



The Transition to Hub-Based Gas Pricing in Continental Europe

Jonathan Stern and Howard Rogers

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Introduction: the basic argument and its dissenters

This is the third paper which the OIES has published dealing with the issue of price changes in Continental European long term gas contracts. The first paper, published in 2007 questioned the rationale of the continuing linkage of prices in long term gas contracts to those of oil products.[1] The second paper published in 2009 argued that a transition away from oil product-related pricing was inevitable and imminent and that the endpoint of the transition would be hub-based prices.[2] This paper examines the progress of that transition since 2009 and its likely evolution over the next few years.

In the six major Continental European gas markets, the rationale for continued linkage of long-term contract gas prices to those of oil products began to weaken during the 1990s, a process which continued during the 2000s.[3] Its original rationale – that end-users had a real choice between burning gas and oil products, and would switch to the latter if given a price incentive to do so – was robust when the netback market pricing mechanism (largely) based on oil product-linkage was established in the 1970s (and earlier in some countries).[4] But a combination of:

- the virtual elimination of oil products from many stationary energy sectors in these markets;
- the cost and inconvenience of maintaining oil-burning equipment and substantial stocks of oil products;
- the emergence of modern gas-burning equipment in which the use of oil products means a substantial loss of efficiency;
- tightening environmental standards in relation to emissions, particularly sulphur content and nitrogen oxide;

rendered the original rationale increasingly dubious, particularly in North West Europe.[5] There is no commercial scenario in which users installing *new* fuel-burning equipment will choose to use oil products rather than gas in stationary uses, unless they have no access to a gas supply.[6]

During 2008-10, as the gap between hub-based and oil-linked prices first widened and then narrowed, the rationale for retaining oil-linked gas pricing in Continental European long term gas contracts was replaced by a number of different arguments:

[1] Stern 2007.

[2] Stern 2009.

[3] Stern 2007 and Stern 2009.

[4] For the history of this mechanism and its logic see Stern 2007 and Energy Charter Treaty.

[5] The position of some smaller markets, especially in South Eastern Europe, is different as they are still burning significant quantities of oil in stationary sectors and have retained greater switchable capacity, see Kovacevic 2007 and 2009 and Giamouridis.

[6] However, they may choose to use other alternatives to gas with the main battleground being in power generation between gas, coal and low carbon (renewable and nuclear) sources. But none of these sources will have prices set in relation to oil products.

- that producers with market power strongly favour oil-linked prices and do not want to change[7];
- That the pricing problems encountered post-2008 were of a temporary nature due to economic recession and that hub and oil-linked prices would "recouple" by 2012;
- that no other appropriate pricing mechanism is available, and specifically that European gas hubs are both insufficiently liquid and prone to manipulation by local market players to be considered an appropriate price reference;
- that abandoning oil-linked prices could lead to price manipulation by a handful of major suppliers – specifically Gazprom – with the possible establishment of a "Gas-Opec".

This paper addresses these arguments, focusing on commercial developments since late 2009, and the likely unfolding of the transition in relation to prices and contracts.

The many factors bearing on European gas prices: 2008-11

The period since late 2008 has seen the emergence of a "two price", but what could arguably be called a "hybrid price", market. This is shown in Figure 1 which compares three different price series:

- The purchase price in German long term contracts mainly with Gazprom, Statoil and Gasterra as determined by the formulae in those contracts based (largely) on fuel oil and gasoil;
- The BAFA – or average price for all German gas imports – reported monthly by the German Federal Office of Economics and Export Control. Given the confidentiality requirements of the European gas business, this is the only transparent *official* price available for European oil-linked long term gas contracts.[8]
- The UK NBP hub price.

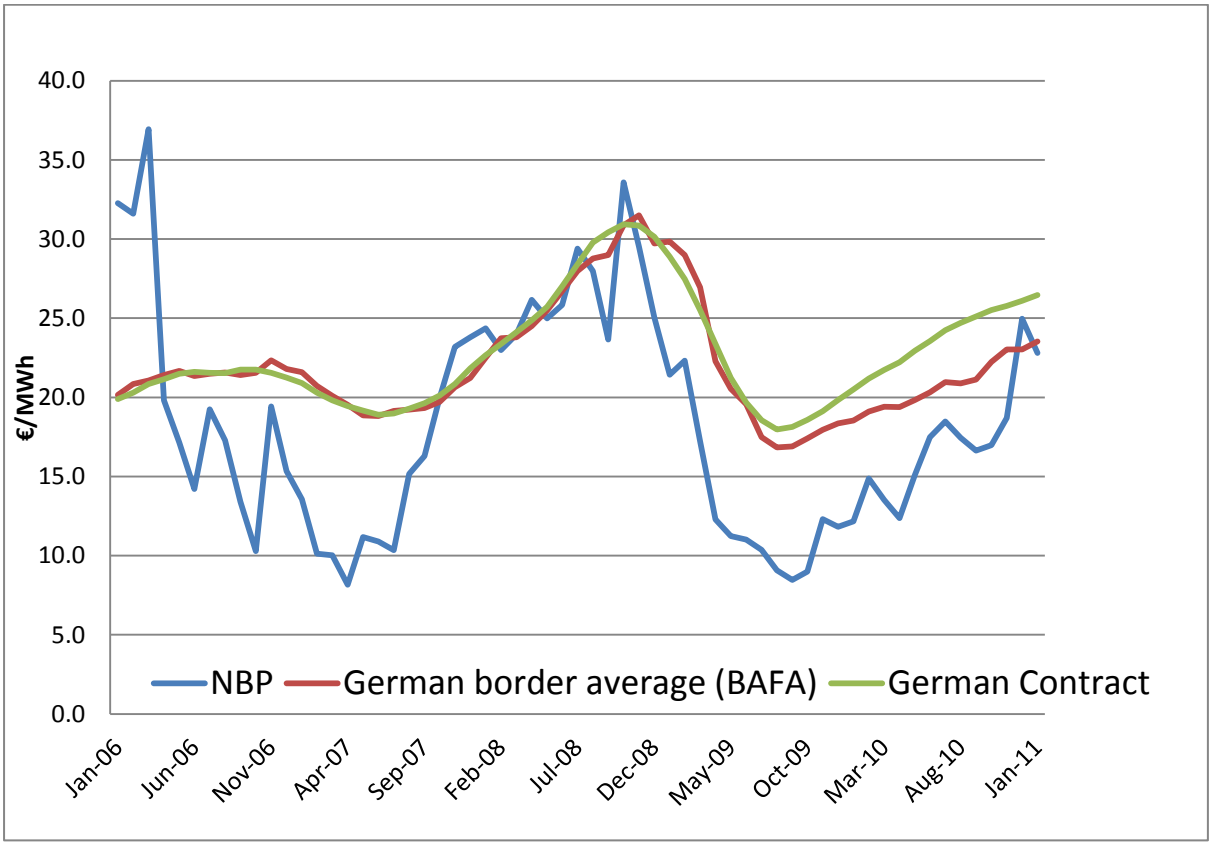
Figure 1 shows that until the middle of 2009, the German contract and German border prices were very similar, showing that very little gas was imported into Germany at other than at oil-linked levels. However from mid-2009, a gap opened up between the two prices which, by mid to late 2010, was 3-4 Euros per MWh or 10-15% below the price according to the fuel oil/gasoil denominated formulae in the long term contracts.

Figure 1 also shows that the NBP price – which is not an exact proxy for all hub prices across Europe, but is usually within one Euro of other North West European hub prices (TTF, NCG, Gaspool, Zeebrugge, PEGs) - diverged substantially from oil-linked prices in late 2008 with an increasing gap in 2009.[9] In late 2010, the gap between NBP and German BAFA prices narrowed and for a brief period at the end of the year spot prices rose above BAFA, but the gap between NBP and German contract prices remained significant. By the first quarter of 2011, with crude oil prices rising above $100/bbl, it was reasonable to assume that the market

[7] The market power argument is well made in Finon 2008.
[8] There are of course many estimates by price reporting services such as Platts, Argus, ICIS-Heren and others.
[9] For an analysis of the pre-2008 period see Stern 2009.

price – ie the price determined by the forces of supply and demand - for gas in North West Europe lay somewhere between NBP and BAFA price levels.

Figure 1: German oil-linked contract and border prices and NBP prices (Euro/MWh)



Source: Howard Rogers, OIES

An alternative methodology for estimating price differentials is provided by Platts, (Table 1) which shows an estimated average of long term oil-linked prices compared with hub prices. The NWE GCI price is probably higher than the German BAFA price in Figure 1 because the latter includes spot (as well as oil-linked) gas imports; and the Dutch TTF usually trades at a slight premium to the UK NBP price in Figure 1. But Table 1 shows that during 2010, the arithmetic average of daily TTF prices was 25% lower than that of oil-linked prices– with a low of 57% and a high of 92% - demonstrating the problems of those facing demands from customers for market based prices, and vulnerable to competition from those able to offer these prices.

Table 1: European spot gas prices as percentage of oil-indexed gas prices in Euro/MWh

	TTF average	NWE GCI	TTF/GCI %
January 2011	22.24	25.84	86
December 2010	24.15	26.13	92
November 2010	19.50	25.98	75
October 2010	18.56	25.54	73
September 2010	18.95	25.07	76
August 2010	18.12	24.21	75
July 2010	19.52	23.55	83
June 2010	19.28	22.62	85
May 2010	16.78	21.80	77
April 2010	13.53	21.56	63
March 2010	11.99	21.00	57
February 2010	13.72	20.74	66
January 2010	14.48	20.02	72
Average 2010	17.38	23.19	75

Source: *Platts European Gas Daily: monthly averages*, January 2011, p.2.

Note: the Table shows TTF day-ahead prices compared with the Platts North West Europe Gas Contract indicator (NWE GCI) which indicates a typical price for long term oil-indexed supplies. The final column shows TTF as a percentage of NWE GCI.

Is an alternative index to oil products possible?

In traditional European commercial gas negotiations it was always assumed that market conditions would be affected by competing fuels, fluctuations in GDP growth rates, inflation, changes in industrial structure, environmental regulations and a range of other country- (or possibly region-) specific conditions. These changes were dealt with by means of a "price review" clause which allows the base price (Po) and the indexation formula to be "reset" generally every three years.[10] Prices are generally reset – according to the contractual formula – quarterly, based on an average of (mainly) oil-product prices in the preceding 6-9 months, often with a lag of three months. Thus in traditional long term gas contracts, the buyer will be paying a price in the first quarter of a year related to an average of oil-product prices in the first two or three quarters of the previous year. And (as we shall see below) there is very limited opportunity to make fundamental changes to the price formula more frequently than allowed by the three-year review.

While these rigidities caused some problems in the period before 2008, since that date negotiations have become substantially more difficult because of the evolution of different prices noted above, but also because of the "globalisation" of gas (and other energy) markets which means that movements in supply, demand and prices elsewhere in the world have much more immediate impacts on European gas prices than was previously the case. Some examples of this since 2008 have been:

[10] Exactly which parameters can be reset, and by how much, is specific to each contract. These provisions are described in more detail in the Energy Charter Treaty, p. 157-161. For more details of commercial contractual terms, see Melling, Appendix 6.

- The 2008-09 global recession which (with a few exceptions) created a sharp downturn in demand for gas followed by an uneven recovery.[11] This was especially important in Europe itself and;
- in Asia where demand in the established LNG markets of Japan, Korea and Taiwan collapsed in 2009 but recovered very substantially in 2010. Demand in the new markets of China and India was significantly less affected by recession[12];
- The unexpectedly rapid development of unconventional (primarily shale) gas production in North America which caused Henry Hub prices to fall to much lower levels than had previously been thought possible, reducing US LNG imports to levels far below both expectations and existing import capacity;
- Substantial fluctuations in international coal prices which caused equivalent fluctuations in gas demand particularly in the power generation sector;
- To a lesser extent (and primarily for power generation customers), short term power and carbon prices leading to changes in the "spark spread" and "dark spread".

All of this has meant that, since 2008, the commercial environment in which European gas companies have been operating has been subject to a number of new (and difficult to predict) forces which have exacerbated the problems of reliance on the relatively rigid oil-linked price formulae in long term contracts. One of the most significant forces was the impact of the 2009-2010 growth in global LNG supplies, compounded by the shale gas "revolution" in North America.[13] Moreover, the different elements of supply and demand have been constantly changing.

The proponents of the 'status quo', (i.e. those unwilling to countenance replacing the current oil-linked pricing with an alternative formula), claim that there are too many new parameters – which are changing too quickly and unpredictably – to construct an alternative index which will be sufficiently stable while reflecting changing market conditions over time. On the contrary, in a world where LNG connects regions and Europe's gas market fundamentals are impacted by events on other continents, the need for a price formation mechanism which responds rapidly to such changes is becoming crucial. This is why – with all of their imperfections (which will be discussed below) – the emerging European gas hubs provide the best indicator of a market price which long term contracts increasingly need to reflect.

Market based gas prices: confusion between price formation and price level

The argument of this paper is that European long term contracts need to move away from oil-linked prices to market prices in order to accurately reflect changing supply and demand conditions; and that hub prices provide the only viable reflection of those conditions. This is principally an argument about price *formation* and the adoption of a mechanism which more

[11] For a detailed assessment of the impact of recession on European gas demand see Honore 2011.

[12] In India, LNG import growth in 2010 was curtailed primarily by increasing domestic gas production.

[13] For background on the globalisation of LNG see Rogers, and for background on North American shale gas see Geny.

closely reflects rapidly and continuously changing supply and demand conditions in European gas markets. Unfortunately, this argument is often construed as an argument to move to a price level which will always be lower than oil-linked prices ie that market prices mean "low" prices. Given the period between late 2008 and mid 2010, when spot prices in North West Europe were at times up to 50% below oil-linked levels, this is an understandable interpretation, but one which is fundamentally incorrect. As December 2010 showed, it is entirely possible that hub prices can approach oil-linked prices (Figure 1). Indeed there is no reason – in theory, as well as in practice – why market prices could not exceed oil-linked levels depending on supply and demand conditions in oil and gas markets.[14] It is therefore important to be clear that proposing a move from oil-linked to hub-based prices does not embody any assumption that the latter will always be lower than the former. The key propositions are that:

- conditions in the gas (rather than the oil) market should set gas price levels;
- gas and oil prices will not "recouple" because their supply/demand dynamics are fundamentally different;
- there should be a single price formation mechanism for gas rather than the hybrid pricing which emerged post-2008.
-

In other words we believe the co-existence of oil-linked and hub-based pricing is unsustainable, and that the latter is the best available indicator of supply and demand conditions in the gas market.

Gas Market developments during 2009-10

The 2009 paper concluded that a transition away from oil linked pricing in European long term gas contracts was inevitable and imminent. In that paper it was suggested that the only way this transition could be halted would be for one or more of the following trends to become reality:[15]

- European economic recovery would need to be sufficient to see energy and gas demand returning rapidly to 2007 levels in order to absorb the supply surplus. This has not yet happened although there was a significant recovery of demand in 2010, mainly due to a very cold winter.[16]
- US Henry Hub prices would need to rise significantly above NBP prices – possibly as a result of falling domestic production – which would direct surplus LNG towards the US and away from Europe. This did not happen; domestic US production levels were maintained principally due to shale gas development. Henry Hub prices – which are

[14] See Stern 2009 (Chart 3) for a discussion of exactly this situation in the UK in 2006 when NBP prices rose far above oil-linked levels for a prolonged period.

[15] Stern 2009, pp.14-15.

[16] Honore 2011.

the benchmark for spot prices across North America - fluctuated in the range of $3-6/MMBtu during 2010 compared with European hub prices of $7-10/MMBtu and oil-linked prices significantly above those levels. Because it was so much more profitable to deliver LNG to Europe, only 13.1 Bcm and 12.3 Bcm of LNG was delivered to the US in 2009 and 2010 respectively compared with a regasification capacity of around 130 Bcm/year.[17]

- Asian LNG demand – specifically from China and India – would need to rise significantly, again diverting LNG away from Europe. This did happen especially in the established markets of Japan, Korea and Taiwan, as well as in China. In 2010, Asian LNG demand rose by 18%, removing perhaps half of the global LNG surplus.
- The anticipated surge of LNG supplies in 2009-10 needed to be delayed by technical or political problems. This did, to some extent, happen because of technical problems with the new Qatari LNG trains, and because of high domestic gas demand in Algeria and Egypt which limited the availability of gas for export. Some have attributed this to deliberate withholding of gas by exporters to support prices (see below).
- International crude oil prices needed to fall below $50/bbl and remain there for long enough to close the gap between spot and long term gas prices to manageable proportions. This did not happen – crude oil prices remained in the range of $75-90/bbl throughout 2010 rising above $100/bbl in the first quarter of 2011.
- A combination of a lack of third party access, insufficient liquidity at market hubs, and the market power of dominant suppliers and buyers was needed to maintain the pricing and contractual status quo. This did not happen to the necessary extent. Liquidity increased at all the European market hubs and, due to improvements in third party access, competition increased and the market power of incumbents declined.
- Not anticipated in the 2009 paper – and a substantial support for gas price levels during 2010 – was the extremely cold weather in the first three, and the last two, months of the year which in many countries broke records established over many decades.[18] This was the major, but by no means the only, factor which over the course of 2010, led European hub gas price levels to converge with the German border (BAFA) oil-indexed price.

As this paper was being completed in March 2011, a huge earthquake and tsunami struck northern Japan which caused around 11GW of nuclear generation capacity to be taken out of service, much of which will be permanently retired. Some part of this capacity will need to be replaced by gas-fired generation which will undoubtedly increase global LNG demand, and create upward pressure on prices.[19] The previous month, political upheaval in Libya caused supplies though the Greenstream pipeline to Italy to be interrupted.[20]

[17] Waterborne 2010 p. 48, Waterborne 2011 p.65, IEA/WEO 2009, p 459.

[18] For example in the UK, January-March 2010 was the coldest such period for 30 years in most parts of the country and December 2010 was the coldest since records began over a century ago.

[19] A less serious earthquake in 2007 removed 8.6 GW of capacity (much of which has been brought back into service). For an analysis of the inter-relationship between LNG and power generation in Japan see Miyamoto.

[20] ENI suspends Libyan gas supplies, *European gas Daily*, February 23, 2011, p.1. These upheavals were followed by external military intervention making it impossible to say when supplies might be resumed given the likelihood of sanctions if the Ghaddafi regime remains in power.

Market-based prices and anticipated supply and demand trends in the 2010s

The mistake of confusing price formation with price level was noted above, as was the fallacy of equating hub-based prices with "low" prices. In the transition to market based prices, the key issue for stakeholders will be whether they can correctly perceive gas supply/demand trends. In particular whether the surplus of supply over demand, which created the hybrid pricing system post-2008, will continue and when the market will tighten and become short of supply.

In 2010, the International Energy Agency (IEA) identified a global "gas glut" and expressed the view that:

> "For as long as the gas glut persists – and our analysis suggests it will for several years – the pressure to move further away from oil indexation will remain, especially for new long term contracts...Contractual price decoupling would not necessarily mean weaker gas prices in the longer term: as the gas glut gradually dissipates, gas prices are likely to come under renewed upward pressure relative to oil prices with the rising cost of supplying gas from remote and difficult locations."[21]
>
> "Based on the projected demand…we estimate that this gas glut...will last longer than many exporters believe or hope keeping pressure on them from their major customers to modify pricing arrangements..This pressure is likely to be greatest in Europe where demand is expected to recover less quickly than in Asia Pacific. Our analysis suggests that it may take several years for the gas glut to be fully eliminated."[22]

OIES research suggests that the IEA may be confusing a glut of gas *transportation capacity* with a glut of *gas*. Using different methodologies, Honore and Rogers both come to the conclusion that oversupply of gas – as opposed to transportation capacity to deliver that gas to Europe – will end sometime during 2012-14. Honore believes that contracted gas is sufficient up to 2014, while Rogers suggests that take or pay levels for pipeline gas will need to be reduced in the early part of the decade but that there will be "a tightening of the system by 2012-13".[23]

These conclusions are the result of exhaustive analysis of country by country European supply and demand (Honore) and global LNG supply/demand analysis (Rogers) which necessarily depend on the interplay of a substantial numbers of macroeconomic and energy/natural gas assumptions. However, they are supported by other OIES research which suggests that, by the second half of the 2010s, incremental gas supply to European markets may be limited due to:

[21] IEA/WEO 2010, p.185
[22] Ibid, p. 195
[23] Honore 2011, p.230; Rogers, Figure 66, p.73 and 80.

- Lack of increased availability from North Africa – Algeria, Egypt and Libya;[24]
- No *substantial* contribution from Caspian and Middle East supplies to Europe until the end of the 2010s;[25]
- No *substantial* contribution from unconventional gas production to offset declining indigenous conventional gas production until the 2020s;[26]
- Uncertainty as to the scale and timing of *new* global LNG supplies from key countries such as Nigeria, Qatar, Australia, Venezuela and Iran, either due to geopolitics, skills resource constraints, or project cost and complexity.[27]

If these conclusions prove to be generally correct then, in the second half of the 2010's incremental European gas supply will need to come from:

- Atlantic Basin-oriented LNG supplies, principally but not exclusively, from Qatar which will be subject to increasing global competition;
- Russian supplies which are considered by many countries to be undesirable due to:
    - security reasons related to transit, principally through Ukraine and Belarus;[28]
    - fears that Russian gas has been, and will in the future be, used as a political weapon against European countries.

A partial counterbalance to this outlook can be found in official energy projections from the European Union and Member States such as the UK, showing that gas demand will have fallen substantially from the levels of the late 2000s due to the introduction of low carbon energy sources and an increase in energy efficiency.[29] If correct, this could mean limited additional import requirements despite peaking and decline of indigenous European production.

The picture which emerges from this somewhat confusing landscape is that, while the early 2010s is likely to be a period of oversupply, by the middle of the decade – and perhaps as early as 2013 – what the IEA refers to as "the gas glut" could disappear and be replaced by a shortage which could become increasingly acute during the late 2010s, until substantial new sources of conventional – and perhaps unconventional – gas become available in the 2020s. This picture may tell us something about the European gas supply/demand balance over the next decade and the expectation that price levels will rise as that balance tightens. However, it says nothing about the relationship of gas prices to oil prices; indeed gas supply and demand fundamentals are likely to be largely independent of oil price levels during this period which, aside from GDP growth levels, will be subject to different dynamics.[30]

[24] See Fattouh and Stern, Chapters 1,3 and 4 and Darbouche. This conclusion was reached prior to the political upheavals in these countries in early 2011.
[25] See Fattouh and Stern, Chapter 15 for Middle Eastern, and Pirani, pp. 401-9, for Caspian analysis.
[26] Geny.
[27] Rogers; in this context "new" means projects for which a final investment decision has not yet been taken.
[28] Yafimava.
[29] EU 2008, Annex 1, p.19; DECC 2009, Chart 7, p.104, and DECC 2010, Figure 4a, p.37.
[30] For a discussion of the changing dynamics of oil price formation, the different oil markets and the relationship between physical benchmarks and financial layers, see Fattouh.

Thus the assertion that, when the gas supply/demand balance tightens, gas prices will "recouple" with oil prices, reflects a fundamental confusion between price level and price formation. A tight supply/demand balance will certainly result in higher prices, but there is no necessary relationship between the latter and oil related price levels.

Hub-based pricing: progress and problems

Trading at Europe's natural gas hubs has made significant progress over the past decade – as shown in Figure 2 – but there are still many questions about whether they have sufficient depth and liquidity to be regarded as acceptable price discovery and reference points. Not shown in Figure 2 is data from the British National Balancing Point (NBP) where trading volumes in 2010 were larger than all of the Continental European hubs combined. This hub can be considered mature with limited growth potential.[31] The "churn ratio" (of traded volume to physical throughput) was estimated at around 15 (and as high as 19) for the NBP in 2010 while none the Continental European hubs rose significantly above 4, and most were in the range of 2-3; the minimum benchmark for a market to be considered liquid is a churn rate of 10, although some consider a higher figure to be more appropriate.[32]

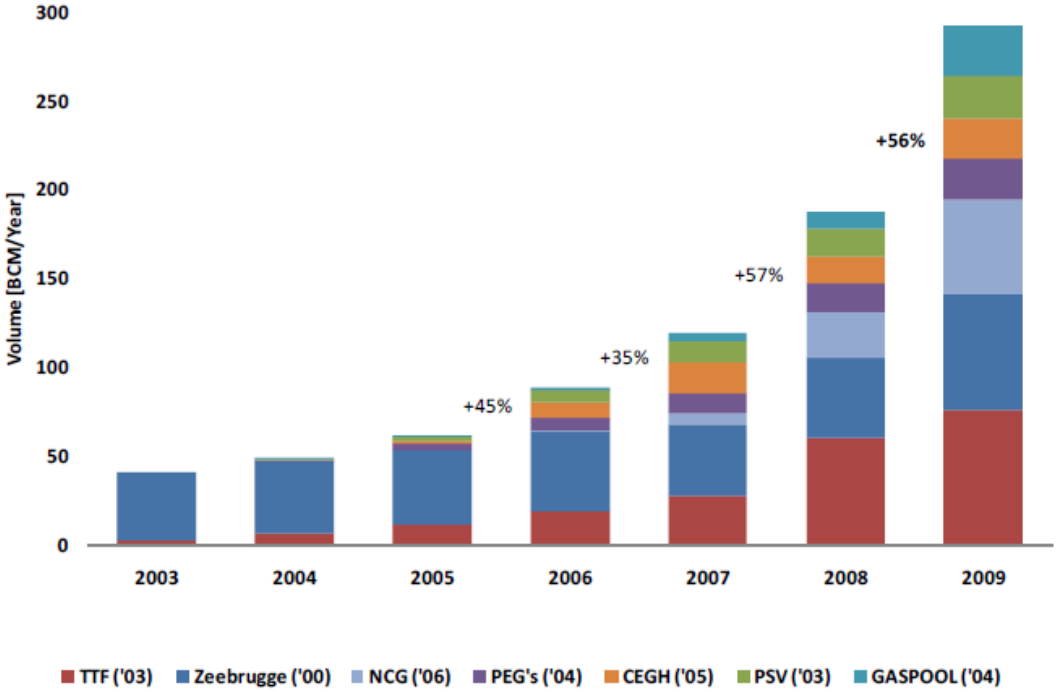
The other major problem with Continental European hubs is that, with one exception, they only have significant liquidity of "prompt" daily trades and hence daily prices. These hubs have little or no "curve" ie future trades which would establish forward prices which could provide a basis for hedging future deliveries. The exception is the Dutch TTF where 2-3 year forward trades are possible, but the hub still needs additional depth and liquidity to consolidate the 'tradeability' of the mid to far curve. The number of active trading participants has continued to grow, reaching 80 and including several companies from Germany's NCG hub.

Belgium's Zeebrugge Hub (ZEE) and Germany's GASPOOL Balancing Services Hub are examples of "physical" hubs, although quite different from each other. ZEE is centred on the actual location of the gas installations and meter points outside Zeebrugge; whereas GASPOOL covers part of the distribution network in the northern half of Germany but is operated as a physical rather than a virtual hub. Trading at ZEE has stagnated and been overtaken by the German and Dutch hubs. Since the BEB hub was re-launched in October 2009 as GASPOOL, trading activity has increased. The operator's description of a "balancing services hub" is indicative of the physical nature of this mainly northern German location and, although it does cover quite a large geographical area, it is mainly used by traders to adjust their storage portfolios in relation to NetConnect Germany (NCG). Despite traded volumes increasing appreciably (compared with its predecessor the BEB hub), the absolute traded volumes are the lowest of the main North West European hubs.

[31] ICIS-Heren, Figures 2-4, p.31.

[32] Ibid, Figure 1; Konoplyanik suggests that a churn rate of 15 or above is required for a market to be considered liquid. The churn rate of Henry Hub in the US is at least twice the level of the NBP.

Figure 2: Development of traded volumes at Continental European gas hubs 2003-09



Source: IEA, *Medium Term Oil and Gas Markets 2010*, Paris: IEA WEO 2010, p.207.

NetConnect Germany (NCG), since its inception in October 2009 (having evolved from the previous E.On Gas Transport (EGT)), has become by far the largest gas market area in Germany and, among the Continental European hubs, probably has most potential for further growth. Unlike GASPOOL, it is a virtual trading point within the pipelines of 5 network companies and, as such, has attracted much traded interest from physical and financial players alike. NCG can be traded on the European Energy Exchange (EEX) electronic cleared platform which has made significant progress towards the creation of a German 'marker' price for natural gas. In January 2011, EEX started to publish an All-German Gas Index (EGIX) which is the arithmetic mean of the daily volume weighted average prices of all the NCG and GASPOOL trades conducted on its exchange.[33] In the following month, EdF Trading became a 'market maker' for the two front months of the NCG contract in order to create and develop further liquidity and therefore traded volume.[34] Traded volumes are growing year on year and liquidity is slowly improving, but NCG will need to develop a curve before it can be considered as a true reference point.

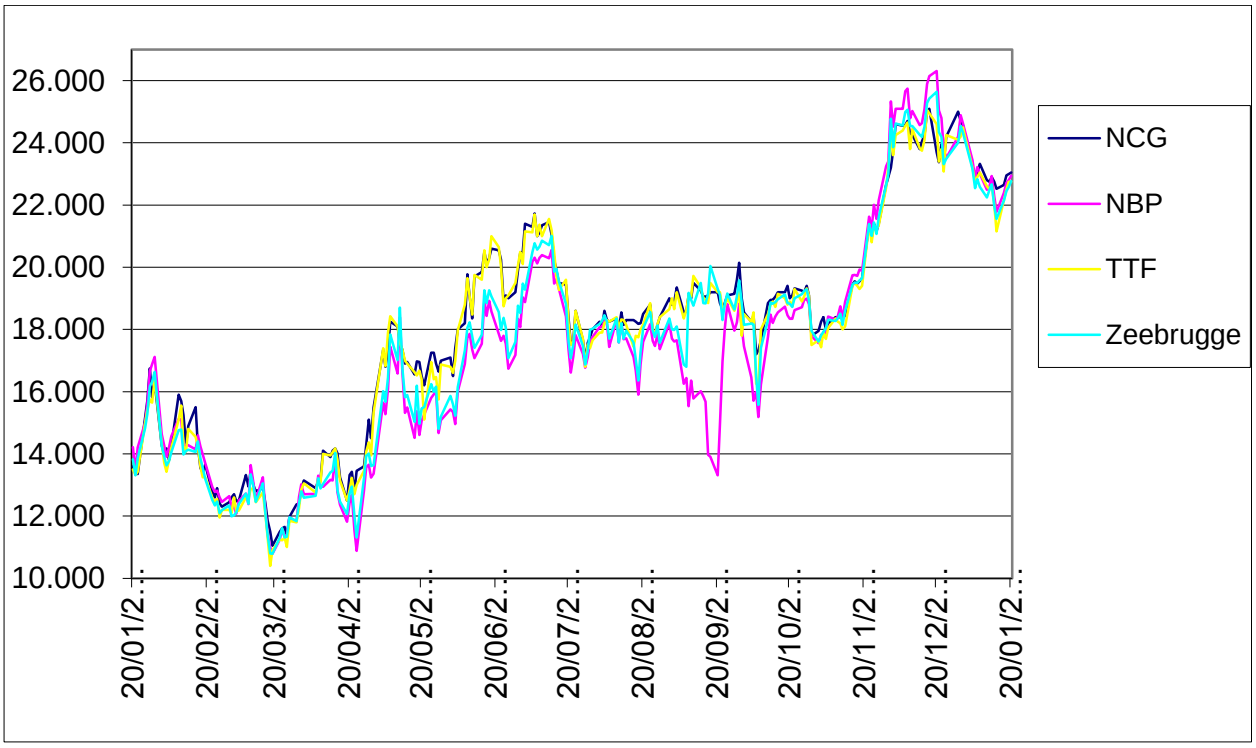
[33] EEX, *Launch of the new EEX Gas Price Index*, Press Release, January 27, 2011 http://www.eex.com/en/Press%20Room/Press%20Release/press/86149

[34] EEX, *EDF New Market Maker in EEX Natural Gas Trading*, Press Release, February 1, 2011, http://www.eex.com/en/Press%20Room/Press%20Release/press/86312

Fears of manipulation

Two of the major arguments against moving to hub-based pricing involve the possibility of manipulation either by sellers or buyers of gas, and the likelihood that these prices will be much more volatile than those produced by the traditional oil-linked contracts. While European hub prices are by no means perfectly harmonised, they do not exhibit any marked pattern of divergence over any significant period of time.[35] For the four main European hubs (NBP, TTF, ZEE and NCG) in 2010, ICIS-Heren data show some divergence in day-ahead pricing (Figure 3) particularly in September when the Interconnector pipeline was closed for maintenance. However this divergence reduces significantly for month-ahead prices (Figure 4), while season-ahead prices (Figure 5) are almost perfectly correlated across the hubs. Less liquid hubs, such as the Central European Gas Hub (CEGH) at Baumgarten in Austria, and the Punto di Scambio Virtuale (PSV) in Italy are less well correlated, but by early 2011 the spread between day-ahead prices at CEGC and North West European hubs had narrowed significantly.[36]

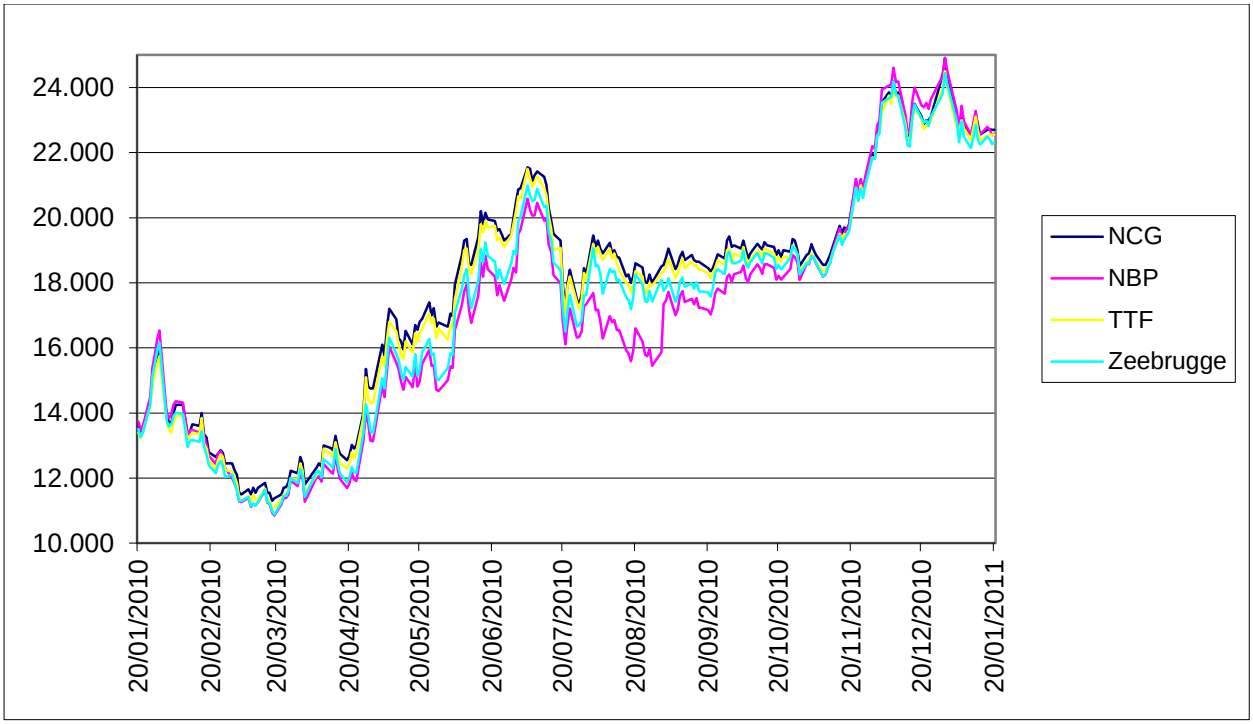
Figure 3: Day ahead prices for NBP, NCG, TTF and Zeebrugge, January 2010-January 2011
(Euros/MWh)



Source: ICIS-Heren, Figure 7, p.32.

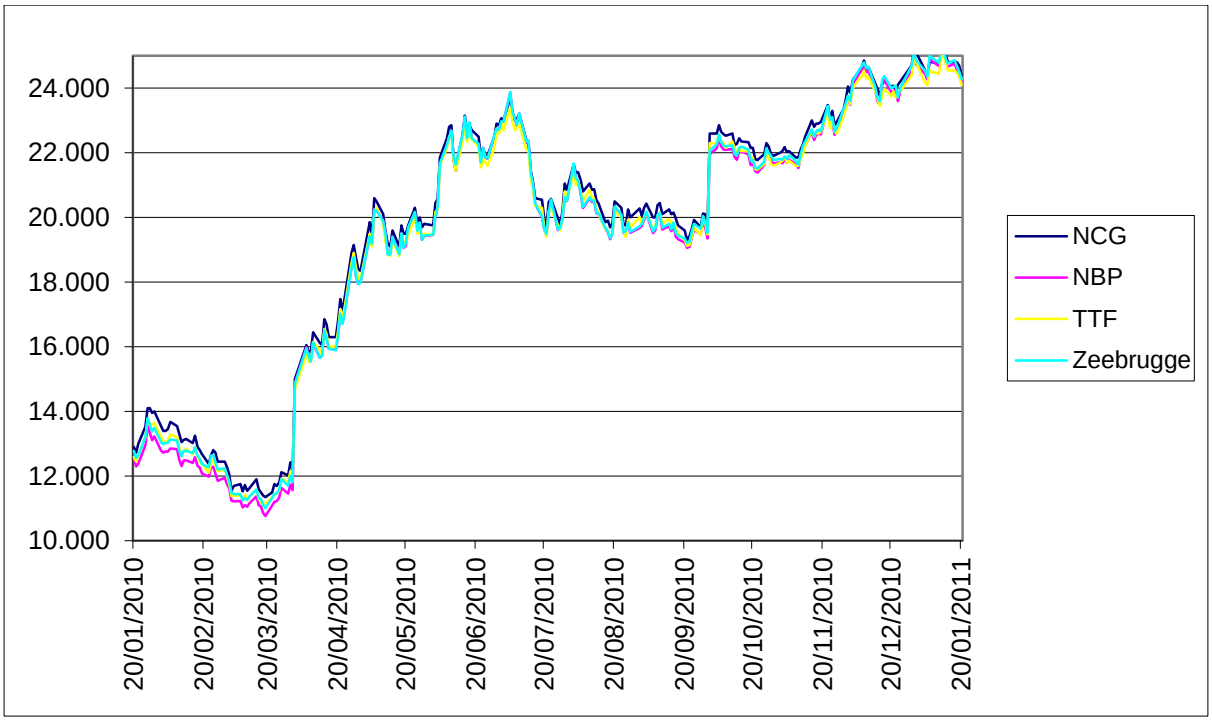
[35] In theory, and other things being equal, the price differences between hubs should reflect the cost of transportation between them. For a debate on whether this did actually happen in the US in the 1990s in the years following the establishment of Henry Hub and NYMEX futures prices see Herbert and Kreil.
[36] ICIS-Heren, Figure 9, p.32.

Figure 4: Month ahead prices for NBP, NCG, TTF and Zeebrugge, January 2010-January 2011
(Euros/MWh)



Source: ICIS-Heren, Figure 8, p.32

Figure 5: Season ahead prices for NBP, NCG, TTF and Zeebrugge, January 2010-January 2011
(Euros/MWh)



Source: ICIS-Heren, Figure 10, p.32

Thus market manipulation of individual hubs, if it is indeed taking place, was not evident over any significant period during 2010, and it would be reasonable to suggest that a contract price based on month ahead prices, or an average of day ahead prices over a monthly period, for a hub or an average of hubs should be robust against such suspicions. Moreover as hubs gain additional participants liquidity, the scope for manipulation by any single player will diminish.

One of the major problems which is regularly and correctly cited in relation to hub-based pricing is the oligopolistic nature of European gas markets, where relatively few buyers face even fewer sellers and there is thus significant potential for manipulation which is not helped by suspicions of both sides. On the sellers' side, this is related to European Commission liberalisation and competition measures, which are suspected of being aimed at reducing both their security of demand and their rents from gas sales. From the buyers' side there is suspicion that the Gas Exporting Countries Forum is essentially a 'Gas-OPEC' in waiting, as evidenced (in this view) by the GECF's support for oil indexed pricing.[37]

This became a topical issue during 2010, when reductions of Qatari exports, officially said to be due to technical problems with six out of twelve LNG trains, led to speculation about deliberate withholding of gas from the market to support prices. In summer 2010, there were reports that 27 Q-class vessels were anchored off Fujairah, including 19 Q-flex (216,000 m^3) and eight Q-max (265,000 m^3) vessels, leading to further speculation that Qatar was using them for floating storage.[38] Some believed they had identified similar reductions in Russian and Algerian deliveries in the second half of 2010, following the Algerian energy minister's call for production cuts to support prices, despite this receiving no documented support at the April 2009 GECF meeting in Oran.[39] Similar comments were heard in relation to Norwegian technical failures at fields and pipelines during 2009-10 and their impact on NBP prices. While there is nothing to substantiate any of this speculation, in an oligopolistic market any event which deprives the market of supply will create debate about possible cartel behaviour. Under the current long term contractual framework, the scope for short term seller manipulation of prices or volumes is limited. But should that contractual framework change significantly (as we suggest below) the possibility of a gas-OPEC – or a group of countries acting in concert to influence prices - could become more plausible.

Concerns about volatility

Concerns have been expressed that, in comparison to the current oil-linked mechanism, hub based prices will substantially increase volatility. In Figures 3-5 the degree of hub price volatility is evident, and this is unsurprising since one of the effects of the averaging process (described above) used to derive quarterly prices in long term contracts was to minimise such volatility to the maximum possible extent. To a degree, increased price volatility is an

[37] Gas Exporters push for oil price parity, *International Gas Report*, April 26, 2010, pp. 3-4.
[38] LNG Storage Off Fujairah Is Equivalent to 3 Months China Demand, *Bloomberg*, June 29, 2010
[39] Carola Hoyos, Algeria calls for united gas supply action, *Financial Times*, March 16, 2010, http://www.ft.com/cms/s/0/c74cc0b8-311a-11df-8e6f-00144feabdc0.html#axzz1EtShBp31

inevitable consequence of the need to balance the market in the short term. However, small and medium sized customers will not be exposed to daily or monthly changes, since companies supplying the residential and small industrial and commercial sectors will use a variety of trading strategies to manage volatility and pass through a smoother price pattern to smaller customers. Larger industrial customers and power generators will often have in-house trading capabilities to optimise their own portfolios.

Can there be a single gas price across Europe?

A short paper cannot possibly do justice to the diversity of gas market conditions in 35 European countries. The discussion above focussed on North West European hubs because this is where trading is most advanced and where it will develop most rapidly. Much more could be said about these hubs and about also the French PEGs, Austrian CEGH, Italian PSV and emerging trading points elsewhere in central and southern Europe.[40] As hub-based pricing grows stronger in North West Europe, this will have a pan-European impact which will be augmented by additional LNG supplies and increasing pipeline interconnections (and reverse-flow capabilities) between these countries.

In theory, and other things being equal, the price differences between hubs in the same region should reflect only the cost of transportation between them.[41] In early 2011, it would require heroic assumptions to suggest a date when these conditions might be reached on a pan-European scale for a number of reasons. First, as we have discussed above, even North West European hubs are not yet perfectly harmonised (although as Figures 3-5 above show the correlation in 2010 was good). Elsewhere in Europe, hubs are less advanced, or are still in the process of being created.

Nevertheless, the fact that from the beginning of 2011, Croatia has been principally supplied by Italian (rather than Russian) gas and has a new pipeline connection to Hungary which in turn has a new pipeline connection to Romania, begins to give an idea of how gas could flow between countries given appropriate price incentives. By 2013, pipeline interconnections will allow LNG arriving in Greece to be delivered to a range of south and central European countries as far north as Austria; or vice-versa for gas to be delivered from the CEGH hub to Greece. While in central and south east Europe these developments are still unfolding, it seems unlikely that any country would wish to remain, and will remain, excluded from the possibility of accessing attractively priced gas from a greater variety of sources. This will be an environment in which hub-based pricing will thrive. A difficult question is whether the new national entry/exit regimes required by the EU's 3rd package may create artificial barriers to well-correlated hub prices across Europe.[42] We are uncertain as to how this will impact the development of hub-based pricing and the relationship between prices at different national hubs.

[40] ICIS-Heren has a complete review of these developments.

[41] For a debate on whether this did actually happen in the US in the 1990s in the years following the establishment of Henry Hub and NYMEX futures prices, see Herbert and Kreil.

[42] See Hunt for a discussion of how entry/exit methodology creates barriers to trading.

The discussion above has assumed that hub-based prices will become the only commercial reflection of market prices, but this is open to debate. Particularly for power generators, some combination of electricity and carbon prices may be a more accurate reflection of market prices. The Statoil-Poweo contract signed in mid-2010, which features a mix of hub-based gas and spark spread prices – serves as an example of possible future market based gas prices for power generation.[43]

Moving European gas prices from oil linkage to a hub basis will introduce considerable complexities around the different components of price formation, including the extent to which international gas prices may become subject to the influence of speculators and market sentiment (both of which are factors which affect oil prices). Such issues are beyond the scope of a short paper, but it is certainly possible that speculative elements and market sentiment will play a part in setting a market-based price for gas, as they do for other commodities.[44] The historical experience of moving from long term to spot pricing in other markets shows that it can be highly disruptive, and require a significant period of time before a new and adequate status quo is established. There may be attempts to manipulate the market; individual players may also default, giving rise to significant litigation. All of these phenomena were seen in the early years of the Brent market before it became established as a worldwide marker price for crude oil.[45] In relation to gas, the NBP encountered serious problems during its early years and its liquidity and depth is still questioned by some.[46] A transition to hub-based gas pricing in Continental Europe is likely to experience similar problems.

Pricing in new greenfield gas projects: Shah Deniz and the Southern Corridor as a test case

One of the most usual arguments for retaining long term contracts with oil linked prices has been that only within this commercial framework can new "greenfield" infrastructure – specifically long distance pipelines and LNG terminals – be constructed. Without such "security of demand", producers will refuse to invest in new gas projects causing future shortages of supply. Gazprom has asserted that moving to hub-based prices may create a "boom and bust" cycle of investments leading to greater long term price volatility.[47] But it is not clear (at least to us) that this risk is substantially greater than with oil-linked prices, and we believe that even if it could be demonstrated it would not provide a rationale for retaining oil linkage.

[43] *Statoil and Poweo conclude innovative gas to power contract*, Statoil Press Release, 25 June, 2010.
[44] See Konoplyanik for more details of these concerns, but also Komlev who suggests that gas prices will never attract the degree of speculative activity associated with oil prices, which will therefore deprive gas exporters of price advantages which flow from this activity.
[45] For a specific account of these events see Horsnell and Mabro, especially pp. 130-147. See Fattouh for a modern account of the evolution of crude oil pricing.
[46] Heather pp.4-6.
[47] Komlev p.9.

While it is certainly true that traditional long term contracts have been the commercial framework favoured by producers (and their bankers) to develop new projects, during the 2000s it became clear that, at least in liberalised markets, projects were being developed where pricing would inevitably be based on hubs. In North America – United States, Canada and Mexico – significant numbers of pipeline and LNG projects were developed during the 2000s for markets based on Henry Hub prices. In the UK, the Ormen Lange project was built in the mid 2000s in order to deliver Norwegian gas to the UK based on NBP prices, as have receiving terminals for Qatari and (largely) north African LNG.[48] Significant LNG receiving terminal capacity – for example the Gate terminal in the Netherlands - has been built without a dedicated source of supply, on the basis of capacity commitments from its shareholders, into which, it is assumed, LNG will be sold at hub (in the case of Gate, TTF) prices.[49]

However, projects requiring large scale investments – in excess of Euros10 billion – have thus far only been built in relation to markets where hub prices were already well established; North America and the UK. But in the 2010s, large projects aimed at supplying Continental European countries are facing the possibility that hub based pricing will be the environment into which they will deliver their product. This particularly applies to the pipeline projects which are aiming to form the "Southern Corridor" – Nabucco, ITGI, TAP and White Stream – bringing gas from the Caspian/ Middle East.[50] The project sponsors are seeking long term gas contracts for pipeline capacity and gas supplies, which will initially be the second phase of the Shah Deniz field in Azerbaijan which will produce 16-17 Bcm/year starting in 2017 requiring an investment of $20-25 billion.[51]

As the first large scale greenfield gas development to be implemented since the start of the price transition in Europe, Shah Deniz Phase 2 will be an important test case for new commercial, and specifically pricing, frameworks, in Europe. Because full production levels will not be reached until 2017, the key commercial question will be the price reference point at that date. In late 2010, the sellers of this gas began negotiations with potential buyers and, although these discussions are confidential, early indications suggest that European gas buyers are willing to sign new long term contracts for these supplies but only at hub-based prices. If this is correct, it will be an important pointer to the future of European gas pricing and could be a complicating factor for the purchase of gas from countries such as Turkmenistan where other external customers – Russia, China and Iran – currently pay oil-related prices.

[48] Ormen Lange and other projects are reviewed in Stern and Honore.

[49] However, at the time that the capacity holders signed their contracts, they almost certainly did so on the expectation of oil-linked prices.

[50] For details of these projects see Honore 2010, pp. 150-154.

[51] Firm supplies needed to free up 4 billion Euros in Nabucco pipeline funding, *Gas Matters*, October 2010, pp. 9-12; this figure is for the upstream investment and pipeline within Azerbaijan, it does not include the cost of any southern corridor pipeline to Europe.

The transformation of the commercial structure and culture of European Gas and energy and gas utilities

The position of the utilities which have traditionally purchased and imported the majority of Continental Europe's gas has fundamentally changed over the past two decades due to the merger and acquisition activity created by the liberalisation of gas and power industries. Until the mid 1990s, a single company had a *de facto* monopoly of gas purchase and sale in each Continental European country. The major exception was Germany where gas companies had regional monopolies but were dominated by Ruhrgas which purchased the majority of imported gas.[52]

European gas (and power) liberalisation and utility ownership restructuring

The commitment to create a "single market" in energy which was made by the EU in the late 1980s, promised to fundamentally change this status quo. This is not the place to review the long, complex – and for nearly two decades largely unsuccessful - legal/regulatory evolution of liberalisation and competition in European gas industries.[53] Suffice it to say that, as EU and national liberalisation programmes began to evolve in the 2000s, following the second EU Gas Directive, European gas utilities began to confront several emerging realities:

- 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 no experience in a sector which would inevitably become crucial as gas and power markets became increasingly closely related. The example of Britain, which had liberalised much earlier and where the market had become dominated by a small number of joint gas and power providers, was clear in this respect.[54]
- Network (transmission and distribution) businesses would remain regulated monopolies which, even if "ownership unbundling" was not required by regulators, would attract a lower rate of return than merchant businesses.

This created a wave of corporate mergers and demergers which, by 2011, had largely been completed except in relation to network ownership. The result was a relatively small number of very large utility companies - E.ON, RWE, EdF, GdFSuez, ENI, Enel, Endesa, Iberdrola and Vattenfall – owning a variety of utility assets across a number of European countries and dominating the European landscape.[55]

[52] For the history and evolution of competition in the German gas market see Lohmann 2006 and 2009.
[53] Haase, Chapter 6 has a good review of these developments.
[54] Wright, pp. 42-46.
[55] By the late 2000s, a combination of European competition decisions, ownership unbundling requirements, and a desire to raise additional funds, was causing integrated utilities to sell off networks to non-affiliated companies.

These changes in industrial organisation were in anticipation of the impacts of "single market" liberalisation and competition measures pursued by the European Commission – and national regulators. In particular, Regulation 715, which became applicable in late 2009, and the "Third Package" of measures (including the third Gas Directive) which became legally binding in March 2011, ushered in fundamental changes to the legal/regulatory status quo in relation to third party access in EU countries.[56] These provisions required: much greater separation of network operations, the introduction of network codes in all countries, and the creation of an Agency for the Cooperation of (European) Energy Regulators (ACER).
All of these suggest that regulatory authorities are likely to reinforce existing trends which are pushing gas markets towards greater competition.

Corporate restructuring and cultural change

As a result of this process, the former gas companies became the gas divisions of power (or more general utility) companies where the electricity business was substantially larger than the gas business. The resulting companies – usually with electricity executives dominating the board-level positions – share little of the corporate culture of the old European gas companies. They do not have the multi-decade "relationship culture" created by long term contracts, or any significant commercial experience of relationships with non-European external suppliers. Nor do they have any cultural affinity with traditional long term gas contracts (and oil-linked prices), tending to see these as a "throwback" to a bygone era. In contrast to their counterparts from the former gas companies, the power utilities were much more comfortable with a "trading mindset", and already had much greater exposure to competitive gas and electricity markets through their ownership of British utility companies. Finally these companies tend to have a "shareholder mentality" which makes them far less tolerant of commercial arrangements which have even a short term negative impact on their share price.

Thus the change in the industrial organisation model in the European utility sector – from single product national/regional companies towards multi-energy pan-European companies – removed much of the historically strong cultural support for the traditional gas business model, and with it much of the support for *oil-linkage* in long term contracts but not for the contracts themselves.[57] This became particularly evident in the post-2008 period as managements recognised the huge financial exposure resulting from oil-linked prices in their long term contracts.

From captive to contestable markets

The commercial model of the traditional gas utilities was relatively simple: they segmented their customer base depending on the ability of the customers to access alternative fuels and

[56] EU Regulation 715 and EU Third Gas Directive.
[57] Utility managements have continually expressed a desire to see these contracts continue, principally for security of supply reasons.

hence the relative value of gas for each customer group; and they differentially priced between (and sometimes within) classes of customers, safe in the knowledge that without either satisfactory third party access or transparent spot pricing, their customer base was essentially captive.

During the 2010s, European energy and competition law created increasing momentum towards effective third party access, ownership unbundling and regulatory oversight. These developments, combined with the elimination of destination clauses, completely transformed the regulatory and market context in which commodity contracts were operating.[58] Two developments were fundamental to that contextual change: the arrival of workable third party access, and the emergence of hubs with transparent prices which could be accessed on a daily basis by any customer with a computer. By early 2011, neither of these developments had reached the level of sophistication of the British market but, to put it at its simplest, the majority of consumers in North West European countries increasingly had a credible choice of suppliers. Thus by the end of the 2000s, the traditional utilities were no longer monopolies which could refuse to take notice of demands from their customers to supply gas at widely available hub price quotations. Nor could they any longer stop customers in their service areas gaining access to lower prices, either by using exclusivity and "no resale" clauses in their contracts with customers, or by maintaining that because they had to pay oil-linked prices under long term contracts, their customers had to accept similar prices.[59]

Commercial difficulties and strategies 2008-10

As noted above, from around the end of 2008, the co-existence of spot gas traded at hubs and oil-indexed gas created a 'hybrid price' market. Oil-indexed gas is sold under long term (typically 25 year) contracts. Buyers have the obligation to take or pay for a minimum volume of gas within a contract year (usually from 1st October to 30th September) which is typically 85% of the Annual Contract Quantity. In the context of European hybrid pricing, buyers are able to purchase both spot gas on the traded hubs and oil-indexed contract gas provided that they meet their minimum take commitments in the contract within the contract year.

From early 2009, the traditional utilities found themselves in a precarious commercial situation. Their long term contracts required them to buy minimum quantities of gas at oil-linked prices and sell those volumes at prices at hub-related levels which, as we have seen above, were significantly lower than oil-linked prices during 2009-10. With oil-linked gas increasingly "out of the money", traditional utilities were required to optimise their purchase and sale activities in a hybrid price market.

[58] During the 2000s, the EU competition authorities oversaw the elimination of restrictions on destination in all long term contracts (ie clauses which provided that gas could only be sold in the market of the first buyer of the gas).

[59] Exclusivity and "no-resale" clauses were widespread in utility contracts with their customers; the first obliged customers to purchase their entire gas requirement from a single utility, while the second prohibited customers from reselling any part of the gas which they received.

Through a process of arbitrage an importing utility, provided it is confident that it will meet its minimum take level by the end of the contract year in question, will seek to maximise its purchase of cheaper spot gas until:

- either it is unable to purchase additional quantities of cheaper spot gas without jeopardising its ability to meet its minimum take commitment;
- or the price of spot gas, due to arbitrage reaches the equivalent price of oil-indexed gas and there is no further benefit from buying it in preference to oil-indexed gas, even though the buyer would still be able to reduce its take of oil-indexed gas and meet its minimum take commitment by the end of the Contract Year.

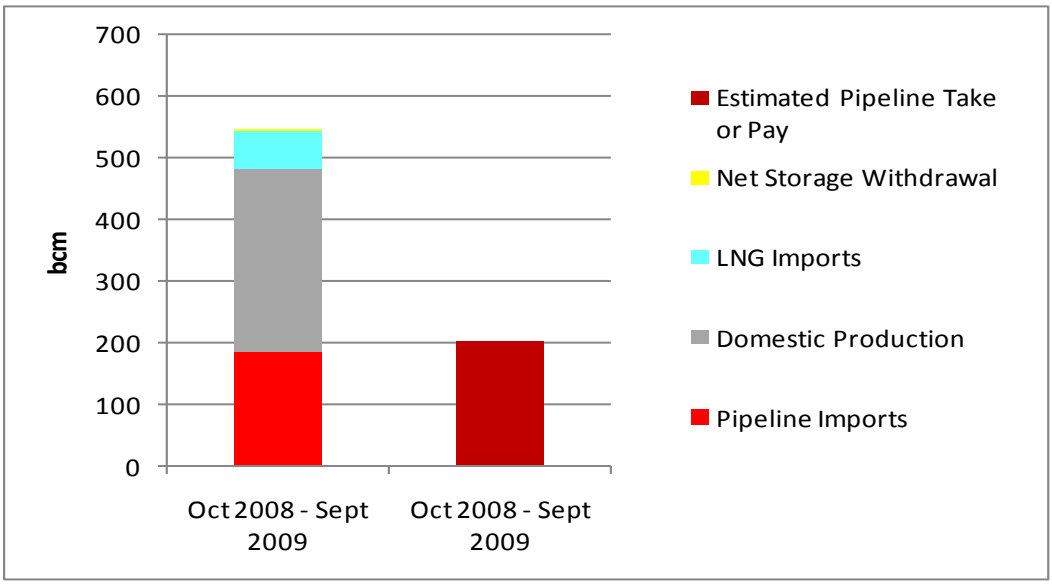
The dilemma facing a European utility, in times of weakened demand and the availability of cheaper spot gas at traded hubs, is how to ensure that all the minimum take volume under a long term contract can be on-sold to end user customers, particularly when spot gas prices are lower and such customers are aware that they have a choice of cheaper supply. This hybrid system came under significant strain during the contract year October 2008 to September 2009.

From an analysis of the European market it is possible to calculate the volume of pipeline imports from Russia, Algeria, Libya, Iran and Azerbaijan in aggregate and compare this to the notional Take or Pay level (assumed to be 85% of Annual Contract Quantity). The key question which emerges from the experience of the 2008/2009 contract year is: why did the buyers fail to take their take or pay volumes? There is a range of possible answers:

- They underestimated the scale of the demand downturn and, while maximising their purchase of spot gas, failed to plan their contract nominations to suit demand patterns as the contract year progressed.
- They took the view that rolling over the 'paid for' gas for consumption in a future year (when demand had recovered) was worth the up-front cost, when balanced against access to near term cheaper spot gas.

- They effectively 'lost control' of their end-user customer base, which demanded that gas be supplied at spot prices, and were able to switch supplier if they met a refusal. The importing utilities were thereby placed in a very difficult commercial position: saddled with the liability to pay for minimum quantities of long term contract gas under take or pay commitments; but only able to sell this gas at a loss due to competition with hub-priced supplies available to their customers.

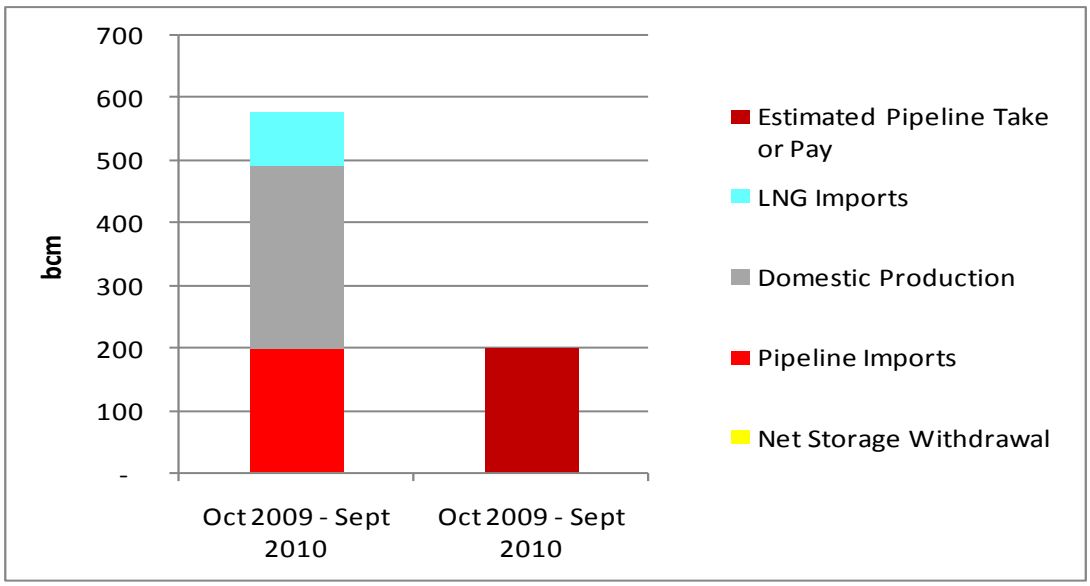
Figure 6: European gas balance for contract year 2008/2009



Source: Howard Rogers, OIES

From Figure 6 it is clear that pipeline imports for Contract Year 2008/2009 were lower than the estimated Take or Pay level – in fact they were only 92% of Take or Pay.[60] At the end of the contract year several buyers of oil-indexed contract gas from Russia entered discussions which resulted in, among other measures, including the roll-over of physical volumes paid for but not taken until such point in the future as they could be consumed, in addition to the Take or pay volume for future contract years.

Figure 7: European gas balance for contract year 2009/2010



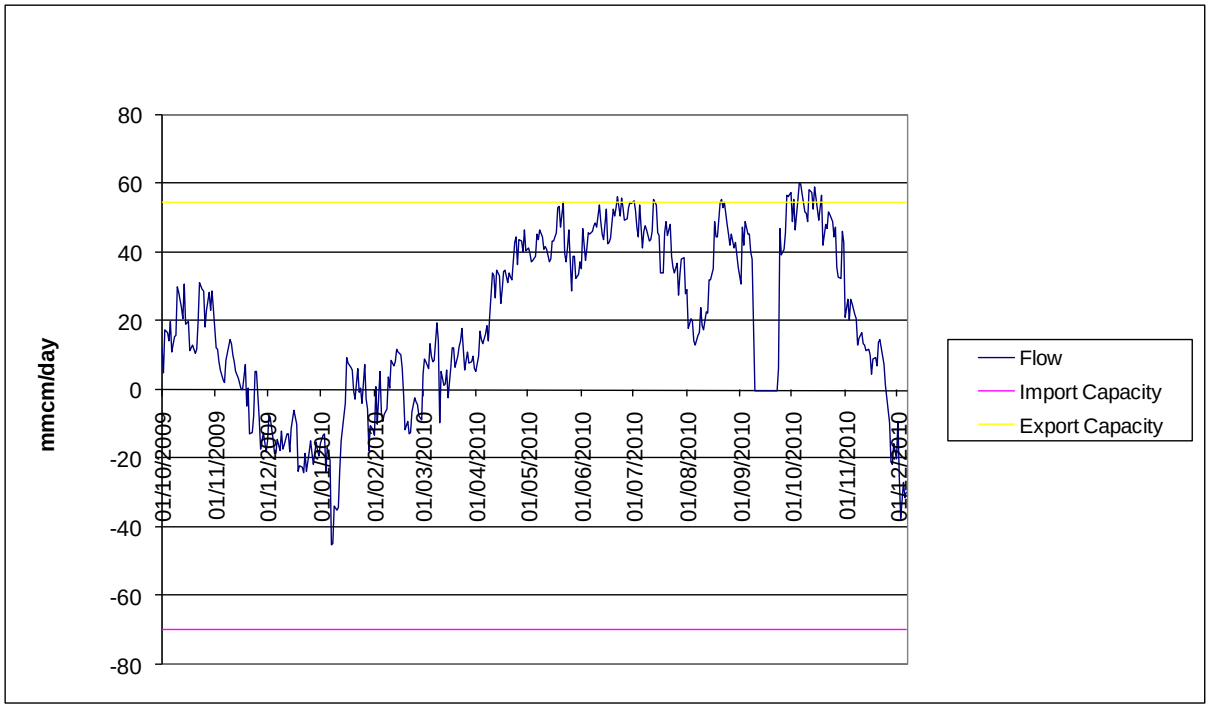
Source: Howard Rogers, OIES

[60] Note the Take or Pay level has been adjusted by the estimate of gas which was unavailable for purchase during the Russia-Ukraine crisis of January 2009, estimated to be 4.5 Bcm.

The situation changed somewhat in Contract Year 2009/2010 (Figure 7). Compared with the previous contract year, demand was noticeably higher as a consequence (noted above) of the cold winter, fuel switching from coal and recovery from the recession. Thus despite the significant increase in LNG imports, pipeline imports were higher at 98% of the estimate of Take or Pay levels.

One explanation of the converging price trend between BAFA and NBP is that upon emerging from the severe winter 2009-10, buyers of oil indexed pipeline gas realised that they could lower their contract nominations *and* increase their purchases of cheaper spot gas and still (just about) meet their take-or pay levels by the end of September 2010. This certainly corresponds to the pattern of spot gas flowing through IUK from the UK to Europe shown in Figure 8. Arbitrage through the summer of 2010 served to bring the UK and North European hub prices closer to the oil indexed price as represented by the German border (BAFA) price in Figure 1.

Figure 8: Bacton – Zeebrugge Interconnector flows October 2009 – October 2010



Source: IUK Website

The question arises however whether this outcome for contract year 2009/2010 was by design or accident. Another explanation of these events would be that:

- Arbitrage led to convergence or near convergence of NBP and North West Europe traded hub prices with the German border (BAFA) price;
- Midstream incumbents 'lost control' of end user customers and were unable to sell on their take or pay volumes in full;
- Upstream suppliers of oil-indexed gas, to mitigate their loss of contract sales volumes to midstream incumbents at oil indexed prices, were selling gas at European hubs directly, using their in-house trading capabilities.

It is not possible to determine from European or Russian data whether imports of pipeline gas into Europe are being sold within a long term contractual framework, or directly by upstream suppliers at the hubs. The alternative explanation outlined above would only be borne out by media reports of take-or-pay shortfall-related discussions between contract sellers and buyers relating to the 2009/2010 contract year.

The position of Gazprom

While the minimum take or pay volumes of all European suppliers came under pressure during 2008-10, the position of Gazprom was of special significance because of the size and centrality of its supplies to the European gas market. As far as can be ascertained, the vast majority of the failures to meet take or pay levels during the 2008-10 were in the Russian contracts.

Table 2: Russian gas exports to Europe, contract years* 2007-2010 (Bcm)

	2007-08	2008-09	2009-10
Germany	39.72	27.02	36.82
Italy	23.57	19.04	12.43
Turkey	24.43	20.75	16.85
France	11.26	9.64	11.16
UK	6.10	7.47	6.68
Total "Western Europe"**	124.08	99.76	101.12
Total "Central Europe"**	44.53	33.4	40.98
TOTAL EUROPE (Gazprom definition)	168.61	133.16	142.10
Total including Baltic Countries***	173.21	136.5	146.28

Sources: Interfax *Russia & CIS Oil and Gas Weekly*: February 14-20, 2008, p.20; November 12-18, 2009, p.27; February 11-17, 2010, p.31; November 11-17, 2010, p.30.

Note: *This is Russian data for *contract years* (October 1-September 30 of respective years) and therefore differs from either Russian or western data for *calendar years*. It also differs from data from sources such as IEA, EIA, Cedigaz, some of which do not include exports to countries such as UK. It is also different from Gazprom IAS data which include all gas sold by Gazprom affiliates in Europe whether or not of Russian origin.

**These are the old "Cold War" categories reflecting countries which were part of the Soviet economic area (CMEA) prior to 1991 and those which were not.

***Gazprom data for exports to Europe do not include Baltic countries which are included in the category of "former Soviet Union".

This resulted in renegotiations between Gazprom and its buyers which were exposed to competition from North West European hub prices. At the beginning of 2010, it was widely reported that a number of companies had demanded both reductions in contractual take or pay volumes and reductions in prices.[61] As a result, Gazprom agreed with a number of companies that a 15% share of the price indexation would be moved to hub based prices for three years

[61] These included E.ON, Wingas, Botas, Eni, RWE and Econgas. `Europe rethinking contracts with Gazprom', *Interfax Russia & CIS Oil and Gas Weekly*, March 4-March 10, 2010, pp. 4-5.

beginning in October 2009.[62] In addition, most companies were allowed to "roll over" volumes not taken below minimum take or pay levels to future years. Although Gazprom sold nearly 9 Bcm more gas to its European customers in contract year 2009/10 compared with 2008/09 (Table 2), Gazprom's customers incurred take or pay liabilities, of 5 Bcm in 2008/09 and around 10 Bcm in 2009/10. However the reasons appear to be different: in 2009 the take or pay shortfall was spread across a number of companies; while in 2009/10 the shortfall was concentrated on two countries – Italy (ENI and Edison) and Turkey (Botas) while all others appeared to have taken their minimum quantities (see Table 2).

Increasing consensus of buyers and continuing opposition of Gazprom

Starting in August 2010, E.ON Ruhrgas began to openly call for a move to hub-based gas pricing and "re-engineering" of existing long term contracts.[63] E.ON made it clear that this was not just about obtaining lower prices but about changing "fundamental elements" of the contracts.[64] Later in the year it was reported that, "Both the CEO of E.ON Ruhrgas and the president of GDF Suez said that the days of oil indexation were over, as far as they were concerned, and gas to gas competition was here to stay."[65] A study by Morten Frisch came to a similar conclusion:[66] "*The two-tier price system that has developed for gas in Continental Europe has unleashed market forces that must be dealt with. The big challenge in solving the price problem that has arisen will be to find reliable alternatives to the oil price indexation elements currently used in price formulae.*"

In addition, there appears to have been a significant change of sentiment among the European gas community as expressed by (relatively unscientific) polls taken at European gas conferences. Annual polls taken at the FLAME Conference during the period 2004-09 found that around three quarters of participants did not expect the basis of gas pricing to change before 2015 or ever; the March 2010 poll showed similar results.[67] By November 2010, a poll taken at the European Autumn Gas Conference showed 50% agreeing that volumes in long term contracts would be renegotiated and 29% believing that contracts would move to hub pricing. Only 16% agreed to the proposition that recent pricing and contractual changes were temporary and would not last more than a few years after which the traditional framework would be reinstated.[68]

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[62] Gazprom agrees to sell a portion of gas delivery to Ruhrgas at spot prices, *Interfax Russia and CIS Oil and Gas Weekly*, February 18-24, 2010, p.20; Anton Doroshev, Gazprom adjusts gas pricing to defend market share, *Reuters*, February 19, 2010, http://uk.reuters.com/article/idUKLDE61I1M320100219?pageNumber=2&virtualBrandChannel=11700&sp=true;

[63] See the presentation by the CEO of EON Ruhrgas to the Offshore Northern Seas Conference in Stavanger in August 2010, http://www.ons.no/index.cfm?event=downloadfile&famid=129806; the video of his presentation gives an expanded version of his view on the need to move away from oil indexation. http://conventor.easymeeting.net/mediasite/Viewer/?peid=583efe3d8e474162b41d3a786a5ea584

[64] Gas merchants' chickens come home to roost, *International Gas Report*, August 16, 2010, pp.12-13.

[65] IEA sees long term gas glut, *International Gas Report*, November 22, 2010, pp.9-11.

[66] Frisch 2010 p.1.

[67] Stern 2009, Table 1.

[68] European Autumn Gas Conference, Berlin, November 2010, responses to Question 9.

What we are observing here is a fundamental mindset change on the part of the traditional buyers from one which was appropriate for those in a dominant position with a relatively captive market, to one which increasingly reflects the competitive environment of access to liquid gas hubs and the trading culture of European utilities. To the traditional utility mindset, a long term oil-indexed contract represented a secure source of supply at prices which could be force-fed to captive end-user customers. If prices were higher than those at the nascent hubs, this could be partially justified by the accompanying volume flexibility embedded within such contracts (see Box).

To the modern utility mindset, a long-term oil-indexed contract represents an unbounded future potential exposure relative to the all important 'market price' at the hubs, and the requirement of the financial community that contracts must be "marked to market". The pressure to resolve this increasing polarity between buyers' and sellers' interests and motivations is unlikely to dissipate. Even if market fundamentals reduce the spread between oil-indexed prices and hub prices, the threat of future exposure in an increasingly uncertain LNG-connected global gas system is incompatible with the modern utility mindset.

This change in sentiment has encountered strong resistance from Gazprom which remained insistent that there is no acceptable alternative to oil-linked pricing and that the gap between long term contract and spot prices would close by 2012.[69] Thus Gazprom believes that the gap between spot and oil-linked prices is a temporary phenomenon which will disappear within three years when supply and demand will once again be in balance. The company's view has been endorsed by Russian prime minister Putin and also by the Gas Exporting Countries Forum.[70]

[69] Gazprom's Miller sees demand for gas slackening in Europe, *Interfax*, June 10-16, 2010, p.4-7.

[70] Third Energy Package will threaten Europe with energy-resource price growth – Putin, *Interfax*, November 11-17, 2010, p. 28; Russia, China sign six energy deals in Petersburg, *Interfax*, November 18-24, p. 5; See the interview with the Secretary General of the GECF in Interfax, February 3-9, 2011, pp. 17-20

Valuing flexibility in long term contracts

A long term gas contract should be regarded as a bundled product of commodity and flexibility with the latter defined by the ability of the buyer to vary offtake between (for instance) 85% and 120% of annual contract quantity (as well as monthly and daily offtake provisions). This flexibility allows buyers to modulate their offtake depending on the demand from their customer base, and their ability to utilise other forms of flexibility, particularly gas in storage. The changes suggested in this paper mean the likely disappearance of offtake flexibility in long term contracts. In such a situation, the question arises as to how buyers would meet their flexibility requirements if in future they will buy gas on a "flat" profile.

The answer to this question is probably two-fold. First flexibility can be (and to some extent is already being) provided by storage facilities. In 2010, Gas Storage Europe data showed that there were facilities under construction in Continental Europe with working gas capacity totalling 22.6 Bcm.[71] This is a veritable "explosion of flexibility" when compared with the existing European working gas volume of 80 Bcm, only half of which is typically used during a gas year. The second way of obtaining flexibility is through trading, buying gas from hubs when it is needed and selling when it is not. Buyers with access to additional LNG supplies may find this a particularly useful way of obtaining short term supply. This is the reason why new LNG terminals, and interconnection with other national networks – which may have been built principally for reasons of security of supply – may serve commercial purposes. As gas trading becomes a normal commercial activity, take or pay and contractual flexibility becomes (at the very least) less relevant because buyers can buy and sell short term gas to balance their requirements.

This suggests that the elimination of contract flexibility which may accompany the changes in long term contracts, may not be problematic for those buyers which are well on the way to making alternative arrangements. It also suggests that the value of contractual flexibility is not sufficient to outweigh the pricing problems with long term contracts.

The future of long term gas contracts: price review and arbitration

As noted above, traditional Continental European long term gas contracts contain clauses which provide for negotiations every three years to change certain elements of the price – indexation and base price; in some contracts volumes and volume flexibility arrangements (take or pay levels and treatment of volumes not taken within a contract year) may also be subject to change.[72] Price clauses in many contracts also contain a "Joker" which allows either party to ask for a price review outside the contractual framework either once during each three year price period, or once during the entire term of a contract.

[71] Gas Storage Europe dataset, June 2010, http://www.gie.eu/maps_data/GSE/database/index.html
[72] See Polkinghorne for legal commentary on price reviews and price break clauses.

The key parameter for a price review is the phrase "changed economic conditions beyond the control of both the buyer and the seller", which refers to how the energy market – and in particular the fuels with which gas competes in end-user markets – has changed since the previous review.[73] Parties need to agree whether and how these circumstances have changed and therefore whether there is a need to adapt the price. If they are unable to agree on the resulting price for the upcoming three year contractual period, their only option (apart from to continue negotiating and hope that their differences can be resolved) is to go to arbitration.

All European gas contracts contain an arbitration clause which typically states that, in the event of unresolved disagreement, the parties will request a decision from an appointed expert or an arbitral tribunal. The expert or arbitral tribunal will hear the case, and reach a decision which will be binding on both parties. In the case of a price dispute, the decision will include the setting of a price by (the expert or) arbitral tribunal, the application of which will be backdated to when legal proceedings commenced. From the point of view of the parties to the contract, this represents a process where the outcome is highly unpredictable.

Over the approximately 40 year history of long term European gas contracts, arbitrations have been extremely rare events.[74] However starting in the second half of the 2000s, rumours and reports of arbitrations have become more frequent. There have been reports of decisions on arbitrations between Sonatrach and Gas Natural, and between Gasterra and ENI.[75] In 2010, the Italian company Edison initiated arbitral proceedings against the Gazprom/ ENI joint venture Promgaz. The CEO of Edison stated that:[76] "We received a [price] proposal and it was quite good for this year but unacceptable for 2011…It is not acceptable...that for 2011 we can have a loss situation with this contract..If we had set a price, we would be stuck for three years and we cannot accept continuing to lose money in the future...". In March 2011, Edison also filed arbitration proceedings against Qatar's RasGas.[77] In addition to Edison, it has been reported that E.ON: "…intends to go to arbitration at the earliest opportunity to signal its determination, even if negotiations would likely continue."[78] And Gazprom's Head of Contract Structuring and Price Formation confirmed that E.ON had made a formal request to fully index long term contract prices to spot levels.[79]

[73] See Frisch pp. 15-18 for the various tests which must be carried out to determine whether changes in price provisions are justified under the contract.
[74] This is a difficult statement to support because of the confidentiality of (even the existence, let alone the outcome) of arbitral proceedings.
[75] Gas Natural loses Sonatrach dispute, Platts, *European Gas Daily*, August 18, 2010, p.2; GasTerra Wins Arbitration Cases Against Eni, Dagblad Reports, *Bloomberg*, November 18, 2010, http://www.bloomberg.com/news/2010-11-18/gasterra-wins-arbitration-cases-against-eni-dagblad-reports.html
[76] Edison takes Gazprom to court, *European Gas Daily*, November 4, 2010, pp. 2-3.
[77] Edison files for RasGas arbitration, *European Gas Daily*, March 14, 2011, p.5.
[78] JP Morgan Cazenove, *E.ON, Useful meeting with Ruhrgas on LTC outlook*, Europe Equity Research, 21 December 2010.
[79] E.ON eyes 100% Gazprom spot indexing, *European Gas Daily*, February 22, 2011, p.4.

Managing the transition: two scenarios

2011 will be a critical year for the future of European gas contracts and prices and hence for the future of the gas industry itself. While a number of different scenarios could be advanced as to how commercial arrangements will unfold, we believe there are essentially two paths which could be followed to address current problems: litigation followed by arbitral awards, and negotiation of transitional arrangements towards a market price. The end-point of both solutions may be similar; the main differences could be the amount of time and financial pain required to reach this end-point, and the consequences for the contracts themselves.

Arbitration Scenario: litigation followed by judgement by an arbitral tribunal

In this scenario, the industry enters into a substantial number of arbitration proceedings with an uncertain time frame and outcome. Before going down this road it will be useful for parties to appreciate that arbitrators are lawyers who are being engaged to interpret the terms of a specific contract. Arbitrators are not typically economists and it is rare to find tribunal members who are very familiar with the details and economics of energy and natural gas industries. It is therefore unrealistic to expect arbitral tribunals to have a deep knowledge of gas pricing and market issues.

Thus while arbitrators can be expected to make legal judgements which could award significant financial damages to one or other of the parties, it is highly unlikely that they will provide innovative solutions to the current pricing impasse that *both* parties believe are satisfactory and workable. The arbitrators will be asked to determine whether a substantial change in economic conditions, sufficient to warrant a change in the reference price, has occurred. There is a fundamental decision for arbitral tribunals to make:

- They may decide that there have been *no substantial changes in economic conditions beyond the control of both the buyer and the seller*. In that case, this will be a strong signal to buyers that they need to find a route to terminate their contracts.
- By contrast, if they decide that there have been substantial changes, the question is then how these changes should be reflected and over what time period.

The key question will be whether arbitrators accept that the traditional netback market price mechanism where:

- the (base price) Po is based on the prices of fuels which compete with gas in the buyer's market (known in Germany as 'Anlegbarkeit');[80]
- indexation is based on (the same or) a similar basket of fuel prices – but mainly oil products;

no longer reflects market conditions.

[80] For details of this mechanism see Stern 2007.

Even if they accept this proposition, tribunals may take the view that to suggest a different price mechanism is "too difficult", with the suggestion that the parties must arrive at an agreement themselves (something which they have already failed to do, which was the reason for the arbitration). In the case that a tribunal rules that either no substantial change in economic conditions has taken place, or that a substantial change has taken place but the impact of such a change is too difficult for the tribunal to interpret in relation to a determination of future prices, the outcome will be that – at the end of proceedings which may have taken more than a year to complete and cost a great deal of money in lawyers' and experts' fees – either negotiations will need to recommence or there will be no alternative but to terminate the contract.

However, should tribunals decide that substantial changes have occurred, they could adopt a more proactive position towards future pricing. It is unlikely they will wish to completely abandon the existing contractual framework, but they may suggest a compromise such as a base price (Po) adjustment, but retaining the oil indexation provision. The basic problem is that there may be no legal precedent – and there will certainly be nothing in the contracts – for interpreting hub prices as a reflection of current market conditions. Whether arbitrators feel empowered to make this conceptual leap will probably depend on their interpretation of the original intention of the parties in relation to market development. Buyers – and probably the industry as a whole - will be seeking a 'landmark' ruling that hub-based prices should be regarded as the best reflection of current economic (supply and demand) conditions in the European gas market.

A landmark arbitral judgement along these lines might set the tone for all subsequent negotiations (and if necessary arbitrations). Although a continuation of oil indexation would not, from a buyer's point of view be ideal, a periodic resetting of the base price could be an acceptable, time-limited compromise. In our view, such arrangements should be seen as part of the transition towards full hub-based pricing.

Negotiation Scenario: transitional arrangements towards a market price

An alternative to litigation would be to agree a transitional arrangement which could lead either to a negotiated settlement or, in the event that at the end of the transitional period the arrangement was deemed unacceptable by one or other party, the options of litigation and/or termination of contract could still be exercised. A transitional arrangement has the merit that it could avoid the poisoning of relations between contractual parties which is a risk in the event of litigation and which, irrespective of the outcome, may make it difficult for the parties to resume a good working relationship thereafter.

Transitional price arrangements will need to focus on three different parameters: the definition of the market price which would be the goal of the transition: the period of adjustment to a new price setting mechanism; and the adjustment of the price during the transitional period. Our aim here is to suggest *principles* of these three elements rather than complex arithmetical solutions. We believe that parties would need to agree on the following major elements:

Definition of the market price to which contracts will be adjusted: this could be the month-ahead price at a single hub, or an average of a number of hubs. It could also be based on day-ahead prices, averaged over a month, at one or a number of hubs.

Period of adjustment: in theory any period up to (probably) two years is possible, but the urgency of the buyers' position suggests the beginning of the gas year commencing October 1, 2011.

Adjustment of price during the transition: a very simple approach would be that, having agreed the definition of the market price, and the number of months until the end of the transitional period, the difference between the contract price and the market price should each month be divided by the number of remaining months until the end of the transition and the price should be adjusted by that fraction each month.

Table 3: Example of a six month transition to market prices: May-October 2011

Six Month Transition	Contract Price*	Market Price**	Monthly Transitional Price
May 1, 2011	100	75	95.83
June 1, 2011	100	75	91.66
July 1, 2011	100	75	87.49
August 1, 2011	100	75	83.32
September 1, 2011	100	75	79.15
October 1, 2011	100	75	74.98
Adjustment completed, market price adopted thereafter			

Note: *quarterly oil-linked long term contract price; **hub-based price as defined by parties

Table 3 shows an extremely simple version of a six month transitional arrangement where both the contract and the market prices remain the same, with the market price 25% below the contract price, for the duration of the period. The transitional price is adjusted by the same proportion in each of the six months until it reaches the market price. Reality will certainly be more complicated. The evolution of the two prices during the period will not be known with any certainty; the two prices will undoubtedly diverge and converge during the period and therefore the calculation of the monthly adjustment will be much less straightforward.

Impact of these scenarios on long term contracts and the commercial role of European utilities

It is very difficult to know how many arbitrations will formally proceed, and what pattern (if any) their outcomes are likely to take. Depending on which sellers are involved, the numbers of contracts which may be affected by these changes are very significant. A very rough estimate would be that there are 50 pipeline and 30 LNG contracts between North West European companies and Norwegian, Russian and other suppliers external to Europe.[81] Clearly taking all of these contracts to arbitration would be unworkable. However, in early

[81] This is a very rough estimate of contracts which extend beyond 2015; it does not include contracts between continental European companies themselves or those involving UK companies. Cedigaz 2008 and Cedigaz 2008a.

2011 Gazprom did not appear to be in conciliatory mood with Deputy CEO Alexander Medvedev quoted as saying: "If it does come to arbitration proceedings, we are pretty confident…God help them if someone takes a risk to go to arbitration."[82]

However, given that the history of similar renegotiation and litigation in both North America and the UK led to the disappearance of long term contracts in those markets, it is important to consider the possibility of a similar impact in Continental Europe.[83] From a legal perspective, a transition away from oil-linked prices in long term contracts would not automatically threaten the existence of these contracts (although it would fundamentally change the commercial gas framework). But if Europe moves away from oil- and towards hub-based prices, sellers would at some stage need to ask themselves what remaining purpose was being served by long term contracts.

Under the traditional commercial framework, sellers relied on the legal obligation of gas buyers to take a minimum volume of gas at an oil-related price. Because sellers did not have access to downstream markets, they relied on their gas and energy utility buyers' access to a large customer base and sufficient market power to ensure that the customer base would pay oil-related prices. However, as noted above, the arrival of competition and third party access in European gas markets means that utility buyers no longer have the ability to force oil-related prices on their customers. And the introduction of simplified third party access conditions means that purchasing gas at hub-based prices is a reality for the majority of these customers.

Sellers may therefore question the value of continuing long term contractual relationships with their traditional buyers. In short, if sellers simply receive hub prices from buyers under a long term contractual arrangement, this will be little different from the price they could achieve by themselves selling directly to end-users (via third party access). This raises a much larger question than this paper can address: the future commercial role of traditional gas/utility buyers in a liberalised and competitive market with hubs as the dominant price reference. A very brief observation would be that in both North America and the UK, sellers (both producers and exporters) established large trading operations. But although in the initial stages of liberalisation in the UK gas market producers established retail sales operations, after a few years they left this market for two main reasons: first they had no corporate culture or expertise to sell to hundreds of thousands (let alone millions) of customers. Second, the rate of return on such operations (particularly in markets which are liberalising and becoming more competitive) is substantially less than the traditional expectation of upstream companies. Following this logic, one might expect the traditional mid-stream utilities to retain a significant aggregation role especially for sales to smaller customer groups, but less

[82] Gazprom Says It Would Win Arbitration on Oil-Linked Contracts, *Bloomberg*, February 15, 2011.

[83] Contracts of up to 8 years still exist in the British market but usually contract lengths are shorter; in the UK and North America anything over 1-2 years is commonly referred to as a "long term" contract.

than previously. They could continue to agree take or pay offtake guarantees – if requested by sellers – as long as prices were hub-based.[84]

Could both scenarios lead to the breakdown of long term contracts - historical precedents

Continental Europe can take some lessons from other countries and regions which have already passed through the transition from long term oil-linked prices. In North America, this process began in 1984 and, although the contractual transition was finally completed only in the 1990s, the transition to Henry Hub pricing was substantially completed within a few years, as reflected in the establishment of the NYMEX futures market in 1990.[85] In the UK, the process began in the early 1990s and again, although the contractual transition probably required the best part of a decade, a spot market was established within a few years with NBP prices becoming the national price marker by 1996.[86]

This is not the place to attempt to tell the story of the North American and UK contractual and price transitions. Suffice it to say that these were extremely commercially painful and involved very difficult negotiations and substantial litigation. In North America, utilities had signed contracts with producers at high prices and high levels of take or pay. The utilities tried to pass those prices through to their customers, but as a gas surplus developed and market prices fell dramatically, federal and state regulators refused to allow high gas prices to be passed through to final customers.[87] In the UK the pain was largely concentrated on the dominant player, British Gas, which had take or pay contracts with producers at prices higher than the evolving spot price, and lost substantial numbers of customers as prices fell during the early stages of liberalisation of the downstream market.[88]

The position of Continental European utilities has similarities to both the UK and North American history. In both markets buyers had signed long term contracts, but without the protection of price reviews afforded by Continental European contracts, which were left stranded when the market became over-supplied and prices crashed. But there is an important factor which distinguishes the Continental European situation: in both North America and the UK, the vast majority of the parties involved were under the same political and legal jurisdiction (or in the case of the US and Canada, similar jurisdictions).[89] In the case of Continental Europe, not only are there a large number of importing companies with differing

[84] This is because, as noted above, they could trade minimum take volumes in excess of their requirements without price penalties.

[85] For a brief sketch of these developments in North America, UK and elsewhere see IEA 1994, pp. 76-83. For an account which focuses specifically on the contractual problems and the development of futures prices see Sutherland.

[86] For details of how markets and prices evolved in the UK see Heather especially pp. 12-32 and Wright, Chapter 3.

[87] A relatively brief but highly informative narrative on the US can be found in Hollis, while Kalt and Schuller has a contemporary account of these problems.

[88] Stoppard; Heather p.29.

[89] This is not to under-estimate the differences between the US and Canada, but the legal/regulatory frameworks of these countries are far more similar than anything seen between Continental Europe and its gas suppliers.

legal systems, but their suppliers – in particular Russia and Algeria, but not forgetting a large number of LNG exporting countries – operate under fundamentally different legal/regulatory frameworks. Thus the complexity of renegotiating Continental European long term gas contracts (particularly) with external gas suppliers can hardly be overestimated given that, as has been said above, even in countries and regions with (largely) common frameworks, the process required several years to complete.

While it has been noted above that there is strong support from all commercial parties for the continuation of existing long term contracts, it has to be said that the outlook is not good. The arbitration scenario could end with termination of contracts, and the negotiation scenario could cause sellers to decide that they can obtain similar (or potentially greater) value by selling the gas directly to customers themselves. The transition to hub-based prices is therefore likely to be accompanied by either a quick, or a slower, termination of *existing* long term contracts similar to what was seen in North America and the UK. However, two important qualifications to this conclusion need to be made: not all existing contracts will be terminated; even under the arbitration scenario, it is likely that some contracts will be renegotiated and continue, at least for some time. Moreover, the termination of some existing contracts does not rule out the possibility that *new long term* contracts could be signed, albeit with somewhat different terms to their predecessors.

Determining the length of new contracts will be an important part of the transition. Neither sellers nor buyers will wish to be selling and buying the totality of their gas at hubs on a daily basis. The most likely outcome, by the end of the transition, is for stakeholders to have developed a portfolio of contracts: some long term, some medium term and some spot. The main differences will be that the new long term contracts will have shorter lengths (8-10 years), smaller volumes and much more flexible terms than the existing ones.[90] Take or pay will become much less relevant (and probably irrelevant) in a trading environment. More important will be the obligations in relation to the source of gas delivered and the point of delivery. But these are issues for discussion at the end of the transition; the immediate debate and problem concerns whether and how prices in existing long term contracts can be brought back "into the money". We believe that hub-based pricing is the only solution to this problem.

[90] Wright Table 3.2, p. 72 has a list of UK contracts signed in the early to mid 2000s with these attributes.

Summary and Conclusions

2011 will be a decisive year for European gas prices and contracts. Starting in late 2008, European utilities encountered increasing commercial difficulty in managing their long term gas contracts, as oil-linked purchase prices rose significantly above hub-based prices, and they were forced to reduce their sales prices in order to retain their customers. At the end of 2010, oil-linked and hub-based prices converged, but this convergence was only temporary – and was partly accounted for by very cold weather in Europe. Moreover the post-2008 period had revealed the financial risk associated with oil-linked prices in an environment where oil prices could be in excess of $100/bbl. In the context of a surplus of European gas supply over demand which is likely to continue until at least 2012 and possibly a further 1-2 years, this is a commercially untenable position for European gas buyers.

This paper suggests that there is no commercially viable alternative to hub-based pricing in the European gas market. The reason is that European utility companies increasingly find themselves in a position where they are paying oil-linked prices in long term contracts but their competitors – and their customers – have the opportunity to buy at hub-based prices. The central problem of this situation is not price *level* but price *formation*. Gas prices will not "recouple" with oil prices because the supply/demand dynamics of the two markets have become fundamentally different. This is not to say that hub-based gas prices cannot rise to similar, and even higher, levels than oil linked prices. Our argument is that a single price formation mechanism needs to be established which will be the same for all gas buyers, with differences reflecting either transportation costs or entry/exit tariffs; that mechanism is hub-based pricing.

We believe that the transition away from oil-linked and towards hub-based prices in Europe which began in 2009 will continue, and hubs will become the dominant price-setting mechanism in the majority of markets relatively quickly in North West Europe and more slowly elsewhere. This transition will not be straightforward for a number of reasons. Continental European gas hubs continue to lack depth and liquidity, although this is improving everywhere. Fears of manipulation can be addressed through a process of averaging prices over periods of time and across different hubs. Price volatility can be partially addressed by a similar process but will become a much more significant feature of this new commercial framework.

More fundamentally, a move to hub-based prices removes much of the logic of the existing long term contracts. Transformation of those contracts will be extremely painful, whether this is achieved by negotiation or litigation. But both processes are likely to reach a similar end-point, the main differences being the length of time and the amount of financial pain suffered by stakeholders. This will result in very substantial changes to, and the probable eventual termination of, significant numbers of existing long term contracts, which in turn will raise serious concerns about security of supply and security of demand. New long term contracts will be shorter, much more flexible than their predecessors and with hub-based prices. But

stakeholders will increasingly develop a portfolio of contracts of different lengths to match their risk profile.

There is a possibility that these events may be accompanied by a significant deterioration of relations between buyers and sellers of gas, which may have much larger consequences for the future of gas in Europe. This is particularly the case since Gazprom has been the principal, and most vocal, public opponent of any fundamental move away from oil-linked prices. While other gas exporters may not be strong supporters of hub-based prices, some appear to have embraced the concept, and perhaps also the inevitability of change, to a much greater extent than has Gazprom. With the security consequences of the January 2009 Russia-Ukraine crisis still fresh in the memory in many countries, a gas conflict with Russia over prices would be highly detrimental to the overall prospects for the fuel in European energy balances, particularly given the general lack of government and EU support for any significant long term role for gas in a low carbon European energy future.[91]

The European gas industry is in the early stages of a commercial paradigm shift towards hub-based pricing and a much more diversified portfolio of contractual arrangements. What is still uncertain is the length of the transition, and the degree of financial pain which stakeholders will suffer. Historical precedents from the North American and UK gas industries suggest a transition lasting several years. But neither of those transitions involved contracts with external suppliers, which makes the Continental European situation substantially more difficult.

In response to the propositions in this paper, the most usual question which is asked is why it is necessary to fundamentally change pricing and contractual structures which have served the industry well over many decades and which, until relatively recently, there was no support for (and indeed considerable opposition to) changing? The answer is that these structures are anathema to the competitive gas market which is emerging in Europe and have become untenable for major utilities operating in an increasingly competitive market. These prices and contracts were well suited to an industry which was establishing itself in European energy balances in the 1970s and 80s, and where supply and demand were tightly controlled by a small number of dominant players. But over the past 30-40 years, market structures and conditions have decisively changed and oil product linkage is no longer the basis on which more than 20% of Europe's primary energy demand can continue to be priced.

[91] See Van Foreest (forthcoming).

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