 2008 due to data availability. Using Eurostat databases and expressing price values in $/MWh (to cope with the pre-Euro period), Figure 41 shows the prices paid by industrial customers[83] in Germany, France, Italy and Britain in the 1990-2013 period. Apart from the 2005-07 period, British industrial customers enjoyed significantly lower gas prices than those in Continental Europe. The 2005-07 period (shown in Figure 41) was characterised by NBP prices rising above those of Continental Europe due to supply-side events.

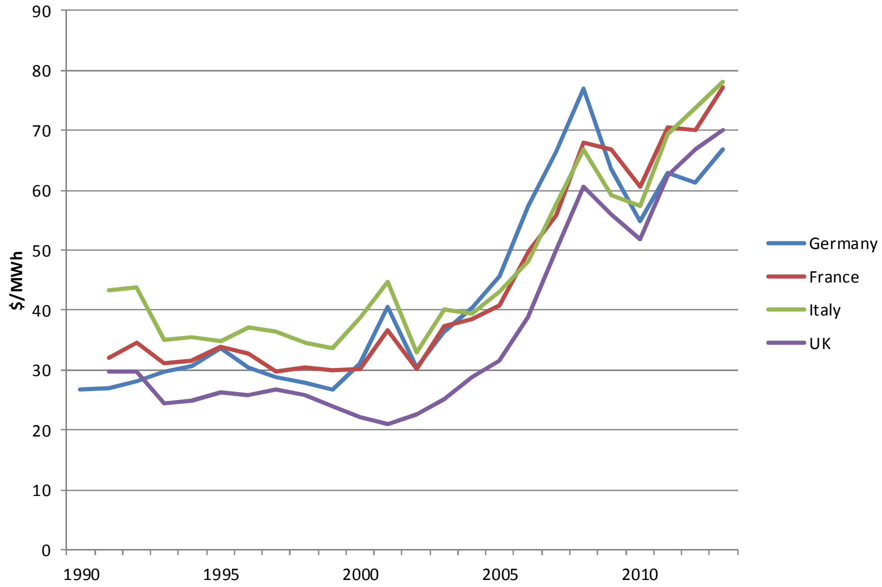
The comparable price trends for residential and commercial customers[84]are shown in Figure 42. This again shows a general price advantage for British customers apart from those in Germany in 1991 and post 2011. Residential/commercial customers in Britain were less exposed to the 2005/2006 NBP price spike than those in the industrial sector.

[82] EU (2007), Executive Summary, pp. 4-17.

[83] Annual consumption greater than 100,000 GJ and less than 1,000,000 GJ, excluding taxes and levies.

[84] Annual consumption greater than 20 GJ and less than 200 GJ, excluding taxes and levies.

Figure 42: Prices Paid by Residential/Commercial Customers in Britain and Major Continental European Gas Markets 1990-2013, $/MWh



Source: Eurostat

Post 2008: the Third Package and its unfolding impact

The 2007 Energy Sector Inquiry had demonstrated that the Second Gas Directive had not, and could not, achieve a competitive and transparent internal market; principally because the long term legacy transportation capacity contracts were beyond its reach. This gave rise to the Third Gas Directive and Regulation 715, adopted in July 2009 (and repealing the Second Gas Directive). These two documents formed a wider set of Internal Energy Market Directives and Regulations which were launched within the 'Third Package'.[85]

The EC viewed the Third Package as the means by which it could achieve its goal of a single liberalised EU gas (and electricity) market by 2014. The main gas components of the Third Package were:[86]

- The Third Gas Directive which:
  - required integrated utilities to separate (unbundle) their network assets from their supply businesses, either by selling them to non-affiliated companies (ownership unbundling), or by placing them in a subsidiary company which would operate independently from their supply and trading divisions with very strong regulatory oversight (independent system operator or independent transmission operator);
  - created an Agency for the Cooperation of Energy Regulators (ACER) to "coordinate the work of national energy regulators at EU level, and work towards the completion of the single EU energy market for (electricity and) natural gas" to play a central role in the development of EU-wide network and market rules.

[85] The documents which comprise the Third Package can be found at: http://ec.europa.eu/energy/gas_electricity/legislation/legislation_en.htm

[86] For a discussion of the gas aspects of the Third Package and the Gas Target Model see Yafimava (2013).

- Gas Regulation 715 (also part of the Third Energy Package) which:
  - made mandatory the certification of transmission system operators meeting the unbundling requirements;
  - established entry-exit organisation of access to transmission system networks i.e. entry capacity must be booked independently from exit capacity and the practice of setting tariffs on the basis of contract paths to be abolished;
  - required the development of 12 binding pan-European Network Codes on cross-border rules for: capacity allocation and congestion management; balancing, tariffs, interoperability, network security and reliability, network connection, third party access, data exchange and settlement, operational procedures in an emergency, trading, transparency, energy efficiency regarding gas networks.

These network codes (within overarching framework guidelines) are being developed by two new EU-wide agencies – the Agency for Co-operation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Gas (ENTSOG), in consultation with the EC.

In contrast to the pre-2008 situation of a collection of national markets, each liberalising under its own model and at its own speed (tolerated under the First and Second Gas Directives and Gas Regulation 1775), the creation of a single EU gas market under the Third Package required an 'end-point' of the liberalisation journey to be defined and agreed upon by all stakeholders. Prompted by the Madrid Forum in 2010, the Council of European Energy Regulators (CEER) produced a Vision for a European Gas Target Model (GTM), which was endorsed by the 21st Madrid Forum in March 2012.[87]

The GTM envisages a progressive reduction of the number of entry/exit (EE) zones inside the EU and hence a reduction in the number of interconnection points (IPs) at which shippers would need to book capacity, thus potentially simplifying the process of (both existing and new/incremental) capacity allocation. The GTM vision suggests that it is the zones – rather than national boundaries – that should facilitate interconnection in the single EU gas market, and therefore it is the IPs between the zones, rather than IPs between member states that should take precedence over the latter in the longer run. The GTM also envisaged that all gas would be delivered to hubs located within the zones, which would therefore act as the price discovery locations and become established as the main price formation mechanism.

By late 2014, the introduction of the first four network codes – capacity allocation (completed), balancing, interoperability and tariffs - and the introduction of entry/exit zones and tariffs was well advanced in the major EU gas markets.[88] Not surprisingly, the development of the European single market has many features in common with the spread of hub pricing discussed in Chapter 1:

- it is more advanced in the north west of the region and less in the south and east, but particularly in the southeast;
- it may take to the end of this decade, and perhaps longer, to become fully functional throughout Europe.

Nevertheless, by 2014 it was clear that progress towards a substantially liberalised gas market – while still falling short of an idealised European single market, particularly in the central and south eastern regions of the Continent – was advancing and unstoppable and that major companies throughout the chain were being required to adapt their business models to the new liberalised and competitive marketplace.

---

[87] CEER (2011).

[88] Despite some slippage in the introduction of some codes, and infringement proceedings which had been issued against some member states for failing to make sufficient progress in their national markets.

2.3 The Impact of Regulation and Competition on Market Structures and the Roles of Market Players

The impact of EU legislation and regulation on Continental European gas industries can be divided into two periods, with the year 2008 as the dividing line. The conclusion of the Energy Sector Inquiry created the conditions for change. These conditions were accelerated by the commercial and market changes described in Chapter 1, which took effect even before the Third Package was passed in 2009 and certainly well before it was implemented.

The period up to 2008

For the period up to 2008, Britain and Continental Europe must be discussed separately for two reasons.[89] Firstly liberalisation policy, legislation and regulation was implemented much earlier in Britain, and hence the key transformative dynamics unfolded much earlier than in the rest of Europe. Secondly, until the opening of the Bacton – Zeebrugge Interconnector pipeline (IUK) in October 1998, the UK gas market was physically separate from that of Continental Europe.[90]

Britain

Up to 1986, the gas market in England, Scotland and Wales was dominated by the British Gas Corporation – a state monopoly – and for some years thereafter by the privatised British Gas (BG). Successive acts of legislation and regulation served to progressively undermine BG's position, which allowed other market players to sell gas directly to the power sector and large industrial users, and progressively to smaller customers until, by 2000, the entire market was open to competition. This catalysed the monetisation of the 'backlog' of undeveloped offshore gas discoveries, with producers competing aggressively for customers in the power and industrial sectors. BG also had to publish its industrial prices and hold them at these levels for a defined period, allowing its competitors to undercut those prices and gain market share with impunity. BG's market share loss was such that it was unable to sell-on the take or pay quantities under its field-specific long term contracts, and was increasingly priced out of the market.[91]

Facing significant financial exposure BG was forced to re-negotiate many of its North Sea depletion contracts and transform them to non-field specific long term supply contracts. As was shown in Chapter 1, the British market became effectively liberalised following the creation of a virtual hub – the National Balancing Point (NBP) in 1996. A key feature of competition in the British gas market, which is highly relevant for this Chapter, is that in the period 1997-2001 there were 50 competing supply companies including: producers, British and Continental European gas and power companies, and independents. However by 2002-3, six companies supplied more than 80% of the non-domestic market, and the same number accounted for the entire domestic market.[92] The "Big 6" companies continued to dominate the domestic market up to the present.[93] British Gas (post privatisation) was the first of the merchant gas companies to be gradually broken up – or, as it later become known, `unbundled' – into (broadly) an upstream (BG Group), downstream supply (Centrica) and network

---

[89] "Britain" is a more accurate national designation than "UK" since the development of the Northern Ireland gas industry proceeded on a completely different timetable.

[90] For the history of IUK see Futyan (2006).

[91] For a detailed account of this history see Stern 1999, pp. 119-138; Wright (2006), Chapters 1 and 2.

[92] Wright (2006), Table 2.10 and Figure 2.2, pp. 41-2.

[93] The "Big 6" are: Centrica (British Gas), EdF, E.ON, RWE npower, Scottish Power and SSE. In June 2014, the British regulator Ofgem referred the Big 6 to the Competition and Markets Authority "because competition is not working as well as it could for consumers". See "Ofgem refers energy market for full competition investigation", Ofgem Press Release, June 26, 2014, https://www.ofgem.gov.uk/news/ofgem-refers-energy-market-full-competition-investigation?utm_medium=email&utm_source=Office+of+Gas+and+Electricity+Markets+(OFGEM)&utm_campaign=4341161_Ofgem+Daily+Update+26%2f06%2f2014&utm_content=ofgemreferstocmatitlelink&dm_i=1QCB,2L1NT,F31EGB,9FO6F,1

company (National Grid Gas). This had been largely achieved, and the whole market opened to competition, prior to 2000. [94]

Continental Europe

We showed above how the merchant transmission companies - British Gas, Ruhrgas, Gaz de France, Gasunie, Distrigaz, SNAM and Enagas – dominated the early decades of the Continental European gas industry. Although change in Continental Europe had been very slow up to 2000, it was about to accelerate. Despite the very limited nature of the provisions of the 2nd Gas Directive, the merchant companies began to confront several emerging realities for their traditional business model:[95]

- Since they were already dominant in their country or region, competition would mean that they would inevitably lose market share. Hence they had an incentive to find other areas of business, and probably other countries, in which to operate;
- They were not large enough companies to compete with electricity utilities, and had little experience in a sector which would inevitably become crucial, as gas and power markets became increasingly closely related. This had been the experience in Britain, which had liberalised much earlier and where the market had become dominated by the "Big Six" gas and power providers;
- Network (transmission and distribution) businesses would become regulated monopolies which would attract a much lower rate of return than their traditional merchant businesses.

The merchant transmission companies had no business experience outside the gas sector. They were essentially single product companies operating in a single country (or region), and it would be very difficult to continue this business model in any type of competitive market. The obvious alternative product for them to diversify into was electricity, but the power companies were much larger and more politically powerful than the gas companies, and this created the conditions for takeovers and mergers.

The first of these takeovers was E.ON's purchase of Ruhrgas finally completed in early 2003, and conditional on a sale of assets (Ruhrgas equity holdings in other German gas companies) and a release gas programme, both of which triggered further structural change in the German gas industry.[96] Other developments included: the purchase of Thyssengas by RWE, the purchase of GVS[97] by ENI and EnBW, the demerger of ExxonMobil and Shell's interests in BEB, and the purchase of stakes in many German gas distribution companies by a number of international companies.[98]

Similar developments followed in other major gas markets throughout the 2000s:

- in the Netherlands, Gasunie was first legally unbundled in 2004; this was followed by the creation and ownership unbundling of Gas Transport Services – which became the state-owned transmission system operator. The trade and supply business of Gasunie was renamed Gasterra and remained in half state/half private ownership.[99]
- in France, the attempt by the Italian company ENEL to take over France's Gaz de France (GdF) in 2006 was countered by the French government's arranged merger of GdF with the

---

[94] Stern (1998), Box 5.1, p.120

[95] This section is largely taken from Stern and Rogers (2011).

[96] For details of the entire episode see Lohmann (2006), pp.110-127.

[97] GasVersorgung Süddeutschland GmbH

[98] Lohmann (2006), pp. 111-33.

[99] The structure and regulation of the Dutch gas industry is set out in Haase (2009), pp.274-280.

French utility company Suez, an initiative which was eventually achieved following the direct intervention of the French president.[100]

- in Belgium, the merchant gas transmission company was Distrigas, majority-owned by the French company Suez. In 2001, its trading and transportation activities were split, trading remained with the parent company Distrigas, and a separate transmission company Fluxys was created (with Suez as a major shareholder in both companies). Fluxys was subsequently moved into separate ownership from the trading company and in 2009, as part of the sale of assets required for the merger of GDF and Suez, Distrigas was sold to ENI.
- in Italy, the vertically integrated structure whereby ENI owned: AGIP (exploration, production and storage), SNAM (import, transmission, storage and wholesale) and Italgas (with a very large share of distribution and retail), was progressively broken up and privatised. ENI retained the exploration and production activities. All other functions were taken over by SNAM Rete Gas, in which ENI retains an 8.5% share ownership.[101]
- in Spain, Enagas became the TSO with Gas Natural as the supply company. The latter lost market share as liberalisation and competition progressed and was jointly acquired by Union Fenosa Gas and ENI in 2011.[102]
- In central Europe, the gas transmission and distribution companies of many of the former socialist countries (such as Hungary, Czech Republic and Slovakia) were purchased by the major west European gas (and power) companies.[103] In Poland, despite frequent privatisation and liberalisation initiatives, PGNiG has remained a dominant state-owned company. In Austria, the Econgas joint venture, created in 2003, has maintained a dominant position (previously held by OMV).

In summary, by the late 2000s, a wave of corporate mergers and demergers had either been completed or, in relation to network ownership, were well underway. The result was that the traditional merchant gas companies had been absorbed into a small number of very large companies - E.ON, RWE, EdF, GdFSuez, ENI, Enel, Endesa, Iberdrola and Vattenfall – which owned a variety of utility (including gas) assets across a number of European countries and dominated the European utility (including gas) landscape.[104] These companies owned gas (and power) supply and trading businesses in a variety of European countries, while their network assets were either in separate subsidiaries under increasingly stringent regulation, or in the process of being sold to meet either regulatory or financial requirements.

The period since 2008

With the changes in regulation arising from the Third Package, the structure of Continental European gas markets changed and many new players, and some new categories of players, emerged. Producers, local distribution companies, industrial customers and power generators still existed. But the merchant transmission companies had been forced to place their networks in separate subsidiary companies, and many had chosen or been forced (by financial pressures) to sell their networks to

---

[100] `Birth of a New Energy Giant: Sarkozy Pushes Through GdF-Suez Merger', *Spiegel Online International*, September 3, 2007. http://www.spiegel.de/international/business/birth-of-a-new-energy-giant-sarkozy-pushes-through-gdf-suez-merger-a-503516.html

[101] For details see Honoré (2013), pp. 11-18.

[102] For details of the Spanish market see Honoré (2011), pp. 65-70.

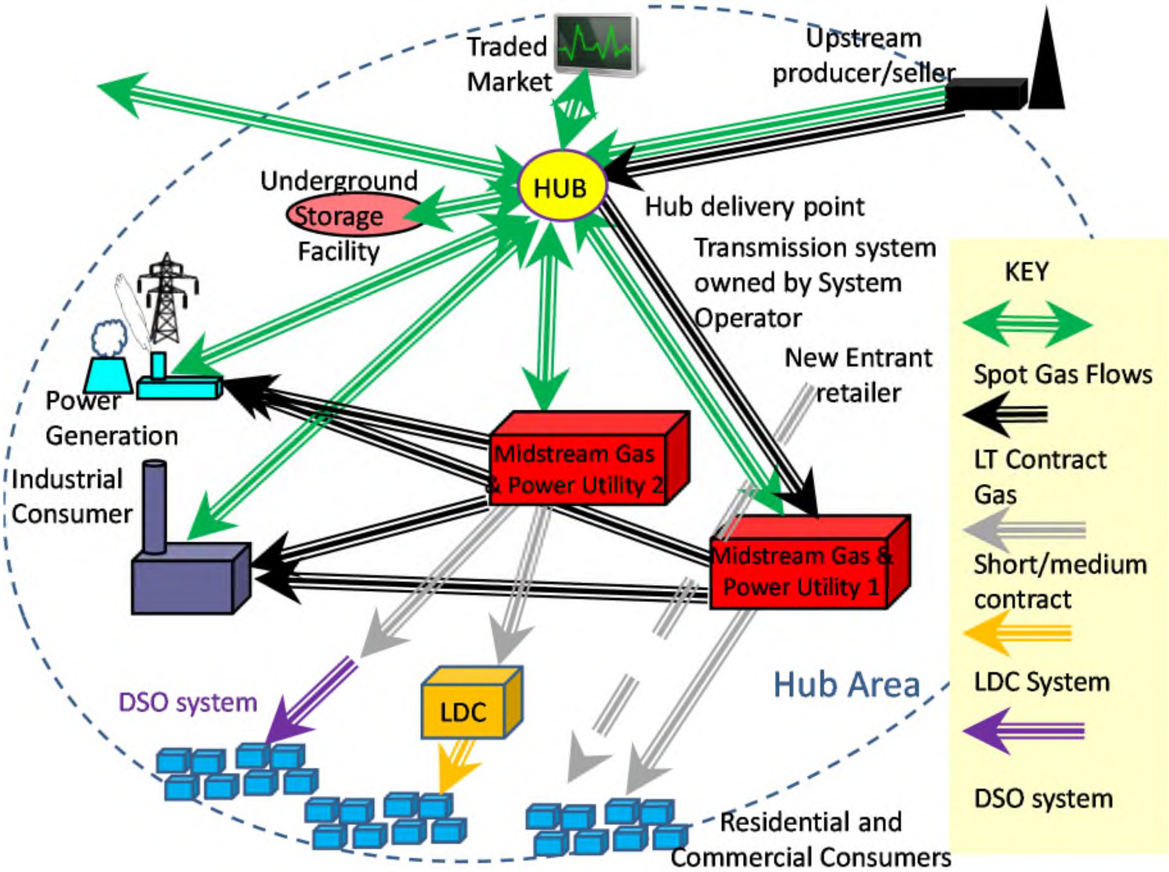
[103] Although by 2014 this process was reversed in Hungary with European gas and power utilities selling their stakes back to the government.

[104] The only supply and trading companies which had no significant presence in other European countries were Britain's Centrica and the Dutch Gasterra. In many countries – such as France and Italy - this restructuring was accompanied by substantial (but not full) privatisation of companies which had previously been completely state-owned.

new owners. Similar measures were applied to LDCs serving more than 100,000 customers, which were required to place their low pressure networks in a separate subsidiary. So two new categories of company – transmission system operators (TSOs) and distribution system operators (DSOs) – appeared, some of which also operated storage assets (although again as a separate subsidiary), unless a storage company under separate ownership had been established. With the arrival of workable third party access, many new players – suppliers and shippers – flooded into the market: some of these from other parts of the energy sector, some non-energy sector players seeking a role in a sector hitherto closed to them.

In addition to structural change, there had been a major commercial change as hubs which, as we saw in Chapter 1, by 2014 had become well-established and replaced oil product indexation as the major price formation mechanism in most of the largest EU gas markets. Figure 43 is a schematic representation of a Continental European gas market with an established gas hub and shows how the market structure and commercial arrangements have changed as a result of the arrival of liberalisation, competition and hub pricing. Rather than a national market, the commercial and pricing context has become a 'hub area' - which might comprise parts of previous national markets – with prices which are becoming increasingly well correlated with other hub areas.

Figure 43: Schematic of a Continental European Market with an Established Gas Hub



Source: Author

Transmission networks have been 'unbundled' and are owned and/or operated by TSOs, distribution networks serving more than 100,000 customers will be operated by DSOs. All networks and storages can be accessed by multiple buyers and sellers.

There are a large number of suppliers buying and selling gas (often the same gas is sold a number of times if through the traded market) to customers which have access to a number of different offers. All gas from producers and exporters is delivered to the hub, as is supply from geographically adjacent hubs (the flow could be bi-directional).[105] Gas supplied under all new contracts, and increasingly medium and long term legacy contracts, is hub-indexed.

Producers and exporters

In a competitive market producers and exporters have to decide how far downstream (i.e. towards the customer) they wish to participate since, with access rights to transmission and distribution pipelines, they can sell directly to all groups of customers. The main uncertainty connected with moving downstream is whether these companies have the commercial mindset, and are willing to set up the administrative structures necessary, to serve large numbers of customers. The British experience suggests this is not the case, and that producers can only compete in the non-residential sector, which means a relatively limited degree of vertical integration.[106] So the role of producers has not changed substantially, and their business model remains similar to the monopoly era although (as we saw in Chapter 1 and discuss again below) commercial decision-making has become more complex. But one additional important issue is the GTM requirement that gas should be delivered to hubs. For most producers this new situation was resolved without major problems, but the position of Gazprom is different because of the remaining length of its legacy (supply and transportation) contracts and because of the number of entry/exit zones that its gas has to cross. Gazprom has additional problems in relation to very substantial new pipeline infrastructure which it is proposing to build (notably South Stream).[107]

Mid-stream energy trading companies

In Europe's restructured competitive energy utility markets, the former merchant gas transmission companies became the gas departments of trading subsidiaries of mid-stream energy (power, gas and other energy products) utilities. With their monopoly position abolished, and stripped of their networks, they found themselves in competition with a large number of other companies to retain their previously captive customer base. At the same time they retained the take or pay obligations in their long term legacy supply contracts with upstream sellers – some of which extend for 10-20 years into the future; and despite the change of status of their networks, they also retained their obligations under long term ship or pay contracts for transportation capacity. The supply contracts require a minimum volume of gas to be taken (or paid for), but the exposure of their customer base to competition increases the risk associated with this obligation, and the need to sell at hub prices (or lose customers to competitors) increases those risks. The capacity contracts require a minimum amount of capacity to be paid for irrespective of whether it is used. The midstream companies are thus exposed to both volume risk (loss of customer base to competitors) and payment obligation risks (from their long-term commodity and capacity contracts, the former albeit modified by negotiated concessions and rebates). These companies perform a `market aggregation role' – i.e. bringing together a substantial volume of demand – but it is not clear whether this still has inherent value, and if so how it will be remunerated, in a competitive market where producers, LDCs and all other parties are free to make their own contractual arrangements. Thus fundamental questions arise as to whether the mid-stream energy trading companies still retain, or can (re)create, a business model which will remunerate them for their commercial risks in the new competitive environment.

---

[105] The delivery points in existing (legacy) long term transportation contracts can be retained until these contracts expire.

[106] in Britain, the absence of LDCs meant that Centrica (successor of the former British Gas) and the former regional electricity incumbents retained virtually the entire residential gas market and more than 20% of the non-residential market despite the entire market having been open to competition for more than a decade. Producers are almost completely absent from the residential market where the "Big Six" have dominated since 2005, see Ofgem (2014), Figure 4, p.9.; in the non-residential market domestic and foreign producers (and their affiliates) accounted for 51% of the market in 2012, see Ofgem (2012), Figure 2.1, p.18.

[107] For details of the issues relating to Gazprom see Yafimava (2013).

Local distribution companies

LDCs have also experienced change in the new market but competition has thus far impacted them differently in comparison with midstream companies. Although their customers are free to seek other suppliers, evidence from 2011-12 suggested that in the household sectors of most countries, competitive offers and switching remained limited.[108] But in order to prevent the loss of customers, competitive pressures have reduced their gas business margins significantly. As a result, LDCs in countries such as Germany and Austria – which operated major cross subsidies to municipal services using profits from their gas (and power) businesses (see Section 2.1 above) – have seen these profits reduce dramatically and, as a result, many are now in financial trouble and making losses. Given the significant influence of local politicians on their managements, it will be very difficult for them to unwind these cross-subsidies. In these cases, competition has impacted LDC financial stability, but if they can deal with cross-subsidy problems, their gas business model remains basically robust.

Network companies

TSOs and DSOs are regulated network businesses which are either separate subsidiaries of, or have been sold by, their former owners. New TSO owners are a specific class of infrastructure investor (very often pension funds) which are content to receive lower (but guaranteed) regulated rates of return on an agreed asset base. Their business model is relatively straightforward: they have long term (legacy) ship or pay contracts with shippers (often the former owners of the networks) which provide guaranteed earnings on existing assets. For new assets they are required to submit a 10 year network development plan for approval by regulators. The tariffs which they are allowed to charge, and the rates of return they are allowed to earn, are determined by regulators based on an agreed methodology.[109] Their owners and managements have little appetite for risks which might jeopardise their regulated rate of return, and so are highly unlikely to propose construction of any infrastructure which is not requested by the market or by regulators. This is an important reason why substantial new cross-border pipelines are only being built by exporters such as Gazprom, and those bringing new gas from Azerbaijan (and potentially other Southern Corridor suppliers) to Europe.[110]

2.4 The impact of the new market structure and regulation on commercial frameworks and risk exposure of market players

In the monopoly era of the European gas market, the roles and business models of the major groups were relatively well-defined, stable and highly profitable. Moreover, as demand continued to grow strongly up to the mid 2000s, all parties focused on the challenges of an expanding market – how to ensure that sufficient supply and sufficient infrastructure to deliver it to customers would be available – with market structures and commercial frameworks remaining relatively stable. When markets liberalised in Britain in the 1990s, amply available supply at relatively low cost created a sharp increase in demand for gas (particularly) in the newly liberalised power sector. As discussed above, British gas market organisation and contractual structures changed radically in the 1990s, but then stabilised in the early 2000s with relatively little change thereafter.[111]

---

[108] ACER/CEER (2013), pp. 142-154. This source does not give comprehensive switching data for the household gas sector but suggests that in 2012, customers were most likely to switch in the Czech Republic, Slovakia, Slovenia and Spain (p.154). Comprehensive data for the electricity sector in 2011 and 2012 (Table 2, p.35) show that switching rates were below 10% in all countries other than Portugal, Belgium, Netherlands, Spain, Britain and Ireland. The inference is that gas switching rates were lower in gas than in electricity.

[109] It is as yet uncertain whether the EU tariff network code – which is to be finalised in 2015 and implemented by October 2017 – will apply to existing ship or pay contracts, and if it does whether this will impact the profitability of individual TSOs.

[110] Another important reason for the lack of major new pipelines is the reduced gas demand expectations in Europe.

[111] It should also be realised that the vast majority of gas contracts during this period were between companies operating under UK legal and regulatory jurisdiction; whereas many Continental European gas contracts not only involve companies in other EU and EEA states, but also state-owned companies in countries outside Europe.

Similar changes arrived in Continental Europe nearly 10 years after the British experience. but coincided with a sharp decline in demand, due to recession and high gas prices, which placed much greater pressure on market organisation and commercial structures. Since 2008, an increasing number of players have been competing for a shrinking market, and established players have been in conflict with upstream sellers over prices in long term contracts which have created substantial losses for merchant gas suppliers. Losses in the gas sector have been compounded by losses in the power sector – although for other reasons – and mothballing or closure of many (often recently built) gas-fired power plants. These conflicts have yet to be resolved – and are not helped by the lack of significant growth foreseen in European gas markets over the next decade.

Contract and price risk in the competitive gas market

Contract and price risk in a competitive gas market is a very large subject, and we concentrate here on two main questions which we address to the three main groups of players discussed in this chapter – producers, merchant gas supply companies and LDCs:

- What is the value – and hence the future – of existing long term, and new, gas contracts?
- What are the main attributes of future contracts in terms of length and price, and which sets of players are most likely to be willing to sign them?

Producers and exporters

The upstream producer's motivation remains revenue maximisation and an adequate return on upstream and pipeline transportation investments. Producers with existing long term (legacy) contracts proved understandably reluctant to convert these to hub prices but as we showed in Chapter 1 (Section 1.3), by 2014 many long term contracts had already been converted, and many others were either under negotiation or in arbitration. New upstream investment must therefore be based on an assessment of future hub prices, rather than oil prices. This requires the upstream producer/supplier to undertake an assessment of long term market fundamentals prior to committing investment in new fields. The critical considerations here are:

- whether a new field is likely to have a lower break-even price compared with other competing gas projects not yet committed;
- whether a new field requires a long term contract to underpin the investment;
- whether the producer has sufficient market power such that withholding physical volumes from the market will increase the hub price, and once the field is in production…
- if through physical supply management the price rises to a higher level, how much competing supply could be developed as a result?

The primary risk for the upstream producer/seller is one of price, which on the hub primarily responds to supply and demand. Assuming that the producer decides to go ahead on the basis that it believes its field to be among the lower cost projects under consideration for development, and that the cost is sufficiently low to allow for adequate profitability given the results of the hub price assessment, there is then the question of whether a long term contract is necessary, and if so how long. One major reason for a long term contract is that it may be required by those financing the project, particularly if the capital expenditure is very large. An example would be the Shah Deniz 2 contracts signed in 2013 with a number of different European buyers which have a 25 year duration.[112] This is a project with an upstream capital investment of $25billion requiring pipelines with an additional capital investment of $20billion to deliver the gas from Azerbaijan to European countries.[113] Europe will not be requiring many projects with this size of capital investment over the next several years, and so this may be an

[112] Shah Deniz (2014), p.9

[113] Ibid, p.3.

unrepresentative example, but it does illustrate the continuing need for long term contracts in the case of `greenfield' projects with very large capital investments.[114]

But in all other circumstances the need for contracts of significant length is much reduced, and with it the volume risk traditionally assumed by producers. The latter no longer need a purchasing counterparty because they can sell directly into the market via the hub, although a guaranteed sales volume over a period of years may be convenient, especially when selling very large volumes on a daily basis. Since producers know they can only expect to receive the hub price, the only price aspect of a contract which would need to be negotiated would be the selection and design of hub reference prices (to which we return below). In general it would seem likely that producers might want to sign a several year (potentially renewable) contract for a portion of their gas, while retaining the remainder for much shorter term contract or prompt (hub) sales. Figure 43 shows this schematically with the producer's gas flowing to the hub, part contracted (black arrow line) and part uncontracted.

So from an international oil company producer's perspective the answer to the questions posed at the beginning of this section appear to be:

- the value of existing long term contracts was high until forced to convert from oil-indexed to hub prices at which point it became much lower or zero. New 15-25 year contracts – unless required by banks for financing greenfield projects with very large capital expenditure – are not necessary (and probably not desirable) given the ability to sell gas directly at the hubs;
- the main attributes of future contracts are that they will be for a portion – possibly up to one half of volumes from a specific field, for a duration of up to five, and certainly not more than 10, years.[115] Prices will be hub-related with the exact hub and price period/average to be decided (and probably periodically renegotiable). The remainder of the volume will be sold on much shorter contracts[116] with durations ranging from within-day to one year.

However for exporters, the answers to these questions may be different or at least not so definite. Pipeline exporters such as Statoil and Gasterra, may have a similar view to IOCs, but Gazprom and Sonatrach tend to prefer the traditional long term contract business model, although Gazprom at least has alternative options given its very large and active European trading subsidiaries. The preferences of LNG exporters may vary depending on their degree of vertical integration in downstream European markets. The optionality to direct cargoes to the highest paying global LNG market – which may very well not be in Europe – speaks against long term contracts, but long term capacity reservations at European LNG terminals may be necessary to provide the ability to move cargoes into the market if prices should so dictate.

Mid-stream energy trading companies

These companies manage the long term take or pay supply contracts, and long term ship or pay transport capacity contracts, as well as shorter term transactions. Since 2008, the long term legacy supply and capacity contracts have become an increasingly serious risk and liability for energy traders. This is not just because of the legal difficulty and cost of moving from oil-linked to hub-based prices, but also relates to the general problem of lack of flexibility in the contracts which, in a competitive market where supply/demand and hence price conditions can change rapidly, places considerable value on optionality.

Dealing with risk is mainly focused on management of a trading portfolio. This entails (continuously revised) estimates of physical supply requirements into the future, secured on a range of forward contracts which are constantly re-traded to seek the highest net margin on delivery. However, this is

---

114 South Stream will probably require an even larger capital investment, but this is not bringing (significant volumes of) *new* gas to Europe, but re-routing volumes under existing contracts.

115 The proportion may depend on the size of the volume to be sold.

116 Generally via OTC brokers and/or trading exchanges and conforming to standardised formats.

mainly an exercise in portfolio aggregation and optimisation of long term contracts – similar to the pure trading optimisation function – with the objective of using trading positions to:

- minimise the potential price exposure created by long-term contracts which are still fully or partially oil-indexed, within the liquid portion of the forward curve;
- establish trading positions to reduce still further the net cost of gas supply acquisition from their long term contracts where possible within the bid-offer spread in the liquid forward curve;
- manage contractual requirements by matching take or pay levels with the physical volume of contracted gas both sold-on to end-user customers and the balance which has to be sold onto the hub.

It is questionable whether this can be considered a business model which will remunerate companies adequately for their risks. Even buying from suppliers at hub prices, midstream energy trading companies must strive to ensure that the margin on sales covers the costs incurred, as well as meeting take or pay levels. In a competitive market, this margin will be put under pressure by both upstream sellers and end-user customers, especially if market demand growth is (at best) weak.

As far as new long term contacts are concerned, we noted above the sale of 10 Bcm/year of gas from Azerbaijan's Shah Deniz 2 field on 25 year contracts to a number of European customers, which demonstrates that it is still possible to sign such contracts, but on very specific terms. These contracts were signed with: Bulgargaz, DEPA, Enel Trading, E.ON Global Commodities, Gas Natural, GDF Suez, Hera Trading (Italy), Shell Energy Europe and Axpo Trading (Switzerland). Bulgargaz and Depa each contracted for 1 Bcm/year, Shell Energy Europe for 1 Bcm/year and E.ON for 1.6 Bcm/year, leaving the remaining five companies with a maximum of just over 1 Bcm/year each.[117] Two of these companies are pure traders (Axpo and Hera) and the rest have large gas portfolios, in the context of which 1 Bcm/year is a relatively small volume.[118]

An important piece of anecdotal evidence about the Shah Deniz sales is that in north west Europe at least, they have been sold at below hub prices generally known as `hub minus'. The emerging commercial reality for mid-stream gas traders is that because they can only sell at hub prices, they need to purchase gas below those prices in order to maintain profitability after they have paid transportation (entry and exit) and administrative charges related to bringing the gas to the hub and delivering it to the customer. In addition, there is also a potential locational problem that legacy transportation contracts include delivery points which can entail additional transportation costs and logistical risks (such as lack of capacity availability).[119]

Thus for European energy trading and supply companies, the value of existing long term contracts even at hub prices, has been much reduced. Future profitability may rest on their ability to purchase gas at hub-minus prices and sell at hub plus prices. The difficulties of achieving a hub-minus/hub-plus commercial model, combined with the costs and legal difficulties experienced with long term contracts since 2008, mean that mid-stream trading companies would be happy to terminate some of these contracts. It certainly means that no company is likely to be willing to sign new long term contracts unless their terms correspond to (what we understand to be) the terms of the Shah Deniz 2 contracts: small volumes (1-1.6 Bcm/year), flexible delivery terms and hub minus prices.

---

[117] `Shah Deniz consortium inks supply deals', Platts, *European Gas Report*, September 20, 2013, pp.1-2.

[118] Note that these companies are not obliged to sell this gas in their home countries, they may trade it anywhere – including in Turkey, through which the gas has to transit before it reaches Europe and where gas demand looks set to increase rapidly.

[119] Although the GTM requires gas to be delivered to hubs, the Third Package allows existing long term transportation contracts to be honoured until they expire (although they cannot be renewed or extended).

Relatively high risks and uncertain returns also raise the question of the number of mid-stream players which will choose, or be able, to compete in this type of gas market on a long term basis.[120] Much more onerous financial regulation, arising from new EU Directives, will also raise costs (and risks) for those with a significant trading business.[121] Moreover (as shown in Chapter 1), while these companies may have managed the most difficult period of price adjustment in their long term legacy contracts, their adjustment problems are by no means over. Ongoing corporate problems caused by losses in both power generation and gas, and increased exposure to competitive and contract risks, suggest that the current situation is unstable and will be subject to further change.

Network companies

TSOs (and to a lesser extent DSOs) are the last strong defenders of long term contracts in the European gas market, albeit for transportation services rather than for gas supply. Where TSOs have long term legacy ship or pay contracts, these can be extremely profitable as shippers are obliged to continue to pay whether or not they use the capacity. TSOs have regulatory requirements to fulfil before they build any significant new transportation capacity. Under the capacity allocation network code, the regulatory regime is in the process of moving to long term capacity auctions, where companies must bid, and make long term commitments to paying, for capacity up to 15 years ahead. Should insufficient bids be received then it is possible that capacity will not be built since TSO managements and shareholders will not take the risk of construction without capacity commitments.[122] Large new transmission infrastructure still requires long term capacity contracts e.g. the Trans-Adriatic Pipeline (TAP) which will carry Shah Deniz 2 gas to Italy. New infrastructure projects can apply for national and EU exemptions from Third Package – specifically third party access, tariff regulation and ownership unbundling – rules.[123]

However, to a significant extent, TSOs (and to a lesser extent) DSOs are being supported by long term legacy ship or pay agreements. When those agreements expire, it is clear that they will not be replaced by equally long term shipper commitments. Evidence to date suggests that shippers will restrict their bookings to as short a term as possible, in order to avoid paying for capacity which they may not need, particularly in markets where demand has been falling for several years. This puts a premium on short term – daily or monthly – bookings, and suggests that few will book capacity for years ahead, in the expectation that it will be available if and when they need it. If true, this will gradually reduce the profitability of (particularly) TSOs, but not endanger their business model since their legacy assets have been fully amortised. The only immediate danger which network companies could face is the proposal from some shippers that they can no longer afford to honour their long term ship or pay contracts and that, complementing the "use it or lose it" provision of the 3rd Gas Directive, they want to see a provision that "if you don't use it you don't pay for it".[124]

---

[120] The example of the British market suggests that a "shake-out" is likely; by the early 2010s, the residential market had six dominant suppliers, and the non-residential market has 14 suppliers. Ofgem (2012) and (2014).

[121] Principally the Regulation of Energy Market Integrity and Transparency (REMIT) Directive.

[122] This is a complex issue and subject to rules which are still unfolding; open seasons may still be part of the process, and regulators have powers to require infrastructure which they believe is needed for (e.g.) security reasons to be built with charges being spread across all system users.

[123] The TAP exemption can be found at:
http://ec.europa.eu/energy/infrastructure/exemptions/doc/doc/gas/2013_tap_decision_en.pdf

[124] "Use it or lose it" was introduced to prevent the major shippers/suppliers hoarding capacity to prevent competition from new entrants. These shippers/suppliers are making the point that in a market where demand has fallen dramatically, they cannot use all of the capacity in their long term ship or pay contracts and should not be expected to pay for capacity beyond what they are able to use.

Local distribution companies

Lack of comprehensive and recent data prevents definite conclusions from being drawn about the impact of competition on LDCs, but the impression is that these companies have not (yet) experienced strong competitive pressures on their customer base. Their contracts with suppliers are much shorter (generally not exceeding three years) and therefore less problematic than those of their mid-stream counterparts. In the event that they do experience substantial customer losses due to competition, they will be able to renegotiate supplies on a more flexible (price and volume) basis. While many are experiencing reduced profitability (in comparison to the monopoly era) and may be forced to unwind cross-subsidies to other municipal services which date from that era, their basic business model remains viable.

Security considerations, design of hub-based prices, and managing sales to different customer classes

We conclude this chapter with brief consideration of three issues: security of supply, design of hub-based price indices, and the problems of managing sales to different customer classes. These issues impact all three groups of market players, although to different extents.

Assessing the value of long term contracts brings us to the question of security. For many decades, the conventional wisdom of the European gas industry has been that long term take or pay contracts, which oblige producers to deliver guaranteed volumes of gas, provide security for an increasingly import-dependent market. This worked well during the monopoly era when not only was gas demand rising fast enough to ensure that the merchant gas companies would be able to sell volumes which they had contracted; but also the monopoly franchise of those companies ensured that they were well remunerated for taking the risks associated with the contracts. But post-2008, both those conditions have progressively disappeared. Some producers – notably Gazprom – continue to assert that long term contracts are essential for new projects and, as we have seen in the case of Shah Deniz 2, this may be correct. But there are very few new gas supply mega-projects under consideration in Europe at present, and as we saw in the case of the Shah Deniz 2 contracts, those that have been agreed involve relatively small volumes (per purchaser) and very different price terms compared with the pre-2008 era. In relation to LNG projects, and as noted above, security is unlikely to be determined through contracts, and will depend on the willingness of European buyers to pay higher prices than those in other regions. While LNG buyers have the option of reloading cargoes which they do not need for sale to other markets, this is a cumbersome process which can be expected to disappear with the expiry of existing long term contracts. [125]

No market player will take on security of supply obligations unless it is required to do so by regulation and the costs of measures which it is required to take are remunerated. EU security requirements are set out in the Security of Supply Regulation, and enforced by national regulatory authorities (coordinated with 10 year Network Development Plans) which have responsibilities to ensure that sufficient gas is available in emergency situations. [126] It seems highly unlikely that a regulatory requirement for new long term *supply* – as opposed to *capacity* - contracts will play a major part in providing security of supply.

Design of hub-based price indices

Chapter 1 suggested that there is growing agreement on the general principle that gas should be priced at hubs. But even for those who accept that proposition, there is also a need to consider some additional complexities of hub based prices between producers and mid-stream companies, and between the latter and their customers. We have already suggested that, in order to make a profit, after the costs of moving gas to the hub and then to the customer, mid-stream companies will seek a

---

[125] Reloading involves taking the cargo off the ship and into a storage tank and then reloading it for delivery to a different market. It is necessary in the case of long term contracts which state that cargoes must be delivered to a particular market.

[126] Regulation EU (2010).

`hub-minus' price (i.e. below the hub price), but the question remains: which hub price? The relevant hub would normally be located in the country where the gas is being sold, but if the seller took the view that the hub was insufficiently liquid and well-correlated with other hubs to produce an acceptable price, or alleged that the price could be manipulated by the buyer, it is possible that a hub in a neighbouring country, or an average of prices at different regional hubs could be used.[127]

Figure 44: Range of Traded Contracts at NBP, March 2014

Platts UK Market Assessments, March 28, 2014

UK NBP Market	p/th	change D-1 (p/th)	$/MMBtu	Eur/MWh
Within-Day	53.50 - 53.70	-1.40	8.89 - 8.92	22.08 - 22.16
DA Midday	51.65 - 51.85	-1.75	8.58 - 8.61	21.32 - 21.40
Day-Ahead	51.80 - 52.00	-1.80	8.60 - 8.64	21.38 - 21.46
Weekend	51.80 - 52.00	-1.10	8.60 - 8.64	21.38 - 21.46
Working week+1	51.90 - 52.10	-1.20	8.62 - 8.65	21.42 - 21.50
Bal Month Mar	51.80 - 52.00	-1.35	8.60 - 8.64	21.38 - 21.46
April	52.40 - 52.60	-1.10	8.70 - 8.74	21.63 - 21.71
May	52.60 - 52.80	-0.85	8.74 - 8.77	21.71 - 21.79
June	52.30 - 52.50	-0.65	8.69 - 8.72	21.58 - 21.67
July	53.00 - 53.20	-0.50	8.80 - 8.84	21.87 - 21.96
Q2 2014	52.50 - 52.70	-0.80	8.72 - 8.75	21.67 - 21.75
Q3 2014	53.65 - 53.85	-0.30	8.91 - 8.95	22.14 - 22.22
Q4 2014	61.45 - 61.65	-0.25	10.21 - 10.24	25.36 - 25.44
Q1 2015	65.45 - 65.65	-0.35	10.87 - 10.91	27.01 - 27.09
Summer 14	53.15 - 53.35	-0.45	8.83 - 8.86	21.93 - 22.02
Winter 14	63.50 - 63.70	-0.20	10.55 - 10.58	26.21 - 26.29
Summer 15	57.60 - 57.80	-0.25	9.57 - 9.60	23.77 - 23.85
Winter 15	66.00 - 66.20	-0.15	10.96 - 11.00	27.24 - 27.32
Summer 16	58.10 - 58.30	-0.10	9.65 - 9.68	23.98 - 24.06
Winter 16	64.40 - 64.60	-0.25	10.70 - 10.73	26.58 - 26.66
Summer 17	57.70 - 57.90	-0.15	9.58 - 9.62	23.81 - 23.89
Winter 17	63.35 - 63.55	0.00	10.52 - 10.56	26.14 - 26.23
Oct 2014 1 yr	60.55 - 60.75	-0.25	10.06 - 10.09	24.99 - 25.07
Cal 2015	61.15 - 61.35	-0.25	10.16 - 10.19	25.24 - 25.32

Source: Platts, *European Gas Daily*, March 31 2014, p.2.

Figure 44 shows the wide range of daily and future prices quoted at the NBP each day[128]. This provides the possibility for market players to select a single price, or a number of different prices, averaged over one month or a period of months, depending on what they believe will be most representative of the contract into which they are entering. A significant risk for mid-stream companies is therefore to design the hub price which it agrees in its purchase contracts to be representative of its sales portfolio. The average observer of the gas market – whether consumer, politician, journalist or in some cases regulator – may find it difficult to understand the 'parallel universe' of traded gas prices. There is a general expectation that there is a single definable 'gas price' from which the validity of end-user prices can be independently assessed. From a simplistic perspective this may seem a reasonable standpoint, but it does not correspond to reality.

[127] In 2011-13 it was common for Continental European sellers, even in countries outside the Netherlands, to use TTF prices for transactions beyond `prompt' trades.

[128] NBP here is used as an example. A similar set of assessments could be presented for TTF.

Figure 44 shows that on a trading day in March 2014 a mid-stream utility might typically have physically taken delivery of gas, different portions of which were:

- Bought 2 years ago on a 2014 Calendar year basis (a 'flat amount' per day for the year).
- Sold 18 months ago as Winter 2013
- Bought 12 months ago as Q1 2014
- Sold 9 months ago as Q1 2014
- Bought 6 months ago as Q1 2014
- Sold 4 months ago as March 2014
- Bought 2 months ago as March 2014
- Sold 1 month ago as March 2014 (month-ahead)
- Bought the previous day as day-ahead

The price paid by the mid-stream utility for its gas on the specific date in March 2014 is the net of the above volume-weighted buy and sell transactions, with the price fixed on the original trade dates, due for payment on the delivery date.

A utility buying gas indexed to hub prices under a medium or long-term contract will need to consider which hub and which time-related trading contracts should be included in the contract price formulae, and with what weighting. The overriding objective should be to ensure that the gas under the contract once delivered and paid for, is not at a price which will materially reduce profit margins. Since observations generally conclude that prompt (day ahead) prices respond more significantly to short term supply or demand side events than month ahead (or longer dated trading contracts), there will be a tendency to give greater weight to month ahead and later contracts. This may forego some upside when prompt price dips suddenly but may also avoid the downside of a short-term price spike. The selection of future contract price products to be included will be confined to products and time periods with adequate liquidity. This will tend to give prominence to the more liquid hubs such as TTF or NBP. The specific weighting of month ahead/future quarters, seasons and years, will be tested either by remodelling outcomes over past periods or by the use of option theory models incorporating a view of future price volatility. Once the hub-index has been defined and the contract signed, the buyer's trading team will incorporate it in the overall trading portfolio as a series of future buy obligations and optimise the net position of the company overall.

Managing sales to different customer classes

The mid-stream utility also has to manage customer risk and customer demand. Customers may request fixed price contracts over a relatively long period of time (such as a year) – especially LDCs seeking to avoid price volatility for their residential customers. This can be very difficult and costly to hedge – but this is a customer base that the mid-stream utilitiy cannot afford to lose, and one which may be particularly susceptible to attractive bids from competitors, especially in a market with surplus supply. Pricing gas for the power sector is another difficult customer risk to be managed. In the period 2010-13, gas-fired generation became completely uncompetitive in most European power markets due to its inability to compete with low price coal (and carbon) and state-financially-supported renewables. It is impossible for mid-stream utilities to give power companies – even power stations owned by the same utility - a `special price', because the market cannot be segmented in this way. Either hub gas prices must converge with prices of alternative power generation fuels – which happened in mid-2014 for a short period in the UK – or the future for gas-fired power generation will be bleak until and unless renewable financial support is phased out, and non-emission compliant (principally coal) plant is closed down.[129]

2.5 Summary and Conclusions

The roles of European gas market players have changed substantially since the monopoly era of regional and local franchises of merchant transmission and distribution companies, in complete control of networks, insulated from competition and able to pass their purchase costs through to a captive customer base. Legislation and regulation - initially in Britain and subsequently at EU level - led to major structural change for former merchant transmission companies which were forced to place their networks in separate subsidiaries (or sell them), and to merge with (primarily) electricity utilities to become the gas departments of mid-stream energy trading companies. Post-2008, EU and national competition and liberalisation measures (which had been in progress for nearly 20 years) coincided with a surplus of supply and sharply rising oil prices to promote hub-based pricing in north west Europe, which subsequently spread east and south (see Chapter 1). Unbundling of, and open access to, networks combined with growing competition at wholesale and (to a lesser extent) retail levels in the major gas markets of Continental Europe, impacted the contractual risks – and hence the business models – of all three major groups of players.

The role of producers and exporters did not change substantially but they acquired the freedom to move downstream and sell directly to customers, or to sell at the hubs thereby avoiding the need for downstream contracting. Local distribution companies (serving more than 100,000 customers) were required to place their networks into separate subsidiaries but otherwise their role remained little changed, perhaps because retail network competition remained at a relatively early stage in most countries. Their main problem appears to be losses in countries where gas (and power) revenues previously cross-subsidised other services. With these caveats, the traditional business models of producers and LDCs still worked reasonably well in the newly liberalised market, albeit with a greater range of risks and uncertainties.

But the business model of the (former merchant transmission companies now) `mid-stream' merchant trading and supply companies had come under much greater pressure. This situation has arisen principally because of the long term legacy contracts which, in a competitive market, have been transformed from valuable assets to potentially open-ended financial liabilities unless their prices can be converted to `hub minus', and their volume obligations can become much more flexible. Likewise, mid-stream companies may have to sell to their customers at "hub-plus" prices in order to create the margin which will remunerate the financial risks inherent in their long term contracts.

It remains unclear whether the demand aggregation role of the mid-stream companies – i.e. the fact that they have a large portfolio of gas supplies and customers, which can guarantee security of demand for producers/exporters and security of supply for end-user buyers – is of sufficient value to sellers and buyers to justify the hub-minus/hub-plus commercial framework which could constitute a viable new business model for mid-stream companies. The former `merchant transmission companies' have become adept at building a trading portfolio capability to hedge against long term contract liabilities, but for contracts which are still oil-indexed, this is likely to be an exercise in loss limitation rather than profit generation. These companies have developed the trading skills necessary to operate on the gas hubs – but this trading optimisation function is possible without an underlying physical supply business. It may be that a physical business provides greater understanding of demand and supply events which enhances trading performance, but improved data transparency reduces this advantage. In any event, as competitive pressure reduces sales margins, none of these functions may constitute a sustainable and profitable business model which remunerates mid-stream companies for the risks inherent in their long term contracts arising from their pricing or take or pay (volume) obligations.

[129] In relation to renewables, this may not affect plant which has been built, but may slow the building of new facilities.

This raises the question of the value – and hence the future – of long term contracts in a market where they may be increasingly viewed as liabilities rather than assets. While they may be necessary for new greenfield supply and infrastructure, such as the Shah Deniz 2 development and the TANAP and TAP pipelines, the relatively small volume exposure and `hub-minus' price terms in these contracts are indicative of the new commercial realities of the competitive market. While network companies receive guaranteed rates of return on new infrastructure via long term auction commitments, there is no similar guarantee for buyers of new gas. In the era of steadily rising gas demand (up to the mid-2000s) this was not such a big problem; indeed the bigger problem was seen as security of supply defined as insufficient long term supply to meet demand.[130] With static or falling gas demand in most European countries this will not become a problem for the market as a whole, until demand begins to increase – or domestic production declines – to the point where new imports are needed and long term security returns to the agenda. But these are, or at least may be, problems of the future, whereas the commercial problems of long term legacy contracts in liberalised markets need to be resolved urgently.

[130] Generally referred to in PowerPoint presentations as the "supply gap".

Chapter 3. Summary and Conclusions

The determinants of hub pricing

Hub pricing and liberalisation and competition are secular trends which are dominant in the north west European gas markets and are spreading to the south and east of the Continent. Individual markets – especially in central/south Eastern Europe – may take much longer to adopt hub pricing and open to competition (due to government opposition), or will be too small for serious competition to develop. Such markets however, will ultimately only account for a small proportion of European gas demand.

This study has found that the most important determinants of hub pricing in the future, which will determine price levels over periods of several years, will be global market dynamics. Domestic (European) market dynamics such as weather-related and security events will impact prices for the duration of the event – likely to be weeks, or at most months - but not longer.

We have identified six major uncertainties in global gas market dynamics which will impact European hub prices over the period up to 2020 and beyond:

- Demand for natural gas and LNG in Asia;
- Transition away from JCC pricing in Asian LNG markets;
- Scale and pace of US LNG export approvals and construction;
- Scale of LNG ramp-up from non-US suppliers;
- Shale gas development outside North America;
- Russian response to `overspill' of excess LNG into the European market.

These six major uncertainties emphasise the importance of three key forces acting on European hub prices:

- the supply and price policies of existing European suppliers – especially Russia, Qatar and possibly, but to a lesser extent, Norway;
- the availability of flexible supplies of pipeline gas (principally from Russia) but particularly LNG (particularly from Qatar but also from new suppliers in North America and Asia);
- the development of Asian LNG demand, particularly from China.

Prior to 2009, oil-linked prices provided a reference price for the gas market, but this progressively weakened in the competitive markets of north west Europe as hubs began to take over as the main price formation mechanism. In the period 2011 to end 2013, European hub pricing was influenced by the price needed to attract into the market the marginal tranche of flexible supply, namely Russian pipeline gas contract volumes above take-or-pay levels, which came to be viewed as a price `benchmark' by market players. This price level varies between contracts whose details are not publically disclosed; and has been the subject of numerous price concessions and latterly a combination of base price reductions and rebates in order to maintain competitiveness with hub-prices. It has therefore become progressively more difficult to define this price for use as a benchmark. In the first half of 2014, a mild Winter (reducing European demand by 51 Bcm compared to that of 2012/2013) and consequent high Spring 2014 storage levels, combined with a redirection of cargoes into Europe and away from Asia (as Asian LNG spot prices softened) led to a dramatic fall in European hub price levels. This can be rationalised as the consequence of the traded market believing that Europe would not require Russian gas above contract take or pay levels, at least until the end of 2014; prices in the meantime being the result of short term supply and demand[131]. However, if Gazprom continues its combination of base price reductions and rebates to its customers, resulting in an effective price paid for long term contract gas equal to hub prices (even at levels of €18/MWh), then the Russian pipeline contract price might no longer be relevant as a benchmark for European hub prices. If buyers of Russian pipeline gas under contract:

- continue nominating volumes , confident that rebates from Gazprom will keep them financially 'whole;

rather than

- holding back nominations at minimum take or pay levels until hub prices reach 'pre-rebate' Russian contract prices,

then the benchmark of pre-rebate Russian contract prices may more correctly be viewed as a `ceiling' for European hub prices.

If this is the case, and from 2014 forward European hub prices are set purely on the basis of supply and demand, with Gazprom continuing its rebate policy (in order to avoid new arbitrations with its customers), then Gazprom must move into a mode of supply management in order to support hub prices. This would entail the purchase of volumes at hubs and re-delivery to contract customers to meet a part of contract nominations, the balance being physical gas supplied from West Siberia. While this would be a radical departure from Russia's public stance regarding gas hubs and trading in general, Gazprom demonstrably has the capability to execute such a strategy within its sizeable trading operation.

Having surveyed this landscape and its uncertainties, we think it likely that:

- to the end of 2015, Europe will rely to a greater extent on Russian pipeline imports (subject to weather trends) due to continued LNG diversion to Asia;
- in the period 2016-18, the LNG market should ease depending on the pace of Japanese nuclear re-starts, start-up of Australian LNG projects and Chinese demand growth;
- post-2018, the global market becomes very unpredictable with potentially large volumes of US LNG and new projects from Australia, Canada, East Africa and Russia. Overspill of 'excess LNG' into Europe could trigger Russia to utilise its considerable spare production and export capacity to reduce European hub prices in an attempt to keep LNG out of Europe (which may not succeed), but…
- should US shale production costs increase (reducing US LNG export volumes), and higher project costs slow the pace of non-US LNG projects, (especially if combined with higher Chinese LNG demand), this would lead to the possibility of a tighter global LNG market in the early 2020s, with very significant impacts on European hub prices.

Gas market players: changing roles and risks

Changes in prices and contracts in the new competitive environment of European gas markets have fundamentally changed the roles and risks of the major groups of gas market players.

Producers and Exporters International oil companies (IOCs) and European pipeline exporters will tend to sell gas at hubs, but may continue to supply larger customers on up to 10 (but probably 1-5) year, hub-related contracts with significant volume flexibility. They will vertically integrate down the supply chain only as far as local distribution companies (LDCs) and large industrial/power generation customers. Non-European exporters such as Gazprom and Sonatrach will continue to seek more traditional contractual structures but, at least in competitive markets, are unlikely to be successful.

[131] In addition to concerns regarding the Russia-Ukraine situation.

The roles and risks of producers and exporters have changed somewhat – in relation to the need to trade more short term gas in their sales portfolio – but their traditional business model remains essentially intact. A major issue still to be determined is the extent to which these players have the incentive and ability to sell their entire supply portfolio directly to large customers and at hubs, without the need to involve midstream energy companies. The latter will clearly play a significant role while long term contracts continue to exist, and it seems unlikely that sellers of very large volumes – such as Gazprom – will want to create the organisational capacity to sell all of those volumes. Moreover, as the Shah Deniz 2 experience has shown, new greenfield projects involving large capital expenditures continue to require traditional long term (20-25 year) contracts for small volumes with mid-stream companies and portfolio traders.

Network companies (TSOs and DSOs) have a well-defined role as owners and/or operators of transmission and distribution assets with long term ship or pay contracts for a large part of existing capacity, and a regulated rate of return which limits their risks on new capacity. However, they will be exposed to two new types of risk: the first arising from the new EU tariff network code (which will be in force by October 2017) which may fundamentally change the profitability of earnings from existing assets. And the second, arising from the first, that when their long term ship or pay contracts expire, shippers are likely to book capacity on much shorter term horizons which will increase financial risks for network companies (albeit in relation to fully amortised assets).

Local distribution companies will retain (most of) their current roles, although they may lose their larger customers, but their traditional business model is still workable, unless:

- they lose a much greater proportion of their customer base through customers switching to new entrant retail suppliers than has been seen thus far;
- their previous business involved substantial cross-subsidy of other municipal services with profits from their gas (and power) businesses which have become substantially smaller due to supply competition and regulation of network tariffs.

Mid-stream energy trading (former merchant gas transmission) companies have the biggest problems in that their traditional business model has become partially obsolete, particularly in competitive markets. They are in the process of:

- Reducing the contractual exposure of oil price indexation which cannot be fully hedged through trading portfolio management.
- seeking to move the prices in their long term supply contracts from oil-indexation to `hub-minus' for the remainder of the contract, to avoid the time and resource consumed by annual renegotiations and threats of arbitration;
- attempting to reduce risk exposure to loss of customers and loss of margins;
- exploring options for the replacement of their long term contractual commitments as these expire;
- assessing the impact of the Third Package and entry/exit pricing on their long term ship or pay contracts

This represents a transitional phase in the evolution of roles and business models of mid-stream energy companies, and it remains to be seen whether the outcomes are successful. Ultimately, midstream energy companies need to demonstrate that the aggregation – i.e. the ability to retain and manage a large demand portfolio - and flexibility service which they can offer to producers and end-users (which have the right, but may not have the skills or desire to carry out these tasks themselves) merits paying hub-minus to producers and charging hub-plus prices to end-users, which will allow them to continue to operate profitably as merchants. But they also need to address problems in relation to legacy ship or pay contracts which are potentially incompatible with entry/exit pricing and auctions. The under-utilisation of transportation infrastructure (partly due to the fall in demand) has created a problem of stranded costs for midstream companies holding long term ship or pay contracts for capacity. As we have noted above, the financial situation of TSOs becomes more precarious following the expiry of these contracts, but the proposition that “if you don’t use it, you don’t pay for it”, would accelerate this process.

Implications of these conclusions for the future of European gas markets

Critical questions for the future are:

- whether hub liquidity continues to increase, and with it the sophistication of financial products which will enable long term contract risks to be adequately managed;
- whether the remuneration for providing aggregation services to producers (security of demand), and customers (security of supply) is sufficient to support a long term business model and if not…
- whether consolidation in the mid-stream sector will create a sustainable business model for a smaller number of players.

It is unclear how these trends will develop over the next several years, but we suggest three possible scenarios:

Scenario 1: Prices in existing and new (long and short term) supply contracts are adjusted – with producers receiving hub-minus, and end-users paying hub-plus prices – such that midstream players can restore their profit margins. This requires producers and end-users to accept that there is intrinsic commercial value in the aggregation – security of demand/security of supply – roles played by mid-stream companies. Under this scenario, mid-stream companies retain their intermediary role in the value chain. They may lose customers to each other in the competitive arena, and also some customers to direct sale and purchase relationships between producers/exporters and end-users, with the loss of customers probably limited to the large industrial and power generation sectors and some LDCs.

Scenario 2: The hub-minus/hub-plus framework in Scenario 1 either does not work (because too few producers/exporters and end-users see greater commercial advantages in such an arrangement) or margins are so slim that they only allow mid-stream energy companies to avoid losses, which is not a sustainable business model. In markets with little (if any) growth and increasing competition, mid-stream energy players cannot restore profit margins, with the result that many are forced to exit the natural gas business. The market consolidates to the point where a smaller number of mid-stream players can earn acceptable returns by performing an aggregation function for the share of the market which does not (for whatever reason) wish to trade directly, and is prepared to accept a discount to (in the case of sellers), and pay a premium over hub prices (in the case of buyers) for this service.

A potentially important consequence of Scenario 2 is that it seems unlikely that the mid-stream companies will retain sufficient sales volume to allow existing long term supply and capacity contracts to continue, even into the 2020s let alone the 2030s. As companies exit the sector, so their long term – both supply and capacity – contracts either need to be passed to others or lapse (with uncertain legal consequences). Another consequence is that the share of the gas market for which any group of players feels a responsibility to provide security, will be at best severely diminished and may have ceased to exist. Regulators which are tasked with enforcing security of supply (as opposed to infrastructure) standards will need to be clear about how market players are to be remunerated to provide this service.

Scenario 3: Concern on the part of governments and regulators about security of supply implications of Scenario 2 may create the conditions for a third scenario. Alarm about the threat to the existence of mid-stream players – and the consequences for security of supply and long term (supply and transportation) contracts – may lead governments in some countries to take measures to ensure minimum commercial profitability (and hence survival) of these players. There are different ways in which this could be achieved, including limiting the potential for competition, and creating revenue via levies on prices and tariffs. Not all governments will choose this option but because, at the time of writing, Scenario 2 appears more likely than Scenario 1, at least in some countries, governments may have to make quick decisions about whether to implement Scenario 3 to protect what were previously (and may still be) regarded as flagship national companies.

If these conclusions are even directionally correct, the second half of the 2010s appears likely to be an extremely turbulent period for European gas markets. Finding a new contractual equilibrium will be extremely difficult but the default position for most players may be the availability and liquidity of hubs on which to sell or source gas on the day at transparent prices. The key question is whether, even if long term contracts can be moved to hub-minus prices and the annual threat of renegotiations/arbitrations can be eliminated (Scenario 1), this can be a stable commercial situation which promises acceptable profitability for mid-stream players. If not, it raises the question as to whether existing long term supply contracts – even if moved to hub-minus prices – can survive into the 2020s (let alone the 2030s).

Some of the problems which have been identified might be eased by a move to a new price equilibrium in the range of €16-20/MWh ($6-8/MMbtu) similar to that of summer 2014. This might allow gas to regain market share and could reduce some of the competitive pressures in what have been, since 2008, a set of markets where gas demand has declined significantly. However, this could place any producers planning to supply new gas to Europe in difficulties. In general, the turbulence which European gas markets have experienced since 2008 shows no signs of abating. Markets are still in transition and, in those countries where competition has been slower to develop, it may be several years before players experience the type of pressures we have identified above. Resolution of problems in markets where these pressures are already evident and acute may point the way to the future.

Glossary

ACQ: Annual Contract Quantity

BAFA: The German Federal Office of Export Control who publish border prices for natural gas at: http://www.bafa.de/bafa/de/energie/erdgas/index.html

Bcm: one billion cubic metres.

Bcma: one billion cubic metres per annum

Bunkers: Fuel tanks used in ocean going ships

DG COMP: EU Director General for Competition

DSO: Distribution System Operator

EE zone: Entry-Exit Zone for gas transmission

Exchange: Computer-based trading platform

FTA, Non-FTA: Relating to countries with which the US has (or has not) a Free Trade Agreement

Gasoil: an oily liquid obtained in the fractional distillation of petroleum, boiling between the kerosene and lubricating oil fractions: used esp. as a diesel fuel and heating oil

Gaspool: A German gas trading hub

GFU: The former Norwegian joint gas marketing body

GTM: Gas Target Model

Hub, Hubs: A point at which gas is traded, either a physical or virtual location.

IP: Interconnection point between two hub zones

IUK: the shorthand name for the Bacton (UK) to Zeebrugge (Belgium) bi-directional gas pipeline. Import capacity 25.5 bcma, export capacity 20 bcma.

JCC – Japanese Customs-cleared Crude Oil Prices – an internationally recognised crude oil price marker, sometimes referred to as the Japan Crude Cocktail.

JKM: Japan Korea Market: a price quoted by Platts for spot LNG cargoes.

Langeled Pipeline: The 725 mile pipeline from the Nyhamna terminal in Norway via the Sleipner Riser platform in the North Sea to Easington Gas Terminal in England. Its capacity is 25.8 bcma.

LDC: Local Distribution Company

Liquefaction Tolling Fee: The price charged for the use of liquefaction facilities.

LNG – Liquefied Natural Gas

Mmbtu: Million British thermal units

MTC: Merchant Transmission Company

MWh: A unit of energy equivalent to a Megawatt of power over the duration of one hour

NBP – National Balancing Point – the UK's virtual gas trading hub.

NDRC, National Development Reform Commission

NGC: Net Connect Germany – a German gas trading hub

OTC: Over the Counter trading facilitated by brokers

PEG Nord: A French gas trading hub

PEG Sud: A French gas trading hub

PSV: The Italian gas trading hub.

Residual Fuel Oil: A heavy fuel oil produced from the residue of the fractional distillation process

Take or Pay (TOP): sometimes called the 'minimum bill', this is the quantity of gas which, during a gas contract year, customers are obliged to pay for regardless of whether they physically take it for use or resale or not.

TANAP: The Trans Anatolian Gas Pipeline

TAP: the Trans Adriatic Pipeline is a proposed project to transport natural gas from the Caspian and Middle East regions via a new gas transportation route starting in Greece via Albania and the Adriatic Sea to Italy and further to Western Europe.

TSO: Transmission System Operator

TTF: The Dutch gas trading hub

TWh: A unit of energy equivalent to a Terawatt of power over the duration of one hour

Bibliography

ACER/CEER (2013), *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2012*, http://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202013.pdf

Aissaoui, A. (1999), `Algerian Gas: Sonatrach's policies and the options ahead', in Mabro and Wybrew-Bond (1999), Chapter 2.

Alterman, S. (2012). `Natural Gas Price Volatility in the UK and North America', NG60, OIES, http://www.oxfordenergy.org/2012/02/natural-gas-price-volatility-in-the-uk-and-north-america/

Arentsen, M.A, and Kunneke, R.W. eds. (2003), *National Reforms in European Gas*, Oxford: Elsevier.

BAFA. The German Federal Office of Economics and Export Control, providing German border price data at http://www.bafa.de/bafa/de/index.html

Bartsch, U. (1999), `Norwegian Gas: the struggle between government control and market developments', in Mabro and Wybrew-Bond, eds. (1999), Chapter 5.

BP Statistical Review of World Energy (various years), for which data is also provided in spreadsheet format at http://www.bp.com/en/global/corporate/about-bp/energy-economics/statistical-review-of-world-energy/statistical-review-downloads.html

Bros, T. (2014), `Putting a Price on Gas or Putin's Gas Price'; Société Générale Cross Asset Research, 19 March 2014.

CEER (2011), `Vision for a European Gas Target Model. Conclusions Paper', Ref: C11-GWG-82-03, http://www.ceer.eu/portal/page/portal/EER_HOME/EER_CONSULT/CLOSED%20PUBLIC%20CONSULTATIONS/GAS/Gas_Target_Model/CD/C11-GWG-82-03_GTM%20vision_Final.pdf

Chen, M.X. (2014), `The Development of Chinese Gas Pricing: drivers, challenges and implications for demand', NG89, OIES, http://www.oxfordenergy.org/2014/07/the-development-of-chinese-gas-pricing-drivers-challenges-and-implications-for-demand/

Corrleljé, A., van der Linde, C., and Westerwoudt, T. (2003). *Natural Gas in the Netherlands: from cooperation to competition?* Amsterdam: Oranje-Nassau Groep.

Darbouche, H. (2011). `Algeria's Natural Gas Market: origins and constraints of export strategy', in Fattouh, B. and Stern J.P., eds. *Natural Gas Markets in the Middle East and North Africa*, (Oxford: OIES/OUP), Chapter 1, pp.12-47.

Estrada, J., Bergeson, H.O., Moe, A. and Sydnes, A.K. (1988), *Natural Gas in Europe: markets, organisation and politics*, London: Pinter.

EIA. The US Energy Information Administration which provides detailed energy statistical data at http://www.eia.gov/

EU (2007), *DG Competition Report on Energy Sector Inquiry* (2007), Brussels, 10 January 2007, SEC(2006) 1724. http://ec.europa.eu/competition/sectors/energy/inquiry/

Flower (2011), ' LNG in Qatar' in Fattouh, B. and Stern J.P., eds. *Natural Gas Markets in the Middle East and North Africa*, (Oxford: OIES/OUP), Chapter 10, pp.343-385

Foss, M.M. (2007), `US natural gas prices to 2015', NG18, OIES, http://www.oxfordenergy.org/2007/02/united-states-natural-gas-prices-to-2015/

Foss, M.M. (2011), `The Outlook for U.S. Gas Prices in 2020: Henry Hub at $3 or $10?', NG58, OIES, http://www.oxfordenergy.org/2011/12/the-outlook-for-u-s-gas-prices-in-2020-henry-hub-at-3-or-10/

Futyan, M. (2006). `The Interconnector Pipeline: a key link in Europe's gas network', OIES, http://www.oxfordenergy.org/2006/03/the-interconnector-pipeline-a-key-link-in-europe%e2%80%99s-gas-network/

Gao, F. (2012), `Will there be a shale gas revolution in China by 2020?', NG 61, OIES, http://www.oxfordenergy.org/2012/04/will-there-be-a-shale-gas-revolution-in-china-by-2020/

Geny, F. (2010), `Can Unconventional Gas be a Game-Changer in European Gas Markets?' NG46, OIES, http://www.oxfordenergy.org/2010/12/can-unconventional-gas-be-a-game-changer-in-european-gas-markets/

GIIGNL. Annual reviews of the LNG industry containing import and other statistics. http://www.giignl.org/

Haase, N. (2008). `European Gas Market Liberalisation: are regulatory regimes moving towards convergence?' NG24, OIES, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2010/11/NG24-EuropeanGasMarketLiberalisationArerRegulatoryRegimesMovingTowardsConvergence-NadineHaase-2008.pdf

Haase, N. (2009), *European Gas Market Liberalisation*, (Groningen: Energy Delta Institute).
Heather, P. (2010). 'The Evolution and Functioning of the Traded Gas Market in Great Britain', OIES, http://www.oxfordenergy.org/2010/08/the-evolution-and-functioning-of-the-traded-gas-market-in-britain/

Heather, P. (2012). `Continental European Gas Hubs: Are They Fit For Purpose?' NG63, OIES, http://www.oxfordenergy.org/2012/06/continental-european-gas-hubs-are-they-fit-for-purpose/

Heather, P. (2015). 'The Evolution of European Gas Trading Hubs', OIES Forthcoming.

Henderson, J. and Heather, P. (2012), `Lessons from the February 2012 Gas 'Crisis'', OIES Energy Comment, http://www.oxfordenergy.org/2012/04/lessons-from-the-february-2012-european-gas-%E2%80%9Ccrisis%E2%80%9D/

Honoré, A. (2011a). `Economic Recession and Natural Gas Demand in Europe: what happened in 2008-10? NG 47, OIES, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/01/NG47-EconomicRecessionandNaturalGasDemandinEurope-whathappenedin20082010-AnoukHonore-2011.pdf

Honoré, A. (2011b). `The Spanish Gas Market: demand trends post-recession and consequences for the industry', NG55, OIES, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/08/NG_552.pdf

Honoré, A. (2013). The Italian Gas Market: Xhallenges and Opportunities, NG 76, OIES, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/06/NG-76.pdf

Honoré, A. (2014). `The Outlook for Natural Gas Demand in Europe', NG87, OIES, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2014/06/NG-87.pdf

IEA (1998), *Natural Gas Distribution: focus on Western Europe*, OECD/IEA.

IEA (2013), *World Energy Outlook 2013*, OECD/IEA.
http://www.worldenergyoutlook.org/publications/weo-2013/

IEA Monthly Data Series. This is a subscription service for monthly data on European natural gas demand, production, imports, exports and national stock levels. When released, data is usually three months old. http://data.iea.org/ieastore/statslisting.asp

IGU (2014), *Wholesale Gas Price Survey – 2014 Edition: a global review of price formation mechanisms 2005-2013*, International Gas Union. http://www.igu.org/sites/default/files/node-document-field_file/IGU_GasPriceReport%20_2014_reduced.pdf

JRC (2012), *Unconventional Gas: Potential Energy Market Impacts in the European Union, Joint Research Centre*, Scientific and Policy Paper Report, European Union.
https://ec.europa.eu/jrc/en/publication/eur-scientific-and-technical-research-reports/unconventional-gas-europe-potential-energy-market-impacts

Kemp, A. (2012a). *The Official History of North Sea Oil and Gas, Volume 1: the growing dominance of the State*, Routledge.

Kemp, A. (2012a). *The Official History of North Sea Oil and Gas, Volume 2: moderating the State's role*, Routledge.

Le Fevre, C. (2013). `Gas storage in Great Britain', NG72, OIES,
http://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/01/NG-72.pdf

Le Fevre, C. (2014). 'The Prospects for Natural Gas as a Transport Fuel in Europe', NG84, OIES,
http://www.oxfordenergy.org/2014/03/the-prospects-for-natural-gas-as-a-transportation-fuel-in-europe/

Lohmann, H. (2006). The German Path to Natural Gas Liberalisation: is it a special case? NG14, OIES, http://www.oxfordenergy.org/2006/01/the-german-path-to-natural-gas-liberalisation-is-it-a-special-case/

Mabro, R. and Wybrew-Bond, I. eds. (1999), *Gas to Europe: the strategies of the four major suppliers*, Oxford: OIES/OUP. http://www.oxfordenergy.org/shop/gas-to-europe-the-strategies-of-four-major-suppliers/

Ofgem (2012), *The Retail Market Review – updated proposals for businesses*. Consultation, 26 October, 2012. https://www.ofgem.gov.uk/ofgem-publications/39457/retail-market-review-updated-domestic-proposals.pdf

Ofgem (2014), *State of the Market Assessment*, 27 March 2014.
https://www.ofgem.gov.uk/publications-and-updates/state-market-assessment

Peebles, M. (1999), `Dutch Gas: its role in the Western European gas market', in Mabro and Wybrew-Bond, eds. (1999), Chapter 3.

Petrovich, B. (2013). `European Gas Hubs – How Strong is Price Correlation?' NG79, OIES,
https://www.oxfordenergy.org/2013/10/european-gas-hubs-how-strong-is-price-correlation-2/

Petrovich, B. (2014), 'European Gas Hubs Price Correlation: Barriers to Convergence?', NG91, OIES,
http://www.oxfordenergy.org/2014/09/european-gas-hubs-price-correlation-barriers-to-convergence/

Pirani, S., Stern, J.P., and Yafimava, K. (2009), 'The Russo-Ukrainian gas dispute of January 2009: a comprehensive assessment', NG27, OIES, http://www.oxfordenergy.org/2009/02/the-russo-ukrainian-gas-dispute-of-january-2009-a-comprehensive-assessment/

Pirani, S. (2014), `Central Asian and Caspian Gas for Russia's Balance', in Henderson and Pirani, eds. (2014), Henderson, J. and Pirani, S. eds. *The Russian Gas Matrix: how markets are driving change*, (Oxford: OIES/OUP) Chapter 14, pp. 347-367. http://www.oxfordenergy.org/shop/the-russian-gas-matrix-how-markets-are-driving-change/

Regulation EU (2010), Regulation (EU) No 994/2010 of the European Parliament and of the Council of 20 October 2010 *Concerning measures to safeguard security of gas supply* and repealing Council Directive 2004/67/EC; Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of Regions on the Directive 2004/67/EC of 26 April 2004 *concerning measures to safeguard security of natural gas supply.* COM(2008) 769 final, Brussels, 13.11.2008.

REMIT (2011), *Regulation (EU) No 1227/2011 of the European Parliament and of the Council on wholesale energy market integrity and transparency*, adopted on 8 December 2011.

Rogers, H.V. (2012) `The Impact of a Globalising Market on Future European Gas Supply and Pricing: The Importance of Asian Demand and North American Supply', NG59, OIES http://www.oxfordenergy.org/2012/01/the-impact-of-a-globalising-market-on-future-european-gas-supply-and-pricing-the-importance-of-asian-demand-and-north-american-supply/

Rogers, H.V. and Stern, J. (2014), `Challenges to JCC Pricing in Asian LNG Markets', NG81, OIES. http://www.oxfordenergy.org/2014/02/challenges-to-jcc-pricing-in-asian-lng-markets-2/

Shah Deniz 2 (2014), *Shah Deniz 2 and the Opening of the Southern Corridor*, BP, http://www.bp.com/content/dam/bp/pdf/Press/shah_deniz_2_brochure_english.pdf

Stern, J.P. (1998). *Competition and Liberalisation in European Gas Markets: a diversity of models*, RIIA/Brookings.

Stern, J.P. (1999), `Soviet and Russian gas: the origins and evolution of Gazprom export strategy', in Mabro and Wybrew-Bond eds. (1999), Chapter 4.

Stern, J. (2007). `Is there a rationale for the continuing link to oil product prices in Continental European long term gas contracts?' NG19, OIES, http://www.oxfordenergy.org/2007/04/is-there-a-rationale-for-the-continuing-link-to-oil-product-prices-in-continental-european-long-term-gas-contracts/

Stern, J. (2009). `Continental European long-term gas contracts: is a transition away from oil product-linked pricing inevitable and imminent?' NG34, OIES, http://www.oxfordenergy.org/2009/09/continental-european-long-term-gas-contracts-is-a-transition-away-from-oil-product-linked-pricing-inevitable-and-imminent/

Stern, J.P. (ed.) (2012). *The Pricing of Internationally Traded Gas*, Oxford: OIES/OUP. https://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/

Stern, J.P. (2012a). `The Pricing of Internationally Traded Gas: an historical survey', in Stern (2012), Chapter 2, pp. 40-84. https://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/

Stern, J. (2014). `Russian Responses to Commercial Change in European Gas Markets', in Henderson, J. and Pirani, S. eds. *The Russian Gas Matrix: how markets are driving change*, (Oxford: OIES/OUP), Chapter 3, pp. 50-81. https://www.oxfordenergy.org/shop/the-russian-gas-matrix-how-markets-are-driving-change/

Stern, J. ed. (2014). `Reducing Dependence on Russian Gas: distinguishing natural gas security from geopolitics', NG92, OIES, http://www.oxfordenergy.org/2014/10/reducing-european-dependence-on-russian-gas-distinguishing-natural-gas-security-from-geopolitics/

Stern, J. and Rogers, H. (2011), `The Transition to Hub-Based Gas Pricing in Continental Europe', NG49, OIES, http://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/03/NG49.pdf

Stern, J. and Rogers, H. (2012). `The Transition to Hub-Based Gas Pricing in Continental Europe', in Stern, J.P. (ed.), *The Pricing of Internationally Traded Gas*, Oxford: OIES, Chapter 4, pp.145-177. http://www.oxfordenergy.org/shop/the-pricing-of-internationally-traded-gas-ed-jonathan-p-stern/

Stern, J. and Rogers, H. (2013). `The Transition to Hub-Based Pricing in Continental Europe: a response to Sergei Komlev of Gazprom Export', OIES: Oxford Energy Comment. http://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/02/Hub-based-Pricing-in-Europe-A-Response-to-Sergei-Komlev-of-Gazprom-Export.pdf

Timera Energy (2013), `A Framework for Understanding European Hub Pricing', http://www.timera-energy.com/uk-gas/a-framework-for-understanding-european-gas-hub-pricing/.

Timera Energy (2013a), `Gas Hub Price Evolution: applying the framework, http://www.timera-energy.com/uk-gas/gas-hub-price-evolution-applying-the-framework/

Talus, K. (2011). *Vertical Natural Gas Transportation Capacity, Upstream Commodity Contracts and EU Competition Law*, Netherlands: Kluwer Law International.

Wright, P. (2006). *Gas Prices in the UK: markets and insecurity of supply*, Oxford: OIES/OUP. https://www.oxfordenergy.org/shop/gas-prices-in-the-uk-markets-and-insecurity-of-supply/

Yafimava, K. (2011). *The Transit Dimension of EU Energy Security*, Oxford: OIES/OUP. http://www.oxfordenergy.org/shop/the-transit-dimension-of-eu-energy-security-russian-gas-transit-across-ukraine-belarus-and-moldova/

Yafimava, K. (2013). The Third EU Package for Gas and the Gas Target Model: major contentious issues inside and outside the EU, NG75, OIES, http://www.oxfordenergy.org/2013/04/the-eu-third-package-for-gas-and-the-gas-target-model-major-contentious-issues-inside-and-outside-the-eu-2/

Yafimava, K. (2015 forthcoming). 'Building new gas transportation infrastructure in the EU: what are the rules of the game?', OIES Working Paper.