

Gas as a Transitional Fuel

Jonathan Stern asks whether the future for international gas trade is constrained

Natural gas trade continues to expand rapidly both regionally and globally. Large numbers of pipeline and LNG projects are under development and many trade publications are kept in business by reporting on projects at various stages of planning. Why then is there any reason to be concerned about future availability of gas in international trade? The problem on the horizon is that, after the current wave of pipeline and LNG export projects have been completed, additional export projects do not appear to be a high priority for most countries.

The standard approach to estimating gas export potential is to look at current reserve and production figures, calculate a reserve to production ratio and make a judgement on the likely export availability. For countries with a reserve to production ratio of less than thirty years, this can be difficult, but for countries with more than fifty years of reserves, it should be unproblematic. There is however a difficulty with this numerical approach as it now reveals less and less about actual developments in individual exporting countries. The crucial missing elements in future export calculations are increases in domestic demand, and the incentives for countries to actually develop the reserves that have been identified.

In 2006, 22 countries exported gas by pipeline and 13 in the form of LNG (with 5 countries appearing in both categories). The position of the 19 largest net exporting countries in 2006 is shown in Table 1.

One event in international gas trade in the early 2000s may, with hindsight, be seen as heralding, if not a trend, then a warning about expectations concerning the future of gas trade.

This was the inability of Indonesia's Pertamina to meet its long-term LNG export contract commitments. The failure can be attributed to a number of country-specific economic and political developments, particularly its very large population and rapidly growing economy. As the decade has unfolded, research at the Oxford Institute for Energy Studies has revealed similar trends in a range of gas-exporting countries where it is increasingly likely either that exports will not be developed, or may be curtailed short of their potential, due to:

- Increasing domestic demand, fuelled by high economic growth and low gas prices;

- Adverse domestic political consequences for governments opting for higher price exports over domestic demand;
- Substantial financial surpluses which have removed the urgency to:
 - significantly increase exports above contracted levels;
 - rapidly develop reserves (which may already have been identified) to support new projects.

It would be easy to place these developments under the convenient catch-all of 'resource nationalism' or, for the more paranoid, cartelisation in pursuit of higher prices. However, persuasive explanations can be found

Table 1: Largest Net Gas-exporting Countries in 2006^a

	<i>Reserves (Tcm)</i>	<i>RP Ratio^b</i>	<i>Exports (Bcm)</i>	<i>% of Gas in Primary Energy Demand</i>
Algeria	4.50	53.3	61.6	64
Argentina	0.42	9.0	6.1	53 ^d
Australia	2.61	67.0	18.0	21
Bolivia	0.74	66.3	10.8	37 ^d
Brunei	0.34	28.6	9.8	76 ^d
Egypt	1.94	43.3	16.9	44
Indonesia	2.63	35.6	34.3	31
Iran	28.13	>100	5.7	53
Libya	1.32	88.9	8.4	28 ^d
Malaysia	2.48	41.2	28.0	54
Myanmar	0.54	40.1	9.0	52 ^d
Nigeria	5.21	>100	17.6	36 ^d
Norway	2.89	33.0	84.0	0
Oman	0.98	39.0	12.9	71 ^d
Qatar	25.36	>100	31.1	80
Russia	47.65	77.8	151.5	55
Trinidad	0.53	15.1	16.3	91
Turkmenistan	2.86	46.0	6.0 ^c	76
UAE	6.06	>100	7.1	66

a) Not in this list but also countries which currently export significant quantities of gas or where projects are under construction are: Kazakhstan, Azerbaijan, Yemen, Timor Leste, Equatorial Guinea, Papua New Guinea, Angola and Peru.

b) years at end 2005;

c) outside CIS only, total exports were around 47 Bcm

Source: *BP Statistical Review of World Energy 2007*, except (d) which are 2005 data from Energy Information Administration, *International Energy Annual*, 2005.

less in conspiracy theories and more in first year economics textbooks.

In the vast majority of countries in Table 1, gas is sold to the domestic market at prices which reflect (usually) fixed levels set in the 1970s and 80s, rather than international levels of the late 2000s. It is unfair to be overly critical of this situation given that energy pricing worldwide has been thrown into confusion not only by recent oil price increases but also by the changing relative prices of oil and gas, and gas and coal (with or without allowances for carbon).

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Many OECD countries continue to use oil as the dominant mechanism for setting gas prices, which means they are similarly divorced from market conditions. But while in OECD countries, this usually leads to overpricing of gas (i.e. higher prices than the supply/demand balance would suggest), in gas-exporting countries the growing problem is serious underpricing of gas. This is commonly labelled a problem of ‘subsidy’ but in only a few countries are gas sales prices lower than the cost of production and delivery. The more usual situation is that the domestic sales price is far below the export price, a problem which has been exacerbated by the post-2003 oil price increases.

Russia

Russia and the Gulf countries present two contrasting examples of the domestic/export pricing conundrum faced by gas-exporting countries.

Russia has by far the most complex set of gas choices with a huge domestic market in Europe, very large export commitments in Europe, and longer-term potential to develop substantial pipeline exports to Asia, and LNG exports to both Asia and North America. But Russia has long had a problem which is only just emerging elsewhere: gas accounts for more than 50 percent of the Russian energy balance with consumption (including all gas uses) of around 450 Bcm per year.

Prices paid by domestic customers during the Soviet period bore no resemblance to the costs of producing and transporting gas from remote fields in Siberia several thousand kilometres to centres of demand, and substantial price rises in the mid 1990s created a wave of non-payment and barter trade. Having extricated the industry from this problem, the Putin administration finally got to grips with domestic price levels in late 2006 with the announcement that by 2011, prices for industrial (including power generation) customers would be equal to those of European border prices on a netback basis. This included a firm commitment that by 2011, industrial prices will be at least 250 percent of the 2007 level which would still only bring them to around \$3.50/mmBtu. There is also a commitment to raise prices for non-industrial customers to these levels but this seems likely to take much longer. Nevertheless, this is an immensely important policy commitment because it means that:

- all new production – including gas currently flared at oil fields and production from the supergiant fields on the Yamal Peninsula – will be profitable to develop;
- for the first time in the history of the Russian gas industry there will be a serious incentive to invest in efficiency improvements and replacement of capital stock.

Unless (oil and therefore) European gas prices fall from current levels, the aspiration of netback equivalence with European border prices by 2011 will turn out to be over-ambitious. But breaking the traditional right of Russian consumers to subsidised

gas is a paradigm shift which both acknowledges that the old system was not sustainable, and sets in motion a gradual transformation of the profitability of the huge domestic market. What this means is that by the late 2010s, the general assumptions that gas exports will always be vastly more profitable than domestic sales, and therefore that Russia will continue to significantly increase exports to Europe, will need to be increasingly questioned.

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The Gulf Oil Producers

Before 1980, Gulf oil producers flared much of their associated gas production, but the past thirty years have seen growing utilisation of this fuel in a range of industrial, feedstock and power generation applications. In countries such as Iran, where reinjection of gas to enhance oil production (and exports) is a major market, it makes absolute sense for governments to divert more gas for this purpose. In most Gulf countries, the position with regard to domestic gas pricing and incentives to develop gas for domestic markets is similar to Russia’s in the period up to 2000. Partly because of the flaring tradition, and partly because the value attributed to gas associated with oil production can vary from zero to the full market price, depending on internal corporate methodology and the tax regime, there has been a tendency for oil producers to distribute gas in their local economies at low fixed prices as part of the social contract.

This was not necessarily a problem until the 1990s when population and economic growth, combined with substantially increased incentives to export oil and substitute gas for oil in

the domestic economy, created rapidly rising internal demand. In most Gulf countries, domestic gas prices in 2007 did not exceed \$1/mmBtu despite LNG export prices of up to ten times that figure. This was thrown into sharp relief with the start of the Dolphin project last year when Qatar began to export pipeline gas to UAE and Oman at a price of around \$1.40/mmBtu, while these importers were exporting LNG at prices of \$6–10/mmBtu. (Justin Dargin, *The Dolphin Project: the development of a Gulf gas initiative*, OIES, 2008)

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Failure to introduce mechanisms to adjust domestic prices to the market conditions of the 2000s, means that Middle East countries increasingly find themselves ‘short of gas’. Without a strong government commitment to increase domestic prices, there will be no incentive for private investment in gas production and infrastructure for domestic markets. This means that without price reform, most governments will incur increasing costs to maintain this part of their social contract. This throws up counter-intuitive situations like that of the UAE where profitable development of domestic sour gas reserves exceeding 6 Tcm, will require domestic gas prices to be raised at least fivefold. The gas price problem is compounded by a lack of electricity price reform with power prices in most countries nowhere near levels which make new domestic gas-fired power generation viable. In this situation, there can surely be no economic rationale for developing much higher cost alternatives such as nuclear power.

Other Exporting Countries

There is virtually no country in

Table 1 to which these observations do not apply, to a greater or lesser extent. From Turkmenistan where gas is given away free to the population, to Western Australia where, although customers pay a commercial price, the State is insisting that 15 percent of gas in fields being developed for LNG exports must be reserved for the domestic market. In most countries, domestic politics will determine the priority given to domestic markets despite the clear economic benefits of increased exports. Politics will also determine the continuation of very low gas prices usually on the grounds that poor people cannot afford to pay market prices for gas. This may be true and – as in Russia where winter temperatures mean that lack of access to affordable energy is life-threatening for residential customers – special measures may need to be extended to vulnerable groups. But arguments about ‘poor pensioners freezing to death in winter’ are too often used to justify subsidised pricing to consumers well able to pay market prices as well as industries where governments are seeking to boost employment.

This takes on a dangerous circularity where prices have to be kept low in order to maintain the social contract with the population, but these same policies encourage wasteful and sub-optimal use of gas which means that reserves are used up more quickly with little incentive for new exploration and development. Not only will these problems not go away, but they are likely to get worse.

Another increasingly common argument is that with the post-2003 increase in international oil and gas prices, exporting countries have no need to increase their revenues and would rather conserve their resources for domestic use and ‘future generations’, than increase exports.

Qatar

A special case here is the current Qatari policy of a ‘moratorium’ on future gas projects until the technical repercussions of the enormous increase in production from the North Field from around 50 Bcm to more than 240 Bcm in 2012 have been fully

appraised. Despite the importance of the moratorium for global gas and LNG development, there is no official document or speech setting out the criteria which will determine whether new exports will be considered post-2011. The Qataris – very understandably – do not want to make future export commitments which for a variety of reasons, they may not wish to pursue.

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Looking around the gas world, there are just a handful of countries which can realistically be expected to *substantially* (that is by more than 30Bcm/year) increase exports *over and above their current contractual commitments* by 2020. These are Australia, Turkmenistan, Libya, the East Siberian and Far East regions of Russia, and possibly Azerbaijan, Kazakhstan and Nigeria. On reserve grounds Saudi Arabia, Venezuela, Iran and Iraq would also qualify but for a variety of reasons ranging from current government policy to long histories of project failure (or at least lack of progress) to problematic internal politics and political relationships with potential major importers, the prospects are poor.

There is no short-term crisis of global gas supplies; projects under development will take the industry through the mid-2010s. But lead times mean that the next generation of pipeline and LNG projects will need to be signed in the early 2010s. At present, aside from the very few countries listed above, it is difficult to see other sources of substantial additional internationally traded gas. A crucial question will be whether domestic gas prices in exporting countries will be raised to levels that encourage new gas

development and efficient utilisation, even if those prices remain substantially below export levels. Russia has made a significant move in this direction (although there is a long way to go) which other exporting countries need to follow. To the extent that they are not able, or choose not, to do so, the outlook for incremental gas in international trade beyond 2020 will become highly uncertain.



Michael Stoppard looks at LNG growth to 2010

It is sometimes said 'the best way to predict the future is to invent it'. In many respects that is what the LNG industry is doing. The LNG business will be radically different in 2010 than it is today. It will be different in size, but more importantly it will be different in regional scope, in its business models, and in its trading practices. And the implications of these changes will affect gas markets and pricing across all the major continents.

To be sure, the full consequences of a wider role for LNG on markets are uncertain, but the underlying drivers of change rest on firm and tangible investments under way today. Namely, over the next 24 months:

- Global LNG supply will grow by almost one third
- Flexible or 'tradeable' LNG supply will double
- Global LNG shipping capacity will grow by more than one half
- LNG regasification utilisation in the Atlantic basin which was about 52 percent in 2007 would have fallen to 43 percent by 2009.

These assertions may surprise some. The trade press is currently littered with reports of substantial delays to LNG projects, a slowdown in project sanctions, tougher upstream terms, joint-venture misalignments, and spiralling costs. These factors do indeed raise major questions about the pace of growth of LNG beyond 2010 and its ability to deliver. They do not, however, materially affect the growth rates over the next two years to 2010 that are 'baked in', based on momentous investment decisions made several years ago. The LNG armada has already set sail, so to speak.

The driver of change is the much-vaunted globalisation of gas. Until now, natural gas has been predominantly a regionally-bound fuel with some important exceptions. Compare gas with the other energy commodities. In 2006, about half of all oil and some 15 percent of coal were sent across water in intercontinental trade. By contrast, seaborne trade of natural gas was less than 8 percent. The growing separation of the world's gas resources from the major demand centres means that seaborne gas trade must increase. LNG – whereby natural gas is cooled to the point it turns into a liquid and can be loaded onto specialised ships for transportation – will be the primary technology to transport gas across the world's oceans. Other niche technologies may also emerge and prosper over time.

The rate of growth of the LNG industry is dramatic. LNG supply, as measured by liquefaction capacity, will increase by approximately 30 percent in the next twenty-four months; an extraordinary rate of growth for an industry that has spent 45 years building to its current level. Supply will increase from 190 Mt (262 Bcm) today to 247 Mt (341 Bcm) by early 2010. Qatar spearheads this drive – about half the investments in LNG supply today are taking place on a single industrial estate at Ras Laffan in Qatar. In addition, Russia (the high profile Sakhalin project in the Far East) and Yemen will join the exclusive ranks of LNG-exporting countries before the decade is out. Australia and Indonesia will also be adding significantly to

their existing projects. The investment decisions on these projects were taken several years back, yet their consequences are still to be seen.

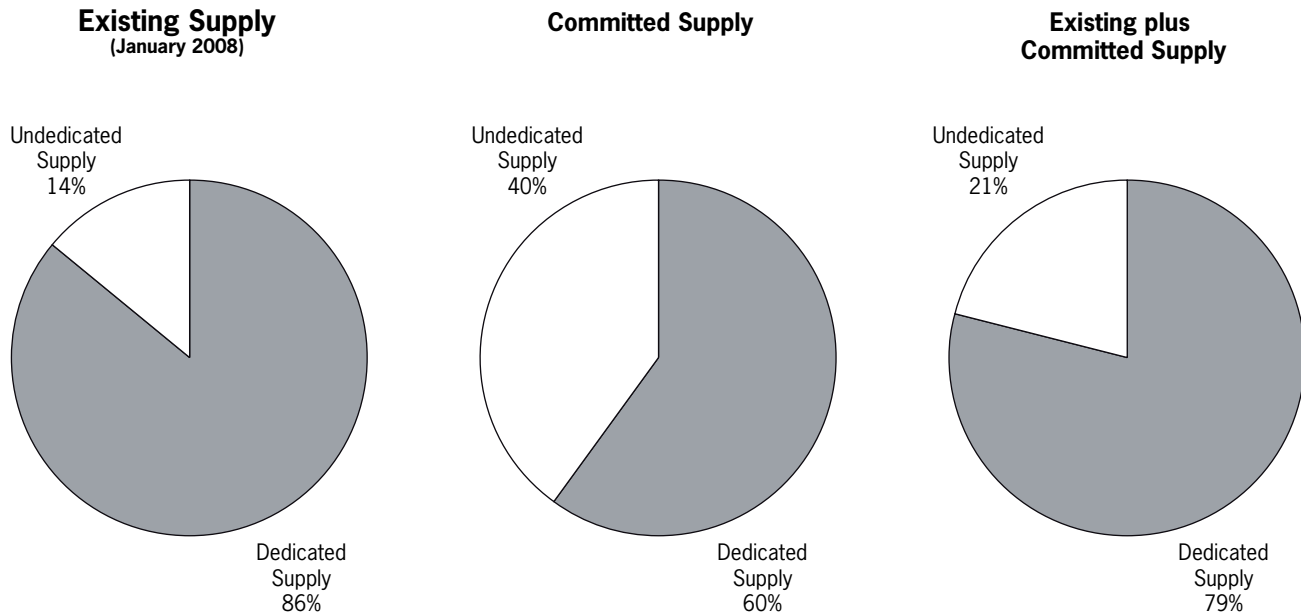
Given the boom in construction, it is not surprising that many projects are reporting a whole host of delays in the face of stretched construction teams and growing equipment lead times. But these delays – serious as they are – do not change the fundamental growth story.

The new LNG supply will be much more market flexible than of old. Traditionally, LNG supply was pre-sold under long-term contracts to a specific country and end-user. What the LNG industry often calls 'tramline trade' where ships ply a regular trade between fixed points of dispatch and delivery. It was said that these rigid contracts were necessary to finance the large capital investments required both by the LNG producer and by the LNG importer.

"The growing separation of the world's gas resources from the major demand centres means that seaborne gas trade must increase"

Yet over the last several years, there has been a dramatic change to the nature of these contracts. The change has not been fully recognised since most LNG supply continues to be sold under long-term contracts. Talk of 'spot' trade is somewhat exaggerated. But many of these newer contracts are not dedicated to a specific market or end-user; rather the counterparty is an aggregator who will seek to move the LNG to the market of highest value – as with any regular commodity. These aggregators – most often the largest International Oil & Gas Companies (IOGCs) and/or their National Oil Company (NOC) partners – have in effect assumed the volume risk of LNG in return for the privilege and opportunity to trade globally. The importance cannot be over-estimated: the new model combines the security of

Figure 1: Flexible LNG Supply Growth by 2010



Source: Cambridge Energy Research Associates

long-term contracts with a transition to a more traded world. LNG projects can continue to develop with the security of long-term offtake contracts but with a new in-built flexibility.

CERA estimates that 40 percent of LNG supply under construction is 'non-dedicated' and flexible to trade (see Figure 1). Most is either in the Atlantic Basin or the Middle East, with the Pacific Basin continuing to favour old-style contracting. The amount of flexible trade will double by 2010, and will surely transform thinking within the industry. Although it should also be noted that supply – whether flexible or tramline – is set to remain, as it always has, in the hands of a relatively small number of key players.

So LNG supply is growing fast, and yet apparently not fast enough. Investments in both shipping and regasification are moving at a faster rate still. Take shipping. The capacity of the world's global LNG shipping will increase by more than half by 2010. 2008 will see a record level of ships delivered – 58 ships added to an existing fleet of 251. The fact that shipping is growing faster than LNG supply can be partially explained by

the need for longer trade routes, but this is unlikely to be sufficient to prevent a growing availability of ships. Abundant shipping will allow for new novel solutions – for example ships are increasingly to be used not only for transporting LNG, but as floating regasification and storage vessels. Available shipping will allow greater arbitrage.

Moreover, just as for supply, so for shipping the industry is also set to become more flexible. Most of the existing ships are dedicated under long-term charters to specific LNG projects. Yet of the ships on order, 16 percent are contracted to aggregators and 20 percent are speculative – builds with no fixed charter arrangements. Shipping may well be the first link in the LNG chain to commoditise as more spot charter deals develop.

Regasification terminals are the vital portals that connect local markets into the emerging global gas system. Investments in regasification are also proceeding apace, well in excess of associated liquefaction. This should not surprise: regas represents only some 10–15 percent of the costs of the full LNG chain and therefore should always be in excess over liquefaction.

For aggregators surplus regasification is essential to be able to move shipments between regions according to need. For aspiring buyers regas has become the table stakes for playing the global gas procurement game.

A recent CERA report *The Great Regas Dilemma* argues that, in spite of an apparent growing surplus of regas capacity, some investment in duplicate regas may make sense as a price and volume hedge, a form of insurance. Nevertheless, as more regas is put in place, it follows that the utilisation of these facilities must decline and the costs for unused infrastructure must be borne.

A rapidly expanding number of countries are looking to join the global gas network adding to competition on the buyers' side. Countries considering building LNG import facilities range from Brazil and the Netherlands, through to Pakistan and New Zealand.

Where will all the incremental LNG go? A part of it will be eagerly bought up by the dominant buyers Japan and Korea but their short-term needs can only accommodate a small part of the growth by 2010. The emerging markets of China, India, and Brazil

will certainly be in the market, but their own needs will be bounded by their own domestic alternatives and by affordability. The bulk of new supply will flow into the Atlantic Basin and, in particular, into North America. North America is the world's largest natural gas market and the most open in terms of liquid traded hubs and accessible gas storage. With its own production reaching a plateau, the North American appetite for LNG will be strong. As a foretaste of things to come, LNG imports to North America reached record levels in 2007 – but the sharp step-up in imports will come in 2009.

The increased role of North America in LNG will challenge the pricing and contracting practices of old. Sales into North America will necessarily be shorter term in nature and involve more spot price risk. A three-way accommodation will need to be reached between the needs of the traditional Asian and Continental European clients with their focus on the long term and security of supply, the market-based needs of North America and Northwestern Europe, and the proliferation of scattered smaller market entrants.

Many of the elements are thus in place for a shift to a more freely-traded and complex global gas market. A growing and more flexible supply, available transportation capacity, the development of a network of regas portals to allow arbitrage to take place, and the bringing together of the great markets of Asia, Europe, and North America. And the players who are making this happen are not predicting the future; they are busy inventing it.



Burckhard Bergmann assesses European gas markets and the interplay of competition, climate protection and supply security

All current forecasts on global energy consumption expect worldwide demand for gas to rise considerably in the years ahead.

In the efforts to ensure gas supplies to European energy markets and especially to the German market, one challenge in particular is emerging: given rising demand and falling indigenous production, the strategic task will be to prevail over demand coming from other regions of the world.

What is more, in the coming years, European gas markets will not only be confronted with increasing globalisation and internationalisation, they will also have to develop against the backdrop of ambitious climate protection targets.

Global Competition to Obtain Gas

Today Europe is the world's largest gas importer, followed by South-East Asia and the United States. To safeguard long-term gas supplies, the European gas industry will have to mobilise additional imports of approximately 150 billion m³ in the period up to 2020. In other words, after 2010 a new long-term import project for a supply volume of approximately 15 billion m³ will have to materialise every year.

In the period between 2010 and 2020, the USA will be looking for approximately 100 billion m³ on the world market as additional imports, and South-East Asia will be seeking 200 billion m³. This means that competition to obtain supplies will become far fiercer between the major gas-consuming regions.

E.ON Ruhrgas sets standards with its broadly diversified gas supplies

from six countries. In 2006, E.ON Ruhrgas received the largest share of its gas supplies from Norway, some 27 percent, while Russia accounted for around 25 percent. About 19 percent came from the Netherlands, 16 percent from indigenous sources, 9 percent from the UK, and 4 percent from Denmark and other sources.

It is a fact that the largest gas reserves are in the hands of a few producer countries, and concentrated there among a few powerful oil and gas companies. To respond to this reality, it is essential to carry on seeking the diversification of gas supplies as well as long-term cooperation. E.ON Ruhrgas's contracts with Norwegian and Russian suppliers have a duration of up to thirty years in some cases. The investment needs for safeguarding Europe's future gas imports will increase. Only long-term import contracts will provide the necessary security and prospects for investments totalling billions of euros, which are needed to implement upstream projects in increasingly inhospitable regions.

“In future, the coexistence of long-term import contracts and gas trading at exchanges will constitute the right mix for the sake of supply security and competitiveness”

Furthermore, long-term import contracts for specific supply volumes ensure that new import infrastructure is used to capacity and are thus the prerequisite for investments in the transmission and storage sectors.

Increasing spot trading at exchanges is not at variance with such long-term gas supply. On the contrary, open trading places within Europe give market players a chance of optimisation, create conditions for competitive supplies to regional markets and widen the customers' choice.

On the other hand, reliable long-term

gas supply in Europe cannot be achieved solely by setting up such trading places. The supply situation in the UK in the winter of 2005/2006 is an example warning us that temporary market scarcity leads to dramatic price fluctuations. A region like the EU which is heavily dependent on imports cannot rely solely on short-term interaction of supply and demand but must take long-term measures to ensure sustainable energy supply. In future, the coexistence of long-term import contracts and gas trading at exchanges will constitute the right mix for the sake of supply security and competitiveness.

European Demands for Ownership Unbundling

On international procurement markets, European energy companies will be able to occupy a stable competitive position only if they can negotiate with producers on an equal footing in future. They must have a critical economic mass so that a large demand potential can be aggregated and capital-intensive projects shouldered.

Incompatible with this are the regulatory ideas of the European Commission which significantly weaken private-sector companies like E.ON. Above all, ownership unbundling should be mentioned in this context.

Ownership unbundling and the so-called alternative of an independent system operator (ISO+) are unsuitable for strengthening competition and contributing towards lower energy prices. Ownership unbundling forces private owners alone to relinquish their assets, while – according to the Commission's proposals – the networks of state-owned companies can stay in state ownership. Paradoxically, far greater intervention is envisaged in free-enterprise markets than in markets with dominant state-owned companies.

At the same time, the recent mergers of Statoil and Hydro in Norway or Gaz de France and Suez in France show that on both the producers' and the traders' side there is a trend towards power and gas champions

positioned Europe-wide. If private-sector European companies are clearly weakened against this background by the European Commission's new energy package, it will be more and more difficult to negotiate on an equal footing with the limited number of powerful producers.

This applies to negotiations with Norwegian and Russian partners and above all when entering the global LNG market of the future.

LNG as an Additional Option?

E.ON Ruhrgas is pursuing a broad-based LNG strategy in order to further diversify its supply sources and benefit from a rapidly expanding market. With the aid of LNG the company intends to tap hitherto inaccessible supply sources and make new volumes available for the European market.

“Ownership unbundling forces private owners alone to relinquish their assets, while ... the networks of state-owned companies can stay in state ownership”

Here, even more than is the case with other gas procurement markets, the German and European gas industry faces the challenge of having to operate in a global environment. LNG, which is transported by tanker, will in future increasingly be delivered to destinations where the highest prices prevail at a particular time. The USA and South-East Asia in particular will to a growing extent compete with Europe to obtain LNG. The geographically favourable location of the main producers (e.g. Qatar) and the different forms of price indexation worldwide (coexistence of oil and gas price indexation) combined with selective rerouting of LNG cargoes depending on the price situation all basically offer a potential for arbitrage and are likely to expedite the development towards a global LNG market

and worldwide competition to obtain supplies.

Yet, this will occur less dynamically than anticipated one or two years ago because LNG costs have risen steeply of late, and projects are repeatedly being delayed by political decisions. This might slightly dampen the euphoric predictions of a rapidly expanding LNG market worldwide, but it will not be able to stop the underlying trend. After all, adequate reserves are available in LNG-exporting countries, the technology is advanced and the projects remain economically viable on the whole.

In the long term, E.ON Ruhrgas is aiming at linking a fully integrated LNG chain to its equity gas production. On the subject of LNG supply, talks are currently being held with various gas producers. Incidentally, the producers that are already important for the EU market are also major stakeholders in the new LNG projects. Parallel to activities on the procurement side, we are pursuing concrete projects concerning LNG unloading and regasification.

E.ON Ruhrgas is currently dealing with terminal projects in Germany, the UK, France and the northern Adriatic coast.

It would be a sensible arrangement if in 2020 Germany could cover 10 to 15 percent of its gas needs with LNG.

Climate Protection by Pipeline

An old 'new issue' will determine the energy agenda in future not only in Germany and Europe: climate protection. In the EU it has been decided to reduce greenhouse gas emissions by 20 percent, raise energy efficiency by 20 percent and increase the share of renewables on the heat energy market by 20 percent by 2020. Germany even wants to exceed those targets: greenhouse gas emissions are to be cut by 40 percent by 2020 compared with 1990.

All in all, this means that Germany has to reduce an even greater quantity of CO₂ than in the last twenty years, but in half the time. The targets are to be reached primarily by doubling energy efficiency by 2020 compared

with 1990 and by increasing the market share of renewables. At the forefront of this very ambitious climate policy is the heat energy market, the main sales sector for gas. At least for Germany this means that, due to intensified promotion of renewables and increased energy conservation, for example by improved thermal insulation on buildings, gas consumption on the heat energy market will decrease.

“to make proper use of the product and market benefits of gas for climate protection, we need a debate and policies that are not encumbered with ideology”

However, it is obvious that neither Germany nor Europe as a whole can attain the ambitious but necessary climate protection goals without systematically exploiting the ecological benefits of gas. It is the fossil fuel with the greatest climate protection potential and the widest use. The famous Hamburg-based Institute for the World Economy stated in a recent study:

Due to its properties – low CO₂ content and direct use without conversion losses as an energy with highly efficient technology in many fields – gas can ensure high security of supply and reconcile the goals of climate protection and energy supply at minimum economic cost.

However, to make proper use of the product and market benefits of gas for climate protection, we need a debate and policies that are not encumbered with ideology. The one-sided claim that climate protection is synonymous with exclusive use of renewables is of no use to anybody. Anyone who wants to accomplish something in practice must answer the following questions without ideological blinkers:

How can I

- 1) achieve truly more efficient use of energy,

- 2) simultaneously reduce CO₂ emissions significantly and
- 3) at the same time keep the cost-benefit ratio acceptable to the consumer and industry?

Gas has great advantages in all three dimensions of efficiency. It can pave the way towards an energy sector with generally lower CO₂ emissions. This way leads, on the one hand, via the natural gas pipeline system as universal infrastructure for fossil fuels and for renewable energies ranging from bio natural gas to hydrogen using photovoltaics. On the other, it leads via highly efficient and innovative natural gas technology, which will in future be increasingly combined with renewable energies.

Conclusion: More Competition, More Climate Protection – More Supply Security?

The importance of gas for the energy industry will tend to increase in the coming years because of the growing thirst for energy in newly industrialising countries like China or India and because of ever more stringent climate protection measures. Global competition to obtain supplies will become even stiffer, while the expansion of renewable energies in tandem with intensified energy conservation will transform the German and European heat energy markets in the medium term. New regulatory actions and debates are causing the market situation for gas to become highly complex. Consequently, far-sighted resource management and the early conclusion of long-term contracts are more important than ever for the purpose of ensuring security of supply. At the same time, the potential of gas must be tapped systematically and be promoted in energy policy for the sake of economically viable climate protection.



Thierry Bros considers that the UK gas model is a system hard to justify

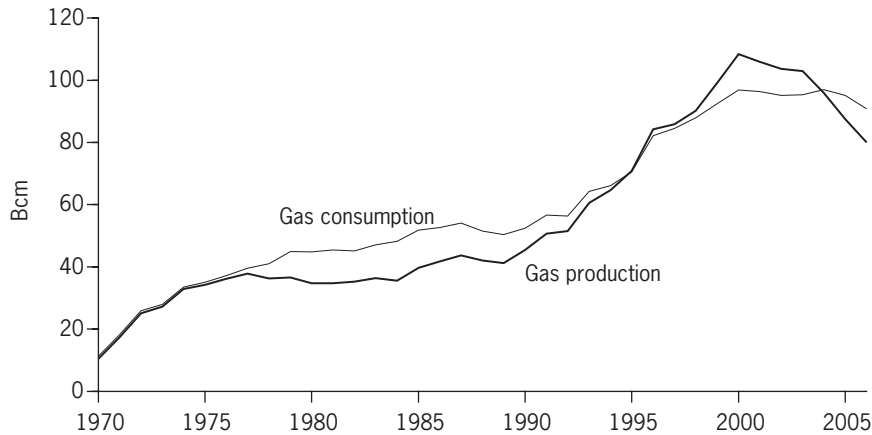
After the Second World War, the UK gas industry was nationalised with the passing of the 1948 Gas Act. British Gas used to have the monopoly as a natural gas supplier in the UK. Liberalisation which started in the USA in 1978 was followed in the UK in 1986. The UK thus became the first market in Europe to open up, long before any other EU country. The ‘National Balancing Point’ (NBP), created in 1996 as a market exchange, has boosted trade and is the most liquid gas trading hub in Europe. To create a level playing field, the regulator, Ofgem, pushed for increased transparency across the system. Today, the NBP is the most transparent gas exchange, allowing a number of players to trade gas and providing a major European price index.

Until 2004, the UK was awash with gas. Prices on the NBP were set on the basis of gas-to-gas competition and were therefore lower than in Continental Europe, where most gas is priced using long-term take or pay contracts based on an oil price formula. Until 2004, liberalisation was seen as bringing down prices and benefiting consumers.

The UK is a deregulated market where tariffs are set not by the government. The UK is considered to be the most competitive market in Europe. It is an unbundled market which meets the criteria contained in the third EU package of proposals published in 2007.

The UK used to be viewed as the perfect liberalised market, but perceptions changed dramatically in 2004 when the country switched from being an exporter to becoming a net gas importer, for the first time since 1995. The UK is the world’s seventh largest natural gas producer after Russia, the USA, Canada, Iran, Norway and Algeria. Production peaked in 2000 and has since fallen by 26 percent. UK

Figure 1: UK Production and Consumption Bcm



Source: SG Equity Research/BP Statistical Review 07

production will continue to decline sharply regardless of the regulatory environment and investment conditions.

Since the gas supply crunch of 2005 the UK model failed to ensure lower gas prices and has not encouraged much needed investment in infrastructure networks. This has caused some to express doubts as to whether the UK market should be used as a model for the rest of Europe. Indeed, on 13 March 2006 National Grid issued a Gas Balancing Alert for the first time because demand could not be met by the available supply. (Figure 1) Prices spiked to 255 pence per therm (p/th), causing a reduction in demand and thereby allowing the system to cope. This warning showed that investment had been insufficient to offset declining domestic production.

Investment in Storage was neglected until it was too late

During the 1990s, when gas prices were depressed, companies went through an 'asset sweating' phase to reduce any spare capacity. The decline in swing production in the North Sea should have triggered an increase in storage capacity, but this failed to materialise. The fall in North Sea output was initially under-estimated, and companies found it more attractive to invest in LNG re-gasification terminals with the hope of making lucrative US/UK arbitrages, viewing

storage as a low return asset. Facing fierce local opposition, storage was left on the back burner until it was too late. Today the few lucky storage owners are making huge profits and companies are running to fast-track any storage project they can find. Meanwhile, the UK lacks anything like the ratio of storage capacity relative to annual demand enjoyed by other European countries. (Figure 2)

Demand has reached an Undulating Plateau

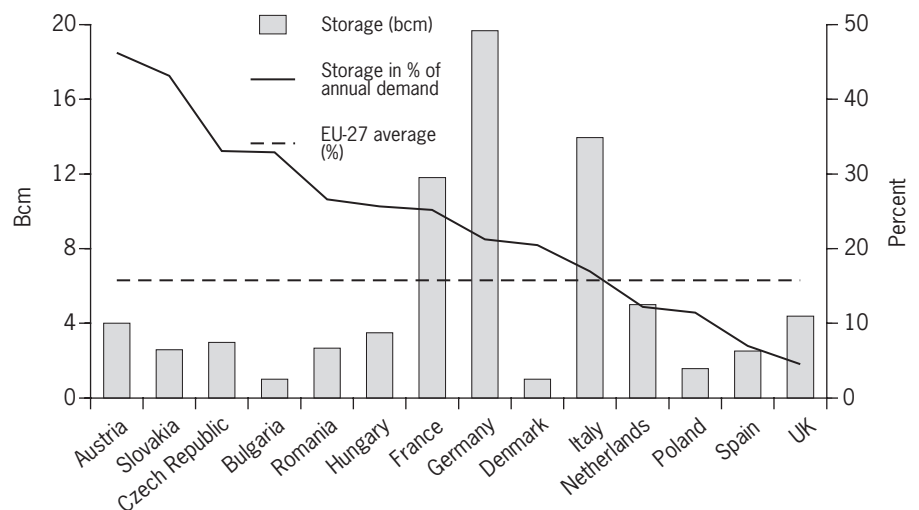
On a worldwide basis, the UK is the fifth largest gas market after the USA,

Russia, Iran and Canada; it is also the EU's biggest gas market by annual consumption, ahead of Germany and Italy.

The future of UK gas demand is uncertain given moves in climate change policies and volatile prices. Annual consumption hit an all-time high in 2004, but has fallen back since then. Extremely high prices are the likely culprit for demand destruction in the winter of 2005/06, although it is difficult to determine whether price was the underlying cause of the declining winter demand growth rate in 2006/07, as the season was unusually warm.

As global warming is now a major concern for customers and political leaders alike, natural gas may no longer be regarded as the 'fuel of choice' going forward. In fact, gas is now a transitional fuel that must compete against other energies. We believe that going forward the UK's natural gas demand will fall by an average of 2 percent per annum (weather-corrected) for the residential and small industry sector on the back of better energy saving measures in buildings. As oil, coal, gas and CO₂ prices move up, the order of merit of electricity producing plants can change rapidly, with gas competing against other fuel sources. We believe that any increase in demand from the power industry will be insufficient to offset the expected 2 percent decline in

Figure 2: Main Storage in Europe



Source: SG Equity Research

domestic consumption. All together, UK gas consumption has reached an undulating plateau and should vary mainly according to weather (winter consumption can vary from +/-13% depending on weather conditions).

More Import Capacity...

In response to the extremely high winter prices of 2005/06 (intra-day maximum of 255p/th vs 26p/th on average in winter 2006/07), efforts to increase the UK's import capacity were made, with the Langeled pipeline from Norway and the Teesside Gasport now on stream. October 2007 saw:

- The start-up of commercial flows from Norway's giant Ormen Lange gas field.
- The start-up of the Norway/UK Tamen Link offshore.
- An increase in the UK–Belgium Interconnector's reverse flow (from Belgium to UK) capacity.

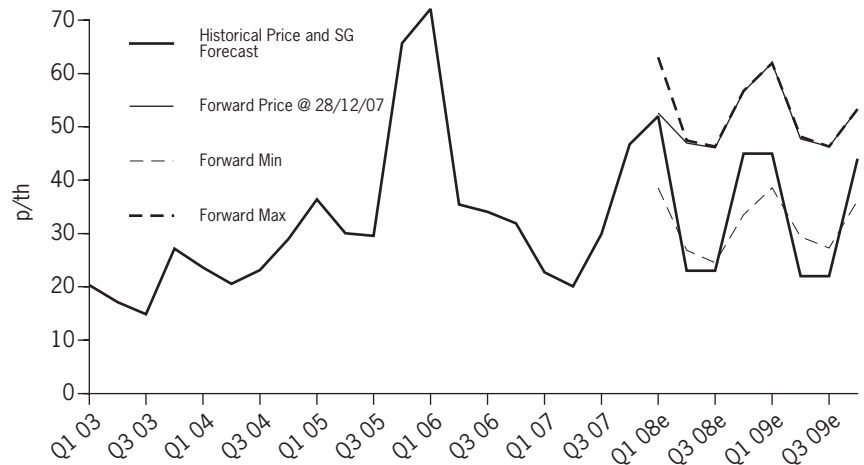
Increases in import capacity more than offset the ongoing decline in supplies from the UK Continental Shelf. On top of this, two new LNG re-gasification terminals (Dragon and South Hook) in Milford Haven should be commissioned during the first half of 2008.

The range of potential supply availability is wide, reflecting not only the normal risks associated with major infrastructure projects, but also commercial uncertainties associated with competing markets on the Continent and LNG on a global scale.

... may not translate into more supply: the Norwegian Question

On 2 October 2006 tests run on the southern leg of the Langeled pipeline caused gas prices to hit an all-time low of *negative* 5p/th (intraday). While the situation was short-lived, Norway learned the hard way that it could lose money monetising its hydrocarbon resources. This experience might have changed the way Norwegians do business, possibly pushing them to exercise more market power (i.e. being more selective) when selling their gas.

Figure 3: NBP quarterly gas prices (history, estimates and forward curve with historical max and min)



Source: SG Equity Research/Datastream

Like all producers, Norway aims to maximise return.

What is the Future Trend?

A tough equation is facing this mature market: domestic supply is declining by 10 percent per annum, demand has reached an undulating plateau, and foreign supply is insecure. Big investment is delivering new import capacity, but storage is still badly lacking.

Greater import capacity does not guarantee security of supply. Once import capacity is available, security of supply can be achieved either with internationally binding long-term take or pay contracts or with higher prices to attract the available (if any) spot gas.

Prices Matter

New import capacity will depress prices temporarily. Given the substantial investments in new UK infrastructure, after hitting a low of 30p/th in 2007 due to a mild winter 06/07, we expect annual prices to stay in the 33–36p/th range until 2010. (Figure 3) We also recognise that upward spikes are always possible this winter in response to global shocks (like British and Japanese nuclear outages). In the event of severe disruption, the UK will have to turn to LNG and the price this winter will be set by Japan.

Our assumptions are:

- New import capacities will have only a bearish effect during summer, while in winter, the UK will have to compete to attract the extra volume needed. Therefore, we see winter prices continuing to be expensive.
- For 2008, we assume the Norwegians are not going to repeat their 'mistake' of flushing the market with too much gas and that they will try to keep summer prices above 20p/th. The summer/winter spread will allow for storage to continue generating a lot of cash. Prices have more upside in winter and more downside in summer.
- Winter 2008/09 should trade at a discount to winter 2007/08 because by then the two Milford Haven re-gasification terminals should be running with, at least, some Qatari gas.

It is important to emphasise again that winter weather represents a very important risk factor that can substantially impact gas prices both on the upside and the downside.

After 2010, we expect natural gas prices to increase due to the lack of worldwide investment to offset declining North Sea and US gas production. The Nord Stream Baltic gas pipeline is being delayed due to political pressure from neighbouring countries, and the

2011 start date now seems optimistic. The huge Russian Shtokman gas field in the Barents Sea will not be developed before 2013. And the list goes on: the Nabucco pipeline is at risk of being stuck in limbo forever; the Norwegian GNE was just stopped; the Qatari moratorium caps LNG production to 104bcm/year for the foreseeable future, and so on. All of these developments suggest major supply bottlenecks after 2013.

In the Context of High Energy Prices, Liberalisation has Failed

The old assertion that liberalisation 'will drive down prices and improve the competitiveness of our industries' has signally failed to materialise at a time of high energy prices. Yes, we have a choice, but in various markets, the exercising of this choice implies choosing to pay sharply higher prices. Thanks, but no thanks.

"The old assertion that liberalisation 'will drive down prices and improve the competitiveness of our industries' has signally failed to materialise"

In an attempt to liberalise markets, political leaders applied the same formula to the energy, telecommunication and transportation sectors. This worked pretty well for UK consumers when the UK was a gas exporter. But by liberalising commodity markets, the unintended medium-term consequence was to shift most of the value away from the downstream sector and towards the upstream sector. And with gas resources concentrated in just a few countries – the vast majority of which have one national company that also enjoys an export monopoly – the power is now in the hands of just a few national companies.

The UK Faces Tough Decisions

The UK has insufficient storage capacity and must address this issue soon.

Having sufficient storage capacity is important not only for security reasons, but also because of the leverage it provides in negotiating with big suppliers. If storage capacity remains low, UK prices will probably remain volatile, with a crisis likely to cause price rises so as to dampen demand in order to achieve a balance between supply and demand.

After relying on North Sea production (which is being rapidly exhausted) and pushing for increased liberalisation, the UK is, with every passing winter, on its way to looking more and more like Continental Europe, i.e. suffering from a shortage of domestic supply. This means it may have to compete for piped gas with Continental Europe, where natural gas is indexed to oil and, on a worldwide level, for LNG. Meanwhile, Norwegians are understandably looking to maximise their return on investments made in fields and pipelines.

Even security of supply which was taken for granted before is now at risk. The UK is selling its gas cheap in summer to Continental Europe and is buying it back at very high prices in winter, when demand is higher!

The UK gas market was indeed a model when it relied on domestic production. But as soon as the country became a net importer, the 'one size fits all liberalisation ideology' led to unintended consequences. Gas is a strategic commodity, and market design in Europe must take into account the fact that all producing states have sovereign control over their resources. This means that a serious energy policy which examines changes in the demand/energy mix between now and 2020 must be devised and enacted quickly.



Simon Pirani explains the pricing policies for Russian gas based on European netbacks

The former Soviet Union is moving towards a new natural gas pricing system, linked to Western European contract prices on a netback basis (European prices minus export duties and transit fees). Gazprom is forcing the pace. The Russian government and Gazprom intend that this substantial shift should be completed in three years' time. But European prices are linked to oil prices, and if these keep increasing at the present rate, it's hard to see how this timetable will be adhered to. In any case, the consequences will be far-reaching for Russia's, and its neighbours', economies.

"The former Soviet Union is moving towards a new natural gas pricing system, linked to Western European contract prices on a netback basis"

Russia completed negotiations on this year's prices with almost all of the largest players (Turkmenistan and Uzbekistan as sellers, Ukraine and Belarus as buyers) in November and December, and although some aspects of the old politically-influenced settlements remain, prices rose steeply. Moreover, it was done without the political drama and supply interruptions that preceded the deal with Ukraine in January 2006, or threats of supply interruptions, in Belarus' case in January 2007. The new frameworks established during those clashes passed a significant test.

In Russia itself, the government did not flinch – as some had thought it would – from the 25 percent price rise for domestic industrial customers prescribed by its own strategy for

bringing those in line with European prices by 2011.

Ukraine, Belarus and Russia

The key turning point was the Russo-Ukrainian settlement of 4 January 2006 – not because of the sumptuous advantages it provided for Gazprom's ally, the trader Dmitry Firtash, that were so widely criticised at the time, but because it marked the beginning of the end of the system of intergovernmental agreements that dominated the CIS gas trade in the immediate post-Soviet period. The agreement was a commercial one between Gazprom, Naftogaz Ukrainy (the state-owned Ukrainian oil and gas company) and Rosukrenergo (the Swiss trader owned 50 percent by Gazprom and 45 percent by Firtash): the participants trumpeted the fact that they, rather than politicians, had negotiated the terms.

As a result of the deal, Ukraine, the largest CIS gas importer (about 55 Bcm a year) and the transit route for most Russian gas to Europe (about 120 Bcm a year), stopped getting Russian gas in lieu of transit fees. Since then its imports have been Turkmen gas, acquired by Gazprom Export at the Turkmen border and resold to Rosukrenergo, Kazakh and Uzbek gas bought by Rosukrenergo, and a minimal amount of Russian gas from Rosukrenergo.

In 2006, this 'cocktail' cost Ukraine only \$95/thousand cubic metre (mcm), much less than many had feared, partly because, in exchange, it handed Rosukrenergo a 50 percent share in a new monopolistic domestic trader, UkgazEnergo, and storage near the Slovak border at rates 40–50 times lower than the European market average. Ukraine's import prices rose in 2007 to \$130/mcm (a 36.8 percent rise) and this year to \$179.50/mcm (a 38.1 percent rise).

The supply interruptions in the days prior to the January 2006 deal being signed damaged Gazprom's reputation in Europe. But in the broader scheme of things, the agreement marked a success for the company, because it resolved a tension in Russian policy

that had persisted throughout the early 2000s. Against a background of rising European gas prices (reflecting the secular increase of oil prices to which they are indexed), Gazprom's commercial interest had found itself increasingly at odds with Russia's political/state interest, in which cheap gas was often used as a bargaining chip with western neighbours. Gazprom lobbied to close the widening differential between European and CIS prices. After the 'Orange revolution' of late 2004, Russia's political leadership felt less inclined to compromise with Kiev. The discord between Gazprom's line and that of the government was resolved. European netback prices were fully embraced as a strategy by the Russian government.

“Russia is not only charging more for gas, it is also paying more”

It is hard to envisage the harmony of state and corporate interests around the European netback principle being disrupted soon, particularly now that the chairman of the Gazprom board, Dmitry Medvedev, has been nominated to succeed president Putin in March. Certainly, since the Russo-Ukrainian agreement of January 2006, these interests have continued to converge. There were two further notable turning-points:

– First, in December 2006, the Russian government thrashed out with Gazprom and the power industry a scheme by which prices in the biggest gas market of all – its own – would rise to European netback levels by 2011. The decree that ensued states that wholesale prices should be set for industry according to 'a formula that ensures equal income from the sale of gas on foreign and domestic markets'. And the industry ministry says that, assuming a constant European gas price, this year's 25 percent increase – which takes the nominal wholesale industrial price (unadjusted for transport) to \$63.30/mcm – will need

to be followed by five further rises, to \$125/mcm in 2011. If European gas prices are higher, that number will be higher too.

– Second, in January 2007, that other troublesome customer on Russia's western borders, Belarus, was knocked into line. Its president, Aleksandr Lukashenko, did what his pro-European Ukrainian counterparts had not been prepared to, and agreed to sell to Gazprom a 50 percent share in Beltransgaz, which owns the export pipelines to Europe. He also agreed to end a lucrative transfer-pricing scheme under which oil products had been refined in Belarus from Russian crude, bought net of duty. In return for these concessions by Minsk, Moscow agreed that Belarus should progress to European netback much more slowly than Ukraine. The two sides set a timetable similar to the one being used for the Russian domestic market. Belarus agreed to buy Russian gas at \$100/mcm in 2007, at 67 percent of the European netback level in 2008, at 80 percent of that level in 2009, 90 percent in 2010 and 100 percent in 2011. If European prices keep moving upwards, the Belarusian timetable seems likely to be slowed further.

The Russo-Belarusian agreement provided for the exact level of prices to be set, within these parameters, annually. The 2008 negotiation was conducted between president Lukashenko and his Russian counterpart, Vladimir Putin. Russia granted Belarus a \$15 billion state stabilisation loan, over fifteen years with a five-year grace period, to help pay for dearer gas. Although price levels for the whole of 2008 were not disclosed, it was announced that they would be \$119/mcm in the first quarter, and a Russian minister indicated publicly that they will average \$125/mcm for the year – well short of the 67 percent of European netback to which they were due to rise.

The cushions provided by Russia to Lukashenko for 2008, in the form (probably) of prices that fall short of the timetable, and (certainly) of the stabilisation loan, show that the transition from politically-influenced haggling to European netback is not

complete, and will not be smooth. The same could be said of the surviving add-ons to agreements with Ukraine, such as the favours granted to Firtash.

A significant test of Moscow's determination to implement its principles evenly will arise in Ukraine soon as a result of the return to the premiership of Yulia Tymoshenko, the former gas trader and populist politician. She has consistently demanded the removal of Rosukrenergo from the import chain. In Moscow Medvedev, among others, has indicated that there is no objection in principle to such a reorganisation. If sales were made directly from Gazprom Export to Naftogaz Ukrainy, the complex buy-sell arrangements by which Rosukrenergo ships Turkmen gas to Ukraine were scrapped and Russian transit tariffs – a key component of any pricing structure – were made public, then the means of implementation of European netback would be more transparent and therefore more rigorous.

Central Asia Gains

Russia is not only charging more for gas, it is also paying more. Turkmenistan, the principal Central Asian supplier, sold gas to Gazprom and its trading allies for \$44/mcm in 2005, \$50–\$60/mcm in 2006 and \$100/mcm in 2007. Turkmenistan will receive \$130/mcm in the first half of this year and \$150/mcm in the second half.

Sales prices for the smaller Uzbek and Kazakh volumes (less than 10 Bcm a year each) are not disclosed, but they seem to track Turkmen prices. Gazprom announced in December that it had agreed to buy Uzbek gas this year at 'the rates prevailing in the regional market'. Kazakhstan, which reportedly received \$140–\$165/mcm in 2007, was demanding \$190/mcm in 2008; at the time of writing, no agreement had been reported.

These prices reflect Russia's dependence on Central Asian gas. As Russian critics of Gazprom's delay in pushing forward crucial domestic investment projects constantly point out, that dependence is increasing year by year, while western Siberian fields' output levels off or declines.

The way that Gazprom has acceded to steep increases in Turkmen sales prices is probably also influenced by pipeline politics. Soon after this year's Turkmen sales prices had been settled upon, on 20 December, the Russian, Turkmen and Kazakh governments signed an agreement on the construction of a gas pipeline around the Caspian shore, with an input capacity of 20 Bcm per year, to meet the existing line at Aleksandrov Gai.

“The way that Gazprom has acceded to steep increases in Turkmen sales prices is probably also influenced by pipeline politics”

It is unclear whether and how Turkmen production will be increased to justify building the new line and/or expanding the existing line via Uzbekistan, which is also proposed. But for Turkmenistan it amounts to an additional export route to Russia that avoids Uzbekistan. For Russia it further weighs the scales against EU- and US-supported projects aimed at opening up a 'fourth corridor' of pipelines from the Caspian to the EU avoiding Russia.

The Brave New World of European Netback

There is little doubt that European netback prices will be achieved across the former Soviet space, but it is not clear when.

Eventually, Russian and neighbouring energy markets will be transformed beyond recognition by the pricing reform. If the differential between European and domestic prices is removed, much of the incentive for Gazprom to prioritise European over domestic sales will also disappear. Its role in meeting growing demand in Western Europe may well be diminished. The bar on other producers making export sales may be reconsidered.

In the Russian, Ukrainian and Belarusian economies, European netback will further tell against energy-intensive manufacturing industries. Even assuming they replace capital stock and become more efficient, they will become substantially more expensive to run. In the long term, this effect will be felt in Central Asia, too. European netback for industry will increase pressure on governments to find answers to the problem of extremely low prices, and excessive consumption that persists among residential consumers and in the district heating sector.

All this is in the future. At present, the observation that may best be made with confidence is that the former Soviet countries' ability to reach European netback as soon as Gazprom proposes depends on the level of European gas prices. If they continue to rise, then the price increases that would be required for Belarus and Ukraine to catch up with them by 2011 could become politically unsustainable, and pull the intra-CIS gas trade back into a vicious circle of debt and non-payment. This year, Belarus has already fallen behind the proposed timetable; Ukraine resisted Russian pressure to hand over transport assets in return for more gradual price increases, but has still achieved import prices far short of European netback. The road has been mapped out; the timing of progress remains in question.

