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“Natural Gas Wholesale Markets”

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Scheme

The diagram below illustrates the content and key ideas addressed in the unit and their interrelationships.

Figure 1 content and key ideas
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1 Introduction

This reader is an introduction into whole-sale gas markets and their restructuring. It is based on an EU perspective. Processes of liberalisation and deregulation in the world gas industry differ substantially from the one country to the other. There are a number of common characteristics, however. These involve:

- The separation of the segments of the gas business which allow for competition (production, trade and supply) from those constituting natural monopolies (transmission and distribution) that must be regulated. In some countries storage and conversion are in the former category, whereas regulation is required in others.
- The establishment of a wholesale gas market where producers and traders compete.
- Third party access to the transmission and distribution network and the respective access rules and tariffs.
- Freedom of choice of supplier for qualified or eligible customers.

As is stated in the FSR Electricity Wholesale Markets module, individuals interact on the marketplace guided by an “invisible hand” that leads them to seek socially optimum results. The market price is the invisible hand that drives economic activity and ensures an efficient allocation of resources. The study of the wholesale market is essential to understanding the workings of the gas industry in this new environment.

It was also argued that state intervention and regulation can improve results when the market is unable to provide an optimum allocation of resources. This so-called second-best solution requires active decision-making as regards gas market design. Like the electricity market, also the gas industry involves specific market failures which require regulatory intervention to correct the unintended outcomes of the failing market. And also in the gas market, the possible objectives and the instruments for intervention must be carefully considered in designing an effective and efficient wholesale market, while ensuring that market operation is distorted as little as possible.

The analysis of the wholesale electricity markets has pointed to specific complexities in their operation and design, as a consequence of the characteristics of this sector. As will be shown in this module, the power sector has a number of characteristics in common with the gas industry, which to some extent justify analogous solutions. Insofar these characteristics and their theoretical underpinnings have been dealt with already in the electricity wholesale market module, they have been skipped in this module.

Nevertheless, as will become clear below, the gas industry has many specific characteristics that require different considerations and regulatory approaches. A main element in this respect is that the whole sale gas market is conditioned by high-ranking decisions, relating to the market structure and institutions and the possible transactions between different market agents. The power market is constituted, by and large, by private and public firms that produce and sell power within the jurisdiction of the Member States of the European Union. In contrast therewith, in the wholesale gas market, natural gas is often produced and commercialized via firms that are controlled - to a varying extent - by the
authorities of the gas producing countries, like Norway, Russia, Algeria and the Netherlands, etc.

Whereas, competition in the several national power markets can be enhanced by increasing the interconnection with neighbouring systems, a major portion of the natural gas requirements has to be imported from only three countries which are outside the EU Single Energy Market. In addition to the investments in exploration and production in the producing areas, the physical infrastructure has to be constructed from the producing area, via transit countries to the consumer countries. International, public and private, agreements form the basis for the system of governance that supports production, transit and trade of gas in all States involved.

This module will provide an insight in the main determinants of wholesale gas markets. It is organized in sections that contain explanatory and illustrative material. This material originates from studies and reports by the author and by others, governmental policy papers, legislation, preambles, regulatory guidelines, etc. On every occasion the origins of the material are provided in the footnotes and the list of references.

1.1 Objectives

• Understand the theoretical fundamentals of natural markets.
• Analyse real-life problems arising around their implementation.
• Analyse the different market components.
• Study different alternatives in market design.
• Analyse and evaluate the merits of different experiences.
• Develop a feeling for the relationship between dynamics in the market, in politics and in the regulatory framework.
2 The supply of natural gas

2.1 Introduction

Electricity production can take place anywhere land planning regimes allow it. This is radically different in respect of the production of natural gas. Producible gas reserves are found only in a few places, sometimes at a large distance from the markets.

![Diagram of Gas reserves distribution](image)

Figure 1 Distribution of Gas reserves (BP 2012)

It is important to highlight a number of techno-economic characteristics of gas systems before proceeding with the analysis of costs, prices, markets, and regulation. Because of the nature of the gas production and transport activities, gas systems involve large, fixed, and specific capital outlays. A key challenge, therefore, is to maximise capacity utilisation of the system, recover the high fixed costs, and achieve an acceptable level of profit. So, gas system operation requires a constant, close-to-capacity production. This also applies to the transmission capacity, and the distribution and storage systems, used to transport the gas from the wellhead to the areas of consumption and to individual consumers.

Moreover, there is the cyclical nature of demand, on a daily, weekly, or seasonal basis. In combination with the fact that the amounts of gas delivered to and flowing out of the system must be equal, this requires a strong match of supply and demand. Storage is technically possible, but comes at a considerable cost.

A crucial spatial element in the evolution of the supply systems is the phenomenon that, by and large, the distance over which gas is to be transported from the production location to the centres of consumption is increasing. Preferably, gas exploration, the development of reserves, and their eventual production take place, as close by centres of consumption the consumer as possible. Transport is expensive and it reduces the flexibility of gas supply to meet the daily and seasonal variation in demand. So, in a stylized way, the development of gas resources should evolve in a pattern of concentric circles, around the center(s) of gravity as regards consumption.
This pattern is of course not consistent with what we actually observe. Old fields keep producing because they are huge, because technological development facilitates a ‘second life’, or because they are conserved for reasons of national resources policy. Nevertheless, most of the ‘greenfield’ gas production will take place further and further away, requiring longer pipelines and more compressors to move the gas through the pipelines. It will also involve more countries to go through.

Moreover, in many places, large volumes of gas are produced in joint-production, dissolved in the crude oil. The characteristics of the joint-production of gas and oil may yield large difficulties in coordinating the output and marketing of both types of output.

Nevertheless, the falling cost of Liquefied Natural Gas (LNG) production, transport and handling have changed traditional supply perspectives. By allowing gas to cross oceans and thus connecting isolated reserves to main consumer markets, geographical, economic patterns of gas supply are experiencing radical shifts. The emerging patterns of trade impose stringent requirements on the coordination of marketing, planning, and investments in production, transport and storage capacity.

Depending on specific regional circumstances these changes may be more or less relevant, but in general they of crucial importance in understanding and conditioning suppliers’ and consumers’ behaviour in the market. Gas production

EU Europe consumed 447.9 Billion cubic meters (Bcm) in 2011\(^1\). There are only a few EU countries in which a significant production of gas takes place. These are the UK (45.2 Bcm), the Netherlands (64.2 Bcm), Germany (10 Bcm), Denmark (7.1), Italy (7.7 Bcm) and Poland (4.3 Bcm). Altogether the EU produced 155 Bcm in 2011. Most of the requirements are imported from outside the EU. Norway (95.4 Bcm) plays an important role as a European supplier. Russia supplied about 140.6 Bcm. Algeria supplied 32.8 Bcm by pipeline and about 16.8 Bcm as LNG. The remaining requirements were imported from a variety of other (LNG) suppliers.

The EU has some 1.8 Trillion cubic meters (Tcm) of proven gas reserves at the end of 2011. Norway has slightly more, 2.1 Tcm. About half of the EU proven reserves is located in Netherlands (1.1 Tcm). The UK holds 0.2 Tcm, Germany and Italy hold 0.1. Smaller levels of reserves exist in other member states\(^2\).

The Netherlands is a major exporter to other European countries, while also importing from Norway, Russia and the UK. The UK exports gas to the continent via the Interconnector and to Ireland. Germany also exports small quantities of gas to neighbouring countries, as does Italy to an even lesser extent. Although Danish reserves are small in the overall European context, they are large enough to supply the entire Danish market and to support exports to Germany, Sweden and the


\(^2\) BP Statistical review of World Energy 2012.
Netherlands. With these exceptions, indigenous reserves are typically exploited by member states for their domestic markets.

Production is expected to decline in most EU countries. By 2015 only the Netherlands and the UK are likely to make significant contributions to EU gas supply. Of course, Norway will continue to export gas. Further requirements will have to be imported from sources outside Europe and the possible development of indigenous shale gas production.

As regards the roles of the several European exporting countries there is quite a variation in the organization of the industry and the role of the states involved.

The Netherlands’ gas market structure is governed by partnerships between the State and private companies. Gas production and exports are vital to the Dutch economy and the government has kept tight control over the industry, since the gas market structure, or Gasgebouw was developed after the discovery of the Groningen field in 1959.

Shell and ExxonMobil are dominant in the Dutch gas industry via their 50/50 joint venture NAM, the largest E&P operator in the country. Both companies also have an interest of 25% each in the wholesale trading company Gasterra, in which the state holds the other 50%. NAM holds the concession for the huge Groningen field.

The state’s 40 or 50% direct interest in most of the other gas production concessions is operated by Energie Beheer Nederland (EBN). EBN and NAM are also involved in the development of other fields, together with Wintershall, Total, GDF, Taqa, and Unocal and some other firms.

Production started with development of the large Groningen field in the early 1960s. The so-called ‘small fields’ started to come on stream in the mid-1970s. Under the small fields policy Gasunie was required to buy all gas on offer from small fields if requested. The prices paid for gas from smaller fields are about the same as those for imported gas. Gas from small fields does not have to be sold to Gasunie anymore, however. The government considers the small fields’ policy as important for security of supply and the long term future of the Dutch gas industry. Some gas producers, though, regard continuation of the small fields’ policy as incompatible with a liberalised market. There are now around 200 small fields in production, on- and off-shore. Just over half of these fields are offshore.

The purpose of the small fields policy, which was introduced in 1974, was to encourage the development of other smaller fields to prolong the life of Groningen field which has a unique flexibility, with production ranging between zero and 500 mcm per day. This is enough flexibility to cope with seasonal variations in the Dutch market and to increase the value of Dutch exports by adding swing. The state has put a cap on the annual production rate of the Groningen field of 425 Bcm over a ten year period. As production from small fields has started to decline, production from Groningen has increased in recent years. Moreover, Gasterra and other players have increased imports to supply both the domestic market and exports.

The UK was among the front runners in liberalizing its gas industry. In the past, all gas produced was sold to British Gas. In several steps and through a steep learning curve, the traditional UK industry was dismantled and converted into the current system. An important prerequisite for a competitive market in the

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production sector is to have a multitude of producers involved in exploration, development, production and sale of the gas reserves. That problem was addressed first through a requirement for producers to sell 10 per cent of the output of new fields to buyers other than British Gas and secondly through a gas release scheme. Producers start selling their equity shares in field production separately to separate buyers. In the UK equity partners now have the option to sell their shares on long term contracts to a third party such as a power generator or another gas supply company or else sell the gas to their own downstream marketing affiliates for direct sale to retail customers.

The UK offshore production currently is rather competitive, with 45 companies involved in oil and gas Exploration and Production in the UKCS. All of the major oil companies are represented (Shell, BP, ChevronTexaco, ConocoPhillips, ExxonMobil, Marathon, Total, Statoil) as well as European gas companies (GdF, Eon Ruhrgas, BG group) together with many smaller independent companies. This structure is supported by an open and non-discriminatory licensing regime and a tax regime which encourages investment.

It is often doubted that producers will develop gas fields without the comfort of a long term sales contracts for all (or a high proportion) of the output of the field. Yet, in the UK some large offshore fields, such as Britannia, have been developed for sale into the spot market. This development clearly required the spot market to develop sufficiently to be able to absorb the producers’ quantities without a material impact on the price.

**Germany** is a significant gas producer. There are 16 exploration and production companies. Two of them, however, are responsible for three-quarters of German production, namely Shell BEB Erdgas und Erdöl (50%) and ExxonMobil (25%). Like NAM in the Netherlands, BEB is jointly owned by ExxonMobil and Shell so these two companies are dominant in the German production sector.

Most production is onshore with limited offshore production in the North Sea which is exported to Netherlands.

Germany has already been fully explored for gas deposits. Proven gas reserves are estimated at 0.1 TCM; considering the current production volume, the proven reserves would be enough to cover 6.4 years of supply. Thereafter, Germany will become fully dependent on imports.

**Italy**, in 2011, had a domestic production of 7.7 BCM, which accounted for less than 10% of total gas consumption. Italy's natural gas fields are located in the Po Valley and offshore in the Adriatic Sea. Proven gas reserves are estimated at over 0.1 TCM. A decrease in indigenous production is expected. Eni is the largest gas producer in Italy as well as controlling the import infrastructure.

**Denmark** is more than self-sufficient in gas and exports to Sweden and Germany. Production in 2011 was 7.1 BCM, which was partly exported to Germany and Sweden. Own consumption was 4.2 Bcm. Reserves stood at less than 0.05 TCM at end 2011. Exploration, Development and Production of oil and gas is concentrated in the hands of the DUC (Dansk Underground Consortium) which is a joint venture between A.P. Møller, Shell and ChevronTexaco.
Poland, in 2011, had a domestic production of 4.3 BCM, which is about a third of its consumption of 15.4 Bcm. Proven gas reserves are estimated at 0.1 TCM. Decrease in indigenous production is expected. The Polish gas industry is dominated by PGNiG (Polish Oil & Gas Company), taking care of 98% of gas the production.

Norway has approximately half of the remaining reserves of oil and gas in Europe. It covers 10 per cent of Europe's gas consumption and within a few years will increase gas exports dramatically and account for 30 per cent of European gas imports. Norwegian pipelines supply gas from the North Sea and the Norwegian Sea to England, Germany, Belgium and France. Norway is the world's biggest operator of submarine gas pipelines. It is preparing to meet the challenge that the liberalisation of the gas markets in Europe will present.

Norway is now preparing the development of the Ormen Lange field, a major gas field situated at a depth of 1,200 metres in the North Sea. This extends the gas perspective northwards on the Norwegian continental shelf. An even more extended perspective includes the Barents Sea, the arctic part of the Norwegian shelf. Plans are also in hand to develop the Snøhvit field on the Tromsøflaket off north Norway, bringing the arctic petroleum perspective even closer.

Norway is a main long term producer, with a huge resource base. Even where a large number of producers are active there may be concentration of sellers’ power through the operation of a cartel such as the GFU in Norway (now disbanded) or by joint venture partners in specific field developments selling gas jointly under identical terms with the revenue split between the partners.

Figure 2 Source: BP 2012.
2.2 Market and Geography

The EU gas market is not simply one single market in one geographical area. It is composed of a set of partly overlapping, partly complementary markets. Within the EU the consumption of gas in the Member states was 447.9 Bcm by 2011. This was supplied from the following sources:

- The current (2011) indigenous gas production within the EU countries of 155 Bcm, partly (88 Bcm) exported to other EU Member states;
- Current long distance pipeline supplies from Russia (117.1 Bcm), Norway (92.8), Algeria (32.8) and Libya (2.3 Bcm).
- Current LNG imports from Norway (2.6 Bcm), Algeria (11.6 Bcm), Nigeria (14.4 Bcm), Qatar (42.8 Bcm), Trinidad & Tobago (3.9 Bcm), Peru (1.9 Bcm), Oman (0.2 Bcm), Egypt (4 Bcm) and Yemen (1.2 Bcm).

Within this context, the Pipeline supply market is most important in terms of volume. The wholesale market served by pipeline is determined by access to the pipelines and other infrastructure in the producer countries and the transit countries and will be of key importance to achieving truly competitive markets within the EU itself.

A further crucial element of the pipeline market is that a significant proportion of the gas used in the EU has to transit a number of other states, like the Ukraine and Byelorussia, before entering the EU. Moreover, the Interconnector with Belgium and the Balgzand-Bacton pipeline (BBL) from the Netherlands are important in supplying the UK and Ireland. This illustrates that access to the infrastructure towards and within the EU will be important for competition to develop within the EU and for security of gas supply.

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4 BP Statistical review of World Energy 2012.
5 Figures don’t add up fully, because of internal re-trade.
The supply of LNG to the EU market is becoming increasingly important and a considerable number of import terminals has been expanded and newly constructed within the EU. In 2004, most of the LNG imported into Europe was supplied by Algeria and Nigeria, and delivered to Spain, Italy and France. Since then, the situation has changing markedly with increased supplies coming on stream from Trinidad & Tobago, Qatar, Egypt and Libya, starting to supply LNG to Europe. State-owned oil and gas companies typically own between 25 and 70 per cent of these projects, compared with 100% in the case of Sonatrach leaving more room for involvement of international oil and gas companies.

Gradually, LNG is also becoming a commodity, particularly, because of the decline in importance of the US, because of the growth in unconventional gas production. This implies that LNG suppliers that were competing to supply the US are now focusing on the European and Asian markets, in which an increasing amount of liquefaction capacity has been constructed. In respect of the contracting structure, a varying amount of uncommitted volumes is offered by suppliers to traders, supporting the development of the short term spot-market. Yet, it remains to be seen how gas demand will evolve. It definitely depends on the speed at which the EU economy will catch up after the crisis, the impact of European policies for a sustainable energy system and the evolution of the supply of piped gas to the EU. A final consideration is the possibility that unconventional gas will be playing a role in (parts of) Europe as well.

2.3 Self-evaluation

- What are the main supply options to Europe?
- How does the spatial pattern of gas supply evolve in the future?
- What kind of change may be brought about by the development of LNG?

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3 Regulating the Natural Gas Industry

3.1 The International Gas Value Chain

Similar to the electricity industry, the gas industry involves two main types of activities: the on-going exploitation and operation of the existing facilities and the decision-making on investments to build new or upgrade existing facilities. Investment is required: firstly, to accommodate demand growth; secondly, to replace obsolete installations; and thirdly, to replace production, treatment and transit assets, when existing natural gas field mature and fall into decline. Within the gas industry value chain, these two activities are linked by the remuneration mechanisms to the several owners of these assets.

Typically gas supply systems involve five segments, each with a more or less specific focus of regulation in a liberalized market.

The exploration and production segment includes a variety of major operators involved in exploration, drilling, production, and the collection of gas from the fields’ wellheads to move it to the transmission pipelines. Main elements of the regulatory environment involve a permit, depletion and taxation regime, plus environmental and safety requirements. Gas exporting countries, such as Russia, Algeria, Norway, the Netherlands, Nigeria and Qatar prefer to maintain substantial government ownership in this segment of the market. Several models exist under which oil and gas reserves are exploited. In a large number of countries, publicly owned National Oil Companies (NOC) have a main role in exploiting the gas reserves. Many of these countries do not allow foreign and international oil companies (IOCs) to directly invest in these activities. Sometimes foreign firms are invited to carry out specific tasks as subcontractors. In other countries, IOCs take part in joint ventures with NOCs, to carry out the activities and to share the profits and royalties. Often, IOCs - sometimes in joint ventures with each other or with NOCs - conclude Production Sharing Agreements (PSA) with the government to arrange the sharing of costs and profits. In some cases, the oil companies are forced, or stimulated, to sell the gas produced to a national state entity that takes care of the export of the gas to foreign consumers. Sometimes, the gas is sold to the neighbouring country’s pipeline operator or a specific wholesale trading firm. Sometimes it is sold directly to an importing trader, or distribution company abroad.

Gas transit and transmission involves the long distance, high-pressure pipeline transport of gas from the producers to the consumer markets, or LNG systems including, gasification, ocean-going tanker transport and re-gasification terminals. A large variety exists in public, private and mixed national and international consortia operating the interconnected segments of these pipelines. Generally, when crossing the border, a different pipeline operator takes over and sometimes the ownership title of the gas changes. The pipeline transmission segment of the industry is seen as a natural monopoly, because of economies of scale and scope, the huge fixed costs of pipeline construction and the relatively low variable costs of their operation, plus their essential facility character. Effective regulation of pipelines is considered problematic, because of the cross-border character of the systems, crossing several jurisdictions with sometimes contrasting principles and interests. LNG gasification terminals, in contrast, are sometimes - but not always - considered as potentially competing facilities and regulated accordingly, via either exemptions or regulated TPA.
The third segment in the value chain involves the **wholesale companies**. These firms, generally, operate on a national basis. They contract the gas from the producing companies and supply the local distribution companies, large consumers or to (a succession of) traders. In the past, these wholesale companies also operated the national transmission system in the consuming countries. Today, these transport systems are operated separately, generally. Unbundling of the vertical column of the gas industry was expected to create a large number of supply companies, which aggregate demand and supply for smaller market participants, by purchasing natural gas and transportation services on their behalf.

In the past, transmission systems were built, owned and controlled by the monopolistic regional or national midstream companies. After the start of the EU gas market liberalisation, the transmission systems had to be functionally, financially and legally unbundled from their parent companies and converted into **Transmission System Operators** (TSOs). The TSOs are required to operate fully independently from the commercial interests of the parent companies. In a number of countries this has been implemented more stringently, via partial or even full ownership unbundling of the TSOs. Currently, every region or country has its own TSO, as is shown in Figure 1.

![Figure 4: National/Regional TSOs in Europe](image)

The **natural gas distribution** segment consists of the local operations necessary to deliver natural gas to the end users, including low-pressure pipeline transportation, metering, and supply activities vis-à-vis the several types of
customer. The distribution segment of the industry is generally seen as a natural monopoly and an essential facility, to be regulated accordingly.

Finally, the gas reaches the **distribution companies or retail traders**, which are either incumbents or new firms that entered into supply contract with smaller consumers. Either these consumers have a free choice of supplier, or they are bound to their local distribution company, depending on the national gas market design. New short-term trading and contractual arrangements may better allocate supply and demand and give market participants the flexibility they need. Yet, end-users may have to be protected from the market power of gas traders, while ex-ante merger control or ex-post competition policy may be necessary to reduce anti-competitive behaviour in this segment.

Additional components may involve the **storage or conversion** of gas. These functions are carried out by a mixture of private and public firms, also involving the TSOs. There is an ongoing discussion about the need for regulation of storage, blending and other facilities, to secure open access and avoid an abuse of a dominant market position in the provision of these services. If, because of the scarcity of such facilities, competition policy fails to provide the required openness, other forms of access regulation – similar to that for pipelines – may be taken into consideration.

### 3.2 Markets for Gas

In preceding units of this course, it has been shown that the existence of a natural monopoly over the whole of the utility value chain has been increasingly challenged over the past decades. In brief, the paradigmatic underpinnings of the regulation of the gas industry, since the end of the 1970s, underwent a shift from a traditional neo-classical view on the functioning of markets, towards paradigms that were based on monetarist and public choice theories. Over the 1980s and 1990s, particularly through the developments in the deregulation of the utilities in the UK, the Austrian school of economics became involved, providing the basis for dynamic regulation. In contrast with the traditional static equilibrium approach, the Austrians focus on the dynamic process in competitive markets. As a substitute for competition, price cap regulation (RPI-X) entices operators of regulated essential facilities to bring down their costs, while letting them keep the increased revenues for some time. Yardstick regulation of costs, tariffs and quality and efficient trading and auctioning arrangements are being applied in the gas and electricity industry. Moreover, as a further requirement for 'dynamic' competition and to harvest its advantages new concepts and solutions, new firms will have to enter the market. So, the success of competition is often defined as the number of (new) competitors in the market.

Liberalization of the gas industry envisages reducing the costs of supply, to enhance quality and to enhance the overall efficiency of the gas supply system. By providing the consumers, or traders, with a choice in respect of their suppliers and the type of contracts they prefer, the customer is in a position to select the supplier with the most attractive conditions. It is assumed that suppliers will try to gain, or protect, their market share by improving supply and price conditions. The traditional whole-sale traders and distribution companies will have to develop new strategies and adjust their organisations, as they will lose both their secured

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market and the integration and coordination between their several types of activities in the supply chain. These firms will also adjust their structure and operations – through mergers and acquisitions – so that their size and activities fit the requirements of the newly emerging competitive market.

As shown above, in the gas chain a distinction has been made between those activities that call for strict regulation and those that can be conducted under competitive conditions. The main candidates for deregulation are the production segment, wholesale trading, storage and LNG terminals and the retail business. Of course, the aim is to bring about a situation in which the various players make their decisions on production and consumption on the basis of their expected individual benefits or utility, as signaled by prices, thus responding to the “law” of supply and demand. The decisions that companies must make cover both short-term operating decisions, as well as investments involving longer term horizons. Both are influenced by the revenues the agents expect to receive for selling their gas in the market.

### 3.2.1 Competitive markets

The classical definition of a competitive market requires that firms are unable to influence the market price by their own behavior. They are ‘price takers’. This is strongly determined by the structure of the industry involved. Three factors strongly influence the competitive character of an industry, in terms of the number of alternative suppliers to a buyer, the potential entry of new suppliers into the industry and the interaction between competitors in setting prices and attempts to increase their relative market shares.

- The technology used determines the **minimum efficient size** for a firm operating in the market. This reflects the extent of economies of scale and scope in the production and delivery processes.
- The **size of the market**, together with technology, determines how many firms can operate profitably in a market.
- The **height of entry barriers**, or the ease with which additional firms can enter a market, determines efficient outcomes, particularly in a small market. These barriers may involve: sunk costs; legal or regulatory barriers; access to scarce resources or cost advantages enjoyed by incumbent firms; and the threat of retaliatory action by incumbents. The ‘height’ of the barrier to entry indicates the extent to which incumbents can raise the market price without attracting new entrants.

### 3.2.2 Characteristics of gas markets

In respect of the design of a competitive gas market, as will be shown below, there are a number of basic options. Before proceeding with the design and organisation of gas markets, it is useful to take note of the fundamental characteristics of gas systems. There are both similarities and differences with the features mentioned in respect of electricity systems.

Firstly, a **high degree of co-ordination** has to maintain a constant gas pressure and quality in the system, in line with the requirements of the system itself and
the appliances and installations supplied. This requires a timely balance between supply and demand and possibly the storage of amounts of gas. Moreover, conversion and blending of different types of gas inflows are required to achieve a stable quality of gas in the system.

Secondly, very large investments may be required and some projects count with lead times in the order of years. Demand trends cannot be predicted with complete accuracy in advance; there is a volume risk. This has become clear, again, in the aftermath of the recent economic crisis. So, constructed production, transmission and distribution capacities may turn out to be higher or lower than anticipated. This, either, may cause excess capacity, the costs of which cannot be recovered in time, or lack of capacity causing problems with the security of supply.

Thirdly, depending on the region, the number of gas producers and/or importing suppliers varies strongly. There are some hard determining factors in this respect. Local geological characteristics give rise to local producible gas occurrences or not. Geographical characteristics allow the supply of gas by pipelines from only one or more origins. Location on the (deep) seaboard may allow for the export and import of Liquefied Natural Gas (LNG) with large ocean going tankers.

Fourthly, the production, transmission and sales of natural gas involve a certain degree of risk due to both physical (contingencies affecting production units or pipelines, temperature changes that increase demand, and so on) and financial (changes in fuel prices, interest rates and so on) circumstances. In the traditional framework of gas market governance, these risks were shared; the producers carrying the volume risk and the consumers and/or taxpayers carrying the price risk. In a liberalized market, the allocation of risk is more complicated and depends on market design, sector governance and the regulatory framework. Risk analysis therefore acquires substantial importance.

3.2.3 International gas markets

Generally, the exploration for gas, its production, LNG liquefaction, international transit, LNG re-gasification and marketing and consumption are activities that fall under the sovereignty of a number of different states involved; it is an international value chain. This is an important difference with the electricity market where the supply and transmission of power is arranged within a nationally organized system; possible with international interconnections. The international character of the gas value chain has a number of important consequences:

Firstly, the value chain of the gas supply systems covers various national jurisdictions with different institutional frameworks and different roles assigned to public and private stakeholders. This implies that determinants of market power and infrastructure regulation in the value chain always will extend beyond the national regulators’ span of control.

Secondly, the international gas industry has to deal with fundamental differences in interest between producers, transit countries and consumers. With an increasing internationalization of the gas market and a future concentration of reserves and supply, the distribution of the rents along the value chain may become prone to political intervention.

Thirdly, the strategies of governments and companies involved in the several stages of the international gas market may vary, depending on market dynamics,
like the shifts from a buyers’ market to a sellers’ market – and back – which may influence the government policies and regulatory choices along the value chain.

Fourthly, the market is evolving in an environment in which the role of governments is changing, towards more liberal systems, where they have lost their role as direct actor, in public firms and in negotiations. Yet, in other countries, governments actually strengthen their position as direct actor in the sector. The consequence is that companies from one jurisdiction must negotiate their terms with governments or state-owned companies.

Fifth, with the internationalization of the value chain, strategic aspects, natural gas supply is increasingly seen as part of the “high politics” arena. This makes objectives of full liberalisation difficult to accept for many governments, while it also tends to politicize commercial conflicts and even the nature of market competition as such.

To an increasing extent gas systems will stretch out over different countries and world regions, which stem from radically different traditions in terms of their institutional and structural characteristics. This may affect national, or EU-wide, regulatory approaches. The question is how this fits into ‘one-size-fits-all’ approaches and recipes for structural reform and market liberalization, as proposed by international organizations and the EU. Conflicts of interest and difficulties to arrive at mutually acceptable (and coherent combinations of) regulatory regimes along the value chain are the logical consequence of this situation.

### 3.3 Efficient operation of the gas market

A primary objective to the regulatory system is to bring about an efficient operation of the gas market. A main issue, therefore, is to define the notion of efficient operation. A fairly general approach is to equalize this notion with a “competitive” market. A report, carried out for the UK Department of Trade and Industry has gone some length in developing an understanding of the meaning of ‘truly competitive natural gas markets’.

The Terms of Reference stated that: ‘we would consider a ‘competitive’ market to be one where no company holds and/or exercises significant market power, where prices reflect the costs of marginal supply (and not, for example, contract prices conventionally linked to oil prices) and where gas is available to anyone anywhere willing to pay the competitive market price.

This definition recognizes the need to be able to identify how, where and when players in the natural gas market could exercise market power. The natural gas industry in Europe has been historically organised as a set of statutory monopolies, which have enjoyed local market power. The political and regulatory challenge of market liberalisation is to remove that market power, without either expropriating

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8 Short *et al* 2003;
the legitimate property rights of the existing players, or causing the market or existing players to fail during transition.

The definition also uses the phrase “where prices reflect the costs of marginal supply”. Pricing at marginal cost underpins the economists’ concept of a competitive market. However, it is not always a straightforward concept in the gas industry. For a gas producer, selling gas at its marginal cost is not the same as simply looking at the variable costs of production, since the choice is between selling the molecule of gas now or selling it at the end of the gas field’s life, which could be in 20 or 30 years’ time. This lost opportunity cost could outweigh the variable costs, making the effective marginal cost negative.

At the infrastructure level there is a high level of fixed costs and the short run marginal cost is very low. The gas supplier, on the other hand, faced with possibly buying at the spot price is looking at a marginal cost much closer to the economists’ concept. Depending on the point of view of the buyer or seller of gas and also whether or not there is an excess supply of gas and/or capacity, the marginal cost of gas can vary enormously.

In principle, the objective is to maximize the so-called “net social benefit”: the sum of producer and consumer surplus and demand; introduced in an earlier module. This objective is nonetheless often modified by other policy driven objectives, like the protection or stimulation of indigenous gas resource, diversification to other sources of gas or the development of technologies with a lower environmental impact. These objectives have an impact in market developments involving investment strategies by governments and operators and shifts in the structure of demand.

Another illustrative example of a definition of a competitive gas market was published by the New Zealand Ministry of Economic Development10. Main elements of this definition included:

- A market where there is full competition in production, wholesaling and retailing natural gas, and where gas can be freely traded between producers, wholesalers, retailers and consumers.

- An interconnected transmission and distribution system with clear rules for access to these essential facilities by all prospective participants. Where pipeline capacity is in competition, capacity is tradable and transmission prices are set by reference to the market. Where natural monopoly exists, clear rules for reference pricing should be available and disclosure arrangements and legal remedies should be available at an economic and timely manner to redress concerns.

- Arrangements in the transmission, distribution and retail sectors should provide confidence in the market that cross-subsidising is not occurring in vertically integrated organisations. This could be usefully extended to include the elimination of cross-subsidies in horizontally integrated companies.

- A market where clear market signals encourage the efficient allocation of resources along the gas supply chain by providing information to market participants through flexible pricing arrangement, contracts of variable length, efficient gas trading mechanisms, and the scope for commercially negotiated settlements.

10 ACIL (2001)
• A market where pricing is established according to a consumer’s willingness to pay and market power does not interfere with the ability of consumers to exercise this preference. This means that product differentiation does not occur between consumer groups exhibiting similar willingness to pay.

• Contestability in the market with the aim of achieving freedom of choice by all consumers to access gas on the most attractive conditions in terms of price, quality and reliability of service from retailers, wholesalers and producers. Industrial consumers able to negotiate supply and pricing terms that are compatible with their business needs.

• In a perfect market information must be available to both buyers and sellers about market prices, product quality and conditions of sale. A particular risk arises where an advantage could arise from a player’s interests elsewhere in the supply chain. For example, if a supply affiliate of a gas transportation company has better knowledge of the system capacity and gas flows, from its ownership of the transportation business, than its competitors.

3.4 Models for Gas Market Liberalisation

The objective to liberalize gas markets can be dated back to the 1980s, when a gradual shift in economic thought began to take shape, in which the stabilizing role of the state and the need to control markets, in general, was questioned. The arguments for restructuring were reinforced by a plea to integrate national and regional markets for goods, as international trade theory argued that economic welfare would be enhanced by allowing production to take place in the most efficient location or country. As countries differed widely in their energy resource endowments, national (energy) markets should integrate to the extent that the process of producing and trading energy would no longer be confined to national territories. To achieve this, national trade regimes should remove existing barriers to trade, while the physical infrastructure to efficiently transport energy between and within countries should be developed.

Gradually, in the several gas consuming regions processes of structural and regulatory change were undertaken. The evolution of these processes was also influenced by local, economic and (geo) political, circumstances. This is reflected in the timing of these processes, the speed with which they evolved and the structural models chosen to reform the gas supply ‘systems’ into actual gas ‘markets’. This module will provide some illustrations of the manner in which some of the main gas markets are being restructured currently.

Competition in the gas market can be achieved by altering the structure of the market, as is suggested by economic theory. Whereas the traditional perspective denied the feasibility of competition in the whole of the gas industry; structural change was based on the hypothesis that the introduction of competition would be possible in some segments, and that this would improve the performance of the whole system. Only the pipeline transportation and distribution segments of the

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11 See Juris (1998a, b,c,d).
industry were considered to constitute a natural monopoly, because of economies of scale and scope, high fixed costs of pipeline construction and relatively low variable costs. The other segments, production and wholesale and retail trade were seen as potentially competitive markets. So, by changing the ownership structure of the sector and by dividing the competitive segments into a number of different firms, competition could be introduced into the sector. In a stylized way, a number of models can be distinguished to break up the industry.

One model, the **Single Buyer Model**, separates production from the rest of the industry and introduces competition among producers. Producers sell natural gas to a gas utility, which then resells it to the end users. The transactions between the producers and the utility lead to the development of a wholesale natural gas market, where natural gas is traded for further resale. Regulation is needed to restrict the market power of the single buyer, relative to both the consumers and the producers. End user prices are regulated. The price of gas sold by producers to the utility is determined through competitive bidding for a supply contract with the single buyer.

A more ambitious model, **Third Party Access**, introduces open access in pipeline transportation, to third-parties that either sell or buy gas from each other. The gas utility, thus, supplies gas to the captive, small, consumers and it provides transportation services to large consumers that purchase their gas independently in the wholesale market. A gas utility may also be separated further, into a pipeline company and several distribution utilities, all providing access to their networks. Open access promotes competition in the wholesale and end-use market. Producers benefit because of the increases in the number of potential buyers, while distribution utilities or large end users benefit from a greater choice in gas suppliers and conditions. The high transaction costs involved with buying gas creates room for natural gas traders, which aggregate demand and supply for a number of smaller market participants by purchasing natural gas and transportation services on their behalf. In this model the end-users may have to be protected from the monopoly power of gas utilities. The price of transport and other services is another crucial factor in achieving competition in the wholesale market.

A third model, **Full Competition** separates natural gas supply from pipeline transportation and distribution and introduces full competition into these markets. Unbundling creates a level playing field for all participants in the natural gas market and creates a large number of supply companies that purchase natural gas in the wholesale market, resell it downstream, using the transportation systems of pipeline and distribution companies. As competition among suppliers reduces excess margins and forces the pass-through of cost savings to the end users, the need for stringent price regulation at the wholesale and retail level will be reduced. In this model, new flexible short-term trading and contractual arrangements will be provided to balance supply and demand and give market participants the flexibility they need. Liquid spot markets are expected to emerge, yielding prices that continuously reflect the market value of natural gas at a specific location.

### 3.5 Trading mechanisms

Trading mechanisms guide interactions in the competitive segments of natural gas markets. They facilitate transactions among market participants with the objective of achieving simultaneous clearing of natural gas and transportation markets at minimum cost to the gas industry. Deregulation of the natural gas industry leads to a separation of the trading of natural gas and the transportation services, which increases the complexity of markets and imposes substantial requirements on
market participants to complete their transactions at the minimum cost. While a vertically integrated gas company optimizes all transactions internally in the hierarchy of the firms, participants in a deregulated gas industry must coordinate their natural gas and transportation transactions in an open market. The process of minimizing the total cost of natural gas supply and transportation to the industry must take place across a number of decentralized transactions. Unless these transactions are guided by a trading model, they can result in suboptimal allocation of resources.

Two distinct trading models have been developed: a) a bilateral trading model and b) a poolco or single buyer, model. Both models achieve market clearing at the minimum cost, though in different ways. The main differences between the models are in the nature of transactions and in the way the transactions are coordinated in natural gas and transportation markets.

3.5.1 Bilateral trading model

The bilateral trading model is based on decentralized bilateral transactions between operators and suppliers. The model relies on competitive gas and transportation markets to generate efficient prices and minimize the cost of natural gas to the end users.

Decentralized spot markets

In the bilateral trading model market participants conclude all deals in bilateral negotiations and conclude contracts that address all issues relevant to a transaction. The drive to minimize of transaction costs leads to the emergence of traders who complete transactions on behalf of other market participants, like producers and consumers. Spot markets develop as market participants require efficient pricing of natural gas at every moment. Spot markets are thus developed through the decentralized market forces.

Competitive spot markets generate signals about the market value of natural gas and give market participants the incentives to complete buying and selling transactions efficiently. As a result, in theory, decentralized bilateral trading among market participants achieves the outcome that is optimal for individual participants as well as for the natural gas industry as a whole.

Distance-based pricing of transportation

Charges for transportation services sold in the primary transportation market are based on the fixed and variable costs of a pipeline company per unit of distance over which individual shipments take place. A capacity charge is set to recover total fixed costs, while a throughput charge is used to recover the variable costs of transporting natural gas. Transportation contracts sold in the secondary market are priced according to the short-run marginal cost of capacity. A secondary capacity market and the availability of many different firm and interruptible transportation contracts enable shippers to match their needs for natural gas with transportation services. They arrange a portfolio of transportation contracts that gives them the minimum acceptable reliability of transportation at the minimum cost. Because each shipper is able to minimize its total cost of natural gas supply
and sales and of transportation, the total cost of natural gas to end users is minimized\(^{12}\).

**Direct access in retail competition**

In the bilateral trading model, retail competition takes place among suppliers who compete by price for supply contracts. End users can choose a supplier of natural gas, which is then responsible for arranging transportation of natural gas to the consumption site. This structure, in which end users enter into supply contracts with suppliers, is referred to as "direct access."

Suppliers charge end users a single price for a unit of delivered natural gas. Competition among suppliers ensures that the retail price is equal to the sum of the wholesale gas price plus the distribution fee. Since suppliers have the ability to acquire natural gas and transportation services at the minimum cost, end users face optimal retail prices. So, all transactions in the natural gas industry lead to the socially optimal outcome.

**3.5.2 Poolco model**

An alternative to the Direct Access Model is the Poolco – or entry-exit - model, in which transactions are coordinated by a single entity, to ensure that all transactions in natural gas and transportation markets are completed at the minimum cost to society. The Poolco model is based on the notion that decentralized bilateral transactions do not always lead to the socially optimal outcome in the gas industry because of the technical characteristics of natural gas pipeline systems.

**Pool operator**

Transactions in the natural gas market are facilitated by a pool operator, which is assigned a market clearing responsibility by the regulator. Market participants inform the pool operator how much natural gas they want to purchase or sell and at what prices. The pool operator aggregates this information into system supply and demand and calculates the system price that will clear the market. This procedure is repeated at short intervals to generate continuous pricing of natural gas. The pool operator can divide the natural gas market into several local markets, if there is insufficient pipeline capacity to move natural gas between locations. It would then determine prices for each node using the same procedure.

The system price reflects the market value of natural gas. Competition among natural gas suppliers and buyers ensures that system prices reflect the short-run marginal costs of natural gas—that is, that they are efficient. Because all market participants complete transactions at system prices or their derivatives the outcome of trading under the Poolco model is socially optimal.

**Locational pricing of transportation**

Transportation is sold as a service that takes natural gas in or releases it from the pipeline system at a particular location. Shippers buy entry and exit capacity at points of injection and withdrawal from a pipeline company or other shippers. They order transportation services by nominating the volume of natural gas they want to ship through the pipeline system on the next day. A pipeline company reviews the nominations of all shippers and determines the schedule of gas flows that minimizes the total cost of transportation. If some capacity remains after the firm

\(^{12}\) This is considered in more detail in Module 9.
nominations, the pipeline company may offer interruptible services to other shippers. Gas flows in the pipeline system do not always follow the contractual paths because a pipeline company can often find a more optimal way to direct flows through the system. There are several ways to establish the prices, or tariffs, for transportation services which can either be cost or market value based\textsuperscript{13}.

**Virtual access in retail competition**

Under the Poolco model retail competition takes place among suppliers who compete by price for financial gas contracts. End users receive physical delivery of natural gas from the local distribution utility, which charges only the distribution tariff and fully passes through the prevailing nodal price of gas to the end users. As a result, end users face spot prices, but they cannot choose another gas supplier, a structure referred to as “virtual access”.

End users are exposed to price risk because they face volatile spot prices. Suppliers therefore sell them insurance plans, as financial gas contracts, that stabilize retail prices by minimizing price risk and end users choose among suppliers based on the insurance premiums. Competition among suppliers ensures that premiums are efficient, reflecting the risk aversion of end users and the costs of hedging. Because end users face both efficient spot prices for natural gas and efficient insurance premiums, the outcome of all transactions in the natural gas industry is socially optimal.

**3.5.3 The bilateral versus the Poolco model**

In theory - and if properly applied - the bilateral and Poolco trading models lead to the same efficient outcome. Which model is more appropriate for a country depends on the characteristics of its gas industry. Countries with relatively large gas markets can rely on the many decentralized transactions of market players, resulting in a liquid and competitive spot market using the bilateral model. Smaller countries with less developed markets may speed up the development of a competitive spot market by establishing a pool operator that facilitates market clearing in the gas and transportation markets.

The structure of a pipeline system also affects the choice of trading model. Pipeline systems with a trunk line structure are ideal for the bilateral model because network externalities are small. By contrast, a pipeline system structured as a dense network exhibits network externalities because loads in one line affect loads in another one. And since bilateral transactions do not take into account load interdependencies, market participants can require transportation services that do not minimize total transportation costs. In this case, then, the Poolco model is more appropriate, because it allows the pipeline operator to determine the optimal gas flow schedule regardless of contractual paths.

Transactions in the bilateral trading model are relatively simple. Being bilateral, they are easy to complete and understand even in complex markets.

\textsuperscript{13} This is considered in more detail in Module 9.
Transactions in the Poolco model place enormous information requirements on the pool operator, which must have access to information about the availability, the prices and the costs of gas and of transportation. The ideal pool operator is a pipeline company, as information about the pipeline system(s) is difficult to obtain in a decentralized market. The alternative is an independent entity, jointly owned by all participants in the gas industry. In such a case, the pool operator must establish confidentiality rules to ensure all participants that sensitive information will be well protected.

Application of these two trading models in the natural gas industry has been uneven. Many countries have opted for the bilateral trading model, because it is simpler to implement than the Poolco model.

In these countries, natural gas is traded as a bilateral transaction in decentralized spot markets. Retail competition, if introduced at all, is based on the direct access scheme, in which end users conclude physical gas contracts with suppliers. A typical example of the bilateral trading model exists in the gas industry in the United States, where natural gas spot markets have developed as a result of deregulation. Resale of transportation contracts has led to the development of a secondary transportation market and promoted variability in transportation contracts. Trading takes place on a bilateral basis in a competitive market. Transaction costs are minimized through the use of natural gas marketing companies and electronic trading systems that aggregate information about the availability and prices of natural gas and transportation across regions. Competition and transparency in the gas and secondary transportation markets promote efficient pricing of natural gas and transportation contracts. And because market participants can coordinate transactions in both natural gas and transportation markets, they can minimize their total cost of natural gas and transportation.

The poolco – or entry-exit - model has been applied in the United Kingdom and the Netherlands, in a limited shape. In the U.K. gas industry, British Gas TransCo, a pipeline system operator, optimized gas transportation regardless of the contractual paths. It has organized a spot market for natural gas, called the "on-system" market, and a spot market for system balances, the "flexibility" market. All other transactions in the gas industry were completed on a bilateral basis.

British Gas TransCo optimizes gas flows through the pipeline system on the basis of the principle of minimizing total transportation costs. Shippers purchase entry and exit point capacity and notify the operator about the volumes and locations of injection and withdrawal. The optimal transportation schedule determines gas flows regardless of the transactions by shippers in the natural gas market.

On-system trading takes place among shippers when they exchange ownership of natural gas that has been injected into the pipeline system. The pipeline system operator takes care of the "natural gas exchange" to facilitate natural gas transactions, but it does not determine the system price of natural gas. Instead, prices are set by market participants in decentralized bilateral negotiations. On-system trading therefore combines the bilateral and Poolco trading models.

In the balance, or flexibility, market, which is representative of Poolco-style gas trading, the operator receives bids for sale or purchase of natural gas from other market participants. If the pipeline system experiences an imbalance, the operator accepts the bids that minimize the cost of restoring system balance. Shippers whose bids are accepted are paid the system price that is equal to the price of the last bid accepted.
3.6 The Role of the Regulator

As argued above, a completely liberalised gas market is governed by the free entry principle. Investors should be able to engage in the market, subject only to certain legal obligations in respect of land use, security and environmental impacts. As shown above, the several segments of the natural gas value chain exhibit specific characteristics in respect of the feasibility of competition and therefore require specific forms of regulatory oversight and intervention.

In respect of the monopolistic segments of the value chain, like transmission, distribution and, possibly, gas storage, gas conversion, LNG terminals, or the long-distance interconnections between national, regulated, systems the regulatory function is substantial.

• Firstly, it has to secure an independent management of the regulated systems by juridical or ownership unbundling and separate bookkeeping;
• Secondly, it has to organize regulated or negotiated access to the networks and other system functions via TPA, including a system of access conditions and tariffs;
• Thirdly, it has to develop procedures to evaluate the need for capacity expansions in the regulated market segments.

The potential free market segments, production, wholesale trade and retail supply are governed by market signals. The amounts of gas sold by producers and traders are determined by supply-demand relationships and prices on the various organised or over-the-counter, spot or forward markets. Main task of regulatory bodies involve:

• Firstly, to guide and control the functioning of these different markets;
• Secondly, to provide oversight to avoid the abuse of dominant market positions and market power by the firms in the industry;
• Thirdly, to facilitate information systems, like the reporting of transactions and prices;
• Fourthly, to provide guidelines in respect of functions with an ambiguous character as regards their competitive nature, like gas storage, gas conversion, LNG terminals, or the long-distance interconnections between national, regulated, systems.

As stated above, to an increasing extent gas systems stretch out over different countries and world regions, which stem from radically different traditions in terms of their institutional and structural characteristics. It is a fact that the gas industry, or value chain, will be ‘governed’ by a variety of regulatory agencies and regimes. This begs for some degree of coordination between these regulatory bodies, to arrive at mutually acceptable (coherent combinations of) regulatory approaches along the value chain. In Europe, cross-border cooperation between NRA’s is a clear obligation under the Third Energy Market Package. ACER is the new instrument for that cooperation. In addition to these new rules, bordering
NRA’s will also have to work together on bilateral, or even tri- or quadri- or pentalateral issues.

General requirements to regulators are that they gain a close to undisputed legitimacy in carrying out their task. Yet, in the absence of adequate experience with the regulation of liberalized gas markets, often experiments take place with their inherent risk of failure and uncertainties about future change. To operate effectively regulators should have a clear, politically determined, legislative mandate, establishing in unambiguous terms, their objectives, their tasks and the degree of freedom in developing guidelines and rules. To operate independently on behalf of their general public responsibilities, regulatory systems and regulators should seek to secure and carefully balance the interests of both the several segments of the gas industry and the (large and small) consumers. To achieve an appropriate level of legitimization, regulators should be held accountable both in respect of the reasons they give for their decisions and by making the regulatory process fair, open and accessible to the firms and stakeholders. To gain trust in the industry and among consumers, regulators should have a more than adequate level of expertise, which is as independent as possible from industrial, consumer, or political interests. Finally, a regulatory system should be efficient, in the sense that the benefits of its involvement to society should outweigh the direct and indirect costs of its interventions.

3.7 Self-evaluation

• List the main differences between gas and power
• What are the consequences of the international character of the value chain for its regulation?
• What are the different market models in a liberalized gas industry?
• Is there a one most efficient market model?
4 The functioning of a competitive gas market

4.1 Marginal costs of gas supply

The marginal cost of supply is a notion that plays a fundamental role in the analysis of competitive markets. Economic theory suggests that in a perfectly competitive market, prices should equal marginal supply costs. Given the assumption that in competitive markets prices are determined by the multitude of bids submitted by the various players on the supply and demand side, market design should be based on a coherent theory of marginal cost. In this theory, market imperfections and market power appear in markets as the main explanation for the difference between observed market prices and estimated marginal costs. Therefore, distorting phenomena like market imperfections and market power should be avoided, as much as possible.

Marginal cost can be defined as the cost of supplying one more unit of output. The total costs of a business are the sum of the fixed costs and the variable costs. The fixed costs are those that do not change with the rate of production. Fixed costs include the capital cost of the plants, machinery and overheads, such as the repayment of loans. Variable costs are those costs that vary with the rate of production and mainly comprise the labour, materials and energy costs. Variable costs do not stay constant at all levels of production. The short run marginal cost is the variable cost incurred in producing the next unit of production.

In the long run all costs are variable, as old plant and machinery has to be replaced with new assets. Long run marginal costs take into account all costs over a planning horizon, including the cost of replacing existing or expanding assets, or supply capacity.

The gas industry is capital intensive. Thus fixed costs tend to be high as a proportion of total costs and variable costs tend to be low. Applying these concepts to gas transmission and distribution networks one finds that the fixed costs represents about 90-95% of total cost and variable costs represent the remaining 5-10%.

This implies that here is large difference between short term and long term marginal cost in the gas industry. Moreover, short term vary with the capacity utilization of the plants and the systems.

4.2 Gas Supply

As was shown above, gas delivered to the EU gas market comes from a number of different sources: indigenously produced gas from the UK, the Netherlands, Germany, Denmark, Italy, etc.; gas imported by pipeline from Norway Russia and Algeria; and LNG from many places. At the peak, demand is also balanced by

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supplies from gas storages and through interrupting demand, if necessary. In a liberalized competitive market, the marginal cost of all of these activities should feed through into the market price of the day, as established by the prevailing market institutions (see above). The continental market, though, is dependent to a large extent on long term contracts with the main suppliers, as will be pointed out below.

If one applies marginal cost analysis to a gas field, one might conclude that the costs of the production platform and associated facilities would be defined as a fixed cost. However a gas field has a more or less fixed amount of reserves and the production facilities are usually dedicated to producing just those reserves. A molecule of gas can only be produced once. This fact affects how gas producers evaluate marginal costs.

As gas production facilities are dedicated to the specific reserves in the gas field, depreciation of the fixed assets is usually charged on a throughput basis. This converts depreciation from a fixed to a variable cost. Although depreciation represents the recovery of sunk costs, generally, gas producers start reducing production if the market price is not sufficient to recover the initial investment. Moreover, as gas can only be produced once, gas producers may take into account the opportunity cost of deferring production until later.

There are a number of other factors that can affect the marginal costs. These include the effect a change in gas production has on liquids production. If natural gas and oil are produced together then the marginal cost will be set against the total income from all products. This is clearly more important where oil is the main product and will impact on the marginal cost of ‘associated gas’ or gas from condensate fields. Oil taxation, production sharing agreements and royalties can feed into the marginal cost as well.

As LNG becomes a more significant part of the mix of supplies into the EU it will have an increasing impact on the market price. The cost structure is different, as LNG involves a higher proportion of variable costs than transportation by pipeline. Moreover, as LNG tankers can be directed (to some extent) to alternative ports, the opportunity cost of selling gas in a different market has to be considered. Overall one would expect LNG imports to be more sensitive to market price than pipeline supplies.

Decision-making in respect of the management of gas systems involves different types of decisions as regards the time frame concerned. To some extent, these different time frames also reflect structural shifts in the marginal costs involved with these decisions. The following time frames are relevant:

- **Very long term (3-10 years):** decisions to start exploiting and developing new gas fields, long distance pipelines, storage and conversion facilities.
- **Long term (1-3 years):** decisions to transform and overhaul plants, long-term gas sales contracts, plant maintenance programming.
- **Medium term (6-12 months):** shorter term gas contracts, bookings of storage capacity.
- **Short term (1 week):** weekend shut-down management, prediction of pool or gas spot market behaviour.
- **Very short term (1 day):** decisions in respect of balancing and submission of bids to the pool or gas spot markets and storage services.
• Hourly: Short term balancing of the network pressure, via input and supply decisions.

This illustrates that there are genuine differences between marginal costs at different time horizons. Moreover, decisions to invest in new fields and transport infrastructure will generally involve more distant locations, more difficult circumstances, at a higher cost. It is, however, assumed that marginal costs of the several types of decisions will converge to one ‘price’ under marketplace pressure. One could assume that there are only two horizons, i.e. a short-term horizon in which operating decisions (for example, which fields to produce and which bid to submit) are made and a long-term horizon in which investment decisions are made. If there is a gas spot market, the price established will be the same as the short-term marginal cost, given existing production and transport facilities. If the short-term marginal cost, or the price, is higher than the long-term marginal cost, it is cost-effective to meet the additional needs by increasing output through additional investment (at long-term marginal cost). If the short term price is lower than the (expected) long term price, no investments will be made and supply will be taken care of through the operation of the existing assets. Consequently, in theory, there is an incentive to invest until the two marginal costs converge.

4.3 Pricing and the organization of a competitive market

The unbundling of gas supply and transportation and the opening of natural gas markets to competition have resulted in new market arrangements for the trade in natural gas and the interaction of the market participants. System operation rules guide the interactions between gas shippers and the monopolistic gas transporters. But the industry structure and trading mechanisms determine the pricing systems and the efficiency of gas markets. An ideal, efficient, natural gas market performs three functions:

Firstly, it aggregates supply and demand to determine system demand and supply patterns in time. Market aggregation is achieved by concentrating trading among producers, traders, and shippers at one or several trading points, or hubs. These trading points are typically located at the major pipeline interconnections or at major entry points to high-pressure transmission systems.

Secondly, it facilitates market clearing and determining the market price. Market clearing is facilitated by trading mechanisms; bilateral trading, brokerage, spot markets, and auctions, as will be shown below. Which of these mechanisms are used depends on the characteristics of supply and demand as reflected in the dimensions of gas contracts, typically time and location of delivery, pressure and calorific value of gas, security of supply, and, of course, the unit price of gas.

Thirdly, it signals the market value of gas. Price signaling is facilitated by the collection and dissemination of information about prices and trading volumes by reporting and consulting agencies, journals, and newsletters. The reporting of this

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15 This paragraph is based on Juris (1998a), Ofgas (1999) and Roeber (1996).
16 This is considered in detail in Module 9.
information enables market participants to choose trading and consumption strategies according to market signals. Several firms regularly report spot market prices and volumes, including World Gas Intelligence, Heren, Platts and Argus Petroleum.

Liberalized gas markets, generally, should allow the trading of long-, medium-, and short-term natural gas. While long- and medium-term gas contracts are more typical for the integrated gas industry. Short-term gas contracts are important in the unbundled gas industry, because of market participants’ need to achieve physical balance between demand and supply in a short time frame (typically between one day and one month). Thus system balancing affects how natural gas is traded.

Short-term gas trading may involve bilateral trading, brokerage, auctions, and spot market mechanisms. Bilateral trading develops first. As the volume of trading increases, markets become in-transparent and trading imposes high transaction costs.

Bilateral trading is therefore replaced by brokerage, which is an advanced bilateral trading model in which brokers, or traders, trade on behalf of buyers and sellers. Brokers aggregate the demand and supply of their clients and trade among themselves or with other market participants. As trading volume increases, market participants tend to concentrate their trade on trading points to reduce transaction costs.

Brokerage trading evolves into spot market trading, which is typically followed by the development of risk management instruments. Because spot market prices reflect system short-run marginal costs of gas and the opportunity costs of capacity, they tend to be volatile, and the inherent price risk is often very high for many market participants. This leads to demand for risk diversification and, ultimately, to the development of a financial gas market where risk-minimizing financial instruments are traded. These markets can be organized or not, depending on the ability of institutions to respond to market needs. Initially, financial institutions offered mostly swaps to customers on an individual basis.

Auctioning is typically used for efficient trading of goods and services, like transport or storage capacity, when one player dominates supply or demand. In the U.K. natural gas industry, gas auctioning was conducted by BGT in trading system imbalances. The trading rules were determined by the Network Code in order to prevent abuse of BGT’s monopoly in this market.

In a competitive market a gas supplier, or trader, buys gas at the prevailing market price from the producers, or operators. In the UK, the US and other liberalized markets, most gas sales contracts are either linked to a gas market index (NBP or Henry Hub) or at a fixed price calculated from the forward market. In continental Europe, longer term supply contracts remain of large importance, with prices often linked to those of oil products. Nevertheless, spot markets are emerging there too. An example is the Dutch Title Transfer Facility (TTF).
4.4 Risk management and contracting\textsuperscript{17}

The general types of risk faced by all businesses can be grouped into five broad categories: \textit{market risk} (unexpected changes in interest rates, exchange rates, stock prices, or commodity prices); \textit{credit/default risk}; \textit{operational risk} (equipment failure, fraud); \textit{liquidity risk} (inability to pay bills, inability to buy or sell commodities at quoted prices); and \textit{political risk} (new regulations, expropriation). In addition, the financial future of a business enterprise can be dramatically altered by unpredictable events—such as depression, war, or technological breakthroughs—whose probability of occurrence cannot be reasonably quantified from historical data\textsuperscript{18}.

As stated above, businesses operating in the natural gas industry are particularly susceptible to market risk - or more specifically, \textit{price risk} - as a consequence of the extreme volatility of energy commodity prices. Generally, energy companies can accurately estimate the likely success of exploration ventures, the likelihood of system failures, etc. Diversification, long-term contracts, inventory maintenance, and insurance are effective tools for managing those risks.

\textbf{Energy Price Risk}

Such traditional approaches do not work well, however, for managing price risk. In liberalized energy markets, prices vary more than the prices of other commodities and are also sensitive to location. Price variation increases the difficulty of cash and credit management and the worth of prospective investments. Historical price data clearly illustrate the relatively high volatility of energy prices.

In contrast to the patterns apparent in other spot prices, the spot market price of natural gas peaks periodically with no obvious warning. Price volatility is caused by shifts in the supply and demand. Natural gas prices are particularly volatile. Demand increases quickly in response to weather, and “surge” production is limited and expensive. In addition, neither can be moved to where it is needed quickly, and local storage is limited. Efforts to reduce volatility have focused on increasing reserve production capability and increasing transmission and transportation capability. Recently there has been an emphasis on making prices more visible to users so that they will conserve when supplies are tight, thus limiting price spikes.

\textbf{Risk Management without Derivatives}

When investors, managers, and/or a firm’s owners are averse to risk, there is an incentive to take actions to reduce it. Diversification—investing in a variety of unrelated businesses, often in different locations—can be effective. In theory it is possible to “diversify away” all the risks of a particular project; in practice, however, diversification is expensive and often fails because of the complexity of

\textsuperscript{17} This section is largely based on Chapter 2 of “Derivatives and Risk Management in the Petroleum, Natural Gas, and Electricity Industries, October 2002, Energy Information Administration, U.S. Department of Energy, Washington, DC 20585

\textsuperscript{18} Knight (1964).
managing diverse businesses. More fundamentally, the success of most projects is strongly tied to the state of the general economy, so that the fortunes of various businesses and projects are not independent but move together. In the real world, therefore, diversification is often not a viable response to risk.

Another method of managing the risk created by fluctuating prices is to use long-term fixed-price contracts. Insurance contracts can also be used to manage risk. The insurance would essentially shift the risks from the owner of the plant to the insurance provider. The counterparty would accept the risk if it had greater ability to pool risks and/or were less averse to risk than was the owner of the plant. The plant owner could also reduce the risk of adverse movements in future natural gas prices by purchasing the fuel in the current period and storing it as inventory. If prices fell, the firm could buy the fuel on the open market; if they increased, it could draw down the inventory. This could be an expensive way to manage risk, because storage costs could be considerable.

**Managing Risk with Derivative Contracts**

Derivatives are contracts, financial instruments, which derive their value from that of an underlying asset. Unlike a stock or securitized asset, a derivative contract does not represent an ownership right in the underlying asset. What is critical is that the value of the underlying commodity or asset be unambiguous; otherwise, the value of the derivative becomes ill-defined. The following sections describe various derivative instruments and how they can be used to isolate and transfer risk. Most of the discussion is in terms of price risk, but derivatives have also been developed with other non-price risks, such as weather or credit.

**Forward contracts** are a simple extension of cash or cash-and-carry transactions. Whereas in a standard cash transaction the transfer of ownership and possession of the commodity occur in the present, delivery under a forward contract is delayed to the future. In energy markets, a gas user may enter into forward contracts to secure gas for future operations, thereby avoiding both volatility in spot prices and the need to store gas. Forward contracts set a (firm) price or pricing formula. Thus, the buyer and seller are able to reduce or eliminate uncertainty with respect to the sale price of the commodity in the future. Forward pricing and the delivery features of forward contracts cause default and credit risks. To deal with the risk of default, parties scrutinize the creditworthiness of counterparties and deal only with parties that maintain good credit ratings. They may also limit how much they will buy from or sell to a particular trader based on his credit rating. Finding suitable counterparties can be difficult. Discovering the market price for a delivery at a specific place far into the future is also daunting.

**Options** are contracts that gives the buyer of the contract the right to buy (a call option) or sell (a put option) at a specified price (the “strike price”) over a specified period of time. Options are used successfully to put floors and ceilings on prices; however, they tend to be expensive.

**Swaps** (also called contracts for differences) are the most recent innovation in finance. Swaps were created in part to give price certainty at a cost that is lower than the cost of options. A swap contract is an agreement between two parties to exchange a series of cash flows generated by underlying assets. No physical commodity is actually transferred between the buyer and seller. The benefits associated with swap contracts are similar to those associated with futures or options contracts. They allow users to manage price exposure risk without having to take possession of the commodity. They differ from exchange-traded futures and options because they are individually negotiated instruments. Users can customize
them to suit their risk management activities to a greater degree than is easily accomplished with more standardized futures contracts or exchange-traded options. Although swaps can be highly customized, the counterparties are exposed to higher credit risk because the contracts generally are not guaranteed by a clearinghouse. In addition, customized swaps generally are less liquid instruments.

4.5 A competitive market: The Victoria Model

The features referred to above are illustrated in more detail in the following section, representing the set-up of Victoria's competitive gas market in Australia\textsuperscript{19}. In this market is expected that most gas is traded by contract between producers and retailers, and that retailers will sell the gas to customers. Parties should be free to enter into any contractual arrangement for the purchase or sale of gas. Contracts may be for any term (years/months) and may allow for flexible purchase quantities (daily/monthly/annual variation).

\textbf{Figure 5 The spot and the contract market}

Figure 5 illustrates the working of the market. In this simplified example, under his longer term contracts with suppliers and buyers, market participant A is withdrawing the same volume from the transport system that it is injecting and is not subject to the spot market. Market participant B is withdrawing more than it is injecting and is purchasing the excess volume from the spot market. Market participant C is withdrawing less than it is injecting and is selling the excess into the spot market.

Because it is difficult for a market participant to precisely forecast its demand for gas on any particular day, on most days the actual quantity of gas purchased under contract will not exactly match the quantity of gas consumed.

\textsuperscript{19} MEP/EPD 1997.
The spot market provides the means of dealing with this imbalance so that the market participant pays for the excess of actual withdrawals over actual injections, or receives payment for the excess of actual injections over actual withdrawals, at a price determined by the spot market. To the extent that he can achieve a balance between injections and withdrawals, that participant can control its exposure to the spot market.

The spot market deals only with the imbalance between actual injections and withdrawals, and this imbalance will generally be small in relation to the total quantity of gas purchased or sold. Therefore it was expected initially that only a small portion of gas will be traded through the spot market.

Only gas is traded in the spot market. There is no trade in transmission system capacity. The design of the spot market allows for the possible future development of secondary markets. For example, a short term forward market could be established, if this were considered to be worthwhile.

There are two points with regard to trading that are worth highlighting: Firstly, parties are not required to trade on the spot market. If a market participant withdraws exactly what it injects and does not submit an offer to sell gas, the market participant is not subject to the spot market. Secondly, a market participant may buy or sell all of its gas from the spot market, provided there is a market participant willing to sell or buy. The spot market is therefore a convenience for market participants rather than an imposition.

Retailers are the merchants of the new gas industry. The role of the retailer is to buy gas and transmission services and to sell a package of delivered gas and related services to customers. Retailers are free to sell a package of gas services in any area to any customer that is contestable.

There is one major producer of gas in Victoria, and that producer has contracted the sale of gas to the wholesale company Gascor for the medium term. Gascor will sell to the Retailers the gas that it purchases from the producer. The contract between retailers and Gascor will have similar terms to the contract between Gascor and the producer. The retailers are actively seeking additional sources of gas supply.

Steps have been taken to ensure that there are minimal barriers to entry for new retailers to compete with the three initial Retailers including the opportunity to secure gas through a gas release program coordinated by the State. It is anticipated that retailers will diversify the products that they offer and will eventually offer both gas and electricity retailing services.

Fundamental features of the spot market are that:

- Gas is scheduled for trading in accordance with nominations and competitive offers from market participants;
- market participants pay or are paid for their actual imbalance at a Market price which is determined from the competitive offers made to the spot market;
- To the extent possible, spot market processes are transparent to market participants.

**Nominations**

Each market participant is required to nominate to the system operator VENCorp, ahead of each gas day the quantity of gas it intends to inject into, or withdraw
from, the transmission system during that day. These nominations are for VENCorp’s scheduling purposes and do not relate to spot market trade.

Market participants will be involved with (at least) two forms of nominations. Contract nominations involve physical nominations to their Producer(s) under the prevailing contracts of their daily requirements. Market nominations involve financial market-based nominations to VENCorp of injections or withdrawals, to determine their net imbalance in the market. Any net daily imbalance is either purchased or paid for at the daily market price.

**Increment/decrement offers**

Each market participant may also, if it wishes, submit increment/decrement offers (called Inc/Dec offers) to increase or decrease the quantity injected or withdrawn at some (or all) connection points. Each Inc/Dec offer may specify several prices and corresponding quantities of injections or withdrawals that the market participant is prepared to implement if the market price reaches the specified value. A market participant can structure its Inc/Dec offers to include conditions on the way in which VENCorp can schedule its injections or withdrawals due, for example to contractual conditions or physical limitations of a Producer’s or Customer’s equipment.

![Injection Inc/Dec Offer](image)

**Figure 6 Bidding for supply and demand**

The left diagram represents an injection Inc/Dec offer where the market participant only wishes to inject gas if the market price is $2.50/GJ or more. It does not wish to inject more than 95 TJ in total, regardless of the market price. If the market price is less than $2.50/GJ, this market participant does not wish to inject any gas. Where the price is exactly $2.50/GJ, the market participant is willing to
inject up to 80 TJ. Where the market price is between $2.50/GJ and $2.65/GJ, the market participant expects that it will have been called to inject 80 TJ. Where the price is exactly $2.65/GJ, the market participant is willing to increase its injection up to 90 TJ. Where the market price is between $2.65/GJ and $95.00/GJ, the market participant expects that it will have been called to inject 90 TJ. Where the price is exactly $95.00/GJ, the market participant is willing to increase its injection up to 95 TJ. Where the market price is more than $95.00/GJ, the market participant expects that it will have been called to inject 95 TJ.

The right diagram represents a withdrawal Inc/Dec where the market participant wishes to be able withdraw a certain quantity of gas, 80 TJ, regardless of the market price. The market participant is willing to withdraw up to 95 TJ of gas if the market price is sufficiently low. Where the market price is less attractive (higher) it wishes to reduce its withdrawals of gas back towards 80 TJ. Where the market price is less than $2.60/GJ, the market participant expects that it will be able to withdraw 95 TJ. The market participant is willing to reduce its withdrawals down to 90 TJ when the market price is exactly $2.60/GJ. Where the market price is between $2.60/GJ and $52.00/GJ, the market participant expects that it will be able to withdraw 90 TJ. The market participant is willing to reduce its withdrawals down to 80 TJ when the market price is exactly $52.00/GJ.

Nominations and Inc/Dec offers are based on intervals of one hour for scheduling and to ensure that VENCorp can manage changing conditions on the gas transmission system during the day. Note that market participants are not required to submit Inc/Dec offers. A market participant who does not submit Inc/Dec offers will have its gas delivered without reference to the spot market, provided they withdraw the same amount they inject. The only time when such a market participant will not receive the gas it injects is in the event of an emergency, when all spot market offers (including LNG) have been scheduled and all known unauthorized transmission system users have been curtailed. In such an event, the market participant would be paid the Value of Lost Load (VoLL), proposed to be $800/GJ.

**How is Gas Scheduled?**

VENCorp prepares a preliminary operating schedule two days ahead of each gas day, setting out the quantities of gas which are to be injected and withdrawn to satisfy the demands nominated by market participants. This schedule is updated one day ahead of the relevant gas day and again at the start of the gas day. If necessary it is further updated during the day, to take account of any changes to conditions during the day. The scheduling process provides market participants with the opportunity to adjust their contract and market nominations and Inc/Dec offers to attempt to maximise their commercial positions.

In preparing operating schedules, all of the spot market nominations are considered. VENCorp is required to utilise Inc/Dec offers in market price order (having due regard to any attached conditions and system security). In this way the defined physical operating criteria for the transmission system are satisfied in the most economic manner using the offers by market participants in the most efficient manner. During each gas day, VENCorp monitors the actual gas demands and other transmission system operating parameters and issues appropriate scheduling instructions calling on market participants to implement their Inc/Dec offers.

**Linepack Management**
VENCorp manages the actual physical linepack in the gas transmission system by considering injections, withdrawals, and VENCorp’s security targets for quantity and distribution of linepack around the system over the day. The objective in doing so is to ensure that this distribution is adequate to reliably meet demand in the next day.

End of Day (EoD) Linepack is a financial instrument which allows market participants to hedge against the day-to-day variation in gas prices. Each day, market participants can submit bids for EoD Linepack. The total amount of EoD Linepack which market participants can purchase is limited by the physical storage capacity of the gas transmission system.

In effect, this allows market participants to bid for and buy an allocation of EoD Linepack at today’s market price, and to sell this allocation at tomorrow’s market price.

**How is the market price determined?**

The operational scheduling of gas flows on the Victorian transmission system needs to take into account the physical capacity and characteristics of the transmission system, and is based on the forecast demand and system conditions for the day, with the schedule being updated during the day whenever there are material changes.

However, analysis of the Victorian transmission system has shown that, over the next few years, binding constraints on the capability of the transmission system to transport gas from Producers to Customers, and significant changes in demand and system conditions from those forecast at the start of the gas day, typically occur on only a few days of the year. In the absence of such constraints, or “surprises” during the day, such as a cold snap, the marginal value of gas will be the same all day everywhere on the system. This is because, under these conditions, any incremental demand, at any time of day, can likewise be met with an injection of gas from the same marginally priced source at any time of the day.

Reflecting this, the spot market is to be implemented initially with a single daily market price which applies all day, everywhere in the gas transmission system. This price is to be determined at the end of each gas day, based on the actual demand for gas during the day and ignoring the effects of transmission constraints and the timing lags in the transport of gas.

For example, the actual demand for gas on the day is 550TJ. In the absence of any constraints, this demand can be met by scheduling all of the gas offered into the spot market by retailers A and B, and 150TJ of the gas offered by Producer X gas at $2.85/GJ. None of Retailer C’s gas at $7.00/GJ would be scheduled to flow.

The market price for the day is set by the highest priced gas scheduled for the day, i.e. Producer X’s gas at $2.85/GJ. All market participants’ imbalances on the day are settled out at the market price of $2.85/GJ - even if these imbalances are due to scheduled injections of gas in accordance with Inc/Dec offers submitted at a lower price, as is the case for Retailers A and B.

**Why Ancillary Payments?**
The spot market is based on a daily market price which applies everywhere in the gas transmission system. This price setting mechanism ignores transmission constraints and the time delays in transport of gas. On most days, the gas transmission system will be constraint free. VENCorp will be able to manage the operation of the gas transmission system so that transmission constraints and surprises do not have an impact on the market outcome.

On the relatively infrequent occasions when transmission constraints arise or there are surprises during the day which impact on the spot market. The uniform daily price will not provide a clear pricing signal which would encourage market participants to respond appropriately.

VENCorp must manage the gas transmission system during the day by scheduling for hourly and locational needs. It will do this by scheduling increases or decreases in injections or withdrawals of gas, in accordance with Inc/Dec offers submitted by market participants.

Since the uniform daily market price is determined after the end of the day, with perfect hindsight of the actual system demand and ignoring pipeline constraints, some market participants may find that the resultant daily market price is less than the price of their scheduled Inc/Dec offer. In these cases, the market participants will expect to be compensated, and will be entitled to be compensated for, complying with VENCorp instructions which put them at a disadvantage in comparison to the market price outcome.

Such compensation is to be provided through “Ancillary Payments”. The need for Ancillary Payments will arise for example, where a transmission constraint requires VENCorp to call on LNG injection offers to cope with a transmission constraint. The single zone model (with a single price) does not address the issue that the value of gas might be higher if the gas is close to the point of consumption relative to gas that is several kilometres away. Consequently there will be occasions when VENCorp need to bridge this value difference. Funding for the ancillary payment is through an “Uplift Charge” allocated to market participants as described in section 8.3.

**Metering and Settlement Arrangements**

To enable gas injections and withdrawals to be determined for each market participant, a metering installation is required at all connection points on the transmission system and for Customers who have elected to become full market participants or have changed the Retailer from whom they purchase their gas. These metering installations measure and store hourly gas flows and the data are periodically transmitted electronically to a central metering database managed by VENCorp. From this data the injection/withdrawal imbalance is determined for each market participant for each gas day.

A spot market settlement statement is prepared by VENCorp at the end of each month for each market participant. For each gas day in the month, the amount payable to or by each market participant is determined from their injection/withdrawal imbalance and the market price. To this is added any relevant Ancillary Payments, uplift charges, market fees and any payment associated with End of Day Linepack and these are aggregated to give a monthly settlement amount. Full supporting data is issued with each settlement statement to enable each market participant to independently confirm all settlement amounts.

Payment occurs on the 20th working day of each month to allow time for market participants to check the settlement statements and for most queries and issues to
be resolved. The intention is that the spot market processes be as transparent as possible while satisfying commercial confidentiality requirements. To this end, VENCorp publishes to market participants a wide range of market information including preliminary and final operating schedules, market price, aggregate gas withdrawals and injections, quantities and prices of Inc/Dec offers and End Of Day Linepack quantities.

In addition, VENCorp publishes an annual planning review containing forecasts of gas supply and demand and transmission system capability for the next five years and quarterly planning reviews giving more detailed forecasts of conditions for the next 12 month period. Market information and settlement statements and relevant supporting data will be published electronically on a market Information Bulletin Board (MIBB). This provides convenient access to the large volumes of information while also providing access controls so that each market participant can only access market information to which they are entitled.

4.6 Another competitive market: The US model

In the 1980s natural gas prices in the US were partially deregulated. Before price deregulation, the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), and the State public utility commissions (PUCs) directly or indirectly controlled the prices of wellhead natural gas, pipeline transmission, and retail gas service. Government was also deeply involved in deciding the merits of pipeline investment and siting. The immediate effect of price controls was to stabilize price. Price certainty was paid for with shortages in some areas and surplus elsewhere and by complex cross-subsidies from areas where prices would have been lower to areas where prices would have been higher, with accompanying efficiency costs. Currently, the prices of natural gas, and all petroleum products are free from federal regulation. The FERC continues to impose price ceilings on pipeline services and has approval authority for new pipeline construction. Many States continue to regulate prices for small users of natural gas (residences and commercial enterprises), but large users are generally free to make their best deals.

**Importance of Gas Market Centres**

The defining characteristics of a natural gas market centre are that it provides customers (shippers and gas marketers primarily) with access to two or more pipeline systems; that it provides transportation between these and that it offers administrative services that facilitate that movement and/or transfer of gas ownership. While interstate pipeline companies have had to provide hub-type services (per FERC Order 637), such as parking and lending, since 2000, they do not provide many of the other ancillary services usually associated with market centres (see Box, "Market Centre Services," below).

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20 Tobin (2003).
When it issued Order 636 in 1993, FERC recognized that the expertise of pipeline companies in managing gas purchases and balancing ever-changing user demand with supply would somehow have to be carried over to the restructured marketplace. As a possible solution, FERC promoted the market center concept. Such centers could provide the services that customers (shippers) needed to manage their market Centre Services portfolios of supply, transportation, and storage; services previously provided by the merchant pipeline company. Moreover, their locations could also increase the interchange of gas across pipeline systems and permit a market to develop for the trading of natural gas volumes, storage, and pipeline capacity. Further, because services would be priced separately, it was suggested that additional efficiencies could develop as competition among centers and pipelines developed over time.

The operational infrastructure of the market centers may vary (Figure 7). Many of the US centers can be described as header systems, with relatively short distances between pipeline transfer points and other facilities such as storage. Examples of "headers" that also operate as full service centers include the Henry Hub and the Egan Hub in Louisiana and the several Katy area centers in eastern Texas. These facilities provide parking and loaning of gas, balancing, and intra-hub transfers of gas, in addition to the transportation and interchange services of a hub.

Figure 7

The remaining gas market centers are associated single pipeline systems to carry out their operations and provide transportation services. Two examples are the Ellisburg-Leidy Market Center in the U.S. Northeast and the Dawn Hub in Ontario, Canada. Both centers support the interchange of gas for their customers via the many interconnections and delivery points.
### Table 1 "Market Centre Services"

<table>
<thead>
<tr>
<th>Service</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Transportation/Wheeling</td>
<td>Transfer of gas from one interconnected pipeline to another through a header (hub), by displacement (including exchanges), or by physical transfer over the transmission of a market center pipeline.</td>
</tr>
<tr>
<td>Parking</td>
<td>A short-term transaction in which the market center holds the shipper's gas for redelivery at a later date. Often uses storage facilities, but may also use displacement or variations in line pack.</td>
</tr>
<tr>
<td>Loaning</td>
<td>A short-term advance of gas to a shipper by a market center that is repaid in kind by the shipper a short time later. Also referred to as advancing, drafting, reverse parking, and imbalance resolution.</td>
</tr>
<tr>
<td>Storage</td>
<td>Storage that is longer than parking, such as seasonal storage. Injection and withdrawal operations may be separately charged.</td>
</tr>
<tr>
<td>Peaking</td>
<td>Short-term (usually less than a day and perhaps hourly) sales of gas to meet unanticipated increases in demand or shortages of gas experienced by the buyer.</td>
</tr>
<tr>
<td>Balancing</td>
<td>A short-term interruptible arrangement to cover a temporary imbalance situation. The service is often provided in conjunction with parking and loaning.</td>
</tr>
<tr>
<td>Title Transfer</td>
<td>A service in which changes in ownership of a specific gas package are recorded by the market center. Title may transfer several times for some gas before it leaves the center. The service is merely an accounting or documentation of title transfers that may be done electronically, by hard copy, or both.</td>
</tr>
<tr>
<td>Electronic Trading</td>
<td>Trading systems that either electronically match buyers with sellers or facilitate direct negotiation for legally binding transactions. A market center or other transaction point serves as the location where gas is transferred from buyer to seller. Customers may connect with the hub electronically to enter gas nominations, examine their account position, and access E-mail and bulletin board services.</td>
</tr>
<tr>
<td>Administration</td>
<td>Assistance to shippers with the administrative aspects of gas transfers, such as nominations and confirmations.</td>
</tr>
<tr>
<td>Compression</td>
<td>Provision of compression as a separate service. If compression is bundled with transportation, it is not a separate service.</td>
</tr>
<tr>
<td>Risk Management</td>
<td>Services that relate to reducing the risk of price changes to gas buyers and sellers, for example, exchange of futures for physicals.</td>
</tr>
<tr>
<td>Hub-to-Hub Transfers</td>
<td>Arranging simultaneous receipt of a customer’s gas into a connection associated with one center and an instantaneous delivery at a distant connection associated with another center.</td>
</tr>
</tbody>
</table>

Several market centers mostly confine their operations to providing transportation services to gas producer clients, dispatching their production volumes onto the mainline transmission grid. A good example of such a production service center is the Waha (Encina) Hub in southwest Texas. This facility mainly offers pipeline interchange and transportation services to producers in the Permian Basin,
directing their product to interconnecting interstate pipelines directly or indirectly though one of the larger market centers located nearby.

Market centers have helped mitigate the transition to a restructured market place and improved the overall management of long-distance gas transportation. The interstate natural gas pipeline system experienced a significant increase in pipeline interconnections after Order 636\(^{21}\). Although most of these connections were developed as individual pipeline companies expanded their transportation services and supply sources, market center development nevertheless spurred many additional interconnections.

Market centers also provide a focal point and location for spot market transactions and gas trading. Henry Hub has become the famous focal point of US gas pricing. Combined, these features provide for greater price discovery opportunities. The availability of market centers has enabled more buyers to seek out the least expensive sources of supply, while providing sellers with a platform to reach those buyers who are willing to pay the most attractive price. The availability of price information at many points within the pipeline grid and access to other buyers and sellers at market centers also helps provide a means of reducing price risk exposure for customers.

Gas transportation and transfer remain the most important market center operations and services provided for the customer. For example, when a shipper with firm capacity on one pipeline wants to deliver gas to an end user located off another pipeline, the shipper can make arrangements to transfer the gas through the market center 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 center if trading services (or traders) are available. Similarly, the shipper can use the center’s services to revise its nominations (or temporarily release some capacity) on either pipeline, with the center handling the administrative requirements, including confirmations, associated with the transactions. 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 center.

These operational balancing agreements illustrate how important the availability of storage is to shippers using market centers and to the centers themselves. For instance, a large end user or local distribution company with firm capacity on a downstream pipeline that buys gas in an area serviced by a separate upstream pipeline, which has only interruptible capacity available, can arrange to have supplies moved on the upstream pipeline during nonpeak periods. Any excess gas can be injected into storage at the center. When the shipper experiences a sudden increase in demand, the center will provide the necessary incremental support from storage. If the shipper temporarily exceeds its storage allotment at the center, the center offers gas loaning, with the shipper responsible for replacement of the gas within a specified period.

Similarly, storage withdrawal and loaning by the center can also be used to cover shortfalls when purchased production flowing into the downstream pipeline does

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\(^{21}\) Before the 1990s, pipeline interconnections were limited and were mainly put in place as insurance to maintain the reliability of the system (emergency interconnects), to receive supply via a major trunk line, or to fulfill exchange gas commitments with other pipeline companies.
not equal transportation nominations. Many centers also provide a real-time tracking service to notify shippers immediately when such imbalances are imminent.

**Price deregulation and market development**

Price deregulation has encouraged the rapid growth of domestic spot markets. According to the New York Mercantile Exchange (NYMEX), “In 1982 a spot market for natural gas hardly existed; by the late 1980s, it accounted for 80% of the entire gas market.” Although spot transactions had fallen to between 35 and 40 percent of the overall market by 1992, most of the remainder was bought and sold under long-term contracts at prices that usually were tied to those in the spot markets.

Spot markets fundamentally change how businesses perceive their opportunities. The opportunity costs of idle assets become apparent, because spot markets make current prices visible. Firms can clearly see how small differences in the timing of their acquisition, production, and storage decisions affect their profits. Firms also have the option of using a liquid spot market as if it were an actual supplier, warehouse, or customer. Customers can easily compare the price of a supplier’s offer with the spot market price. In addition, spot markets are critical for the valuation of cash-settled derivative contracts.

Yet, the advent of energy spot markets has also introduced some new risks. Sometimes commodities cannot be sold in the spot market or, if they can, only at prices substantially different from the last reported market price. Sometimes spot market prices appear to be manipulated. If the reported spot prices are not accurate, or if the market is subject to manipulation or turmoil, traders may be unable to design, much less trade, derivatives. The best defense against these problems is large, liquid spot markets with many buyers and sellers.

Analysis shows that, in the US, there is not a single domestic natural gas market; instead there is a collection of loosely connected, relatively small spot markets. New pipeline construction and capacity additions should eventually promote more competition in the markets they serve, by relieving the congestion that may account for some of the variation in transmission charges. Until then, market fragmentation will make large trades hard to execute and limit the number of buyers and sellers. It may also encourage attempts to manipulate market prices.

4.7 Self-evaluation

- Are marginal costs a theoretical concept or a ‘real’ phenomenon, used in the business?
- What are the most important functions of a hub, within the network and the market.
- What are the causes of market risk in the gas industry?
- Consider to what extent markets can be designed, or emerge?
The wholesale gas market in the EU

5.1 Introduction: Market power in the wholesale market

The design of wholesale gas markets in the general sense may involve all kinds of configurations as regards the organization of the production, wholesale and retail markets and the required transport and ancillary services. Nevertheless, in the context of the EU, over the past decade, the European Commission has provided an increasingly detailed framework for the market design and for the regulatory approaches, to be implemented in detail by the Member States.

It is useful, however, to take a brief look at the notion of market power in the EU gas market. Whereas the existence of market power is a recurrent issue in the analysis of electricity markets, in the natural gas market it is a permanent issue. Indeed, market power, defined as the capacity to maintain prices at a higher than the competitive level (marginal cost) and make a super-normal profit, is the essence of the existing producers’ regime in the EU gas market. There is no need to further elaborate on the concept of market power as such. The more interesting question is how market power is being interpreted in the case of the gas industry. This section will provide, firstly, some general insights in the reduction of market power in the wholesale gas market. Thereupon we will discuss the main elements of the EU regulatory framework, as it has evolved over time.

5.1.1 Concentration and Market structure

Production Segment

A prerequisite for competition in the production segment is to have a multitude of producers involved in exploration, development, production and sale of the gas reserves. This clearly requires open and non-discriminatory licensing regimes and a tax regime which encourages investment, also in production areas in decline. Licensing procedures should also ensure that large companies cannot just buy up exploration and production licenses, while delaying field development. Yet, such competition always requires an upstream production sector with a sufficient scale, to sustain a large number of firms. This is hardly the case within the context of the EU, where only the UK and the Netherlands count with a sufficiently large resource base.

But, even where a large number of producers are active there may be concentration of sellers’ power through the operation of a quasi-cartel structure such as the GFU in Norway (now disbanded), formerly Gasunie in the Netherlands, or by joint venture partners in specific fields, selling gas jointly under identical terms with the revenue split between the partners. Chapter 6 below will discuss the pros and cons of such coordinative efforts.

In Europe, the requirement for multiple competing producers is only met in the UK. One problem, which also applies to other countries, was that all gas produced was sold to British Gas. That problem was addressed, first, through a requirement for producers had to sell 10 per cent of the output of new fields to buyers other than British Gas and, secondly, through a gas release scheme.

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23 See the relevant section in the power wholesale market module.
A characteristic of competitive producer markets is that producers move away from the joint market approach and start to sell the equity shares in the field’s gas production independently to the buyers. For example in the UK, equity partners have the option to sell their shares on long term contracts to a third party such as a power generator or another gas supply company, or to sell the gas to their own down-stream marketing affiliates for direct sale to retail customers.

The Community legislation, apart from plain competition law, does not include any measures that directly address the concentrated up-stream market structures inherited from the monopoly era, which thus remains a key issue for the internal gas market. But, even more important, most of the EU’s gas requirements are imported from outside the EU jurisdiction.

**Wholesale Market**

The functioning of the wholesale gas market in the EU is regarded as a high priority by the Commission, however. As argued above, the development of competition requires effective regulation and competition control. As gas markets move from monopolistic structures to competitive markets it is necessary to tackle the issue of market power and dominance by one, or a few, companies. Here we have to take into consideration both the commodity and the transport segments of the unbundled gas markets, and the interaction between these segments.

On the **commodity side** a genuinely competitive wholesale market requires:

- A multitude of alternative producers/importers willing and able to sell gas to a multitude of wholesalers and suppliers on the wholesale market, engaging in gas-to-gas competition.
- Diversity of supply: low reliance on a dominant source of supply, possibly aided by gas release schemes.
- Flexibility of supply; medium term responsiveness of supply to price movements.
- A move to shorter term and smaller contracts, away from the traditional long term contracts.
- A removal of take-or-pay clauses in contracts.
- A removal of ‘destination clauses’ in long term contracts which restrict the resale of gas outside the specified territory.
- The use of spot and future price indexation in longer term contracts, thereby increasing their importance above physical share of the total market.

Some Member States have introduced measures to reduce concentration in the whole-sale market via gas release programs or market share caps in which the mid-stream monopolistic wholesale companies where forced to relinquish some market share.

Yet, a set of liberalised national markets will not in themselves guarantee competition at EU-level. To create an integrated European gas market, it is crucial to enable and facilitate cross-border trade. Sufficient **transport and cross border transit capacity** is therefore a primary requirement. First of all, this requires
effective unbundling. Clear financial and physical separation of the transportation and supply functions should guarantee that the transmission network operator (TSO) treats the supply function like any other shipper. In respect of access to essential facilities, like networks, LNG terminals and storage facilities, the following elements are important:

- Third party access on a non-discriminatory basis with clear and transparent access rules. The availability of precise information is crucial in respect of the exact obligations of network operators, including the protection of network users’ commercial data.
- Regulation of charges, tariffs and prices for transportation, storage and LNG facilities, in the absence of true competition.
- Effective capacity allocation procedures and booking arrangements which allow new entrants to obtain capacity on an equal basis to the incumbent gas supplier. Measures such as “use it or lose it” (UIOLI) and the secondary trading of un-used long term contracted capacity are proposed to transfer capacity from incumbents to new entrants as the latter build up market share.

The removal of (cross-border) transmission constraints and capacity bottlenecks requires that the proper incentives are in place to make capacity available to shippers. Under the Gas Directives and the Regulations, so far, transit pipelines and connections to storages and LNG facilities are covered by the same access rules as other transmission services.

Yet, there exists a nasty dilemma. On the one hand, the value of new and existing long-term transit, storage and LNG supply contracts requires parallel access to (cross border) transport capacity, to exercise the supply option at any time. It is a question to what extent this capacity – if not nominated for use – should be considered as un-used; prone to be lost. Lack of certainty on such transport rights may keep potential suppliers from contracting supply contracts. In respect of the TSO, on the other hand, regulated access tariffs may constitute an important obstacle in investing in the “right” amount of transit capacity. Generally, it is argued that the maturity of the depreciated networks has reduced the volume risk significantly, so that tariffs can be low. Yet, investments in expensive new capacity by regulated TSOs may require long term certainties that the additional capacity will be used, or paid for at least. This, most likely, will take the form of longer term capacity commitments by suppliers, by means of “Open Season” procedures. This is still a problematic issue, as it conflicts with the principle of effective non-discriminatory capacity allocation.

The retail market

In the retail market, customer pressure should drive retail suppliers to service them at lower prices and/or improved or innovative services. This requires many alternative buyers of gas and the entry of new, strongly capitalised and committed, retail players into the market. Short term price elasticity of demand must be enhanced via fuel switching and commercial interruptible contracts.

5.2 Gas Market Regulation in the EU

The main objective of European energy policy in the area of gas has been the gradual liberalisation of the sector and the creation of a competitive integrated energy market, with security of supply ensured at a reasonable price. The
Community legislative process of liberalising the gas markets began in the 1990s, first with the Price Transparency Directive. Thereupon the Hydrocarbons Directive gave on- and off-shore operators the explicit freedom to contract and sell their gas to any customers. Then the first Gas Directive provided for the abolition of import monopolies, gradual market opening, accounting unbundling for vertically integrated network companies, and an option of regulated third party network access.

5.2.1 The First Gas Directive

The EU Council accepted the First Gas Directive in December 1997, it entered into force on the 10th of August 1998 (98/30/EC) and had to be implemented by the Member States two years later. The main elements of this Directive where broadly formulated as:

- The provision of regulated or negotiated third party access (TPA) to the national transmission and regional distribution networks;
- A step by step introduction of free choice of suppliers to eligible customers, defined as percentage shares of the respective markets;
- Separate accounts for generation, transmission, distribution and any other activities, but no explicit unbundling.

5.2.2 The Second Gas Directive

The Second Gas Directive was adopted in June 2003 and was to be implemented by 1 July 2004. This new Directive (2003/55/EC) was more explicit and more stringent in a number of aspects and, thus, reduced the leeway in national implementation:

- The supply of gas to final customers should depend on the possibilities to use existing transport infrastructure, which can in many cases be considered as a natural monopoly. To ensure that access is granted in a nondiscriminatory and transparent manner, Regulated third party access was required, based on approved and published tariffs, applying to transmission, distribution and LNG operators, as well as to balancing services (i.e. negotiated access was no longer allowed). The operators must refrain from discriminating between system users, and provide them all with the information needed for efficient access.

- In order to increase competition on a liberalised market, the second Gas Directive required full market opening. All commercial customers must be free to choose their supplier by 1 July 2004 and household customers by the 1st July 2007. By that date, at the latest, the retail market should, consequently, be

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fully open to competition. Several Member States had already introduced full market opening\textsuperscript{26}.

- Transmission and distribution system operators must, in addition to the previous accounting unbundling (i.e. the keeping of separate accounts), also be legally unbundled and management unbundled (i.e. independent from activities not related to the network operation as regards legal form, organisation and decision making). Whereas ownership unbundling was not required by EU legislation, several Member States have found it necessary also to require separate ownership of network and supply companies.

- Unbundling requirements were more limited for distribution system operators, as the legal unbundling only had to be completed by 1 July 2007, and Member States can also exempt small distribution system operators, serving fewer than 100,000 connected customers, from the obligation of legal unbundling (but not from accounting unbundling). Moreover, only accounting unbundling is required for storage and LNG operators.

A genuinely new element was that the second Gas Directive required the creation of national energy regulators, or national regulatory authorities (NRAs). Their main roles included approving and controlling tariffs (or methodologies), ensuring non-discriminatory network access and effective unbundling, and dealing with complaints.

Moreover, regulated access to necessary infrastructure was far from universal. Member States still retained a choice between applying negotiated or regulated access for storage, line pack and other ancillary services. Derogation from third party access rights, whereby investors can reserve the capacity for themselves, could also be granted in order to provide incentives for risky investments in important new infrastructure. The second Gas Directive foresaw a number of criteria to be fulfilled in order to allow such exemptions including the condition that competition is not negatively affected. Such derogations could be limited in time and to a part of the capacity.

The Directive was complemented by the Gas Regulation\textsuperscript{27}, which expanded on several of its provisions. It provided further requirements aimed at ensuring fair access to transmission networks. Services should be offered in a non-discriminatory manner on terms that also suit new entrants (e.g. firm and interruptible capacity; long and short-term contracts). It required non-discriminatory capacity allocation mechanisms, congestion management procedures based on a use-it-or-lose-it principle, and a functioning secondary capacity market. Balancing rules should reflect genuine system needs (excessively stringent rules hampered new entrants), and imbalance charges must be cost-reflective, while still providing appropriate incentives for balance.

Community legislation was supplemented by other binding and non-binding instruments, such as Community guidelines (under the Gas Regulation), voluntary

\textsuperscript{26} Some Member States benefit from derogations as, for example, isolated or emerging markets.

\textsuperscript{27} Regulation (EC) No 1775/2005 of 28 September 2005 on conditions for access to the natural gas transmission networks (OJ 2005 L 289/1). Date of application of entry into force is 1 July 2006.
guidelines developed within ERGEG\textsuperscript{28} and the Madrid Forum\textsuperscript{29} (e.g. Guidelines for Good Third Party Access Practice for Storage System Operators – GGPSSO) and technical standards prepared by EASEE-gas\textsuperscript{30}.

5.2.3 The sector inquiry 2006\textsuperscript{31}

Responding to concerns voiced by consumers and new entrants in the sector about the development of wholesale gas and electricity markets and limited choice for consumers, the DG Competition launched the energy sector inquiry, by June 2005. This inquiry has assessed the wholesale markets for gas and power, identifying issues that hamper the development of these markets. It made clear that competition between upstream producers outside the EU falls outside the scope of the sector inquiry, although competitive conditions on these markets influence the price of the basic commodity.

It was acknowledged that there are only a few global players active in the upstream gas chain. Due to infrastructure constraints some regions in the EU are dependent on a limited number of upstream producers for their gas. However, as was argued, the future development of new infrastructure and LNG sources is likely to provide new economically viable sources of gas to Europe, thereby reducing dependence on a few producers and hence reducing concentration at this level of the gas supply chain.

The sector inquiry was thus concerned with the competitive conditions within the EU. It observed that, at the wholesale level of the gas supply chain, EU liberalisation has not significantly changed the degree of market concentration in most national markets. Neither had a liquid wholesale market emerged, while traded markets (gas hubs) represented only a minor part of gas supply. This caused a lack of liquidity on European wholesale markets, which crucially affected the competitive conditions at the retail level. New entrants wishing to enter the retail market did not have access to gas supplies directly from gas producers and so they needed to procure gas on wholesale markets.

The review addressed respectively: Market concentration, Vertical foreclosure, Lack of market integration, Lack of transparency and price formation. Subsequently, on the basis of the findings, the Commission started to pursue the infringements in the sector.

\textsuperscript{28}The European Regulators Group for Electricity and Gas established by Commission Decision of 11 November 2003 (OJ 2003 L 296/34), http://www.energy-regulators.eu/

\textsuperscript{29}The European Gas Regulatory Forum (“the Madrid forum”); participants include national regulatory authorities, Member States, the European Commission, network operators, gas suppliers and traders, consumers, network users, and gas exchanges. http://ec.europa.eu/energy/gas_electricity/forum_gas_madrid_en.htm


\textsuperscript{31}http://ec.europa.eu/competition/sectors/energy/inquiry/index.html
Market concentration

Wholesale markets maintained a high level of concentration and trade has been slow to develop. The incumbents remained dominant by largely controlling upstream gas imports and/or gas production, while trading only small amounts of their gas on hubs. With little new entry in retail markets, customer choice has been limited and competitive pressure remained reduced. Potential new entrants stayed dependent on the vertically integrated incumbents for services throughout the supply chain. The main remedy, in this respect, was merger regulation.

Vertical foreclosure

Lack of liquidity and limited access to infrastructure prevented new entrant suppliers from offering their services to the consumer. The network of long term supply contracts between gas producers and incumbent importers made it very difficult for new entrants to access gas on the upstream markets. The highly concentrated upstream market propagated into market foreclosure downstream because networks and storages were mostly owned by the incumbent gas importers. Despite EU rules on third party access and legal/functional unbundling, new entrants often lacked effective access to networks, the operators of which are alleged to favour their own affiliates.

Market integration

Cross-border sales did not exert any significant competitive pressure. Incumbents rarely entered other national markets as competitors and available capacity on cross border import pipelines was limited. New entrants were unable to secure transit capacity on key routes. The primary capacity on transit pipelines was controlled by incumbents based on legacy contracts that derogate from normal third party access rules. This was reinforced by ineffective congestion management mechanisms, which can made it hard to secure even small volumes of short-term, interruptible capacity on the secondary market. In most cases, new entrants had not even secured capacity when there had been expansions of transit pipeline capacity.

Transparency

There was a lack of reliable and timely information on the markets - normally the lifeblood of healthy competition. Network users requested more transparency on access to networks, transit capacity and storage, going beyond the current minimum requirements set by EU legislation. To ensure a level playing field, users required information to be made available on an equal footing. Confidentiality rules also undermined effective transparency when given too wide an interpretation.

5.2.3.1 Price formation

The Energy Sector Enquiry (2006) by the EU DG Competition provided some insight in the actual system of gas pricing; a notoriously vague area in the European gas market. Wholesale market prices are in most European markets
dominated by the indexation mechanisms in contracts with producers. The Sector Inquiry focused on the indexation mechanisms actually used in these contracts\(^{32}\).

As gas import contracts use price indices that are linked to oil products, the price increases over the recent past have closely followed developments in oil markets\(^{33}\). Wholesale prices failed to react to changes in the supply and demand for gas. No clear trend towards more market based pricing mechanisms could be observed in long-term import contracts. Gas prices on existing gas hubs had also been rising. Ensuring liquidity was seen as crucial to improve confidence in price formation on gas hubs. Even when different producers were selling from the same field, the contracts generally contained the same price index and often even the same actual price.

**Oil indexation of long-term gas contracts in the EU**

As prices in European long-term gas contracts were mainly linked to oil and oil derivatives, contract prices paid to different producers by the suppliers were moving in an almost identical manner over time. As a result, prices paid by purchasers under long-term contracts did not react smoothly (or at all) to changes in the supply and demand of gas markets. The indexation in long-term contracts was usually linked to variables calculated with trailing averages, further reducing response to price signals. The indexation arrangements in the pricing of gas under long-term contracts resulted in wholesale prices for gas that reflected the developments of the oil market\(^{34}\), and in particular the market for oil derivatives such as heavy or light fuel oil, which accounted for around three quarters of gas price volatility\(^{35}\).

Long-term contracts from the Netherlands, Norway and Russia had almost identical indexation patterns, including over 80% of heavy and light fuel oil indexation. Because these three regions supplied over 275 billion cubic metres of gas, representing around 60% of the EU’s requirements, this indexation model was most influential in determining the prices paid by European companies. In respect of other regions, the inquiry found that Algerian gas was even more directly linked

\(^{32}\) For the preliminary report, oil price indexation has been analysed in long term purchase agreements of thirty major producers and wholesalers of gas. Over 500 long term contracts (any contract of over 12 months was considered to be a long-term contract), representing around 400 billion cubic metres of contracted gas, were reviewed. These contracts included those between companies exporting gas to Europe and major EU gas wholesalers, as well as contracts between different EU gas wholesalers.


\(^{34}\) There are often ceiling clauses on crude oil, light fuel oil and heavy fuel oil prices within gas contracts. In the contracts analysed in the inquiry, however, these do not apply to the full amount indexed within the contract but only to a specific part; for instance, if the contract includes 50% indexing to light fuel oil, the ceiling might only apply to 20% of the total light fuel oil element.

\(^{35}\) It should also be noted that a wider range of pricing arrangements are often included in the contracts, such as options to reduce off-take, summer discounts, seasonal prices and options to take a proportion of gas at a spot or fixed price.
to oil prices, with almost 70% of changes to the price level being determined by crude oil prices, and an additional 25% by heavy and light fuel oil. Long-term gas sourced from UK fields had a very different indexation pattern than gas from the other regions, with the main determinants being UK hub (NBP) gas prices (around 37%) and general inflation indices (just under 30%). Heavy and light fuel oil accounted for only 20% of the price indexation.

**Price levels of long-term contracts**

The enquiry also examined the actual commodity price levels of gas by region, in 2004, excluding the transport component. The average price level during 2004 for gas from long-term contracts varied between around 9.8€/MWh for Algeria and 12.8€/MWh for the Netherlands. All other regions settled between these two values, with most gas being purchased at levels between 10.5€/MWh and 11.5€/MWh.

The fact that gas purchased from the Netherlands, Norway and Russia had similar price levels is not unexpected, as they have comparable indexation patterns. However, it is surprising to find that gas purchased under long-term contracts from the UK is also being purchased at around the same price level, as the UK displays distinct indexation patterns.

The enquiry indicated a very strong similarity between the indexation in long term supply contracts of different producers selling from the same field. Most likely as a consequence of this, there was also a strong similarity between the actual prices paid by a wholesaler to several gas producers selling from the same field.

The inquiry looked for all long-term gas purchase agreements involving deliveries of gas from the same field by more than one gas producer to the same gas wholesaler. In almost 90% of cases where two or more producers are selling from the same field to the same wholesaler, the price indexation in the long-term contracts is the same. Furthermore, in almost two thirds of these cases, the same actual price was paid by the wholesaler to the producers.

Over the recent period, change is occurring in the pricing practices, like some degree of indexation with gas spot prices\(^\text{36}\). The question remains however, how far these developments will go and what to what kind of reactions this may lead. This issue will be dealt with in Chapter 6 below.

### 5.2.4 Towards the Third Gas Directive

In January 2007, to make the internal market work for all consumers and to help the EU achieve more secure, competitive and sustainable energy, the Commission formulated a new package of measures: The Third Package. This package was adopted in September 2007. The Commission proposed the following:

- **Network ownership and operation should be effectively "unbundled".** This refers to the separation between the network operation of electricity and gas from supply and generation activities. A single company can no longer own

\(^{36}\) See Melling (2010) for a recent and informative overview of these changes. See also Glachant, Jean-Michel and De Hauteclocque (2009) and
both transmission and be occupied in energy production or supply activities. In addition, the Commission proposes a second option, the "independent system operator" (ISO) which makes it possible for existing vertically integrated companies to retain network ownership, provided that the system is actually operated completely independent from it.

- Recognizing the strategic importance of Energy Policy. Therefore the package contained safeguards to ensure that when companies from third countries would wish to acquire a significant interest or even control over an EU network, they would have to comply with the same unbundling requirements as EU companies.
- To establish an **Agency for the cooperation of National Energy Regulators**, with binding decision powers, to complement National Regulators. This would ensure the proper handling of cross-border cases and enable the EU to develop a real European network working as one single grid, promoting diversity and security of supply.
- Measures to strengthen and guarantee the independence of national regulators in Member States.
- A new **European Network for Transmission System Operators for Gas** would have to be set up. EU grid operators would cooperate and develop common commercial and technical codes and security standards, as well as plan and coordinate the investments needed at EU level. This would also ease cross border trade and create a more level playing field for operators.
- Steps to improve **market transparency on network operation and supply** would have to guarantee equal access to information, make pricing more transparent, increase trust in the market and help avoid market manipulation.
- By increasing **solidarity by bringing national markets closer together**, the Commission foresaw more potential for Member States to assist one another in the face of energy supply threats.

In the absence of single cross-border regulator, national regulators should cooperate with each other in monitoring the management and allocation of interconnection capacity. ERGEG would provide a forum for co-operation. However, the powers of regulators are varying between Member States, since Community legislation only provides for a certain minimum competencies. Also the manner in which Community rules have been implemented varies between Member States. This gives rise to regulatory vacuum – especially in cross-border situations. In addition to the requirements under Community law, there is also a considerable scope for Member States to apply their own specific national rules, like authorisations or licences to operate gas facilities or to supply gas, planning permission for constructing new infrastructure, etc.³⁷

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³⁷ The European Council in March 2007 called for further harmonisation of the powers and strengthening of the independence of national energy regulators and the establishment of an independent mechanism for national regulators to cooperate and take decisions on important cross-border issues.
In its package of measures of January 2007, the Commission formulated a number of objectives, in respect of the further alignment of the national regulatory frameworks. It argued that, first, the powers and the independence of energy regulators need to be harmonized on the basis of the highest, not the lowest, common denominator in the EU. Secondly, they must be given not only the task of promoting the effective development of their national market, but also that of promoting the development of the Internal Energy Market. In addition, the technical standards necessary for cross-border trade to function effectively needed harmonisation.

**The Third Gas Directive**


The new Directive, of course, also pursued the objective of creating a competitive, secure and environmentally sustainable market in natural gas. It, however, also explicitly refers to biogas and gas from biomass. A number of new, more ambitious objectives were formulated.

Member States will explicitly allow for public service obligations which cover issues of security and security of supply, regularity and quality of service, price, environmental protection and energy efficiency.

Customers will have the right to choose their gas supplier and to change supplier easily, with their operator’s assistance, within three weeks.

Member States are responsible for monitoring security of supply issues and in particular those related to the balance of supply and demand on the national market, available supplies, maintenance of the networks and the measures to be taken in the event of supply problems. Regional or international cooperation may be put in place to ensure security of supply. These provision where accompanied by a specific Regulation, discussed below\(^{39}\).

Member States shall ensure the integration of national markets at one or more regional levels, as a first step towards the integration of a fully liberalised internal market. National regulatory authorities shall cooperate with the Agency for the Cooperation of Energy Regulators.

As regards the organization of transmission, storage and LNG facilities, the following principles were included.

Member States shall unbundle transmission systems and transmission system operators. “(5) Without effective separation of networks from activities of production and supply (effective unbundling), there is a risk of discrimination not only in the operation of the network but also in the incentives for vertically integrated undertakings to invest adequately in their networks.”

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Member States shall designate one or more storage and LNG system operators responsible for operating, maintaining and developing transmission systems, storage and/or LNG facilities, while ensuring non-discrimination between system users. The operators should provide the information necessary to ensure the interconnection to transmission system users’ access to the system (23).

As regards the future development of the transmission systems, operators shall build sufficient cross-border capacity to integrate the European transmission infrastructure. This includes an annual ten-year network development plan, indicating the main infrastructure that needs to be built or modernised and the required investments.

Member States shall designate distribution system operators or require undertakings which own or are responsible for distribution systems to do so. These operators shall be independent in legal terms from other activities not relating to distribution. They also have to provide transparent information to system users. Their main responsibility is in ensuring the long-term capacity of the system in terms of the distribution of gas, operation, maintenance, development and environmental protection.

As regards the unbundling and transparency of accounts, Member States and competent authorities shall have right of access to the accounts of natural gas undertakings, under confidentiality of certain information. Moreover, natural gas undertakings shall keep separate accounts for all of their activities relating to the supply of gas, such as transmission and distribution.

Member States or the competent regulatory authorities shall define the conditions for access to storage facilities and line-pack. They shall take measures to ensure that eligible customers can obtain access to upstream pipeline networks. Moreover, they shall organise a system of third party access to transmission and distribution systems.

Member State may take the necessary safeguard measures in the event of a sudden crisis in the market or where the safety of persons is threatened. These measures shall be notified to the other Member States and to the Commission.

That same month, July 2010, a Regulation No 715/2009 was published, more specifically addressing the role of natural gas transmission networks, gas storage and LNG facilities in reducing the barriers to competition in the internal gas market. Whereas the 2002 and 2003 European Gas Regulatory Forums (the Madrid Forums) had yielded best practices, it was acknowledged that these guidelines should be made legally enforceable via a Regulation. This Regulation concerns access to certified infrastructures, particularly by determining the establishment of access tariffs, services to be offered, allocation of capacity, transparency and balancing of the network.

It also provides for the foreseen establishment of the European Network of Transmission System Operators (ENTSO) for gas, thus formalizing and guiding the cooperation between the TSOs. ENTSO was given a number of marching orders. In respect of network codes, together with ACER, it would have to advise the Commission in establishing an annual list of the priorities in the development of network codes. They should cover network security and reliability; data interchange; technical and operational exchanges; transparency rules; harmonised transmission tariff structures; and energy efficiency.

Moreover, the ENTSO for Gas is responsible for adopting: common network operation tools; a ten-year network development plan and recommendations relating to the coordination of technical cooperation between Community transmission system operators.

As regards costs and tariffs, the NRAs shall determine tariffs or methodologies for their calculation. Member States may take decisions relating to tariffs such as fixing auction arrangements.

In respect of third-party access services, TSOs shall offer their services equitably to all network users on a rolling basis in the long and short term. LNG and storage facility operators must also offer their services according to the procedure described above and make them compatible with the use of interconnected gas transport networks.

Regarding, allocation of capacity and congestion management, it was stated that all market participants must have access to maximum network capacity as well as storage and LNG facilities. Operators will have to implement non-discriminatory and transparent congestion-management procedures which facilitate cross-border exchanges in gas on a non-discriminatory basis.

5.3 Self-evaluation

- Form yourself an idea of how the EU market design ‘prescriptions’ have evolved over time…
- What particular characteristic complicates the regulation of long distance supply and transport of natural gas?
- What is relation between transit network regulation and market power?
- Is the position taken by DG Competition in respect of market power, in line with the need to secure future gas supply?
6  Reliability of gas supply

6.1 Introduction

Unlike the power sector, the gas industry will never experience the situation in which business strategies can allow to fully focus on the consumer. In the power industry, consumers have much to say about system reliability and the short- and long-term security of supply that they regard as suitable. The regulatory framework just has to ensure the existence of sufficient financial incentives for security and quality of supply to be kept at socially optimal levels. The gas industry is different because the production and transport gas involves ‘third’ countries, like Russia, Algeria and Norway and others, which define the production and transport of natural resources as being part of their sovereign rights, as a nation state. As a consequence, the security of supplying natural gas in the medium-long term has a stronger strategic component than in electric power systems. This chapter analyses the nature of the longer term supply of natural gas. As will be shown, the already complex problems of guaranteeing the supply of electric power are compounded by the presence of the national interest of producing and transit countries in the gas industry.

6.2 Reliability and security of supply in the EU

The first explicit steps in respect of security of energy supply were taken by the Commission in the 2000 Green Paper Towards a European strategy for the security of energy supply. It was stated that "The European Union's long-term strategy for energy supply security must be geared to ensuring, for the well-being of its citizens and the proper functioning of the economy, the uninterrupted physical availability of energy products on the market, at a price which is affordable for all consumers (private and industrial), while respecting environmental concerns and looking towards sustainable development".

The Internal Gas Market (IGM) Directive (2003/5//EC) contained a number of provisions with regard to the security of gas supply. Pursuant to Art 2(32) of the directive, "security" means both security of supply of natural gas and technical safety. The provisions address six different aspects: 1) Public Service Obligations (PSO) and long-term planning; 2) Monitoring and reporting duties of the Commission and Member States; 3) Third party access to upstream pipelines; 4) Reasons for granting an exemption from TPA rules to new major gas infrastructures; 5) Reasons for refusing access to the network, if security of supply obligations form part or are defined as PSO; 6) Criteria to decide on derogations in relation to take-or-pay commitments.

These provisions were complemented by a specific Directive on security of gas supply adopted in April 2004 (EC 2004/67). This directive required Member States to define transparent and non-discriminatory security of supply standards that are compatible with a competitive internal gas market. A non-exhaustive list of

41 COM/2000/0769
possible instruments for security of supply was included, e.g. storage capacity, cross-border pipeline capacities, domestic production, liquid markets, LNG facilities, diversification of supply sources, long-term contracts, etc. Member States should define clear roles and responsibilities of market actors, and publish them, and must also establish standards to ensure supplies for household customers (e.g. for protecting against temporary disruptions and high gas demand in cold periods).

It is obvious that this perspective on security of supply is strongly oriented towards the functioning of transmission and distribution network. In respect of the development of wholesale gas trade, essentially, the market is assumed to provide security of supply. The overall objective of the directive is the completion of the internal market, by promoting competition between the market participants. As stated, “...it is important that the completion of the internal energy market [...] must not be hampered or in any other way negatively affected by any means contained in that directive. Security of supply obligations, defined as PSOs, should affect the development of trade and competition only in the least possible manner. Recourse to PSOs should only be sought “if and as long as there is no alternative solution reasonably and economically available.”

This approach can be contrasted with that of the gas industry (see Eurogas 2002). “Security of supply of gas, a concept which includes physical system security, economic security and continuity of supply, has in principle two main aspects. Firstly, long-term security, which concerns the EU’s ability to ensure a reliable and economic supply of efficient energy in the long-term; Secondly, short-term security, which concerns the avoidance of interruptions to contracted gas supply, and the guarantee for customers to receive their gas supply in fulfilment of their contracts.” Both short-term and long-term security of supply should address two aspects: First, the availability of physical gas (indigenous production, imports, gas storage etc) to meet firm demands; and, secondly, the physical transportation capacity to move these volumes of gas to the end consumer.

Eurogas suggested how responsibilities should be redistributed among the different market participants, to maintain security of supply in line with commercial and entrepreneurial initiatives. It argues that in a competitive gas market a single entity can no longer be assigned the responsibility for all security of supply aspects; the correct distribution of responsibilities is a shared task. Output requirements will provide the best results and will reduce the need for detailed ex-ante regulation. Eurogas argued ex ante regulation is taking away the incentives of market players to provide adequate security of gas supply on a commercial basis.

The regulatory approach to reliability of gas supply needs to address both the short term strategic dimension of security of supply, as well as the longer term security of supply. Both dimensions involve a commodity and an infrastructure component.

6.3 Recent EU initiatives on the Security of Supply of gas.

In November 2008, in the context of the third Internal Energy Market package of March 2007, the Commission proposed the EU Energy Security and Solidarity Action Plan, as part its second Strategic Energy Review. It

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43 COM(2007) 0528-32
44 COM(2008) 781 final
considered that complementary measures would be necessary to foster security of supply, particular in gas, as some Member States, namely those in central and Eastern Europe, where too dependent on one single supplier, i.e. Russia, and vulnerable to supply interruptions because of political incidents in supplier or transit countries, accidents or natural disasters and the impacts of climate change. It was stated that, whereas each Member State is responsible for its own security, solidarity between Member States is a basic feature of EU membership. As specific national solutions were considered insufficient, it was deemed necessary to develop strategies to share and spread risk, and employ the weight of the EU in world affairs.

Moreover, given global developments, the EU should take action to secure its energy future and to protect its essential energy interests. To this end, the EU should develop an effective external energy policy vis-à-vis producers and other large consuming states; “speaking with one voice, identifying infrastructure of major importance to its energy security and then ensuring its construction, and acting coherently to deepen its partnerships with key energy suppliers, transit countries and consumers.” Moreover, it should “tap the full potential of its oceans and seas for energy generation, rapidly evolve its transport system and make real progress in terms of the interconnection of the European energy market. To achieve these ends, the Commission proposed the five-point EU Energy Security and Solidarity Action Plan, focusing on 1) Infrastructure needs and the diversification of energy supplies; 2) External energy relations, 3) Oil and gas stocks and crisis response mechanisms, 4) Energy efficiency, 5) Making the best use of the EU’s indigenous energy resources.

Meanwhile, however, the perception regarding Europe's security of gas supply was rapidly changing. In the context of a growing dependence on imports, supply and transit risks were considered increasingly serious. This was underlined by the Russian-Ukraine gas crisis in January 2009, which caused a substantial disruption of gas supplies to Europe; 30% of Europe's imports were cut off for two weeks. The situation within Europe had also changed; because of the growing importance of long-distance network flows of gas and the development of the internal gas market, the gas supply crises were felt across large parts of Europe. Yet, it was argued that “by the same token, the internal gas market is offering an increasingly powerful means of mitigating gas supply disruptions”\textsuperscript{45}. These developments induced the European Commission to further expand on the notion of Security of Supply in the gas sector. After the Russian-Ukrainian gas crisis in January 2009, the Council, Parliament and the European Council all called for the revision of the Directive to be accelerated.

The main principle remained that “the internal gas market should be well-functioning and flexible enough, with sufficient infrastructure, to mitigate most gas supply disruptions”. Yet, it was acknowledged that there could be disruptions beyond the capacity of the market to mitigate. Indeed, “If an integrated liquid EU gas market already existed, it could be expected that most supply disruptions could

\textsuperscript{45} SEC(2009) 979 final. p.3.
be mitigated. But this is not yet the case”. Within the framework of the 2004 Directive, complementing the functioning of the market, emergency measures would have to be established, like standards for security of supply, to be implemented by market participants.

The Energy Council stated that it "recognizes the need to improve, as an urgent priority, both national and EU level instruments for ensuring security of gas supply, through the revision of the Directive, with notably a better definition of the major supply disruption indicator and a more effective crisis response mechanism (e.g. through predefined emergency plans at the appropriate levels)".

For the European Council, the revision should include "an appropriate crisis mechanism ensuring the preparedness of all actors, including the energy industry, transparency and prior information through the development of plans for security of supply; solidarity among Member States through the development of regional plans; and improved assessment and coordination through the redefinition of the threshold for deciding actions at Community level”.

For the Parliament, key elements in the revision are "mandatory and effective national and EU emergency action plans, which among other things, define a common declaration of an emergency situation, allocation of available supplies and infrastructure capacity among the affected countries, coordinated dispatching, activation of emergency measures in unaffected or less affected states in order to increase the amount of gas available to the affected markets using all means possible, including, among others, interruptible contracts, fuel switching, storage withdrawal, supply flexibilities for example; considers that it is essential to improve the functioning of the market through transparency and increase the availability of gas in the market; calls on the EU and its Member States to develop gas storage with fast-release capacity".

By July 2009, the Commission proposed a new regulation to improve the security of gas supply, combining most of the elements referred to. Most items of this proposal are formulated as direct obligations for the member states:

- To ensure that the state and their gas market players take effective action well in advance.
- To create mechanisms for Member States to work together to deal effectively with any major gas disruptions which might arise.
- To establish clear and effective emergency plans involving all stakeholders and incorporating fully the EU dimension of any significant disruption.
- To apply a common indicator to define a serious gas supply disruption, known as N-1, involving the shutdown of a major supply infrastructure or equivalent (e.g. import pipeline or production facility).
- To have a national competent authority, responsible for monitoring gas supply developments, assessing risks to supplies, establishing preventive action plans and setting up emergency plans.
- To collaborate closely in a crisis, including through a strengthened Gas Coordination Group and through shared access to reliable supply information and data.

Yet, it also announced a revision of the framework for investment in new cross-border interconnections, new import corridors, reverse flows capacities and
storages. Moreover, it should provide a sound basis for the EU to defend its interests more effectively in its relations with external gas suppliers.

On the 12th of November 2010, a new Regulation No 994/2010 was published, entering into force on the 2nd December 2010. It was based on the lessons drawn from the Russian-Ukrainian gas crisis of January 2009 and the ensuing discussion. To strengthen the crisis response mechanisms, Member States and gas market participants should take effective action to prevent and mitigate potential disruptions to gas supplies.

To this end they have to identify risks to security of gas supply through the establishment of a risk assessment and establish preventive action plans and emergency plans to address the risks identified.

Criteria established were that they have to ensure gas supplies to households and a range of protected customers under severe conditions. (a) extreme temperatures during a 7-day peak period occurring with a statistical probability of once in 20 years; (b) any period of at least 30 days of exceptionally high gas demand, occurring with a statistical probability of once in 20 years; and (c) for a period of at least 30 days in case of the disruption of the single largest gas infrastructure under average winter conditions.

A European approach, with a well-defined role of the Commission and of the Gas Coordination Group including mechanisms for Member States' cooperation, in a spirit of solidarity, shall deal effectively with any major gas disruption. This includes the development of regional approaches on security of gas supply measures.

Transparency shall be created of all emergency measures and public service obligations relating to security of gas supply and on gas contracts;

The market players, i.e. gas suppliers and transmission system operators, shall be allowed to secure supplies for as long as possible, while ensuring that the right measures are taken by the competent authorities of the Member States, in a coordinated way at regional and EU levels, in case market measures alone are no longer sufficient.

The flexibility of the gas infrastructure shall be enhanced, to cope with the disruption of the single largest gas infrastructure (N-1), including enabling bi-directional physical capacity on cross-border interconnections where this enhances security of gas supply.

The realization of projects to enhance the flexibility and security of gas supply and better interconnect all EU Member States, in particular the isolated systems, has already started. In 2010/11 the European Energy Programme for Recovery (EEPR) supports the construction of 31 gas infrastructure projects with 1.39 billion. The EEPR supports projects for reverse flow in 9 Member States with around 80 million Euros and gas interconnectors with around 1.3 billion Euros, including new import pipelines.
6.4 Future gas supply: developments and conditions

Gas is very different from oil because there are less supply options, pipeline transport and handling systems are more rigid, while the storage of large volumes of gas is much more expensive than for oil. Moreover, the development of new gas supplies requires large efforts of private oil and gas companies and a substantial involvement of governments. This section will expand on these issues against the background of the particular circumstances in international markets for natural gas.

6.4.1 Demand

Natural gas is the most dynamically growing fossil fuel in the international energy market. The reasons for this growth are obvious: it has been competitively priced and is highly convenient in both industrial and domestic use, as well as in power generation. Furthermore, it is the most environmental friendly fossil fuel. Governments of consuming countries are often in favour of natural gas because it offers an opportunity to further diversify the energy mix of their countries.

For countries with reserves of gas it is attractive to develop their gas resources. In addition to the domestic market and industrial activities based on gas, selling gas in the international market provides an opportunity to expand export revenues. Furthermore, the export of gas allows oil producing countries, also those adhering to OPEC oil production quota, to increase and stabilize their export revenues.

International oil companies are interested in developing their equity portfolio and have increasingly become oil and gas companies. Also because of their limited access to low cost oil reserves. Indeed, investments by international oil companies in new oil developments are mainly frontier developments in the offshore sector, while national oil companies mainly invest in onshore oil developments. The gas sector, also onshore, is more open for Foreign Direct Investment (FDI) by the international oil companies. Moreover, in the context of their portfolio development, many oil companies are also interested in further developing their activities in the gas sector.

Given these parallel interests in the further development of natural gas and the premise of ongoing competitiveness of gas prices, it is not surprising that most energy forecasts, among them the IEA World Energy Outlook, suggest a continuing, substantial growth in the demand for gas. There is even the notion of a “Golden Age for Gas”. Despite the brief decline in demand as a consequence of the economic crisis, it is expected that by 2030 world demand for gas is expected to have grown by some 41%, from 3,000 bcm in pre-crisis 2007 to 4,000 bcm. Driven by the assumption of a considerable relative cost advantage of natural gas in power generation in many regional markets, most of the growth of gas use is projected in the power sector. To compare; the total consumption of natural gas was 2,527 bcm in 2000 (IEA, 2002, p. 110).

The largest growth will take place in Asia, where the consumption of China and India will increase by around 5% annually. Also in the Middle East, Africa and South America demand will grow by around 3% annually. Gas consumption in North America stagnates.

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47 Global figures are based on the IEA reference scenario World Energy Outlook 2009.
America and Europe will increase less strongly; below one percent. The growth rate of the latter two regions is of course a function of the already large share of gas in overall energy use. In Europe, the power sector accounts for most of this growth. Whereas the use of gas in industry and the domestic and services sector may expand, it is expected that this is limited by energy conservation and the impact of sustainable energy sources. This, of course, strongly depends on the intensity with which climate policy will be implemented.

In addition to the traditional domains of natural gas use is it possible that the so-called gas-to-liquids (GTL) projects will provide a new market. Gas is then converted into transport fuels like diesel. This is particularly promising for those gas occurrences with low production costs, but at a large distance from main markets. GTL is then an interesting alternative to LNG production. GTL projects, such as those developed in Qatar, Malaysia and Brazil, may generate a growth in demand from 4 bcm in 2002 to about 70 bcm by 2030; which is less than 2% of world gas demand by then.

These demand-side growth projections, however, will only be realised when the required additional volumes of gas will be made available in a timely and coordinated manner. This cannot be taken for granted. The development of new natural gas supplies faces a variety of obstacles. It can be argued that substantial government action might be necessary to facilitate the timely development of production and transport capacity to realise the envisaged growth. We begin with an overview of the issues surrounding natural gas market developments. Then we turn specifically to the situation in the regional gas markets, their supply sources and to the question what national governments can do to efficiently facilitate to realise the growth of the gas markets.

6.4.2 Gas reserves are large

Gas reserves are ample and current proven reserves can satisfy the projected demand in 2030. At the current rate of consumption, there is sufficient gas for at least another 60 years. At the project rate of growth, current reserves allow for another 40 years of gas consumption. Undoubtedly, these proven reserves will grow by increasingly effective E&P activities, the re-evaluation of gas fields that are producing already and improved production technologies, enabling enhanced recovery factors. Aside from the current proven reserves of 180,000 bcm, an additional amount of 290,000 bcm is foreseen of so-called ultimately recoverable resources.

However, in most places the ‘easy’ indigenous sources of gas have now been exploited. Indeed, in the major gas markets, gas reserves were developed relatively close to the end-use markets. In the United States, Russia, North West Europe and countries like Australia, gas production, transport and trade initially developed within territories, with a more or less homogenous framework for governance. As a consequence, investments in the systems were supported by appropriate legal and regulatory structures along the whole of the gas chain, from the well-head to the burner tip.
So far, common wisdom foresees that the new supplies, needed to meet growing demand, will have to come from sources much more remote from today’s markets, by means of expensive, long distance transport through pipelines or in the form of Liquefied Natural Gas (LNG). Most of the currently proven gas reserves are located outside the main continental gas markets. About 30% is located in the Russian Federation, 40% in the Middle East (16% in Iran and 13.5% in Qatar). This implies that sufficient production and export facilities will have to be constructed in these regions. The indigenous production in the Europe will gradually decline, as a consequence of ongoing reserves depletion; initially in the UK and later on also in the Netherlands and Norway. Obviously, gas production as such will continue, but not in the volumes required.

Of course, there is the ‘promise’ that unconventional gas may start playing a role in the EU, like it did in the US over the past decennium. Yet, to what extent this will materialize remains to be seen. Problems of spatial planning, NIMBY, equipment availability, environmental requirements and an oil and gas industry with a very different structure, obviously, will play a role here.

The EU27 was in 2009 already dependent on imports for about 63% of its requirements. This figure is expected to rise to 69% by 2015, 75% by 2020 and 84% by 2030. To satisfy this demand for imported gas, two things are crucial. Firstly, the reserves abroad will have to be developed into productive gas fields. This issue will be dealt with below. Secondly, new transport facilities are required to transport the gas to Europe, both pipelines as well as LNG terminals.

Currently, new pipelines are already in function or possibly constructed from Russia; respectively the Nord Stream and the South Stream. In addition, there is the EU sponsored Nabuco project in development, to carry gas from the Caspian Sea region to Europe, avoiding Russia’s pipelines, and some other smaller initiatives. Moreover BP recently announced another large-scale project. Upstream there is competition to secure the supply of gas from ‘difficult’ countries, like Turkmenistan and Kazakhstan. So far, political issues, regulatory design and the harmonisation of economics, as well as the struggle to sufficiently secure upstream gas supply risk, prove to be very difficult to align.

It is also unclear to what extent the US will be able to sustain its reliance on unconventional gas. Until recently, the perspective was that the US would start importing LNG on a large scale, which explains the huge investments in LNG gasification capacity along the US shores; these are now standing idle. But they are there! Now, the discussion is about the conversion of these terminals into export terminals for liquefied shale gas...

Asia is already much longer dependent on LNG imports from Australia and the Middle East. The growing demand in this area will have to be met by increasing imports of LNG and possibly piped gas from Russia and the Caspian Sea region. Yet, also in Asia unconventional gas may become a serious alternative for imported conventional natural gas, looking at the estimates of potential reserves.

50 See Stevens (2010).
It can be concluded that to satisfy their gas demand, two important markets (Asia and Europe) may depend on imports from the same regions and that they may have to compete to secure sufficient gas. In that case, both the European and the Asian consumers will have to pay sufficiently high prices to justify the huge investments in exploration, production capacity and transport facilities; both long distance pipelines and LNG. And they will have to offer attractive revenues to the producing countries involved. Otherwise, it is difficult to see how this potential for gas supply will develop on a sufficient scale (see Nies 2009).

6.4.3 The promises of LNG

For the next 25 years the International Energy Agency expects a 300 % increase in international trade between the major supply and demand areas around the world. Indeed, the notion of a global market for LNG is gaining ground.

LNG is freeing up gas that was considered locked-in until recently. A substantial part of world gas reserves was stranded, located at a place far away from centres of significant consumption, separated by oceans, or ‘difficult’ territory. Major cost reductions, in LNG and new pipeline technology, now allow that these stranded gas reserves are unlocked. Supply may therefore expand substantially.

Particularly the LNG business has become more dynamic than it has ever been. For about 30 years, the Asia-Pacific region and the Mediterranean were the main areas of activity in LNG, but today markets and supply options are expanding further into the Atlantic Basin. Many regions are now bristling with activities. Costs have come down sufficiently to extend the economic reach of LNG supplies. Consequently, the traditional regional boundaries are fading when new supply sources become available.

Particularly the Middle East, just in between the two main LNG markets, will be able to supply markets further away in both the Asia Pacific and the Transatlantic markets. In the Asia Pacific region, existing markets may further expand with LNG from old and new supply sources. New markets are currently being opened. In the Atlantic Basin, southern European markets and the UK show a growing appetite for LNG, while the US which has no immediate pipeline alternative has been developing plans for massive LNG imports to offset declining indigenous conventional gas production. However, these days, much of the expected additional demand in the US is satisfied from newly developed indigenous unconventional gas resources. This development has no (yet) taken off in Europe on a substantial scale.

The LNG share in international gas trade was expected to grow strongly, mainly due to imports into the US. In the period to 2020, LNG trade was expected to grow manifold, with the most optimistic projections assuming a quadruplicating of LNG trade to around 600 bcm annually. This brought about the fear that the projected growth in demand could not be met.

Today, however, the picture looks different. The combined effect of the US unconventional gas boom and the economic crisis have seriously reduced global gas demand. This happened precisely at the time that considerable amounts of the planned new LNG liquefaction and gasification capacity came on stream. As a consequence, the short term price for gas fell dramatically and has not recovered
since. A substantial part of the new capacity is now operating at low rates of throughput and profitability or mothballed, while other planned LNG projects are put on hold, for the time being.

Also the current development of international gas pipelines yields a less dynamic perspective with regard to the actual commitment to new investments. Concepts and opportunities are being discussed and explored. And indeed, these will be very much needed if growth catches up. But, then, it will take at least 5 and usually up to 10 years for projects to get off the ground52.

6.4.4 A context for investments

It is clear that, to realise further growth in gas supply and demand, additional investments in gas supplies and supporting assets are needed in both producing, transit and consuming countries. But investments in the gas industry have to overcome higher obstacles than investments in the oil or coal industry, since they are of a different nature.

As has been argued above, characteristic for the gas industry is the great risk involved and the long horizon over which these risks have to be managed, based on the combination of very high investment costs and the lack of flexibility in the supply chain. Huge, specific investments have to be made into facilities that produce gas and transport that gas from a specific gas province, or field, to a specific area of consumption over a very long period of time. The system locks producers and the consumers into a long term, mutual relationship of significant dependence. Each side has to face the risk that the other will drop out, for whatever reason, or that prices will go up or down to an unacceptable extent. The recent post crisis experience, with a dwindling demand and falling gas prices globally, has shown that this risk is by no means a fiction, as was often stated. Long term contracts with competitive pricing clauses have formed an important basis to ameliorate and manage these risks. Yet, they are now put under pressure, precisely because of the falling spot market prices for.

Transportation and storage of gas are an order of magnitude more expensive than that for any other fossil fuel. Investments in gas production and long distance gas transit require large incremental capacities and volumes of gas throughput, to obtain the necessary economies of scale. Investments are ‘lumpy’, so to say. Consequently, every addition in supply capacity is a large project, requiring careful planning and coordinated investments along the whole chain. These multibillion dollar projects bring large volumes of gas to the market when they have come on-stream; far more than is needed by a single customer or even a single region. Markets will have to be ‘created’, market regions will have to be connected via (cross border) transmission pipelines and buyers across these different market regions may have to co-operate to absorb the new large volumes of gas, particularly in the case of new pipelines.

The preparation of such investments is complex and the lead times are long; the commitment to invest is made many years before the first gas will flow. Together with the long payment this means that investors and financial institutions look for an environment which offers reasonable financial and economic security. It is widely perceived that these issues do not apply to the same extent to LNG: indeed the ‘parcels’ of gas are smaller and LNG carriers can be diverted to different

52 See Jong, de, Linde van der, Smeenk (2010: 221-245)
markets. However, the size of the investments is still considerable and the availability of spare capacity in up- and downstream LNG terminals is limited, making the perceived flexibility largely illusory. Unless, an unforeseen decline in demand occurs, like what is happening these days. An then, the price risk is consirable!

Natural gas projects will only materialise if the risks inherent to investment in these projects can be properly mitigated. Security of supply to consumers is as important as security of demand is to producers and transporters of gas. As is shown above, investments in gas supply chains require the perspective that an adequate level of sales over a long period can be achieved at market reflective prices. The development of gas demand, in part, depends on government policies, such as security of supply and environmental policies, restricting the use of fossil fuels. Security of supply policies can either be aimed at a reduction of the dependence on imported fuels or at an increased diversification of suppliers. Yet, other aspects may also be determined by government policy. Transparency, consistency and predictability of government policies form the backbone of successful gas development. But in addition, positive action and supportive participation in the orchestration of a new gas supply chain is essential.

6.4.5 Market Structure

The gas markets around the world differ substantially in their stage of development. Some markets have already matured, such as the United States, Japan and South Korea, while other markets are still in a first expansionary phase (such as India and China). Europe covers the full spectrum from emerging to mature markets. But even mature markets will require considerable new investments in infrastructure to meet projected growth. The United States was in a process of changing from a predominantly domestic gas resource base to a mixed resource base with increasing LNG imports entering an already liquid market. Yet, the emergence of unconventional gas in the market changed this perspective rather unexpectedly, which underlines the inherent uncertainty in market developments. In Europe there are mature markets, mostly based on (declining) domestic supplies and/or long term supply contracts from external resources; and new markets (mostly in the periphery) based entirely on imports from outside the region. Based on its economic and ecological competitiveness, it is predicted that in the EU gas will contribute substantially to the fuel in the power sector. The Asian market remains a mosaic of national gas markets which largely depend on LNG imports and which have different regulatory structures. There are very few mature markets and a relatively high proportion of countries where gas is either a new fuel, or accounts for a relatively small proportion of energy demand (Wybrew-Bond, Stern 2002).

In an expansionary power market, gas will predominantly be used to fuel new power capacity. Yet in a more mature market, the additional gas demand must come from the replacement of other fuels in the power sector. The size of both new and replacement gas demand will depend on the economics of gas in the power sector and the portfolio management of large power suppliers and environmental policies of governments. In many markets, both developing and mature, the power
industry has an “anchor” role in developing new gas supply lines as a consequence of its capacity to absorb significant additional ‘portions’ of natural gas. However, if newly planned power stations at the end of the supply line are not built in line with the development of the rest of the infrastructure, less gas will flow and financial risks are incurred of an unacceptable scale.

The firmness of contractual obligations and the assurance that contracts can be efficiently enforced is crucial in this respect; certainly these days. Ask the bankers! Yet, given the key role of the power sector, regulatory certainty in the power sector and environmental policies is a precondition for a smooth development of the gas sector. In liberalised electricity markets, the commitments for gas purchases have to be made by the power industry. In countries where the power sector is a public utility market, the authorities will have to commit. In either case, keeping options open is not going to bring new gas to the market. It will be hard enough to reconcile the volumes and flexibility that the prospective power generator is looking for with the “security of demand” needed to line up the supply chain. Uncertainty about government energy and climate policies and regulation in a liberalising business environment will not help in making these commitments.

6.4.6 Pricing

The immense investments require a certain level of prices for natural gas. Tensions may arise with regard to the understandable objective of consuming governments to keep prices low, especially for small consumers. Regulated low prices, however, discourage natural gas developments in many markets with growth potential, which in turn could frustrate the growth of the national economy. In other markets, governments have been promoting the introduction of competition and consequently introduced market prices into natural gas markets. Changing markets bring changes in prices and pricing principles. Increasingly, even long term contracts develop different indexations.

In the future, short term price volatility, like in other fossil fuel markets, will be a fact of life. However, the greater risk, affecting gas prices over the longer term could well be the lack of timely investments in new supplies: shortages of gas supplies drive up gas prices in the markets, leading to economic pain for consumers and in the second instance to a loss of confidence in the competitiveness of gas among the investors in the power sector. It is argued that the governments have the responsibility to foster investments climate conducive to these timely investments and thus prevent unnecessary and prolonged price fluctuations.

Yet, in the current situation in the EU, relatively low priced spot gas is competing with high priced, oil linked, gas under long term supply contracts. Many long term buyers are now in the process of renegotiating their contracts... The judge is still out on what may happen.

6.4.7 Transportation

Shipping oil is much cheaper than transporting pipeline gas. LNG can only compete with pipeline gas beyond a few thousand kilometers from the market. Especially for pipelines, inadequate or non-existing legal and regulatory regimes add extra hurdles to bringing the needed regular supplies to the market at viable economic costs. For transit pipeline projects - that is projects which cross third countries between exporter and importer - unstable bilateral political, economic
and regulatory conditions can prevent gas from reaching the markets. The gas chain is as strong as its weakest link\textsuperscript{53}.

In some regions in the world political tensions between countries prevent the construction of international gas pipelines, effectively reducing the availability of competitively priced supplies to the local markets. A trivial suggestion is that the improvement of international relations and a reduction of tension in those regions is a key precondition for the successful exploitation of economic gas resources. Also internal conflicts play a role in the realisation of gas projects; if the security of installations is in doubt, the likelihood that investments will take place reduces drastically.

6.5 Self-evaluation

- What is the difference between short term and long term security of supply?
- Will the market ever be able to deliver security of supply? Why (not?).
- Between which parties will the main conflict of interest occur in respect of the proposed policy aiming to achieve long term security of supply?

\textsuperscript{53} This argument is further developed in CIEP (2009)
7 Future gas market regulation

Where the new rules for a liberalised market environment are still in the process of evolution, natural gas projects, given their long repayment periods, are suffering from a lack of certainty about the future regulatory framework and energy policy in general. Liberalisation may, in addition, lead to fragmentation – or lack of integration – of markets and create noise in the information flow, which in turn could delay the signals that invoke new investments.

In response to the characteristics of the gas industry, as was shown, in the past, a variety of hierarchical relationships have been established amongst gas producers, transporters and consumers. Towards the end of the last century a new perspective on regulation developed, driven by, on the one hand, the international economic integration of national markets for goods, labour, capital and services, and on the other, by the general aim to reduce the role of the state in the coordination and ownership of economic activities, in favour of the more efficient market and private initiatives. Yet, empirical evidence has also shown that economies need an adequate institutional framework to reduce uncertainties among market participants, to correct un-avoidable failures in the operation of the market, or the sheer lack of a market, for certain categories of goods and services and to safeguard public interests.

As part of the process of economic restructuring in the network industries, the accompanying sets of rules and regulations appeared on the agendas of policy makers, industry associations and researchers. Deregulation became re-regulation, and privatization was to be undertaken more as a strategic process. Moreover, it was accepted that structural change should pay due attention to both public interest issues as well as to the objectives of competition policy. Of course, this refinement of the recipe for restructuring induced an expansion of the regulatory framework and the toolbox of regulatory instruments and, associated therewith, the responsibilities of the regulatory agencies. These, initially, were meant to operate as lean and mean executive organizations, but being forced to develop and apply new insights in regulatory practice, they rapidly grew in scale and scope.

7.1 Perspectives on gas market regulation

Perhaps more so than in other fields of regulation, it is clear that the policy towards the functioning of markets and the safeguarding of public interest is an extremely urgent concern. In complex, specific, international, gas networks essential facilities are involved, through which the controlling party is able to obstruct any serious competition by other (potential) suppliers, while exploiting its monopolistic position vis-à-vis the consumers. At the same time, natural gas projects are delicate ventures as a consequence of their high sunk costs, long repayment periods, their vulnerability for variations in supply and demand and their political sensitivity.

Unfortunately, there is a serious question whether there is a uniformly applicable approach for all stages of development of the gas market. Quite apart from the fact that a regulatory structure is very much a system and context dependent phenomenon, it can be doubted that such an approach would provide an optimal route. We argue that four main facets stand out in respect of the regulation of these systems.

• The manner in which the value chain of the industry is re-structured *ex-ante* is related to the question as to what vertical segments of the supply system should be characterized as an *essential facility*, requiring regulation, and which segments could be potentially *competition driven*, if an adequate horizontal structure could be arrived at.

• The determination of the *ownership of the essential facilities* in the value chain is a strategic issue, involving aspects like the attractiveness to private investors, the degree to which their information can and should be checked by regulators, the possibility to create mutual commitment by establishing public private partnerships, etc.

• The need for *coherence* between the economic and technological nature of the components of the overall system, like gas production, transport and supply, and their coordination. This coordination can take the shape of market oriented contracts of a shorter or longer duration and a variety of provisions, or forms of regulation; which can also be seen as a contract between the regulator and the regulated firms. Lack of coherence creates additional uncertainty, because it enhances incomplete contracting and asymmetric information to market actors.

• The *marching orders of the regulatory agency* on how to structure the industry and its processes so as to maximise the objective of creating a competitive environment, *vis-à-vis* the government, the industry and other agencies involved, like competition authorities and other countries’ regulatory approaches.

Unlike the traditional perspective that denied the feasibility of competition in the whole of the gas industry, the proponents of structural change start from the hypothesis that the introduction of competition is possible in particular segments, and that this would improve the performance of the whole of the value chain. A general perspective on the future regulation of these different segments of the value chain should recognize that liberalization, regulation and unbundling, and merger control, are means to achieve an end.

The aim is to establish efficient and effective systems that supply energy, including natural gas, to end consumers in a manner that is commercially sound and that supports the overall welfare, from an economic, a social and an environmental perspective. This implies that, given these objectives, a deliberate choice will have to be made with respect to the precise means to achieve these goals. Arguably, it is in the combination of context, objectives and instruments that the appropriate outcome emerges in different countries and regions.

As is argued by Helm (2005), we may even be forced to consider a new energy paradigm, under the pressure of, first, the need to modernize and expand the current energy supply systems and, second, the need to adapt the energy system to the consequences of global warming by reducing carbon dioxide emissions. These pressures can be perceived as being market failures of the (by and large) liberalized international gas/energy market, as a consequence of externalities, high transaction costs and geopolitics. The market based system also promoted a short term focus on efficiency of the market, while longer term security of delivery and
security of supply issues could not easily be incorporated in the companies’ market strategies. Helm suggests that these problems could be solved by: a) the (failing) market, causing very high costs and volatile prices; b) the development of new market-based regulatory concepts; or c) vertical and horizontal integration to reduce the uncertainties of incomplete contracting and asymmetric information. Helm therewith explicitly invokes an alternative perspective on economic coordination, the New Institutional Economics (NIE), which is based on the concept of transaction costs.

7.2 An institutional perspective

Traditional economic theories, referred to above, consider the structure of markets as a crucial driver for the conduct of firms and the eventual economic performance. The configuration and relative size of the firm itself was seen merely as a means to acquire economies of scale and scope through vertical and horizontal integration, to the end of achieving market power in up or downstream markets (Scherer 1980). The institutional, transaction cost approach takes a broader perspective in respect of the rationale of vertical integration. It considers the shape of firms and the associated structure of the markets as alternative arrangements of internal and market governance, to deal with the risk involved in transacting.

The adequacy of particular arrangements is seen as dependent on the attributes of individual transactions between buyers and sellers of goods or services in a specific market and how that affects the overall cost of a transaction. Transaction costs include the direct costs of writing, monitoring and enforcing contracts, plus the costs associated with the risk of ex ante investments having an ex post performance that is lower than anticipated, as a consequence of contractual hazards of various types and of the costs associated with internal organization of the transactions. As stated by Joskow (2003): “The inefficiencies of particular interest are those that arise as a consequence of ex post bargaining, haggling, pricing and production decisions, especially those that arise as the relationship must adapt to changes in supply and demand conditions over time, though inefficiencies in ex ante investments are also relevant”

The preferable arrangement of governance structures are those that best fit the character of the transactions involved and the broader context in which these take place. Main characteristics involve, on the one hand, the extent to which parties to a transaction are locked-in, as a consequence of asset specificity. On the other, attributes like uncertainty, product complexity and information asymmetries play a role. In respect of asset specificity in the gas industry:

- It can be argued that a large portion of the investments are site specific, often linking up buyers and seller in tight relationship over the use of the asset.
- Physical asset specificity may be relevant as well, particularly when looking at the relation between suppliers and end-users, which have invested in boilers and appliances to burn gas of a specific type and composition, or investments in, for example, gas storage or treatment capacity.
- Dedicated assets involve the investment by a gas supplier in a remote field to sell a significant amount of gas to a particular (set of) customer(s) at a specific level of revenues, justifying the investment.

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The realization of lower sales or lower prices would imply an ex post hazard, not anticipated in the investment decision ex ante.

In essence, the idea is that by selecting the right form of governance, either involving the spot-market, a specific contract or a vertically integrated structure, the parties to a transaction will be able to modify the costs of the transaction and of the exposure to ex ante risks. When, ex ante, it is considered that these costs are not manageable at an acceptable level, most likely, the transaction or investment will never materialize. No additional volumes of natural gas would reach the market. In respect of the gas markets, therefore, a leading question would be to what extent the regional/local governance regimes in place reflect the characteristics of the several types of transactions in the regional gas markets. Referring to these characteristics, it may emerge that the efficient development of markets of a different nature, maturity and risk profile may require different structures of governance, instead of one single market design geared towards a fully competitive market (see Wolak 1996).

As argued above, the size and the complexity of gas projects require a high degree of confidence and assurance. Often, the economic risk, particularly for large scale international supply systems, is mediated by sellers and buyers, through appropriate arrangements embedded in long term contracts and only to a lesser extent through spot-markets and hedging facilities. Nevertheless, the need to co-ordinate investments in projects throughout the supply chain and the objective to minimise the lead times will require full cooperation between all stakeholders. Agreements between these parties, as a precondition for investments in large-scale gas projects are complex and may require government support.

7.3 The role of governments

This important role for government applies both to the active involvement prior to the investments, facilitating the process of putting the necessary conditions in place, as well as to provide the comfort for a prolonged business climate, positive to these large investments. We have argued that the sellers and buyers, together with equity investors and financial institutions, also consider risks which are fully in the domain of governments, such as:

- The political stability of producing countries and the risk that gas supply, or transit, will be refused for political or economic purposes.
- The creation of a regulator in consuming countries with the narrow task to create a competitive environment while other oversight is needed to balance the process of liberalisation and security of supply because the tools and processes used by regulators may negatively affect the ability to secure new supplies for the future.
- The political and regulatory stability of consuming countries and the risk that market circumstances may change unexpectedly for reasons of economic, environmental or other policies.

Thus, despite the ability of the private sector to manage many of the risks involved in complex gas projects, the government plays a crucial role in creating such a climate that these risks remain manageable over time. International gas markets
as well as public interests are not static but dynamic. The task of the government is to facilitate an investment climate that evolves in line with the various stages of market development but that also secures the public interests over time. In addition to the establishment of international treaties, transit arrangements and adequate regulation, governments may wish to participate in the development of a gas industry through some state participation in production and distribution entities. In certain markets or countries public participation may provide the stability required for gas developments, solidifying the confidence among the stakeholders involved, and assuring that risks and rents will be distributed in a balanced manner. Government can also decide to participate in the gas industry for its strategic importance, particularly when key counterparts in the consuming or producing countries also have a mixed ownership structure and government is convinced that public interests can be best serves this way.

Regarding the regulatory perspective, the question seems to arise as to how this new institutional paradigm can to a greater degree contribute to the future gas market regulation. Currently, much of the regulator's toolkit and the framework for competition policy are based on the former paradigm of ‘full unbundling’ and maximum entry in competitive segments. Nevertheless, in the daily practice of regulation, elements of the transaction cost-based approach are already incorporated, like the conditional allowance of exemptions and large-scale mergers. Moreover, the New Institutional – or Transaction Cost - Economics, also underscores abuse of market power as a strategy, which depending on the circumstances should be tackled by regulatory intervention. Generally, the literature on regulation, as such, seems more advanced in incorporating elements of the transaction cost approach\(^56\).

What conclusions should one draw from these developments? The observations suggest the need for a careful New Institutional reassessment of those coordination mechanisms, which are considered as less beneficial for consumers under ‘structure-conduct-performance’ approaches. This, of course, should also involve an analysis of their potential market distortion, as there may exist a trade-off between the stability provided by a dominant position and the potential for abuse. A further question would be whether there exists a trade-off between the several components of a governance structure, like the degree of integration or unbundling, the regulated or ‘free’ determination of contract prices and tariffs, destination clauses and regulated access to markets, Take or Pay provisions, etc. Is it necessary to arrive at particular ‘packages’ of measures of governance? Is it possible that a ‘workable’ balance between the required investments, the anticipated profits and risk and the costs of governance can be struck, while preferably maintaining a ‘credible’ pressure of the dynamically competitive market?

7.4 Self-evaluation

- What is the difference between standard economic approach and the New Institutional views on horizontal and vertical integration?
- Is the changing role of the state a ‘real’ change, or is it just the perspective that is changing?
- Is asset specificity a static phenomenon or not?

\(^{56}\) See for recent examples focusing on gas markets: Creti, Villeneuve (2004).
8 References and Supplementary Material


Nies, Susanne (2009) Oil and gas delivery to Europe: An Overview of Existing and Planned Infrastructures, 4 bis, French Institute for International Relations (Ifri), Brussels.


