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DEVELOPMENT OF COMPETITIVE GAS TRADING IN CONTINENTAL EUROPE

How to achieve workable competition in European gas markets?

IEA Information paper

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Foreword

Natural gas markets are globalising, and the trends affecting one region may have consequences beyond the geographical span of the physical market. Development of competitive trading in continental Europe since the beginning of the liberalisation process in the late 1990s has been a complex process and must take into account the differences compared to other regional gas markets such as North America.

Meeting the efficiency, transparency and security challenges in European gas markets in the present context is a high-priority task for policy makers in European governments and the European Commission. At a time when a third package of legislative proposals is being negotiated, rising prices, tight supply prospects and the necessity to curb greenhouse gas emissions impact heavily on energy policies in consuming countries.

In this challenging context, the IEA has studied the history, the fundamentals and the possible evolution of liberalised natural gas markets in Europe, in order to outline the major issues that should be addressed while leading reforms further on the path to workable competition.

This book examines the history of major gas markets' development in OECD Europe, and explores the expansion of trading throughout the setting of different hubs on the European markets. However, proper competition does not yet exist at a European level. An analysis of the North American market allows some lessons to be drawn to identify the fundamentals for workable competition in natural gas. European markets require particular efforts on enforcing more transparency throughout the value chain, as well as a more investor-friendly regulation and investment in supply and flexibility infrastructure.

Competitive trading based on transparent, non-discriminatory rules in a flexible and integrated European gas market will lead to more efficiency and market resilience, enabling markets to absorb large incremental volumes that might come from new pipeline supply projects, or in extreme cases, to manage potential supply interruptions. Thus competitive markets can afford more security for both customers and suppliers in the long term. At a time of sharply rising energy prices and increasing concern over energy security, the benefits of these reforms are substantial. They should be pursued vigorously, and supported by all EU members, and indeed all energy users.

Nobuo Tanaka
Executive Director

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Executive summary

Based on experience from other IEA countries and regions, it is clear that in order to achieve an efficient and integrated market structure for European gas, governments should focus on several measures to implement within the legislative and regulatory framework of the industry: transparency of information, enhanced investment and regulatory convergence.

Transparency, adequacy and relevance of information available to the market are a priority, and should focus on production levels, flows, infrastructure planning and utilisation and demand levels.

Governments should also propose measures to increase commercial investment – in transmission and distribution networks, in international interconnection as well as in flexibility tools. Promotion of an interlinked and transparent internal network within Europe should trigger upstream investment in turn.

Investment-friendly regulatory convergence between European gas markets is the third pillar of the necessary measures to achieve a functioning integrated market. The regulatory framework should be designed to enhance investment and not impede it; noting that all infrastructure when mature "returns" to the free market.

History of European gas markets

Energy diversification was the principal driving force for the dramatic increase in the use of natural gas in IEA European countries, turning a locally produced fuel into a major international energy source. After the first oil shock, West-European economies were given new impetus to diversify their energy mix and substitute away from oil in favour of other sources. For many applications, particularly in stationary energy use, natural gas was an effective substitute. Although there was opposition to European dependence on imported natural gas, particularly that from the Soviet Union, the huge Siberian gas fields were able to provide Europe with a non-OPEC source of energy. A compromise was agreed whereby Europe would restrict its dependence on Soviet Union to 30%, and the development of Norway's Troll field would be promoted as a counterweight to Russian influence. Soon after, Algeria also became a major supply source for Europe.

Meanwhile, in Eastern Europe, the barter principle "gas for manufactured goods" was promoted, with the USSR becoming the region's energy supplier. The immensity of the Soviet reserves matched well with the East-European countries' heavy industries. Gas, as energy in general, was considered as a central tool of economic policy, and was sold for a symbolic price in many of the countries that are now European Union member states.

National governments became aware that they would have to support the growth of the natural gas industry, in order to achieve their national energy policy objectives. Gas systems in general - and international gas pipelines in particular – required significantly larger investments than their counterparts in the oil industry. The industry required long-term commitments from consumers in order to minimise the risk of these investments. For example, the Dutch pioneered a type of long-term commitment which involved granting one company an exclusive right to market gas in the country. Long-term contracts were put in place to match the lifetime of investments, with minimum take-or-pay obligations on customers to guarantee cashflow for the financiers. With only weak downstream competition to keep pressure on consumer prices, the price of gas was linked to oil, to ensure its competitiveness.

The market reform process

The aim to build a single market for gas and electricity is a principle embedded in the creation of the European Union – the EC Treaty mandates the achievement of a common market including energy. In 1996, the EU embarked on a process aimed at reforming first electricity, then in parallel, starting in 1998, gas markets. Making the energy sector in Europe competitive and more efficient was viewed as part of the response to growing concerns on the competitiveness of European industries in globalising markets. Introducing competition in the gas sector was aimed particularly at creating a more appropriate competitive framework, notably more gas-to-gas competition, thus increasing economic efficiency and lowering costs for final consumers in markets frequently monopoly dominated. This process has advanced over the last decade with competitiveness being supplemented by concerns on security and environmental performance of the energy sector. Although not specifically mentioned at the time, it is clear from experience in IEA member countries that a single workable gas market delivers resilience in the event of supply disruptions from any cause, thus increasing gas security.

By 2008, key goals remain to be achieved. Europe remains in a transition towards truly competitive markets. The outcome and the conclusions of this process are a complex set of proposals, some of which are binding (industry structure). Other proposed measures are based on non-binding encouragement (energy efficiency) or left to the initiative of member states (investment, security of supply, foreign relations).

Generally, in continental Europe, real reform progress has been observed in markets under strong and independent regulatory authority. Another trend visible in some countries (in Western and Eastern Europe) is the separation of national networks from private sector activities like supply or sales; this unbundling happened in the Netherlands, Poland, Romania, and Hungary before the EU proposal of full ownership unbundling. These decisions were based on a national strategic vision or on business model decisions such as in the Netherlands, where ownership had to be cleared between the Dutch state and two historical private energy players, Shell and ExxonMobil. In other countries, a similar logic was used to justify the preservation of an integrated model (France, Germany, Czech and Slovak Republics, Bulgaria, Baltic States).

The future evolution of European gas markets

While demand continues to grow, domestic supply has stagnated and Europe is on course to increase its import dependency. A huge amount of upstream and infrastructure investment is needed to respond to this import challenge. Gas imports will increasingly come from LNG, priced on a global market basis, influenced by North American and Asian prices, and hence the circumstances in those markets. New large-scale import pipelines will be needed, crossing multiple national frontiers within and outside Europe. But the present industrial and regulatory conditions are struggling to deliver this. Europe is therefore under increasing risk of underinvestment, which could lead to supply and market consequences if not addressed.

After the 2005-2006 supply crises, energy policy has progressively focused on security of supply issues. There are different explanations of the meaning of "security of supply", but clearly neither "security" nor "supply" can occur unless there is sufficient investment in the gas value chain. In the absence of the right conditions for such investment, it will be very challenging to bring increasing supplies of long-distance gas imports to the market and ensure reliable, affordable supply in the long term. Competitive gas markets in other IEA member countries such as the US, Canada and the UK have been shown to deliver investment, but through radically different means than in the utility markets in continental Europe before the liberalisation process in the 1990s.

From the perspective of some companies, governments and customers, it is quite understandable that many European energy companies have moved defensively and tended to resist change to their traditional business model. Instead they have played a waiting game, expanding geographically to the East and West, as other countries' companies have been privatised. In addition, the presence of giant upstream state-owned players, with significant supply market share and not necessarily subject to the same regulatory or market reforms as European companies, is a major issue for development of competition throughout the value chain in European markets.

In the current transition period between administered and competitive markets, the consumer has yet to see the security and price benefits of competition. Its development has suffered from regulatory uncertainty downstream, while geopolitical and economic upstream risks were growing. Europe has remained a set of national gas markets, rather than a single market, and is still dominated by incumbents. There is pressing need to complete market reforms to stimulate a new round of much needed investment at lowest cost, through a new business model based on efficient, affordable, pan-European competition, while securing external relations with producing countries and affordable long-term supplies for the consumers.

Chapter I – The Past. Evolution of European gas markets (1960 to 2008)

I. History of European gas: 1960 – 1998

The first part of this chapter is intended to set the scene for the liberalisation process in Europe by giving an overview of the evolution of the European gas industry. The focus of the chapter is on five countries in Western Europe, which account for roughly 70% of European gas consumption (United Kingdom, Germany, Italy, France and the Netherlands) and on Eastern Europe[1] as a whole, because of its importance as main transit region and the differences in its history.

The development of the gas industry in Europe is divided into three time-frames charting the growth of indigenous gas industries and the major companies which they spawned.

- The first period starts with the use of manufactured gas and ends with the start of domestic gas production and how it replaced manufactured gas in each country.
- The second period looks at the developments in the time-frame between the first international gas trades and the high oil prices during the 1970s and their influence on the energy policies of the different countries.
- The third period starts in 1986, characterised by low oil prices, and ends with the start of the liberalisation of gas markets in 1998.

The process of market liberalisation itself is covered in the next part of the chapter: EU liberalisation plan and the industry response.

A. First usage of gas in Europe – Start of domestic production

In the early 19th century, before natural gas was found in Europe, manufactured gas, mostly produced from coal, was used, mainly for lighting. Starting from the early 20th century, manufactured gas has also been used for cooking. The companies producing manufactured gas were private or owned by the municipality and the market was unregulated. Manufactured gas is often referred to as town gas, which clarifies the fact that it was produced and could be used only locally. This changed in the beginning of the 20th century when the first long-distance pipelines were built to distribute coke-gas, an industrial by-product, to residential users. In the 20th century electricity and petroleum took over many roles formerly filled by manufactured gas, but with the introduction of natural gas, manufactured gas was phased out completely.

The West-European countries studied in this book already had their own often modest gas production, before international trade started. The United Kingdom is an exception; it started importing liquefied natural gas (LNG) in the 1950s while domestic gas production only started in the 1960s. In Italy and France gas was first discovered at the end of the 1930s, while in the Netherlands and Germany first production was in the 1950s.

1. France

The French gas industry first developed in the 19th century with the production of gas from coal. In 1946, the gas industry was nationalised amidst post-war economic reforms. At the time, there was no national gas network and many gas manufacturing sites were not economically viable; the nationalisation was viewed as a means to revive and develop this stagnating sector. Nationalisation covered 94% of all the town gas production, transportation and distribution assets in France,

[1] East-European countries allied to the URSS before 1989 – Bulgaria, Romania, former Czechoslovakia and Yugoslavia, Hungary, Poland.

transferred to a newly created state company – Gaz de France (GdF). In the beginning GdF was joined to its sister company Electricité de France (EdF), but in 1949 Gaz de France became an independent state-owned "industrial and commercial institution" (EPIC).

Natural gas was discovered at Saint Marcet in the south of France in 1939, which in 1948 was supplying one eighth of all gas sales in France. However, production of natural gas (rather than manufactured gas) had been excluded from the decree of nationalization in 1946, natural gas being controlled by the oil industry at the time. Nevertheless, GdF received the sole rights of natural gas distribution in France, with the exception of 17 non-nationalized distribution companies, which had a majority public shareholding.

In the 1950s, a rationalisation of the production segment and the building of a national gas transport system spurred the renaissance of the French gas industry. The National Society of Oil in Aquitaine (SNPA – which would later become known as Elf Aquitaine, now part of Total) discovered in 1951 a major gas field in Lacq, southern France, which it subsequently developed. Transportation of gas in northern and eastern France was done by GdF, in south-western France by Société Nationale de Gaz du Sud Ouest (SNGSO) (owned by Elf and GdF) and in central France by Compagnie Française du Méthane (CFM) (owned by GdF, Elf and Total). This structure would remain in place until 2004 when CFM and GSO were merged with respectively the GdF and Total networks.

2. Italy

The first step towards domestic natural gas production was the creation of the state-owned refinery company Agenzia Generale Italiana Petroli (AGIP) in 1926 as a counterbalance to the major oil companies Standard Oil of New Jersey (later Exxon) and Shell, which had come to dominate the Italian market. During the second half of the 1930s the Italian government exerted considerable pressure on AGIP for a rapid exploitation of national mineral resources to achieve self-sufficiency. Backed by government financing, AGIP focused its energies on exploration in Italy, primarily in the Po Valley (in the north). When gas was found there in 1938, AGIP became the first natural gas producer in Italy. In 1939 a pipeline was built to Florence. In 1941 the state-owned company Società Nazionale Metanodotti (SNAM) was created for the purchase, transport and marketing of gas in Italy. Gas production was driven by rapid industrial development concentrated in the northern regions. To speed up the use of gas, in 1949 the first Italian gas-fired power station was set up.

Local gas distribution was controlled either by municipal companies or by small firms on the basis of local concessions granted by municipalities. In distribution and retail sales, a fragmented market structure allowed the existence of small private firms and municipal undertakings operating as local natural monopolies. Since its creation, SNAM has gained significant interests in the largest local distribution companies, but the local distribution market remains fragmented up till the present time.

After the Second World War, the government decided that AGIP should be liquidated and sold to private companies. In the liquidation process it became clear that the Caviaga field (discovered in 1944) was a major deposit. Despite the pressure from the various multi-nationals AGIP managed to halt the liquidation, with the argument that Italy should have a national company which could defend national interests.

In 1953 Ente Nazionale Idrocarburi (ENI) was created by law to manage all the state-owned energy companies, including SNAM and AGIP. ENI was given the exclusive right to look for and exploit hydrocarbon deposits and the exclusive right to build and run gas and oil pipelines in the Po Valley.

Driven by robust economic growth during the 1950s and 1960s and subsequently the high demand for gas, more gas infrastructure was built connecting the Po Valley with the north of Italy. The high profits from natural gas funded the search for new fields, the development of pipelines and the acquisition of new customers. While Italy followed the general European path from coal-based energy to oil-based, it had an unusually high proportion of natural gas consumption by the end of the 1960s. The chosen marketing strategy for the natural gas business was that methane was a cheaper and more functional substitute for imported coal for the growing industrial activities in the north of Italy.

Gas tariffs were set by public authorities (the Inter-ministerial Price Commission), in negotiation with ENI. Price controls coupled with legal monopoly at the wholesale level led to some cross subsidies among consumers. In order to extend the gas network to the south of Italy, for example, the denser consumer base in the north effectively subsidised the south. By spreading most of the commodity costs over consumers located in the coldest regions of the country, natural gas became available at competitive prices all over Italy.

3. The Netherlands

In the 1930s a subsidiary of Shell called BPM (Bataafse Petroleum Maatschappij) acquired exclusive oil and gas exploration rights for the north-eastern part of the Netherlands. In 1947 BPM and Standard Oil Company of New Jersey (later to become Exxon) established the NAM (Nederlandse Aardolie Maatschappij), a joint venture for oil and gas exploration and production in the Netherlands. Natural gas was first found in 1948 and a number of moderately sized fields of oil and gas were then discovered in the 1950s.

In 1959 NAM discovered a huge gas field in northern Netherlands, in the province of Groningen. Shell, Esso and the government started negotiations in 1960, with the field size estimated at 60 bcm. In the following years, the size of the field was re-estimated several times, before the final size was confirmed at 2,600 bcm 30 years later.

In 1962, three years after the discovery of Groningen, the main principles of the Dutch gas policy were established. Gasunie - a 50/50 public-private partnership between the government, and Shell and Exxon - was created in 1963, for the transportation and marketing of Dutch gas. First of all the "market-value" principle was introduced as the basis on which the gas should be produced and sold. This meant that the price of gas was linked to the price of the alternative fuels for that customer. So, consumers would never have to pay more (but also not less) for gas than for competing fuels. Secondly, production of Dutch gas resources were harmonised with the sales of gas achieved. Control over the supply of gas was understood to be a government responsibility, while exploitation and marketing of the gas reserves should be undertaken by the private concession holders.

The main target for Groningen gas was premium markets, such as the replacement of manufactured gas as well as the chemical, metallurgical and ceramic industries. Groningen gas was sold to those segments, in order for the government to reap profits as soon as possible. The government was keen to act quickly as commercial nuclear power – at the time – was making people question if energy would have anything more than a token value in the future. A transport network was built with great speed. The municipalities were encouraged to connect as many households as possible through premiums given by Gasunie. The most densely populated areas were connected first, followed by rural areas.

4. United Kingdom

In the initial period after the Second World War (1945-1951), the UK domestic energy sector was nationalized, including the gas sector with the Gas Act 1948. The manufactured gas companies were divided into twelve Area Gas Boards. A Gas Council was established which had advisory functions to the government, as well as assisting the Area Boards, though it had no direct powers over them. The Gas Council was made up of the twelve Area Board Chairmen and had a chairman of its own.

As consumption grew, it became obvious that the gas manufacturing plants could not keep up with demand. With no discovered sources of natural gas within pipeline distance of the United Kingdom, Shell proposed a novel method of transporting supercooled gas via tanker. In 1959 the first LNG cargo came from the Gulf of Mexico and five years later LNG supplies started arriving in bulk from Algeria. In 1963 a pipeline from Canvey Island near London to Leeds was completed, which enabled eight regions to be supplied with Algerian gas.

Triggered by the onshore gas discoveries in the Netherlands, the United Kingdom also started surveying the North Sea between the Netherlands and the British islands in 1962. Oil and gas were soon discovered and production started in 1967 whereupon a national gas grid was built. The government encouraged the industry to build up the use of natural gas speedily to enable it to benefit as soon as possible from the advantages of this new indigenous energy source.

The Continental Shelf Act 1964 and the Gas Act 1965 gave monopoly powers to the Gas Council on both buying and selling. All gas produced in Great Britain had to be sold to the Council and all Area Boards were supplied by the Council, which negotiated long-term contract prices (averaging 25 years) with North Sea companies and paid them cost-based prices. These prices were low (below coal-based manufactured gas and LNG).

5. Germany

The big gas industries of Germany also have their origin in the days when gas was a co-product of coke manufacture. Massive regional concentrations of coal and steel production in the Ruhr area provided the basis for an urban gas supply from the first half of the 19th century. The dominant company in the sector was Ruhrgas, established in 1926 to sell town gas based on coke-oven gas in the Ruhr and Rhine basins, and ultimately expanded to become a supra-regional supplier. Ruhrgas' earliest shareholders were steel producers and coal companies.

Government initiative transformed the coke- and steel-based regional into more suitable vehicles for supplying gas on a national level. In Germany a kind of private-sector nationalisation was implemented before the Second World War by the establishment of the so-called Demarkationsvertrag: agreements to divide markets on a territorial basis. If a community chose to license a private provider, it issued an exclusive concession, usually for 20-25 years. The municipalities generated income from the utilities to subsidise other municipal services. The prevalent opinion in Germany was that energy issues were better left to the market and to economic actors than to the public sector.

Small amounts of natural gas were found in the 1950s, but German natural gas consumption really took off after the discovery of the Groningen field over the border in the Netherlands. Large volumes of gas were imported from the field, starting in the mid 1960s. Also, as in the United Kingdom, the exploration of German territory adjacent to Groningen intensified and significant discoveries were made. The international oil companies started to play an important role in Germany; between them, Shell and Esso (Exxon) gained a 50% share in Ruhrgas, in order to financially strengthen it into a regional pipeline company. Later also BP and Texaco moved into the German gas market.

The German gas industry was (and still is) divided into three types of companies:

- Upstream companies, mainly owned by international oil companies.
- Sales and transmission, consisting of companies with production interest, importers and companies purely acting as transporters of gas. They were partly owned by the producers (Shell, Exxon etc) and partly by the consumers (coal and steel companies). In addition, some of the companies are publicly owned.
- Utilities, mostly owned by the various municipalities in conjunction with the sales and transmission companies (not dissimilar to the Dutch model for municipalities). The municipalities have very heterogeneous interests regarding energy sources, prices, taxation and distribution.

6. Eastern Europe

After the Second World War, many countries from Eastern Europe became linked with the USSR and gradually reduced economic, social and political relationships with Western Europe. This new East-European order was structured by the foundation in 1949 by the USSR of the Council for Mutual Economic Assistance (CMEA), in response to the US-backed Marshall Plan for Western Europe and the creation of the European Community.

East-European states developed their national industries on centrally planned economic basis within the Socialist bloc they formed. Initially based on indigenous resources like coal, their economies were modified to run on hydrocarbon imports from the USSR, the major source of significant oil and gas supplies in the CMEA zone.

The Soviet gas industry was developed in the 1940s in the oil-rich region of the Volga, and became quickly a centrepiece in the economic strategy of the USSR. The Ministry of Gas, which would become later Gazprom, was created in 1956, to handle this rapidly developing industry.

B. Start of international gas trade – Energy diversification

During the 1960s and 1970s the demand for natural gas in France, Italy and Germany started to outpace indigenous production and imports were needed. The United Kingdom had enough production for domestic consumption and remained a gas island (it only started exporting in the late 1990s after the construction of the Interconnector[2]). The Netherlands, after the discovery of Groningen, started exporting on a large scale. This period of time is therefore characterised by the large transportation network which was built in Europe in order to trade gas internationally, first from the Netherlands, then from Russia and Norway and most recently the United Kingdom.

For international trading – particularly from the Netherlands to Italy - an international network of high-pressure pipelines in Europe was needed. These were funded via the netback principal – the price of gas in the destination country remained linked to competing fuels, and the producer received those revenues less transportation costs (see box 1). In the 1960s and early 1970s, Gasunie of the Netherlands became the dominant party within the European international gas trade.

Box 1: Long-term contracts in Europe

International gas exports required significant investments in the upstream production and especially the transmission system. Export sales were based on long-term contracts in order to minimise the risk of these investments. The Dutch started with this type of contract, but they would become so popular that Russian and Norwegian gas would also be sold on the basis of similar contracts. The contracts had the following structure:

- Long-term: 20-30 years contracts, matching the duration of investments.

- Take-or-pay: the buyer has to pay for a certain amount of gas regardless of whether he uses it or not.

- Market-value principle: price of gas was linked to the price of the alternative fuels for that customer. This was added to the long-term contracts after the first oil crisis, although it was already used in the Dutch domestic market.

- Netback price: transportation costs were subtracted from the price the producer received. Destination clauses in some supply contracts assured that gas would flow to the destined market. Hence, a local market-value approach could be maintained.

- Price review clauses (typically 3-year reviews): were introduced in the mid 1980s to ensure that the contract price always represented the market value.

- Many aspects of these contracts mirrored the long-term contracts being written to support the developing LNG trade at roughly the same time.

After the first oil shock, Western economies were given new impetus to diversify their energy mix. Although the United States in particular opposed European dependence on Soviet Union gas, the huge Siberian gas fields were able to provide Europe with a non-OPEC source of energy. A compromise was agreed whereby the Europeans would restrict their dependence on Soviet Union to 30%, and the development of Norway's Troll field would be promoted as a counterweight to Russian influence.

The first Soviet pipeline to be finished was Brotherhood in 1967, connecting gas fields in Ukraine to Czechoslovakia, but this was not initially intended for exporting to Europe on large scale. At the

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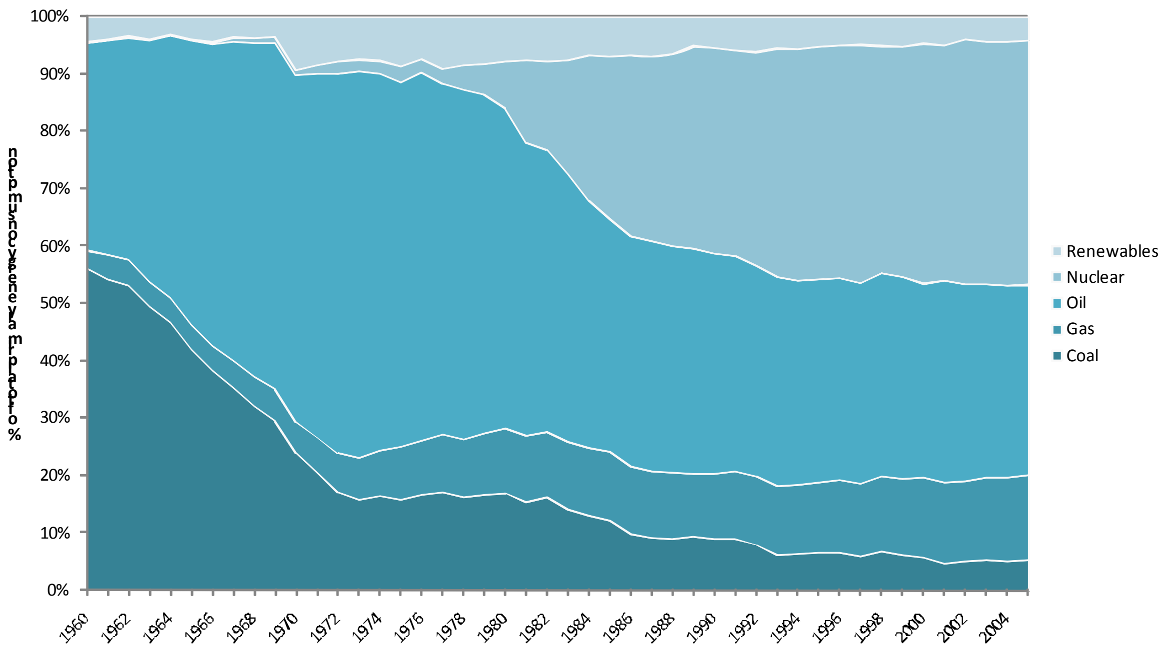
2 Some fields lying across borders or on the UK side of the North Sea were produced before 1990 and sent to the continent, marking the technical start of exports from the UK.

same time, Russia started producing from the Siberian fields. The Urengoi field was opened in 1978; to export gas to Europe new export routes were created, starting with the Transgas pipeline network in 1974. The first Norwegian deliveries from the Ekofisk field started in 1973 and in 1986; deliveries were made from Troll. In 1983 the Transmed pipeline came on stream connecting Algeria with Italy.

1. France

The discovery of Lacq wasn't followed by other major discoveries in France; however, the development of natural gas fields in Europe spurred the negotiation of long-term supply contracts to ensure that sufficient supply would meet growing gas demand in France. Natural gas supply contracts were signed with Algeria and with the Netherlands in the 1960s, and later in the 1970s and the 1980s, with the USSR and Norway.

Fig.1: Primary energy consumption of France (1960-2006)



Source: IEA

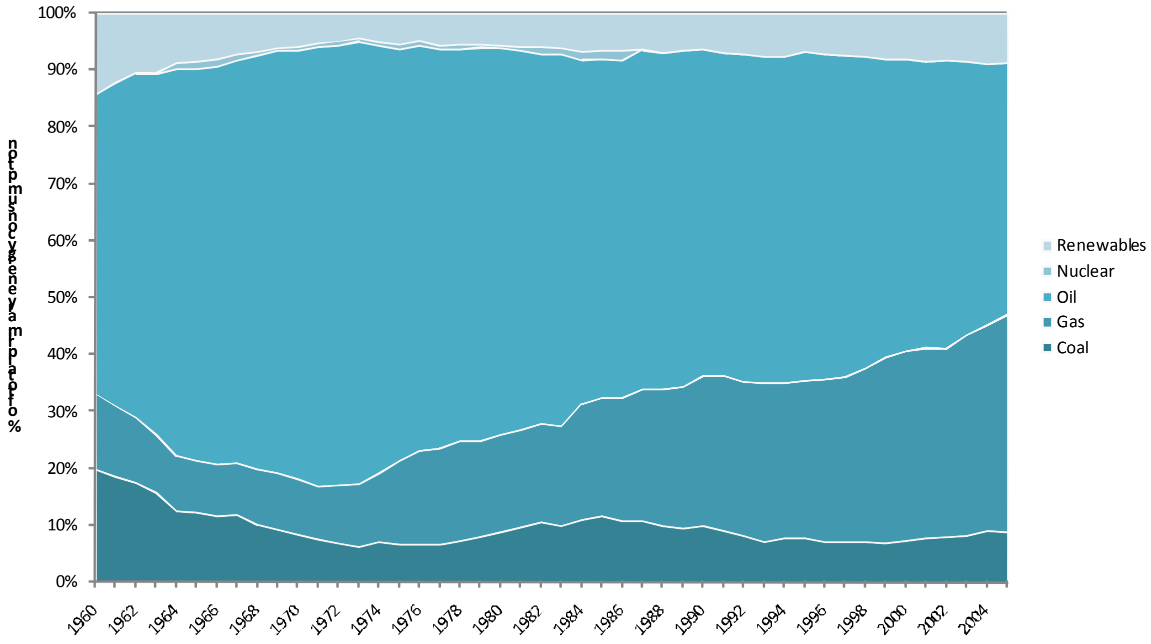
Gaz de France positioned itself at this time as a major marketer in the French gas market, shifting from locally produced town gas to imported natural gas. Indeed, the production of gas from coal and oil products was progressively diminishing; this trend being accentuated after the first oil shock. These events helped increase the role of natural gas in the French energy balance (although nuclear provided the major means of diversification from imported oil), and increased the status of Gaz de France as the primary natural gas wholesaler in France. Gaz de France's role was enhanced by the building of the first big transit pipelines in Europe in consortium with other European and external players.

2. Italy

Italian economic growth in the 1950s and 1960s was mainly powered by oil; in 1973 the share of oil in primary energy consumption reached 79%. After the first oil crisis, natural gas was identified as an alternative source of energy. An increasing share of oil consumption was substituted by natural gas, mainly in the household/service sector for space-heating, but also in industry and power generation. In absolute terms, oil consumption has remained relatively static since 1970, but its primary energy share has decreased significantly, steadily replaced in particular by natural gas.

SNAM started importing gas on a large scale in the 1970s. In 1971 Italy finished its first (and still only) LNG regasification plant Panigaglia situated near Genoa. To bring Dutch gas to Italy the TENP (owned by Ruhrgas and SNAM) and Transitgas (owned by Swissgas, SNAM and Ruhrgas) pipelines were built and the TAG pipeline (owned by ENI and OMV) crossing Austria was constructed to import Russian gas. In 1977 an agreement was concluded between SNAM and Sonatrach for gas delivery starting in 1981 through the Transmed pipeline between Tunisia and Italy, which was completed in 1983. Italy thus pioneered deep underwater gas pipeline transport.

Fig.2: Primary energy consumption of Italy (1960-2006)



Source: IEA

3. The Netherlands

During the mid 1960s, when the actual size of the Groningen field became clearer, the policy of reserving gas use to premium markets became less relevant. In particular, it was feared that it might be impossible to sell gas after the year 2000, because it was expected that low-cost nuclear energy would by then have taken much of the energy supply. As a result, even the power sector, which had previously been prevented, started to use gas.

The first oil crisis led to another change in policy. The level of reliance on oil for energy was made clear by this crisis, and two white papers were produced in 1974 and 1979. Energy saving was cited as a means of reducing the exposure to oil, as was reducing the use of oil and gas by switching to nuclear energy and coal in electricity generation. The Dutch gas reserves, and particularly Groningen, gained in international importance. Three approaches were suggested to reduce its depletion rate.

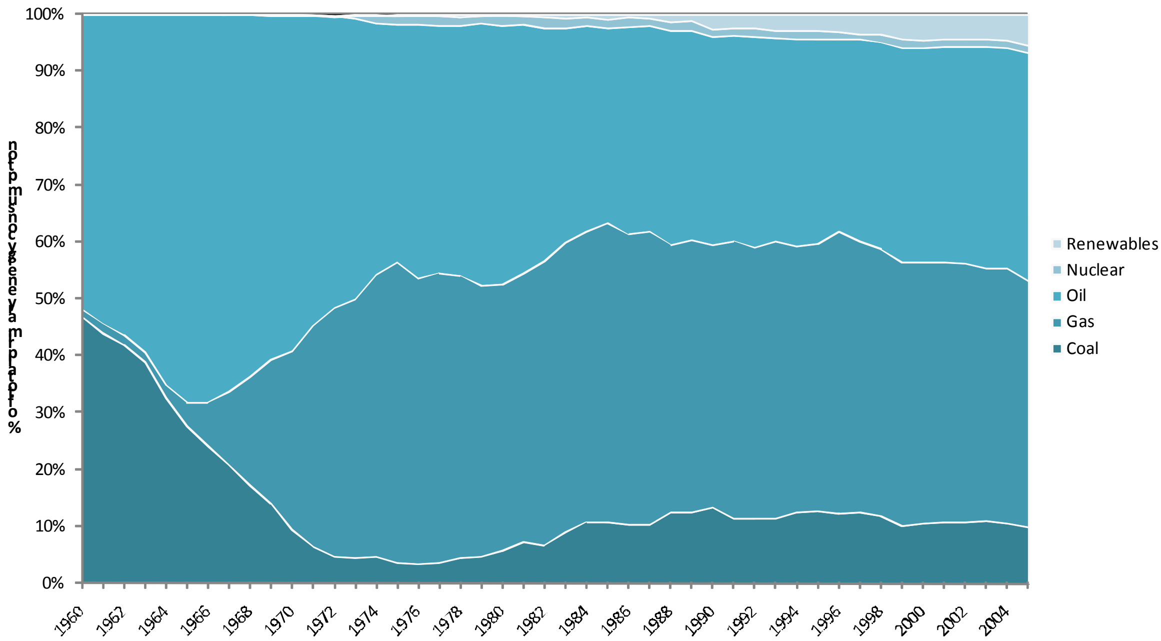
Firstly, national gas sales were limited through a revised gas pricing and sales policy. Within the Netherlands the government imposed a reduction of gas use in the power sector. Domestic prices had been linked to oil products, but with a limited ability to follow those prices. When oil prices rose, the price for gas was only allowed to rise by a reduced percentage. To achieve oil-parity, a law was passed in 1974 that enabled the government to intervene in the price negotiations between Gasunie and the distribution companies and to establish minimum prices for supply by Gasunie.

Regarding the export of gas, Gasunie told its customers that it was planning to reduce its exports; existing contracts would be honoured, but there would not be new additional contracts. Because of the large increase in oil prices, especially after the second oil shock, export prices were below market value. Substantial price increases in the renegotiations of the export contracts were sought.

Secondly, the small field policy was implemented. The exploration and production from other fields in Dutch territory were to be encouraged at the expense of production from Groningen. Gasunie was obliged to buy gas from any producer of a "small" gas field at a high load factor at a reasonable price related to the market value of gas and producers were obliged to sell the gas to Gasunie. Since 1996, the producers' obligation changed into an option, Gasunie (and since 2006 GasTerra), however, still has the obligation to offer a market value price for all Dutch small fields.

And thirdly, gas imports were planned. First gas imports from the Ekofisk field in the Norwegian North Sea arrived in 1977. At that moment, gas prices were lower in the Netherlands than in neighbouring countries. In order to import gas, Gasunie had to be able to get a consumer price consistent with the import price, which resulted in a price increase in the domestic market.

Fig.3: Primary energy consumption of the Netherlands (1960-2006)



Source: IEA

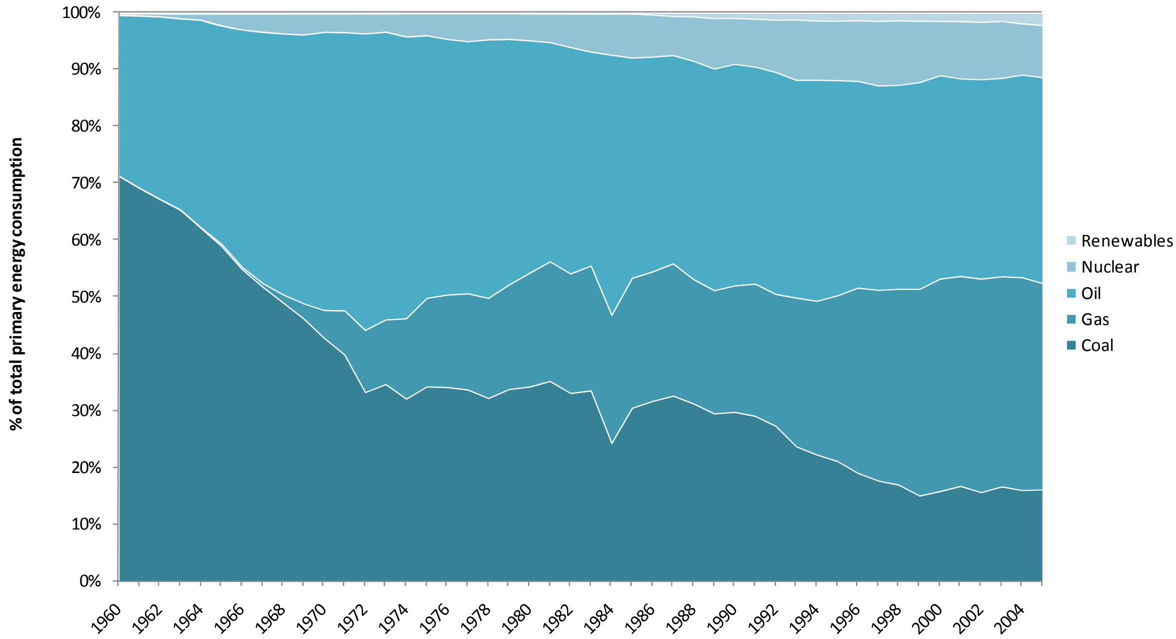
4. United Kingdom

After the United Kingdom started producing significant quantities of gas in the early 1970s, imports were no longer needed. With the Gas Act of 1972 the Gas Council was abolished and replaced by the fully integrated British Gas Corporation (BGC), which was to continue the monopoly activities. BGC set the gas purchase price from producers, the sales price to consumers, the supply/demand balance (assisted by 'take-or-pay' arrangements and interruptible contracts) and managed all necessary storage. All gas produced on the United Kingdom Continental Shelf (UKCS) had to be sold to BGC (apart from that lying close to the maritime borders which could be exported). In the period 1978-1981, BGC entered long-term take-or-pay contracts with offshore oil and gas companies.

The fact that British gas producers had to sell gas to the BGC was not popular because of the pricing policy. BGC bought gas from the oil companies on an individual cost-plus basis and sold on the basis of marginal costs (the most expensive production). The cheaper southern basin gas-only fields were the first to be produced, after that the more difficult fields were produced, and therefore the marginal costs rose, as did BGC profits. Nevertheless, gas was still much cheaper than oil, especially after the oil shocks. As a consequence, gas demand rose and there was a real danger that demand would exceed supply. The supply problem was solved when BGC contracted gas from the Anglo-Norwegian "Frigg" field, which was priced on an oil basis, for the first time. The deal aggravated the pricing disputes because Frigg was bought at a higher price than BGC was paying to its British suppliers.

In order to reduce BGC's monopsony, the Oil and Gas Act of 1982 permitted gas-producing companies to supply customers directly and to have access to BGC transmission network. The Act applied solely to large industrial sales. The Act also removed the obligation of BGC to make an offer for gas and the producer no longer had the right to appeal to the Department of Energy if an offer from BGC appeared unreasonable.

Fig.4: Primary energy consumption in the United Kingdom (1960-2006)



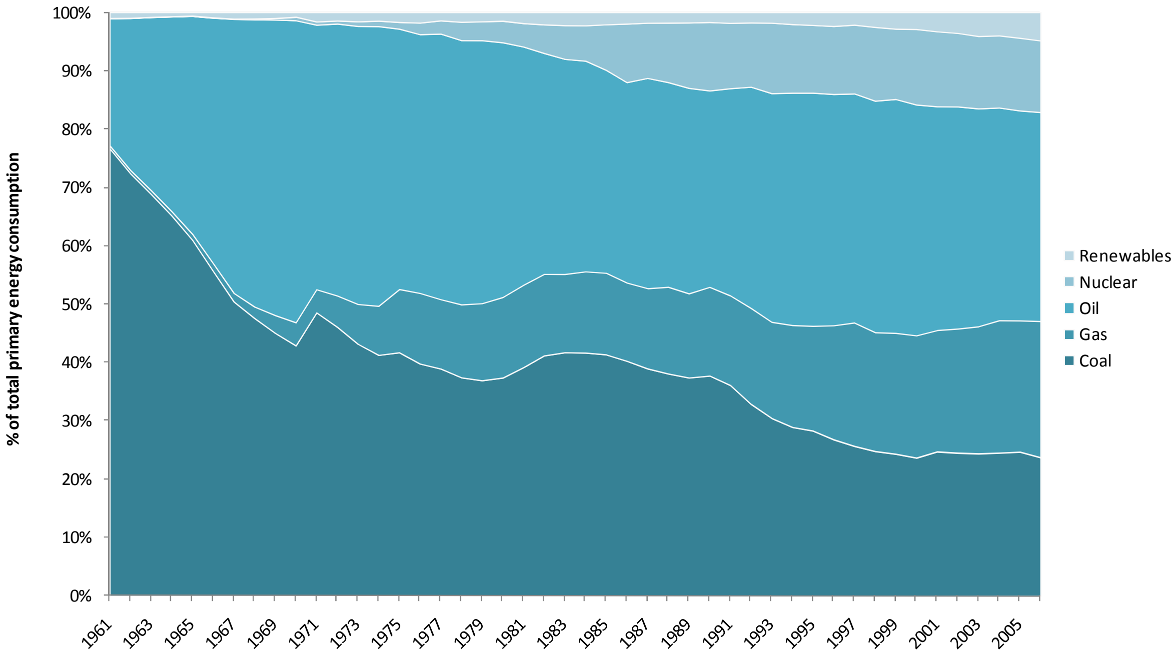
Source: IEA

5. Germany

From the 1970s, with the availability of more imports, the role of gas in Germany gained in importance and Ruhrgas started to take a dominant role in the west. The network owned and controlled by Ruhrgas extended from the Ruhr region east and south across the country and became by far the largest and most strategically located in West Germany. The network encompassed both the north-south corridor and the east-west passage (of West Germany). Ruhrgas was also well diversified, with domestic production, Norwegian, Dutch and Russian imports in its portfolio, and because of this and the size of its network, it was difficult for other companies to buy gas from anyone else. Examples are Gelsenberg, which tried to buy Norwegian and Russian gas, and Bayerngas which tried to get Algerian gas. Gelsenberg was outbid by Ruhrgas regarding the Norwegian gas, and while able to buy the Russian gas, it was unable to transport it to the final customer and therefore eventually had to sell to Ruhrgas. Bayerngas, after Ruhrgas changed the prices, tried to obtain Algerian gas, but also had to use the Ruhrgas transport system; in this way Ruhrgas was able to block that deal. Before the Russians sold gas to Wintershall in the 1990s, the only company they were dealing with was Ruhrgas because of its dominant position, particularly its control over the gas pipeline transport system.

The first Russian gas arrived in 1973 and Norwegian gas came in 1977. Fearing excessive dependence on Russia, in the early 1980s the government set a 30% limit for Soviet gas supplies to West Germany.

Fig.5: Primary energy consumption in Germany (1960-2006)



Source: IEA

6. Eastern Europe

With the help of East-European states, gas production in Russia expanded to the huge gas deposits in Siberia. Under the CMEA agreement, on a mutual investment basis, the USSR allies contributed to the development of the gas reserves and of the required transport infrastructure starting in the 1960s, and received in exchange long-term gas supply contracts.

The principle of "gas for manufactured goods" was initiated in the Soviet bloc, with the USSR becoming the region's major energy exporter, boosted by the immensity of the Siberian reserves, and East-European countries developing heavy industries fuelled by the barter-exchanged Soviet oil and gas. Gas, as energy in general, was considered as a central tool of the socialist economic policy, and was sold for a symbolic price in the whole CMEA bloc.

The first Soviet natural gas arrived in East-European countries at the turn of the 1970s. The European allies of the USSR had played a major role in the Soviet fuel-switching strategy, accelerating the importance of natural gas as a major energy resource. Even so, the Siberian gas reserves were much larger than the CMEA market could absorb.

Box 2: Russia –Europe transit pipelines

Despite the Iron Curtain that divided Europe into two hostile parts, the USSR started discussions with some import-dependent countries in Western Europe, who, having suffered a severe blow with the first oil shock, were in search of new energy supply to diversify from OPEC oil and satisfy the growing energy demand of their economies. France, Germany, Austria and Italy were keen, despite geopolitical tensions, to contract with the USSR.

Brotherhood-Transgas - The first gas deliveries to Czechoslovakia arrived in 1967; the transit line was prolonged to Austria where it reached Baumgarten in 1967 and France in 1984. From less than 1 bcm in 1969, this transit system shipped around 80 bcm in its latest stage, thirty years after.

Southern corridor - In parallel to the Brotherhood system, another transit line was built to the south to Romania and Bulgaria in 1974, and was extended to Turkey in 1987 and Greece in 1988. The southern branch was initially planned, like Brotherhood, under the CMEA agreement on a mutual investment basis.

Yamal – The Europol pipeline represented a new type of investment. Initially intending to bring gas from the undeveloped Yamal Peninsula in the far north of Siberia to lucrative West-European markets, the main rationale of the pipeline was the first transit by-pass by Russia, passing through Belarus rather than Ukraine. Yamal delivered first gas to Poland in 1996 and Germany in 1997.

Western gas markets became, from 1985, the biggest source of revenues from gas exports for the USSR, compared to Eastern Europe. They now account for around 80 bcm out of 200 bcm per year of Russian gas exports.

Map 1: Main transit lines in Eastern Europe

The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.
Sources: Petroleum Economist, IEA

C. Low oil prices – Path to liberalisation – The era of cheap energy

This time frame covers the period from the low oil prices in 1986 to the start of the liberalisation in 1998. After the high oil and gas prices and the perception of scarcity, the efforts in exploration and investment in production and transport facilities all over the world increased. Substantial volumes of gas became available in Europe, produced particularly through an expansion of activities in the United Kingdom, Norway, Soviet Union and Algeria. From 1989 Russia made increasing amounts of gas and oil available for export because internal demand had dropped after the demise of the Communist regime. A situation emerged in which Europe could be supplied by a number of potential suppliers.

1. France

In 1993 an interconnection was made with the Spanish network, the first Trans-Pyrenees gas pipeline, linking Lacq with Calahorra in Spain. The Franpipe connected the Norwegian Sea to France in 1998. In the period between 1972 and 1980 two LNG re-gasification terminals were built, one near Marseille and one near Nantes.

2. Italy

ENI was converted into a joint stock company in 1992 with the Treasury owning 100% of the shares. Between 1995 and 1998 the government's shareholding in ENI was reduced to 30.3% through four tranches of public offerings. Prior to ENEL signing its own import contract in 1992, ENI, through SNAM, was the sole importer of gas into Italy.

Legislation passed in 1988 included provisions making possible some restricted form of TPA in SNAM pipelines. The intention of this reform was to enable ENEL, the national electricity company, to purchase gas directly from the producers, at home and abroad. The right for producers to gain access was conditional upon the availability of spare capacity. Since there was no regulation forcing the transmission company to increase its transport capacity to accommodate the gas of third parties, SNAM in practice was able to refuse this type of operation, except during summer months when consumption was low.

Gas imports from Algeria increased after the signing of contracts in 1991 and 1993. The capacity of the Trans-Med pipeline was doubled and, import levels reached 19 bcm in 1996 (of which 4 bcm was for ENEL) up from 13 bcm in 1993.

3. The Netherlands

In the 1980s radical changes began to take place in the Dutch position in the European gas market. National and export sales had fallen significantly, while reserves improved. The small-fields policy proved successful and many new fields were found, particularly offshore. To sell more gas, Gasunie was allowed to sell to the electricity sector (20 bcm during the period 1982-1987). In 1984 the restrictions on the use of gas in power plants and export were terminated.

In the period 1985-1995 the Netherlands strongly opposed EU initiatives to liberalise the gas market. It was thought these initiatives would jeopardise traditional Dutch gas policy objectives and to interfere with the market-value principle. The third white paper in 1995 was a turning point; instead of opposing liberalisation, it concluded that it would be more advantageous to reap the benefits a free market would provide. The first direct supply of gas from a foreign company occurred at the end of the 1980s, when a gas-fired power generator in the Groningen Province was supplied with Norwegian gas. The contract was based on coal-parity (the competing fuel). Many local distribution companies, seeking the benefits of scale, merged. In 1985 there were 158 local distribution companies, in 1998 the number had fallen to 26, and currently approximately 10 remain, of which Essent, Nuon and Eneco are the largest.

4. United Kingdom

With the Gas Act 1986, BGC was privatised and renamed British Gas plc (BG) and a regulator, Ofgas, was set up. Although the Gas Act also provided third-party access to the national pipeline network, competition came only very slowly. In the following years three Monopolies and Mergers Commission (MMC) investigations would be needed in order to find the right framework to increase competition.

In November 1987, BG was referred to the MMC for the first time by the Office of Fair Trading (OFT), which had received complaints from industrial consumers that, despite the Gas Act, there was no real competition and that price reductions were only being given by BG to customers who had an alternative source of supply. The MMC reported in 1988 that British Gas was 'guilty of extensive discrimination in the pricing and supply of gas to contract customers' and that this resulted from the monopoly position and was against public interest. The MMC proposed the following:

- BG had to publish price-schedules for large industrial and commercial consumers.
- Interruption rights under contracts should be even-handed.
- Common pipeline carriage terms should be published.
- BG was prevented from contracting more than 90 per cent of the production of any new gas field.

The second MMC investigation (1993) suggested British Gas to be broken in two. British Gas fought break-up and a compromise was sought. Instead of breaking up, BG accepted a fast-track to competition in 1998, and accounting separation ("Chinese walls" between network monopoly and supply, as if it were two different companies) to overcome conflict of interest. The Gas Act 1995 effected the removal of the monopoly. Now it became clear that British Gas had signed up long-term contracts with North Sea producers on the basis that costs could be passed on to customers. Now customers could desert to cheaper spot-priced gas and BG was left holding much more costly long-term contracts.

BG needed to separate out and protect its transmission and distribution businesses from its supply contracts problem, and the way to do this was to break itself up, and to place the contracts within a separate company, called Centrica, which was formally demerged from BG in 1997. The new company would not be financially viable if it contained only the contracts and the supply business, which was expected to be loss making. Therefore assets in the form of the producing area Morecambe Bay were added in.

In summary, the liberalisation process in the United Kingdom lasted from 1982 to 1997, and resulted in the restructuring of the industry. BGC was replaced by a transport company (Transco, later National grid), an upstream company (BG international) and a downstream company (Centrica). Other functions necessary in the new market design were taken on by a new gas regulator (Ofgas, later Ofgem) and by the government (DTI).

5. Germany

An important factor for the introduction of the first real gas-to-gas competition in Germany was the strategy of the German gas supply company Wingas, a joint venture between Gazprom and Wintershall (a subsidiary of the chemical company BASF), created in 1993. Wintershall and Gazprom shared opposition to the monopoly position of Ruhrgas. Gazprom saw bypassing Ruhrgas as a way to get higher export prices by securing part of the wholesale mark-up that Ruhrgas had traditionally obtained. BASF helped secure Gazprom's role in Wingas by agreeing in 1993 to build a large chemical complex in western Siberia; in return, Gazprom pledged that Wingas would hold exclusive marketing rights for the Yamal output. The joint venture would allow Wingas to sell directly to large customers – including BASF - and to gas distributors. Costs for pipelines were shared.

Gazprom handed the task of renegotiating the main supply contracts to Wingas, and in 1994 the firm created new contracts with prices that were only slightly higher than existing arrangements—

disappointing Gazprom. Wingas opened the first pipeline in the Belarus Connector in 1996 — a connection between Poland and Germany that allowed quantities of gas to flow as Wingas lined up buyers. The net effect of this competition between Wingas and Ruhrgas was to drive down prices for distribution companies and for final consumers. As wholesale contracts between Ruhrgas and distributors expired, Wingas would attempt to entice the distributors with rebates, only to find that Ruhrgas would match the offers and in most cases win the contracts. Margins for Ruhrgas declined in the regions where Wingas also operated, and Wingas struggled to gain market share. Throughout this process, Gazprom nonetheless sustained a close relationship with Ruhrgas as its largest customer; Ruhrgas bought the largest non-Russian share of Gazprom (currently 6.5%).

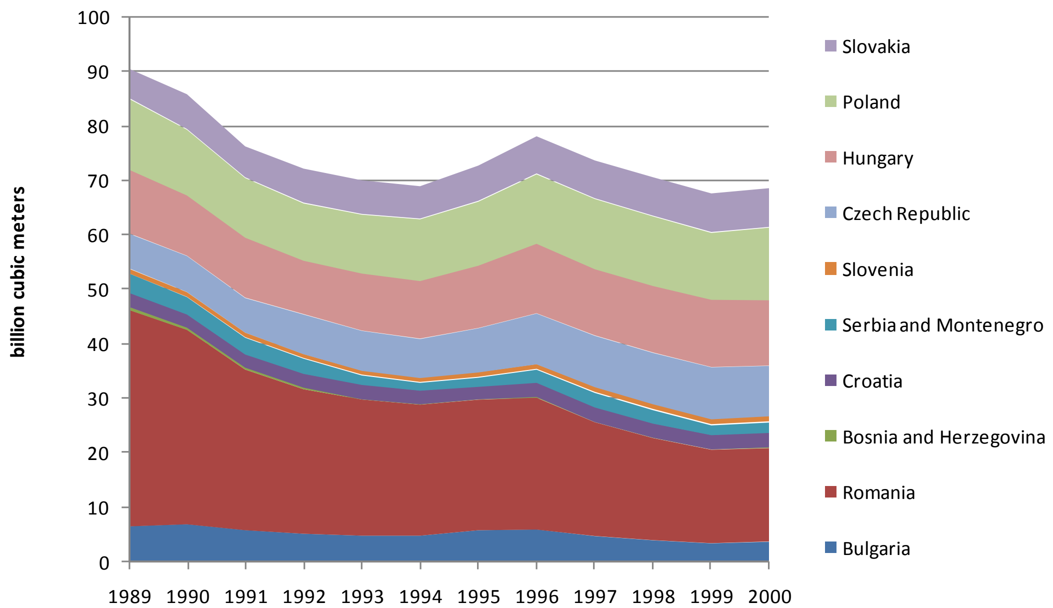
6. Eastern Europe

In 1989 the CMEA bloc broke up progressively; two years later this was followed by the demise of the USSR. Despite the collapse of the Soviet regime in Eastern Europe, the gas agreements endured, remarkable given the changes afoot. However, two major issues arose for the countries entering in a process of transition: firstly, strong hydrocarbon import dependency from Russia, and secondly, massive inefficiency in energy use encouraged by low state-administered prices.

Whilst the former USSR ministry of gas became Gazprom, so the East-European gas administrations each were reformed by their governments into state gas companies. Under pressure from Gazprom to renegotiate CMEA barter deals for dollar-denominated contracts, these state companies entered into difficult negotiations. On the one hand, they served consumers used to paying token values for their energy supplies; on the other hand they were being told that economic relations with their energy supplier had to be comparable to the market-based deals with Western Europe.

In a context of growing globalisation and international competition, East-European countries engaged in radical reform of their economies, based generally on liberalisation, stabilisation and privatisation. Large scale and rapid privatisation was the hallmark of the transition period from Soviet-designed to market-based economies. East-European economies saw a drastic drop in industrial output following the break-up of the centrally planned regime which led to a fall in energy consumption. The total consumption of natural gas in Eastern Europe fell by more than 20 bcm from 90 bcm per year in 1989 to a total of 70 bcm per year in 2000. In the former USSR, consumption dropped between 1991 and 1997 by some 185 bcm. Gas consumption in the former USSR returned to its 1991 level only in 2005.

Fig.6: Gas consumption in Eastern Europe during transition



Source: IEA

Nevertheless, the heavy industrial bias of the former CMEA countries remained, and with it their gas import dependency fed by branches of gas transit pipelines. In this sense, East-European countries didn't inherit a truly integrated gas network, but one that more closely resembled a chain of major consumers aligned along major transit pipelines. Furthermore, there are no alternative supply routes. This situation has reinforced the dependency of East-European countries on their major supplier, and almost 20 years after the break-up of the CMEA bloc, gas import dependency from Russia is still a major consideration, particularly since Gazprom exercises a monopoly on gas exports from Russia.

Box 3: Eastern Europe in 1998 on the eve of first Gas Directive and EU enlargement

The rush to liberalisation

Many East-European states in 1998 were considering a political process of major importance: accession to the European Union. A fundamental condition for the accession of new member states in the EU was (and still is) the adoption in national law of the European "*acquis*", comprising European laws and directives such as those liberalising the gas and electricity markets.

The integration of Eastern Europe and the liberalisation process in the gas and electricity markets were concomitant – the first Gas Directive was issued in 1998 while the European Councils in 1998 and 1999 identified ten former socialist economies in Eastern Europe as candidates for EU accession.

As the accession to the EU was a political priority for these countries, the prerequisite of adopting the Gas and Electricity Directives was almost viewed as a formality among many (of 31 chapters in discussion during pre-accession, energy was but one). Only two countries asked for transitional periods in which their energy industries could develop and modernise. These periods were reviewed and shortened after accession.

Therefore, after emerging from 40 years of a centrally planned economic regime with state ownership and no free market, Eastern Europe had to rapidly adjust its energy sector to a market-based economy and the new competition rules of the European Union.

Weaknesses of the gas industries

Several market imperfections characterised the East-European gas sector that would make it difficult to successfully transform the organisation of these gas markets.

The industrial structures within the Soviet bloc were based on nationally administered prices and volumes, and on gas import barter exchanges (including services, raw materials and manufactured goods). With the collapse of the Soviet Union, and the need on both sides to proceed to market reforms, barter contracts were progressively replaced by new ones labelled in US dollars. As the terms of exchange during Soviet times were unclear, the price and volume adjustments created tensions and conflicts among former allies.

In this particular context, the single supplier of gas to Eastern Europe, having alternative and more lucrative markets in Western Europe, exercised substantial market power in the transit states. This market power was enhanced by the lack of interconnections among the Eastern markets as pipelines evolved as transit and supply corridors from the source in the East to the destination in the West. The enlargement of the EU increased the degree of heterogeneity in EU gas markets, thus necessitating a differentiated approach to liberalisation as shall be shown in the subsequent section.

For East-European states, engaged in profound political and economic reforms, achieving workable competition in the energy industry was thus a substantial challenge. Some governments, incapable of managing electricity and gas administrations in a dynamic context, opted for privatisation of energy industries.

II. EU liberalisation push and the industry's response

A. 1998-2008: ten years of continued regulatory change

The aim to build a single market for gas and electricity is a principle embedded in the creation of the European Union – the EC Treaty mandates the building of a common market including energy (Treaty of Rome 1957, Single European Treaty 1985, Treaty of Maastricht 1992). Making the energy sector in Europe competitive and more efficient was viewed as part of the response to growing concerns on the competitiveness of European industries in globalising markets. Introducing competition in the gas sector was aimed particularly at creating a more appropriate competitive framework, notably more gas-to-gas competition, thus increasing economic efficiency and lowering costs for the final consumers in markets frequently monopoly dominated. A truly working internal market would also deliver more resilience in the event of supply disruptions from any cause, thus increasing gas security.

1. 1998: Liberalisation "à la carte"

Negotiations between the EU authorities, the member states and the market stakeholders during the 1990s culminated in an Electricity Directive (96/92/EC) and, two years later, in a Gas Directive (98/30/EC) introducing a first set of common rules for the EU energy markets. On natural gas, the new legal framework was aimed at opening the gas networks to third parties. This was to be achieved through unbundling of the vertically integrated historical gas operators, thus allowing competition for supplies and customers within the natural monopoly network. The European Commission encouraged the industrial re-organisation within each country to be supervised by an independent regulatory authority, but this was not mandated. The member states had two years to implement the corresponding national legislation and industrial regulation reforms.

Initially, the opening to competition granted the choice of supplier to big gas customers such as power plants and big industrial facilities. A level of eligibility was to be defined by the member states such that at least 20% of the national market was free to choose suppliers when the Directive entered in force, the level being updated five years later to minimum of 28%, and 33% after another five-year period. The eligible customers were free to contract their gas supply with the supplier of their choice, the latter being authorised to ship gas through the existing network with the Third Party Access (TPA) provision of the Directive.

To ensure transparent and non-discriminatory access to all potential suppliers of the market, the infrastructure operator was to be unbundled – separated – from the integrated undertaking. This unbundling requirement was, at a minimum accordance with the first Gas Directive, on an accounting level, which in practice had to put an end to cross subsidies and transform the mature networks into essential facilities.

The monitoring of this new system was assigned to a regulatory body which had to be independent from the market and from the state, to ensure transparent and non-discriminatory operations on the market. The regulator had the prerogatives to grant licenses to suppliers and infrastructure operators in the market, supervise tariffs and ensure the efficient functioning of the market. TPA could however be either regulated (tariffs and conditions published by the transport operator *ex-ante*), or negotiated on a bilateral case-by-case basis.

The member states could choose different approaches to implement the opening to competition process (negotiated or regulated TPA, accounting unbundling, legal unbundling or complete separation, ex-ante or ex-post regulation of the market), but overall equivalent economic results and market opening were required between the national markets.

The gas market liberalisation was conceived taking into account existing national features such as the level of maturity of the market, import dependency, public service obligations etc. On the light of these, the first fallowed certain derogations granted to member states.

Derogations were granted in the following cases:

- If the opening to competition process was contrary to existing public service obligations, to long-term take-or-pay obligations, to security of supply prerogatives, or was likely to create other economic difficulties;
- If the national or regional market was not sufficiently interconnected with other EU markets, or had only one external supplier and no indigenous resources;
- In the case of emerging and developing markets in need of substantial investments.

Subsidiarity was therefore embedded in these new common energy market rules, made "à la carte" to address the quite heterogeneous natural gas markets in the EU. Nevertheless, this process tried to create a harmonised and integrated market, and the member states were only allowed to choose the best solutions appropriated to their specific contexts in order to achieve the common goal.

The negotiations of this first Gas Directive began in a Europe of 12 which in 1995 became the EU-15 with Austria, Finland and Sweden joining the club. By the time the Directive was effectively implemented by the member states in 2000, the perspective of a new unprecedented enlargement was confirmed by the European Council, which adopted the outlines of a future Europe of 25 and later of 27. Yet of the continental countries of the EU-15, only Portugal, Finland and Greece were considered as developing gas markets - the rest of Europe was legally regarded as quite mature in terms of gas industry development. As was demonstrated in the previous section, the gas industry had developed in a different manner in East-European countries.

2. 2003: Acceleration under the Lisbon agenda

Even before the implementation of the first Gas Directive there was already a push to accelerate gas and electricity liberalisation. The European Council, held in Lisbon in March 2000, requested that the Commission undertake further steps towards the completion of the internal energy market. The new aims were far more ambitious and global than the first Gas Directive, and this time gas and electricity were treated jointly in one proposal. Therefore, a second Gas Directive was postulated before the first had been fully incorporated into some member countries' national laws.

Market conditions partially justified this further step: several markets had opened more than the required consumption level (79% in real average compared to 20% of legal minimum); nine out of fifteen EU member states were planning total market opening by 2008; eight member states had opted for regulated TPA. At the same time the benefits of a competitive market weren't obvious yet; after the coming into force of the first Gas Directive, price rises were observed in EU gas markets, while in the electricity market, prices decreased after liberalisation. This encouraged policy makers to consider that the objective of liberalisation was not to reduce prices *per se*, but instead to make them more cost reflective and exert maximum downward competitive pressure on them. It became clear that wholesale gas price rise was linked to oil price increases and was not related to the opening to competition.

The analysis made by the Commission on the implementation of the first Gas Directive revealed an unequal level of market opening, tariff and TPA problems, concentration of gas production and imports. Because of these main reasons, competition at this stage was not effective, and consumers were seeing little benefit. Further structural measures and full market opening were deemed necessary in order to advance towards the initial objectives of lower prices and efficient markets.

The EU Council at Barcelona in March 2002 decided on full market opening for industrial gas consumers in 2004 while total market opening was intended for 2005. It launched the preparation of a new legislation to implement these decisions. A year later, the second Gas Directive was adopted (2003/55/EC). Concomitant to a second Electricity Directive (2003/54/EC), the new EU gas law mandated regulated TPA as the basic rule (for all existing infrastructure) as well as moving the level of unbundling of TSOs to the level of legal separation (e.g. regulated activities under the responsibility of separate entities). The role of independent regulators was also reinforced.

The new Directive was accompanied by deeper analysis of the public service obligations and of the security of supply issues. Although the first Directive already recognised the weight of these issues in the European gas industry by relying on subsidiarity and "*made to measure*" solutions for each state, in the new diagnosis, the process of liberalisation was treated separately from security of supply measures, which was to be a matter for a separate directive. While the push for more competition was adopted in 2003, the security of supply issue was subject to substantial problems and the Directive adopted on the subject in 2004 (2004/67/EC) was not as binding as is the one on liberalisation.

Another interesting feature of the second Gas Directive was the proposal for updating the Transit Directive issued in 1991 and for joint regulation of all high-pressure transport pipelines in the EU, which would be subjected to TPA. This proposal implied the end of the special status of "transit pipelines" as exempt from TPA rules under the first Gas Directive dispositions by "demoting" transit pipelines to European distribution lines. The Energy Charter Treaty and its clauses were impacted by this move, as the Treaty only refers to transit pipelines.

The subject of pipelines in the liberalisation process was handled with a certain caution – new pipeline projects were temporarily exempted from TPA in order to make the investment and its repayment possible. But the question of whether temporary TPA exemption would be sufficient to trigger the necessary investment for the pan-European gas networks remained unresolved.

3. 2003-2006: "More needs to be done"

By 2003, the market reality in Europe was that competition was still very slow to develop. After two attempts to open the energy sector to competition, a new series of benchmarking reports made by the Commission (third & fourth[3]) in 2004 pointed out the issues that seemed to impede the creation of a truly competitive and functioning energy market in the EU:

- **Customer switching** was not sufficient.
- In the absence of increased **interconnection**, new suppliers were not able to enter the markets, and gas could not circulate freely from one point to another.
- Competition between suppliers was difficult to achieve on a national basis where **one import source** often dominated the market (to the extent that a wider European natural gas market could be created, this concern might be alleviated).
- **Prices** might had not fallen as expected, while regulated end-user prices were distorting market functioning.
- **Investment** had become an issue, especially in cross-border interconnections. In the medium term, a number of projects, particularly for LNG terminals, were either in progress or being considered. It was expected that such investments would be forthcoming without specific support measures.
- The **industry structure** was far too concentrated, and TSOs were not sufficiently independent.

These conclusions, added to anti-trust enquiries led by the Competition Directorate of the Commission, shifted the focus from changing the basic conditions (which failed to yield results rapidly), to changing directly the market structures in the gas and electricity sector (in electricity, conclusions were similar).

The fifth benchmarking report[4] in 2005 stated that the "*most persisting shortcoming is the lack of integration between national markets*"[5]. Lack of liquidity, market concentration and cross-border infrastructure still remained major problems according to this report. In particular, long-term take-

3 Brussels, 5.1.2005 – COM/2004/863 final. http://ec.europa.eu/energy/gas/benchmarking/doc/4/com_2004_0863_en.pdf
4 Brussels, 15.11.2005 – COM/2005/568 final. http://ec.europa.eu/energy/electricity/report_2005/doc/2005_report_en.pdf
5 Idem p. 2

or-pay contracts were singled out as a problem, contributing to market foreclosure, and also the lack of investment in new pipelines, which would drive market integration.

The Commission also recognised that reforms were being enacted legally, but that some member states were (perhaps intentionally) reducing their effectiveness, noting that "*Member states need to give careful consideration to ensure that in their implementation of the Directives in practice, they pursue their spirit and not only their letter*".

The security of supply analysis led by the Commission arrived at the conclusion that in a context of a globalising market, the EU must ensure that it remains attractive to suppliers – requiring an internal market which functions properly and has a stable regulatory regime. Nevertheless, the Security of Supply Directive issued in 2004 only suggested ways of improving the security situation, without imposing concrete measures to actually promote investment at a time when the market was not complete.

Overall, the flexible approach initially adopted for energy market liberalisation has shown to deliver results at best slowly. Hence new measures have been taken in order to accelerate the reforms in the part of the gas value chain which is under EU responsibility – the common market. No further solutions concerning external relations and geopolitical issues concerning the gas imports have been taken beyond the already existing "dialogue" with external stakeholders.

4. 2007: Towards a third Directive

The 6th benchmarking report was issued in January 2007 and provided a general overview of the future energy policy of the EU. It envisaged a "third package" of legislative proposals for the European gas and electricity markets. The rationale of this third package is the integration of the energy and the environment objectives of the EU through the use of market based environmental and other measures.

The EU Commission proposed ambitious and far-ranging measures such as complete de-integration of the gas operators through ownership unbundling and further institutions to back-up the creation of an integrated EU gas market (European regulatory agency). On a practical level the solutions put forward concerning investment between national markets are left to the member states' bilateral cooperation and initiatives.

Consequently, the main new feature of the third package for market liberalisation consists in internal industry structural change – namely ownership unbundling; the others being acceleration of already existing measures such as network harmonisation, continuous identification of missing infrastructure, increased coordination between TSOs and regulators through existing institutional groups (ERGEG, GIE etc.).

The main features of the third package concerning the natural gas markets are:

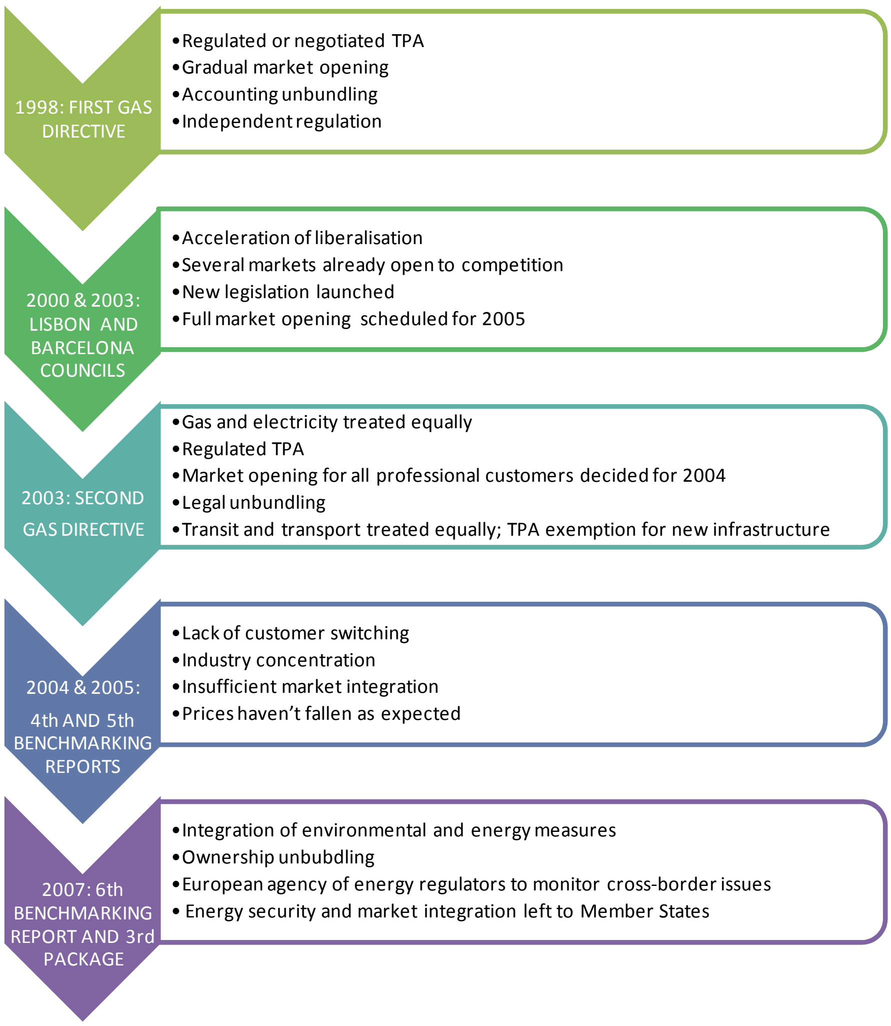
- Energy and environmental issues to be treated together
- Gas and electricity to be treated equally
- Ownership unbundling between transport and sales
- A European agency of energy regulators set by the Commission to monitor cross-border issues
- Energy security and market integration to be dealt with by member states and companies

Stakeholders' views on these measures are summarised below:

- On the regulators' side, ERGEG (European Regulators' Group for electricity and gas) proposed that the new legislation include more concrete measures in order to define high level public interest objectives, EU operating and security standards, roles and responsibilities to ensure investment, enhance the EU-level vision and responsibilities over regulation, networks, and their accountability. Concerning infrastructure issues, despite some disagreement, the overall outcome of the ERGEG proposal favours ownership unbundling because it would allow more effective monitoring of TSOs. On the TPA exemption issue on new pipelines, ERGEG states that a balance should be found between incentives for new investments and competition.

- The infrastructure operators through GIE (Gas Infrastructures Europe) proposed a nuanced vision on the ownership unbundling issue, including the possibility for a moderate model called ISO (independent system operator) implying vertical integration on ownership but separate management of transport companies. GIE points out that in already liberalised markets alternative models can work efficiently next to each other and that one solution for all EU markets might be provided by TSOs integrated in supply companies, but providing transparent and non-discriminatory services to the whole market, and thus acting independently.
- Finally, the gas operators (represented by Eurogas) confirmed their commitment to progress towards a secure, sustainable and competitive European energy market. They state that security for the market relies on a sound, consistent, single foreign policy for the EU, adequate investment notably in importing facilities, and a balance between internal and external dimensions of EU energy policy. In relation to the objective of a well functioning energy market, Eurogas generally aligns with the other stakeholders in demanding improved regional cooperation and a well-functioning TPA regime which, as in the GIE view, does not necessarily need to embrace total separation of infrastructure and other activities.

Fig.7: Chronology of EU liberalisation (1998-2008)



Source: European Commission

5. Critique

At the moment (May 2008), the outcome and the conclusions of this dialogue are a complex set of proposals, some of which are binding – compulsory for all member states. These include internal market provisions on industry structure change (ownership unbundling) as well as some measures on emissions trading and renewable energy objectives. Other proposed measures are based on non-binding encouragement (R&D and energy efficiency for instance) or left to the initiative of member states (external relations, solidarity in the case of supply disruption and general security of supply issues).

It is not clear whether this mix of compulsory and non-binding measures will deliver key objectives, notably security and diversity of supply, and sustainability. Globally, gas supplies from both pipeline and LNG are tightening, and supply side investment is weak everywhere. Infrastructure investment is lagging, including for storage. Governments are demanding ever higher shares of renewable electricity, which given its current intermittent production regime almost certainly necessitates gas-fired back up power. In any event, lagging investment in alternative sources for electricity generation guarantees a more prominent place for gas-fired power, rising from less than 15% ten years ago to 25% by 2015.

As structural changes to the gas industry occur, consideration needs to be given to integrating policies for security and sustainability in order that those functions performed currently by companies within national borders are not lost. Perhaps a single gas market in the future would automatically produce some of the security outcomes, but perhaps additional policy levers or market mechanisms are needed which can act on the market to make it deliver desirable outcomes. Other reforming markets have found it necessary to establish legally binding reliability standards in, for example, electricity markets, e.g. in North America.

A second issue concerns investments – especially the investments required to integrate the markets such as missing interconnections not linked to new supply routes. Inconsistent and changing regulatory regimes across member states remain a major barrier to cross-border investment, including new large-scale import infrastructure (e.g. Nabucco).

Generally, the liberalisation process in the EU should still focus on the main industrial problem for European gas, which is not specifically linked to the EU markets but is a global issue: how to ensure bringing increasing supplies of long-distance gas imports to the market and secure reliable, affordable supply in the long term? This issue is presently left to companies to guarantee. Any set of reforms must continue to keep sight of this fundamental objective, so that companies and investors in general can work towards this aim, and so that the relevant institutions can be put in place in a timely way.

B. The Industrial and National response

1. The industry's response to the EU regulatory revolution

Since the beginning of the 1990s and the renewal of the EU internal market construction, European energy companies have started preparing for the potential effects of the opening to competition of their historically protected national or regional markets. In the interest of their shareholders, the expected loss of historical market share in their domestic markets had to be compensated in some new way, and different strategies were deployed by the energy companies in order to ensure their growth within the EU energy market.

Generally, the natural gas industry in Europe made certain that they complied (sometimes in advance) with national laws by the time these incorporated the first Gas Directive. In 2000, at least a minimal compliance with the basic provisions of the Directive could be observed in most member states not under a derogation protection (with very few exceptions). In parallel, the energy companies involved in the natural gas business in the EU were preparing for this organizational change by implementing new development strategies. Four general trends may be observed since the mid-1990s to the present period.

- First, the big national or regional incumbent operators, with the perspective of losing their monopolistic market share, started acquiring assets in other European countries and abroad.
- Second, downstream local utilities merged on a national or regional basis, reducing therefore the number of downstream players in their markets.
- Third, synergies were sought across gas and power industries. There was an increase of mergers and acquisitions between gas and power companies.
- Fourth, the newly created pan-European energy groups engaged in a policy of vertical integration up- or downstream in order to secure market shares and their supplies.

With the acceleration of the opening to competition process, (second Directive and following benchmarking reports and sector inquiries in 2004-05), these parallel development strategies became more aggressive and were viewed as vital to many firms, but anti-competitive issues quickly surfaced. The EU authorities noted these trends in the fifth benchmarking report[6]: "*In addition to the high levels of concentration in national markets, an increasing number of cross-border acquisitions can be observed. In certain electricity markets there also seems to be a tendency towards growing vertical integration between generation and supply activities, which might lead to a reduction of liquidity on the wholesale markets concerned, aggravating the risks associated with concentration. Furthermore there have been attempts by incumbent gas and electricity companies to merge. These mergers can reduce incentives for competitors to build new gas fired plants. The Commission is monitoring these developments carefully and – to the extent applicable – strictly applies its merger rules. In its competition cases the Commission pays particular attention to remedies that facilitate market opening and integration. The Commission is investigating the concentration and consolidation of the industry in more detail as part of the ongoing sector inquiry launched in June 2005.*"

Here are several examples of the outcome of these market changes in Europe:

- Gas incumbents like Gaz de France, Eni and E.ON Ruhrgas acquired gas assets in other European markets, thus increasing their gas customer base to counter the trend of their local markets.
- Downstream utilities started merging and concentrating on a regional and national level (examples of Dutch utilities Essent, Nuon, Eneco, as well as of Italian utilities Hera, AEM)
- Power companies acquired significant gas operators in Europe: EDF buying out EnBW in Germany and Edison in Italy, but also power assets and clients in the United Kingdom, Germany, Central and Eastern Europe. In 2001, RWE bought the Czech gas incumbent Transgas (after securing by the acquisition of VEW a total of 38% of German electricity sales in 2000).
- The acquisition of Ruhrgas by E.ON is a specific example of power companies taking over gas companies in their own countries. The German competition commission itself tried to block the deal, but was overruled by the government. In a similar vein, the Italian electricity player Enel developed in the gas business on its home market, and DONG acquired power assets in its native Denmark.
- European gas suppliers were facing a severe reaction by external gas producers and their main suppliers. Companies lacking significant production assets such as Gaz de France or Centrica (having been separated from the upstream part of the British Gas monopoly) and even newly merged entities like E.ON, started exploration and production activities, mainly in the North Sea, but also abroad.

The enlargement of the EU to Eastern Europe and the transition from centrally planned to market-based economies in that region triggered the concentration of the gas business on a pan-European

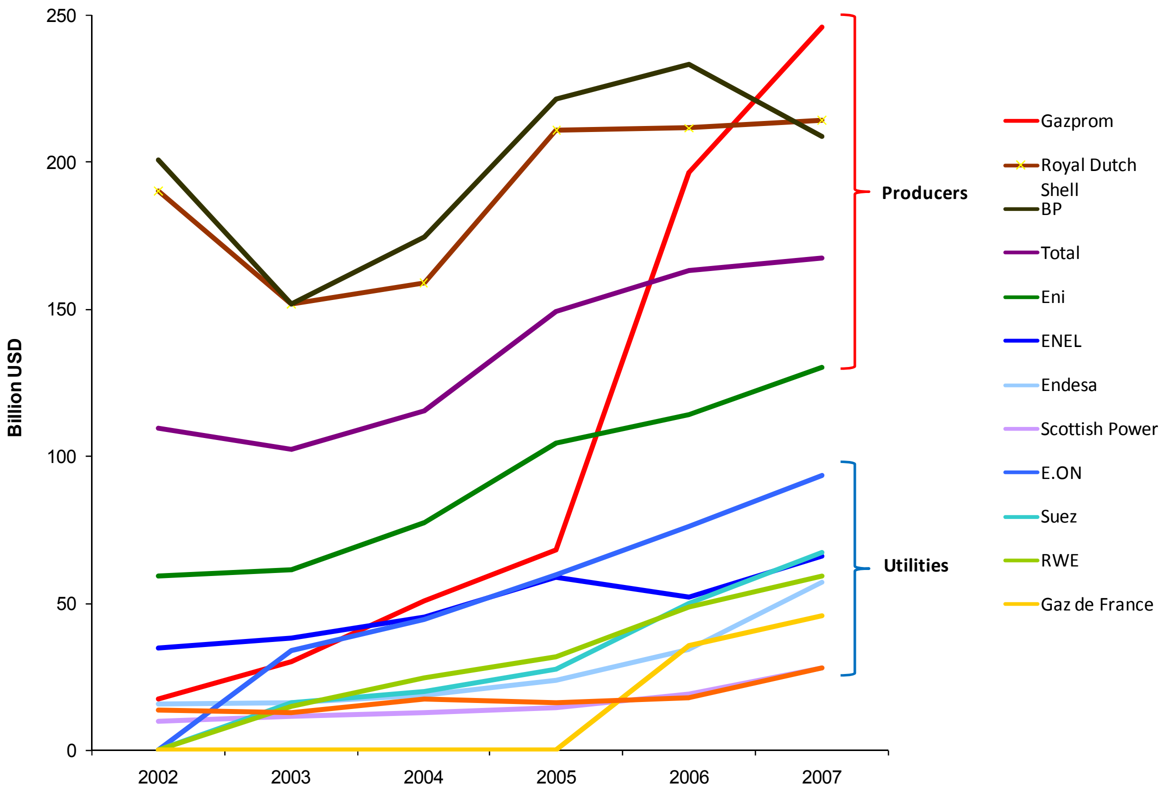
6 COM/2005/568 final, p.8

level. As noted previously, the East-European governments were facing difficult objectives in the overall economic restructuring of their countries; therefore many of them chose to entrust management of the energy businesses to large and market experienced western energy players, be they public or private.

Downstream gas utilities were sold in Hungary and Romania, transport and sales companies were privatised in Czech and Slovak Republics, while whole integrated incumbent operators were acquired by foreign utilities in the Baltic States. The main gas assets were transferred to the already growing energy oligopoly in the EU as well as to Gazprom itself in some neighbouring countries. Only two countries retained state-ownership of the majority of gas assets (Bulgaria and Poland). Some other countries realised a compromise by retaining either a majority of the company or ownership of the transport assets, which were considered by them to be strategic (e.g. Romania, Hungary).

Generally, the concentration and the vertical integration by key market players on the midstream and downstream in the European markets may be viewed as a strategy to counter-balance the growing uncertainties and risks in the European and in the global energy scene. While such concentration may adversely affect competition at national levels, it might ultimately facilitate pan-European competition. Arguments that such consolidation is essential for adequate market power vis-à-vis upstream suppliers need to be seen in the light of the still small size of such consolidated players.

Fig.8: Market value of major European gas companies



Source: data from FT Global 500 (2002-2007)

2. National reactions to the liberalisation process

EU member states, having different industrial structures in the energy sector, have set differing priorities in their national energy policies.

a. Impact in Western Europe

In **France**, the first Directive was implemented with some delay; nevertheless the two incumbents in gas and electricity went ahead with the liberalisation process and started reorganising internally in order to be ready for European-level competition. The second Directive pushed forward the restructuring process with the creation of regulated third party access on the gas grid, which was transformed into an independent affiliate in 2005. The presence of a strong regulator in France and the basic compliance of the French incumbent with the EU legislation provided a relatively transparent and non-discriminatory access to the network. However, the absence of local production and the dependency on external long-term supply contracts made it difficult for competition to develop organically. Only neighbouring energy players (from Belgium, Italy, Germany) could enter the market and supply industrial consumers with gas.

The **German** situation is different from the French one precisely because of the regulator's role in the ex-post monitoring of the energy market, as well as because of the different industry structure. Firstly, Germany entrusted the already existing Bundeskartellamt (competition commission) to supervise the energy markets liberalisation. However, this competition commission was empowered to perform only *ex post* regulation, and not *ex ante* as it could be interpreted from the first and second Directive. A dedicated regulatory authority was finally created only in 2005 (Bundesnetzagentur) which has taken time to acquire experience and appropriate skills. Secondly, a merger between the major gas player Ruhrgas and one of the main electricity players, E.ON (itself a merger between Veba and Viag), created a dominant energy company which rapidly built on an already significant presence of the two companies in Germany and abroad. Thirdly, the presence of several regional players in Germany, and therefore of several networks, complicated the access to networks by third parties. All these factors help explain why the German market remained relatively closed to new entrants and retained its initial rigid structure. Since the creation of the energy regulator, new laws have been passed, intending to curb the market dominance of the big players and to develop a more flexible industry structure, notably by restraining downstream long-term contracts (between wholesalers and retailers).

The **Italian** restructuring is also linked to a tug of war between the regulator (l'Autorità) and the gas and electricity incumbents. Although the networks have been partially separated from the incumbents, two strategic moves characterise the Italian energy market today: the gas incumbent has moved upstream, thus becoming a real oil & gas producer, while the electricity incumbent has developed strongly in the gas market through dual fuel supply. The major issue for Italy remains the security in primary energy supplies: being a peninsula, gas connections and transit lines are limited compared to the size of the market, and authorisation procedures to build LNG terminals have slowed or stopped many projects (Italy has only one LNG terminal despite being 80% dependent on imports) and thus undermined the overall gas supply security.

In the **United Kingdom**, market restructuring had taken place before energy liberalisation became an issue on European level. The United Kingdom has widely supported EU liberalisation processes, and has underlined the delays in implementing appropriate measures to open the continental markets, considering that these needed restructuring and that the British energy industry should also benefit from market opening in continental Europe as the French and German operators for instance took advantage of the liberalised British market. Furthermore, since UK liberalisation, the NBP has started to act as the balancing market for continental Europe, in the absence of liquid hubs there. The most dramatic example of this can be found in the price spikes of winter 2005-2006, and in the low prices of winter 2006-2007.

The white paper of 1995 formed the turning point for the **Netherlands** in energy policy. As noted earlier, prior to that time the Netherlands opposed liberalising energy markets, because it was thought to jeopardise traditional Dutch gas policy objectives. After the white paper it was decided it would be more advantageous to realise the benefits of a free market. This was done by first privatising electricity utilities, then allowing some concentration on the downstream level and finally in 2005 by unbundling the incumbent Gasunie into a state-owned transportation part and a public-private trading company, exclusive marketer of Groningen gas. In order to preserve the Groningen field, in 2006 the 80 bcm per year annually overall Dutch gas production objective was replaced by a ten-year cap of 425 bcm in total on solely the Groningen field. Unbundling of the downstream energy utilities into a trading and a distribution part has been heavily discussed over the recent years and currently is planned for 2012.

Generally, in continental Europe, real reform progress has been observed in markets under strong and independent regulatory authority. After the 2005-2006 supply crises, energy policy orientations have progressively incorporated a renewed concern on security of supply issues. Another trend visible in some countries (in Western and Eastern Europe) is the separation of national networks from private sector activities like supply or sales, and this unbundling has happened in the Netherlands, Poland, Romania, and Hungary before the EU proposal of full ownership unbundling. These decisions were based on a national strategic vision or on business model decisions such as in the Netherlands, where ownership had to be cleared between the Dutch state and two historical private energy players, Shell and ExxonMobil. In other countries, a similar logic was used to justify the preservation of an integrated model (France, Germany, Czech and Slovak Republic, Bulgaria, Baltic States).

Finland was among the few countries that demanded an exemption from the Gas Directive, as it had only one gas provider, Russia. The other countries exempted from the gas Directives were Greece and Portugal, because of relative market immaturity. Surprisingly, East-European countries that are in the same situation (Bulgaria, Poland) did not seek such derogation and accordingly had to comply with the Directive principles.

b. Impact on Eastern Europe

As many governments in Eastern Europe were facing profound economic difficulties in their countries during the transition period (post-1989), some adopted the denationalisation strategy as a way to deal with the difficult but necessary market reform of the centrally planned economic system. Many state assets were privatised, either by mass privatisation or by sale to strategic investors, as financial markets weren't sufficiently developed to take over important companies.

The restructuring and privatisation of the energy industry in Eastern Europe offered the West-European energy players unique opportunities for international business development. Many big European utilities started European expansion with the privatisation of East-European companies.

Privatisation of state assets wasn't required by the European *acquis*[7]. But privatisation of their assets gave these governments vital cash injections as well as helped them to quickly establish a new economic system. Privatisations in the East were thus to some extent motivated by the political decision to join the EU. On the eve of the first wave of European accession in 2004, only two countries out of ten candidates hadn't started privatising their gas industries (Bulgaria and Poland).

The privatisation that occurred after 1989 in the East-European gas industries may be explained through the main players' strategies: those of governments, and of the big European energy players.

The national governments in Eastern Europe had several complex issues to deal with. The European *acquis* compliance implied a trade-off between price liberalisation and cost reflective tariffs, and socially acceptable level of energy prices. In the same time governments had to deal with local pollution due to inefficient coal usage in power and heat generation, and generally with weak

7 The energy chapter was only one among more than 30 in the pre-accession negotiations between the East-European countries and the EU; some compromises were made by East-European governments willing to integrate quickly with the Union. This was necessary as the energy chapter was open for the majority of East-European candidates in 1999 and closed before 2003.

management of energy companies. On an external level, they had to manage complicated relations with the former Russian ally (end of historical barter exchange, price rises and unilateral contract revisions by their major energy supplier) while at the same time attempt to interconnect gas networks on a regional basis. Several governments then chose to transfer these responsibilities totally or partly to market-experienced western utilities, which was seen as a move parallel to that of the future EU-integration.

In the mean-time, big West-European energy players had to prepare for the forthcoming opening to competition of their historic markets and face an inevitable fall of their historical market share. An opportunity to gain in size was presented by geographical expansion and vertical integration at a European level. The restructuring and the privatisation of East-European markets offered the needed opportunities to achieve this.

c. Impact on non-EU member countries

With the start of the liberalisation process in Europe, some external suppliers have progressively expressed their worries about the potential threats that this process could bring onto the long-term supply contracts existing with European countries, as well as on the investment prospects on supply infrastructure.

From 2000 on, Gazprom was a strong and vocal critic of the liberalisation directives as potentially leading to the destruction of long-term contracts in a context where Europe seemed to be favouring spot deals and shorter-term supply agreements. At the same time, the Competition Commission of the European Union was starting to question the restrictive "destination clauses" in long-term supply contracts between Gazprom and European utilities. Producers expressed concerns on the ability of the liberalisation process to ensure the financing of the supply projects needed to meet rising gas demand, especially when these would require long-term take-or-pay contracts to secure upstream investment. These concerns persist.

The Gas Exporting Countries Forum was founded in Tehran in 2001, concomitant with rising concerns about the outcome of the downstream market restructuring in Europe on producers' revenues. With Russia and Algeria, two of Europe's largest suppliers are member countries of this forum; Norway is an observer.

In 2002 Gazprom agreed to eventually drop territorial restrictions in supply contracts, although, producers were keen to find a new balance in the risk and profit sharing between the upstream and the downstream. At the same time, Russia started considering shifting to Asia for part of its future exports, although, apart from the shortly to commence Sakhalin LNG project, purchased from Shell, Mitsubishi & Mitsui, nothing material has emerged from this strategy. The transit diversification strategy (avoiding transit countries and multiplying transit routes to diminish the negotiation power of transit countries) gained momentum with the proposal for the North Transgas pipeline (now Nordstream).

With the acceleration of reforms and the second Gas Directive adopted in 2003, the Russian position toughened. The Russian president announced that Russia would resist "excessive liberalisation" especially of the Russian gas market and that the gas exports monopoly was a "red line" that the Russian government would not cross[8]. The hydrocarbon business is clearly important for Russia: in 2002, the oil and gas business accounted for half of government revenues and 55% of exports; in 2007, the overall share of oil and gas related revenues in the federal budget was still growing. Discussions on the Energy Charter Treaty and its Transit Protocol continue, but seem unlikely to be concluded successfully in the near term.

8 FT 16/10/2003, « Russia toughens stance on energy prices »

Box 4: The Energy Charter

In 1990, with the ending of the Cold War regime, the European Union proposed a charter aiming at energy market international rules harmonisation, especially between Western Europe and Eastern Europe and former Soviet republics. The treaty was developed to help the transition to market economies and democracy in the East, as well as to contribute to the stability of the energy trade with the West.

The treaty was signed in 1994 on the basis of this energy charter by the majority of these stakeholders (including all OECD Europe and EU countries).

The Energy Charter treaty is a multilateral agreement for cooperation in the energy market and improvement of energy trade and investment. The main principles of the treaty are equity, transparency, dialogue, and non-discrimination between signatory members. A major objective of the treaty is the guarantee of international energy transit, stating that transit costs should be fair and based on real transport expenditures, therefore suppressing potential "royalties" and transit rents. An eventual outcome of the treaty was a move towards the integration of east and west energy markets and greater security of energy supplies in the zone. With rising geopolitical concerns, supply tightening and high energy prices, energy transit remains an issue, and the main energy supplier in the region, Russia, has not yet ratified this treaty.

Algeria followed a similar line to Russia: in 2002, the Algerian president declared that the EU plans to liberalise its gas markets would undermine investment and that it was against the producers' interests, those plans being actually conceived without consulting them. The Algerian proposal at the time was based on profit-sharing agreements replacing the logic of destination clauses. In 2003 Sonatrach agreed to end the destination clauses, and like Gazprom, proposed to replace those with fixed delivery point, to ensure visibility for the producers on the added value of the gas sales in the European market.

These critical arguments were developed and underlined over the following years, with Russia and Algeria both opposing the effects judged as negative on their long-term revenue guarantees, and turning to new markets to reduce the interdependence with the European markets by stressing LNG development or new supply routes to other gas consuming regions.

It remains to be seen whether in fact the effect of "liberalisation" in Europe will be actually positive or negative for producers. Certainly the early signs are that they have achieved unprecedented access to internal EU market, and at record prices.

Chapter II – The Present. Tensions in a hybrid market

I. The managed markets – Growing uncertainties and slowing investments

As noted in chapter I, the old industrial model is struggling to deliver adequate investment and security of supply, while a new industrial model is not yet clearly established. The present hybrid model, combining legacies of the managed markets with new market mechanisms, is not sustainable. There is need to complete market reforms to stimulate a new round of much needed investment, as well as measures to deliver policy objectives, such as enhanced security of supply.

A. Current issues in European gas markets – Investment and security

1. Old industrial model unsuitable for new industry challenges

The transmission of gas from the production site to the border of the European market, comprising pipelines outside the EU, can be viewed as specific investment because no alternative uses are possible than the ones designed initially. In Europe, the gas networks inherited at the start of liberalisation were not designed to be contestable. Even without the effects of national monopoly exporters, investment specificity alone tends to restrict the potential contestability of a given market area as it is supplied by limited number of production sites through a limited number of transport infrastructures. It is worth noting that for electricity this constraint is minor.

In the "old" industrial model, the downstream market areas and the transmission pipelines were developed and operated under legal or *de facto* monopolies with a reserved market base, as discussed in chapter I. As gas networks matured, the classical vision of the "natural monopoly", which was granted to almost the whole industry, was narrowed.

In modern industrial economics, only the infrastructure part of network industries is viewed as natural monopoly, the services (gas sales) being potentially subject to competition. Third party access to pipelines and the unbundling of sales and infrastructure activities were derived from this new vision. Opening to competition was thus possible as third party access to essential facilities gave the final consumer the choice of supplier.

A major problem with investment in the European gas industry is that the majority of companies used to operate on the principal of geographic concession (often, but not always, a country). The industry delivered on the following model: within that exclusive geographic area, a company can market a volume of gas (generally at oil-based substitution value prices) secured by long-term contracts. Given the security of the customer base, the importer can make long-term investments in import pipelines, at low risk, knowing that it can get its money back over a period of the import contract because there is no threat to its customer base. In some countries there are checks and balances to ensure that this arrangement does not cost the consumer too much – for example in France, where Gaz de France's remuneration is regulated by the government partly using the total cost of supplies. However, in other countries, such as Germany, no such regulation by the government is in place.

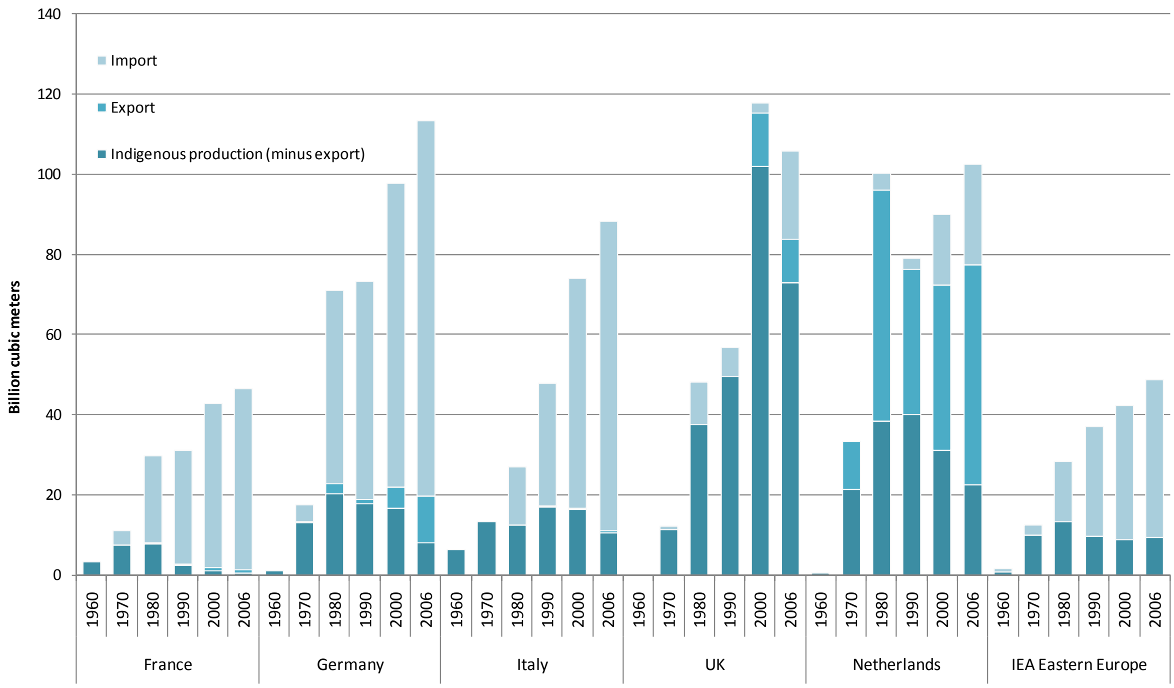
It is clear that this investment methodology had to change in a competitive environment – competition is diametrically opposed to concession. Downstream energy companies have therefore been forced to take defensive steps and have tried to resist change. From the perspective of some downstream stakeholders (companies, governments, customers), this is understandable – their relatively low risk business, was often linked to public service activities, and used to bring high security to the market at a cost. The opening to competition imbalanced the system, bringing regulatory restructuring and uncertainty downstream, while geopolitical and economic upstream risks were growing.

Competition was thus viewed as a threat to companies and to the sustainable growth of the business on the long term. The incumbent companies were armed with a variety of weapons to prevent such competition, from restricting infrastructure access, to splitting the market, designing punitive balancing regimes etc. Despite this, many companies also took competition also as an opportunity and started considering their development strategy no longer on a purely national but on a European level, and tried to limit the potential loss of historical market share in their original markets. Where markets have been more successfully liberalised, downward pressure on gas prices has occurred, resulting in quite low prices when gas supplies are abundant. Asset utilisation and optimisation has improved, especially where independent system operators have been established.

Overall, however, continental Europe has remained a set of national gas markets, rather than a single market, and is still dominated by incumbents. The growing mood of resource nationalism upstream did little to diminish the difficulties of establishing a competitive market downstream, creating a vicious circle reinforced by unprecedented energy price inflation on global scale.

While demand continues to grow, domestic supply has stagnated and Europe is on course to increase its import dependency. A huge amount of upstream and infrastructure investment is needed to respond to this import challenge. Gas imports will increasingly come from LNG, priced on a global market basis, influenced by North American and Asian import prices, and hence the circumstances in those markets. New large-scale import pipelines will be needed, crossing multiple national frontiers within and outside Europe. But the present industrial and regulatory conditions are struggling to deliver this. Europe is therefore under increasing risk of underinvestment, which could lead to supply and market consequences if not addressed.

Fig.9: Overview of import dependency

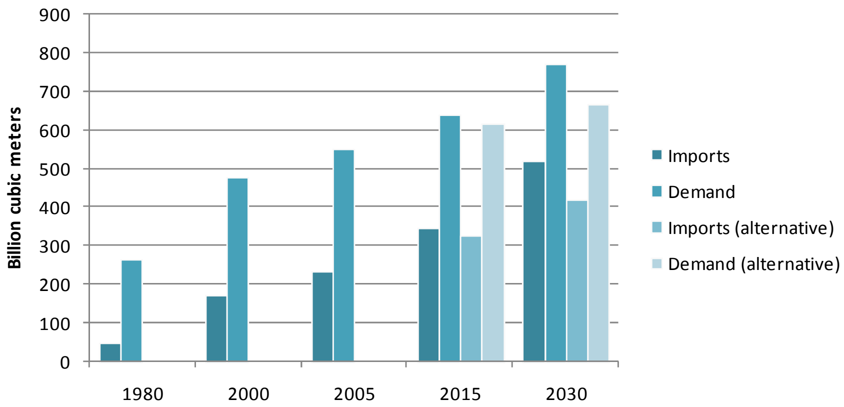


Source: IEA

New factors will impact the European markets in the near future. Firstly, there is a growing vulnerability coming from the increased usage of gas to power where oil pricing is either inappropriate or irrelevant. Moreover, a strong winter-summer differential without sufficient coverage in terms of flexibility emerges. In addition, the threat of external disruptions like those that happened in the US (natural disasters, terrorist threats, financial market tensions, Enron bankruptcy for example) as well as global warming and heat waves in Europe (in 2003) simply are not addressed by current gas market arrangements, notably oil-based pricing. All those elements are likely to impact the markets at least as extensively as the generally considered security threats which are traditionally linked to geopolitical and regulatory uncertainty. In short, the European gas markets are becoming more dynamic, and more exposed to risk factors, including those of global gas markets.

Given this market context, it is perhaps surprising to see that new investment has been lagging. On pipe-to-pipe competition, the 1998 Directive's provision of freedom to build and operate gas facilities has not seen a rise in new entrants contesting others' markets by building competitive infrastructure downstream. New pipeline construction has been confined to the historical TSOs. New entries were made by actually buying out the historical player, including its transport facilities, except in the specific case of the LNG terminals which represent a relatively low barrier to entry in the gas and electricity markets (where regulatory approval can be obtained readily).

Fig.10: Gas demand and import dependency projections (reference and alternative) for OECD Europe to 2030



Source: IEA World Energy Outlook 2007

In Eastern Europe, there is a continuing inability to create diversification in sources of supply, or to build new import corridors, due to the proximity to Russia and the existing transit pipelines. The global issue of the impact of the enlargement to the East, apart from creating opportunities for market growth to already market-experienced western incumbents, consisted in the inability of the former communist countries to create functioning markets. This problem was based on the historical lack of market mechanisms in the energy business – in most countries during the 1990s energy imports were still dealt with at state level – and before 1989 there was no market at all as most of the economy was centrally planned and administered by the state. Moreover, gas import dependency often reaching 100% with a single supplier (Russia) impeded further potential gas-to-gas competition that was expected to happen with the introduction of the liberalisation *acquis* of the European Union's jurisdiction in their national laws. In comparison, West-European markets were already supplied by several producers, and their national economies were based historically on market principles.

2. Investment mechanisms that delivered in the managed markets

It is interesting to analyse the drivers for investment in managed and competitive markets to try to understand some differences in the incentives and therefore the nature of the investment decisions made.

As already noted, large national or regional gas incumbents, who existed in all European gas markets, were each established with similar goals in mind – to develop the gas business as a monopoly within a geographic area. A business case for midstream and downstream infrastructure investment had to convince the producer that such investment was necessary in order to market his gas to the largest possible number of clients, and hence maximise revenue from future gas production. The downstream monopoly in turn saw the need to ensure a certain level of security in its supply pattern (whether through diversity, investment or strengthened relationships with the producers).

Within managed markets, the mechanism of gas pricing (linked to inter-fuel substitution value, often oil products) was intended to maximise the revenue from the sale of gas at the burner tip. The risks of the value chain were shared between the downstream sales entities and the upstream production entities (foreign or otherwise). The downstream entity was responsible for a large part of the volume risk (essentially sales/market making and infrastructure investment) while the upstream entity was responsible for the price risk. In both cases, risk was mitigated by direct links to oil price. Such arrangements were backed by the creditworthiness of downstream companies who underwrote the large long-term capital commitments required to deliver gas to West-European markets.

Having a secure market to penetrate without worrying about the threat of competition allowed each of these monopolies to plan investment in what it understood to be the best interests of the consumer, whether as an individual or as a region. In such an environment, the downstream companies had incentives to satisfy all potential gas demand and invest in the necessary infrastructure given that each investment decision was relatively low risk[9]. Nevertheless, the long-term contract negotiations with the producers acted as a brake on overspending in the downstream, as these negotiations specified the allowable costs of marketing (including investment) in whatever form.

Hence the level of investment along each gas supply chain tended to take into account the nature of each specific supply field and each demand region. If demand for flexibility services was projected to increase, the companies along the value chain could jointly work out the cheapest way to satisfy that demand. In this case, a producer with a more flexible production profile would be less inclined to want to cover the cost of downstream investment in gas storage, while a producer with flatter production might be prepared to pay for storage. Whatever solution was decided upon was then formalised in long-term contracts, which were offered as collateral to banks in order to make investments.

As the downstream markets diversified their sources of supply and grew a portfolio of assets, so the downstream companies were better able to negotiate with the upstream – they alone had knowledge of the demand profile and potential in their region, and therefore the cost (and value) of infrastructure built there.

3. What are the barriers to new investment?

Currently, there is substantial lack of investments accumulating in European markets. This comes at a time when some investment fundamentals are positive: demand is rising while supply is tightening with domestic supply falling, so there is a clear need for import infrastructure, storage and new gas for Europe. However, new concerns such as resource nationalism, local opposition to new energy installations, and/or slow or complex planning and approval procedures, loosely called "NIMBY" ("not in my backyard"), may impede further potential investment in the market.

Fig.11: Investment projections to 2030 (OECD Europe)

Reference Scenario WEO 2007						
OECD Europe	**Cumulative**			**Notional Yearly Average**		
Billion $ 2005	**2006-2015**	**2016-2030**	**2006-2030**	**2006-2015**	**2015-2030**	**2006-2030**
Exploration & Development	120.6	110.3	**230.9**	12.1	7.4	**9.2**
LNG	21.2	13.5	**34.8**	2.1	0.9	**1.4**
T&D	24.0	24.9	**48.9**	2.4	1.7	**2.0**

Source: IEA World Energy Outlook 2007

9 Being guaranteed by the customer, or in some cases the government, and paid for by the producer who had to accept a certain "cost of sales".

On the upstream side, the increasing European demand should be an incentive to invest in additional production and supply infrastructure. Nevertheless, there have been rising concerns over the existing investment level in the producing countries. Moreover, the major upstream producers have focused on the shifting regulatory environment, in particular the perceived threat to long-term contracts, as a major risk to their business.

Box 5: The upstream position – the example of Russia

The present position of a major upstream player in European gas towards the proposals of the third package provides some insights into the strategic positioning of external stakeholders in the future EU gas markets organisation but also highlights some major issues still unresolved in this reform. Here is a brief view on the Russian vision on the current reforms.

The third package has on one hand positive aspects for the Russian position: it gives Gazprom the possibility of bypassing its present competitors and accessing the whole EU gas market through a transparent and non-discriminatory access to all pipelines, as stated by Commissioner Piebalgs in a meeting in October 2007 in Russia. There has never been an attempt to limit the expansion of Russian companies in Europe. Given the fact that Gazprom doesn't own a majority in any existing infrastructure in Europe, the ownership unbundling shouldn't be a concern for Russia (at least not a major one, as existing shares in pipelines like Yamal or Wingas are all subject to potential negotiation). Moreover, TSOs willing to maximize the volume of flows through their pipelines should facilitate Russian supplies. Thus, Gazprom could flow gas from Siberia to Spain – while today it cannot. Concerning new infrastructure, it is possible for the investor to control the pipeline for many years (unbundling exemption clauses) – therefore there is no immediate impact on Nordstream.[10]

The response of the minister for energy in Russia (in October 2007, V.Khristenko) was that considering the gas and the electricity market on the same level was not appropriate. The major trans-national infrastructure projects should, in his view, be excluded from the current third package proposals which may bring heavy risks to the gas industry.[11] If European plans may be viewed as not directly impacting Gazprom's present position in the European markets, they go however against its strategy to become a major vertically integrated energy player in Europe. The EU reform plans are considered by some Russian analysts as a "vertically integrated murder"[12] especially for Gazprom's main clients and potential competitors (E.ON, Gaz de France, Eni…).

If the EU Commission has tried to persuade Russia of the benefits of splitting the supply and the transport business, and even state that it is in Russia's interests to ratify the Energy Charter treaty, the Russian authorities have made clear to the EU that if any of the new proposals are perceived as a threat to Russia, this could lead to a risk for the global supply security of the European gas markets. Russia, supplying a quarter of total European gas consumption, is interested in being deeply involved in the discussions over the third package, while up to now the Russians claim to have learned about the third package proposals in the press. This could have been interpreted as a clear sign of the European will to bar Gazprom's further expansion on the EU markets. However, the EU Commission has underlined the positive aspects of weakening Gazprom's main competitors and former allies on the European markets, as being one major change that the third package of reforms represents to the Russian energy interests.

Midstreamers are reluctant to invest in new pipelines or storage capacity without long-term guarantees, given the threat to their future market size. Cross-border investment is further threatened by insufficient regulatory harmonisation and lack of regulatory responsibility for such international projects.

The absence of a European market means that storage, flexibility and consumer protection is handled either on national or on company level. Each country has its own criteria and requirements concerning flexibility and public service. TSOs generally have responsibility for networks in their own sub-region or country, and not for optimising networks on a larger regional or Europe-wide basis. Therefore, the market remains fragmented and the majority of investment takes place within national borders.

The global overview of the European market is that of a patchwork of national or sub-national TSOs with their own regulations, responsible for their respective territories. In terms of investment, some

10 A.Piebalgs cited by Kommersant, 24/10/2007
11 Idem
12 Gazeta, 24/10/2007

regulators performed better than others. In the absence of sufficient European-level guidelines on regulation or investment, there is no sharing of best practices and it is left to individual regulators to implement home-grown models.

Furthermore, little attention is given to the idea of minimum essential infrastructure requirements before a market can physically operate. Many EU countries do not have interconnected networks to their neighbours, but are still required to implement a market structure based on multiple suppliers and multiple customers. Particularly in Eastern Europe, this is a significant problem to the development of a competitive market. Regarding Europe as a whole, clearly this problem must be solved through much greater interconnection capacity before a single European internal market can be realised.

It is generally recognised that a degree of multiple source capacity and even overcapacity are preferable in gas networks in order to guard against unforeseen or low probability events. Overcapacities are a means to provide physical insurance for the gas market, whether in the form of larger pipelines than absolutely necessary, additional storage capacities, or multiple supply routes or LNG terminals. In the old industrial model, investment in overcapacity was mandated and justified on public service and national security criteria, and not solely on financial grounds. In a competitive market environment, these factors need to be priced, included in the market design or internalised in the regulatory framework, so that there are financial incentives to deliver it. This is a matter for further general security of supply policies on national and European level.

Overcapacities do not only correspond to security of supply or European policy objectives – they help also increase the flexibility and resilience of a given network and increase the number of potential supply routes, thus increasing competition in the market. In order for a competitive market to deliver these overcapacities, their benefits must be internalised and priced. A properly functioning market can be a powerful tool for delivering objectives such as greater diversity, storage or even supply security at least cost.

B. Transition towards traded markets in Europe

1. Oil indexation vs. hub pricing

Historically, gas in Europe has been sold indexed to the price of certain alternative fuels. Such a pricing mechanism is markedly different from the one found in traded gas markets, where price is determined solely by gas demand and supply at market areas or "hubs". This has led some to pose the natural question of whether oil indexed and hub-priced contracts can co-exist. The simple answer to this question is that they already do. This is easily observed in the United Kingdom, where the majority of gas is sold at the NBP price (around 60%), but a substantial minority of oil indexation nevertheless still exists, originating from old long-term contracts that are yet to expire. On the continent the case is different in that oil indexed contracts still dominate, with hardly any hub-priced long-term contracts having been signed. However, a number of short or medium contracts do exist which are either fully or partially hub-priced.

Where gas priced markets co-exist with long-term fuel substitute contracts, there will be a competition between the two contracted sources of gas. If long-term oil-based contract prices are higher than the gas hub prices, than it is likely that customers will buy at the hub and try to minimise purchases at the contract price. This will drive hub prices up to contract prices. If there is a well functioning, deep and liquid hub, then it is possible the hub price will influence the long-term contract price.

In the case of the United Kingdom, in a cold winter, we see the interaction of large long-term contracts with a hub-based market in a supply constrained environment. In this case, the long-term contract price is likely to be a floor price to the hub with players looking to buy additional gas in the traded market, driving prices up. Conversely, in an oversupplied market, such as winter 2006/2007 in the United Kingdom, long-term contract holders look for an outlet for take-or-pay volumes and sell on the hub, driving prices down; in this case the long-term contract price is likely to be a cap for the hub price. The continental markets are mainly supplied on long-term take-or-pay basis, while the United Kingdom represents a liquid hub. Therefore, the British hub is likely to experience increased volatility because of this interaction, a trend observable over the year 2007. Such relativity can also drive storage investment, which can act as a countervailing trend.

Even in the cases where short- to medium-term contracts are indexed to oil, these will be influenced by the level of the hub-based forward markets. The logic being that even though oil products might sometimes be a good alternative to gas, if gas can be bought at a hub this will naturally be a perfect substitute. It can therefore be seen that suppliers will adjust the price level of their oil indexed short- to medium-term contracts, so as to be consistent with the forward markets at the hubs, as this is the customers best sourcing alternative. If such an adjustment to the price of the long-term contracts is not undertaken regularly, suppliers will achieve less profit as the customer will only choose the oil formula when this is beneath the forward hub price. However, the reverse is also true leading customers to simply source their gas from the hubs either directly or through intermediaries when it is lower than the contract price.

This same logic dictates that with time even the longer-term contracts in Europe will be affected by the existence of the traded markets, as the price level of these will have to be inline with the expectations of the level of future spot prices at the hubs. The mechanism by which the two markets affect each other should not be new to the markets, as it is in fact quite similar to the reasoning behind the traditional oil indexed contracts, namely that for customers to have the incentive to use gas this cannot be priced above the price of alternative commodities (oil products), or – in the case of hub versus oil indexation – above the price of sourcing the gas at an alternative market place (the hub).

From the perspective of a producer, who is supplying to the wholesale market, on a traditional oil-indexed contract, the situation is different. The industry has long argued that the long-term gas will be priced by inter-fuel competition. If this is a fact, then a supplier should be indifferent as to whether he prices his gas at a hub or at an alternative fuel. Furthermore, there could be additional benefits to the producers of supplying at a hub namely to avoid the opportunity cost described in the previous paragraph, in the short term. However, the lack of liquid hubs in continental Europe currently discourages producers from selling at that price. Moreover, the industry has operated on oil-based prices for more than thirty years and views such a major change in business practice as a huge risk to its business sustainability. Finally, in the current environment, oil prices are at record heights. This removes the incentive to the producer to try a different pricing system.

2. Sharing flexibility down the value chain

Traditionally a large share of European supply contracts have contained a substantial amount of flexibility allowing the buyer a certain variation in his daily, monthly and yearly take. Suppliers have therefore been able to pay for the physical flexibility provided by the producer’s infrastructure. OECD Europe has import capacity of roughly 50% more than its yearly consumption.

This flexibility is of considerable value in allowing suppliers to respond to variations in demand, or even shortfalls from another supplier (e.g. Russia supplying extra gas to Turkey in 2008 when Iran was unable to meet export obligations), or allowing producers to optimise transit routes. But as European gas production declines, this flexibility will increasingly come from outside the EU.

As traded markets are being introduced, the value of this flexibility becomes much clearer, the reason being that flexibility can also be monetised by bringing it to a hub where all users and suppliers can bid for it. It is important to realise that the change to a hub-based market involves a large portfolio benefit; instead of every customer contracting for his worst case flexibility needs. Now all customers can rely on one source of flexibility, potentially quite cheaply, but also possibly at times at a very high cost.

Most long-term import contracts contain an element of flexibility which has historically been difficult to price. A move towards hub-based prices thus means that unless flexibility is priced differently in existing contracts, wholesalers will make a profit by arbitraging between the production contracts and the hubs. This can be done by several methods, either by reselling the flexibility to other suppliers in the form of traditional gas contracts or swaps, by offering virtual storage services, or finally by managing the flexibility directly in the market. The simplest strategy when optimising flexible contracts directly in the market will be to each day compare the contract prices with the expectations of future spot prices. On the basis of this price comparison, the customers should either maximise or minimise their daily purchase on the contract and sell or buy the difference from the market. From the perspective of the flexible producer, the easiest way to avoid this is to sell on a hub-based price. Often however traders will use more refined methods, when optimising, in order to obtain a certain risk profile, mitigate liquidity concerns, or take advantage of changes in market volatility.

Because all market participants will be able to see the market value of flexibility, they will be able to resell any under-priced flexibility in their long-term contracts. This marks quite a change from the old world in which consumers had no way of selling that flexibility, because they had no access to a market place. Depending on the amount of flexibility that the producers have available, such a full scale optimisation can require daily trading of potentially rather large volumes. In order for this process to happen, the market must be sufficiently mature to be able to absorb the volumes. Currently only the combined market areas spanning north-western Europe (United Kingdom, Belgium, and the Netherlands) are sufficiently developed to allow flexibility trading.

Many historical long-term contracts have flexibility clauses. However, valuing flexibility in the gas markets is notoriously difficult, and underinvestment in this area, such as storage, is inevitable in these circumstances. In the near future, producers may become more reluctant to sign new long-term contracts including large amounts of flexibility, preferring to use the traded markets. An important question arises therefore as to the future distribution of value in the gas chain. The control of flexibility is likely to move upstream from a situation where such flexibility used to be shared through these long-term contracts. Therefore, midstreamers would need to invest in storage and other flexibility instruments, and promoting and using hubs, in order to balance demand profile. In a perfect market, the cost of acquiring storage capacity would be identical to the cost of acquiring the same flexibility at a hub. In the European market, it is likely therefore that the role of hubs in providing flexibility services will increase, but utility companies will be needed to provide flexibility for small industrial and domestic users and to manage their demand profile.

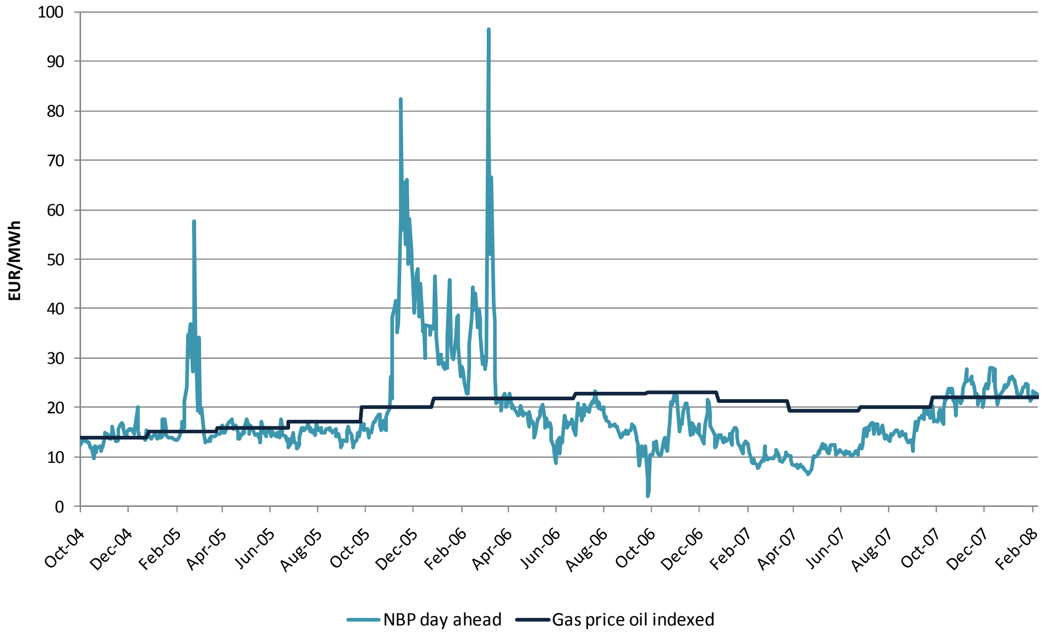
3. Increased volatility?

An argument often heard against supplying gas at the supply/demand determined prices of the traded markets, as opposed to oil indexed contracts, is that hub prices exhibit greater volatility. The implication being that this will be to the disadvantage for the “ordinary” customer as it greatly increases the uncertainty of his gas bill. Figure 12 shows a standard oil indexed contract where price changes four times a year against a gas hub price which changes every day. It is understandable why this argument is raised.

At a first glance it might look as if a customer with a gas contract linked to the daily spot price would indeed be facing much greater uncertainty as to his yearly gas bill than a customer having a traditional oil indexed contract. This however is not necessarily the case because the price that the customer with a hub contract faces can be the average of the spot price over the entire period of his contract.

The relationship between the customer and the spot price in a competitive market is not dissimilar to the relationship between the customer and the spot oil price under the traditional price formula. So if we instead take a historical look at how a given gas customer’s annual bill would have been had he signed up on a given date for a one year contract indexed to the NBP Day-ahead, compared to a traditional oil indexed contract, the picture changes somewhat. While it is not possible using only historical data to deduce anything about how volatility in the future will differ between markets, figure 13 gives an indication that historically the order of magnitude of volatility between the two types of contracts does not differ substantially. In both situations, if there is a physical shortage of gas, this has negative consequences for the consumer – either in the form of high prices or physical interruptions.

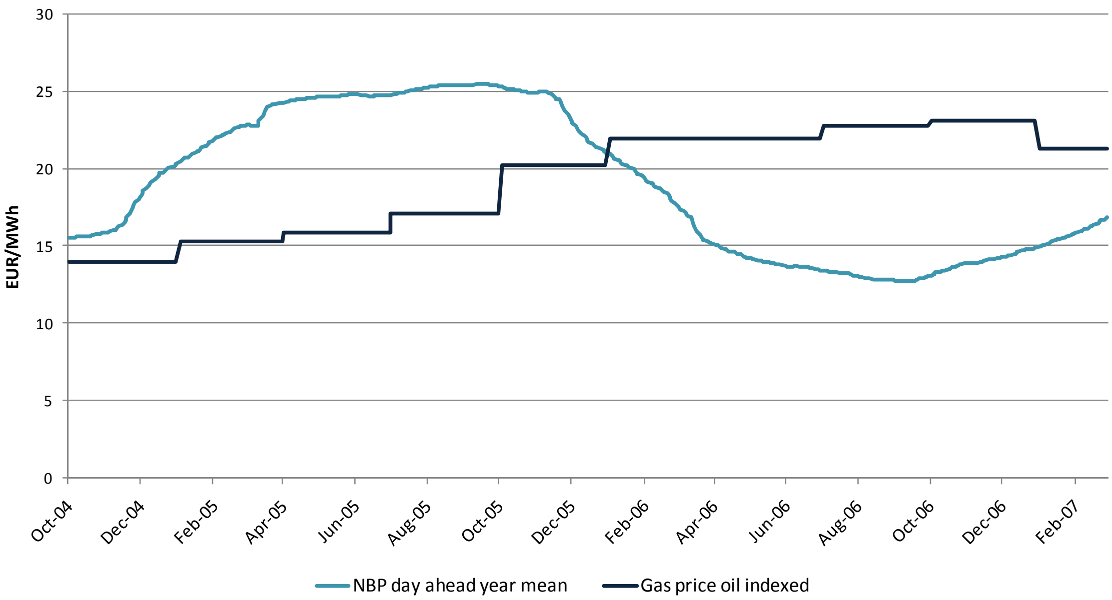
Fig.12: Oil indexed price vs. NBP Day-ahead



Source: Heren, industry sources

In fact, many consumer goods are priced on a daily basis and are therefore volatile (grain, steel, gold, money…). However, end-user customers hardly notice. In fact, on a wholesale basis, the most volatile of these commodities is electricity, because it cannot be stored and is expensive to produce, but most customers are billed monthly, quarterly or yearly on the basis of average prices, and hence only observe moderate changes.

Fig.13: Oil indexed price vs. yearly averaged NBP Day-ahead price



Source: Heren, industry sources

Furthermore, certain customers are able to profit from volatility by varying their demand with the price level. These price-elastic customers reduce the volatility of prices and therefore increase the flexibility and security of the system as well. A risk of this daily balanced market is the question as to who is responsible for long-term security. Both short-term and long-term security measures are necessary for a well functioning spot market. The real challenge is therefore to design a market that puts a proper value to security. For example, recent changes to US electricity markets embodied in the Energy Policy Act 2005 recognise this issue by providing legally enforceable reliability standards.

4. Development of derivatives markets

At a certain level of maturity, more complex "derivatives" markets emerge. These are financial products based on an underlying asset price which is the price of gas at a hub. This level of maturity can only be achieved once counterparties are confident that the hub price represents the true value of gas, then they will base futures pricing and options pricing on the spot market. These derivatives markets are then used by various companies. An example of the use of derivatives by a company supplying gas to end consumers might be that it sells gas to these consumers at a fixed price on one-year contract and then buys the gas back in the futures market. This is an example of "hedging", or mitigating price risk by purchasing derivatives (in this example the company is said to be "short" of physical gas and "long" on derivatives). In general, the derivatives markets are used to modify the risk profile of a company given its physical assets.

The risk profile that a given company will aim for, and thereby the share of exposure it would like to hedge, differs between different segments of the industry, and amongst individual businesses. Traditional producers, most noticeably pure E&P companies, have historically had little desire to hedge very much of their market risk, and if so, seldom more than a couple of years ahead. Utilities, on the other hand, will often want to have stable cash flows due to their very different capital structure, which explains why they have traditionally been the most active users of hedging instruments, compared to their share of market exposure. However, in the past, gas consumers (barring power producers and a few others) have been somewhat reluctant to hedge large parts of their exposure to energy commodities, often because their competitors do not hedge. As the hedging needs from producers, utilities and customers do not necessarily complement each other perfectly; banks and other investment entities play an important role in satisfying market needs for derivatives, by taking risk onto their books, naturally in expectation of a profit.

It is observed that the cost of using derivatives products on an immature hub is higher than the cost of using such derivatives in a mature market. European gas companies currently have exposure to the oil markets, through oil-linked gas pricing which allows them to modify their risk profile through oil hedging: they do not need a mature gas market in order to hedge against a price rise as they can obtain this insurance through the oil market. As has been seen on the most active hubs TTF and NBP, forward products will naturally develop at gas hubs as companies' exposure shifts from oil to a higher share of spot gas. This will mean that the cost of hedging gas exposure will decrease over time. Banks and other financial intermediaries will play an important role on this development as they grow more comfortable with the supply and demand risks of the gas market.

It is however true that trading in oil products can be conducted further into the future, in some instances out to 10 years, but in general the market becomes very thin beyond 3 years into the future, as liquidity is reduced. On the NBP, liquidity can also be observed for a maximum of five years and this can be expected to extend into the future as the market develops further, although again forward liquidity declines quickly beyond two-three years even for the most liquid hubs.

II. Current status of the European gas trading hubs

A. Concept of a gas trading hub

A successful gas trading hub has two basic characteristics: first and foremost it must be possible to easily move gas into and out of the market, whether the market is defined as a single point or as a whole area (virtual hub); second, there must be a use for the gas, either through the existence of a significant customer base, or through the demand from other markets that can be reached from the traded hub.

An important requisite for a trading hub is the ability for market players to manage volume risk (swings in consumer or export demand, compared to production or import supply) at a competitive cost. For a gas marketer, volume risk can be mitigated either by the use of storage or by having a customer base of a size and mix that matches the supply characteristics; similarly, a gas consumer will manage his volume risk by purchasing flexibility services from his supplier, or by having access to storage himself. Most hubs in North America also have access to significant quantities of storage.

Another major element of trading hubs is the legal and financial framework of the marketplace. For existing markets a number of master trading agreements have developed, most noticeably the EFET (European Federation of Energy Traders) contract for physical gas trading, and various annexes to the ISDA (International Swaps and Derivatives Association) contract. These frameworks contain the basic legal text for most standard provisions, serving as a foundation on which contracts are negotiated. The negotiation of credit terms in particular is often very time-consuming, as different ownership structures require different solutions. One way of overcoming such barriers is, instead of trading bilaterally, to have all trading cleared by a central body, in which all parties have confidence. The principle behind such a cleared exchange is that all contractual obligations and claims are directed toward one single creditworthy company, thus paving the way for a setup in which only one contract needs to be signed with the exchange. Forwards and futures are essential risk management products within this framework.

If any trading company is asked if they are looking to go into a new untried market, the response will most likely be, yes if the liquidity is there. Liquidity can be a somewhat elusive concept, since it incorporates four distinct characteristics of a market namely: depth, breadth, immediacy, and resilience. Deep markets are ones in which large volumes can be bought or sold without moving the price excessively, and wide markets are ones in which a large number of different bids and offers are present in the market. Immediacy on the other hand relates to the ability to trade large volumes in a short period of time, and resilience to the ability of the market to recover towards its natural supply/demand equilibrium after having been exposed to a shock. Liquidity itself tends to develop as market players become more confident in the fairness of a market – and once liquidity increases it tends to form a virtuous circle.

We can thus summarise the minimum requirements for a successful new trading market as:

- Access to gas sources, and to customer base.
- Possibility of managing volume risk for all market participants at a competitive cost.
- Low barriers to entry for new players, known contractual setup and possible clearing services, with low transaction costs.
- Managing price risk, through the market (existence of a forward/futures market).
- Fairness and transparency, leading to confidence and liquidity.

B. Development and access conditions to the European gas hubs

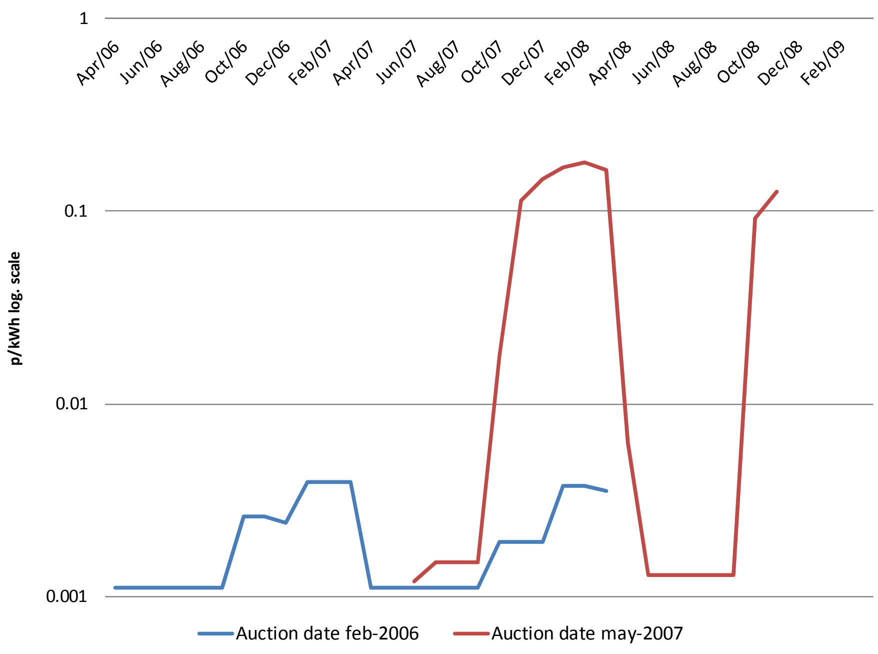
1. British hub

The gas transmission network in the United Kingdom is owned by National Grid Gas plc, the transport company separated from the British Gas monopoly in 1997. National Grid also owns four of the local distribution networks, while the other eight are owned by Scotia Gas Networks, Wales and West Utilities, and Northern Gas Networks. Capacity charges in the distribution networks are in general offered on a cost basis, but if capacity constraints are expected, auctions can be held. Most gas at the National Balancing Point (NBP), the virtual British gas hub, originates from the North Sea, from where it is brought in through one of five the entry points, also known as beach terminals: St. Fergus, Teeside, Easington, Theddlethorpe and Bacton. Capacities at entry/exit terminals are allocated in periodic auctions, where both long-term and short-term capacity is offered. Actors in the market are also free to trade capacity bilaterally in a secondary market outside of the primary market. This primary market is based on auctions and the fairest way of allocating scarce resource.

The capacity auction process has the added benefit, besides allowing equal access to the network for all, of providing strong price signals when capacity constraints are experienced by the market. Figure 14 shows the development in price for entry capacity at the Easington terminal: a steep price increase can be seen in some future winter months. This is a clear signal that the network has not been upgraded to cope with all of the newly added Norwegian production, some of which will have to go to the continent instead. This price signal, if strong enough, will naturally give incentives to start construction of expansion where necessary. Designing a system that allows fair entry, is however no guarantee for success, as shippers' ability to move through neighbouring systems, is just as important.

The majority of gas imports arriving from the Norwegian offshore pipelines are jointly owned by the oil and gas producing companies in the Norwegian sector through the company Gasled. The Norwegian state operates the network through the company Gassco which is committed to provide access to the system on an objective and transparent basis. This means that fair access is provided to the market participants from the production platforms in the North Sea right into the home of the local customer, something that undoubtedly has been an important factor in the development of the NBP into the most competitive and liquid market in Europe.

Fig.14: Entry capacity price at Easington



Source: National Grid

Gas can also be brought into the United Kingdom, at Bacton, from sources outside the North Sea, namely the Belgian market through the Interconnector pipeline coming from Zeebrugge, from LNG (Isle of Grain terminal), and from the Dutch market through the BBL (Balgzand-Bacton Line) pipeline. The Interconnector, which at present is owned by seven different gas suppliers, offers physical flow in both directions, so that gas can also be exported from the United Kingdom to Belgium. Some 15 shippers hold primary capacity in the pipeline that was sold on 20 year contracts (ending in 2018) at fixed capacity charges when construction on the pipeline started in the mid 1990's. The transfer to other parties of primary capacity, together with the related long-term obligations, is possible but a rather arduous process. The usual way for third parties to obtain capacity is through subletting it from primary capacity holders, who against a bilaterally negotiated fee will allow the access to the pipeline, while still retaining all obligations towards the pipeline owner Interconnector UK (IUK) Ltd.

When there is transport and entry capacity available, the price difference, or spread between prices on markets connected should be limited to the cost for transportation. Otherwise traders are able to arbitrage between the two markets and narrow the price differential. However, when there is congestion, price differences can be larger.

Because of the extended North Sea offshore pipeline network, many of the North Sea gas fields are connected both to the United Kingdom and continental Europe. This allows producers to flow the gas to the highest priced market, creating another link between the United Kingdom and continental Europe.

2. Belgian hub

The Zeebrugge hub is the main gas trading hub in Belgium, connected to the United Kingdom, to the Norwegian offshore fields and to the Belgian transit pipelines to France, Germany and the Netherlands, and receiving LNG. Getting capacity to move the gas east of Zeebrugge however is much more difficult, in that the major high-pressure pipeline systems running through Belgium to Germany, Netherlands and France are in practical terms unavailable to third party access due to their historic role as "transit" pipelines. Currently all capacity in these pipelines is reserved on long-term contracts, which makes more difficult the development of more competitive markets in the region. If the Zeebrugge hub is often referred to as the one of the most liquid continental hubs, it is counterbalanced with its inadequate market connection with the continent. In fact, the Zeebrugge hub price displays close historical price correlation with NBP, and is even priced in British units (pence per therm) rather than continental EUR per MWh.

There are three other major entry points in the Belgian network: Blaregnies (French border), Hilvarenbeek (Dutch border) and Aachen/Eynatten (German border). Each of them is connected to the main transit pipelines and to the distribution networks.

3. Dutch hub

Other markets than the NBP have also benefited from direct connectivity to the North Sea gas fields, most significantly the Dutch TTF (Title Transfer Facility) which is linked directly to onshore and offshore gas production pipelines at the Dutch shoreline from British, Danish, German and Dutch fields. In addition, large volumes can also be imported from Germany, where the Emden/Dornum area just across the border receives gas from three major North Sea pipelines.

A more direct link between the TTF and the NBP also exists through the Balgzand-Bacton Line (BBL), which has been flowing gas from the Netherlands to the United Kingdom since winter 2006. The pipeline has a capacity of 15 bcm per year of which 8 bcm per year is tied up in a long-term contract, under which GasTerra supplies Centrica in the United Kingdom. Currently the pipeline is not capable of physical reverse flow. However, gas can flow indirectly from the United Kingdom to TTF via Zeebrugge using the 6 bcm per year Zebra pipeline. The Zebra pipeline connects the Dutch-Belgium border point Zelzate to the Dutch high pressure grid and was created in 2001 by two Dutch utilities (Essent and Delta) to be able to import cheap gas from the United Kingdom.

In 2007 Gasunie, owner of the Dutch gas transportation grid, announced a takeover of the transportation division of BEB in Germany (see below). Gasunie expect this to boost liquidity on both BEB and TTF, although it will take some years to implement the changes.

4. German hubs

The German market is divided between several transport operators each developing different hubs. The BEB V.P in north-west Germany, for a long time the most developed, has an entry point in Emden and receives also gas through the Danish-German Deudan pipeline. It has undoubtedly benefited from being in the middle of transit gas flows, leading to relatively high natural liquidity, although fair access to the grid was also a key factor.

Regulators have taken a somewhat firmer stance against other German network owners where hubs had not developed sufficiently. Observers questioned the commitment of the big regional gas companies to making the hubs work – Germany has a similar sized gas market to the United Kingdom, but where the United Kingdom has one market area, Germany had 21 at the start of 2007. As a response to regulatory pressure, companies have volunteered to merge different parts of their networks into larger market areas to facilitate trading by third parties. But even though by October 2008 the number of market zones will be reduced to eight, the market remains very fragmented.

Of particular interest are the two market areas, each for a different gas quality, established by the largest gas supplier in Germany, E.ON Gastransport (E.ON GT). If fair and competitive physical access terms were to be provided, E.ON GT certainly has the potential to be the future price setter in the continental market because of its size and the variety of suppliers[13]. The market area extends from Emden/Bunde (where important North Sea pipelines makes landfall) eastwards to Frankfurt am Oder (where Russian gas is piped into Germany from Poland). If in the future the covered area is extended to the entry point of the planned Nordstream pipeline, the significance of E.ON GT to European gas markets will only increase. In the south, it brings gas from Russia at the Austrian and Czech borders and provides an export route to France, while the central area ties the north and south together and borders Belgium, and by extension, the United Kingdom.

The consolidation/merger of the 21 former market areas in Germany towards just one or two in the future would, if it could be made to occur, make a significant difference to gas trade in Europe. However, the availability of capacity in the transmission network to third parties needs addressing if the ambitions of establishing a truly competitive market are to materialise, otherwise the German market would still be effectively monopolised and dominated by a handful of companies operating in their own market areas.

5. French hubs

France currently has five market hubs, four belonging to GRTgaz (transportation subsidiary of Gaz de France) and one belonging to TIGF (transportation subsidiary of Total). GRTgaz will merge the three northern PEG (Point d'Echange de Gaz), named North H, West and East, into one hub by 2009. This will undoubtedly be an important step in increasing liquidity in this important part of Europe, as the proposed new market area has pipeline connections to Belgium, Germany and Switzerland as well as access to LNG imports at the terminal at Montoir de Bretagne near Nantes. The expansion of the LNG terminal at Montoir as well as the planned construction of new LNG terminals, at Antifer near Le Havre and Dunkerque will require extensive debottlenecking of the network if this import capacity is to be effectively utilised. GRTgaz therefore estimates investing EUR 3.7-5.7 billion over the next 10 years, in upgrading its network to be able to cope with greater demand and new import routes.

The southern part of GRTgaz's network covers the planned LNG terminal at Fos Cavaou near Marseille, the existing terminal at Fos Tonkin also near Marseille, and will be connected to both the

[13] For a total market of 90 bcm per year, Germany has access to Russian, Dutch, Danish and Norwegian gas, but also to local production covering 18% of total demand. E.ON GT area has access to all these sources.

northern hubs and the south-eastern area connecting the Spanish pipeline system with the French. Interconnection between the south-western area operated by TIGF, and the south-eastern, managed by GRTgaz, is however somewhat hampered by the pipeline systems not originally being designed to interact, making it difficult to move larger volumes of gas originating from the new planned terminal at Fos Cavaou, northwards in the system. Currently it is also only possible to flow gas in the southward direction through the Larrau pipeline between France and Spain, making it impossible to physically import gas from the extensive network of Spanish LNG terminals (capacity 58 bcm per year). For these reasons GRTgaz and TIGF, are looking at jointly upgrading the infrastructure of the two areas. If the planned projects are carried out they will considerably improve liquidity in the southern gas markets. GRTgaz is also looking at expanding export capacity to Italy, transiting Switzerland, by increasing exit capacity at Oltingue near Basel. It is however uncertain when this project, which requires the cooperation of Italian Eni CH, could realistically be completed.

The PEG connectivity with both north-west European pipeline gas and LNG terminals in France and Spain, makes the market areas interesting to a number of different players operating in European gas markets, whether it be companies looking to arbitrage LNG-pipeline differentials, source gas to other markets such as Italy, or explore opportunities presented by the French opening of the domestic gas market. It is therefore not surprising that GRTgaz has more than 30 different companies registered as shippers, even if still only a small handful of these are responsible for the vast majority of trading at the PEG.

6. Italian hub

Further east is another market into which gas flows from a large number of different sources, namely the Italian gas hub Punto Scambio Virtuale (PSV). To the north, Russian gas transiting Austria is imported, as well as gas coming from the North Sea flowing from France and Germany across Switzerland. In addition to this, gas is brought into the PSV from the LNG terminal at Panigaglia near Genoa, as well as further south by two pipelines originating in Algeria and Libya. Bringing gas into the PSV is however a major problem for new entrants, as virtually all pipeline capacity is booked on existing contracts with Italian incumbents who have shown a marked lack of enthusiasm to either expand capacity, or offer unused capacity to new entrants. Recent regulation requiring that 10% of imports be traded on the hub might improve liquidity and efficiency on PSV.

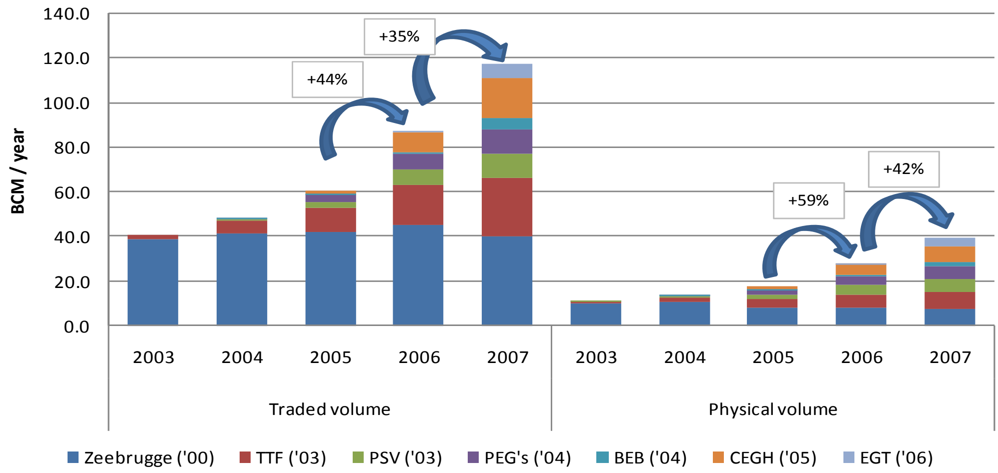
7. Austrian hubs

The Central European Gas Hub (CEGH) offers a title transfer facility at the location of the pipeline import interconnections at Baumgarten in Austria. This location is the confluence of the Brotherhood and Transgas pipeline systems that flow Russian gas to Europe.

A major difference between Europe’s other gas hubs and the CEGH is that all gas flowing into Baumgarten physically originates from Russia. Furthermore, thanks to its export monopoly, this gas all ultimately originates from one company: Gazprom. In January 2008, an agreement has been signed between OMV Gas International GmbH (originally owning 100% of CEGH) and Gazprom, giving the Russian company a 50% stake in the Austrian hub. Both shareholders stated the aim that CEGH will become one of continental Europe’s most liquid hubs. Although there is only one source of gas at the CEGH, there are many destinations, meaning that it has the potential to become a buyer’s hub. Gas can be moved away from Baumgarten by the TAG pipeline going to Italy and the WAG pipeline going to Germany. Due to the supply situation, most of the trading takes place around the flexibility of existing long-term contracts held by established European suppliers. Traditionally most of the volumes traded at the hub have been bought by players looking to flow gas to Italy.

While Baumgarten holds great importance as a transit point for large volumes of Russian gas, it is not at all clear if the ambitions of the CEGH of becoming one of the big liquid European hubs can be fulfilled in the absence of significant suppliers to the market other than Gazprom. Figure 15 shows the development of volumes transferred at the facility from the gas year 2005 until May 2007. While it appears that volumes have increased steadily over time some caution should be exercised when drawing conclusions from this data. Higher volumes traded in the summer could be due to optimisation of flexibility in the incumbents' contracts. A year on year increase in activity from 2005 to 2006 is likely due to unusually mild weather which caused unused flexibility in incumbents' contracts to come to the market.

Fig.15: Volumes traded at European hubs[14]



Source: based on TSOs published data

8. Russia's traded market

The majority of gas used by Russian industrial customers is bought from Gazprom at regulated tariffs, the exact price depends on which of the 13 price zones the customer is located. Regulated prices net of VAT for 2008 are expected to be around 35 euros per 1000m3 for residential users and 45 euros per 1000m3 for non-residential users. As these prices would be unsustainably low in an open market, gas is rationed by only allowing each customer to buy a certain volume. The principles that Gazprom uses to allocate extra quotas are rather opaque. If a customer has a need for more gas, traditionally he has two options, either to ask Gazprom to raise his quota, or, if pipeline capacity is available, to purchase the gas from some of the independent producers at non-regulated prices. The regulated price is the lower one and acts as a floor to the non-regulated price.

In November 2006, Gazprom through its 100% owned subsidiary Mezhregiongaz (MRG), introduced an additional way for industrials to purchase excess gas: via auctions. Initially monthly auctions were held for front-month deliveries, but later the schedule was expanded so now auctions are held every 10 days. For the first year a total of 10 bcm were planned to be auctioned off, with 5 bcm supplied by Gazprom and 5 bcm by independent producers out of total Russian 2006 gas demand of 453 bcm. After this it will be assessed whether the auctions are to continue and whether the yearly volume is to be increased. Customers can bid on gas delivered at three different compressor stations in western Siberia, namely Nadym, Yuzhno Balyksky, and Vyngapurovskoye, through the "Electronic Trading Exchange" (Elektronaya Turgovaya Ploshchadka – ETP). About one day before each auction MRG publishes how much spare capacity Gazprom has in its pipelines running from the three delivery points to the exit zones in which the customers are located. This capacity is then allocated together with the gas to the successful bidders. Since its inception prices at the exchange have been around 120%-140% of the regulated prices, making the state of under pricing clear.

[14] In case of PSV, CEGH and BEB only the physical volumes for only the last years were given, while for PEG's no physical volumes were given. The missing physical volumes had to be estimated. The physical volume (often also the physical throughput) is the amount of gas delivered through the hub at then end, while the traded volume is the amount of gas that has been traded. Because gas can be traded more often before finally delivered, the traded volume is higher than the physical volume. The churn ratio represents the amount of times gas is being traded before it is delivered. Therefore the traded volume divided by the physical volume equals the churn ratio.

Fig.16: Evolution between TTF and ETP month-ahead prices

Source: based on Heren and industry sources

Even though such a market consisting of weekly auctions completely dominated by one single player seems very far from the more liquid gas hubs of Western Europe in terms of market design, Gazprom's reasons for launching the ETP are relevant for these markets as well. First and foremost it is of importance to Gazprom that the current situation where gas is priced below the market is addressed, since both over- consumption and under-investment will result. This is consistent with the current policy of removing all price regulation for the industrial sector by 2011, thus bringing prices up, on a net back basis, to the level charged for exports to the rest of Europe. Such a move will also end the current situation where domestic demand cannot be met but has to be rationed, as well as increasing the general efficiency of the industrial sector by the abolition of artificially low prices.

Whether it will be possible to remove all subsidies within the relatively short time horizon without creating unacceptable disturbances to the local economy is another matter, but it is worth noticing that the "net-back" price is exclusive both of transport out of Russia, and crucially export duties (which are currently 30% of export revenue), so even when prices are fully liberalised within Russia, gas will still be markedly cheaper domestically compared to delivered export prices. Secondly Gazprom considers a market based price important in order to give signals so as to "more accurately identify industry's real gas needs[15]". This last argument is very similar to the idea that the existence of traded hub-based markets will provide price signals as to where and when production and infrastructure investments are most needed.

The future success of the ETP as a competitive market place for gas depends on whether more volumes will be committed to the exchange in the future, as well as on which terms the independent producers will be allowed to compete against Gazprom, notably concerning pipeline access. For the exchange determined price to be robust enough to be used as the benchmark for gas contracts within Russia, Gazprom estimates that 5% – 10%[16] (33 to 66 bcm per year) of the industry's output should be traded at the ETP.

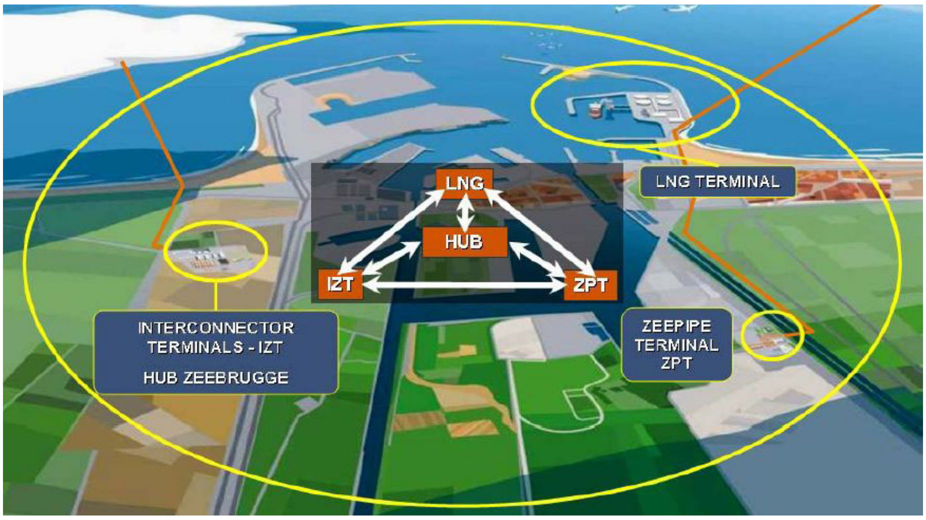
15 Source: http://eng.gazpromquestions.ru/index.php?id=19 (May 2008)
16 Idem

C. Other properties of European hubs

1. Geographical span and capacity constraints

Historically there have been two very different ways of defining the geographical span of a traded commodity market. One way is to assign delivery at a very specific physical point such as the nexus of two pipelines. This is seen in physical hubs such as Zeebrugge, which is defined as being the location within the Fluxys landing terminal of the Interconnector in Zeebrugge (IZT). While it may seem logical at first glance to limit delivery to a specific point, this will imply the necessity of having many such points within a given network. If gas trade within a region is conducted at many different geographical locations in the transportation system, then gas in fact ceases to be a fungible commodity (because the number of products that companies need to be able to trade is multiplied). The more the market is sub-divided, the more that liquidity is diluted, meaning that market zones become more susceptible to manipulation by key players at those points. In other words, defining a commodity market too narrowly reduces what is often seen as its prime benefit – a commodity should be a specific standardised product concentrating liquidity and leading to confidence in the validity of its price. Alternatively, if commodity prices are to mean anything in the real world, they must carry some locational information. Therefore, there is a balance to be made between defining a market so tightly that the locational information is perfect, but liquidity is low, and defining a market so loosely that liquidity is high, but the price gives less useful supply, demand and location signals. When the UK market was liberalised there was a debate as to whether trading should occur on beach terminals (physical points) or at a virtual point. In the end the advantages of having one single market outweighed those of "real" locations, and the NBP was created, the principal reason being to ensure liquidity.

Fig.17: Map of Zeebrugge area



Source: Fluxys

When looking at the Zeebrugge area map (figure 17), it should be obvious how some further aggregation of delivery points in the area was needed. In the limited geographical area around the Zeebrugge harbour, three different pipelines connect with the transmission system, one being the Interconnector at the IZT defining the actual hub, and the other two being the landing terminal of the Zeepipe pipeline (ZPT) and the LNG terminal, thus defining three unique but often highly correlated markets. This system means that if for instance an LNG cargo arriving at the terminal is to be flowed by pipeline to the United Kingdom, capacity has to be booked beforehand not only at the terminal and in the Interconnector, but also from the LNG terminal into the IZT. Huberator, the company running the hub (fully owned by the Belgian TSO Fluxys), has realised this difficulty and has therefore simplified this complex situation by creating the ZEE Platform Service, expanding the traded hub to the two other pipeline points. Under this new service agreement, shippers will have the right to unlimited transfer between all entry points (Interconnector terminal, Zeepipe terminal, LNG terminal and the Zeebrugge hub) without needing to book capacity separately, by paying a flat monthly membership fee plus a certain usage fee for volumes effectively transferred. From February 2008, Huberator offers such unlimited capacity transfers in the Zeebrugge area. Expectations are this will further increase liquidity. The demand and supply of capacity at the three specific points, being un-transparent to the market, will be replaced by a price signal representing the Zeebrugge hub as an entity and not by physical flows

The opposite method to determine where delivery is to take place is by legally defining a "virtual point", a non-physical point through which all gas in a particular transmission network must flow. This is the case for the British NBP that spans on the whole of the national transmission system. The NBP is the theoretical point through which the operator requires all producers to sell and all buyers to take delivery in the United Kingdom's network of transmission pipelines. The advantage of such system is that gas becomes a completely standardised commodity having a uniform price no matter where it is delivered within the domestic transmission system. An evident obstacle of this design is if a bottleneck emerges within the transmission system, this could have the potential to force the TSO to reduce capacity in the entire system, instead of only in a specific part of the pipelines. There are several indirect ways in which National Grid can manage such bottlenecks, including its own actions to buy capacity. It is also possible to scale up and down available capacity into the system from the different points receiving domestic production or imports, or into the twelve local distribution zones. National Grid can closely monitor the degree of congestion, optimise system operation, debottleneck with smarter investments, and invest to meet growing transport demand, thus overcoming some of the weaknesses of the "postage stamp" transport pricing system.

The geographical span of the Dutch TTF is designed similar to the NBP, being however more complex with 50 separate entry points into the system and 1100 exit points, compared to the NBP 8 entry and 14 exit points. Moreover, there is only limited access to quality conversion facilities, sub-dividing the Dutch gas market between the historically important Groningen gas and that from other sources. This means that the design of the Dutch gas market in reality is somewhere in between the virtual NBP and the physical Zeebrugge hub, with respect to standardisation and ease with which gas can be moved to different parts of the system.

When assessing capacity constraints in traded markets, two different aspects are equally important, one is capacity into and out of the geographical area that the market spans, the other is capacity from the traded market to local consumers, usually connected to the distribution network. Also it is not enough only to look at whether unused pipeline capacity is available, but just as much whether this spare capacity is offered equally to all market participants on a fair and competitive basis.

2. Balancing regimes

As actual physical gas supply and demand can vary more rapidly than the timeframe in which commercial action can be taken, all markets may experience imbalances. These can be caused by various factors, e.g. a rapid demand variation, a pipeline disruption, an upstream problem, or a downstream interruption. As imbalances are a normal feature of markets, it is necessary for network operators to have some flexibility to ensure that the pressure of the system they manage is kept within its physical constraints.

Any balancing action by the TSO incurs costs to the system; therefore it is better for the TSO to operate in an environment where all major market participants are actively incentivised, through the market design, to have balanced portfolios. In this way, it is only in a minimum of events that the TSO should step in and take balancing actions.

In Europe two different time frames, or balancing periods, exist for dividing the balancing responsibilities between the TSO and the other actors in the market. Most TSOs require daily balancing, meaning that the each shipper's flows into and out of the system must be balanced by the end of the gas day. Within each day, it is the responsibility of the TSO to balance the system. There are however a few countries, most notably Germany, the Netherlands, and Austria (for its domestic system), which require hourly balancing. The advantage of hourly balancing is that it makes those customers who have high intraday variability in their demand pay for it, instead of spreading the costs across the whole market[17]. But there are major drawbacks of having hourly balancing periods: firstly, that it further subdivides liquidity on the market by splitting the commodity in time rather than in geography; and secondly, that it requires the actors on the market to hold a substantial portfolio of hourly flexibility. For new entrants without a substantial supply portfolio, the only way to achieve this is through purchase of high deliverability storage in the market zone, which represents a significant barrier to entry.

As mentioned before, imbalances are a fact of life for the gas industry. Indeed, on a small scale, it will be impossible for physical actors in the market to be fully in balance all the time even if there are no unexpected events. Recognising this, TSOs in general allow shippers to be out of balance within some small technical tolerance, which usually is defined as some percentage deviation in total flows. These imbalance tolerances are charged for the hour (where hourly balancing applies), day and month. Most often there will also be limits not only on imbalances within the different time periods but also on the cumulative imbalances. In some cases the TSO offers to sell additional tolerance services to shippers, such as Energinet (the Danish TSO) does at its GTF (Gas Transfer Facility). Most commonly, however, requirements for additional services can be met by purchasing unused tolerance services from other shippers. In some instances imbalances can also be traded amongst shippers. For example, in Belgium, this can only be done in advance, whereas other TSOs, such as National Grid in the United Kingdom, allow system users to net off imbalances with other shippers retroactively.

Box 6: Cash-out balancing mechanism in the United Kingdom

National Grid is balancing the United Kingdom gas grid through the traded market. If a shipper at the end of the day has injected too much gas in an *over*-pressured system, he will be penalised by receiving a relatively low price for the extra gas (below the average of the within day deals on the market), giving the shipper an incentive to balance its portfolio. The same applies when at the end of the day a shipper has injected too little gas in an *under*-pressured system, he will have to pay a relatively high price (higher than the average of the trades) for his shortfall.

National Grid on the other hand rewards shippers that are 'helping' keep the system in balance. Shippers who at the end of the day, injected gas above their obligations in an *under*-pressured system are rewarded as are shippers who injected gas below their obligations in an *over*-pressured system. To ensure that shippers can respond to this incentive, National Grid posts the pressure of the system to all shippers very frequently throughout the day, allowing shippers to undertake balancing actions, in the hope of being cashed out at a higher price than the within-day price. This arrangement means that the shipper destabilising the system will lose money because of his imbalance, but that the loss will be proportional to the cost of rebalancing the system, while the shipper rectifying the system imbalance may earn money for his actions. When during the day the system becomes too much over- or under-pressured, National Grid also has the option to rectify imbalances by buying or selling on the electronic OCM market which is also open outside ordinary office hours.

The TSO can thus to some extent be seen as a form of market maker for within-day gas because it is acting in the balancing market at the end of the day to cash out shippers with imbalances, or during the day if the aggregate system imbalances become too important. This approach provides liquidity to the within-day market, and ensures shippers that in the event of unforeseen imbalances these can be rectified at near market prices.

3. Storage services

The most successful hubs offer a degree of flexibility services, most often in the form of gas storage. The hub operator can offer additional services like short-term parking and loaning of gas. The fundamental demand for storage in any gas system comes from the high variability in daily and seasonal demand for gas compared to the usually limited flexibility in gas production.

[17] Power generators benefit from this aggregation as they can quickly increase gas use to respond to peak power needs, while the whole gas market pays for their hourly demand variations.

The amount of available storage varies greatly from hub to hub in Europe, but as markets are increasingly interconnected, the amount of flexibility available at a current point is likely to be affected by nearby storage beyond the country or regional borders. One example of such inter-market exchanges of storage has traditionally been seen between the Dutch TTF and the German BEB V.P., where in summer gas has flowed from TTF into German storage to be withdrawn again in the winter. This has historically resulted in the BEB trading at a premium to the TTF in summer and at a discount in the winter. Another example is the interaction between the CEGH and PSV, where gas stemming from excess flexibility in Russian supply contracts going through Baumgarten, where there are large storage facilities, has been bought by Italian companies for use in the PSV market area. As the Italian use of gas for electricity generation increases, it can be expected that flexibility increasingly will be exchanged not only through physical gas flows, but also through the power lines. Gas and electricity sectors may provide flexibility for each other, with important implications, if there are mismatches between the ways in which the two markets work.

When an area with prices mostly based on the traded market, such as the United Kingdom, is interconnected with an area mainly priced on long-term oil contracts, such as continental Europe, this can have particular implications for the use of storage. In times of a gas shortage with supplies from long-term contract being insufficient, the continental utility has the choice to either get more supplies or to interrupt customers. Because of existing public service obligations utilities have a strong preference for increasing supply, even when it is highly priced. This can be seen from the winters of 2004-2005 and 2005-2006, when the NBP acted as a supply of last resource for continental utilities. The volumes being relatively small, the continental utilities have been able to add the high priced gas in their portfolio with a small overall price increase averaged over their supply portfolio. However, the action of these companies on a nearby hub can have quite a dramatic upward effect on price volatility.

The introduction of seasonality and short-term volatility into prices through trade at hubs gives a clear incentive to companies to develop storage facilities which allow delivery to and from the hubs. However, it is difficult to base business decisions on these prices if a lack of transparency makes it difficult to see the fundamentals behind them. In the case of the United Kingdom winter 2005-2006, the behaviour of continental utilities was not based on fundamentals that the market could assess, due to lack of transparency. Therefore, it would be particularly risky to build storage in the United Kingdom in anticipation of the event repeating itself.

Market players' access to storage services varies greatly from region to region, both in terms of transparency of rules and regulations, and in terms of the amount of uncommitted capacity available. Although the amount of storage is small relative to demand and in absolute terms, the United Kingdom has the most liquid market for storage services. A number of different gas storages exist, the biggest being the Rough storage owned and operated by Centrica Storage, which is under common ownership with Centrica Plc, and therefore subject to strict regulation. Under the terms of British regulations, Rough storage services are offered to the market both through periodic auctions and on the secondary market. Standardised storage packages, also known as "Standard Bundled Units" (SBUs) made up of injection and withdrawal capacity are traded freely amongst market participants. The number of users, who own capacity rights for the Rough storage (39 in 2006), is an approximate indication of its high level of accessibility for third parties to acquire flexibility at the NBP. This number is markedly higher than for access to storage in continental Europe, with the exception of Italy's Stogit. Stogit operates a storage volume nearly five times the size of Rough on behalf of similar number of users. In the market areas where only a handful of companies have access to a given storage, naturally a secondary market for storage services will be practically nonexistent. It is particularly important in the case where few companies own the majority of storage, that storage is accessible (perhaps as an entry/exit point) from the hub itself, in order to facilitate access for new players.

One significant problem for new entrants who try to gain access to flexibility in continental Europe is the lack of harmonisation and transparency of rules and regulations to which different storage operators are subject. This is particularly important in the case where storage is used across borders. Another prevalent problem is that companies in some markets are given incentives to hoard storage, in particular by the penalising balancing regimes described earlier. Hoarding of capacity is further exacerbated by the majority of storage capacity being booked by long-term contracts.

Proper congestion management can somewhat alleviate this problem by offering interruptible capacity, so that physical utilisation of the storage is maximised. In some markets the so called “rucksack principle”, well known from transport capacity allocations, has been utilised. A supply company who gains a new customer inherits storage services from the former supplier – the storage services are said to be carried with the customer like a rucksack. Such redistribution methods can be used to kick start competition in a largely closed market, but it should be realised that they are not market-based mechanisms. In a rucksack system, the amount of storage in the rucksack carried by each customer must be administratively managed.

In conclusion it seems clear that a significant problem with storage availability in Europe is that the majority of continental storage is reserved on long-term basis, exempted from third party access or unregulated. Whilst it is not a necessary condition for all storage to be regulated, it is clear that storage is essential for gas markets to function effectively. Those markets in which it is not necessary to regulate storage should be readily diagnosed by the variety of owners and operators and their fair and transparent sales methods. As the production flexibility declines with gas output, greater access to storage will become necessary. This change in production capability will make reform to storage markets even more urgent.

4. Preferred framework contracts / Master trading agreements

Commodities trading is characterised by many agents conducting a relatively large number of small block trades in standard products. Therefore a contractual framework suited for this purpose is needed in order to define the terms of the trade, and the nature of the standard product.

Where trading is conducted through an exchange, the exchange will most often require that all members sign up to a uniform contract drawn up specifically for that exchange. This is one of the main advantages of trading through an exchange, since it means a minimum of contract negotiation is required, and with a single counterparty only, namely the exchange. Having only the exchange as counterparty also greatly simplifies the task of managing credit exposure. This is because the products traded on most exchanges are futures, which are financially settled daily, as opposed to forward contracts where payments are conducted after delivery. With strict margin requirements, day to day changes in credit exposure are therefore limited. Furthermore the credit exposure that does remain will be with a single counterparty, namely the clearing house, which most often will be a top rated bank. Especially in the trade of contracts for delivery several months or years into the future, credit concerns are particularly important to address.

Most trading on gas hubs takes place OTC (over the counter), whereby two companies enter into contracts on the basis of a bilaterally negotiated framework. This means that framework contracts, also known as master trading agreements, have to be negotiated with all counterparties with whom a company wants to trade. As these contracts have to govern all legal aspects of gas trading (gas quality, payment terms, credit provisions, *force majeure* clauses, etc.) their negotiation can be a rather cumbersome process. A number of standard contracts exist, enabling trading arrangements to be drawn up from a menu of standard clauses. As companies are increasingly being active on more than one market, there is a gradual shift towards contracts that, by adding standardised appendices, can be used on multiple markets.

The standard contract of the International Swaps and Derivatives Association (ISDA) has been long favoured especially by banks and other financial institutions. The ISDA initially focused purely on financial derivatives now has appendices for physical gas trading at the NBP and ZBT, as well as for a number of other commodities on different markets. Since many established companies already have ISDAs in place with several banks for other purposes, when they enter into hub-based gas trading they can just add the relevant annex. When entering into master trading agreements with other energy companies, most will however prefer the standard contracts drawn up by the European Federation of Energy Traders (EFET). As the name suggests these are tailored specifically to the trading of energy commodities, primarily natural gas and electricity. As the EFET has published appendices for the most developed gas hubs in Europe (NBP, TTF, ZBT, PEG and PSV), these will suit the legal needs of most short-term trading between energy companies.

5. Trading platforms

A number of different trading platforms exist for the different gas hubs of Europe. These can be divided into exchanges and brokered markets or bilateral without a broker. As will be described in the following each method has its own characteristics and therefore own usage (see table 1).

All exchanges in Europe offer an electronic trading platform where traders can post bids and offers. For example, in the United Kingdom physical futures trading takes place for month ahead and forward on the Intercontinental Exchange (ICE), while within-day and day-ahead trading is conducted on the APX Gas UK (APX). A similar setup exists for the TTF where the ENDEX exchange offers curve trading, while day-ahead trading can be done at the APX Gas NL.

Most trading within the brokered market is conducted as OTC forward trading. Brokers offer electronic platforms similar to those of the exchanges, they also complement this with voice brokering (over a telephone line). One major difference between the exchanges and the brokered market is that at the exchange it is possible (in principal) to accept any deals, while in the brokered market, the only deals allowed are with a counterparty with whom a master trading agreement exists. This means that the situation can arise where a company cannot trade at the best price in the brokered market, simply because it does not have a contract with the counterparty. As it is in the interest of all market participants to have as much liquidity (and speed and low transaction costs) as possible, in the most liquid markets (NBP, TTF and ZBT) it is possible to get some other party to "sleeve" the deal. This means that a third party, with which both companies have a master trading agreement, acts as middleman. This is done on an entirely voluntary basis, and has the potential to increase the credit exposure of the third party. Another possibility is to "give up" the trade to an exchange if one offering this service is active at the current market. The disadvantage of this approach is however that the transaction cost of conducting the trade increases, as it will now include fees to the broker, the exchange and the clearing house.

Another substantial difference between OTC trading and on an exchange is that an exchange-based market guarantees anonymity of buyer and seller. The bilateral nature of the contracts employed in the brokered (OTC) market means that the buyer or seller will have to reveal his identity to the counterparty when a trade has been conducted. While this is a disadvantage for some individual players who want to hide their actions, it also creates increases the transparency in the market.

While exchanges are popular for standardisation, the brokered market is popular because it makes it possible to gauge the market for interest in rarely-traded products. This is particularly valuable for new markets, in which there is lower liquidity and perhaps less confidence in where the over all price level should be (an example might be hourly within-day gas at the TTF).

Finally there is of course the opportunity for a trader to call directly to another company with which a master trading agreement is in place. While this method is only used in a minority of the trading on the most liquid hubs, it is more prevalent at the less liquid ones. It is also something that can be necessary if a change in position occurs outside normal office hours, for instance as a result of interruptions.

6. Transparency

The concept of market transparency covers a wide area of subjects, from information about how the industry decision making process functions, to accessibility to rules and regulations covering the different market areas. Here the focus however will be on two important basic aspects, namely price and physical flow information. Observing prices and physical flows not only gives a snapshot of the immediate state of the market, but also an important overview on storage levels, congestion points in the network, flexibility of supply/demand, and potentially signals as to where future investments are needed.

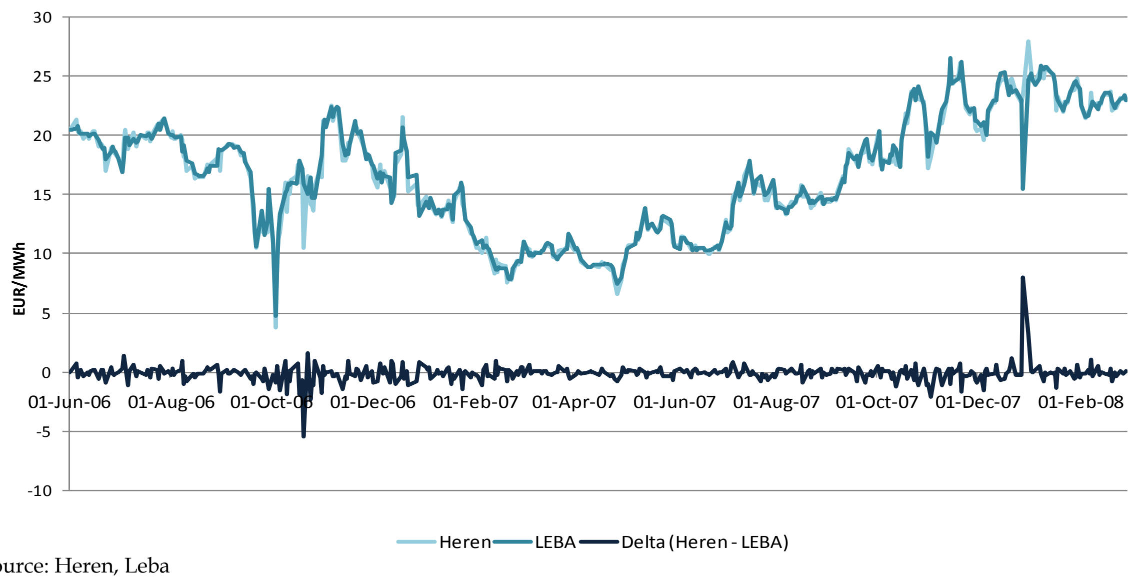
a. Price transparency

A number of daily publications provide price assessments for the European gas hubs (ex. Argus, Heren, Platts). The published assessments are an attempt to describe the price levels at a specific point in time, most often 16:30 GMT. This cut-off time is often referred to as "the close" even though there is no formal closing time of the OTC markets. Many supply contracts exist in which the gas price is indexed to these published price assessments, so some actors will have an interest in where the price stands exactly at the close. At the most liquid hubs, such as the NBP and the TTF, there can therefore be a flurry of trading conducted in the minutes leading up to this point in time.

It is argued that certain market players, either buyers or sellers of an index, might have an interest in manipulating the published prices by misreporting trading to the daily price publications. However, the most popular publications have become more or less industry standards, implying a general interest in having reliable published prices. Potential monitoring between traders on reported prices, as well as auditing of the prices used to value the trading portfolios, particularly at important times in the year (end of the month and of the year), provide good reasons to be confident that the published prices in general are a good representation of the market.

For the day-ahead market at the TTF, another source of information on OTC trades exists, namely the price indices published by the London Energy Broker's Association (LEBA). The "day-ahead index" is the weighted average of all trades brokered, between 08:00 and 17:00 GMT by ICAP, Spectron and Prebon, who between them account for nearly all brokering at the TTF. LEBA also publishes a "day-ahead window index", being the volume weighted average of all day-ahead trades conducted in the time between 16:20 and 16:30 GMT.

Fig.18: Difference between the close day-ahead TTF and the LEBA day-ahead index



Source: Heren, Leba

In general there is better transparency on price levels for those trades done on exchanges, since all participants can see all prices that are published and all trades that happen. The exchange will also publish settlement prices for all tradable contracts, often complementing this with information about the volumes traded.

In general therefore, there is abundant information on the level of prices and to some degree on the dynamics of price formation in both exchange and OTC markets, which are of course related[18]. There

18Exchange prices for a future period will be similar to, but not necessarily the same as, forwards prices for the same period. The difference is due to the nature of the contracts. With the OTC market, profits or losses on trading are realised at a time in the future which corresponds with the period traded, while exchange traded profits are paid out once the deal is closed. The difference in valuation of a future period should therefore be calculated factoring in the cost of financing. This difference is clearly small for month-ahead contracts, but can be substantial for several years in the future.

is however an extra layer of information available to the most active players on the OTC markets about the trading patterns of the different companies in the market. This is quite exclusive in that it can only be learned through being present in the market continuously and actively with a large number of counterparties.

b. Physical flow transparency

The level of information on physical flows differs widely from market to market despite the fact that EC regulation (No. 1775/2005) sets out some minimum standards on the publication of flow and capacity information. Notably, TSOs are required to publish capacity information such as: maximum technical capacity, total contracted and interruptible capacity, and available capacity on a regular basis. Often TSO limit themselves to the publication of "historical maximum and minimum monthly capacity utilisation rates and annual average flows at all relevant points". Furthermore pipelines with less than three capacity holders can have exemption from the transparency requirements, under the so called "three shipper rule" issued from the EC regulation mentioned above.

The lack of firm unified regulation means that the amount of information on physical flows differs widely across the traded markets. The most advanced TSO with regards to publication of flows is the National grid, that every 12 minutes publishes physical flows on the Internet for all entry points into the NBP with a two minute resolution. Also available to shippers daily is detailed information on the flows out of the NBP at the exit points. On the opposite end of the spectrum is a large part of the markets in Germany, where for instance information on physical flows from Poland into Germany is only available to the few capacity holders; it is unavailable to all others, including governmental agencies. The available information on the other traded hubs in Europe in general tends to be at best monthly information again most often only for points with more than two shippers, thus excluding important transit and import pipelines.

Table 1: Comparing trading platforms

	OTC	EXCHANGE	BILATERAL WITHOUT BROKER
CONTRACTS	An agreement between the companies is needed (or use a sleeve)	One agreement with the exchange	An agreement between the companies is needed
TRADING METHOD	Through broker – either Electronic platform or voice brokering	Electronic platform	Personal contact
COUNTERPARTY	Other company	Exchange	Other company
TRANSACTION COSTS	Medium	High	Low
TRANSPARENCY	Good, different publications on end of day prices	High, information given by the exchange	None
ANONYMITY	Company has to reveal it self to other company after deal	Anonymous	Before deal companies already know others' identity
MAIN USAGE	All products	Most liquid products	Illiquid products and large volumes
TYPE OF AGREEMENT	Framework contract	One agreement with exchange	Bilateral contract

Source: IEA analysis

Chapter III – The Crystal Ball – What could the European gas market look like?

I. The North American example of a competitive gas market

Liberalisation in the North American gas market started in 1979. A highly competitive market has evolved along the whole value chain. The first part of this chapter will examine how the North American market is structured, policed and operated, with particular focus on the drivers for new investment. This study is relevant because the future of the European gas market is often described in terms of the current North American gas market. We have to emphasise, however, that the European gas history fundamentals are vastly different from those found in North America. In the second part of this chapter – workable EU competition – we will address how competition can actually develop in the EU, taking into account these differences.

A. The process of deregulation in the IEA North American markets

1. Overview of the IEA North American gas market

The North American market (US and Canada) consumes annually 770 bcm compared to 540 bcm per year in IEA Europe. As a whole, North America is almost self-sufficient, but there is considerable trade between its component parts – overall, the US imports around 14% of total consumption from Canada, although the trade is not unidirectional as the north-eastern US exports gas to Canada.

Before the market was opened to competition, the gas delivery chain had a linear structure which was not dissimilar to the one which has evolved in Europe. E&P companies produced gas, sold it to inter-state pipeline companies, who in turn delivered it to the city gate and sold it to the LDC (Local Distribution Company), who then sold it to the end-user.

The deregulation of the market meant that the roles of the market participants were changed, most significantly the role of the pipeline company. Their role changed from marketing and transportation of gas as a single service, to gas transportation alone. Nevertheless, it was recognized that the expertise of pipeline companies in managing gas transactions as well as in balancing supply and demand would somehow have to be carried over into a structured marketplace. The principal of market centres was proposed. These centres were to be places where services could be provided to customers so that they might manage their own portfolios of supply, transportation, and storage. The federal regulators promoted the concept of the market centres, but left it up to the actors whether to make use of it. Largely due to the key pieces of regulation, which are discussed in the next section, the concept caught on. The North American gas market is now traded as a system of "hubs and spokes", in which balancing is done at market centres, with pipelines connecting them.

In this new market structure, the market centres manage information flows, producing real-time prices of gas. These prices act as the mechanism of coordination in the market, allowing many specialist companies (including new participants) to emerge. Information which had traditionally been kept inside several vertically integrated companies was available to all players on equal terms, allowing maximum opportunity for the use of resources. This part will describe the North American market by looking at each actor and their interaction with market hubs.

2. The deregulation of the North American gas market

US wellhead price regulations were put in place in 1954 with the Supreme Court's Philips Decision, meaning that gas destined for inter-state consumption would be produced at government determined prices. Intra-state regulation remained the prerogative of the individual states. At non-market based prices, gas did not respond to the realities of the changing US energy market. In the early 1970s, oil prices rose dramatically, but gas prices remained low, driving gas demand. As demand increased, the gas supply was unable to keep up. At the same time unregulated intra-state gas buyers in production regions of Texas and Louisiana were able to outbid regulated tariffs for the scarce gas, intensifying the shortages on the inter-state market to the north.

At the moment that oil prices started to rise, in the early 1970s, Canadian prices were still unregulated. As a result of the gas shortage in the price-controlled US market, more gas was bought in Canada. The export price of Canadian gas increased, leading to higher prices in Canada than in the regulated US market. To avert this, Canada decided to regulate its gas prices in 1975 and have a single border price for exports to the US (Petroleum Administration Act). The regulated gas prices were tied to crude oil prices, export prices were permitted to exceed domestic prices, and the export price premium had to be distributed to all Canadian producers, even the ones that did not have export contracts.

From 1980 the Canadian government became the sole exporter of gas. The government 'bought' the gas from the producers, exported it and divided the rents pro-rata to each seller according to his production. After the deregulation of the gas prices in the US in 1979, with the Natural Gas Policy Act of 1978, gas prices increased and gas demand fell. As a result it became difficult for Canada to maintain the regulated tariff and it was decided to deregulate gas prices in 1985 with the Halloween Agreement.

It would take different Federal Energy Regulatory Commission (FERC) and National Energy Board (NEB) orders before the gas prices in North America were finally deregulated in 1993. The most important orders are:

- (US) 1979 – Natural Gas Policy Act of 1978: wellhead price controls were removed through a 'partial de-regulation' of wellhead prices. Because of a gas shortage at the time, this act was meant to give incentives for new production, but also to reduce the intra-state purchasing advantage by placing it under pricing regulation. The old contracts would stay under regulated tariffs (in 1993 `The Natural Gas Wellhead Decontrol Act of 1989' repealed the remaining price regulation), but new contracts were partially or completely deregulated.
- (US) 1984 – FERC order 380: removed contractual minimum bill obligation. The pipeline companies had long-term sales contracts with a minimum bill obligation (referred to in Europe as a Take or Pay commitment). This order was put in place against a background of rapidly falling gas prices, but consumers not being able to make use of it because of the minimum bill obligations in their existing contracts. The removal of this obligation allowed buyers to buy the cheapest gas and escape their commitments for the more expensive gas.
- (Canada) 1985 - Agreement on Natural Gas Markets and Prices (often called the `Halloween Agreement'): deregulation of gas prices. The system of a price regulated Canadian market and a deregulated US market became difficult to manage and Canada decided to deregulate the gas price (while keeping gas transportation regulated). Before the US market was deregulated, Canadian gas exports were higher priced than the regulated US tariffs. Hence, Canada fulfilled the role of swing supplier: when supply was short, the US pipeline companies had to buy Canadian gas. The final blow to this system was FERC order 380, which also applied to US companies purchasing Canadian gas: utilities had no minimum bill obligation anymore. Because imports from Canada were one of the more expensive sources, Canadian exports dropped.
- (US) 1985 - FERC Order 436: allowed pipeline companies, on a voluntary basis, to offer transportation services to customers. With prices (partially) deregulated, a spot market for natural gas arose. However the ability of end-use markets to access spot gas was severely restricted because most inter-state pipeline capacity was controlled by the pipeline companies themselves, which moved only the gas they owned. Transportation rate minimums and maximums were set, but within those boundaries the pipeline companies were free to offer competitive rates to their customers. Although the framework established was voluntary, all of the major pipeline systems eventually took part. As a result the transportation function became the primary function of pipelines, as opposed to offering bundled merchant services.

- (US) 1992 – FERC Order 636: required pipelines to separate their sales service from their transportation service and provide all transportation on an equal basis for all gas suppliers. Transportation remained a regulated monopoly but sales were opened to competition. Arguably it was this instrument which was the most significant single instrument in the market opening process, but as set out above, it was one event in a long process of improving market functioning in a period of rapid and marked energy price changes. Storage was also placed on an open access basis.

3. The present regulation authorities

In North America there are two levels of regulation: a federal and a state/province[19] level. The FERC and NEB are the federal regulators for respectively the US and Canada. Both are independent government agencies and have mandates for inter-state issues. An overview of the mandates of the federal regulators is given in box 7.

Since 2003 the federal regulators of the US, Canada and Mexico have worked closely and meet regularly to share perspectives on regulatory approaches and to work on eliminating inconsistencies. An example is the agreement signed in 2004 between NEB and FERC which reinforces the existing cooperative relationship and further commits each agency to work together to harmonise the regulatory approaches to cross-border projects.

State regulators, often called public service commissions or public utilities boards, have mandates on an intra-state level, not only for gas, but for all types of energy and often also for water, telecommunications, transportation and sometimes even automobile insurance. Opening up the intra-State market to competition is a decision made by state regulators, as a result, some states have opened the residential market for competition and some have not.

The NARUC (National Association of Regulatory Utility Commissioners) and CAMPUT (Canadian Association of Members of Public Utility Tribunals) are overarching bodies providing a forum for the exchange of information and views among its state regulator members (NEB is also a member of CAMPUT).

Box 7: North American federal regulators

The FERC and NEB have the following mandates involving gas:

- Monitoring and investigating energy markets
- Approving the construction of inter-state and international natural gas pipelines and Liquefied Natural Gas (LNG) terminals.
- Approving the construction of storage facilities (FERC only).
- Inter-state pipeline tariffs (in some cases also intra-state pipelines).
- Gas production activities not covered by state regulator.
- Approving long-term contracts (NEB only, in the US this is done by state regulators).

4. The role of hubs

Natural gas can be traded or priced at almost any location in North America. Over time, some pricing points have evolved into trading hubs. This has occurred when multiple buyers and sellers have expressed a wish to transact at the location, and when an infrastructure owner decided to facilitate the trade by providing transaction services. These pricing points then become physical exchanges where gas can be easily bought or sold. Trading hubs have tended to develop at the junction of multiple pipeline interconnections, and usually have access to natural gas storage facilities, allowing the hub operator to offer balancing services, enhancing the trading options for

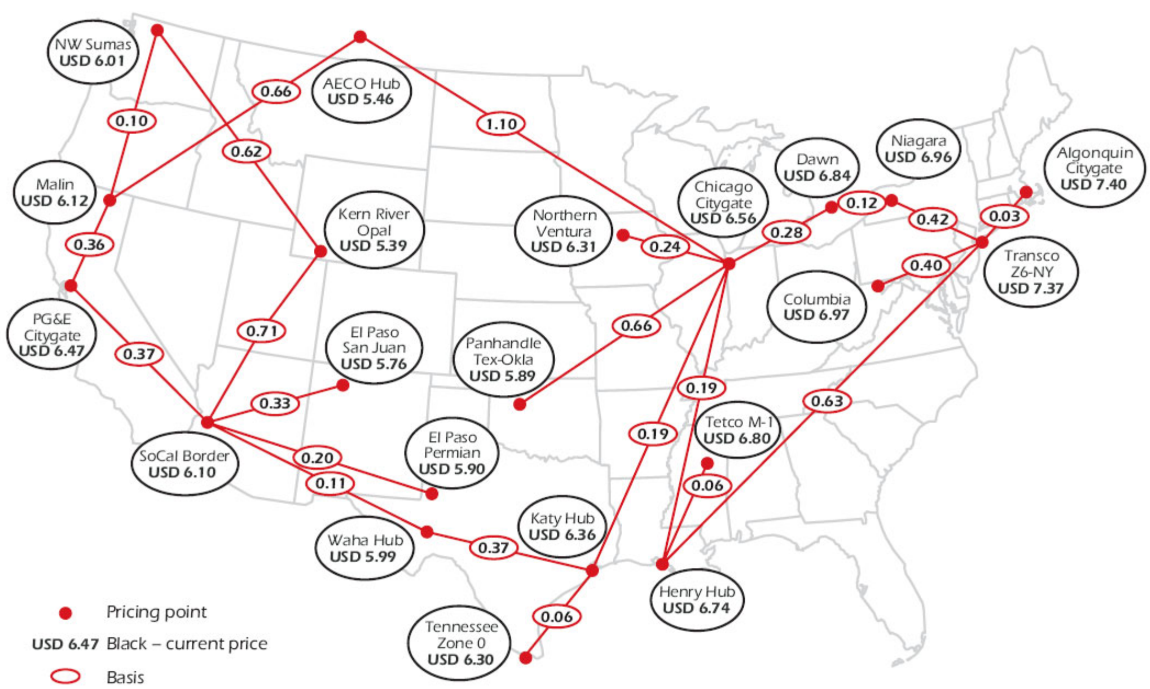
19 For simplicity reasons, in the following, when referring to a State, we also refer to a Canadian province.

buyers and sellers. In North America there are 38 different hubs (29 in US and 9 in Canada). Trading hubs, whether a producing area hub located near a gas supply basin or a market area hub located near a market centre, are characterised by numerous market participants and access to services, such as balancing and title transfer, organised by the hub operator.

Gas transportation and ownership transfer are the most important hub services for the customer. For example, when a shipper with firm capacity on one pipeline wants to deliver gas to an end-user located on another pipeline connected to it via a hub, the shipper can make arrangements to transfer the gas through the hub administrator. The administrator will arrange for compression-adjustment services if the pipelines operate at different pressures. Needed capacity on the receiving pipeline may be acquired at the hub if trading services (or traders) are available. Similarly, the shipper can use the hub's services to revise its nominations on either pipeline, with the centre handling the administrative requirements such as the confirmations process required to effect the transaction. To cover any imbalances that might occur when the receipt/delivery volume exceeds nominated capacity on either pipeline, the shipper can execute an operational balancing agreement with the hub.

If sufficient capacity is available to transport gas between hubs, price differentials between these hubs will represent the marginal transportation costs between the different locations (see map 2). This is because any increase in the differential beyond the costs of transportation will lead to more gas physically flowing – countering the increase. However, if there is no incremental capacity available, price differentials can increase above the transportation costs. Congestion can be caused by many events - temporary congestion due to a disruptive event such as a fire – or systematic congestion in which case it is a signal that supply/demand fundamentals have changed. As we will see later in the discussion on the Rocky Express Pipeline case, systematic price differentials give pipeline companies a clear timely signal and an incentive to build new gas infrastructure between hubs.

Map 2: US natural gas spot prices at major trading hubs, 2006 ($/MBtu)



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.
Source: FERC - State of the Market Report 2006

Changing market conditions impact prices and influence North American gas flows. For example, suppose that the price of natural gas in the U.S. Midwest rose relative to California. In such a situation, Canadian and U.S. natural gas sellers would prefer to sell in the U.S. Midwest because the returns would be higher. More supplies would be offered in the U.S. Midwest and sellers would divert their volumes from California. As more supplies were offered in the U.S. Midwest, the price there would tend to fall; conversely, as less natural gas was offered in California, the price would tend to rise. This process would continue until sellers were indifferent between selling in either market.

Henry Hub and NIT are the most liquid *producing* hubs in North America (see box 8 for an overview of these hubs). Both are located close to producing regions enabling producers to sell their gas and from here gas flows to consuming regions mostly to consuming hubs.

An example of a *consuming* hub is the Chicago Citygate hub. It is strategically located at a point where different major inter-state pipelines from the Gulf of Mexico and Canada converge, together with different storage sites (aquifer and depleted gas fields). This enables consumers to trade between the different producing areas. With the construction of the Rocky Express Pipeline, the Chicago Citygate will indirectly also be linked to the Rocky Mountains producing area (see below), giving more trade opportunities.

Box 8: North American hubs: Henry Hub and NIT

The most liquid hubs in North America are Henry Hub, located at the Gulf of Mexico in Louisiana, and NIT hub (NOVA Inventory Transfer – NIT is often also referred to as Alberta hub or AECO hub) located in the western Canadian Sedimentary Basin in Alberta. Both hubs are located in the largest producing areas of their country and serve different markets. Prices at other hubs typically will be referenced as a differential between Henry Hub or NIT. From Henry Hub, most gas flows to eastern markets and gas from NIT is either used in western Canada or exported to the US. The following elements have made these hubs a success:

- Connected to many large pipelines serving different markets (Henry Hub: 14 and NIT hub: 6).
- Large volume of gas flows (Gulf of Mexico: 20% of US production, western Canadian Sedimentary Basin: 80% of Canadian production). Henry Hub is also connected to the country's largest grouping of LNG re-gasification terminals.
- Connected to high deliverability storage facilities.
- Prices and other relevant information available. Delivery point of exchanges (Henry Hub: Nymex, NIT: NGX).
- Many different types of buyers and sellers.
- Large daily volume of transactions

Timely, transparent, accurate and affordable price information for market players is vital when making market decisions. There are different sources to get information. Firstly there are the independent energy trading platforms (such as ICE, NYMEX, NGX or TradeSpark, among others). They publish subscription-based spot price information for multiple locations in North America.

Secondly there are previous-day gas prices which are available for various gas trading points in the United States and Canada. These are available through several trade press publications also on a subscription basis. The information of the underlying trades are based on a network of individual market traders, the details on the transaction and prices are provided by the parties involved in the trades, rather than by the centres. This price information has been used extensively as a source for price indexing of gas-purchase contracts. Following the collapse of Enron's on-line energy trading platform in 2001, such price indexing came under close scrutiny. Investigation discovered that some traders reported daily trade erroneously at times, perhaps in an attempt to influence market behaviour. In 2003 FERC and the Securities Exchange Commission developed voluntary guidelines for gas price reporting that are intended to eliminate similar abuses in the future.

In addition the Energy Information Administration (EIA) of the US Department of Energy reports various historical monthly prices (wellhead, import, city gate, residential, commercial, industrial and power generator prices) split by state. Besides prices, the EIA also publishes historical data on production, exploration and reserves, imports/exports, storage and consumption again all split up per state. This data give much transparency to the North American market.

B. The physical market / the value chain

1. Upstream: role of producers

The upstream gas sector is highly competitive, with literally thousands of producers in the US and hundreds of producers in Canada (in stark contrast to Europe). The market share of each individual producer is small. In the US for instance there are around 20 to 30 major gas producers, often (but not always) also major oil companies, but the market share of the largest producer is approximately 3 to 4%.

The upstream players sell the gas they produce on the hub against a daily index price which represents for them the "fair price of gas". Because the daily index price is set by supply and demand of gas, these companies get a direct financial incentive to increase production when gas prices are increasing. Therefore a normal reaction for them would be to increase production if possible – in the short term through surge production, in the longer term through increased production drilling and exploration. This can be demonstrated by the high correlation between drilling rates and gas prices, usually with a time lag of 6 months.

The majority of the gas consumed in the US is produced domestically (84%), with most of it coming from the Gulf of Mexico, Texas and Louisiana. However, as mature areas have declined, so have gas prices been rising. This has led to higher cost reserves becoming attractive, including tight gas and shales as well as coalbed methane. However, there have also been more conventional gas discoveries in the Rocky Mountains area. The Rockies production and associated pipelines provides a good recent example as to how the North American market delivers new supplies.

The remaining gas used in the US is imported. Most of the imported gas comes from Canada (86%), flowing to the north-east, Midwest and western area. The remaining 14% imports come from LNG, with Trinidad & Tobago being the biggest LNG supplier, followed by Egypt, Nigeria and Algeria. Most of the LNG regasification capacity is located in the Gulf of Mexico area, which despite being distant from consuming areas is relatively well connected to other market zones. The US is also an exporter of relatively small volumes of gas to both Mexico and Canada (and Alaska exports a small quantity of LNG to Japan).

2. New midstream players

After deregulation, inter-state pipeline companies changed their focus to gas infrastructure services. The midstream gap that opened was filled by different actors, most prominently the unregulated marketers (in addition to brokers and retail agents) and energy traders. Both these actors make extensive use of hubs.

Independent gas marketers act as middlemen and, in addition to marketing gas supply can arrange for a "package" of sales and transportation services or even arrange demand management services. The difference between marketers and brokers/retail agents, is that marketers actually own the gas, while brokers/retail agents usually do not. Successful marketers add value by saving producers and end-users the trouble of finding each other, by arranging transportation and storage, and sometimes even by arranging financing or assuming price risk. Partly as a consequence, there are now about 250 independent natural gas marketers.

Energy traders, who optimise the system by taking risks, such as basis (or location) risk, timing risk or commodity risk, can be divided into two groups. First are the physical traders; these are players with an actual need for a surplus of gas (a physical position on the market) which they try to optimise. These players are often active on the short-term (spot) and long-term (futures and forwards) market. The other players are financial players, mostly banks, which are most active on the forward/future market.

Many market participants do not wish or cannot tolerate the risk of price fluctuations that occur in the commodity market, e.g. manufacturers offering fixed price products such as ammonia, or even plate glass. Often these risks can be covered through the use of futures contracts with e.g. the NYMEX, or through direct contracts with other counter parties for delivery at a hub. However in some cases a financial services company, trader or bank may be used to offer a fixed price in exchange for a particularly complex trade. For some buyers or sellers, the fee charged by financial service companies is a small price to pay for the services offered, such as price stability.

3. A varying transport structure

Inter-state pipeline tariffs are regulated by the federal regulators, while, apart from a few exceptions, intra-state pipelines are regulated by the state regulator. There is a general framework for setting the cost of transportation. Most often these rates are cost-of-service based, that is, they are set at a level that is expected to generate enough revenues to allow the company to recover its expenses plus an allowed rate of return on assets used in producing the service.

Pipeline tariffs can be divided into a *reservation charge* and a *usage charge*. The reservation charge covers all the fixed costs related to the transportation. For companies to reserve pipeline capacity – most often done via long-term contracts – they have to pay the reservation charge. As we will see later on in the case study on the Rockies Express Pipeline, the long-term capacity contracts, sold in an open-season, underpin new investment in pipelines. The usage charge is the price which shippers have to pay when making use of the capacity. Interruptible capacity users generally only pay a usage charge (often higher than for a shipper with firm capacity), because another shipper has already paid for the reservation charge.

4. Storage as a flexibility tool

The role of storage has changed fundamentally since FERC order 636 required pipeline companies to operate storage facilities on an open-access basis. Beside the inter-state/intra-state pipeline companies and Local Distribution Companies, independent storage service providers became owners of gas storage. Storage services have more and more developed as financial instruments; on the NYMEX exchange, a liquid market has emerged for futures and options for natural gas storages.

Access to storage is vital for the proper functioning of gas markets and, in particular, gas hubs. Hub prices and particularly their volatility are directly influenced by available storage levels. A good example of the interaction between price levels on hubs and storage levels was the shortage following the hurricanes Katrina and Rita, as is described in box 9.

Underground storages can be divided into three categories: depleted gas fields, aquifers and salt domes. Each type of storage has its own characteristics such as the working gas capacity, injection and withdrawal rates. Generally, however, only salt domes have high injection and withdrawal rates needed for intra-day balancing, whereas depleted fields and aquifers are more useful for seasonal injection and withdrawal. Gas can also be stored above-ground in LNG facilities and gas tanks, these facilities having a low working gas capacity and a high withdrawal rate.

Most existing gas storage in North America is in depleted natural gas or oil fields. Depleted gas fields have large working gas capacity, and a relatively lower injection and withdrawal rate. They are normally filled in periods of low prices, between April and November and emptied when demand and prices rise, between December and March. In some areas, most notably the U.S. Midwest, natural aquifers have been converted to gas storage reservoirs. The large majority of salt dome storage facilities have been developed in salt dome formations located in the Gulf Coast states.

Since 2000 inter-state pipeline companies have to provide short-term storage services on a hub (FERC Order 637), such as parking (short-term transaction in which the market centre holds the shipper's gas for redelivery at a later date) and lending (short-term advance of gas to a shipper by a market centre that is repaid in kind by the shipper a short time later). While most hubs are connected to storage, some lack access to storage and instead have to use the line-pack (or production flexibility) available to offer short-term storage services.

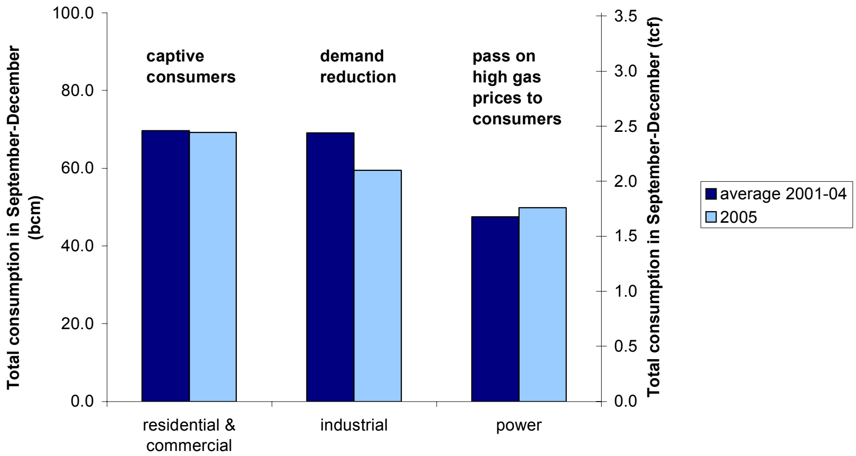
Box 9: Aftermath of hurricanes Katrina & Rita: dealing with a crisis

In 2005, after hurricanes Katrina and Rita, gas production in the US was heavily affected. With no possibility of increased production or gas imports making up for this shortfall, the US was in a situation in which demand response was needed to overcome a gas shortage. Hurricane Katrina, after striking the south of Florida on 25 August 2005, continued into the Gulf of Mexico, where it did much damage to the region's oil and gas production before it hit the coast on August 29. Rita, a second large hurricane, struck on September 24. The latter particularly hit much of the region's natural gas processing capacity. Total shut-in capacity amounted to about 80% of production in the Gulf and 25% of total national production. The few parts of the production chain which were left in operational status, or could be quickly brought back online, often did not correspond to the necessary next or previous step – meaning that where processing plants were available, they often had no gas to process. Conversely, even if platforms and pipelines were either unaffected or readily restored to service, the gas often couldn't flow to market without treatment.

As a result of the loss of gas supply, prices rose and volatility increased. Although spot trading on Henry Hub was not possible for two weeks due to flooding, the price was $16/MBtu when the centre re-opened up from an average of $6.7/MBtu in July. This resulted in demand reduction, particularly in the industrial sector, so that large scale shortages in other sectors were averted. The demand response from the different sectors is represented in figure 19 (originally published in the IEA Natural Gas Market Review 2006).

The market reacted in a logical manner. Draining all storage facilities after Katrina struck could have led to large shortages in winter. However futures prices further increased as the hurricanes struck, which formed an incentive to retain and expand storage levels. Save a short period in which gas was withdrawn from storages in the producing region, this meant that gas continued to be injected into storage facilities – especially in the eastern region.

Fig.19: High prices cause demand reduction in US industry



Source: IEA Natural Gas Market review 2006

5. Impacts on the downstream segment

The deregulation of the market and the arrival of hubs represented a major change to consumers. The price of gas is related to supply and demand fundamentals, and consumers (especially larger ones) were directly exposed to changing price signals. Hence gas procurement became an active process, rather than a passive one – when gas prices are high enough, consumers are now able to make a profit by switching fuels or just by reducing gas consumption, through for example industrial users reducing their output by drawing on inventories. As will be shown in this section some end-users are better equipped to make use of these opportunities than others.

In a non-liberalised market, demand side response is almost never available, and if so, only on an administered basis; imbalances are solved primarily by increasing supplies (withdrawing more from storages, increasing imports or if possible increasing production). Only in cases of physical gas shortages, will the gas company enforce demand response through interruptible contracts which it has with some of its customers. Interruptible contracts give the supplier the right to interrupt a customer in case of gas shortages. As compensation the customer receives a discount on its gas contract.

In a liberalised market, the price is based on the balance between supply and demand, and thus demand response is used continuously. In cases of gas shortage price signals are perceived quickly by larger users. As the price each consumer is willing to pay is best known by the consumer itself, this results in a more efficient allocation of supplies than when the supplier decides who to interrupt.

a. Residential and commercial users

While Europe opened the residential and commercial markets rapidly to competition, in North America only a part of this consumers group is able to purchase natural gas from another supplier than their incumbent utility company – the decision whether to open the residential market to competition is up to the individual states.

Within the US, twenty-one states and the District of Columbia allow residential users to switch supplier. Seven states and the District of Columbia allow all residential consumers to choose their natural gas suppliers, but a lack of marketer participation has precluded the development of competitive retail markets in three of these states. Six states are in the process of implementing consumer choice state-wide, with programs available to more than half of their residential customers, and another eight states have pilot or partial opening to competition programs in place or awaiting development. The remaining states are not considering residential consumer choice programs. From the 35 million customers who are theoretically allowed to choose their gas supplier, only 12% actually switched to another company.

b. Industrial users

Industrial users are the gas consumers most responsive to prices in the North American market. The group is heterogeneous, with a wide variety of uses and therefore also with different responsiveness to prices, including over time and seasons. It is impossible to evaluate the demand developments from all these different sectors. Box 10 provides the example of the fertiliser industry, which is particularly responsive to price signals.

Box 10: Fertiliser producers in the competitive gas market

The fertiliser industry is a good example of an industry on which the liberalisation of the gas market has had a large impact. Natural gas is the main ingredient of fertiliser manufacture as it is a relatively cheap hydrocarbon and is easily converted to ammonia. Fertilisers are well equipped to actively manage their input costs: they are in general large firms and gas prices are a major part of marginal production costs. Together with ammonia production, fertilisers consume 4% of North American gas (and a similar proportion in Europe).

However, as there are no easy substitutes, the only way for a fertiliser to reduce demand is to reduce production. Fertiliser producers have to make a produce or no-produce decision at high gas prices to prevent it being a loss-making operation. As a result of this price-sensitivity, fertiliser production is one of the gas-consuming industries which are able to provide a large demand response and thereby reduce volatility on the gas market.

During the high gas prices in winter 2005/2006, many fertiliser producers in both North America and Europe had to shut down production. In continental Europe this happened mainly because suppliers interrupted the (interruptible) gas deliveries, while in North America and the British markets fertiliser producers reacted themselves to the increased gas prices. Both in North America and Europe this resulted in a – much needed – reduction of demand.

In general all industrial customers have a "make or buy" decision. This theoretically means that if marginal costs exceed marginal revenue, they will decide not to operate their plants. However in real life this decision is more complicated. First of all, many industrials have a back-up fuel. The decision then becomes a three-way optimisation involving the marginal cost of production from each fuel and the marginal revenue of the product.

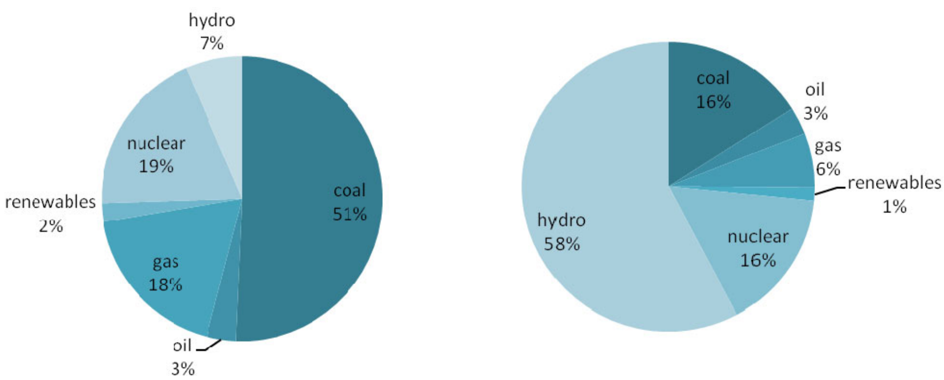
Secondly, most industrial users have made a commitment to supply customers. When gas prices are high the producer can try to arrange a settlement with the end-user instead of delivering the product, or buy its product on the market and deliver it to the customer. In the longer run, it can be commercially attractive for an industrial user to hold stocks of either raw material or finished product (quite contrary to the theory of ``just-in-time-management"). Production may be therefore increased in periods of lower gas prices, and decreased when prices are high. The industry will progressively start to take these risks into account when contracting with its own customers.

Not every industrial user will be pro-active in the market, because it requires significant investment (IT, back-up fuel, knowledge, etc). Energy costs must constitute a significant part of total costs; otherwise the costs of actively participating in the market will outweigh the benefits.

c. Power generation

Gas is responsible for one fifth of power generation in North America. The main alternatives – coal, nuclear and renewables – have relatively high up-front investment costs but relatively low marginal costs. In the case of coal, the marginal costs have increased considerably in some areas with the increases in coal prices. Because a power plant will only produce electricity if the marginal costs are covered by the market price of electricity, sources with the lowest marginal cost will be used first, and sources with the highest marginal cost last. Renewables and nuclear are the first to be used, followed by coal and then gas, depending on coal and gas prices. So, often, gas is last in the merit order. In that case gas will then determine the price of electricity. Gas tends to be the fuel meeting expensive peak electricity demands in both winter and summer (air-conditioning load). On a price weighted basis, it contributes to the average cost of electricity much more than its 20% contribution to total electricity production suggest.

Fig.20: US and Canadian electricity generation mix (2006)



Source: IEA

As a result gas-fired power generators are relatively less responsive to gas prices' variations. When electricity demand is too low, they will not produce. And when electricity demand is high enough, producers are able to pass on increases in gas prices into electricity prices. Even when gas prices may be very high, gas-fired power producers will generally not have an incentive to reduce gas consumption, since they are among the only generators who can respond to peaks, and hence set the power price[20].

[20] However, coal and gas have been competing, and coal prices have increased substantially. Often the final plants in the merit order are open cycle gas turbines, but after that old coal and oil plants may enter the merit order.

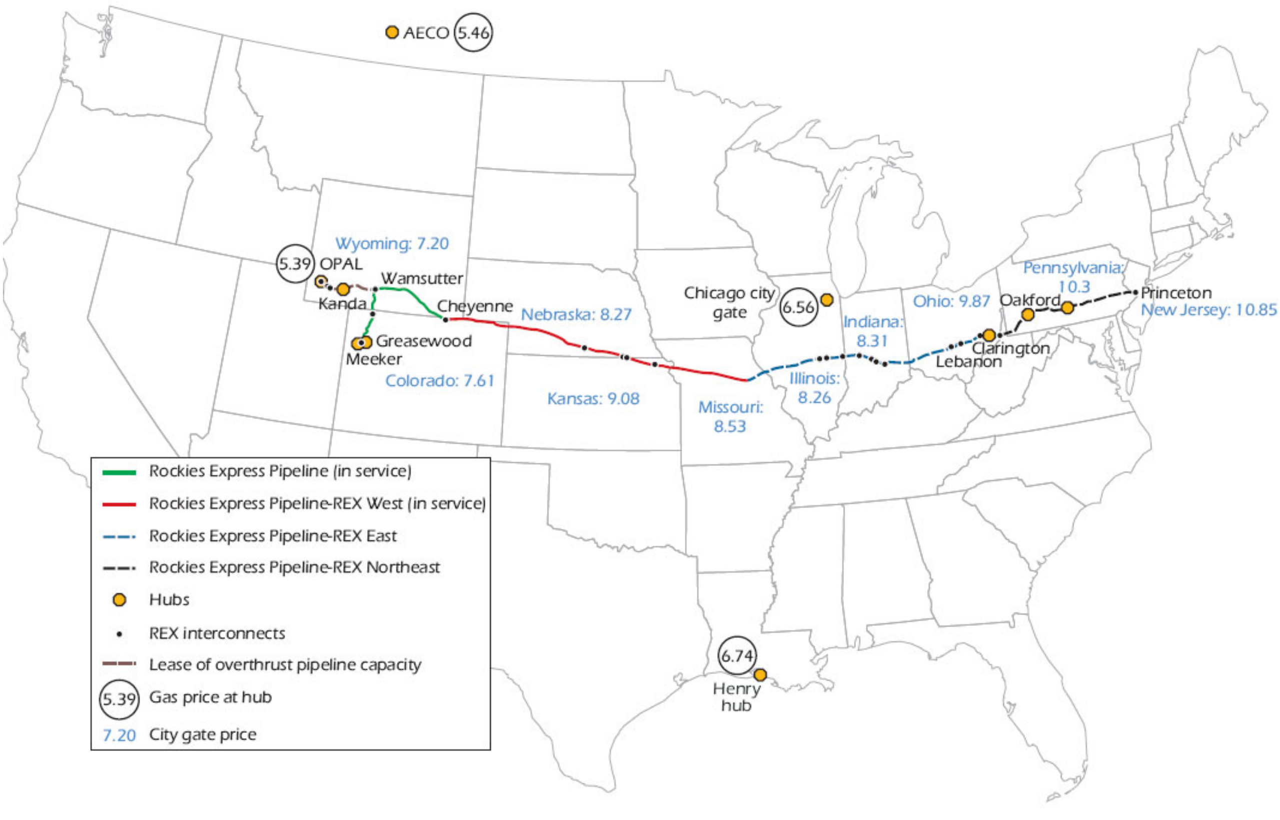
The share of gas fired power in North America is growing. In the US, this trend is likely to continue to 25% by 2010 and 35% by 2020. This will mean that in the future, the electricity price will more and more be determined by the gas price.

C. Case study - Rockies Express Pipeline. Investment in a liberalised market

Gas production in the Rocky Mountains producing area has increased by more than 4 percent per year since 1998 and is expected to increase by another 18% by 2010. With nearly 22% of total proven natural gas reserves in the United States, gas production in North America is becoming more and more dependent on this area. Because gas consumption is much lower than production in this area, the remaining is exported to other states (both western and eastern markets). However, in recent years, the inter-state pipelines exporting natural gas were already running close to maximum capacity, resulting in low and volatile prices in the Rocky Mountains area. In order to export the anticipated new production, extra infrastructure was needed.

In 2005, the signing of a Memorandum of Understanding between Kinder Morgan Energy Partners (KMP) and Sempra Energy marked the start of the construction of the largest pipeline in the US in the last 20 years: the Rocky Express Pipeline (REX-pipeline). This 2700 km pipeline, crossing eight different states, will cost in total $4.4 billon. It will open up producing areas in the Rocky Mountains with consumers in the east. In the original proposal, REX consisted of three parts: REX Entrega, REX West and REX East (see map 3). After its initial success, in 2007 an open season was held to extent the pipeline further north-east to New Jersey.

Map 3: Overview of Rockies Express Pipeline Project



The boundaries and names shown and the designations used on maps included in this publication do not imply official endorsement or acceptance by the IEA.
Source: data based on FERC and industry sources

Price signals for pipeline investment are not based on absolute price levels at any one location, but on the "basis differential" between the value of gas at one point and another. It is therefore common for pipeline companies to look at basis differentials between hubs in order to determine the need for infrastructure investment. During the period 2002-2003 the differential between the Rocky Mountain region and the Northern Natural Gas Demarcation (DEMARC), which is the end point of REX-West, reached 2 – 3 USD per MBtu. At the time, different pipeline extensions, but most importantly the expansion of the Kern River pipeline (adding 0.9 bcm per year of capacity), caused price differentials to decrease in the short term. Between the end of 2003 and the time when the companies held the open season for REX, price differentials were small. However the demand for infrastructure became clear when at the end of 2006, gas prices in the Rocky Mountains became very volatile and low. Part of the cause for such swings was that transportation bottlenecks constrained Rockies gas deliveries to markets, at a time of rising production.

Even though price differentials weren't that high at the time of the open season, the business case for the REX pipeline was based on expectations of the basis differential once the pipe was complete. Based on increasing production, there was a good case for a new pipeline even in 2004/5, as was proven by the price differentials actually seen in summer 2007. Looking further in the future, more additional pipeline capacity will be needed to prevent transportation bottlenecks for deliveries out of the Rockies production region.

The capacity on the pipeline was sold before the pipeline itself was built, using an open season process. In this process, expressions of interest are sought by the pipeline company from any shipper. The pipeline company calculated that there needed to be a minimum interest 15.5 bcm per year for the project to go ahead. In the period before the open season, three companies – EnCana, Wyoming Natural Gas Pipeline Authority (WNGPA) and Sempra Pipelines & Storage – indicated they would buy in total 9 bcm per year of the capacity in the pipeline. EnCana at that time was constructing a 530 km pipeline in the Rocky Mountains linking producing zones. As part of the REX open season process, EnCana also offered capacity on their pipeline. In February 2006 this (production zone) part of the pipeline was incorporated in the REX-pipeline company.

The pipeline open season attracted interest from gas traders and producers; however, there was also interest from several unusual parties:

- The WNGPA was keen to provide debt financing for the project and provide support for (another) extension into Wyoming. The state of Wyoming was keen to support the REX project because gas prices in the state had been forced down before by over-production and pipeline capacity bottlenecks, causing a knock-on decrease in state revenues. The state of Wyoming calculated that each 0.50 USD fall in price represents a loss of state revenue of approximately USD 150 million per year.
- The Federal Minerals Management Service (MMS) provided support for the project through its decision to subscribe for 0.5 bcm per year of long-haul capacity on a long-term basis to service its royalty in kind gas program in Wyoming. The MMS decision underscores the strong business case for Rockies Express. Creditworthy major and independent producers form the bulk of the remaining firm commitments, and their support reflects the importance of this project to the region and to the United States as a whole.

After the open season REX executed binding agreements for a long-term lease of capacity on this pipeline. Total upfront commitments from all shippers to the project amounted to over USD 4 billion – enough for the pipeline to be constructed. Prices to transport gas through Entrega (zone 1) started at USD 0.25/MBtu, through REX-West (zone 2) started at USD 0.704 /MBtu and finally transporting gas from west to east started (zone 3) at USD 1.074/MBtu.

The shipper commitments resulted in a final capacity for the REX pipeline as follows; REX-Entrega (production zone) and REX-West, a capacity of 15.5 bcm per year; and REX-East a capacity of 18.5 bcm per year. The REX-Entrega pipeline was finished in February 2007, the REX-West pipeline was finished in January 2008 and the REX-East pipeline will be in service partially in December 2008 and fully in June 2009. KMP is the pipeline owner, and it intends to finance the projects with 50 % equity and 50 % debt.

Being an inter-state pipeline, FERC had jurisdiction over the proposed REX pipeline. In order to secure the project's regulatory approval, a dialogue was initiated with FERC as soon as the start of the project. FERC granted the REX request to commence the FERC pre-filing process under the National Energy Policy Act in November 2005. The regulatory process was run in parallel to the project development, saving much time for the sponsors who would normally have run the regulatory process in series (one regulatory stage following a project stage etc.). Thus a major new pipeline development carrying more than 30 bcm per year over 2.700 km was brought from concept to operation in 3 years. The key factors in this relatively rapid process were:

- Transparent market signals that gave investors confidence in project fundamentals.
- Strong links between producers and the pipeline owner operator.
- Open season process which encapsulated these factors, allowing markets to be identified clearly for pipeline services, giving confidence in "right-sizing" of the pipeline, and attracting project finance.
- Transparent, expeditious regulatory processes for a pipeline crossing several state boundaries, implemented by a single Federal agency, backed by the Energy Policy Act changes allowing "parallel" approval processes.
- Pipeline routes utilising existing utility corridors for 90% of the length.

II. The workable competition scenario for Europe[21]

A. The European market for natural gas

The North American market serves as an interesting case study for liberalisation of European gas markets, but while there are some similarities, there are also differences in the European situation which may require different policy approaches and measures to achieve the necessary level of competition in Europe. Of these differences, two are most often cited; the importance of an oligopoly of external gas supplying countries, much greater in Europe, which accounts for nearly half of total supply (and growing), compared with North America which was almost self sufficient at the time of reform and where no single producer has a dominant position; and, how to replicate the role of regional bodies to act as a means of coordination during the process of market reform as FERC and NEB did in North America.

1. The European market in a globalising context

The European gas industry value chain extends beyond the actual borders of the OECD Europe consuming countries. Given that nearly half of the production of natural gas used in Europe is imported (the majority by pipelines dedicated to European markets), some non-European regions are an intrinsic part of the European gas industry. That the reform of the European gas market directly impacts non-European companies and countries is a major characteristic which distinguishes the process from that in North American gas markets. Often the British gas market is seen as a blue-print for liberalisation, but it too was almost entirely self sufficient at the time of reform. It is useful to note that if the North American market is characterised by the international gas trade between the US and Canada, and to a smaller extent Mexico, these three countries are bound together under the framework of the NAFTA (North American Free Trade Agreement).

The increasing need for imports, the concentration of upstream reserves and their progressive remoteness and rising costs will be key features for all OECD gas markets, even if diversification of routes and of gas sources may alleviate this to some degree. Natural gas markets are globalising, and Europe must remain an attractive consuming region in the long term, if it is to obtain necessary imports. Major producers and marketers will continue to optimise gas sales between European, North American, Asian and emerging markets, wherever physically possible, which is likely to become increasingly so. Notwithstanding existing pipeline infrastructure, upstream players like Russia or Algeria are no longer as tied as in the past to European markets as an outlet. The US and Asia are becoming alternative prospects through the LNG trade, for short- and long-term contractual arrangements, putting Europe potentially in competition as the target market for new investments by its historical suppliers. Russia and Central Asian producers may also take advantage of growing Asian demand to develop pipeline delivery systems to that region in the medium to longer term. Gas demand is high and rising in many gas rich regions, for uses from power supply, oil field reinjection, petrochemical development, and desalinisation in the Gulf. Finally, the lack of sufficient investment on upstream, or at least the lack of transparency on the production prospects in the next 10-15 years, brings more uncertainty on whether new supply contracts could be signed with the traditional foreign suppliers of Europe in order to fill the potential supply gap for European demand.

Import dependency is not a short-term issue for Europe; indeed it will rise continuously to more than two-thirds by 2030. External import dependency is not problematic in itself, however, from a policy perspective, it does bring a major foreign policy element to the evolution of European gas markets. Therefore, a clear and consensual global energy policy dialogue with external stakeholders is needed in order to ensure the security and sustainability of European energy markets, while achieving market liberalisation and integration. To build such a global European policy within an industry controlled by bilateral relationships, the common market for gas must be completed if there is to be sufficient coherence in the foreign policies of the member states.

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[21] For the purposes of this analysis, "Europe" will mean "OECD Europe".

The majority of industry analyses on the future of European gas markets have underlined the potential positive effect of upstream competition on downstream markets. However, the tightening global energy supply has undermined moves towards a more competitive upstream landscape; even if one very clear lesson of North America and the British reform processes is that they were both very beneficial for suppliers' market position, allowing them much more assured, easier and more transparent customer access. However, upstream concentration in the European gas market is much higher than in the US – in Europe, the largest supplier detains one fourth of market share (Gazprom), followed by two other big suppliers, Sonatrach and Statoil; while in the US, the largest supplier's share is no more than 3-4%.

2. Prerequisites for functioning competitive gas markets in Europe

Against this background, as we described earlier, the European Union has undertaken a long process of market reform and integration, to make markets more responsive, flexible and competitive, and adaptive to new market needs and supply sources.

Gas markets within individual European countries have different levels of gas penetration, network development, supply profile, customer protection standards and regulatory experience. Harmonisation on all these levels is required in the process of integration within the single EU gas market. In comparison with the North American gas market, where wholesale and inter-state regulatory harmonisation and consumer protection are achieved through federal regulatory framework, in Europe this process has yet to be developed.

a. Network integration

An integrated European network, adapted to local structures and energy balances' profiles, must be in place to guarantee that market operations can be deployed on a regional level, beyond national boundaries. Today, the market is not integrated primarily because the networks are not. For instance, the Baltic countries, Finland, Iberia, Turkey and the Balkan Peninsula are only weakly connected to the rest of the European gas grid. In general, in Eastern Europe, market integration on a European level is quasi non-existent, leaving aside East-West transit lines (but which are often technically separated or separable from the national local transport networks). While we expect market signals to drive infrastructure investment, there should ideally be multiple players along the value chain before there can be a market – these participants can only be present if the infrastructure allows it. Even in Western Europe, many downstream networks were built independently – for example there are at least three separate networks in Germany with minimal interconnections. Many network interconnections between member states in Europe are insufficient and serve mostly transit requirements. While they were not designed for market integration, there is at least the potential for buyers and sellers to transact in many countries; unfortunately this is discouraged in many circumstances by lack of optimisation of spare transport capacity. This state of affairs is, as noted above, a significant difference between Europe and North America.

b. Regulatory build-up

Regulatory harmonisation and a build-up of international experience are necessary across many European countries. Regulatory reforms must tackle internal harmonisation but also deal with the likely absence of similar reforms in neighbouring markets. Many European gas operators are importers of gas, therefore their main industrial assets are infrastructure (pipelines, storage, and LNG terminals), in some cases representing more than half of their balance sheet. This financial structure has been vital for negotiating long-term contracts and underpinning large investments with suppliers.

US gas regulatory policy is strongly grounded in pro-competitive, anti-monopoly law, naturally taking account of existing industry structures. Thus the approach has been to shrink the regulatory fence around monopoly parts of the system to the greatest degree possible, leaving other parts of the gas supply chain to compete effectively. Given the US gas upstream supply industry structure, with quite low concentration, this has led to a strong focus on the downstream part of the chain. Many FERC orders and regulatory efforts were designed to achieve greater separation between transmission and downstream sales, to ensure effective competition for consumers, avoiding monopoly abuses, and maintaining downward pressure on prices. These efforts culminated in order 636, legally separating transmission and sales. For Europe, with a high and growing concentration of suppliers upstream, theoretical considerations alone point strongly to the need of effective separation between production and transmission. It is worth noting that FERC, a well resourced, vigorous energy regulator, late in the reform process, having full jurisdiction over inter-state transmission companies, used legal separation to address monopoly issues. In Europe, where such an energy regulator doesn't exist (although a competition one does) vigorous action will be required to achieve desired market reform goals.

c. Investment challenges

The investment issue is of prime importance in the current European gas market because, on the one hand, such investments ensure security of supply and sustainable development of the industry over the long term and on the other hand, investment may well be necessary to make way for competition in the first place. Therefore, an important place must be given to the issue of investment in EU natural gas policy. First, demand is expected to grow in IEA member countries, while indigenous production declines and additional supply infrastructure is needed. This supply infrastructure includes long-distance pipelines from surrounding production regions as well as new LNG terminals to reach more distant supply sources. Moreover, as pointed out previously, markets need to be integrated in order to provide both more competition and security, meaning investments are required as well on internal level – interconnection pipelines and insurance capacity (notably storage) infrastructure.

3. Lessons learned from North America

Even if fundamentals differ in Europe, there are some lessons to be learned from the North American liberalisation experience.

Availability of gas for the market has been a major trigger for competition development in the US market. The absence of market power upstream and a demand-responsive production has contributed to create a flexible and competitive wholesale market.

Greater market integration can deliver more competitive, resilient and secure gas supplies, all the more given the rising role of gas in power generation. The network integration in North America around different market hubs, completed through market and regulatory mechanisms, has been fundamental for opening to competition. Such market structure is favourable for delivering large amounts of timely investment in all parts of the value chain, especially in long distance transmission.

The process of liberalisation is long, and could take more than a decade. The wholesale market restructuring in the US started in the end of the 1970s and reached its conclusion in the 1990s; still today, the regulatory process is being completed through continuous innovation and adjustment to the market evolution, and has not yet been extended to the majority of intra-state companies. Regulation needs to focus on clear identification of the areas of market failure and monopoly abuse, and target these effectively.

A clear advantage has been the existence of a single regulator for the market before the start of liberalisation, allowing a harmonised approach over inter-state issues, and ensuring long-term consistency of the regulatory approaches to the greatest extent possible.

Gas quality and technical standards harmonisation has also constituted an advantage for effective market integration and liberalisation.

However, even in a harmonised and integrated market, prices vary on different hubs and are set for different lengths of term and on many different bases (electricity, fertilisers etc.). Price differentials are due essentially to transportation costs.

Transparency and available information made compulsory by the regulators on federal and state levels have created the confidence that all players can have network access provided physical capacity is available. Greatly improved transparency can "shine a light into dark corners" highlighting monopoly abuses which need to be eliminated, such as capacity hoarding, or deliberate underinvestment to forestall competition. For investment, the role of the open season process has been essential to ensure future capacities match shippers demand. The sustainability of this system is based on its investor friendly characteristic, with first movers / first investors getting an advantage.

Legal separation of transport and sales in the US market was a key step to greater competition. In Europe, with notably fewer suppliers, legal separation of supply and transport should be completed with vigorous anti-competitive activity of a well resourced single regulator like FERC.

Natural gas will always be a regulated market – a totally free market is not possible. However, the regulatory framework, when designed to be "investor-friendly", can deliver a competitive and efficient market functioning.

B. What the European market could look like in the future

The European Commission is reforming the regional European gas markets in order to integrate them into a single European gas market, characterised by a workable competition delivering benefits to all customers. If workable competition is to be achieved in the European gas market, the following statements could describe the future features of such a market.

1. Market fundamentals

The concentration in the gas market leads to a small number of international companies operating on the European gas market; however, niche operators have also a place on this market especially on the trading, retail and service parts of the value chain, and increasingly in specific investment, e.g. storage.

Different layers of ex-ante regulation exist: a single European regulator for inter-state, transit and certain external activities; national regulators for retail customers and national companies. Ex-post regulation is possible for competition issues. Regulation is ever present in the gas business but remains stable, predictable, investor-friendly and aims at customers' protection.

The market is organised on a regional basis around several hubs, naturally bordered by physical infrastructure bottlenecks and not necessarily by national boundaries, with interconnections between the different market zones. These hubs have different characteristics – supply hubs, demand hubs, LNG etc. with appropriate and different pricing bases. Transmission capacities, storage and other services will be easily available and tradable.

The infrastructure profile of this market will be characterised by inter-state pipelines regulated on a European basis, national pipelines supervised on a national basis, with strong coordination between the two; storage serving either local or regional markets. The main features of the European network system are its flexibility and its resilience. Transparent and non-discriminatory third party access creates confidence in the market for all players.

Transparency of information will be radically improved.

2. Prices and market power

It will be possible to trade gas at prices set by the supply and demand of gas at that moment, taking into account future supply and demand as it is assessed. This will reflect the true market value of gas in a dynamic way.

The true market value of gas may, or may not, follow oil or other energy prices over the short, medium or long term; however, given the influence of so many other price determining factors such as coal, carbon, electricity, gas supply and demand in globalising markets, gas prices are highly unlikely to follow oil prices on any given day, or even for extended periods, in the same mathematical way as now.

Pricing systems in different parts of the European market will be interlinked through free trade and network integration. Supply shortfalls and surpluses will be shared without the need for administrative mechanisms; however, this may not totally obviate the need for additional security mechanisms.

Prices at the different trading points in Europe will not be identical. Wholesale price differentials between the different locations are justified essentially by transportation costs.

By aggregating all European demand into one interlinked market, upstream investment targeting that market will be more attractive, notably by becoming less risky, particularly for large supply increments.

Transparency is essential in this market. Market power abuses will be easier to identify, particularly those due to manipulation of physical gas flows as these become transparent. An agency tasked with investigative and punitive powers will be essential to monitor market functioning, as in the US and Canada, and will need the remit to investigate all companies active on the European gas market. Moreover, as the market becomes more dynamic, a short-term supply side response will reduce the impact of such physical market manipulation.

Gas markets will be less open to manipulation over the long term, because the principal of controlling market areas by major suppliers will be challenged by market transparency and customer choice in a globalising market. Consistent track record of market manipulation, e.g. due to under-delivery, will be punished by a loss of market share as price increases draw gas from other sources.

As in North America, wholesale gas prices will vary with time more than at present because gas demand and supply varies faster than oil, though less than electricity. Such variations, especially transparent predictable ones, will encourage investment in flexibility mechanisms, especially storage.

Gas prices will automatically reflect fair value – there will be no need to have price re-opening clauses if long-term gas contracts are indexed to hub prices. However, price regulation may be necessary in naturally uncompetitive areas of the market, as well as infrastructure itself; some groups of small users may also represent a natural monopoly, e.g. local utilities in small, emerging markets.

In a competitive market it is important that prices are subjected to competitive forces to ensure they are cost-reflective. In particular, price regulation of a potentially competitive market will distort the ability of the market to respond to supply interruptions, reducing collective security.

Futures prices represent an opportunity to reduce price exposure for several years (up to say five) but, even when the market is fully mature, are unlikely to be able to offer insurance for one business cycle of 15 to 20 years.

Futures prices and current spot prices (on-the-day prices) should not be seen to be a sufficient signal for new investment; investments will be made following analysis of long-term gas supply and demand in the expectation that this will be reflected in prices.

The EU ETS carbon price will be able to interact more strongly with a gas market priced every day rather than one priced every few months. This will give more cost-reflective carbon, power and gas prices, and better carbon mitigation outcomes.

3. Information and data collection

Transparency of information will be far greater, allowing more efficient use of pipelines and storage sites across the market place. Experience in other jurisdictions suggests productivity gains of 10-20% are available when fragmented networks are integrated in this way.

More information and data will benefit the understanding of the market by both producers and consumers, leading to better forecasting and greater long-term security of demand and supply.

Data collection will need to focus on the physical aspects of gas flows; storage and pipeline capacity availability and LNG terminal availability as well as supply and demand.

Financial data collection will become more difficult, the users of such information (regulators) will need special powers to access trading data in order to monitor the market, as with financial markets.

4. Companies

The European gas industry is likely to contain a mixture of vertically integrated, horizontally integrated, and specialist companies, as is the case in the US market. The main trigger for the structure of these companies will be the risk-reward profile and the shareholders' objectives. For example, regulated pipeline ownership will be a marginally profitable business for a highly leveraged company, which will probably render it financially unattractive to the shareholders of upstream companies. However, shareholders seeking steady if unspectacular returns may be attracted to these assets (e.g. pension funds). Potential market manipulation and cross-subsidisation by integrated companies will be prevented by strong pan-European regulatory authorities.

Banks will become more comfortable with gas-price risk based on a large liquid gas market. Upstream companies which are active in the debt markets will no longer have strong financing incentives to sell gas only at oil-indexed contracts, but will still be able to do so should they find counterparties.

Trading companies will have an important role by accepting pricing risks in a fair market. Trading companies will have a role in aggregating market knowledge and taking opportunities on behalf of risk-averse market participants, enhancing overall efficiency of the system. Proper financial regulation should prevent potential drawbacks from the trading activity.

A formal pan-European regulatory oversight and promotion of the trading hubs themselves to increase liquidity and depth should prevent use of market power in a concentrated gas market.

Production companies (especially if few in number) stand to gain financially over the short term from physical under-delivery to market centres. This increases the uncertainty, which causes in turn volatility in prices. Such a situation would give incentives for storage investment, providing an insurance against this behaviour in the short term.

Long-term reductions in production by underinvestment will draw more suppliers into Europe, such as LNG, or favour other energy sources, especially in the electricity sector.

Large gas consumers will be exposed to industry fundamentals for the first time through gas prices. Over time this will drive demand response in the industry. In some situations it may be more efficient for manufacturers to store finished products than pay high volatile prices – this activity will lower the volatility of the gas market as well as saving the gas buyer money.

5. Producer interests

The EU will represent a pool of demand for nearly 500 million consumers capable of paying attractive gas prices in the world market. Such buying power in one market will ensure security of demand for even the largest supply increment, and at the same time contribute greatly to security of supply.

It will be easier to add large, incremental supply to a Europe-wide market than it is currently to deliver the same supply to just one or a few individual countries.

Rather than having to displace existing sources of supply at the same oil-indexed price, new supplies will be complementary at a hub price.

Since pipelines will be open to third party access, in an integrated European market, a new supply project of moderate scale will be able to get gas to hubs without necessarily having to rely on a marketing company.

The supply-demand fundamentals for European gas will be clearer to all stakeholders: customers, suppliers, analysts and policy makers. Better investment decisions and better policy are likely to result from this increased transparency.

The true environmental and scarcity value of gas will be reflected in the price, potentially representing a premium on oil-indexed prices, in certain uses at certain times of the year, for example.

Producers have the option to supply their customers with gas from hubs rather than from their own production. This could be the case when gas prices are below marginal costs, or when they have an interruption in production, or a surge in demand in their home markets.

6. Consumer protection

National and EU regulators will have responsibility for consumer protection; they will no longer have the responsibility for increasing competition, but will need to focus on ensuring security of supply through incentives for sufficient investment.

Should they so desire, consumers can opt to be protected from volatility in the gas market as they are protected from the volatility of the oil market on which their prices currently depend in many cases; by paying an intermediary to sign a fixed price contract for a period they choose.

Consumers will be able to take an active part in energy procurement, either by switching supplier (residential + small industrial) or by actively managing their exposure to hub prices (industrial). Small industrials can rely on energy service companies to organise demand response for them. This will enhance the security of the gas system in the same time.

Careful consideration must be given to the level of consumer protection implemented in neighbouring countries as it could affect trade between them. This is the reason why such measures, including public service obligations and last-resort supplier mechanisms, need to be integrated within pan-European standards.

It will be possible to influence the behaviour of the gas industry through market-based mechanisms, for example, in order to encourage the development of more gas storage, or to invest in spare capacity.

The market should be regarded as a means of achieving an end and can be designed to be a very inexpensive or on the contrary very secure. By careful design the market can be weighted in favour of consumer protection, e.g. a law stating that residential customers must be physically insured against a gas demand peak corresponding to a 1 in 100 winter. Making the costs and benefits of these policies quite transparent is consistent with functioning markets.

Under normal conditions, some countries in Europe physically receive gas from only one source. Greater flexibility provided by an interconnected, integrated European market will allow gas from other sources to supply them in the event of a supply shortage – something currently impossible, even when there are potentially multiple supply sources, as pipeline capacity is often not contractually available (a form of market abuse).

7. Infrastructure and investment

In an integrated European market, additional infrastructure investments will no longer depend on large companies recovering costs from a critical mass of customers to which they have more or less exclusive access. Investments will serve market areas rather than specific customer groups.

Storage investment will occur first where it is of least cost and most value; storage built anywhere in Europe will contribute to security of the whole market and not just to the region in which it is built, given the increasing degree of pan-European network integration.

Prices within market areas will vary with supply and demand; an economic rationale will exist for pipeline investment between areas – to connect lower priced (over-supplied) regions to higher priced (undersupplied) ones.

“Open season” processes and capacity auctions will occur designed to split the cost and share the risks of substantial infrastructure investments among many companies (of different sizes), and determine the appropriate size for expansion of new projects.

Large investments can be made by informal consortia for the benefit of the market rather than by individual companies for the benefit of “their” customers – this lowers risks for companies, who can spread risk geographically, and consumers who will suffer less if one company under-invests.

Larger investments will have lower risk in a large integrated market; it is lower risk to add a 1 bcm storage site to the European market of consuming 540 bcm per year than to an individual country consuming 20 bcm per year.

Competition will be enhanced because barriers to entry and exit of the gas market will be lower – third party access to infrastructure will be enforced by powerful EU and country regulators.

As national and European regulatory bodies are to some extent responsible for security of supply, they play a greater role in the monitoring of gas networks maintenance and development. Regulators can take a pro-active stance by examining transmission system needs, and publishing regular "transmission investment opportunity statements". This function could also be performed by TSOs.

Should markets not be responding to consumer needs, or should lack of investment cause higher costs to consumers, in the absence of market based remedies, the regulator might seek to have certain links constructed if cost-effective. Similar approaches could be adopted for storage, in both cases taking account of government policy on for example provision of service to certain types of customers (e.g. households, hospitals) or overall security of supply objectives.

Box 11: How could the European market work in 10 years time if competitive trading develops?

In ten years time, European domestic production will have declined further, leaving Europe more reliant on imports. The major production areas (Russia, Central Asia, Algeria, and most LNG-producers) are located outside Europe and most gas is supplied by the producers on long-term contracts. However, more and more is also being sold directly into the hubs. LNG to some markets is almost all on a hub basis, with significant use of spot contracts (10% or more). In map 4 an overview is given of a possible market organisation.

The Central-European market will acts as a producer's hub, where Russian and Central-Asian gas will be sold. Depending on which area is priced most attractively, Algeria will either supply the South-West or the Adriatic market and gas from the North Sea will either flow to the United Kingdom or the North-West market.

The United Kingdom, North-Western and South-Western European markets will import large amounts of LNG, while the other supply markets (Baltic, South-East, Central-European, Adriatic and North-West) will be more reliant on pipeline gas. LNG prices will need at least to match US Henry Hub prices, and potentially compete with Asian buyers too.

In the following, to make the scenario more concrete, a year in the future will be simulated. At the start of the summer, with storage levels at around the five-year average, gas will be flowing from production areas, mostly outside Europe, into storage. The amount of gas storage and the type of storage will differ per market area, depending on the geological characteristics of a region, and its demand characteristics. While some areas will have more seasonal storage (depleted gas fields and aquifers) others will have more high-deliverability storage (salt caverns and LNG); however as long as the market areas are interconnected, storage can also be used in other market areas.

In the summer, especially in southern Europe, there is a growing peak electricity demand for cooling. Over time, power generation has become more and more dependent on gas, resulting in a high gas demand. Following price signals, most gas flowing through the Central-European gas hub will head for the Adriatic market and possible also the South-West market. Depending on Henry Hub prices, and potentially Asian prices, LNG will arrive in Europe.

If summer demand and prices are low, producers (especially in the smaller North Sea fields) might decide not to produce gas, but instead use it for injection into oil fields. In order to fulfil their commitments, producers would have to buy on the hub to deliver to their customers.

At the start of the winter, storages are full. Let's assume that temperatures in the northern markets, but also in Russia, are unseasonably low. Because of the low temperatures, Russia has a high domestic demand and needs to buy a small amount of gas on various hubs to fulfil its commitments to the market. As a result prices on the hubs will rise, and gas flows will be reset. The increased prices will have various effects.

First of all, gas flows will adjust to hub prices. The major gas flows through the Central European market will now head to northern markets with little flowing to southern markets. Although temperatures are not below average in the southern market, prices there still rise because less gas will be supplied to these markets.

Secondly, more LNG is being shipped to (the whole of) Europe. Prices on Henry Hub, the most important competitor for LNG in the Atlantic basin, are below European levels and available (spot) cargoes are transported to Europe. This will also tend to raise prices on the North American market.

Thirdly, the European market takes gas out of storage. Because it is still at the start of the winter, this is a difficult choice and depends on the marketer's expectation for the rest of the winter. Banks who are willing to accept risks and traders will make the system as efficient as possible.

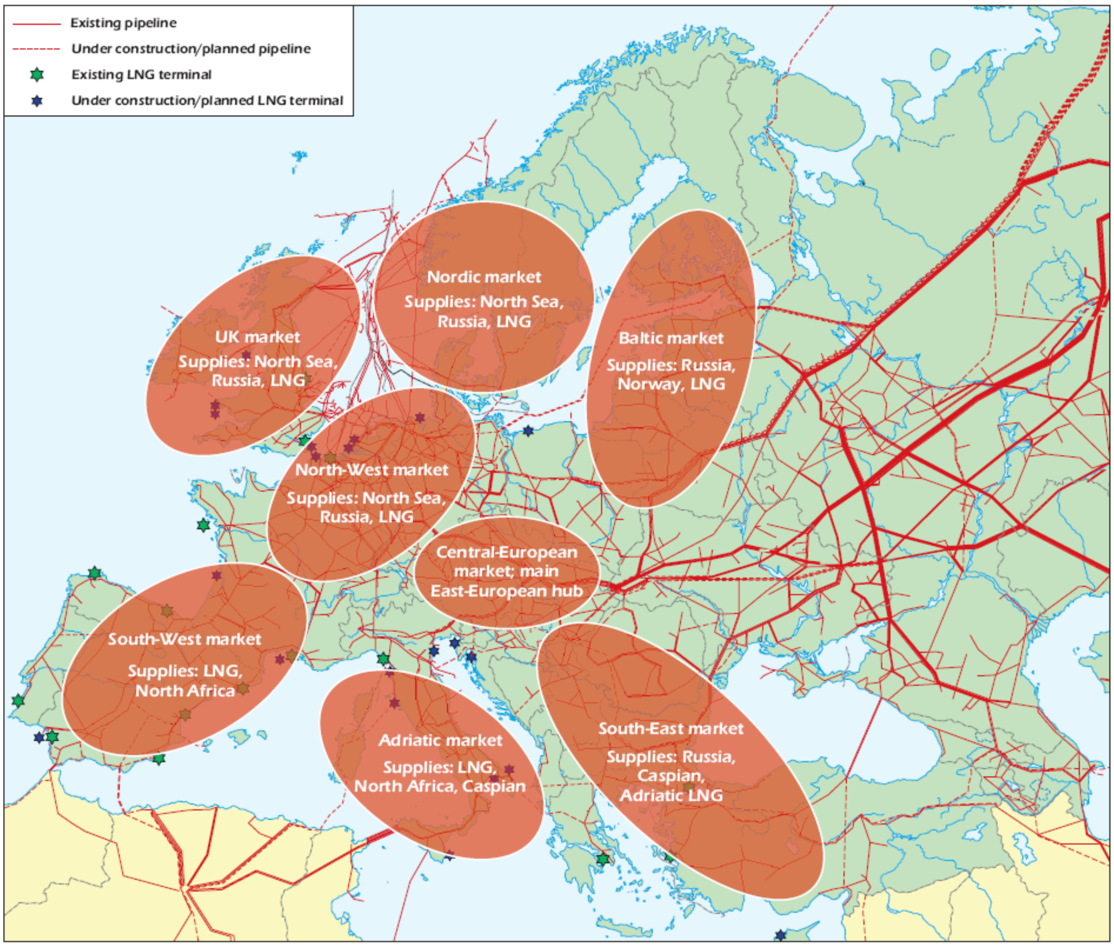
Fourthly, industrials and power generators will respond to increased prices. They have to decide whether or not it is attractive to switch to back-up fuel or reduce production. In 2018, switching possibilities have increased, as the added value to the consumer is based on market prices, which is higher than currently. Even if consumers, before the start of the winter, have bought gas on a forward basis, it might be attractive for them to sell the gas when it generates higher revenues. This will also be dependent on the carbon price, potentially to a significant degree.

All these actions will have a dampening effect on prices. The better the market is equipped to deal with these price increases, the lower the volatility on the market will be. For the market to react efficiently, real time information on gas flows, available pipeline capacities and storage levels is essential, which will give the market insight into the availability of gas and bottlenecks in the system and will allow the Energy Market Monitoring Agency – a single market-wide European agency charged with market monitoring and regulation – to investigate possible market manipulation (e.g. under-delivery). Unused capacity is made available to the market with the UIOLI principle, ensuring flexibility in changing circumstances.

When there is no congestion in interconnection between market areas, price differentials between hubs should not be larger than transportation costs; where such differences exist, they provide strong transparent signals for investment in pipelines, or possibly storage.

After a cold start of the winter, temperatures in the months January to April are above seasonal average. Gas flows from the Central-European market again will flow to the North-West and Adriatic markets. The more the winter progresses, the more gas prices weaken. At some point European prices will be below Henry Hub prices, causing most of the LNG to flow to the US and other consuming areas (e.g. South America, Asia or Pacific).

Map 4: Possible future market organisation



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Sources: Petroleum Economist, IEA

Chapter IV – IEA proposals for the European gas market

In order to achieve an efficient and integrated market structure for European gas, governments should focus on the following measures to implement within the legislative and regulatory framework of the industry: transparency of information, enhancing investment and regulatory convergence:

Transparency, adequacy and relevance of information available to the market are a priority, and should focus on production levels, flows, infrastructure planning and utilisation, and demand levels.

Governments should also propose **measures to increase commercial investment** – in transmission and distribution networks, in international interconnection as well as in flexibility tools. Promotion of an integrated and transparent internal network within Europe should trigger upstream investment in turn.

Investment-friendly regulatory convergence between European gas markets is the third pillar of the necessary measures to achieve a functioning integrated market. The regulatory framework should be designed to enhance investment and not impede it, noting that all infrastructure when mature "returns" to the free market.

I. Necessary transparency measures

One of the largest changes from the previous industrial model to the competitive market is that a substantial amount of information which was formally only needed by and available to individual monopolies now must be made available to the whole market. Clearly, confidentiality has value in a competitive market, but a high level of information to all participants is essential for the market to function.

In the old model, information was kept private unless it could be demonstrated that it should be public, whereas in a competitive market, information should be automatically publicly available unless it can be demonstrated that it threatens commercial functioning. Commercial integrity is not threatened in many circumstances despite the availability of large amounts of information on system operation, supply, demand etc.

For example, in both the North American and the British markets transparency measures are enforced and the market participants have adapted to the new situation. Timeliness of this information is also critical. For example, indicating that an LNG terminal is free the next day is not useful to markets as LNG shipping takes sometimes weeks. However, there are many barriers: institutional, technical and corporate culture to this information becoming available. The most important outcome is that governments, policy makers, regulators, markets participants and final consumers are better able to play a role in the market. Set out below are some types of information that well functioning markets receive.

A. Production

1. Economic reserves

Proven reserves are often published for a country as a whole. This gives the market uncertainty as to where the gas is coming from and the likelihood of its production. The information would be very useful if each producer has to publish their known reserves split up per field in a standardised way.

This approach provides market insight about the amount of gas per field that is able to flow in the future to the market. Market-players themselves can make investment decisions accordingly. Ideally this approach should apply to all reserves capable of supplying the European market.

2. Production rates

Supply forecasting is greatly improved if information is provided on actual field performance over time. Accordingly, annual / monthly production should be published by producers.

This will enable the market to build up better knowledge of the performance of certain types of gas fields in order to predict life cycles of new and existing supplies.

In both the North Sea and the US Gulf of Mexico production regions, surprisingly high decline rates have been observed; information on field performance could aid supply forecasting at other locations worldwide, and provide producers and consumers alike greater certainty for investment.

3. Planned production profile

Customers and prospective producers / suppliers should have an accurate view on the timing of production projects and their supply profile, probably well into the medium term, say 5 to 10 years. These data give the market insight about the amount of expected production. A history of such forecasts will give the market the ability to evaluate the quality of these estimates. Producers and consumers have an interest in gaining a clearer understanding of expected future supply into their market(s).

For example, the IEA produces a monthly oil market report which incorporates a market view on the timing of new field developments globally. This is a very important tool for the oil industry in assessing future supplies. A similar tool would be very useful for the gas industry.

B. Consumption

1. Historical consumption

It is very important for demand forecasting to have accurate information on the actual consumption by sector and sub-sector over time. The IEA collects monthly consumption data from its members. Each country should ensure that it has the necessary means to continue publishing consumption levels on a monthly basis despite changes to market structure. This will enable the market to build a more complete knowledge of the variation of demand in order to have better understanding of emerging market trends in the market, such as summer demand peaks in southern Europe.

2. Consumption forecasts

Producers, suppliers and consumers alike need to have as accurate as possible a view of future consumption evolution and the demand profile of markets they currently or potentially supply, over the same time frame as production forecasts, split up by sector and sub-sector in a standardised way.

The market will be better able to assess the required investments. In particular, producers will have a better idea as to what investments are needed. Rising gas demand is driven by power generation in IEA Europe: this will require for instance specific investments in the gas sector, like more short-term high-deliverability storage downstream.

C. Infrastructure

1. Capacities and historical flow data

It is impossible to know the level of congestion of infrastructure without daily information on capacity utilisation.

For each cross border entry-point into the system, the technical capacity and historical (and future) utilisation rates must be published with sufficient detail.

Transparent timely information on flows and capacities including LNG, storage and major pipelines will help to value gas at different locations and will enable greater efficiency of the use of the transmission system.

During winter 2005/2006, prices at Zeebrugge (and NBP) spiked; however, according to the companies it was impossible to transfer gas from continental Europe because of bottlenecks. Historical flows will show where the bottlenecks are, and enable investments to be confidently made to avoid them in the future.

2. Inventory and storage levels

Currently, many countries already give working gas inventories, but not all. Storage operators and LNG operators have to publish the amount of gas in inventory on a daily basis and the historical storage levels. In case of LNG also the utilisation rate must be given.

Inclusion of all countries on a comparable basis will give insight into the amount of gas available to the market, which enables available gas to be used more effectively, enhancing security of supply.

The EIA in the US publishes charts with current storage level compared to storage levels of the last five years (per region).

3. Future capacity availability

While the majority of firm capacity is allocated in long-term contracts, it is very important that the remaining capacity is made available to ensure that the infrastructure is fully used, balance the need for long-term capacity reservation and short-term optimisation.

A full schedule of infrastructure availability (including advanced reservations and maintenance periods) should be made freely available and UIOLI ("use it or lose it") principle should be strictly enforced on a regional basis. Capacity hoarding needs to be identified and unused capacity, both physical and contractual, freed up.

The Commission's sector enquiry pointed out that much of the transportation capacity in Europe was not open to competition due to foreclosure, even when not actually being used. This represents a substantial barrier to entry in the market. On the contrary, in the US market, FERC requires pipeline companies to establish electronic bulletin boards to provide shippers with equal and timely access to information about the availability of service on their systems.

4. Short-term balancing

For liquidity to develop at traded locations, all market participants must have access to the same quality of information on the day-ahead and within-day balancing markets.

Transportation business practices should be standardised across Europe to provide common nomination and scheduling timelines as well as internet-based communication with all counterparties on an equal basis. Also, temperature-dependent demand curves should also be made available to all market participants.

No single market participant has access to physical balancing information before its competitors. This will generate confidence in the market and attract liquidity.

For instance, FERC order 636 in the US market required pipelines to provide open access transportation services that are equal in quality whether the gas is purchased directly from the pipeline company or elsewhere, such as from a producer or a marketer.

5. Commercial transparency

Tariffs and commercial conditions for storage, LNG and transmission services are fundamental but frequently difficult to determine on a comparative basis.

Hence all regulated tariffs should be published and be freely available to potential clients on a comparable basis. This will create a level playing field and allow system optimisation as capacity services will be easier to transact.

II. Proposals to enhance investments

A. Regulatory predictability and stability

Multiple regulatory regimes, and the resultant potential for inconsistent changes in the regulatory framework, can have a detrimental effect on investment by increasing the level of risk. This is one major reason for the current shortfall of European investment. A single regulator offers the opportunity for simple, stable, predictable transparent regulation, certainly for pipelines crossing national frontiers. Such a central regulator should strive for regulatory convergence among national regulators to avoid distortions between intra-country and cross-border investments.

In order to reduce the investment risk, inevitable regulatory changes whilst the market develops should be set in a context of a coherent energy policy and a long-term vision.

B. Regulated investment planning

Not all European TSOs are open about their investment planning nor are such plans coordinated among TSOs.

Each TSO should produce a medium- to long-term investment plan. The investment plans of the TSOs have to be coordinated and optimised on a regional / European level.

Providing insights on overall investment planning by European TSOs would help increase visibility in network development and improve confidence in the market. It also helps regulators to benchmark their TSOs investment plans.

For instance, the French TSO is already publishing a ten-year investment plan coordinated with the French regulator, and thus giving clear insight on the French network development to shippers and suppliers.

C. Cross-border investment commission

Many markets in Europe are not sufficiently interconnected and there is no responsibility for cross-border regulation which would allow this interconnection to be made by individual country TSOs (indeed for many, it would be beyond their powers). The anticipation is that market-based mechanisms will drive investment between hubs, but the hubs have not yet developed sufficiently to allow this – therefore the investment is not forthcoming. But without more cross-border investments, hubs will not develop, or certainly not in an optimal way and in a reasonable time span.

A European body should be established to act as a catalyst for cross-border investment (as well as assess transmission adequacy) in the absence of companies with this skill set. The body might identify potential interconnection possibilities in concert with the TSOs and national regulators and then identify and aggregate shipper interest through an open season process. This body should act on projects which enhance efficiency through completion of the internal market and also increase security through greater diversity of supply routes and sources.

There is a role for a single, central administration to support and enhance the market at its early stages. The European gas market would clearly benefit from measures which would allow new market entrants to own capacity in new interconnections, thus improving competition and security. It would be expected that private companies would step in to manage the project once sufficient shipper interest is identified, and stakeholders are convened. In the case of marginal projects (from the point of view of shippers' opportunities), support mechanisms might be considered if these serve the purpose of European network integration, or system security. In Eastern Europe, for example, more diverse pipelines need to be present in order to bring multiple suppliers and multiple consumers together in a competitive market. One possible way to do this might be through a North-South interconnector, linking existing, mainly East-West pipelines.

D. New supply for Europe

The European Commission has recently introduced a mechanism whereby significant new supply for Europe can be given political support in order to align stakeholders' interests. However, criteria for European interest project status are ill-defined. Projects which are worthy of such status and support should be able to demonstrate substantial enhancement of European security through greater diversity of supply routes and sources, and efficiency through completion of the internal market.

Ensuring that these projects fulfil multiple criteria simultaneously will help attain the main objective of the single European gas market.

Nabucco is an example of a European priority supply project and has been given a European coordinator support, because it offers a means for greater cross-border interconnection in south-east Europe, as well as diversity of gas sources and supply routes.

III. Regulation

A. Regulatory authorities

1. European regulatory body

Since the beginning of the liberalisation process, regulation has been at country level. A single European regulator is needed to ensure proper market functioning, including market integration, and balance of power between all stakeholders, including customers.

As with national regulators, the European regulatory body should be independent from executive powers as well as from the market players.

In the United States, Canada, and the United Kingdom, independent regulators are charged with the mission of consumer welfare through regional regulation.

2. Consolidation of regulatory powers for national regulators

Consumer welfare protection and efficient market functioning should be priority missions to all national regulators, including the European regulatory body. National regulators currently have a tendency to focus on the long-term reduction of costs without due attention to the impact on investment and hence security.

The regulators should be explicitly entrusted with consumer welfare protection and correct market functioning. For example, regulators should scrutinise supply contracts signed on behalf of consumers to ensure these are market-based and beneficial to the consumers, while recognizing contractual freedom and the necessity of a long-term outlook for investors.

Expanding the missions of the regulators to these aspects ensures that the markets deliver at the best price and optimal security.

In the US, the role of state-level Utility Commissions is to ensure that long-term contracts are market-based and to the benefit of the customers. The state Utility Commission has the power to intervene if such contracts can be proved not to be in the interest of consumers.

B. Enhanced regulatory prerogatives

1. Common preferred balancing regime and trading contracts

Different market areas in Europe have individual balancing mechanisms in order to suit the needs of the local markets. There is a role for an EU-wide body in harmonising the balancing regimes and trading contracts across the European market to aid liquidity and market functioning.

Balancing regimes and trading contracts should be market-based and harmonised to the greatest extent possible. Guidelines or minimum requirements at EU-level would help in convergence of systems and to prevent balancing systems based on a non-cost reflective penalty.

More harmonised balancing regimes and trading contracts will promote competition on a European level rather than a national level and remove potential barriers to entry in more onerous balancing systems. More harmonisation between regional operators will ultimately lead to the ability to book bundled multiple capacity across Europe on a common platform. A totally fluid pan-European "gas pool" is not necessary - the speed and the cost of gas transport does not make the prospect of physically flowing gas from "Stockholm to Sofia" economically possible or desirable, especially given that such a trade can be achieved indirectly by re-routing gas flows at the margins. This will allocate flexibility more efficiently between the European markets and therefore increase their collective security.

An example of market-based balancing regime may be found in the United Kingdom where incentives are given to keep the system in balance. As for harmonised trading contracts, work on this aspect is being done by EASEE-gas (European Association for the Streamlining of Energy Exchange – gas).

2. Secondary capacity markets

The optimal use of infrastructure is one of the main benefits achievable through the EU market reorganisation. However, as secondary capacity markets are not obligatory in Europe (and are, at best weak, illiquid, or non-existent), capacity hoarding is possible.

Secondary capacity markets should become obligatory, and use it or lose it clauses should be applied to firm capacity purchases. Derogations might be possible if not contrary to competition development.

These measures will allow the maximum opportunity for market participants to obtain access to infrastructure.

To help the capacity release market develop in the USA, FERC required pipeline companies to establish electronic bulletin boards to provide shippers with equal and timely access to information about the availability of service on their systems.

C. Global objectives

1. Investment-friendly regulation

In the present market context, significant shortfall in investment throughout the value chain of the industry can be observed globally. The regulatory framework implemented in European gas markets should be designed as "investment-friendly", to allow costly and long-term investments needed by the markets to be realised. Regulatory holidays / exemptions are an important tool to encourage new investment in the gas industry. For example, TPA access exemptions (time-limited) undoubtedly encourage LNG terminal and large transmission investment.

In the US market, this approach has been adopted to enhance infrastructure investment. Once the infrastructure is mature, it can return to the free market and be opened to third parties.

2. Promotion of European network standard

There is not yet sufficient confidence in European markets as being part of the same system – external suppliers still seek to bypass transit countries even if these countries are situated inside the European Union or are IEA member countries.

Harmonised and transparent access to networks within Europe should be promoted to avoid excessive costs of bypassing supply infrastructure and duplication of pipelines for non-economic reasons.

Once gas enters a European network, the shippers should be completely confident about its transport or transit throughout European territory, including cost and other conditions of access.

Glossary

AGIP – Agenzia Generale Italiana Petroli (oil and gas producer in Italy)
BASF – Badische Anilin- und Soda-Fabrik (German chemical company)
BCM – billion cubic meters
BEB – Brigitta und Elwerath Betriebsführungs (German gas company)
BGC – British Gas Corporation, now British Gas (former UK gas incumbent)
BMP – Bataafse Petroleum Maatschappij (Dutch gas company)
BP – British Petroleum (international oil and gas company)
CAMPUT – Canadian Association of Members of Public Utility Tribunals
CEGH – Central European gas Hub (Austria)
CMEA – Council for Mutual Economic Assistance, USSR-backed trade organisation in East Europe before 1991
DONG – Dansk Olie OG Naturgas (Danish gas incumbent)
DTI – Department of Trade and Industry (UK)
EDF – Electricité de France (French electricity incumbent)
EEA – European Economic Area (EU + Norway, Iceland, Liechtenstein)
EFET – European Federation of Energy Traders
ISDA – International Swaps and Derivatives Association
EIA – Energy Information Administration (USA)
EnBW - Energie Baden-Württemberg (German energy company)
ENEL – Ente Nazionale per l'energia Elettrica (Italian electricity incumbent)
ENI - Ente Nazionale Idrocarburi (Italian oil and gas integrated operator)
ERGEG - European Regulators' Group for electricity and gas
ETP – Elektronaya Turgovaya Ploshchadka (Russian hub)
FERC – Federal Energy Regulatory Commission, (USA)
GdF – Gaz de France (French gas incumbent)
GIE – Gas Infrastructure Europe
GRTgaz – Gaz de France Réseau de Transport (TSO of Gaz de France)
ICE – Intercontinental Exchange
ISO – Independent System Operator
IZTF – Interconnector in Zeebrugge terminal facility
LEBA – London Energy Broker's Association
LDC – Local Distribution Company (USA)
LNG – liquefied natural gas
MMC – Monopolies and Mergers Commission (UK)
NAFTA – North American Free Trade Agreement
NAM – Nederlandse Aardolie Maatschappij (gas production company in the Netherlands)
NARUC – National Association of Regulatory Utility Commissioners (USA)
NBP –National Balancing Point (UK)
NEB – National Energy Board (Canada)
NIMBY – « Not In My Back-Yard »
NIT – NOVA Inventory Transfer hub (USA)
NYMEX – New York Mercantile Exchange (USA)
OFGAS-OFGEM – Office of Gas Supply / of Gas and Electricity Market (UK regulator)
OMV – Österreichische Mineralölverwaltung (Austrian oil and gas incumbent)
OTC – "Over The Counter"
PEG – Point d'échange de gaz (French trading hub)
PSV – Punto Scambio Virtuale (Italian hub)
REX – Rockies Express pipeline (USA)
RWE - Rheinisch-Westfälisches Elektrizitätswerk (German energy company)
SNAM – Società Nazionale Metanodotti (Italian gas transport operator)
TAG – Trans-Austria gas pipeline
TIGF – Total Infrastructures Gaz France (TSO of Total in France)
TPA – Third Party Access
TSO – Transport System Operator
TTF – Title Transfer Facility (Dutch trading hub)
UIOLI – "Use It Or Lose It"
UKCS – United Kingdom Continental Shelf
ZBT – Belgian trading hub, Zeebrugge Trading
ZPT – Zeepipe pipeline terminal (Belgium)

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