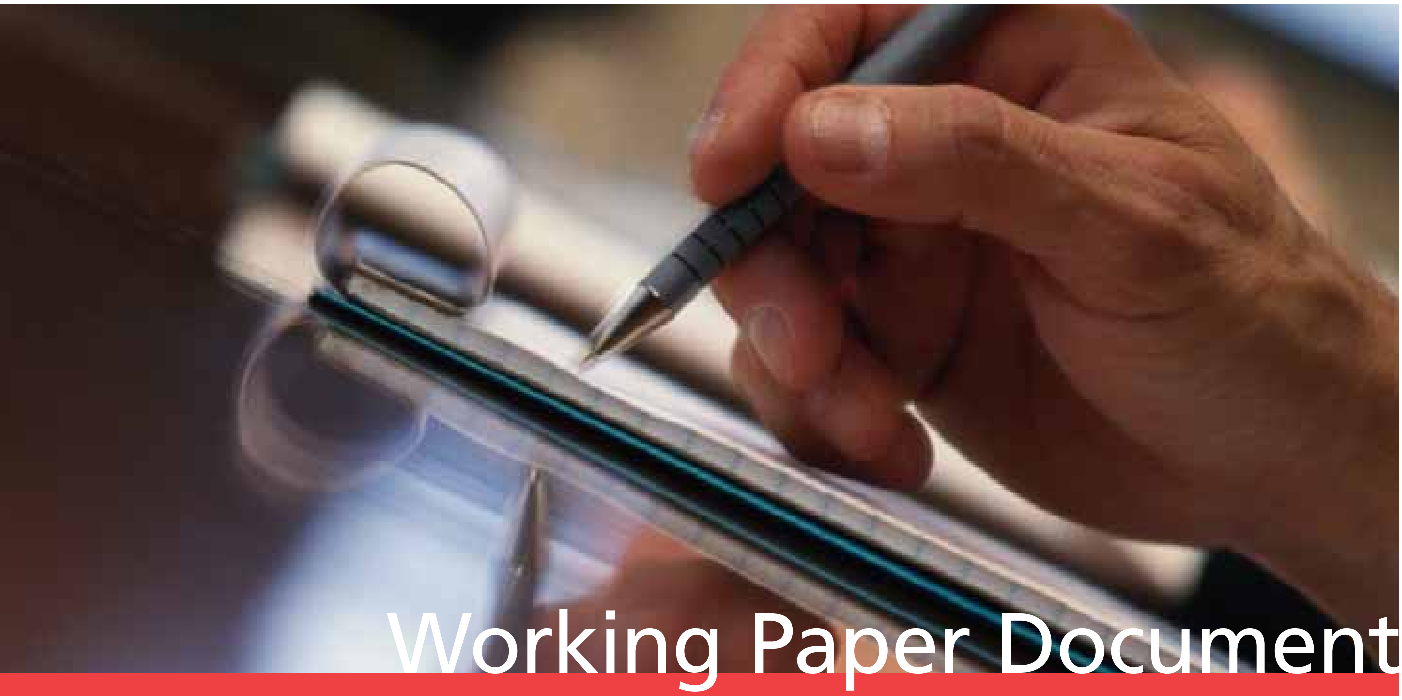
The gas chain: influence of its specificities on the liberalisation process



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Abstract

Like other network industries, the European gas supply industry has been liberalised, along the lines of what has been done in the United Kingdom and the United States, by opening up to competition the upstream and downstream segments of essential transmission infrastructure.

The aim of this first working paper is to draw attention to some of the stakes in the liberalisation of the gas market whose functioning cannot disregard the network infrastructure required to bring this fuel to the consumer, a feature it shares with the electricity market. However, gas also has the specific feature of being a primary energy source that must be transported from its point of extraction. Consequently, opening the upstream supply segment of the market to competition is not so obvious in the European context, because, contrary to the examples of the North American and British gas markets, these supply channels are largely in the hands of external suppliers and thus fall outside the scope of EU legislation on the liberalisation and organisation of the internal market in gas. Competition on the downstream gas supply segment must also adapt to the constraints imposed by access to the grid infrastructure, which, in the case of gas in Europe, goes hand in hand with the constraint of dependence on external suppliers. Hence the opening to competition of upstream and downstream markets is not "synchronous", a discrepancy which can weaken the impact of liberalisation.

Moreover, the separation of activities necessary for ensuring free competition in some segments of the market is coupled with major changes in the way the gas chain operates, with the appearance of new markets, new price mechanisms and new intermediaries. Starting out from a situation where gas supply was in the hands of vertically-integrated operators, the new regulatory framework that has been set up must, on the one hand, ensure that competitive forces can be given free rein, and, on the other hand, that free and fair competition helps the gas chain to operate coherently, at lower cost and in the interests of consumers, for whom the stakes are high as natural gas is an important input for many industrial manufacturing processes, even a "commodity" almost of basic necessity.

JEL-code : D23, D43, L13, L43, L95, L97.

Keywords: network industries, gas industry, gas utility, liberalisation, regulation, deregulation, market structure, European gas supply, oligopoly, OPEG

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<u>**TABLE OF CONTENTS**</u>

LIST OF CHARTS, TABLES AND BOXES

INTRODUCTION

Since 1 July 2007, gas and electricity markets have been liberalised for all consumers in the European Union who are now free to choose their gas and power suppliers. Since consumers had previously been faced with a single intermediary for their gas supply, the process of liberalisation has enhanced the roles and responsibilities of the various participants in the gas chain, whose (new) remit does not always appear clear to the novice in an area also characterised by technical complexity.

In Belgium, the gas and electricity markets were fully opened up to competition by 1 January 2007. On a day-to-day basis, this market opening implies a radical overhaul of the way they work, notably when it comes to price-setting mechanisms. For a central bank primarily concerned with pursuing an objective of price stability, understanding correctly how these markets function and the essential features that drive them is a major issue, not least because of the importance of these energy sources as inputs in many industrial processes and the impact that their cost can have on competitiveness and on household budgets.

The aim of this first working paper is to draw the reader's attention to some of the stakes in the liberalisation of the gas market whose functioning cannot disregard the network infrastructure required to bring this fuel to the consumer, a feature it shares with the electricity market. In the first part, the specific features of the gas sector are put into perspective with those of other network industries, based on the observation that while there are similarities, these network industries have seen their own technological developments, even if they have sometimes been required to evolve in regulatory environments based on common concepts. Several technical terms and concepts specific to the gas industry are also briefly explained for readers who are not so familiar with the subject, when these factors are likely to have an impact on how the gas market operates. The second part tackles the question of gas market liberalisation with reference to the European context, first of all by pointing out the factors that have driven this process, and then by emphasising the consequences of this liberalisation on the way the market operates.

It is our intention to extend this "general" analysis of the gas markets with other contributions that will endeavour to describe more deeply the European context which is characterised by greater dependence on suppliers outside the European Union but also by big differences in gas supply within the EU. This situation has implications for the internal gas market liberalisation process and the expected results as well as on the way operators adapt to this changing environment. Particular attention will be paid to the question of security of supply in the context of a liberalised market within which responsibilities need to be redefined. The analysis will then be developed individually for Belgium and the various component parts that make up its domestic gas market.

1 GAS SUPPLY, JUST ANOTHER NETWORK INDUSTRY?

1.1 GENERAL ORGANISATION OF NETWORK INDUSTRIES

The specific nature of a network industry lies in the fact that in order to carry its product/service from the producer(s) to a vast number of consumers, the industry requires its own physical or organisational infrastructure providing these connections that is, the network. Furthermore, the necessary infrastructure involves such high installation and maintenance costs that any duplication is economically irrational, investment costs often being irreversible (sunk costs). Some qualify it as bottleneck infrastructure[1] with the characteristics of a natural monopoly with increasing returns to scale (average costs continue to fall as production expands). This infrastructure often benefits from network externalities, i.e. their operational efficiency increases with the number of users (club effect).

Network industries mainly concern carriage of gas, electricity, heat and water and delivery of mail, as well as telecommunications and rail and air transport. They influence economic activity both in terms of production (almost 9% of the value of production in the EU25) and employment (accounting for 4.5% of European employment) and also through the consumer price index (some 7.4%). This economic impact is further reinforced mainly by the fact that the goods and services supplied by these industries are important, even indispensable, inputs for production processes in other economic sectors.

TABLE 1: THE ECONOMIC ROLE OF NETWORK INDUSTRIES IN THE EU25

Percentage share of sectors in	HICP* 2005	employment ** 2004	production ** 2004
Electricity	2.1	0.9 ***	4.5 ****
Gas	1.4		
Telecommunications	2.7	0.9	2.6
Postal services	0.2	1.5	0.7
Rail and air transport	1.0	1.1	1.2
Total	7.4	4.5	8.9

* HICP = harmonised index of consumer prices.

** As a percentage of the total, excluding financial activities.

*** Including supply of heat.

**** Including supply of heat and water.

Source: Eurostat (2007), Structural business statistics (Industry, Construction, Trade and Services).

[1] This infrastructure is essential for delivering the goods to the final consumer and, therefore, to induce competition within the upstream and downstream segments. Consequently, its owner enjoys a certain amount of market power against new entrants. This can be offset by granting access to the infrastructure on reasonable but sufficiently lucrative conditions so it encourages the owner to ensure the adequate development of this infrastructure.

On the other hand, network industries mainly provide goods and services that are of general interest, a reason often cited in the past in order to ensure widespread access to them at the same price for all consumers and in all areas (universal service obligation), something that the market does not always guarantee[2]. And when essential goods are concerned, the question of security of supply also comes up. All these factors, as well as the need to keep control over any monopolistic activity, have justified the need for regulation and wider intervention by public authorities in the organisation of these industries than in other sectors. For these reasons, the establishment of such networks has traditionally often come under the public remit.

Their organisation has thus shifted towards one of regulated monopolies or State monopolies which have been required to integrate social and collective considerations into the way they operate. In so doing, some economic inefficiencies encountered in a public monopoly are more likely to be corrected than in the case of a private monopoly where the emphasis is on maximising its own profits[3]. However, this organisation under public control carries no guarantee when it comes to efficient resource allocation according to the Pareto principle. And, in this respect, allocation resulting from perfect competition is regarded as optimal, because unlike the monopoly situation, it is impossible to improve the situation of one economic agent (seller) without worsening the situation of another economic agent (buyer)[4].

The classic setup used in the past for these industries was therefore based on an enterprise that was often state-owned, integrating the four segments of the chain organised around the network, namely production (non-existent in the telecommunications sector), imports (sometimes required for gas), transport, distribution and sale to the final consumer in the form of a telecommunications/transport service or electricity/gas/water supply, this vertical (and to a certain extent horizontal) integration being justified by the existence of economies of scale.

From the end of the 1970s onwards, several network industries have been reformed and their component companies required to operate in a competitive environment, a process that originated in the United States in air transport, telecommunications and natural gas. In the United Kingdom, the accession to the government of the Conservative Party in 1979 was the starting point of a

2 Competition naturally favours the most profitable market activities or segments, at the risk of excluding some types or groups of consumers. In the case of network-industry services, the universal service obligation is based on two principles: accessibility to the network for all consumers wherever and whenever the service is requested, and non-discrimination via identical prices wherever it is located and, therefore, whatever the cost of connection to the network.

3 In contrast to a private monopoly, a public monopoly can rectify some inefficiency because, in this case, the wider profit margin of the public monopoly holder (received to the detriment of the consumer's purchasing power) is recorded in the State accounts. These profits can then be allocated in the general public interest. For an overview of reflections on monopolies and economic efficiency, see van der Linden J. (2005), pp. 14-16.

4 For a brief analysis of the theoretical aspects of liberalisation, see Coppens F. and D. Vivet (2004), pp. 2-6.

privatisation programme of public enterprises mainly active in network industries, with British Gas being privatised as early as 1986. The rest of the European Community fell into line with this trend by taking on board the Electricity and Gas Directives adopted in 1996 and 1998 respectively. These Directives lay down common rules for the internal market in electricity and gas with a view to making the European market competitive and geared towards the end user, without however deciding on the question whether the concerned companies were public or private property as was the case in the United Kingdom.

According to J. Percebois, various reasons can be put forward to explain the general process of market opening and liberalisation of network industries set in motion in Europe since the beginning of the 1990s (Percebois 1997).

The monopoly has been criticised for its assumed or proven (economic) inefficiency: armed with its natural advantage of being the only supplier, and facing no competition, the behaviour of the monopoly holder can lead to expensive practices, a pricing policy geared more towards appropriation of revenue to the detriment of the community at large, and a weak innovation capacity. Developments in the transaction cost and contestable market theories have in fact fuelled debates on the optimum structure for network industries[5].

The transaction cost theory has thrown some light on the effect of transaction costs on the way economic activities are structured: assuming that each transaction can be carried out internally within the enterprise or externally on the market, the most appropriate choice is the one that keeps the transaction cost to a minimum. Vertical integration of activities is sometimes preferable to the market and vice versa, depending on the activity in question and the transaction costs that arise from its structure. Thus, transaction costs on the market include costs related to information research, negotiation, conclusion of contracts, to the uncertainty and the suitable execution of the transactions. A company's internal transaction costs mainly comprise the costs of monitoring and coordinating its activities. Vertical integration, in particular, is still preferable in terms of transaction costs when it is a "specific" activity that cannot be reassigned to other clients at no extra cost, or when there are activities that require many exchanges of information, a major coordination effort or are marred by uncertainty – all features that tend to push up transaction costs on the market. This vertical integration can nevertheless be called into question when the "specific" nature of the activity decreases as a result of technological progress, for example.

As for the contestable market theory, this has put the usefulness and nature of natural monopoly regulation back into perspective. A market is said to be "contestable" when there are no barriers to market entry and/or exit, whether of a legal (exclusive rights and concessions) or economic (high infrastructure, training and know-how costs, as well as other sunk costs that cannot be recovered)

5 In: Percebois J. (1999).

nature. In the absence of any barriers, potential competition from new entrants has had the effect of bringing the incumbent(s) into line and *de facto* regulating the market. With barriers to entry in place, potential competition has no influence on the behaviour of incumbents which are able to take advantage of their position. The public authorities must therefore intervene to restore conditions of market "contestability" and to make the threat of new entrants more likely.

A more optimal organisation structure for network industries therefore seems possible by combining de-integration of the various business "chains" and opening up some of these activities to competition: in the telecommunications industry, both service provision and the infrastructure have been liberalised; but in the gas and electricity sectors, only production and sales are open to competition.

Next, technological change has brought back into question the extent of the economies of scale in one or another network industry segment and thus their "specific" nature, too. The arrival of the new combined cycle gas turbine power plant (CCGT) in the electricity-generating segment has significantly reduced entry costs for new generators. More obviously, new multiplexing techniques have enabled an increase in telecommunication network capacity with limited investment, while new competition has been facilitated by the relatively easy interconnection of the various networks[6]. And it should be pointed out that advances in the field of information technology have also proved an undeniable asset in collection, sorting, storage, processing and exchange of the mass of data required to coordinate operations that have become autonomous as a result of liberalisation.

Finally, the liberalisation of the network industries also illustrates the political will for further European integration. The single market that was born out of the 1957 Treaty of Rome is founded on the four freedoms, namely free movement of people, goods, capital and services and its functioning is based on competition. Any barrier to this free movement must be broken down, including monopolies if need be. In fact, Article 90 of the Treaty of Rome (on Community competition law concerning public services), subjects "undertakings entrusted with the operation of services of general economic interest" to competition rules, but only "insofar as the application of such rules does not obstruct the performance, in law or in fact, of the particular tasks assigned to them". At the same time, "the development of trade must not be affected to such an extent as would be contrary to the interests of the Community". The notion of public service is respected, but if this service is not covered by a natural monopoly, it must operate under a regime of free and fair competition. It was in this spirit that the Gas and Electricity Directives were drafted, with the

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6 At the same time, the multi-functionality of telecommunications networks, namely their data, image and sound transmission capacity, has raised the potential volume of this market, especially with the advent of the Internet. Also, the size of the economies of scale has fallen back in relation to an expanding market volume, a combination of developments that has reinforced "potential" competition from new entrants. In: Coppens F. and D. Vivet (2004), pp. 10-11.

objective for the restructured network industries of being able to boost their economic performance through the adoption of competition. It is generally felt that it is indeed possible for these industries to improve the way they operate, since the expected advantage of competition is that it will force companies to make more effort to sharpen their competitive edge, so that they will cut their costs and, hence their prices, which will help maximise consumer welfare. The only segment that constitutes a natural monopoly is that in charge of the infrastructure which requires oversight by a regulator in order to avoid any temptation on the part of its management to abuse a dominant position.

However, as the Commission pointed out in its Communication to the Council of Ministers and the European Parliament on prospects for the internal gas and electricity market (Brussels, 10.1.2007 - COM(2006) 841 final): "As far as gas is concerned, the factors affecting prices, such as the need to move to higher cost sources of supply, for example liquefied natural gas (LNG), and the continued linkage of some gas imports to the price of oil, would have occurred whether or not competition had been introduced. It must be recalled that energy prices cannot be expected to always remain low regardless of external factors. ... Competitive and open markets shall however bring the best prices to end users including to the energy intensive industry." It should be noted that the expectations on prices have been adapted against the 2001 version of the explanatory memorandum on the revision of the Electricity and Gas Directives: "the Community is to create a real and effective internal market for electricity and gas" ... which includes ... "the progressive freeing of all electricity and gas consumers to choose their supplier. There are three reasons for pursuing an ambitious programme in this respect. First, to ensure that all EU companies receive the benefits of competition in terms of increased efficiency and lower prices, leading to increased EU competitiveness...". If it appears that "there is no guarantee that you will save money overnight just by changing energy supplier - prices also vary for other reasons" … "competition in the marketplace will certainly help hold prices down" [7]. In its latest Communication on the internal energy market, "the EU has clearly recognised that the internal energy market is the policy line that ensures fair prices to citizens and industries".[8]

The liberalisation of the American and British markets effectively set an example: network industries can operate in a different way to the vertically integrated enterprise (monopoly) model, and what's more, with convincing results as regards price movements. The situation on the US and UK gas markets at the time they were opened up to competition was however quite different from that of the continental Europe gas market – a situation that is analysed in section 2.1.

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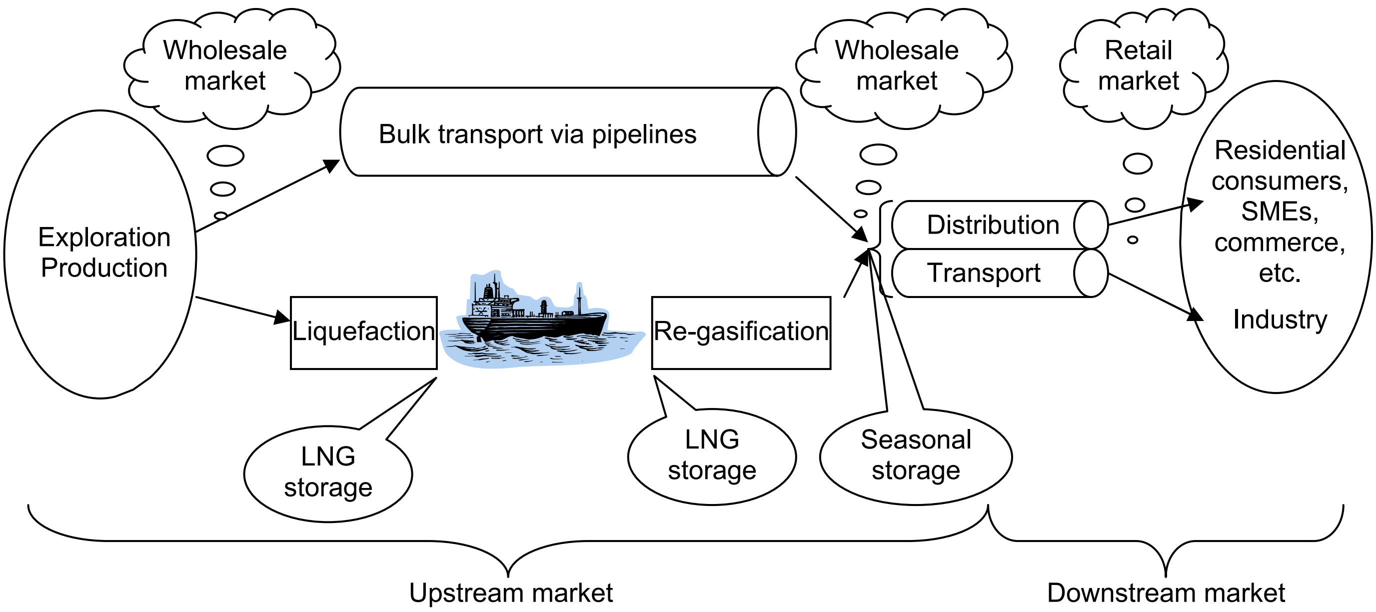
7 Brochure on the Internal Energy Market: "Your power to choose. The European Union promotes freedom of energy supplies".

8 In: "European Commission sets out a new impetus for the internal energy market", MEMO/07/9, 10.01.2007.

1.2 THE GAS SUPPLY CHAIN AND ITS SPECIFIC FEATURES

CHART 1: SIMPLIFIED DIAGRAM OF THE GAS CHAIN



The supply and marketing chain bringing gas from the producer to the final consumer can be split into several segments:

- production of natural gas through the development of gas deposits both in Europe and beyond;
- "bulk" transport of gas within which a distinction must be made between transport from the gas field to the national grid of the country of destination which can be served by pipelines or LNG tankers, and the national network as such, which ensures the pipeline connections with local distribution networks and large industrial consumers;
- gas storage, used to match variations in supply with changes in demand over different timescales (from peak hourly demand to seasonal fluctuations);
- distribution, which differs from bulk transport on the basis of the pressure of the gas transported to the final consumer. In Belgium, it comprises the low pressure grid where the maximum service pressure admitted may not exceed 98.07 mbar and the medium pressure grid which has a maximum service pressure of between 98.07 mbar and 14.71 bar;
- commercial gas purchasing and sales activities, whether upstream among producers and suppliers on the wholesale market (this includes further resale to traders, suppliers, pipeline and distribution companies) or downstream with final consumers on the retail market.

In comparison to the electricity supply chain, natural gas supply has its own specific features, too, in the field of:

- production: natural gas is a primary energy source whose production depends directly on the availability of gas reserves;

- the gas grid: in view of its intrinsic characteristics, the carriage of gas requires a specific infrastructure from the point of extraction right through to the final consumer;
- its storability.

1.2.1 PRODUCTION OF NATURAL GAS, A PRIMARY ENERGY SOURCE

Natural gas is a primary source of energy, found naturally in the crude state and used as such after being treated for impurities. Its production is dependent on the availability of reserves in the form of conventional non-associated gas, associated gas in oil fields, and even non-conventional gas[9]. The distinction between these categories of gas is not so much a question of quality criteria (sulphur or inert gas content – see the end of section 1.2.2) as of differences related to where they come from, and therefore how difficult the gas is to extract, unlike in the case of oil where non-conventional oil is distinguished from conventional oil by its "technical" characteristics such as density, viscosity and sulphur content.

Worldwide proven reserves of natural gas stood at 181 Tcm (trillion cubic metres) at the end of 2006 and at the current rate of production will last for 65 years. Their geographical breakdown is marked by a strong concentration in Russia, Iran and Qatar which together account for more than 55% of these reserves. The rest is shared between the Middle East (10.9%), Asia-Pacific (8.3%), Africa (8.0%), the Americas (8.0%), Eurasia (6.0%) and Western Europe (3.0%).

[9] Non-conventional gases include coal gas, shale gas as well as gas trapped in deposits of tight gas sands, all of which have the common feature of being scattered about in the rock without actually forming reservoirs, which makes their extraction complicated (rate of recovery of some 10% compared with 80% for conventional gas). These non-conventional gases nevertheless have a huge potential (on this subject, see Boussena S., Pauwels J.-P., Locatelli C. and C. Swartenbroekx, (2006), pp. 330-333). Methane hydrates are one last sizeable potential source although research is still at a very early stage of developing techniques for recovering gas from the hydrates found in permafrost or in deep oceanic sediments (In: Institut Français du Pétrole (2006)).

TABLE 2: BREAKDOWN OF WORLD RESERVES, PRODUCTION AND EXPORTS OF NATURAL GAS

2006	Proven reserves * Tcm		Commercial production Bcm/year		Reserves / Production years **	Gross exports X Bcm/year	Gross X/ Production %
Russian Federation	47.65	26.3%	612.1	21.4%	77.8	151.5	25%
Iran	28.13	15.5%	105.0	3.7%	>100	5.7	5%
Qatar	25.36	14.0%	49.5	1.7%	>100	31.1	63%
Saudi Arabia	7.07	3.9%	73.7	2.6%	95.9	0.0	0%
United Arab Emirates	6.06	3.3%	47.4	1.7%	> 100	7.1	15%
United States	5.93	3.3%	524.1	18.3%	11.3	20.9	4%
Nigeria	5.21	2.9%	28.2	1.0%	> 100	17.6	62%
Algeria	4.50	2.5%	84.5	2.9%	53.3	61.6	73%
Venezuela	4.32	2.4%	28.7	1.0%	> 100	-	-
Iraq	3.17	1.7%	1.8	0.1%	>100	-	-
…	...	...	...	...	...	...	...
Norway	2.89	1.6%	87.6	3.1%	33.0	84.0	96%
EU25	2.43	1.3%	190.0	6.6%	12.8	2.1	1%
the Netherlands	1.35	*0.7%*	61.9	*2.2%*	*21.8*	48.6	79%
United Kingdom	0.48	*0.3%*	80.0	*2.8%*	*6.0*	9.9	12%
World	181.46	100.0%	2865.3	100.0%	63.3	748.1	26%

Sources: BP (June 2007), "Statistical review of world energy" & IEA (2006), "Natural gas information 2006" for the Iraqi production figures.

* The proven reserves refer to volumes that can be recovered with reasonable certainty from known reservoirs under existing economic and operating conditions. Data expressed in standard cubic metres (Scm) are measured at 15°C and 1,013 mbar.

** The volume of proven reserves in year t compared to production in year t gives an indication of the life (n years) of these reserves at production levels in t. This is a purely "theoretical" concept since it corresponds to an instantaneous depletion of reserves in t+(n+1).

Currently, these reserves are being developed to varying degrees and the breakdown of production does not exactly match that of reserves, apart from Russia which, with a share of some 21% of global production, is the world’s leading gas producer, followed closely by the United States (18%). Yet these two countries’ prospects in terms of future production are very different. The United States has already largely used up its much smaller gas reserves and consequently its reserves will only last for about ten more years, while in Russia’s case the lifespan is nearer 80 years. In the gas-producing regions in Europe (EU25), extraction of known reserves can at best cover a little more than a decade of production at current rates. Among the European producer countries with the most gas, only the Netherlands and Norway have reserves likely to last for more than twenty years. The gas reserves of the former Soviet Union republics of Central Asia, which account for 5.1% of worldwide reserves and which had already been developed in the Soviet era, have seen a gradual recovery and rise in production over the last 5 to 10 years. Apart from Algeria, a forerunner in the "production" of LNG from as early as 1964, the development of natural gas has been more recent for the other producer countries, as gas had long been regarded as a fatal by-product of oil drilling and flared. Asian LNG producers emerged at the end of the 1970s and were joined by the Middle East producers and Nigeria in the second half of the 1990s.

Production and reserves only make up part of the factors determining gas market supply potential. The gas still has to be brought onto the international markets, and, in this respect, each producing country has its own objectives and will, if needed, give priority to its own domestic market supply (like Saudi Arabia and Iran). But globally speaking, the relative share of gas production sold on the international markets (excluding intra-FSU and intra-CIS trade)[10] has risen constantly: from 4.4% of production in 1970 to 13% in 1980, 15% in 1990 and 26% in 2005. Beside the impact of the rise in oil prices since 1973 which has made gas prices at the burner more competitive and made it more profitable to sell, this expansion can also be explained by the adoption of gas export promotion policies by several producer countries (Algeria, Nigeria, Qatar), by the growing shortage of production in relation to consumption in several gas-consuming countries which has been offset by higher imports (United States and United Kingdom), and more recently, within the last decade, by the development of LNG transport for which costs have fallen considerably and capacities expanded, which has made new outlets on the international markets accessible at a reasonable cost.

Unlike electricity generation, production and supply of natural gas are largely governed by transactions concluded outside the scope of European energy market liberalisation. Therefore, part of the final price of gas is fixed outside this context and in the framework of negotiations between European wholesale market operators and a relatively limited number of producers located beyond Europe’s borders. This situation is not without impact on the way the European gas market works. Opportunities for competition at the production stage effectively depend on the number of (independent) gas producers and the possibilities for gaining access to these resources.

Even today, access to resources is still largely dependent on long-term contracts of 20 to 25 years which specify:

- the volume taken: this can be covered by a "depletion contract" through which the buyer commits to buying up the entire volume of gas available as the (generally small-scale) field is being developed or, more frequently, a "supply contract" in which the annual take is clearly stated along with the minimum seasonal flexibility conditions;
- the price paid: in the majority of ongoing contracts on the gas markets in continental Europe (and also Asia), this price is index-linked to the price of competing fuels in the final consumer’s market where the competition takes place, and follows a "net-back" logic: the price of the gas is negotiated by the importer/buyer on the basis of substitutes (fuel oil and gasoil) on the outlet markets, from which the various costs to be borne up to the point of delivery (cost of distribution, storage, transport and possible re-gasification) are removed. The amount thus

[10] FSU = Former Soviet Union - CIS = Commonwealth of Independent States.

calculated "backwards" represents the maximum price that the importer is prepared to pay for the gas. On the producer/seller's side, the minimum price he wants to get is one which covers, over and above production costs, transport costs up to the point of delivery (with possible liquefaction) and royalties. The price that is finally agreed falls somewhere between the two. It will depend on the bargaining power of the parties involved and will determine the splitting of revenues between them.

Specific clauses conforming to a logic of risk-sharing are often written into contracts: the "take or pay" clause obliges the buyer to take a minimum volume of gas, which implies a transfer of the risk of putting the quantities under the responsibility of the buyer, while the price indexation clause puts the price risk on the seller who enters into a commitment to supply the gas at a competitive price on the buyer's end-user market as it is index-linked to the price of competing energy sources. To compensate for any adverse effects of this principle of "net-back pricing" for distant producers, a destination clause has often been included preventing the buyer of the gas from selling it on to a third party without the prior agreement of the producer/supplier. These clauses have been ruled illegal by the European Commission, because they appreciably restrict the scope for competition between operators. Non-EU suppliers have already adapted - at least in part - to this contractual provision being scrapped by carrying the gas directly to the final market (for instance, by delivering the gas on an *ex-ship* basis, which means that the supplier remains the owner of the LNG cargo until it is unloaded), or even by getting a foot directly in the European market.

The long-term nature of these contracts has enabled producers to raise the necessary finance for the completion of specific production and transport infrastructure, while at the same time supporting the buyers' security of supply which has tended to perpetuate trade flows. However, in the context of a liberalised market, these long-term contracts can have an inhibiting effect on the development of price competition by limiting the supply opportunities for new entrants. They sometimes lack flexibility even though the Commission points out that the contracts recorded in its gas sector inquiry offer buyers on average 25% flexibility (i.e. the minimum that could be taken is 75% of the maximum total take). The degree of flexibility varies considerably from one contract to another, but very few contracts offer extreme flexibility. Most of them have some 20% - 40% flexibility with a degree of flexibility which tends to diminish the greater the distance to the place of extraction.

1.2.2 SPECIFIC FEATURES OF A GAS TRANSMISSION NETWORK

There are still some disparities between network industries related to the very nature of the goods delivered/services provided, to technological development and to the existence of possible physical competition from another network. In Table 3, the specific features of a gas network are compared with those of telecommunications and electricity networks, in line with articles previously published in this series on the liberalisation of electricity markets in Europe[11].

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[11] Coppens F. and D. Vivet (2004).

TABLE 3: CHARACTERISTICS OF GAS, ELECTRICITY AND TELECOMMUNICATIONS NETWORKS

	Nature of the good	Technological progress and/or competition from an "alternative" physical network
Gas	- Supply of a commodity with few captive uses and based on a "reduced" public service - Storable product - Transit network and interconnections required for the transmission of a primary energy, which includes also a geopolitical dimension - Network balancing required (= system manager) - Flows of gas can be directed - Different quality specifications	- At the level of international supply and transport: development of gas transport in the form of liquefied natural gas (LNG) at an increasingly affordable cost
Electricity	- Supply of a commodity for captive use under the universal service principle - Non-storable product - Limited interconnections between "national" grids (secondary energy source produced locally) - Real-time balancing/reconfiguration required (= system manager) - Flow of electricity follows the path with the least resistance - Homogeneous product	- Development of combined cycle gas turbine (CCGT) power plants has reduced entry costs in the electricity generation segment (lower costs and shorter construction time) - Development of small decentralised generation units producing electricity from renewable energy
Telecom-munications	- Provision of a service - no production segment - Multi-functional network - Worldwide network	- Multiplexing has allowed to increased the network capacity at a low cost - Multi-functionality has widened the range of products provided - Development of mobile telephony also leads to competition at network infrastructure level

Unlike electricity, gas is a fossil fuel that has only very few captive uses, and must therefore compete with other fuels. As a result, and again in contrast to electricity, the public authorities have not imposed a universal service obligation for gas distribution, but rather a kind of reduced public service obligation[12]. The intervention of the public authorities is also required to obtain construction permits for the different infrastructure (LNG terminals, storage sites, pipelines). The pipeline paths mainly have to cross public property and frequently go through private property (rights of way, concessions), while storage sites and LNG terminals have to comply with environmental legislations and safety rules, etc. Hence, procedures have to be followed with several different public bodies under many different laws, all of which takes time (3 to 5 years) when construction times are already substantial.

Since it can be stored, gas allows a more flexible adjustment of supply to meet changes in demand than electricity does, which is no small advantage when more than half of all consumption depends on climate conditions[13]. So, 94.2% of the natural gas in Belgium (97.5% in the EU15) is devoted to a thermal use as a heating fuel or for generating heat and power (including for steam reforming processes in the chemicals sector), while the rest is used in methane form as a chemical reagent in the chemicals and petrochemicals industries' own cracking/reforming processes[14]. However, storage sites are limited (as they depend on the geological structures available - see section 1.2.3) while flexibility needs are increasing (i.e. greater distance for LNG supplies to travel).

As far as international transport is concerned, carrying gas, whether in gaseous or liquid (LNG) form, is expensive: some 6 to 7 times more costly than transporting oil (based on the same energy content), which is largely explained by the fact that the energy content of a cubic metre of gas is a

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12 Unlike electricity, the supply of gas cannot be considered as falling under a universal service: at the infrastructure access level, it is quite rational to limit the obligation to build and/or operate extra transmission facilities to those that could be built in economically justifiable conditions; for when it comes to energy supply, most users cannot be considered as being totally dependent on gas as it can be replaced by another fuel (unlike electricity, gas has very few captive uses). The public service obligation, on the other hand, comes into play as soon as the customer is connected to the grid, via the obligation for the holders of a supply permit to ensure the continuity of gas supplies to distribution companies for example, and therefore to safeguard their security of supply. For a detailed description of the potential content of these public service obligations, see Percebois J. (2002).

13 A very rough estimate of this dependence is provided by the share in final consumption of gas of the residential and commercial sectors where it can reasonable be assumed that natural gas consumption is mainly intended for heating.

Share of residential and commercial sectors in final consumption (2004).

EU15	Belgium	France	Germany	Italy	the Netherlands	UK
61%	51%	62%	66%	56%	65%	77%

Source: Eurostat.

14 Because of its composition, methane (CH_4) is a source of carbon and hydrogen often used in industrial chemical and petrochemical processes such as production of ammonia, methanol or carbon black. When the methane conversion process is based on an endothermic reaction and steam cracking like ammonia and methanol synthesis, the gas comes under "energy use". If the methane is used as a chemical reagent (feedstocks) in cracking and reforming operations for the production of ethylene, propylene, butylene, aromatic compounds, and other plastic raw materials for non-energy use, it is classified as being for non-energy use. The breakdown of chemical and petrochemical industries' gas consumption may therefore vary considerably depending on the type of activities covered and their size.

thousand times less than that found in an equivalent volume of oil[15]. It requires the use of specific techniques designed to reduce the volume of gas transported by lowering its temperature and/or pressure.

Transport via pipelines is based on fairly straightforward technology that has not developed much, apart from the materials used and their resistance to pressure, which enables either the pressure for an identical pipeline diameter to be raised or the diameter itself to be increased and thus reduce frictional losses. The economies of scale are high especially since pipeline capacity increases exponentially with larger diameters. Transport (and distribution) of gas by pipeline involves high fixed investment costs in network infrastructure (pipes and compressor stations) alongside low variable operating costs (labour and the gas needed for compression) and maintenance costs. These fixed costs depend on the length of the network, the required peak output, the optimum number[16] of compressor stations required for the chosen diameter of the pipes and the topology of the land crossed, while the variable costs are directly linked to pressure maintenance and vary according to the length of the network, the distance between compressor stations and losses due to distance and the state of the network. On top of these operational costs transit fees have to be paid in some cases when the pipelines run across transit countries.

Transport costs for liquefied natural gas (LNG) are also high and this can be explained by the fact that leading-edge "cryogenisation" technology is used to carry the gas in liquid state, which reduces its volume by 1/600th, and to keep it like that. Sending LNG overseas requires the use of specific facilities, both at the dispatching terminal and the reception terminal. The gas first goes through a pre-processing stage intended to reduce sources of corrosion to aluminium facilities (demercurisation) and to avoid any obstruction of valves and interchangers caused by cristallisation of "impurities" (deacidification of gas containing CO_2 and dehumidification of gas with H_2O) at low temperature, the gas being gradually cooled at a temperature of -161°C, a temperature at which it remains in liquid state at its boiling point at the pressure level of storage and transport. LNG is transported by sea on tankers, isothermal vessels built specially to withstand the mechanical constraints of transporting liquids on the high seas and to meet the thermal constraint of keeping the cargo at a temperature of -161°C while limiting any losses of materials through evaporation. The reception terminals are also specially equipped with flexible pipelines for unloading and carrying the liquefied natural gas to LNG storage facilities, with compressors, regasifiers intended

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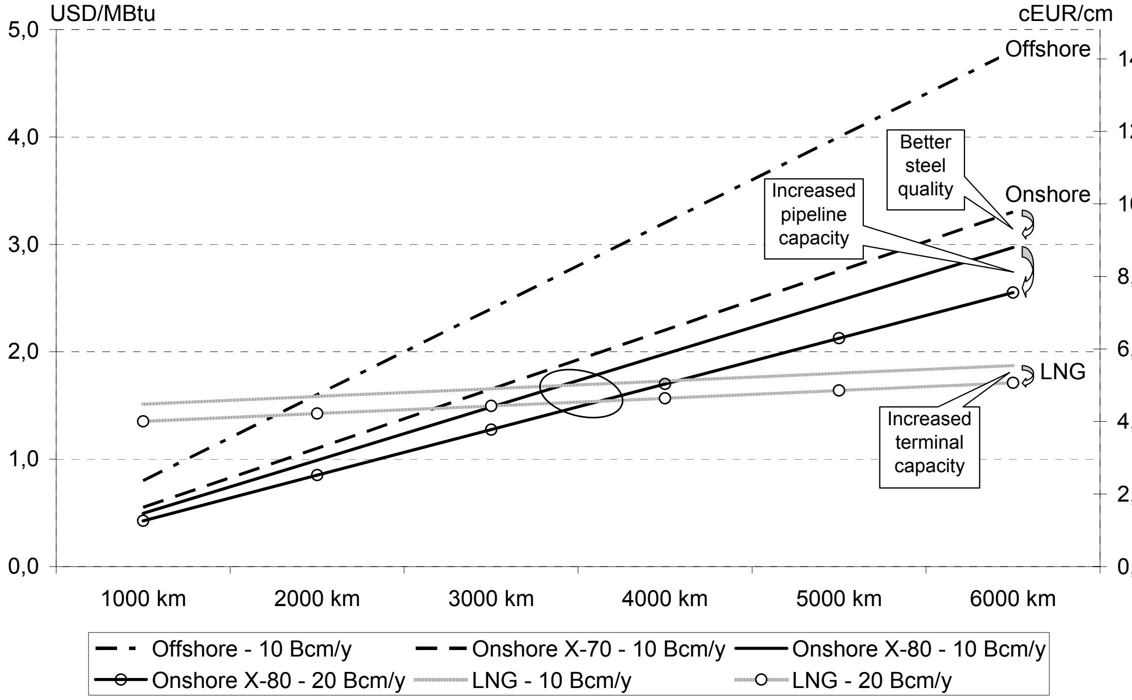
15 For an average crude oil density of 853 kg/cm and an average higher (or gross) calorific value (GCV - see annex) of 47.37 MJ/kg, 1 cm of crude oil ≈ 40407 MJ, as compared to the GCV of 1 cm of Algerian (39.19 MJ/cm) or Norwegian (40 MJ/cm) natural gas. In: IEA (2006a) and IEA (2006b).

16 Pipeline economics combines three cost elements: pipelines, compression stations and the energy used for recompression. For a given diameter, expenditure on pipes per million British thermal units (MBtu) of gas carried decreases as output increases, while expenditure on compressor stations - facilities and energy used - increase with output. It is therefore possible to establish an optimum output that keeps all these costs to a minimum for a given diameter, and vice versa, to optimise infrastructure according to the characteristics required for the network.

to vaporise compressed LNG as well as reprocessing and odorisation units before putting the gas on the transmission network. The LNG storage units at the dispatching terminal enable large enough quantities of gas to accumulate to fill a cargo, while at the reception terminal, they enable irregular batches of LNG shipments to be modulated into a continuous flow prior to re-gasification and to sending the gas on the grid. In this respect, the recent development of tankers with on-board re-gasification facilities (LNG re-gasification vessel or LNGRV - see below), widens the range of options available to solve the problem of any potential unavailability of storage capacity, while ensuring the gasification of the LNG. Apart from this largely operational function, LNG storage can also provide a reserve function in reception zones to cover seasonal peak releases in the winter if alternative underground storage facilities are not available (as in Japan, for example).

Chart 2 maps the evolution of the unit cost of bulk transport of gas over distance, in both liquid and gaseous state, from facilities with a capacity of 10 and 20 Bcm/year[17].

CHART 2: UNIT COST OF TRANSPORT BY TANKER AND BY PIPELINE



Costs calculated with an internal rate of return of 10%, expressed in USD per million British thermal units and in euro cents per Standard cubic metre (see annex for definitions). The (onshore) X-70 and X-80 refer to differences in steel quality.

Source: Observatoire Méditerranéen de l'Energie.

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17 Existing very large volume pipelines have a diameter of 1,400 mm and a transport capacity of 25-30 Bcm/year. The average size of a liquefaction train is currently 5 Mt/year (6.7 Bcm/year) and has even reached 7.5 Mt/year (10 Bcm/year) in the latest projects being carried out in Qatar.

Although there is not always a choice between these two alternatives, it is worthwhile pointing out their specificities:

- the unit cost of transport falls as output increases thanks to the economies of scale that exist in the two chains;
- LNG liquefaction/re-gasification facilities represent a major fixed cost that does not vary with distance while the costs that do vary over distance (i.e. more tankers needed for longer distances) are limited;
- in the case of pipeline transport, the total unit cost rises more in proportion to the distance covered than LNG costs (due to the high fixed costs incurred for the pipes and compression facilities according to distance), while fixed costs that do not depend on distance are almost non-existent. The use of higher-performance steel products enables the pressure to be raised from 70-80 bar (X-70 steel pipe) to 140 bar (X-80 steel pipe) and thus allows larger volumes to be transported for the same diameter, while reducing frictional losses, and hence the number of compressor stations required. Costs of using offshore pipelines are higher for obvious reasons of a more complex implementation and because of the need to use materials that can withstand the pressure of deep-sea depths.

The cost of LNG transport evidently becomes cheaper for distances of more than 3,500 - 4,000 km. However, this "break-even" distance increases with output, as the unit cost of transporting LNG is more proportional to output than pipeline transport, which leads to a more significant reduction in the slope of the cost curve for pipeline transport when volumes are larger.

In view of the shortage of re-gasification terminals experienced at the start of the decade[18] and taking account of the difficulty in getting a licence for constructing and operating this kind of infrastructure in densely populated areas and/or subject to stricter regulations, an alternative to traditional LNG reception terminals has emerged with the development of offshore unloading sites. The LNG re-gasification vessel (LNGRV) solution, namely to use tankers equipped for on-board re-gasification and unloading via an offshore pipeline linked up to the overland network, is the most advanced[19]. This approach has several advantages over the conventional LNG terminal:

- the reception infrastructure is slimmer and simply composed of a marker buoy at sea which the LNGRV hooks up to in order to unload the re-gasified gas or it can also dock at a wharf that has been suitably equipped in advance. The gas is then injected into the grid. Infrastructure costs are lower (equivalent to 15 to 20% of the cost of a land-based terminal[20]) and licences easier to obtain because of the more limited impact on the neighbouring area;

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18 Nowadays, there is a growing concern about the lack of liquefaction capacity, similar to the situation experienced a few years ago when the LNG market suffered from a deficiency of tankers.

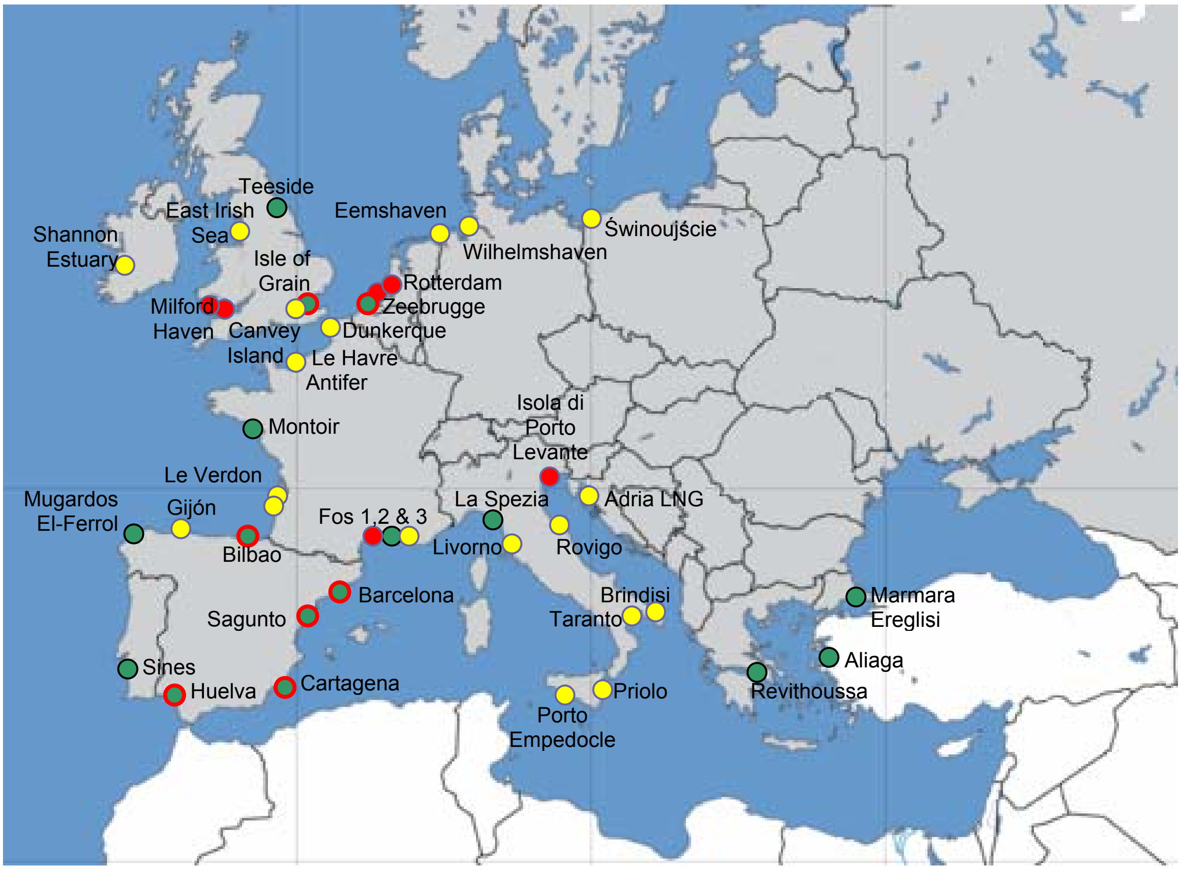
19 For a list of the various possibilities, see: Boussena S., Pauwels J.-P., Locatelli C. and C. Swartenbroekx, (2006), pp. 298-299.

20 On the other hand, the cost announced for a 145,000 cm LNGRV is $290 million, compared with a cost of $225 million for a conventional 155,000 cm tanker. In: LNG 15 News (2007) and Coltoncompany (2007).

- the flexibility of LNG transport is boosted by wider delivery possibilities, including towards port zones where unloading from large vessels had previously proved to be impossible. Partial unloading of a cargo is also possible and can be rapidly resumed in the event of any interruption owing to unfavourable weather conditions in the unloading zone (e.g. hurricanes).

As the gas is regasified on board, its delivery remains subject to the availability of sufficient downstream transmission capacity to be able to absorb the subsequent quantities carried in this way (150,000 cm of LNG for most of the LNGRV on order) or at least depends on the availability of an appropriate storage site nearby. The duration of unloading is also longer owing to the re-gasification process, rising to 5-6 days compared with 12 to 24 hours for unloading an LNG cargo.

CHART 3: MAIN LNG RECEPTION TERMINALS IN WESTERN EUROPE

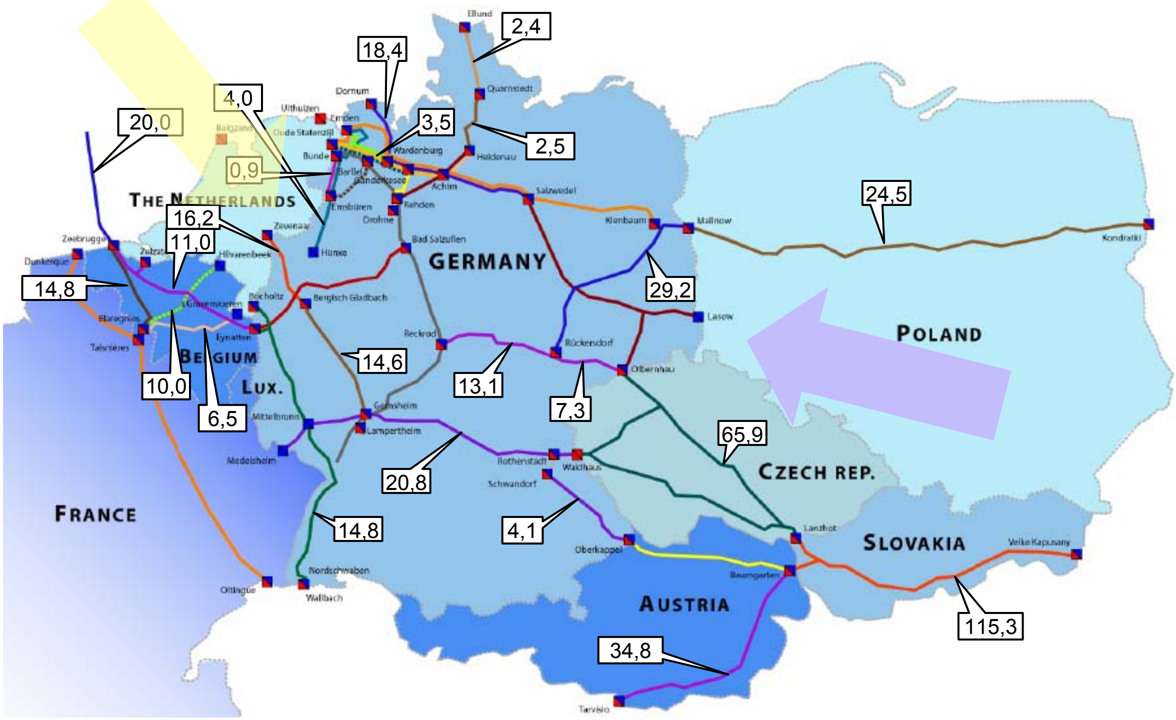


Existing terminals in May 2007 | Terminals under construction | Proposed new terminals
Existing terminals being extended

Source: Based on GRTgaz.

Carriage of both gas and electricity hinges on an essential transmission infrastructure. However, since natural gas is a primary energy partly imported from its extraction zones, making it available on the different national markets in Europe has required the installation of transit and interconnection pipes between these markets. This is a less urgent necessity for electricity which is a secondary energy source generated "locally". Even before liberalisation, the need for these gas interconnections had been felt and several countries have emerged as indispensable for the transit of gas to markets not bordering production areas. In the eastern part of the EU, these transit countries are mainly Slovakia, the Czech Republic and Poland, while in the west, several major transit pipelines run through Belgium with a total capacity three times the level of its own domestic consumption. In this respect, the real issue at stake in the context of a liberalised market is a non-discriminatory and transparent access to infrastructure with sufficient capacity.

CHART 4: MAIN GAS TRANSIT ROUTES AND THEIR TECHNICAL TRANSPORT CAPACITY IN BCM/YEAR - 2004



Source: European Commission (2007), "DG Competition report on energy sector inquiry".

The gas is then carried to the final consumer (residential and commercial sectors and small industries) via the distribution network which has a lower service pressure, in a similar way to the electric power system with its low-, medium- and high-voltage grids. From a technical point of view, the electricity and gas distribution networks can nevertheless be distinguished from one another:

- by the degree of balancing prescribed for the network to operate properly, a power grid requiring balancing in real time and the intervention of a system manager[21]; for the gas grid, intervention of this kind is also necessary, but is less constraining since there is a degree of flexibility for gas pressure in the grid pipelines which can help offset variations between gas inputs and off-takes. The volume of gas present in the grid can vary in response to changes in temperature and/or pressure. It is also possible to store small quantities of gas for short periods by raising the pressure in the pipes. These fluctuations in the volume of gas in the grid (line-

21 Indeed, by the very nature of the physical properties of the electric current and in particular currents coming in and going out in a junction on the grid, no electric charge can be lost and currents entering and exiting a junction must be equivalent (known as Kirchhoff's junction rule).

pack fluctuations) contribute to a better management of the network with increases in pressure in off-peak periods in order to boost supply capacity in periods of higher demand[22];

- by whether it is possible or not to direct the flows of energy transported: moving an electric current conforms to a physical law whereby the current entering a junction in the grid is split into outgoing currents according to the resistance of the outgoing cables (known as Kirchhoff's loop rule), thus making it impossible to direct the current towards any one particular junction; while in the case of gas, transmission can be directed, subject to a correct calibration of the grid and its component parts (see Box 1).

So, in contrast to an electric current, it is possible to get a good understanding of the physical carriage of gas and any resultant losses in transmission and distribution, and therefore to charge them to the consumer on the basis of a price that is based on distance. In the case of electricity, it is not possible to set such a rate if there is no way of knowing the physical path followed by the electrons. These differences related to the specific physical laws governing the carriage of gas and electricity have a direct impact on the nature of prices to be applied for third party access (TPA) to the grid, for instance: for electricity a (flat rate) "postage stamp" pricing mechanism is required, while for gas, pricing based on distance is possible (see section 2.4.1)[23].

BOX 1: GAS GRID CALIBRATION CRITERIA

Apart from the need to guarantee a specific delivery pressure, correct shipment of natural gas also implies maintaining a sufficient flow rate at each junction of the grid so as to be able to direct the movement of the gas among the various pipes in the main system, while taking account of load losses between system entry and exit points. The aim is therefore to see that enough kinetic energy is maintained to ensure that the pressure gradient between any two points and the load loss caused by friction along the pipes between these points remain the same. The components of a gas transmission network are influenced by two other variables which are of direct relevance to the consumer at the end of the gas pipes: the output and calorific value of the gas carried, especially if it is intended for industrial use as in chemicals, for instance (feedstock). Apart from these operational requirements, it is also of utmost importance to keep up a minimum pressure over and above atmospheric pressure in order to avoid any air or oxygen getting into the grid and causing an explosive interaction.

[22] This flexibility in gas grid balancing is nevertheless limited by its technical and operational characteristics with a tolerance threshold that varies considerably with pressure levels and volumes flowing through the pipes.

[23] For a detailed description of the different pricing methods on the electricity and gas grids, see Percebois J. (2003), pp. 10-12.

The gas grid hinges on four types of installations:

- main pipelines: these consist of welded steel pipes from one end to the other; those in the transmission system are usually arranged in the form of an arborescent network, that is, there is only one single path between two junctions in the grid. Generally speaking, the distribution network is designed as a meshed network, i.e. there are at least two paths between two grid junctions. However, the gas grid is generally less integrated than the power grid because of its high transmission costs (need for a critical mass of customers to justify building such a network in the first place);
- interconnector stations located at each junction of the grid: this set of valves make it possible to regulate the transit flow between pipelines, taking account of the precise pressure and flow rate needed for each pipeline;
- compressor stations: with the gradual lowering of the pressure of the gas as it is moved, it is necessary to raise pressure levels by installing compressor stations along the grid in order to maintain the pressure level required for the transport of the gas as well as for the final consumer[24];
- blending stations: as calorific value can vary from one gas to another, the quality of the gas present in the grid is harmonised by the addition of methane (to raise the calorific value) or an inert gas (to reduce the calorific value) in order to ensure the correct functioning of customers' equipment.

Lastly, and again unlike electricity which only has to meet tension and frequency criteria, natural gas is not such a homogenous product and its composition can vary considerably depending on its origin. But the quality of the gas injected into the network is important both for the proper functioning of combustion installations and appliances and for its use for chemical purposes by industry. Quality specifications for gas mainly concern its upper calorific value, its Wobbe index[25], the water dew point, the hydrocarbon dew point, and the sulphur, carbon dioxide and oxygen contents. These characteristics do matter for gas buyers and have to be respected both by the supplier and the transporter. Indeed, the gas injected into the network is mixed with the quantities of gas present and each transporter is responsible for the quality of the gas it is carrying on its network, within very precise limits.

24 GRTgaz (2006).

25 The Wobbe index is used to compare the combustion energy output of different composition fuel gases in an appliance. It is measured on the basis of the relationship between the calorific value of the gas and the square root of the ratio of the gas density to the density of air. The relative density in relation to air will determine the speed at which the gas goes through the burner. Thus, the combination of the calorific value and the gas density will determine the speed at which the energy is transmitted to the burner. If the Wobbe index is very high, it could be that the oxygen in the air does not have enough time to mix with the gas causing incomplete combustion. Conversely, in the case of gas with too low an index, the energy released by the burner diminishes which can adversely affect the performance of the equipment and even extinguish the flame.

These differences in quality also interfere with supply conditions on the Dutch, Belgian, French and German gas markets, where both low calorific value gas (9,769 kWh/cm) and high calorific value gas (11,630 kWh/cm) are sold. Poor gas (L-gas), coming mainly from the huge Slochteren field in the Netherlands, is carried on networks that are physically separate from the networks shipping high gas (H-gas) and also requires separate storage sites[26]. Moreover, 20% more L-gas has to be carried in volume for the same amount of energy than with H-gas.

1.2.3 THE ADVANTAGE OF A STORABLE FUEL

Both trade in gas and electricity can only be subject to limited arbitrage between different places, since producers and consumers have to be linked up by a physical infrastructure. Nevertheless, unlike electricity, gas has the advantage of being storable and allowing arbitrage over time, a real asset for meeting the seasonality of demand for gas which varies considerably over the year because it is largely used for heating.

There are several options possible for storing gas:

- various types of storage facilities are used for seasonal demand management either in surface or underground sites. Underground sites are replenished during the off-peak (summer) season so as to have sufficient volumes in periods of high demand – while surface storage of liquid LNG is used to cover peak demand. The 261,000 cm LNG storage capacity available at Zeebrugge makes it possible for gas to be injected into the grid over the equivalent of about 6.6 days at the maximum withdrawal rate of 950,000 cm/h from these storage facilities;
- an indirect form of storage is provided by the network through the "line-pack": pipeline pressure and diameter are calibrated so as to be able to meet day-time fluctuations in consumption, even as far as to meet all peak demand. Although expensive in infrastructure terms, this latter solution is conceivable in the case of shorter distances between points of production and consumption. The Dutch and British networks have therefore been equipped with compressors that can raise the pressure in the grid in order to meet peak demand, since the relative proximity of their gas fields enables them to be used as basic storage sites.

The advantages and drawbacks of these different types of storage are shown in Table 4. The physical characteristics (porosity, presence of water, etc.) of storage sites effectively determine the speed at which the gas is injected and withdrawn, and therefore, its availability.

[26] As far as Belgium is concerned, the proximity and the flexibility in the contracts with the Dutch supplier mean that no L-gas storage has been foreseen (In: CREG (2004)). However within a relatively short period of time (2012-2019), the Dutch L-gas supply contracts will dry up, which will require the H-gas grid to be extended to L-gas customers with significant costs at stake in adapting the infrastructures (network, burners, etc.).

TABLE 4: THE DIFFERENT TYPES OF STORAGE AND THEIR FEATURES

Type of storage	Advantages	Disadvantages
Storage in aquifers and in former gas and oil fields	- large capacity and low withdrawal flow rate favouring use for seasonal management and for strategic stocks	- presence of 50% of "cushion" gas required to ensure withdrawal (pressure may not fall below the initial pressure level) - risk of mixing with water or with the "cushion" gas which is not always the same quality as the gas injected - location depends on geologically available sites
Storage in salt caverns obtained by leaching into deep salt layers (done by cycling water into the structure to dissolve a cavern)	- more limited capacity and high withdrawal flow rate	- presence of 30-35% of "cushion" gas required to preserve the cavity's storage capacity - location depends on geologically available sites
Cryogenic storage (in LNG form)	- high withdrawal flow rate	- limited capacity - surface location near LNG reception units
Disused mines		- pressure at which the gas can be stored depends on the depth of the mine - location depends on geologically available sites
Line-pack	- a possible solution when the source of supply is not too far away	- expensive - not a very credible alternative in the event of supply interruption

In terms of market forces, the possibility of storing gas can have a moderating effect on gas price volatility when prices are determined on a liberalised market, because it constitutes an additional source available to meet fluctuations in demand for gas[27]. This alternative is not available[28] for electricity and goes some way to explaining the high volatility in the price of electricity in a context of similarly fluctuating demand in the very short term.

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27 The purely operational use of storage sites for good technical management of the network should not be underestimated.

28 There is of course still a small margin of manoeuvre in storing electricity with the use of a pumped-storage plant like the Coo-Trois-Ponts hydro-power plant: during off-peak energy consumption hours, the water is pumped towards an upper reservoir and stored as a potential source of energy. During hours of peak electricity demand, the water is pumped into the lower reservoir with a difference in height of 250 m whilst driving a turbine, linked up to an alternator.

At the same time, it is this very same price volatility that generates incentives for and revenue from new investment in storage infrastructure. Any action taken by the authorities in this area, for instance within a context of a strategic gas storage as it exists for oil, should be entirely transparent. Unlike "commercial" stocks which enable operators to work in normal circumstances, strategic stocks would be intended for use in circumstances where the market alone cannot provide enough gas owing to unusual conditions (extreme weather conditions, pipeline rupture, etc.). However, they may not physically replace existing seasonal storage (due to the scarcity of available sites), neither replace commercial stocks, if only in the minds of the operators themselves: if there was any doubt about the conditions of release on the market of such a strategic storage, it could contribute to under-investment in commercial storage.

The high costs of gas storage have to be weighed up against the advantage brought by its availability in the first place. According to the IEA and on the basis of a survey of investment in commercial storage sites under construction, the initial cost of the capital needed for underground gas storage facilities is 5 to 7 times higher than for underground oil storage (comparison per tonne of oil equivalent stored). And when it comes to LNG storage *versus* storage in oil tanks, the ratio is 10 to 1[29]. With a view to building up strategic stocks, and assuming that there are sites available, the capital cost of constructing the infrastructure necessary to cover 90 days of net imports of gas (2015 level) by IEA member countries would be around $54 billion (constant 2005 $ price) to which another $40 billion (constant 2005 $ price) should be added for the purchase of the gas (at 2005 prices) and annual variable costs equivalent to 10% of the capital cost, due to losses incurred through gas leakage (estimated at 2%).

Finally, in exceptional circumstances, storage space can be provided by the tankers themselves, if needed, when market conditions make this immobilisation of floating cargoes economically acceptable. So, in 2006, the fall in gas prices on spot markets to below the price of long-term supply contracts encouraged the appearance of these "floating storage" facilities, as owners of spot cargoes preferred to keep them at sea (at their own cost) awaiting more favourable spot price evolutions (Petrostrategies 2007a).

29 See: IEA (2007), pp. 69-77.

2 LIBERALISATION OF THE GAS MARKET

Following the examples set by the Americans and the British, the European Union has launched into a process of gas and electricity market liberalisation, with a view to establishing a common, integrated European energy market governed by the same competition conditions in all Member States.

2.1 LIBERALISATION PARTLY INSPIRED BY THE NORTH AMERICAN AND BRITISH EXAMPLES

The American and British gas markets were deregulated for similar motives, against a backdrop of mature markets with practically no dependence on imports, unlike the gas market in continental Europe.

The US gas industry was the first to develop around the middle of the 1920s, first locally and then gradually extending to other US States along with the development of long-distance gas transport technologies. Faced with local producers' exclusive rights over the transmission networks in exchange for financing them, the need for regulation soon became evident.

In practice, the gas sector is regulated by the individual States and at federal level as soon as the gas is carried beyond a State's own borders. Up until 1978, the industry was subject to strict price controls, even price freezes, encouraging strong demand but having an inhibiting effect on domestic production. So, after several periods of gas shortages, sales prices at the mouth of the wells (wellhead prices) were gradually raised from 1978 onwards. Nevertheless, this wellhead price regulation system was only to be abandoned from 1985, a move that would contribute to bursting the gas bubble that had appeared at the beginning of the 1980s under the combined effect of a domestic production base that had shifted into over-capacity, under the impetus of higher regulated prices, chasing demand that had effectively flattened out. At the same time as prices were deregulated, open and non-discriminatory access to the transmission network was granted to all suppliers. This approach was later extended to the distribution networks, too. All these measures served to boost competition, including at local producer level, the key being a 50% cut in exploration and discovery costs. The favourable evolution of prices has relaunched demand, boosted grid output and reduced the unit cost of transmission (IEEJ 2003). Today, the American market is similar to a regulated competitive market where market entry is open although subject to compliance with the (strict) regulations in force.

Among the companies active in oil and gas production in the United States are the "majors", a category of producers which the US energy authorities (EIA/DOE) define as including: "US-based publicly-owned companies or US-based subsidiaries of publicly-owned foreign companies that had at least 1% of either production or reserves of oil or gas in the United States, or 1% of either refining capacity or petroleum product sales in the United States". Alongside these majors, some

5,000 independent producers exclusively active in hydrocarbons exploration and production coexist, scattered across the 33 States where oil and/or gas deposits are exploited in the United States. Despite often being very small (they employ 12 people on average), in 2005 these independent producers hold 51% of total gas reserves and account for around 58% of production – the equivalent of 48% of US consumption.

TABLE 5: RESPECTIVE IMPORTANCE OF THE MAJORS AND INDEPENDENT PRODUCERS IN THE UNITED STATES

United States	1995	2000	2005	Number of wells drilled in 2005 *	Reserves at end 2005
	Bcm/year	Bcm/year	Bcm/year		Bcm/year
Consumption	596.1	626.3	597.0		
Domestic production	482.2	515.9	495.4	27,397	5486.1
- majors	*216.2*	*223.9*	*208.7*	*7,622*	*2668.9*
- independent producers	*266.0*	*292.0*	*286.8*	*19,775*	*2817.2*

* Exploratory wells and development wells (dry holes excluded).

Source: EIA/DOE (2006), "Performance profiles of major energy producers 2005".

The natural gas industry in the United Kingdom took off a bit later, at the end of the 1950s, but could use the existing town gas distribution infrastructure, and largely rely on the gas sector operators (manufactured gas producers and distributors) when the North Sea gas fields were discovered[30]. The giant British Gas was to emerge from the closer links between these operators and soon gain monopoly status, except for production, although it obtained exclusive purchase rights. In a similar way to the American model, the liberalisation of the UK gas market was used to a certain extent to re-launch a production base that had become rather flat as a result of the obligation to sell the gas on to a single intermediary under not very good conditions and that had become indispensable for gaining market access. Under the Oil and Gas Act passed in 1982, the obligation to sell gas exclusively to British Gas was lifted and, in 1986, the company was privatised.

North Sea gas fields on the British continental shelf are developed by 25 different operators who share the 129 gas field exploration licences granted by the British authorities since 1976.

[30] At the beginning of the 1950s, the UK gas companies (town gas suppliers) in fact became very interested by natural gas for various reasons (rise in coal prices, problem of smog, etc.) and were to promote the first imports of LNG from the United States and then from Algeria, just a few years before the first gas fields in the North Sea were discovered.

In both cases, the production and supply structure on national territory can be partly regulated with the rest of the gas chain. By comparison, with an external dependence on gas of nearly 55%, a large proportion of the EU27's upstream gas supply is not subject to the provisions of EU legislation but is reliant on commercial transactions with a much smaller group of third-country producers than those operating on the UK and US markets. Obviously, this margin of manoeuvre for suppliers to compete is very thin in the context of the liberalisation of the European market whose upstream supply largely escapes EU regulation. Shortly after they were opened up to competition, the US and British markets distinguished themselves from the others by their maturity and the availability of a domestic source of supply freeing them from the need to import gas.

Among the oil and gas companies supplying the European market, the five leading producers - ExxonMobil, Shell, Statoil, Total and BP – together produced some 137 Bcm of gas in 2005 that is 48% of European production (including Norwegian output).

2.2 THE SUPPLIERS' OLIGOPOLY

The composition of gas supply is characterised by the primary energy nature of this fuel whose reserves are geographically concentrated in a few individual countries, even more so than for oil: the three biggest holders of proven oil reserves have a relative cumulative share of 44.8% compared with 55.7% for natural gas. Gas endowment around the world distinguishes itself from oil in the sense that it is available in separate regions which tends to have a favourable influence on the geopolitics of gas and acts in favour of security of supply.

A supplier's market power is even more determined by its relative share of the volume traded on the international markets than by its reserves. The three leading net exporters of gas hold a cumulative market share of nearly 49% compared with 40% (2004 figures) for oil exports. This ranking on the basis of gas exports differs considerably from that based on proven reserves, reflecting the higher degree of development in gas distribution in Europe and North America (also taking into account that the United States is the world's second largest producer – see Table 2).

TABLE 6: THE TEN MAIN NATURAL GAS RESERVE HOLDERS AND NET EXPORTERS

Proven reserves - 2006			Net exports - 2006		
	Tcm	Cumulative share		Bcm/year	Cumulative share
Russian Federation	47.7	26.3%	Russian Federation	151.5	22.8%
Iran	28.1	41.8%	Canada	90.4	36.4%
Qatar	25.4	55.7%	Norway	84.0	49.0%
Saudi Arabia	7.1	59.6%	Algeria	61.6	58.2%
United Arab Emirates	6.1	63.0%	Indonesia	34.4	63.4%
United States	5.9	66.2%	Qatar	31.1	68.1%
Nigeria	5.2	69.1%	the Netherlands	30.1	72.6%
Algeria	4.5	71.6%	Malaysia	29.8	77.1%
Venezuela	4.3	74.0%	Australia	18.0	79.8%
Iraq	3.2	75.7%	Nigeria	17.6	82.4%

Source: BP (2007), Statistical Review of World Energy June 2007.

The concentration of gas supplies in the hands of barely more than ten producer countries is even further pronounced when it comes to supplies to European consumers, in view of the highly regionalised nature of international gas trade.

Today's gas market cannot really be described as being global, but rather one that is articulated around three big regional markets, namely Europe, Asia and North America. Due to the high cost of transporting it, trade in natural gas tends to expand first from fields located on its (even sometimes distant) periphery, with:

- a North American market mainly supplied by Canadian exports by pipeline and some LNG which is expected to increase in the future;
- a European market supplied by pipelines gas from Russia, Norway and Algeria and by LNG stemming mainly from Algeria, Nigeria and Qatar;
- and an Asian market where the insular nature of consumer zones led to reliance on LNG supplies from regional producers (Brunei, Indonesia, Malaysia and Australia) and which will probably get some supplies from "Russian pipelines" in the future.

The advent of LNG, driven notably by a reduction in the cost of liquefaction and transport, has led to more and more supply routes and made it possible to reduce to some extent the existing partitioning of the major regional markets. The volume carried in LNG form accounted for 26% of world gas trade in 2005, with 65% destined for Asian markets, 25% going to European markets and 10% to American markets. LNG has enabled an increase in supplies on a spot market basis, although trade governed by long-term supply contracts is still the rule (especially for Asia).

Against a backdrop of rising European demand (expected to grow by 1.6% a year up to 2020) that can clearly not be met by domestic production, the contribution of external producers/suppliers is essential, putting them in a key position (within limits) towards Europe (and others), influencing their strategic position.

Since the 1970s, Europe's upstream natural gas market has operated as an oligopoly, an observation confirmed by work on energy system modelling[31], even though often leading to incomplete representations of how the gas economy functions. The main features of the European gas market are as follows:

- a limited number of domestic and external suppliers to the EU: the Netherlands (13% of total gas demand), the United Kingdom (18% of total demand), Russia (26%), Norway (16%), Algeria (11%) and other origins (Qatar, Nigeria, Egypt, Libya). The EU's three main suppliers (Russia, Norway, Algeria) account for 54% of its gas consumption and 84% of its gross imports. Domestic suppliers (mainly the United Kingdom and the Netherlands and, to a much lesser extent, Germany, Romania, Italy and Denmark) account for 42% of total gas demand. In several Member States, the gas even comes from one sole supplier (Russia in the case of the Baltic States and Bulgaria, for example) or from a dominant supplier (Algeria in Spain's case, for instance);
- a concentration of supply that is expected to become even more pronounced with the decline in European suppliers' production; the EU's gas supply will then be in the hands of four big suppliers (Russia, Algeria, Norway and Qatar), or maybe five if Iran starts gas development for the export market, which looks promising from the point of view of its reserves. In the medium term, LNG exports from Qatar could have a bigger impact on the EU's gas supply, in view of the expected expansion of liquefaction capacities (77 Bcm/year by 2010) in this country with large gas reserves;
- a relatively homogenous product, still subject to upgrading of quality specifications by technological processes, the exception being L-gas from the Dutch field at Slochteren which requires its own specific network, but which is now nearing depletion;
- major barriers to entry in terms of exploration-production and transport infrastructure costs, even when access to resources and the transmission network is not restricted by legal provisions decreed by the authorities (as in the case of Russia and the Gazprom network, for instance).

[31] For a short survey of the state of the literature see Holz F., von Hirschausen C. and C. Kemfert (2006).

2.2.1 HOW DOES THE EU GAS SUPPLIERS' OLIGOPOLY WORK?

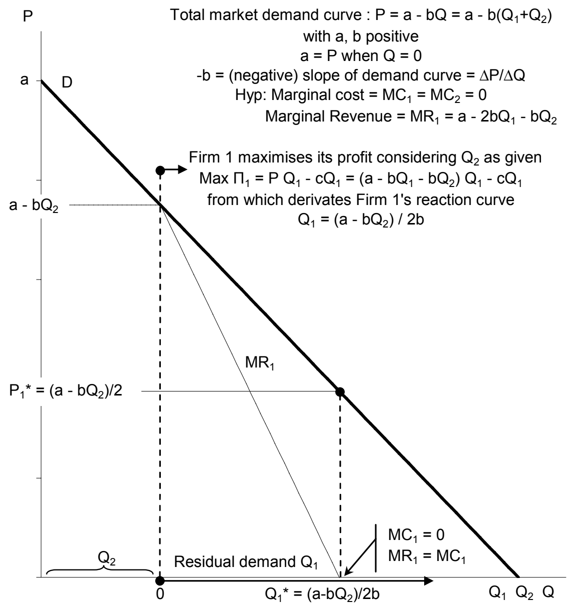
In a perfectly competitive market, companies do not care about what their competitors are doing; in a monopoly situation, the company has no competitors. The oligopoly position is marked by an intermediate situation with a small number of competitors holding consequent market shares: any action by one of them triggers a reaction by the other operators, whether in terms of price or quantities supplied.

BOX 2: OLIGOPOLISTIC MODELS

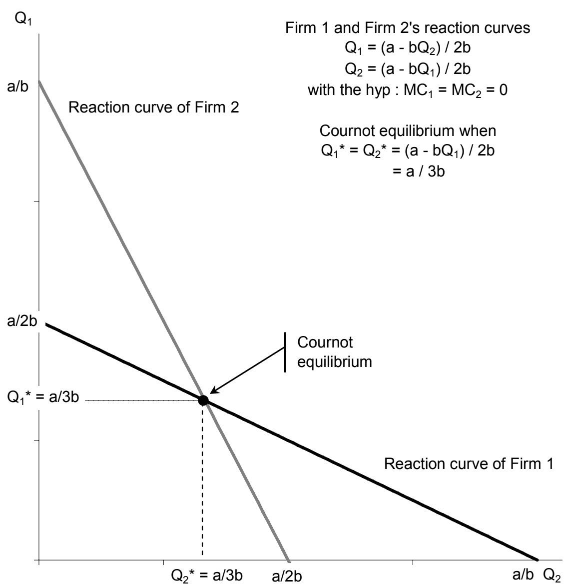
The Cournot model

First and foremost, the Cournot model is a duopoly. It is assumed that the two firms present on the market make their decisions about production volumes simultaneously, which means that the decision of one firm does not influence the decision of the other one. Each firm decides to maximise its profit and the quantity it is going to produce by taking the other company's production into consideration as a fact. In so doing, each firm has a reaction curve (expressed in production volume terms) in response to the supposed production of the other company. The intersection of the two reaction curves produces the Cournot equilibrium quantity. The equilibrium price is derived from the demand function. By extending the Cournot model to several firms with identical costs, it can be shown that the equilibrium price decreases when the number of firms increases.

The profit maximising Cournot duopolist



Reaction curves for the Cournot duopolist



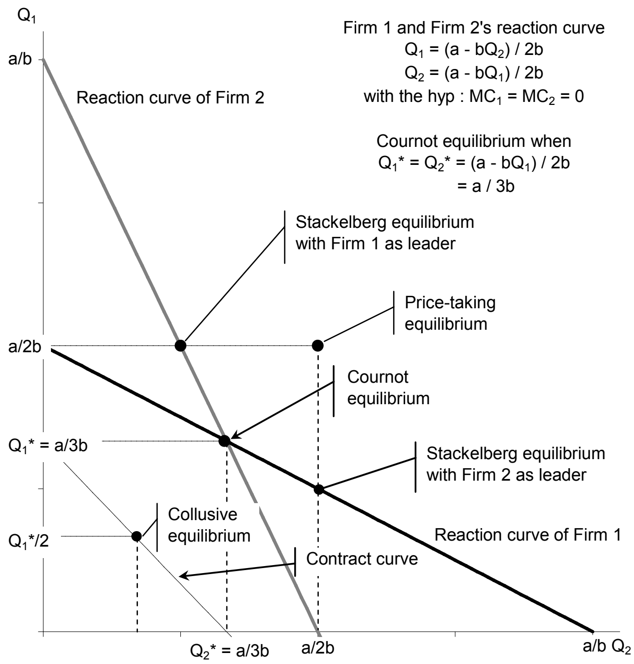
The Bertrand model

Close to the Cournot model on the conceptual front, the Bertrand duopoly model assumes that firm 1 sets its price supposing that firm 2 keeps its price unchanged. With consumers making their choice on the basis of the best price, each company is encouraged to reduce its price to conquer the whole market, the only restriction being that the marginal cost is covered. If marginal costs are equal, the equilibrium price is equal to the marginal cost (situation of perfect competition) and both firms make no profit (Bertrand's paradox).

The Stackelberg model

In the Cournot model, the two firms make their decision on the quantity supplied at the same time. In the Stackelberg model, on the other hand, one of the two firms (defined as the leader) agrees on the quantity supplied before the other (qualified as the follower), which is of course the case when a company gets a foot in the gas market before another one. H. von Stackelberg adapted the Cournot model by taking into account the sequence of the companies' supply decisions in order to answer the question whether the leader company has a comparative advantage. In the case of this model, the leader takes its decision in full knowledge that the follower will respond by using its Cournot reaction curve to fix its supply. The leader thus has a comparative advantage over the follower and takes advantage of it to maximise its profit.

Comparison of the Cournot, Stackelberg and cartel equilibria



Oligopolistic collusion models

In the previous models, there is no collusion, either organised or informal, between the companies. It is effectively the market that introduced the reaction functions.

In the models with collusion, this collusion can be organised as in the case of a cartel seeking global profit maximisation for its members to then be shared out according to some or other key. The cartel can also be based on market-sharing agreements. Collusion can also be arranged on an informal basis, whether or not by market-fixing as in the case of the dominant firm. The latter, which sets the price of the good produced, is regarded as dominant because it has a major market share as well as the capacity to make other followers respect the price it has set. Respect for a price can be won, for instance, through a price war that penalises "followers" who cheat[32]. The informal rule of collusion implies that the dominant firm fixes the price (preferably the one that is maximising its

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[32] On this subject, see Boussena S., Pauwels J.-P., Locatelli C. and C. Swartenbroekx (2006), chapter 1, pp. 52-63.

profit), and, in return, the "follower" companies can produce to maximum capacity, the market being foreclosed by the dominant firm (referred to as "swing producer" in an oil market context). In the world oil market, OPEC can be considered to be the dominant "firm" in relation to the "followers" (even Russia, Norway and Mexico have never contested OPEC's prices). In this type of collusive model, there is no formal agreement between firms as in a cartel.

In the case of the EU's external supply of gas by the oligopoly of its three main suppliers (Russia, Norway, Algeria), the price of the supplies can be considered to be the result of "informal" collusion. Within OPEC, the dominant firm is Saudi Arabia and on the world oil market, this role is played by OPEC itself. In the international gas market, Russia is the dominant firm. The price of "collusive" gas takes account of the price of oil which is used as a reference price, as well as the distance between the EU border and the production fields. The prices charged by the different suppliers are very similar, with Dutch prices (12.8 EUR/MWh in 2004) being higher than Algerian prices (9.8 EUR/MWh) because of the higher degree of flexibility with deliveries from the Netherlands and the higher backup capacity[33].

The collusion stems not only from informal contacts between producers but also from bargaining on the sidelines during highly official meetings such as those of the Gas Exporting Countries Forum (GECF - see below). This reality of the business world is disappointing for energy systems modelling. It was in this way that the functioning of the gas wholesale market was grasped using the GASMOD model for which the validity of its hypotheses of a similar set-up to the Cournot-type oligopoly was tested on the European market situation in 2003[34]. The model makes a distinction between the upstream export market and the downstream wholesale market, while also taking account of existing infrastructure and any resultant constraints. A simulation on the basis of Cournot's oligopoly gives a realistic result in terms of gas consumption and total import volumes. However, when it comes to the breakdown of imports by origin, it takes account of the economic cost of production and especially the cost of transport in the sequence of the "call" on suppliers. According to the modelled findings, the Russian supplier is less present in the market than in reality, owing to the proximity of supposedly cheaper suppliers whose relative share is boosted. This modelling exercise actually disregards the fact that despite production costs varying from one producer to another and transport costs sometimes being quite significant as they are proportional to the distance covered, the "monetisation" of gas on outlet markets is based on the principle of net-back sales: since gas has only very few captive markets (except when environmental externalities are taken into account), it must have a competitive price at the burner compared to the price of substituting fuels. Some gas producers give up part of their profits to ensure that it does.

33 This is the average price of gas (commodity price, excluding capacity charge) purchased under long-term supply contracts, most gas from other origins having even been acquired at prices in the range of 10.5 to 11.5 EUR/MWh. In: European Commission (2007b), p. 105.

34 Holz F., von Hirschausen C. and C. Kemfert (2006).

2.2.2 TOWARDS AN OPEG FOR GAS?

The first meeting of the Gas Exporting Countries Forum (GECF) was held in May 2001 and brought together representatives from 11 gas-producing countries, a (varying according to circumstances) participation that has since been gradually raised to 17 nations[35]. The current participants together with Norway account for 73% of proven reserves worldwide, 46% of production and 67% of international trade flows. The Russian Federation is a heavyweight member (if it is excluded, the above-mentioned percentages fall back to respectively 47%, 25% and 46%). This informal gathering forms a basis for the exchange of information and provides a forum for producers to discuss common problems, along the lines of other producer associations. The perceived danger for consumers is that it might develop into a cartel with some kind of price collusion.

An oligopoly assumes non-collusive behaviour on the part of market operators. Another hypothesis is to envisage cartel-like cooperation between producers, similar to the cartel formed by the OPEC countries on the oil market. Nonetheless, the oil market does not have the same characteristics as the gas market:

- unlike a globalised oil market, international gas trade flows are still highly regionalised, with a strong existing link between consumption and extraction zones, especially in pipeline trade, and for the share of LNG trade based on long-term contracts (which accounted for some 84% of LNG trade in 2006)[36];
- the cost of transport represents a multiple of production costs and the cost of storing gas is high too, unlike oil which can be easily traded on a global scale owing to cheaper and technologically less restrictive means of transport and storage. The resultant geographic partitioning of markets does not permit any global action on supply through a quota system, like OPEC's, to influence some kind of world gas price;
- the price of gas is still linked to the price of oil, albeit more autonomously in the United States and the United Kingdom, but not to the same extent as the price of coal where the supply market is more competitive;
- the existence of a wider range of substitute fuels for gas than for oil increases the price elasticity of demand for gas and at the same time reduces the market power of any gas cartel.

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35 Algeria, Bolivia, Brunei, Egypt, Equatorial Guinea, Indonesia, Iran, Libya, Malaysia, Nigeria, Oman, Qatar, Russia, Trinidad & Tobago, the United Arab Emirates and Venezuela have met in this Forum six times since 2001. Norway has observer status.

36 On the basis of the latest estimates from the International Group of Liquefied Natural Gas Importers (GIIGNL), spot and short-term (up to 4 years) trade accounted for 16% of all LNG trade in 2006, an equivalent of 56 Bcm/year for a total volume of gas traded internationally (LNG and pipelines) of 886 Bcm. In: Petrostrategies (May 2007).

Several short-term considerations suggest that operating a gas cartel along the lines of OPEC is not very plausible:

- there is no surplus supply, yet the very principle of a cartel is to play on market liquidity (through supply) and influence prices, while gas prices are still primarily influenced by their indexation to oil prices;
- the specific features of the contractual relations that still govern most international gas trade (since long-term supply contracts often include take-or-pay clauses) do not allow supply to be easily adjusted in the current context. In fact, spot markets affect less than 7% of all international gas trade. And recently, several Russian gas supply contracts with European gas operators like GDF, ENI, DONG (Denmark) or OMV (Austria) have been extended for another 20 to 25 years.

Although Russia is a dominant producer among the GECF members with significant production, export and reserve capacity enabling it to play the role of "swing producer" like Saudi Arabia in OPEC, it is by no means clear that it is prepared to take on such a role, since voluntary withholding of gas supply is financially more penalising than for oil. So, making a gas cartel work on the basis of a price target is a much more delicate task in view of the cost of keeping excess capacity: according to Fawzi A. (In: Jaffe A.M. and R. Soligo (2006)), 1% of capacity surplus in terms of world oil production (on the basis of an investment cost of $3,000 per barrel per day) works out at a cost of $2.2 billion compared with $13.8 billion for a capacity surplus of 1% in terms of gas production (only in the form of LNG, including gas field development, liquefaction and tankers). Therefore, in the case of gas, it is not so much controlling production as such that matters, but rather controlling the rhythm of production capacity expansion, since the high level of infrastructure costs encourages their use at full capacity. But these checks on capacity expansion are more complicated to implement because they imply some producers giving up development of their gas reserves to benefit others[37]. Qatar could also take on this role, especially as its export capacity is in the form of LNG, but 94% of the export volumes are already dedicated under contracts expiring in 2022 at the earliest. Furthermore, the capacities of liquefaction trains under construction have already been allocated and, as a new entrant, Qatar prefers to stick to free trade.

Setting up a cartel similar to OPEC's is not an easy task either: Qatar is pursuing a proactive policy towards consumers; Russia's Gazprom has renewed several of its gas contracts and is thus striving to secure its outlets which bring in hard currency revenue worth 14.5% of total Russian goods exports in value (2006); Iran and Saudi Arabia are giving priority to supplying gas to their rapidly expanding domestic markets (by injecting gas into oil fields, by developing their local petrochemicals industry and by following a policy of oil substitution by gas so as to free up larger quantities of oil for export); the majority of the other members of the GECF are (recent) LNG

[37] This renunciation could be compensated financially, but it would then be even more difficult to assess the value of giving up production capacities rather than production volumes. For more details on this subject, see Jaffe A.M. and R. Soligo (2006), pp. 457-458.

exporters looking for a quick payback on their investment; the interdependence between gas and oil markets would also make running two cartels side by side more complicated because of the potential competition that could spring up between large producers of gas and oil whose interests are not always the same, and could even spark rivalries in winning market share for one or the other fuel.

In the longer term, the following factors should not be ruled out:

- the possibility of more abundant supplies of gas (and energy in its wider sense) which, if need be, would justify a market rationing policy by the suppliers: return of (clean) coal for power generation, higher exports from Russia as its domestic demand could drop following the alignment of Russian domestic prices with those on the international markets,
- and greater liberalisation of outlet markets that would enable producers to arbitrate their sales more easily through "wider" spot markets (notably depending on the development of LNG marketing methods).

2.2.3 IMPLICATIONS FOR THE LIBERALISATION PROCESS

Before liberalisation, the international gas supply market featured a small number of buyers and sellers. On the buyers' side, the process of liberalising the European gas market seeks to encourage the entry of new operators likely to enhance competition in this segment of the gas chain. However, it has to be admitted that, liberalisation or not, the European gas market will still shift at best from a situation of a bilateral oligopoly over upstream/downstream supply to at least one of a unilateral oligopoly on the producers' (supply) side. Opening the European upstream supply segment of the market to competition is not as spontaneous as on other markets, since most supplies (as far as external suppliers' production is concerned) fall outside the scope of EU legislation on the liberalisation and organisation of the internal gas market.

Over the years, the European Union's supply structure has been built up on the basis of long-term contracts because of the high costs of investment in the gas chain, which effectively limits new entrants' supply possibilities and, consequently, liquidity on the wholesale markets and competition at this level. Two measures have been adopted on this front:

- removal of destination clauses which prevent the buyer of selling the gas to a third party without prior agreement of the seller: ruled illegal under Community law by the European Commission, these clauses have nevertheless not been questioned in existing contracts. Negotiations have been held (and concluded) by the EC with Russian and Algerian suppliers with a view to dropping the destination clauses from these contracts, while Norwegian and Nigerian suppliers have already scrapped them;
- gas release programmes which oblige historical incumbents to make gas available for new entrants. However, some are wondering about the impact such provisions may have on end-user prices, despite greater competition in the market (see section 2.4.2.2.1 – page 43).

2.2.4 THE ROLE OF LNG TRANSACTIONS

Up until the early 1990s, LNG was marketed in the framework of integrated projects that involved all liquefaction capacity in a particular project being sold directly to several clearly identified buyers on the basis of long-term contracts that allowed little flexibility to adjust shipments and/or cargo destination. After that, against a backdrop of surplus liquefaction capacity and tankers available (owing to new facilities coming into service and others being extended), the first short-term contracts were negotiated. This trend has continued as buyers wanted this type of contract and sales outlets at attractive prices were available, especially in the United States[38].

Contractual relations thus restructured towards more flexible LNG purchase and/or sales contracts - a greater degree of flexibility having been requested by buyers exposed to the impact of energy market liberalisation in their outlets which were from now on open to competition. At the same time, there were plenty of LNG cargoes available (due to overcapacity and more flexible clauses) to supply the short-term markets which have developed as the liberalisation process has gathered pace. Naturally, these cargoes are attracted to and oriented towards the most profitable markets for the producers (United States, Far East, South of Europe), outlet regions which compete for these LNG volumes. Simultaneously, long-term reservations (20 years) for re-gasification capacities have been made by producers (Isle of Grain terminal (UK), Zeebrugge) without dedicated supply.

2.3 EUROPEAN LEGISLATION

At EU level, there are four main pieces of legislation governing the structure and functioning of the internal market in natural gas:

- the First Gas Directive 98/30/EC concerning common rules for the internal market in natural gas lays down detailed rules on the organisation and functioning of the various segments of the gas sector (with the exception of production) with a view to opening the market for the supply of gas to final customers up to competition and ensuring free and non-discriminatory access to the network;
- the Second Gas Directive 2003/55/EC, bearing the same name and replacing Directive 98/30/EC, was adopted in June 2003 and lays down additional measures: it requires full marketing opening for industrial and commercial customers (other than households) by 1 July 2004 and for all customers by 1 July 2007[39]; it puts more emphasis on public service obligations, the universal service, consumer protection, independence of infrastructure (network, storage and LNG facilities) operators and the unbundling of their activities, the reorganisation of third party network access (negotiated TPA), the reinforcement of the

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38 For a detailed description of the LNG market, see Boussena S., Pauwels J.-P., Locatelli C. and C. Swartenbroekx (2006), chapter 6.

39 By way of a derogation, Greece and Portugal benefited from a later deadline for opening up their emergent gas markets, while Cyprus and Malta neither distribute nor market natural gas on their territory.

regulators' role and security of supply. This Directive was transposed into Belgian legislation by the law of 1 June 2005 amending the law of 12 April 1965 on the transport of gaseous products and other pipelines;

- supplementary measures were adopted for transmission system operators under Regulation (EC) No 1775/2005 of the European Parliament and of the Council of 28 September 2005 on conditions for access to the natural gas transmission networks, which aims to reinforce the internal market and encourage effective competition. More specifically, these rules concern third party access services, capacity allocation mechanisms, congestion management, balancing and trading of capacity rights, and explicitly reinforce the obligation for operators to ensure that users are treated in a transparent and non-discriminatory manner;
- Directive 2004/67/EC of the Council of 26 April 2004 concerning measures to safeguard security of natural gas supply.

Two other Directives of the Council have been forerunners to the First Gas Directive in establishing the internal market:

- Directive 91/296/EEC of 31 May 1991 "on the transit of natural gas through grids" which requires to make the necessary arrangements to facilitate the transit between these grids (non discriminatory and fair transit conditions for all parties concerned, notification to the public authorities) and to ensure the completion of the internal market;
- and Council Directive 90/377/EEC of 29 June 1990 "concerning a Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users" which enables a monitoring of gas prices and their publicity with a view to increasing transparency and encouraging comparisons.

The production segment of the market is not taken into consideration by the Gas Directives. The only provisions in this field are laid down by Directive 94/22/EC of the European Parliament and of the Council of 30 May 1994 on the conditions for granting and using authorisations for the prospecting, exploration and production of hydrocarbons.

However, considering their high dependence on gas imports, all EU Member States and the European Communities have ratified the Energy Charter Treaty with twenty other countries[40]. It entered into force in April 1998. This Treaty intends to provide a legal framework to promote long term cooperation on energy matters between Western and Easter European countries as well as the Former Soviet Union States. The main arrangements provide legally binding rules for investment protection, trade and transit of energy commodities as well as dispute settlement

[40] Albania, Armenia, Azerbaijan, Bosnia and Herzegovina, Croatia, Georgia, Japan, Kazakhstan, Kyrgyzstan, Liechtenstein, Moldova, Mongolia, Switzerland, Tajikistan, The former Yugoslav Republic of Macedonia, Turkey, Turkmenistan, Ukraine, Uzbekistan and Pakistan (currently finalising ratification). In Australia, Belarus, Iceland, Norway and the Russian Federation the ratification of the Energy Charter Treaty is still pending.

provisions. This process sustains the energy trade flows and a better investment climate with third countries neighbouring the EU, some of which have significant energy resources. Nevertheless further progress on these matters partly depends on the ratification of the Treaty by Russia since as long there is no Russian ratification, some ambiguity will remain about the extent of Russia's legal rights and obligations under the Treaty.

2.4 THE LIBERALISATION PROCESS

Liberalisation seeks to open up to competition, wherever possible, activities that were previously organised in monopolies. This process can be split into three phases: separation of the supply/production chain, introducing competition in market segments wherever conceivable and maintaining regulatory control in segments where there is still a natural monopoly.

It should be pointed out that this is a long drawn-out process because it involves an in-depth restructuring of the market segments concerned; it also requires additional investment, if only for mechanisms for exchanging information and setting up new circuits and market mechanisms linked to the de-integration of the gas chain.

Chart 5 sets out in table form the different markets that have been established on these "new" segments of the gas chain as well as the operators active on the supply and demand side. The last column covers the various contractual relations that have to be built up.

As far as the markets are concerned, the main change lies in the emergence of secondary markets offering gas supplies and available infrastructure capacity. Nor can the proliferation of contractual relations concerning this commodity disregard the need to have the necessary transmission and storage infrastructure for which contracts must also be concluded.

CHART 5: FUNCTIONAL OUTLINE OF THE GAS CHAIN

Segment concerned	Markets concerned	Operators concerned Supply >< Demand	Contractual relations
Exploration Production	Over The Counter market Spot markets (LNG)	Producers >< importers & suppliers	Long-term sales/purchase contracts with price reference (oil products or gas spot prices) Physical trading on a regulated stock market (or gas hub), over the counter and by auction
Supply	Secondary gas release market	Owners of long-term volumes >< other wholesale market suppliers (traders)	
International LNG bulk transport International bulk transport by pipeline	Secondary market for access capacity	Transmission companies >< suppliers + shippers	LNG terminal access contract * TPA contract * with capacity reservation
Storage	Secondary market for storage capacity	SSO & Transmission company >< suppliers & shippers	TPAs contract * with capacity reservation
National bulk transport	Secondary market for transmission capacity	TSO + Transmission company >< suppliers + shippers	TPA contract * with capacity reservation Balancing contract
Distribution	-	DSO >< suppliers DSO >< final customers	Access contract Connection contract
Commercial supply	Market for eligible customers	Supply authorisation holder >< final customer	Supply contract

TPA = Third Party Access - TPAs = Third Party Access to Storage - SSO = Storage System Operator - TSO = Transmission System Operator - DSO = Distribution System Operator.

* Without prejudice to contracts concluded prior to 1 July 2004 and taking into account that major new gas infrastructures (i.e. interconnectors between Member States, LNG and storage facilities) may be exempted from TPA pursuant to Article 22 of the Second Gas Directive 2003/55/EC.

Regulated relations.

2.4.1 THE PARTITION OF ACTIVITIES OR UNBUNDLING

2.4.1.1 Intensity of unbundling

Unbundling of activities within the gas chain involves separating transmission and distribution activities related to network infrastructure which are natural monopolies by their very nature, from marketing activities (upstream and downstream sales and purchase) where there is likely to be competition. The intensity of this separation of activities varies from accounting or management to legal or ownership unbundling. Currently, under the Second Gas Directive of 2003, transmission and distribution system operators within a vertically integrated enterprise must be independent from other activities as regards legal form, organisation and decision-making (i.e. legal and management unbundling). Likewise, integrated natural gas companies' accounts must be transparent and clearly establish the distinction between transmission and distribution activities, storage and LNG (accounting unbundling). However, in its extended sectoral inquiry into the European gas and electricity markets concluded in January 2007 and its proposal for "a new European energy policy to combat climate change and boost the EU's energy security and competitiveness", the European Commission recommends reinforcing the separation of ownership between network companies and the production companies upstream, as well as towards the distribution enterprises downstream. The second best option should be the recourse to an independent transmission system operator in charge of operation, maintenance and development of the network which remains then the property of the historical operator for which a regulated fee is paid. This proposal was nevertheless rejected at a later meeting of EU Energy Ministers (EC 2007a).

Through this approach, the Commission is aiming to stamp out any attempt at collusion between stakeholders previously active in the supply chain, in view of the fact that there is still a danger of discrimination towards new entrants when a firm controls the network infrastructure at the same time as supply or sales and effectively prevents competition. The result is also a situation that encourages little or none expansion in network capacity to the benefit of the whole market because that means boosting competition to the detriment of the firm making the investment. More generally, this throws up the question of incentives to invest in extension of capacity on a network infrastructure in a liberalised market. The negotiated TPA tarification system with the regulatory authority is especially at stake here, as that is what determines the remuneration of the transmission system operator and stimulates its investment policy.

2.4.1.2 The emergence of new intermediaries

The separation of activities encourages the emergence of new intermediaries who hold a linking position in the gas chain. Shippers step in to arrange trade in transmission capacity (LNG and pipelines) between network users, establishing for the occasion new contractual relations. Traders serve as intermediaries in gas purchase and sales transactions between producers, suppliers and final customers, acting like brokers between counterparties who are unaware of each other, and taking advantage of the possibilities for arbitrage on the market.

The professionalisation of these intermediary functions tends to have a dampening effect on transaction costs incurred by resorting to the markets and limits uncertainty. By centralising the information, these intermediary "aggregators" enjoy the effects of economies of scale in handling information compared with individual intervening parties (gathering and centralising data, one single negotiation, costs spread over more transactions, acquisition of expertise). With information on both the supply and demand side, they are more able to match supply and demand and can possibly even combine different supplementary products and services (bundling): the professional shipper can reserve capacity with the system operator and also with the operators in charge of storage and balancing. Lastly, with an eye on safeguarding their good reputation, these professional intermediaries aim to deal successfully with their transactions and restrict any opportunistic behaviour, which has a favourable impact on uncertainty (Codognet 2004).

Alongside the transactions concluded on the primary market directly with the transmission system, transit, LNG terminal or storage operators, intermediaries also carry out transactions on new secondary markets. Indeed, unused capacities are traded between shippers and network users, enabling these operators to adapt their transmission services, including transit, reception at LNG terminals and/or storage.

In the context of liberalisation and the "reconstruction" of the gas chain through market mechanisms, it still has to be asked whether these transaction costs offset the profits generated through liberalisation[41].

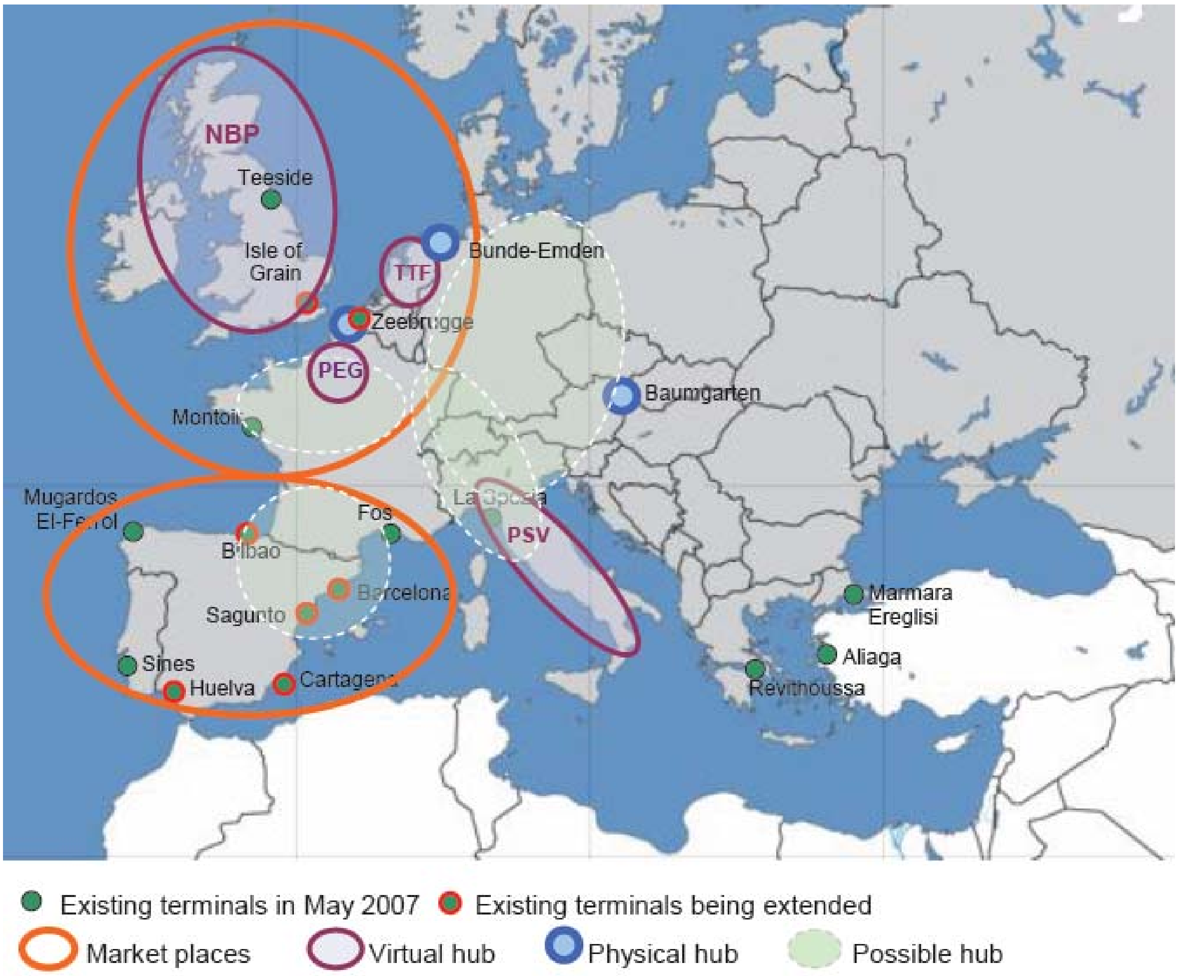
2.4.2 DEREGULATION OR OPENING TO COMPETITION

2.4.2.1 <u>The emergence of new physical and derivative markets</u>

With market liberalisation, new gas trading platforms have appeared with the hubs that enable network users to engage in physical trade in natural gas. The physical hubs have an infrastructure of multiple pipelines and storage units and offer additional logistical services designed to facilitate trade. These are mainly balancing services, hub services (centralisation of nominations, matching, follow-up of ownership transfers, etc.), price information services, even the organisation of electronic trading platforms for standardised transactions. The trading place can be a precise physical site on the network that is particularly easy to access (an LNG terminal, transit pipeline intersection, etc.) like Zeebrugge, or can be very broadly defined and cover a whole network, since the gas is tradable as soon as it is delivered on the network with the required quality (GCV, Wobbe index, etc.). This is the case for transactions on virtual hubs like the National Balancing Point in the United Kingdom, the Title Transfer Facility hub in the Netherlands, Punto di Scambio Virtuale in Italy and the Point d'Echange de Gaz in France. The emergence of these new market places has been facilitated by the use of Internet.

[41] A similar inference can be made in the context of electricity market liberalisation. See: Coppens F. and D. Vivet (2004) and (2006).

CHART 6: PRINCIPAL GAS HUBS IN WESTERN EUROPE



Source: Based on CRE, "Activity report 2005", part 2.

These hubs are a balancing instrument for the physical market by enabling users to balance injected or withdrawn quantities and thus avoid penalties[42]. They are also the place of intervention for several kinds of stakeholders seeking to settle arbitration operations or simply conclude the transactions necessary in their broker's role. By structuring supply and demand for gas deliveries at different deadlines, the hubs provide more visibility about the market situation (as long as the number of transactions is representative), which traders tend to capitalise on in order to arbitrate their gas purchases/sales to their own interest. In 2006, among the members of the Zeebrugge hub, 17% were active in gas trading, 10% in financial trading, 10% in electricity generation, 42% in gas marketing and 21% of them were integrated energy sector enterprises. Finally, several hubs have joined forces with stock markets to set up commercial platforms offering standardised contracts. The introduction of such financial derivatives has enabled traders to hedge against volatility, as long as there is sufficient liquidity in the market. In the old integrated structure, these balancing functions were carried out according to a technical logic. The unbundling of the gas chain

42 Indeed, penalties are incurred by the users of the grid who do not succeed to balance their gas injections and off-takes as preliminary notified, requiring the intervention of the Transport System Operator. Tariff supplements are then to be paid.

has added to it - or even replaced it with – a new economic logic that is taking shape within three different types of market: the so-called "over the counter" markets between operators seeking to balance their injections into and withdrawals from the network (suppliers, traders, shippers, system operators), the spot markets which enable fine-tuning operations via a voluntary or mandatory stock market, and the financial futures markets which make it possible to hedge against price fluctuations (see section 2.4.2.3).

Alongside these spot markets on the gas hubs a secondary market is also emerging for trading gas emanating from the "gas releases" required by the regulators with a view to reducing historical incumbents' market share at the upstream supply level and injecting liquidity into the market. The underlying idea is that by making more gas available to new entrants, the extra competition will be reflected in the end-user price. Hence, several incumbent operators have had to make some gas available to new entrants, either by auction or in the framework of bilateral transactions. The volumes traded are clearly on the rise but are acquired by the new entrants at a price that, at best, corresponds to the historical supplier's purchase price which is often set in the framework of long-term supply contracts. In order to offer the final customer a lower price than that of the historical incumbent, the new entrant must have lower structural costs or resort to dumping in a bid to win market share. A limited price cut is possible for some niche customers for whom logistical costs are not very high, but it is a lot less feasible for standard products for which the historical operator has a well-established structure at its disposal. The new entrant faces upstream exposure to prices that are not necessarily competitive, while downstream it has to get a foothold in a niche market that is very much open to competition. Indeed, until autumn 2006, prices on this secondary market for gas releases were lower than spot prices, which proved to be attractive for new entrants. With the fall in spot prices due to a surplus of supply on the British market and a mild winter in 2006, long-term supply contract prices overtook spot prices as they were barely influenced by the spot market for gas (but instead influenced by oil prices to which they are index-linked) (Petrostrategies 2007b).

2.4.2.2 New price formation mechanisms

Unbundling of activities requires (new) price formation mechanisms to be set up between segments. These mechanisms are based on long-term supply contracts and on the spot markets as far as production and upstream supply is concerned (wholesale markets), on regulated tariffs for access to the transmission and distribution systems, and on tariffs subject to competition (since 1 January 2007 throughout Belgium) when it comes to supplying the final customer (retail markets).

The challenge for the regulatory authorities and for the correct functioning of the market lies in setting up a coherent, global price structure, knowing that there are different approaches to price formation in the gas chain. Capping residential tariffs, for example, can cause problems for operators obliged to buy on upstream markets opened up to competition when wholesale prices are rising, as it was the case for the Californian power distributors during the summer of 2000.

2.4.2.2.1 Price formation on wholesale markets

While spot-market transactions do allow for some adjustment between supply and demand by market forces, they admittedly have a limited role on the European wholesale gas markets. Volumes traded at the different hubs are only marginal for European gas supply and their prices exert only a moderate influence as most gas is imported into Europe under long-term supply contracts that still have price clauses mainly index-linked to competing oil products. The other references used for indexation are the general rate of inflation, coal and/or electricity prices or fixed price arrangements.

According to DG Competition's latest energy sector inquiry (EC 2007b), 77.9% of the quantities covered by these long-term contracts are concerned by indexation clauses linking tariffs to oil prices (gasoil, heavy fuel oil, crude oil), and only 9.8% of the total volume are covered by contracts indexed to the price of gas. Dutch, Russian, Norwegian and Algerian contracts all use indexation formulas based on oil prices for up to 85-95% of the quantities covered by these contracts (see Table 7). This indexation model is a determining factor for the European market since these four external suppliers together account for 66% of European consumption. On the other hand on the British market where gas-to-gas competition is fiercer than on the continent, spot or future prices for gas at the National Balancing Point hub are also used as a reference for up to 37% of the volume sold on the British market, where general inflation indices are also taken into account for indexation (28.1%). Indexation on oil prices actually only accounts for 21% of the long-term sales volume marketed by British producers. And gas produced in other EU Member States is marketed in more mixed indexation conditions with 68.2% of the quantities being indexed on oil prices and 30.2% on the price of gas.

The same inquiry by the Commission analysed price indexation under these long-term contracts grouped together by outlet region and found clear distinctions between the United Kingdom, Western Europe and Eastern Europe. Price-indexation formulas for gas supplies on the British market use the hub price of gas as a reference for 40.1% of the volume traded, a general inflation index for 16.5%, while for 30.8% of the total volume, prices are pegged to oil products. In continental Europe, 80% of long-term deliveries on Western European markets take oil products as a reference (and 4.9% are linked to the price of gas), while in Eastern Europe oil products are used for 95.3% of all indexation, no gas delivery contracts in this region were found to be indexed to hub gas prices. As a result, the price paid for gas on the wholesale markets hardly reacts to changes in supply and demand conditions on the European gas market, albeit with a big difference as far as the British market is concerned.

TABLE 7: INDEXATION FORMULAS IN LONG-TERM CONTRACTS (% OF VOLUMES COVERED)

Main indexation references *	By supplier		
	the Netherlands	Other EU producers	United Kingdom
- price of gas	1.8%	30.2%	37.0%
- oil prices	92.8%	68.3%	21.0%
- inflation	0.0%	1.0%	28.1%
	Algeria	Norway	Russia
- price of gas	0.0%	4.0%	0.0%
- oil prices	94.4%	87.3%	92.1%
- inflation	0.0%	2.7%	0.0%
	By outlet region		
	United Kingdom	Western Europe	Eastern Europe
- price of gas	40.1%	4.9%	0.0%
- oil prices	31.4%	84.7%	95.3%
- inflation	16.5%	2.0%	1.1%

Source: European Commission (2007), "DG Competition report on energy sector inquiry".

* Other references used for indexation are coal and electricity prices. Some contracts are also based on fixed price arrangements.

2.4.2.2.2 Price formation for transmission and distribution

With the entry into force of the Second Gas Directive, tariffs for transmission and distribution can no longer be set on the basis of direct negotiation between operators and system operators, but are subject to a regime of regulated access open to all. Network access conditions are set in advance by regulation: tariffs (or the way they are calculated) are fixed on the basis of real costs, sent to the regulatory authority for approval and then published prior to their entry into force.

Contrary to electricity transmission, distance-related pricing is possible for gas transport. Two formulas are used:

- pricing on the basis of the distance between the point of injection and the point of withdrawal, possibly with a cap or limited to the distance between the customer and the nearest point of delivery, with the system operator having the right to carry out swap operations between its various points of delivery;
- pricing with entry-exit points (the Belgian option) using an "entry" price when the gas is injected and an "exit" price when it is withdrawn. The physical flows in the different portions of the network determine the pricing which in turn takes account of operating costs of the existing network in the short term and the need for the network to be extended as a result of these physical flows in the long term.

2.4.2.2.3 Price formation on retail markets

As of 1 July 2007, all European consumers are free to choose the supplier with which they negotiate a supply contract. The retail prices resulting from such contracts differ from "integrated" tariffs by implicitly abandoning the principle of spatial cross-subsidization which had previously made it possible to offset the costs from less densely populated regions against more heavily populated areas and to have an identical invoice price for all residential customers wherever the point of consumption. With liberalisation, the price charged to the final customer is the sum of:

- transmission and distribution costs, including the cost of storage, LNG activities and flexibility: these are of course regulated under the methodology for calculating flat-rate costs for all customers, but true costs also imply differentiated costs according to location (which is a determining factor for the physical structure of the distribution network);
- the cost of supplying the energy negotiated with the supplier, covering the cost of buying the gas and the cost of supplying it;
- and the taxation of the different component parts.

According to the type of customer (and the volume of gas taken), the relative importance of these different costs in the overall price tends to vary, since the burden of transmission and distribution costs is proportionally larger for a small-volume consumer. In both cases, the cost of the raw material is predominant, accounting for 45 to 85% of the price charged to the final customer in Belgium. Compensation for transmission and distribution activities, whose tariffs are subject to regulatory control, accounts for 39% of the price paid by a residential consumer compared with 8% for an industrial consumer. The main components of the price charged to the consumer are now open to competition but there is still some doubt as to whether this competition really is effective, especially on the upstream markets. Over the last four winters, the United States has also seen a rise in the cost of energy which has become the predominant element in the price paid by the residential consumer.

TABLE 8: THE COMPONENTS OF THE PRICE OF NATURAL GAS IN BELGIUM AND THE UNITED STATES

	Residential customer* 22 MWh/year	Industrial customer* 25000 MWh/year	US residential customer - price paid during the 2005-06 heating season
Import	45%	85%	58%
Transmission (flexibility & storage)	10%	4%	
Distribution	29%	4%	
Supply	13%	6%	42%
Various taxes	4%	1%	

* Breakdown established on the basis of ex-VAT prices.

Sources: CREG (2006) "Les différentes composantes du prix du gaz naturel en Belgique et les possibilités de diminution" - Press conference on 5 July 2006 and EIA/DOE (2006), "Residential natural gas prices: what consumers should know".

2.4.2.3 New risks

Using market forces in price determination also infers new risks of price formation and volatility for counterparties. This volatility stems from the short-term inelasticity of both demand for gas (limited possibility for short-term substitution for gas unless bi-fuel capacity is available) and supply of gas (high cost of storing the gas and constrained transmission capacity). Price volatility can be exacerbated not just by inappropriate gas supply/demand volumes available but also by problems of congestion on the network when it is approaching saturation point. In practice, the big industrial consumers can buy the quantity of gas they need directly on the wholesale markets at spot prices quoted on the (local) hub which ensures a balance between supply and demand at the time. Since this spot price is highly volatile, consumers have at their disposal on the same wholesale market derivative products in the form of futures contracts that make it possible to hedge against spot price fluctuations[43]. In this way, the risk management implicitly linked to price volatility is transferred from the seller/supplier to the buyer of the gas, representing an extra cost for the latter when he is trying to limit the impact of this price volatility and the uncertainty it entails. However, having a market that is liquid, wide and deep is the best guarantee for reducing hedging costs and limiting the risk of futures price manipulations.

43 For example, a gas buyer wants to acquire the gas in t_1. Anxious to cover against any price risk, he acquires in t_0 a futures contract at futures price P_Ft_1. In t_1, he buys the gas at spot price P_St_1 and resells his futures contract in cash at price P_St_1. The cash flows related to these transactions are: $-P_Ft_1$ (purchase of the contract) $-P_St_1$ (payment for the gas) $+P_St_1$ (contract sale) = $-P_Ft_1$. By acquiring a futures contract with maturity at t_1, the buyer of the gas fixes in t_0 the price at which his gas is acquired at this maturity which will be P_Ft_1. The uncertainty surrounding price developments has thus been removed. For a more in-depth discussion of these points, see Boussena S., Pauwels J.-P., Locatelli C. and C. Swartenbroekx, (2006), chapter 5.

Another way of hedging against spot price volatility for the consumer is to conclude long-term contracts. Downstream consumers (and/or their suppliers) can protect themselves from price fluctuations by signing up to long-term contracts, a practice that is still well established among some large European consumers, according to the Commission's latest inquiry which reveals that the average lifetime of outstanding contracts (weighted by volume) ranges from 15 years for German consumers, 6.5 and 6 years for Polish and Dutch industrial consumers, to 4 and 2 years for French and Italian industrial customers[44]. For the Commission, this can create market foreclosure by tying (mainly) large consumers to their suppliers and if a significant portion of demand is tied up by these long-term contracts, it will make it difficult to establish well-functioning energy markets.

For residential customers, management of price volatility is a more delicate issue: their gas demand is highly inelastic, dependent on external factors such as climatic conditions and their transaction costs related to the active management of their consumption bill (follow-up of prices and market developments) are proportionately high. This management burden is passed onto the suppliers and reflected in the pricing formulas offered to customers who then make their choice depending on their price-risk aversion, with a default formula also proposed. The same clients can eventually be backed up here by the specialised services of a watchdog like Energywatch in the United Kingdom[45].

2.4.3 REGULATION

Regulation on markets opened up to competition basically aims to meet two objectives:

- to adapt the system of competition so as to take account of the socio-economic stakes;
- to encourage competition by making it possible for new entrants to gain a foothold on the markets, especially to compete with historical operators owning transmission and distribution infrastructure.

Introducing competition is no panacea for the gas sector, especially when it concerns the supply of a commodity recognised as being a public service and when delivery to the final customer is dependent on a fixed infrastructure. More specific objectives can be pursued, such as guaranteeing a minimum universal service for disadvantaged categories of consumers or the appointment of a system operator capable of guaranteeing system integrity, including the ability to manage

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44 The Commission examined the contractual conditions in force on the retail market on the basis of a sample of 1,000 supply contracts of large industrial customers, electricity generators and distributors, in five Member States (France, Italy, the Netherlands, Germany and Poland), covering a volume of 200 Bcm/year or the equivalent of 76% of these five countries' consumption.

45 This independent body was set up in November 2000 through the Utility Act with the "statutory duty to protect and promote the interests of existing and future gas and electricity consumers". It provides free and impartial information, takes up complaints on behalf of consumers and uses this experience to highlight the issues and hence, give advice to public bodies about consumer matters. The regulator and energy companies are also involved so that changes to the policies, processes and systems are conducted in a way that will make these more responsive to the needs of the consumers.

congestion[46]. Apart from the definition of the exact scope of these public service missions, which is set by law, it is the regulator's job to allocate these missions to an operator (by a tender system, by selecting the best candidate or opting for the historical operator by default) and to set a fair method of compensation that does not distort competition.

A second aspect of regulation concerns all the measures necessary to allow potential new entrants non-discriminatory access to infrastructure. Setting up a third party access (TPA) system implies dismantling the incumbent network operator's monopoly on its historical market and an obligation to carry gas on behalf of potential competitors. In practice, the transmission monopoly stays in place but this activity is clearly separated from the services of the transmission system operator (through accounting and legal unbundling as of 1 July 2004). The TSO ensures that the network functions properly, is open to all on equal terms and is subject to a regulated price. The same approach is adopted for the distribution networks.

The benefits of regulation for the final consumer lie in the reduction of the intermediation margins as a result of greater competition, while preserving strong and sufficiently sound enterprises to finance heavy investment in infrastructure, preferably in a stable regulatory environment which is more conducive to the investment climate.

While the regulator is in charge of making sure that the market operates properly and in a spirit of fair competition, it is the national competition authorities and the European Commission who have the right to impose sanctions for any abuse of dominant position.

2.4.4 MONITORING COMPETITION

As for any economic activity carried out on EU territory, the European Commission is responsible for a general "monitoring" of the state of competition, together with the national competition authorities. The intervention of the authorities is necessary in order to guarantee free and fair competition within the EU. The measures that can be taken include antitrust actions combating restrictive business practices and the close examination of mergers and acquisitions in order to establish whether they might restrict competition or not.

Antitrust law is based on the provisions laid down in two key articles of the EC Treaty which seek to safeguard competition as an effective means of guaranteeing consumers goods and services at reasonable prices and satisfactory quality. It is premised on a market made up of independent suppliers, each being subject to competitive pressure from the others. Under Article 81 of the EC Treaty, restrictive business agreements are prohibited (such as price-fixing or cartels) and pursuant to Article 82 of the EC Treaty, enterprises with a dominant market position may not abuse this

[46] For a detailed description of the challenges of carrying out public service tasks in a liberalised gas market, see: Percebois J. (2002).

position. Antitrust rules are designed to prevent restrictive business agreements or abuse of a dominant market position from distorting competition in the common market and this applies to any firm that operates directly or indirectly in the EU, wherever it is established. The Treaty gives the Commission authority to apply these rules as well as the ability to investigate and to check compliance. It can impose fines in the event of any infringements of these rules.

Scrutiny of mergers and acquisitions leading to concentration is designed to prevent any harmful effects on competition that might result from the proposed transactions. While such concentrations often bring efficiency gains, they can also occasionally restrict competition on a market, usually by creating or reinforcing a dominant position. In these circumstances, the merger or acquisition is likely to harm consumers by triggering higher prices, reducing choice and/or putting a brake on innovation. Stronger competition in the single market and globalisation are of course just two factors that can encourage firms to join forces. But there is a still a need to check whether such reorganisation poses an obstacle to free and fair competition. As the Commission explains itself, "the purpose of the merger control rules is not to stand in way of necessary and efficiency-enhancing restructuring, but to ensure that those mergers are stopped or modified that would harm competition"[47]. Since 1990, only a very small percentage of concentrations have been blocked[48], because even if the Commission does find that a planned merger is likely to disrupt competition, the parties to the transaction can offer concessions and commit to taking corrective measures to try and remedy a situation of unfair competition.

Intervention on the part of the EU competition authorities is not without impact on the reorganisation of European gas (and electricity) industry operators. Under its merger control procedure, the Commission defines the scope of geographical markets and the products affected by the transaction in order to systematically assess the competitive pressures likely to weigh on the new entity (calculation of market share in order to determine market power and, if need be, to point up a situation of dominant position). This assessment is backed up by an analysis of the merger from the point of view of competition: market position of the companies involved, existence of barriers to entry and/or competitive pressure exerted by the client base, access to sources of supply or to outlets, etc. A merger plan can then be accepted subject to remedies which usually involve a requirement to reduce market share on a relevant market. Here, the European dimension favours horizontal mergers between operators from different Member States, while vertical mergers

47 In: Commission of the European Communities (2004), p. 11.

48 Only 19 merger operations across all sectors have been blocked (concentration declared incompatible with the common market) out of 3,388 cases notified to the Commission's Competition Directorate-General over the period from September 1990 to April 2007 (In: European merger control - Council Regulation 139/2004 - statistics). Among the mergers and acquisitions between companies in the gas and electricity sectors examined by the Commission, only one transaction was found to be incompatible, namely the plan notified in July 2004 for acquisition of joint control of Gás de Portugal by Energias de Portugal (EDP) and ENI. The remedies proposed by EDP and ENI (on four occasions) were deemed insufficient to remove competition concerns.

are more easily rejected owing to the constraint imposed by the national market considered as being the relevant market.

3 CONCLUSION

The liberalisation of the gas market cannot ignore the specific nature of this "commodity" - a primary energy source that cannot be produced locally as reserves must be available and the gas transported from its point of extraction. Moreover, its intrinsic physical properties require specific infrastructure, as in other network industries.

The liberalisation of these industries has been carried out by unbundling activities upstream and downstream of the infrastructure so as to open them up to competition. Access to infrastructure is one of the big challenges of this process, but in the case of gas, opening upstream supply to competition is not so obvious in the European context. Contrary to the examples of the North American and British gas markets, completion of the internal market cannot disregard the fact that upstream supply channels are largely in the hands of external suppliers and thus fall outside the scope of EU legislation on the liberalisation and organisation of the internal market in gas, unlike in the case of electricity generation, for example. Hence the opening to competition of upstream and downstream markets is not "synchronous", a discrepancy which tends to weaken the impact of liberalisation.

Finally, the separation of activities required for ensuring free competition in some segments of the market is coupled with major changes in the way the gas chain operates, with the appearance of new markets, new price mechanisms and new intermediaries. Starting out from a situation where gas supply was in the hands of vertically-integrated operators, the regulators have to see that there is no abuse of dominant position on the part of the historical incumbents and owners of the infrastructure and ensure that competitive forces can be given free rein to the benefit of the consumer. At the same time, they have to act in the general interest to make sure that the various operators on the market do not neglect certain obligations that come with a "commodity" acknowledged as a basic necessity and which represents an important input for production processes in many sectors of economic activity.

ANNEX

Lower or net calorific value (NCV) = the amount of heat released by complete combustion of a unit of fuel in the determination of which the water produced is assumed to be not fully condensed and the heat not recovered (World Energy Council definition).

Higher or gross calorific value (GCV) = the amount of heat released by complete combustion of a unit of fuel in the determination of which the water produced is assumed to be completely condensed and the heat recovered. Gas-sector operators tend to carry out their conversions on the basis of the GCV of gas, while in the oil and coal sectors the NCV is more traditionally used. Energy balances expressed in tonnes of oil equivalent (toe) are conventionally established through energy conversions on the basis of the NCV of the different fuels. The GCV/NCV ratio is different for each type of fuel and represents the latent heat of vaporisation of the water vapour produced during the combustion of the fuel. In the case of natural gas, a ratio of 1.10 is generally used.

MBtu = million British thermal units = the Btu corresponds to the amount of heat required to raise the temperature of one pound of water by one degree Fahrenheit, i.e. from 39.2 °F to 40.2 °F. 1 Btu = 1055,06 J and 1 MBtu = 1,0556 GJ.

therm = unit of energy equal to 100000 Btu = 105506 kJ. Gas trading prices are mostly expressed in USD/MBtu, in pence/therm or c€/therm

cm = cubic metre.

Bcm = billion cubic metres = 10^9 cubic metre.

Tcm = billion cubic metres = 10^{12} cubic metre.

Gas volumes expressed in cm can be measured:
- in standard conditions at 15°C and 1013 mbar (= 1 Scm);
- in normal conditions at 0°C and 1013 mbar (= 1 Ncm);
- or according to Russian standards at 20°C and 1013 mbar;

and consequently 1 Ncm = 1.055 Scm, the Anglo-Saxons tending to express their figures in Scm.

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