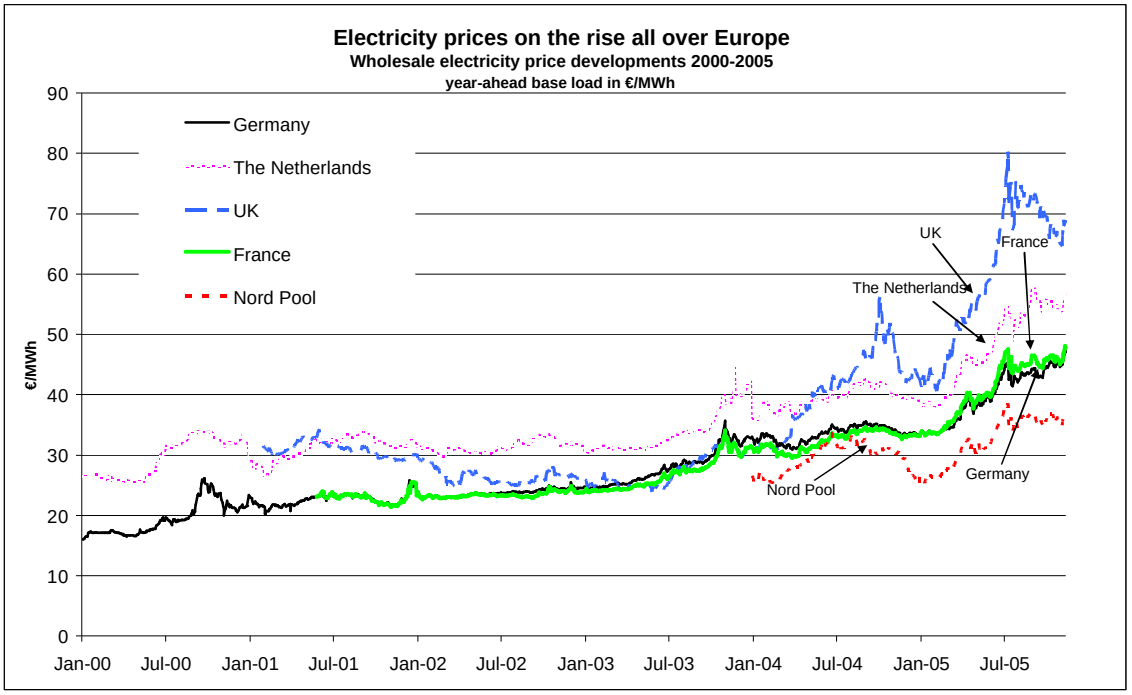
C. ELECTRICITY

I. Introduction

Figure 38



Source: information received within the scope of the sector inquiry from Argus Media, platts, and Nord Pool.

(289) Following market liberalisation, electricity wholesale prices were initially relatively stable[158].

(290) Around the summer of 2003, however, electricity wholesale prices started to rise on most markets. Not only did prices increase, they also diverged strongly between Member States suggesting a lack of market integration. Price rises have been strong especially since the beginning of 2005.

(291) As wholesale prices directly impact supply prices offered to final customers (especially to industrial users) in a number of Member States, their increase gave rise to wide-spread concerns about the overall functioning of the electricity markets. In addition many industrial consumers complained about the difficulties to secure competitive offers by different suppliers. These and other concerns expressed by market participants triggered the initiation of the sector inquiry into the European electricity sector.

158 Prices for certain end users even showed a downward trend after 2000.

I.1. Main market features

I.1.1. Overview

(292) During 2003, the countries today forming EU25 consumed 2605 TWh of electricity. This represents approximately 19.4 % of all final energy consumption in the EU[159]. The largest markets are, respectively, Germany, France, the UK, Italy and Spain. Less than 0.2% of the electricity required to meet this consumption was imported from outside the EU. In contrast to gas, the EU is thus essentially self-sufficient in the production of electricity and increasingly so as net imports decreased 81% over the period 1990-2003. Primarily fuels for electricity generation are of course often imported.

(293) Within the EU cross-border trading of electricity is more important than exchange with countries outside the EU. Luxembourg, Latvia and Hungary have net imports of respectively 62%, 51% and 22% of their national consumption. At the other end of the picture sit the Czech Republic and Estonia that have net exports amounting to 31% and 41% of their domestic consumption whereas Lithuania's net exports are with 106% even higher than its domestic consumption. In terms of volumes the largest net exporter of electricity is France, which exported 67 TWh in 2003, 4 times more electricity than the next largest net exporter, the Czech Republic whose exports however grew 23-fold since 1990. Poland is third in this ranking. Italy was by far the most important net importer of electricity, importing approximately three times as much as the Netherlands with Sweden coming as third largest net importer.

(294) A clear and important link between the functioning of the gas and electricity markets exists. The prices for gas significantly affect electricity price levels, since in many Member States, gas-fired power plants are responsible for setting the price level of electricity, in particular during peak hours. Moreover, a considerable and increasing quantity of gas is used in thermal power plants. During 2004, gas fired power plants in EU25 consumed approximately 4000 PJ GCV (gross calorific value) of gas corresponding to 22,1 % of the entire consumption of natural gas in the EU[160]. Hence, electricity generators rely heavily on competitive gas markets. Malfunctioning gas markets thus adversely affect the price levels of electricity.

I.1.2. Essential features of electricity markets

(295) The electricity industry chain involves five main activities: (1) the production or generation of electricity, (2) the transport of electricity on high voltage levels (transmission), (3) its transportation on low voltage levels (distribution), (4) the marketing of electricity to final customers (supply), and (5) the selling and buying of electricity on wholesale markets (trading). Sometimes services such as metering are mentioned as additional activity.

159 Eurogas, Annual Report 2004-2005, p. 27.

160 Eurogas, Annual Report 2004-2005, p. 28.

(296) Prior to liberalisation, vertically integrated companies executed these activities serving exclusively certain regions or even a whole country, and prices were regulated. This has profoundly changed with European-wide market opening. The electricity business was split up into regulated and competitive segments. Because transport activities were considered to be a natural monopoly, they remained regulated. However, generation, wholesale trading, and retail supply were opened to competition. Although a number of Member States retained however regulated supply tariffs.

(297) Like the gas industry the electricity sector is a network industry. Without access to the network customers cannot be reached. Third Party Access to the network is thus essential. The existing network is often a natural monopoly that cannot be duplicated in an economic manner and/or in a reasonably short time frame.

(298) An important feature of electricity is that it cannot be stored economically once produced. In order to ensure network stability electricity generation and consumption have to be in balance at all times. Electricity demand fluctuates significantly during the day and seasonally and has a very low price elasticity, i.e. price fluctuations do not give rise to large changes in electricity consumption.

(299) A specific feature of electricity production is that it can be produced by using a large variety of technologies and on the basis of different fuels (nuclear, hydro, coal, gas, renewables etc.). Cost structures have important implications for the price formation on short term electricity markets (concept of a marginal plant setting the price). The price formation mechanism also renders electricity markets vulnerable to the exercise of market power, be it through withdrawing generation capacity or be it by pricing above competitive levels at times when the generator is indispensable to meet demand (for further details see below chapter II.1).

(300) As electricity cannot be stored, balancing regimes exist to settle market participants' real-time imbalances resulting from discrepancies between scheduled and actual electricity demand. The present analysis, however, mainly concentrates on wholesale issues and does not systematically deal with balancing regimes, even if it is generally accepted that these markets are vulnerable to the exercise of market power. The balancing markets will be analysed in more detail in the final report.

(301) Various business models exist on electricity markets, ranging from stand-alone generators and independent supply companies to fully integrated utilities. In more recently liberalised Member States the vertically integrated company is predominant. In markets that were liberalised earlier, such as the UK and Nord Pool, business strategies seem to be somewhat more diverse. In the UK, apart from larger integrated companies, a number of independent generators with their own business strategies exist. Also on the Nordic market(s) consisting of Norway, Sweden, Finland and Denmark independent suppliers are relatively important.

(302) Typically, within fully integrated utilities, specialised affiliates are dedicated to the different activities, such as generation, trading, supply and network operations. Usually, all output of the generation affiliate is sold under intra-firm arrangements to the affiliated trading entity[161] which in turn manages the undertakings overall portfolio i.e. supplies the

[161] Important exceptions are Spain and to some extend Italy and the Nordic markets around Nord Pool. In all these cases there is an obligation or incentive to trade through the pool (see further I.3.4).

supply affiliate(s) and sells energy to or buys it from third parties through bespoke bilateral contracts or traded wholesale markets. Integrated companies can produce more or less electricity than is required for their own customer portfolio. The larger integrated companies often generate more electricity than they need for their final customers.

I.2. The regulatory framework

(303) EU energy policy pursues three objectives: (1) the creation of a competitive, integrated internal market (higher growth rates and increased competitiveness); (2) maintaining an adequate level of security of supply; and (3) increasing the effectiveness of environmental protection. This section provides a brief description of EU legislation aimed at achieving these objectives but focuses on the first objectives.

I.2.1. Liberalisation

I.2.1.1. The beginning of the liberalisation process:

(304) The first important community legislation aimed at liberalisation of the electricity sector was Directive 96/92/EC[162] ("First Electricity Directive"). The Directive removed legal monopolies by requiring Member States gradually to allow large electricity customers to choose their suppliers (concept of "eligibility"). It also obliged vertically integrated companies to grant third parties access to their transmission and distribution networks ("third party access"). Furthermore, for vertically integrated companies active in generation, transmission and supply it finally mandated a minimum level of separation of the network business from the other activities ("unbundling"). In a nutshell the Directive introduced the distinction between a regulated part of the market (network) and competitive parts of the market (generation and supply).

(305) The gradual market opening introduced by the First Electricity Directive resulted in significant differences between Member States regarding the level of market opening. The existence of negotiated third party access regimes, the limited level of unbundling obligations and the lack of an obligation to establish a national energy regulator were also viewed as obstacles to create competitive markets. To address these concerns, further measures were proposed by the Commission leading to the adoption of Directive 2003/54/EC[163] ("Second Electricity Directive") and Regulation (EC) No 1228/2003[164] ("Cross Border Electricity Trading Regulation").

I.2.1.2. The Second electricity Directive

Full market opening

(306) The Second Electricity Directive aimed at complete market opening by ensuring that all non-household electricity customers become eligible by 1 July 2004. This will be followed by the opening of the electricity markets for all household customers by 1 July

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162 Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity (OJ 1997 L 27/20).

163 Directive 2003/54/EC European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in electricity and repealing Directive 96/92, (OJ 2003 L 176/37).

164 Regulation (EC) No 1228/2003 of the European Parliament and of the Council of 26 June 2003 on conditions for access to the network for cross-border exchanges of electricity, (OJ 2003 L 176/1).

2007[165]. This approach will remove the discrepancies in the level of market opening between Member States.

(307) Market opening by legislation does not, however, automatically lead to the introduction of competition in supply markets previously dominated by incumbent players. Whilst the Second Electricity Directive is silent on the issue, some Member States introduced (temporary) measures such as market share caps for incumbent operators to address concentration. In the UK the existing generation company was split up into competing undertakings, which facilitated the creation of competitive markets.

Regulated third party access and creation of regulators

(308) The Second Electricity Directive obliges Member States to introduce a "regulated third party access" regime under which third parties have a right to access the network in a non-discriminatory manner based on published tariffs. The Directive removes the possibility of negotiated third party access regimes, which were considered not to give the same results as regulated third party access regimes.

(309) In order to ensure efficient and constant supervision of fair network access, the Second Electricity Directive mandates the appointment of a national regulator that is independent from the electricity industry (but not necessarily independent from the Governments). The regulators must monitor the overall activities of the network companies, deal with complaints, and control network tariffs[166], a key element in creating competitive conditions.

(310) Some market participants raised concerns that the powers of regulators vary and that there are significant differences in market design. The regulators recognised the need for close cooperation – in particular for cross border trade – and formed an association for discussion and the development of common positions (CEER). They play an essential role when it comes to the creation of an efficient third party access regime. They also give advice to the Commission on legislative and other projects through ERGEG.[167]

Unbundling

(311) In order to limit further the risks of discrimination and cross subsidies associated with the existence of vertically integrated companies the Directive requires legal unbundling - in addition to accounting and management unbundling - between network activities (transmission and distribution) and all other activities. In practice this means that transmission and distribution system operators must be independent in their legal form, organisation and decision making (separate headquarters and separate board of directors). However a holding company is still entitled to approve the annual financial plan and to set global limits on the level of indebtness.

(312) The Directive permits the postponement of legal unbundling of distribution companies until 1 July 2007 and allows Member States to exempt them from the legal unbundling

165 Several Member States have already opened their markets for all electricity customers.

166 The regulator must approve the terms and conditions for network connection and tariffs, or at least the method of calculation the tariffs, prior to their entry into force. This power also exists with regard to balancing services.

167 Commission Decision 2003/796/EC of 11 November 2003 on establishing the European Regulators Group for Electricity and Gas (OJ 2003 L 296/34).

obligation altogether if the distribution companies serve less than 100,000 connected customers.

(313) The Directive does not impose that the network operator must own the network assets or that there is ownership unbundling[168] from the affiliated supply activities. Nevertheless, several Member States have introduced ownership unbundling for transmission systems arguing that only this form of unbundling removes the incentives in vertically integrated companies for the transmission branch to favour the supply branch.

(314) The issue of structural integration between generation and retail is also not addressed in the Second Electricity Directive. The same applies to long term power purchase agreements, which can also lead to a reduction of liquidity of wholesale markets. This form of vertical integration can be subject to EC competition law (antitrust rules or state aid rules).

Conclusion

(315) The Second Electricity Directive has significantly contributed to the creation of a common electricity market provided that all Member States properly implement it – not only in form, but also in spirit. The Commission is actively pursuing the lack of adequate implementation of the Directive in certain Member States.

(316) On the other hand it is worth recalling that the Directive only contains minimum requirements, leading to different market designs between Member States. Some market participants raised concerns in this respect as the differences in market design can amount to entry barriers and undermine the level playing field for operators located in different Member States.

I.2.1.3. The Cross Border Electricity Trading Regulation

(317) The legislative measures for electricity adopted in 2003 included a second element: the Cross Border Electricity Trading Regulation. This Regulation addresses issues relating to cross-border trading in electricity, such as harmonised principles for payments between transmission system operators and for tariff setting as well as congestion management and the allocation of cross border capacity. The Regulation entitles the Commission to adopt and amend legally binding guidelines for more detailed rules.

(318) The Regulation's rules on congestion management[169] are of central importance, as mechanisms to allocate congested interconnection capacity play a crucial role in market integration[170]. The Regulation requires that congestion problems on interconnectors be addressed through non-discriminatory, market-based solutions. The Guidelines on

168 Ownership unbundling means that a supply company is prevented from owning an entity that operates a network.

169 Regulators are also given tasks under the Second Electricity Directive regarding cross-border electricity trading as they must monitor rules on the allocation of interconnector capacity in cooperation with the other regulators of Member States connected by the interconnector.

170 Congestion problems are aggravated by long term contracts for capacity reservations on interconnectors which were concluded before liberalisation. In a recent judgment (C-17/03, Vereiniging voor Energie, Milieu an Water) the ECJ stated that preferential access based on such contracts amounted to discrimination prohibited by the first Electricity Directive and was, as such, contrary to EC law. The Member States concerned in this case had not applied under Article 24 of the First Electricity Directive for a derogation from relevant provisions of that Directive.

congestion management[171] are currently being amended, and the new Guidelines will probably identify both explicit and implicit auctions as methods complying with this requirement[172]. The preliminary report's chapter on market integration examines these methods in more detail.

(319) The Regulation also contains provisions to allow private investment in interconnectors ("merchant lines"), as the existence of sufficient interconnector capacity is essential for the development of an integrated market. To this end, new interconnectors (DC lines only) may be exempted from the rules on how revenues from capacity allocation are spent as well as from provisions relating to non-discriminatory network access. For the exemption to be granted, it must be shown that the interconnector enhances competition and that the investment would not take place in the absence of an exemption. Whereas in the gas sector several applications for an exemption of a similar type were notified to the Commission, the Commission has so far received only one notification regarding an exemption for an electricity interconnnector (a second is under preparation).

I.2.2. Security of Supply

(320) EU energy policy also aims at maintaining a high level of supply security. Security of supply comprises of two elements: the need for system security as well as the need for adequate supply of electricity in the medium and the long term. Whilst the issue of security of supply is already addressed in the Second Electricity Directive and in the Cross Border Electricity Trading Regulation, in 2003 the Commission made a proposal for a comprehensive set of rules regarding this matter.

(321) The recently adopted Directive on Electricity Security of Supply and Infrastructure (2005/89/EC) requires Member States to ensure that an appropriate level of network security is maintained[173] and that stable and transparent market rules are in place regarding any action taken to balance supply and demand. In addition, networks must set performance objectives and the regulatory framework must provide appropriate signals for network development and facilitate appropriate network maintenance. The Directive will enter into force in December 2007.

I.2.3. Environmental protection

(322) Last but not least EU energy policy must take into account the need to improve environmental protection and sustainable development. To that end, and to help comply with the Kyoto Protocol, the EU has adopted a number of important legislative measures.

(323) Pursuant to Directive 2003/87/EC[174] (the "Emissions Trading Directive"), Member States must ensure that all plants with a rated thermal input exceeding 20MW emitting CO2

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171 Guidelines on the management and allocation of available transfer capacity of interconnections between national systems, (OJ 2003 L 176/9).

172 In an explicit auction, market participants bid for available interconnector capacity which is purchased separately from the electricity that is the subject of the transaction. In an implicit auction, interconnector capacity would be made available to the power exchanges, and a market clearing procedure would determine the most efficient use of such capacity. Explicit auctions are already provided for in the existing Guidelines.

173 Operational security rules for TSOs on continental Europe are also described in the Union for the Co-ordination of Transmission of Electricity (UCTE)'s Operation Handbook

174 Directive 2003/87/EC of the European Parliament and of the Council 13 October 2003 establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC, (OJ 2003 L 275/32).

only operate if they have greenhouse gas permit. Member States decide periodically in national allocation plans about the number of allowances allocated for free to each plant. The Directive established the European Union Greenhouse Gas Emission Trading Scheme (EU ETS), which, since 1 January 2005, serves as a trading framework for emission allowances. Plants emitting below the level of allowances allocated can sell their excess, and those exceeding their allocation must purchase additional allowances. The ETS and in particular the alleged effects on electricity prices is discussed below in the chapter on price formation.

(324) Directive 2001/77/EC[175] (the "Renewable Electricity Directive") is an important step in the development of power generation from renewable sources, most of which would otherwise not be attractive for investment. It mandates that Member States set national targets to meet the Community target of increasing the share of electricity consumption from renewable sources to 22% by 2010[176]. It also encourages Member States to apply various support mechanisms[177] in favour of green electricity production. The Directive permits Member States to require priority access to the grid for producers of green electricity and mandates that priority is given to green electricity when dispatching electricity. Directive 2004/8/EC on the promotion of cogeneration[178] contains provisions on network access for such electricity similar to those in the Renewable Electricity Directive. Electricity produced from a renewable source or from cogeneration is also promoted by the Community guidelines on State aid for environmental protection[179], which explains the conditions under which such State aid will be deemed to be compatible with the common market. Some market participants claimed that electricity produced from renewable sources lead to new challenges for network operations.

(325) In 2003 the Commission proposed a Directive on energy end-use efficiency and energy services (COM (2003) 739 final) to address environmental concerns relating to energy consumption. According to the Draft Directive, Member States would be required to achieve an overall national indicative energy savings target of 9% for the ninth year following the entry into force of the Directive by measures improving energy efficiency. It is expected that the Directive is adopted in the not too distant future.

175 Directive 2001/77/EC of the European Parliament and of the Council of 27 September 2001 on the promotion of electricity produced from renewable energy sources in the internal electricity market (OJ 2001 L 283/33).

176 An analysis of progress reports of Member States shows that measures currently in place will probably be insufficient to achieve this target. Report on the Green Paper on Energy, p. 7.

177 These support schemes include green certificates, feed-in tariffs, tendering and tax incentives.

178 Directive 2004/8/EC of the European Parliament and of the Council of 11 February 2004 on the promotion of cogeneration based on useful heat demand in the internal electricity market and amending Directive 92/42/EEC (OJ 2004 L52/50).

179 OJ 2001 C 37/3.

I.3. Electricity wholesale markets

(326) Wholesale trading, which is the main focus of this report, is the selling and buying of electricity in bulk. On wholesale markets generators can sell their output and suppliers can source the energy they need to supply end consumers. Trust in properly functioning wholesale mechanisms and the prices formed on these markets is of the utmost importance, not just for generators and suppliers, but also for electricity consumers whose energy bills are strongly affected by the prices formed on these markets.

I.3.1. The benefits of competitive wholesale markets

(327) Competitive wholesale markets generate efficiencies in the overall performance of the electricity sector by providing price signals to market participants[180]. In particular, the main benefits of efficient wholesale markets are:

1. **effective competition in generation and retail**, because competitive wholesale markets reduce the entry barriers for independent generators and retailers. Otherwise new entrants might be obliged to enter both the generation and the retail markets at the same time as a vertically integrated supplier;

2. **efficient investment and improved security of supply**, because competitive wholesale markets provide price signals on demand and supply and so encourage new investment when necessary and give the signals to potential investors on the type of investment (e.g. base-load or peak) that is most required in the market;

3. **efficient operation**, because well-functioning wholesale markets will give signals to the market to dispatch low cost plant and to plan maintenance at times with the lowest demand. On the other hand price signals can encourage flexible customers to reduce their demand at times of peak consumption etc;

4. **efficient risk management**, because wholesale markets allow suppliers and consumers to fine tune their portfolio of electricity at a minimum volume and price risk; and,

5. **efficient use and expansion of transmission infrastructure**, because competitive wholesale markets provide the price signals necessary for the TSO and regulatory agencies to identify when market participants should transmit energy from one zone to another and furthermore to identify when and where additional interconnection capacity would be cost effective.

[180] See for example, EFET Position Paper: Transparency and Availability of Information in Continental European Wholesale Electricity Markets, July 2003.

I.3.2. Basic features of wholesale markets

I.3.2.1. Wholesale market participants

(328) There are different reasons to be active on electricity wholesale markets. Generally speaking market participants can be divided in two groups: players with inherent physical positions (generators and suppliers) and participants without inherent physical positions (traders).

(329) The interest for generators to trade stems mainly from the need to sell their generation output and optimise the operation of their generation portfolio. In a number of Member States this selling is predominantly executed on forward markets, whereas optimisation of the power plant portfolio is carried out on spot markets i.e. day-ahead or within-the-day markets. By selling electricity forward, generators hedge themselves against spot price fluctuations.

(330) Retailers, on the other hand, trade on wholesale markets to procure the electricity needed for their customers. The vast majority of the electricity is contracted forward in a number of Member States. By doing so, retailers limit their risk exposure that would arise from changes in spot prices.

(331) In comparison to generators and retailers, (financial) traders buy and sell to exploit price differences e.g. between two geographical areas (arbitrage). Traders also take speculative positions, aggregate and disaggregate purchases and sales over different time horizons or locations thus offering to others the chance to manage their risks.

(332) Our analysis shows that larger electricity companies take part in active trading for all the reasons mentioned above. They do not just sell their surplus generation or cover their supply commitments but engage in arbitrage deals or take speculative positions. On the other hand smaller companies tend to be active on the wholesale market only to optimise their physical portfolios.

I.3.2.2. Market places

(333) The inquiry has looked at wholesale trading in standardised contracts which takes place on two different marketplaces. Transactions are either executed via power exchanges or over the counter (‘OTC’).

(334) Power exchanges are organised marketplaces. Market participants transact anonymously using the exchange as central counterpart. Trades are cleared by the power exchange or its appointed clearing house, thereby greatly reducing counterparty risk, i.e. the risk that a party defaults on its contractual obligations. Power exchanges that have gained some significance include Nord Pool, EEX in Germany, APX in Holland, Powernext in France, OMEL in Spain and GME in Italy.

(335) Unlike exchange trading, OTC transactions do not per se involve organised marketplaces. Rules governing the trade are typically derived from practice and based on industry

agreements.[181] Transactions are carried out bilaterally and counterparty risk is born by the market participants. Increasingly, transactions on traded OTC electricity markets are cleared by third parties, such as brokers or power exchanges, thus helping liquidity develop. Most standard transactions are facilitated by brokers' telephone or screen-based services. The main brokers included in our inquiry are GFI, ICAP, Prebon, Spectron and TFS.

(336) Apart from standardised exchange and OTC trading there are also bespoke bilateral transactions. These deals can be very different in terms of products delivered or services included ranging from back-up agreements to full supply contracts including volume flexibilities and balancing energy.

Table 14

Selected features of power exchange and OTC markets

	Power Exchange	OTC
anonymity of trading	yes	no
counterparty	central counterpart	bilateral trading
counterparty risk	no	yes (if not cleared)
spot trading	single auction	continuous trading
price and volume transparency	directly	indirectly

Source: Energy Sector Inquiry 2005/2006

I.3.2.3. Traded products, time horizons

(337) Depending on the delivery period, bulk electricity can be traded on spot or forward markets. Spot markets are mainly day-ahead markets on which electricity is traded one day before physical delivery takes place. On forward markets, power is traded for delivery further ahead in time.

(338) Typical spot products on continental markets are single hours or groups of hours, whereas forward products include weekly, monthly, quarterly and yearly products. Forward electricity can either be traded as a 'base' or a 'peak' contract. The term 'base' implies a continuous delivery throughout the delivery period (e.g. a month), whereas 'peak' typically only involves a delivery on business days from 08:00 till 20:00. The definitions and contract specifications may differ between countries.

(339) Electricity for spot and forward delivery can be traded on both power exchanges and OTC markets. Standardised forward contracts traded on exchanges are called futures.[182] Contract specifications of exchange traded and OTC products are in practice very similar or identical allowing for efficient arbitrage. To illustrate this, Table 15 shows the different spot and forward/futures contracts which can be traded on Powernext, the French power exchange, and the French OTC market.

[181] e.g. 'Standard Electricity Contract' of the European Federation of Energy Traders.

[182] Depending on the contract specification of the power exchange in question, futures contracts can be settled physically or financially. The later means that during the delivery period of the contract no physical electricity delivery takes place but a difference is paid between the prevailing spot price and the contract settlement price.

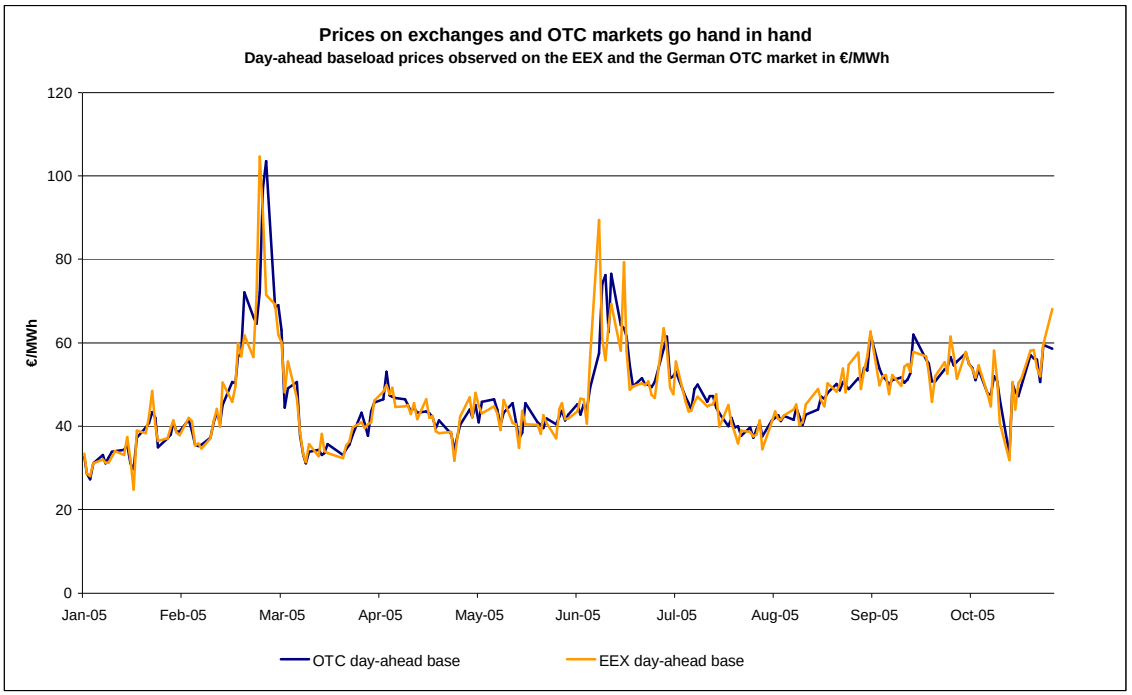
Table 15

Traded contracts on the French electricity wholesale market		
	Powernext	**French OTC market as assessed by platts**
day-ahead	24 single hours and 11 different blocks of hours	base & peak
week-end	-	base
week-ahead	-	base & peak
months	3 consecutive months, base & peak	3 consecutive months, base & peak
quarters	4 consecutive quarters, base & peak	2 consecutive quarters, base & peak
years	3 consecutive years, base & peak	2 consecutive years, base & peak

Source: platts, Powernext

(340) As a result of continuous arbitrage, prices of identical products traded on different marketplaces (i.e. on power exchanges or OTC markets) go hand in hand. Indeed, Figure 39 shows that, for instance, prices for day-ahead baseload delivery observed on the EEX, the German power exchange, and the German OTC market are closely correlated both in terms of development and levels.

Figure 39



Source: EEX, Argus Media

I.3.2.4. Price formation on short term markets

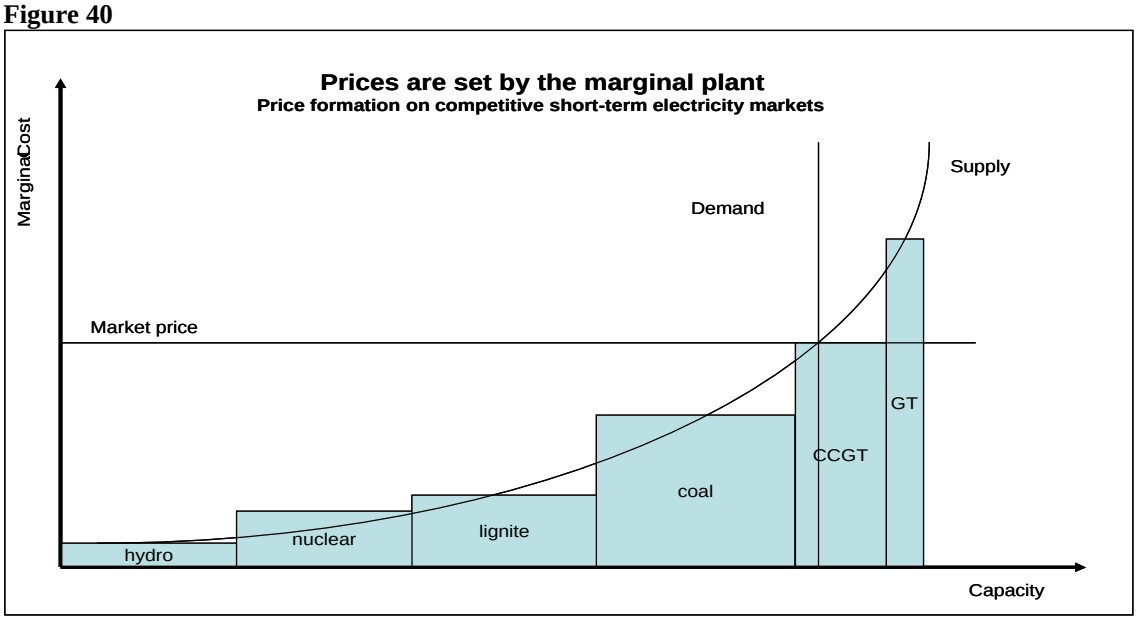
(341) As noted above electricity can be produced in many ways using a variety of fuels and applying different technologies. This diversity also results in different cost structures. Generation technologies that use low-cost fuels (e.g. nuclear fuel, lignite) often require relatively large capital investments[183]. On the other hand, generation technologies requiring relatively expensive fuels (e.g. gas turbines) have relatively low fixed costs. These differences in cost structures have important implications for the price formation on short-term electricity markets.

183 Including run-of-river plants that do not use fuels to generate electricity

(342) On competitive short term markets and in absence of generation capacity constraints, economic theory would suggest that prices are set by the short run marginal cost ('SRMC') of the plant producing the last unit of electricity required to meet demand. SRMC are mainly the fuel costs and some other, less substantial, variable production costs. The last, or marginal, unit needed to meet demand is also the one with the highest SRMC of all units running at a given point in time. The logic of this process ensures that only those power plants operate that have the lowest SRMC among all generation units available to operate[184]. As a consequence, it can be expected that nuclear or lignite fired power plants will be dispatched continuously and serve as base load units. For marginal and therefore price setting units – depending on the market in question – it would be expected that they are fuelled by natural gas or black coal.[185]

(343) In this respect it is important to underline that the SRMC of the price setting unit determines not only the revenues of the owner of the marginal plant, but also of all other operators with e.g. nuclear, lignite or run-of-river units. Whilst their marginal costs are often significantly lower it is generally argued that they need a higher price than the marginal costs to recover the higher fixed costs associated with base load generation. Figure 40 also explains this concept graphically using a schematic 'merit order'.[186]

Figure 40



Source: Energy Sector Inquiry 2005/2006
Note: This graph is only an abstract representation. It does not necessarily reflect actual cost relations between different types of generation and equally does not include the value of CO2 allowances

184 This price mechanism only applies for short-term markets and not for the price formation on forward markets.

185 In some markets, such as the Nordic market, hydro storage plants might often be on the margin. The SRMC of these plants is based on the alternative value of the water in storage

186 The term 'merit order' refers to the sequence of generating units according to their SRMC.

(344) Spot prices on power exchanges are usually set in single auctions, separately for 24 individual hours.[187] Each market participant hands in price-quantity pairs for its selling and purchasing plans from which the exchange derives aggregate supply and demand curves. The market price and the corresponding clearing quantity are then set as a result of the matching process. Prices and volumes for the individual hours are publicised and made available by the power exchange. In this respect it is important to note that generators may decide to offer electricity from their plants also at price levels other than SRMC.

(345) In comparison, on OTC markets spot transactions are carried out in continuous trading. Bids and offers are communicated to the market by brokers, usually by entering them into brokers' internet-based trading platforms. Since trading is done by using a number of brokers or directly between parties, prices are not directly known to all participants. Price discovery is the work of price reporters, such as Argus or platts, which assess the market based on market participants' voluntary reporting of prices and traded volumes. A variety of these assessments and indices are sold to the wider public.

I.3.2.5. Price formation on forward markets

(346) Wholesale electricity prices are influenced by both supply and demand factors. However, factors influencing prices in the short run can be somewhat different from those in the long run. According to the answers of market participants in the sector inquiry, short term prices are mainly influenced by plant availability, fuel prices, precipitation, wind speed, interconnector availability, temperature and, since 2005, CO2 prices. Prices in the long run are predominantly determined by forward fuel prices, (new) generation capacity (or capacity retirement), water reservoir levels, weather trends, interconnector capacities, CO2 prices and economic growth.

(347) Whereas forward prices are largely influenced by supply-demand fundamentals that are expected to prevail in the future, spot prices are determined by the out-turn of these fundamentals. In this way forward prices can give an indication of the overall market expectation about future spot prices[188]. The role that individual expectations play in the setting of forward prices also implies that no explicit price benchmark (similarly to the one that was introduced in the Chapter I.3.2.4. for short-term markets) can be used to determine what the price of a certain forward product should be at a given point in time.

(348) In addition to this forward prices are not only influenced by the expected supply-demand balance. Sellers and buyers engage in forward contracts because they prefer price certainty to unknown spot prices in the future. Therefore forward prices will also include a risk element. Depending on whether buyers or sellers attach a higher value to price certainty this will be a premium or a discount – though in practice it appears often be a premium. The buyer's willingness to pay for price certainty depends – amongst other factors – on the volatility of spot prices. The more volatile spot prices are, the less buyers will be likely to rely on spot transactions and turn to forward markets instead.

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187 On most of the power exchanges different blocks of hours can be traded as well.

188 This does not mean of course that forward prices should at any time necessarily be equal to out-turn prices. Expectations as regards future fundamentals might be very different from their outcome.

(349) Therefore, generators with market power on spot markets have ample opportunities to influence forward prices indirectly. For example dominant operators could withhold a part of their generation capacity. This would not only raise spot prices but also change market participants' expectations of the development of this fundamental supply side factor resulting in higher forward prices. Generators could also increase the volatility of spot prices (without changing the overall level of prices), which would increase the value of hedging them in advance on the forward market and may raise the premium of forward prices over expected spot prices. While pursuing these strategies might be costly for generators, this could be outweighed by higher revenues on their total portfolio.

I.3.3. Wholesale market outcome and end-customer pricing

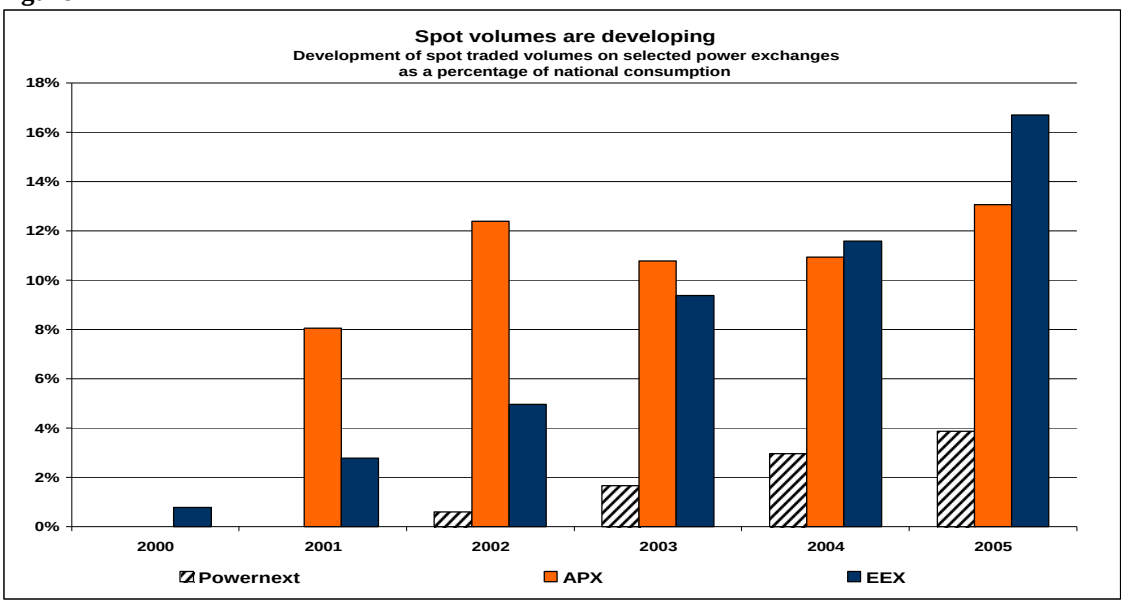
(350) Especially in countries where generators sell a considerable part of their generation months or even years ahead of actual delivery and where traded forward markets exist (e.g. Germany, France, UK, The Netherlands); it is a common practice for suppliers to offer fixed price supply contracts to their large business or industrial customers. Fixed price contracts also appear to reflect industrial energy users' preference.

(351) The inquiry shows that suppliers have fairly similar ways to set prices for fixed term contracts. The prospective consumers' hourly consumption over the contract duration (most often 1 to 2 years) is estimated on the basis of past consumption patterns assuming that these are indicative for future ones. The cost to serve this expected consumption is assessed with the help of an hourly forward price curve derived from relevant forward wholesale price quotations prevailing at the time the offer is prepared. The result is the actual cost of covering forward the customer's consumption on the wholesale market. The final price quoted to the customer will in addition contain other cost components such as expected cost of balancing or the supplier's own margin.

(352) The described pricing practice applies irrespective of whether the customer will in reality be supplied from the supplier's own generation portfolio or covered by electricity purchases on the market. Business units (i.e. generation and supply units) of integrated electricity companies generally act as profit centres and their performance is measured against the best alternative opportunity on the market.

I.3.4. Traded volumes on spot markets

Figure 41



Source: Powernext, APX, EEX

(353) Figure 41 shows the development of traded spot volumes relative to the consumption in the relevant geographical area for some selected markets. Over the whole period, traded volumes developed positively.[189]

Table 16

Spot traded volumes as a percentage of national electricity consumption (June 2004 - May 2005)

	Power exchanges	OTC brokered
OMEL - Spain	84,02%	negligible
GME - Italy	43,67%	n.a.
Nord Pool - Nordic region	42,82%	n.a.
EEX -Germany	13,24%	5,40%
APX - The Netherlands	11,88%	5,90%
Belgium	no power exchange	0,04%
Powernext - France	3,37%	1,50%
EXAA - Austria	2,96%	n.a.
UKPX - UK	2,17%	8,60%
Pol PX - Poland	1,28%	n.a.

Source: exchanges' and brokers' data
Note: This table does not contain an exhaustive list of all power exchanges in Europe. OTC brokered numbers refer to volumes reported to us by major energy brokers.

(354) Table 16 shows spot volumes traded on power exchanges and on OTC markets relative to electricity consumption in the relevant geographical area. It is evident that large differences exist between geographical areas. These differences are partly the result of diverging national wholesale market frameworks. According to their design, power exchanges can be divided into two broad groups. In the first group members of power exchanges have some kind of need or incentive to trade via the exchange (OMEL, GME,

189 Some respondents noted that the (temporary) decrease in traded spot volumes on APX during 2003, was to be ascribed to the distrust of market participant after strong price spikes had occurred when some power plants shut down due to cooling water constraints in the summer

Nord Pool).[190] In the second group exchange members have no such incentives. In this group EEX and APX saw significantly higher spot volumes traded than Powernext, EXAA, Pol PX and the UKPX. For reasons mentioned above, a direct comparison between the two groups of exchanges is not reasonable.

(355) From this table it also emerges that traded spot volumes on exchanges are larger than brokered spot markets in most of the countries we have examined. Thus market results on power exchanges seem to be setting the pace for the overall traded spot market.

I.3.5. Traded volumes on forward markets

(356) As can be seen from Table 17, total traded volumes in standardised forward contracts show large variations among countries, suggesting varying degrees of market development. Yet again, market design appears to be an important factor. Forward trading in Spain is insignificant, reflecting the de facto mandatory nature of the pool system on OMEL[191]. In contrast, the Dutch and German OTC forward markets traded by far the highest volumes (relative to consumption) on the Continent as data received from brokers suggest.

Table 17

Traded volumes in futures/forward contracts as a percentage of national electricity consumption (June 2004 - May 2005)			
	power exchanges	OTC brokered	power exchange + OTC
OMEL - Spain	no exchange trading	negligible	n.a.
GME - Italy	no exchange trading	n.a.	n.a.
Nord Pool - Nordic region (2004)	151%	n.a.	n.a.
EEX -Germany	74%	565%	639%
Endex - The Netherlands (since dec. 2004)	39%	509%	548%
Belgium	no exchange trading	22%	22%
Powernext - France	6%	79%	85%
EXAA - Austria	no exchange trading	n.a.	n.a.
Pol PX - Poland	no exchange trading	n.a.	n.a.
UKPX - UK	0%	146%	146%

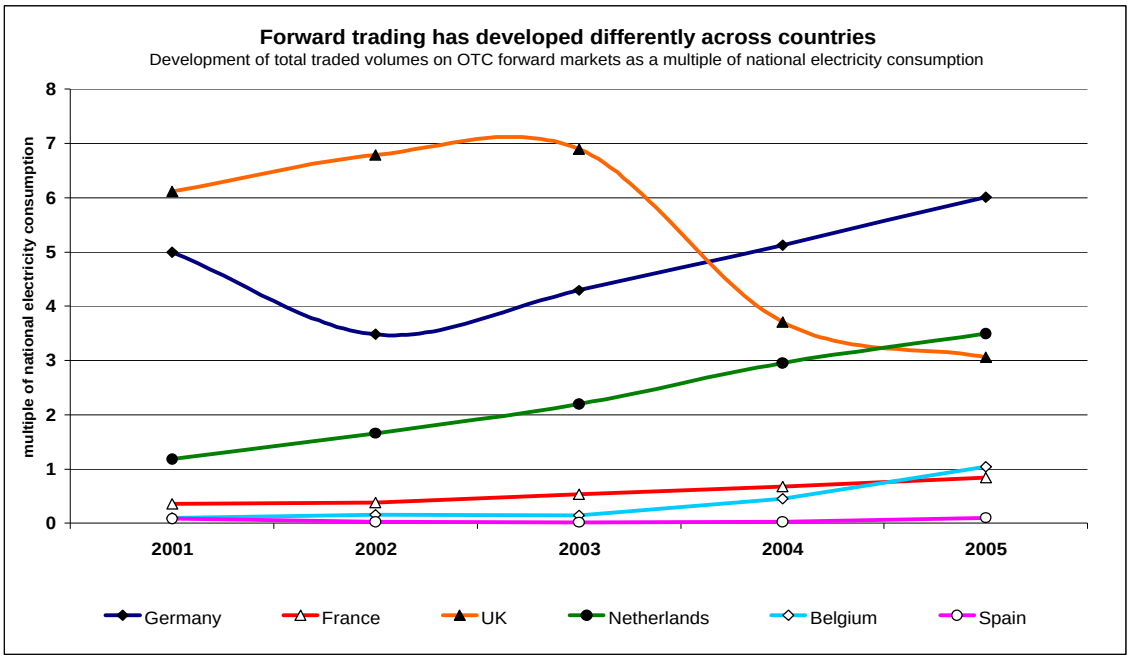
Source: exchanges' and brokers' data
Note: OTC brokered numbers refer to volumes reported to us by major energy brokers.

(357) Figure 42 depicts the development of total traded volumes as a proportion of national electricity consumption. The figures are derived from assessments of respondents in the sector inquiry that actively trade on European wholesale markets. In terms of trades a number of continental markets saw their volumes rise. Especially, the German and the Dutch markets experienced increasing OTC volumes.

190 In Spain only electricity traded via OMEL is entitled to receive capacity payments. In Italy the Single Buyer (Acqirente Unico) apparently covers an important share of its energy requirements to supply the captive market segment on GME. This contributed largely to a rise in spot traded volumes from 29 % in 2004 to 64% in 2005 (January – May). On the Nordic market there is a need for market participants to transact via Nord Pool once crossing different price areas, since the market mechanism applied there is also implicitly used to allocate limited transmission capacities between different price regions.

191 Only some minor transactions are executed one-year ahead of generation or more. This concerns output from cogeneration and renewable unit. Some generators reported however that also this electricity is increasingly sold day ahead.

Figure 42



Source: Energy Sector Inquiry 2005/2006.

(358) The UK is the only market in the comparison where traded volumes have significantly declined during the last two years. This is often ascribed by respondents to ongoing vertical reintegration of the industry, i.e. the trend to bring independent generation and supply businesses into a single operation under the same ownership. Volumes continue to be quite low in France and in Belgium owing to the high level of concentration and vertical integration in these countries.

I.3.6. Number of market participants

(359) Wholesale markets do not only need electricity but also a large number of market participants trading actively. The numbers in Table 18 are based on the data we have received from major brokers.

Table 18

Number of active market participants on forward and futures markets			
	total number of participants trading	local generators	pure financial traders
Nord Pool	36	16	8
Germany	34	8	10
UK	23	12	7
France	20	2	4
The Netherlands	18	5	5
Belgium	5	1	0

Source: exchanges' and brokers' data

Note: The number of participants in the table represents companies that are reported to have traded yearly or seasonally benchmark contracts over the period January-May 2005 and represented at least 0.5 % of the total volumes traded in those contracts.

(360) The total number of participants in the comparison given in the table includes not only local utilities and financial players but also trading affiliates of incumbents established in

other European countries and major oil and gas companies. All market participants act on the market as both sellers and buyers. The number of active participants on the power exchanges (EEX, Powernext) trading futures products is significantly lower than on the respective OTC markets.

(361) Nord Pool together with the German OTC forward market has the highest number of participants and also attracts the largest number of financial traders, followed by the UK, France Netherlands and Belgium. The number of pure financial traders is a useful indicator, since traders only enter markets once they are comfortable with the level of activity and consider that they can get in and out of trading positions relatively easily.

(362) It is interesting to note that although the total number of trading participants is very similar in the UK and France, the UK forward market has six times as many local generators and suppliers as the French. In France there are also relatively few pure financial traders. These relations suggest that in France trading is mostly pursued by affiliates of incumbents in other European countries and – to some extent – by oil and gas companies active in the electricity business.

Table 19

Number of active market participants trading electricty day-ahead on selected power exchanges

	Number of sellers	Number of buyers
Germany - EEX	35-26	31-36
France - Powernext	27-28	29-32
The Netherlands - APX	23-24	24-22
Austria - EXAA	21	22
Sweden - Nord Pool	24	7
Denmark West - Nord Pool	19	16
Finland - Nord Pool	14	9
Denmark East - Nord Pool	7	7
UK - UKPX	18-19	15-19
Spain - OMEL	15-13	6-7
Italy - GME North	15-14	26-21
Italy - GME Sicily	7-8	9

Source: power exchanges' data

Note: The number of participants in the table represents companies that are reported to have traded spot electricity over the period January-May 2005 and represented at least 0.5 % of the total volumes traded. The values are given in ranges, since the number of participants change depending on the hourly product in question. The first values in the range represent the number of participants traded 'Hour 3', the second ones the number of participants traded 'Hour 12'. For data availability reasons no such distinction is made for EXAA and Nord Pool

(363) The number of market participants trading spot electricity on power exchanges is presented in Table 19. The number of participants trading in spot markets compares well with those trading forward contracts on OTC markets. On most power exchanges the vast majority of participants act in general as both sellers and buyers of electricity. It is important to note that on most power exchanges a relatively small number of market participants accounts for a large part of the overall spot volume traded on both the selling and buying side. This is especially true for OMEL of Spain, GME of Italy and Denmark West on Nord Pool. Reference is also made to the chapter II.1.

II. Issues

(364) Whilst the electricity markets underwent significant changes over recent years (e.g. creation of power exchanges in many Member States) and some significant progress has been made in the creation of a single market place, it is currently the overall perception of many market participants that significant efforts are still needed to create a competitive common market for electricity.

(365) It is not the purpose of this report to downplay the progress made in the liberalisation exercise, but to analyse where many market participants currently see major deficiencies that still need to be overcome. The focus is thus on problem identification. As for gas the issues identified by market participants can be grouped into five large areas:

1. concentration and market power,
2. vertical foreclosure,
3. lack of market integration,
4. lack of transparency, and
5. prices.

II.1. Concentration and market power

II.1.1. Introduction

(366) One of the main concerns expressed by market participants in the sector inquiry is the concentration in national wholesale markets (whether in terms of ownership of generation assets or in terms of trade in a given product or exchange forum) which gives scope for exercising market power. In general the larger generators in a given national market found that the market was competitive whereas smaller generators, retailers without generation, traders and industrial customers found that there was scope for market power and disputed that the prices were at competitive levels.

(367) The following customers' views on the functioning of the spot and forward markets illustrate this:

Customers' views on the functioning of spot and forward markets

"There is an oligopoly on the supply side (…) accounting for 80% of generation output."

"French and Belgian markets are dominated by single players – thus distortions can easily occur there."

"Forward and futures prices at EEX do not react to supply and demand. A very dry summer such as 2003 drives up prices, the end of the dry period should thus result in a price decrease. However a downward trend after a price peak is not observable. Obviously the few players at the power exchange are able to prevent price decreases by limiting the offer."

(368) The sector inquiry was launched to carry out a competitive assessment of electricity markets notably in order to investigate the above allegations and to assess the reasons for rigidity in prices. This chapter starts the competition assessment of electricity markets by

looking, in line with traditional competition assessment, at levels of concentration using conventional indicators such as market shares. However, due to the characteristics of the electricity markets such indicators are insufficient to assess the scope for market power. Hence, this chapter will present preliminary results from a set of additional indicators that could reveal to what extent players are able (unilaterally or collectively) to influence prices. This set of indicators does not exclude the use of other possible indicators at a later stage.

(369) The organisation of this chapter is as follows. After explaining in section 2 how the Commission traditionally defines electricity markets, section 3 will present concentration in generation using conventional indicators. Results of similar indicators in the level of concentration in trade on forward markets and power exchanges are presented in section 4. Subsequently, in section 5, preliminarily results are presented using additional indicators for power exchanges and generation aimed to assess in more detail the extent to which electricity markets are vulnerable to manipulation based on market power. A conclusion ends this chapter.

II.1.2. The relevant markets

II.1.2.1. Product market

(370) The relevant product market in this analysis is the wholesale trade in electricity. Previous analysis of the Commission[192] has defined the wholesale supply of electricity to cover the production of electricity at power stations and the import of electricity through interconnectors for purpose of resale to retailers or to a lesser extent directly to large industrial end-users.

(371) Some market participants have indicated that product markets could be narrowed down according to the time of delivery. For instance, one could distinguish between peak and off-peak periods because of the different nature and level of demand in those periods. Others suggested even narrower markets down to hourly markets. For the purpose of this report it is not necessary to take any position on further refinements of the relevant product market.

(372) When analysing whether operators have market power giving them scope to influence prices, the Commission looked in particular at two specific products (one year forward products and day ahead products) sold on power exchanges and brokers' platforms since they provide the main public price indicators in electricity markets. In this respect it is important to underline that these contracts are analysed below as different segments of the same product market i.e. do not constitute a relevant market under EC competition law.

[192] See i.a. cases COMP/M.3440 EDP/ENI/GDP, COMP/M.3696 E.ON/MOL, COMP/M.3729 EdF/AEM/Edison, COMP/M.3867-Vattenfall/Elsam and Energi E2.

II.1.2.2. Geographic market

(373) As regards the geographic market, despite efforts by the Community to reduce barriers between the different markets in the EU, the Commission has usually found that the geographic markets are most of the time national in scope[193], but that they may sometimes be smaller[194] or larger[195].

(374) Relevant elements which support the existence of a smaller or larger market include system design, the existence of congestion at points in the grid, the existence of price correlations and price differentials and the differing nature of supply and demand on both sides of congestion points (in particular the existence of an operator that is indispensable to meet demand[196]).

(375) Annex A that is attached to this report includes a preliminary analysis of the regional scope of certain wholesale market. A complete analysis would have to include further supply and demand substitution of assessment, in particular the systematic assessment of whether there are operators who are indispensable to meet demand (calculation of residual demand). Given the need to do such an assessment on a very detailed basis, it was not considered useful to do such an assessment for all markets, but to leave that to further investigation in individual cases. However, on the basis of the analysis carried out so far, all markets will be considered to be national in scope, except Denmark and Italy, where regional markets clearly exist.

II.1.3. Concentration in generation

(376) Many market participants complain about price distortions linked to the degree of concentration in generation. It is often argued that generators' ability to influence the electricity price levels are due to the characteristics of electricity - the non-storability of electricity, the high inelasticity of demand, a very wide spectrum of costs of production and a price equal to the highest offer made in power exchanges. According to market participants generators can influence prices either

- by withdrawing capacity (which may force recourse to more expensive sources of supply) or
- by imposing high prices when they know they are indispensable to meet demand.

(377) In the first scenario, the withdrawal of capacity is profitable if the "loss" on electricity not being produced is exceeded by the increase in profit for the remaining electricity sold. Large capacity portfolios (in particular large low marginal cost generation capacity portfolios) can have such an effect because the higher price that results from the withdrawal of capacity will be more than compensated by substantial additional profits

193 See i.a. cases COMP/M.3440 EDP/ENI/GDP, COMP/M.3696 E.ON/MOL.

194 See case COMP/M.3729 EdF/AEM/Edison

195 See cases COMP/M.3268 Sydkraft Graninge and COMP/M.2847 Verbund/Energie Allianz.

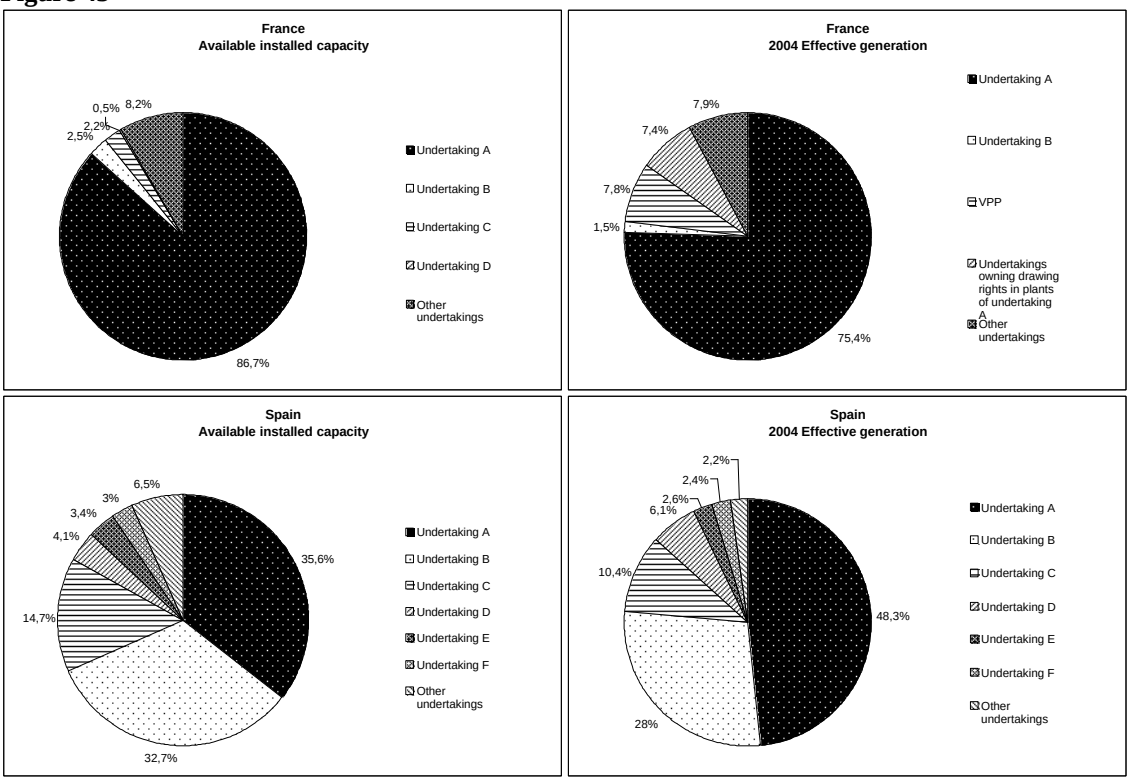
196 An operator is theoretically indispensable to meet demand if total demand (D) in the area is larger than the sum of the capacity (SC) of the other generators in the area and of the import capacity (IC) of the area. Given the little flexibility of demand and provided that the capacity of this operator is much larger than (D-SC-IC), such an operator would be able to raise prices without constraint.

from the generation assets being used. Assessing overall concentration of generation assets thus helps to identify the scope for such profitable withdrawals of capacity.

(378) In the second scenario, it is possible to raise prices ("excessive pricing") even with a relatively small portfolio because the structure of the generation assets and indispensability of certain assets to meet demand at parts of the merit curve. The higher the concentration in the relevant parts of the merit curve concerned the greater is the scope for influencing prices (as presented in chapter I.1). This will be elaborated later in this chapter.

(379) Although the extent to which generators may successfully influence the price level, may not (always) correlate with the level of concentration, it is a necessary element of the analysis of electricity markets across Member States. Figure 43 shows the share of available capacity and of effective generation of the main operators in France[197] and Spain. Charts for other Member States can be found in annex B.

Figure 43



Source: Energy Sector Inquiry 2005/2006

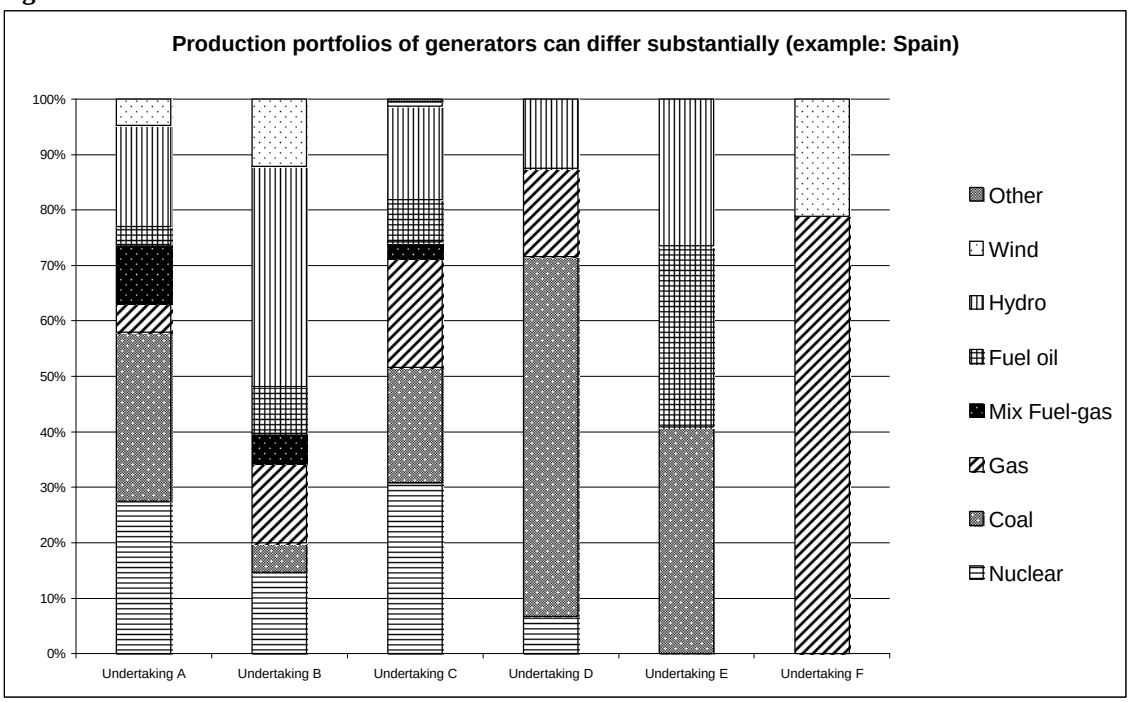
(380) The charts show that the production assets remain largely in the hands of one or a few large operators. This stems from the pre-liberalisation concentration of generation, which was rarely mitigated by decisions to force divestitures of the incumbent operators. Further, the strong position of incumbent operators has not been eroded in a significant way by investments in generation by new entrants. Indeed, there has been little new build of generation facilities across Europe, though in the past few years new generation has involved a build-out of new gas-fired plant in Italy, Spain and the UK and some new

197 For France the VPPs are plotted separately since this share is not controlled by the major generator. That being said, it is unclear to what extent VPPs limit the scope of market manipulation.

wind and other renewable generation facilities, primarily (in terms of total size) in Spain, Italy, Germany, and Denmark.

(381) The charts also point to the possibility that companies with a limited share in generation capacity might have market power at certain moments. For instance, in Spain, the second largest operator has almost the same size of installed capacity as the largest one (and both of them represent one third of total capacity respectively). However, the second largest one accounts only for a quarter of the effective output of the largest operator (while the two of them represent three quarters of the total production). This is because the main operator predominantly operates base load plants (essentially nuclear and coal), as can be seen in Figure 44, whilst the second largest operator is likely to serve more peak load demand (especially with hydro plants). Whilst further analysis would certainly be necessary the largest producer might have scope for profitable withdrawals of capacity according to the first scenario mentioned above, whereas the second largest operator might rather have scope for charging high prices at times of peak load.

Figure 44



Source: Energy Sector Inquiry 2005/2006

(382) The different possibilities to influence prices by the two generators concerned can be further explained by recalling the analytical concept of the merit order explained in chapter I. Figure 44 shows the technologies used in the portfolios of the different generators. As regards the largest operator, most of its plants will be on the left of the merit curve, representing generation with low marginal costs. If it withdraws capacity (i.e. limits its production), the curve will shift to the left and force recourse to more expensive plants to meet demand. Given its very large portfolio, this operator may compensate fully the lack of production with the increase in prices.

(383) The example of the second-largest operator shows on the other hand the scope for market power resulting from control over fewer plants which are more on the right of the curve or which are based on hydro. If an operator owns most of the plants on the right of the

curve, then it can increase prices with little risk of being replaced by another operator. It is precisely for this reason that the distribution of the power generation technologies becomes relevant. It is however important to underline that having scope for influencing prices does not automatically mean that market power was abused in an anticompetitive manner, as many market participants claim. Rather, this first step in the analysis serves to identify possible scope for influencing prices.

II.1.4. Concentration in trade

II.1.4.1. Introduction

(384) Analysing concentration in traded forward and spot markets is important because many retailers wish to procure their demand through these markets, be it partly or entirely. Similarly many generators wish to secure their sales through these forward markets. In addition forward (and sometimes spot prices) established on observable markets (broker's platform and power exchanges) provide an index for bilateral wholesale contracts and for retail sales to large users. So these markets serve as an important means of sale and purchase and develop reference prices.

(385) Below we analyse first forward trading and then spot trading.

II.1.4.2. Forward markets

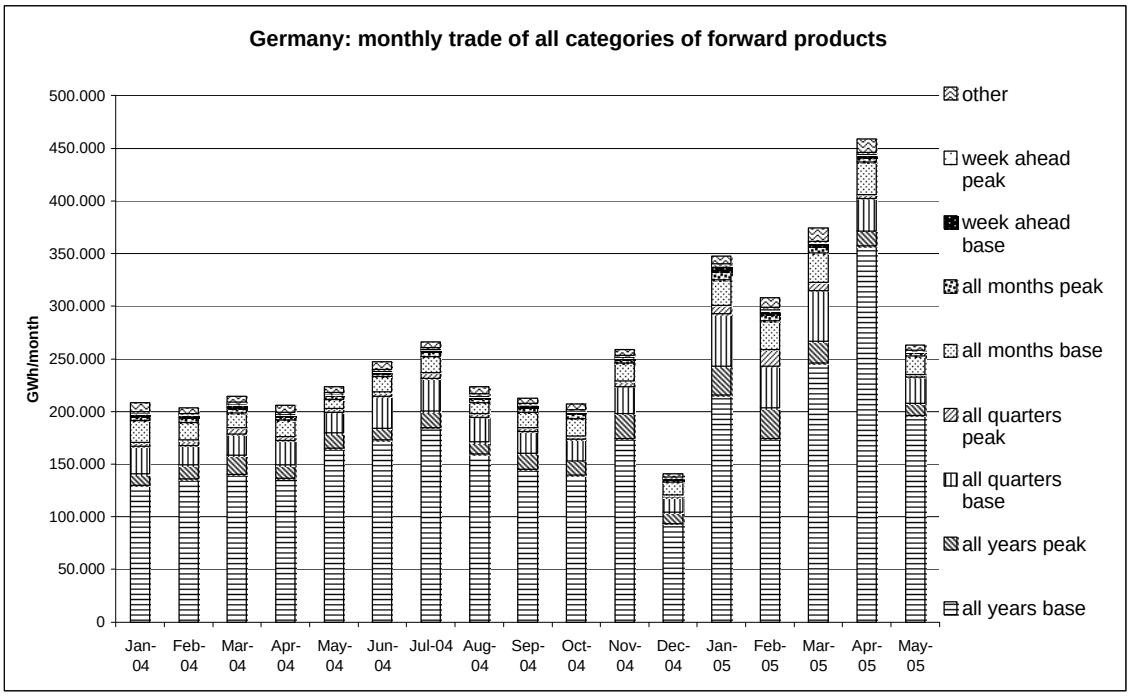
II.1.4.2.1. Degree of concentration in forward markets

(386) The most traded product by far on forward markets is the yearly contract for base load hours. An exception is the UK market where products for different seasons are the most traded[198]. Figure 45 shows for example the proportion of trade of the different forward products in Germany. Further, the yearly forward prices are the main forward price indicator in all markets, for both wholesale and downstream retail contracts.

(387) Thus, it seems that yearly base load products are a good candidate to investigate concentration in trade in forward markets. For this purpose the sector inquiry has collected and aggregated the sales and purchases per operator on all OTC trading platforms and on the power exchanges which trade forward products. Buying and selling have been separately assessed.

[198] This was also the case in Nord Pool until 2004 when yearly forward products started to be traded much more.

Figure 45



Source: Energy Sector Inquiry 2005/2006

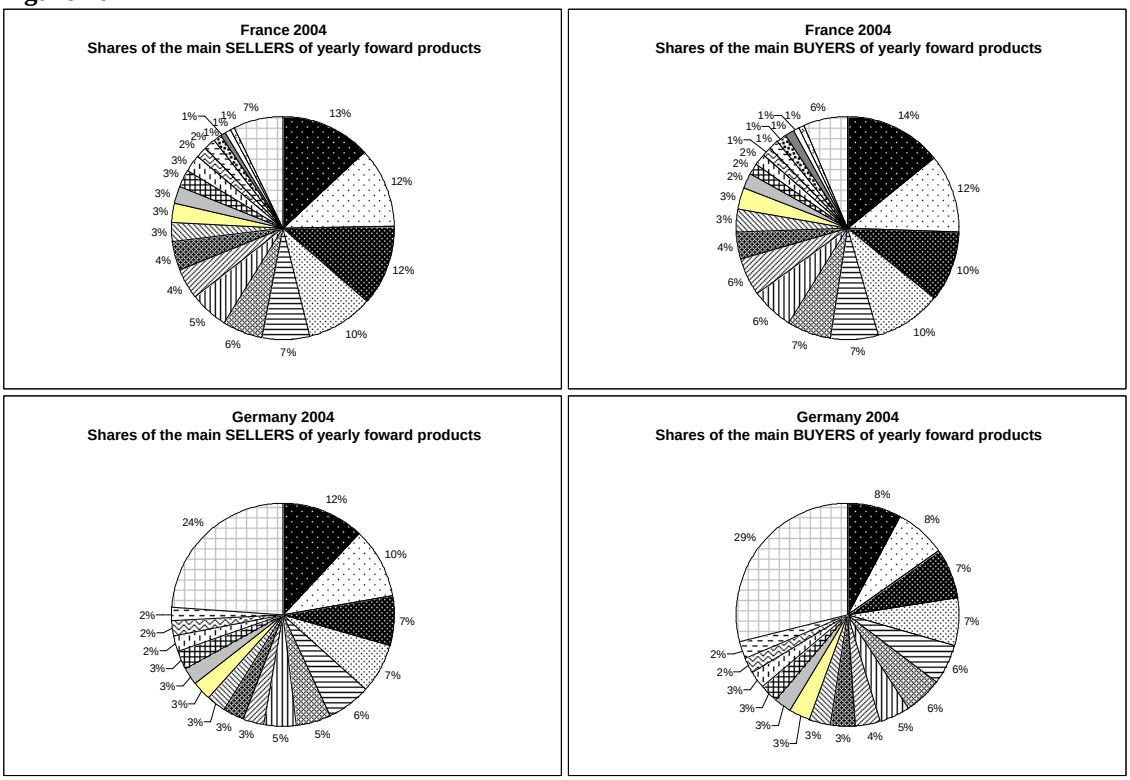
(388) Figure 46 illustrates for France and Germany in 2004 the trade in yearly forward contracts (indicating the shares of the main sellers and the main buyers separately[199]). Charts for other forward markets can be found in Annex C. The charts represented here and in the annex show that, except for Belgium, the degree of concentration is not comparable to that in generation. Given the many transactions that take place, the trading affiliates of main generators in any given market usually represent together between 30% and 40% of all sales. Furthermore, trading affiliates of the main generators represent together between 20% and 30% of all purchases. The other large market participants are usually the trading arms of the large European generators located in other markets as well as some "pure traders" (i.e. operators without generation assets). The top five players on the selling side are usually the top five players on the buying side, though not in the same order.

(389) That being said, it is important to note that in all markets (except Belgium) there are at least two participants without generation assets and without retail activity in that market, which can be found among the top five players. Further, at least one of these two players is a "pure trader"[200]. This may suggest that some "pure traders" have reached a sufficient degree of knowledge and confidence in the markets to provide liquidity and arbitrage in the markets.

199 Note in that respect that the same colour does not correspond to the same undertaking in both pie charts (for sellers and buyers).

200 In one market, this pure trader is even the biggest trader overall (in terms of total and purchases).

Figure 46



Source: Energy Sector Inquiry 2005/2006
Note: The pattern represents in each Figure the category "other undertakings", i.e. the aggregation of all undertakings which have not been represented individually in the Figures.

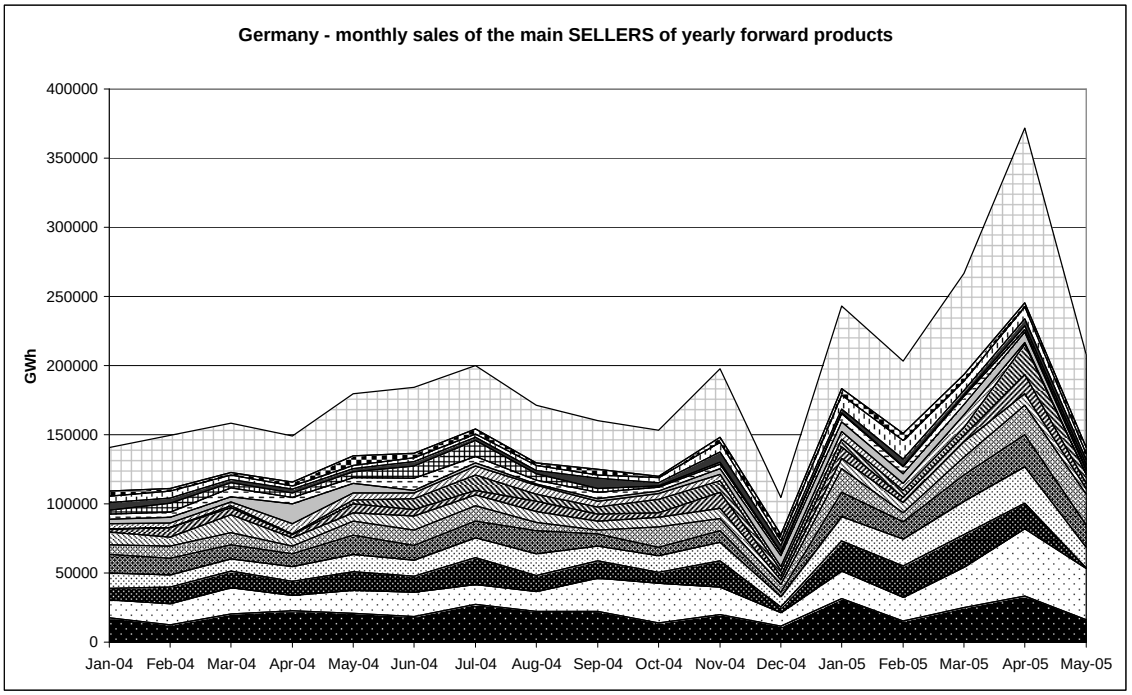
(390) An important result, shown in the charts, is that shares in trade do not reflect shares in generation. Furthermore, for the markets analysed, almost no trading platform has been identified where operators systematically have a dominant position on supply or demand as is claimed by a number of market participants[201].

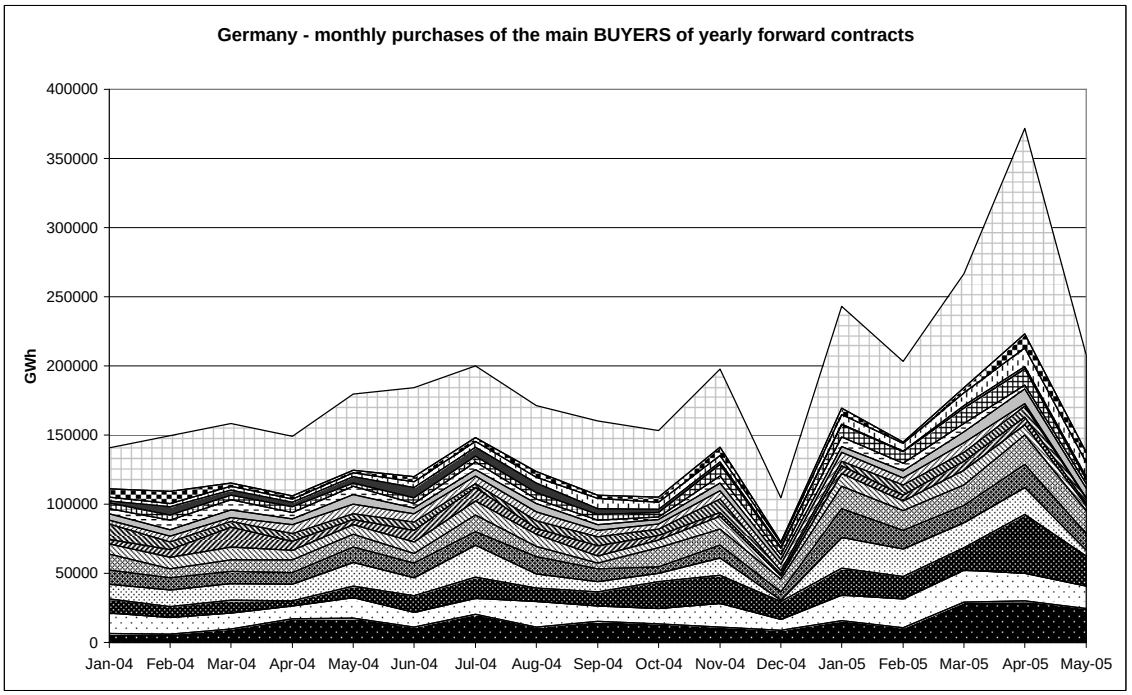
II.1.4.2.2. Evolution of concentration in forward trade over time

(391) Whilst the overall concentration levels may look reassuring in the yearly forward market contract, at certain moments in time there may be a high level of concentration which is not shown in the static presentation in the previous chart. Figure 47 therefore shows the monthly evolution of sales and purchases in Germany during the period January 2004 – May 2005 (see Annex D for all other forward markets). Though more detail may be required for a more thorough analysis, such as hourly evolution, it gives a preliminary insight into concentration at different times.

201 In that respect, it is important to note that in most markets, there are more than ten very active participants which trade on all platforms and can thus arbitrage between them. Thus even if there had been a main operator on a given platform, it would have been arbitraged against other platforms. That being said, if there had been a main trader behind a given platform it might have been able to give signals through its bids and offers on that platform: that is the reason why it was useful to check this allegation.

Figure 47





Source: Energy Sector Inquiry 2005/2006
Note: The pattern ▭ represents in each Figure the category "other undertakings", i.e. the aggregation of all undertakings which have not been represented individually in the Figures.

(392) The monthly evolution of relative trading positions for the annual contract during the period January 2004 – May 2005 shows that, except in Belgium[202] and in the Netherlands at certain moments in time, there does not seem to be concentration at a monthly time scale. In Germany the relative proportions of trade on both sides of the market per player

202 The charts for Belgium cannot be shown given the very few operators actively involved: it would reveal the strategy of those operators.

remain rather constant, though in December 2004 and April 2005 the evolution of the market shifts significantly. As regards December 2004, this decrease is due to the fact that at the end of the year the trading of the product of the following year stops. As regards April 2005, this peak may be related to the change that occurred in CO2 trading. The Nord Pool market is growing fast because of the replacement of the seasonal products by yearly products, though this has hardly altered the relative proportions of trade per player. The UK market on the other hand is drying up and trade of all operators seems to be reducing similarly. In France, there are important variations but trading shares of most operators change accordingly. In the Netherlands on the other hand, at times of decreasing trade, the main sellers become fairly important and the two main sellers can reach up to 50% of total sales, which is a fairly high level and creates room for those operators to move the market. In Belgium, the concentration can become even more acute in certain months than the figures in the preceding section suggest.

(393) It is also clear from the data gathered that in the beginning of the year 2005 a number of new pure traders entered the market. An increase of trading activity by some of the main players was also observed in that period.

(394) In addition, the evolution of the net position (sales minus purchases) of the main operators active on each forward market was studied, as it shows their underlying sales and buying strategies (e.g. financial traders avoiding large open positions). For obvious confidentiality reasons, the corresponding graphs cannot be reproduced here[203]. However it can be said that in certain markets the main generators have so far been able to take much larger net positions in the forward market than all other participants. It remains to be seen if the generators in those markets could affect the markets by changing abruptly their net positions. It also remains to be analysed why certain generators were not taking any net positions during certain periods of time. For further analysis on this issue reference is also made to chapter II.2.

II.1.4.3. Concentration in spot markets

(395) Power exchanges, where one can trade day-ahead on an hourly basis, often function as a last resort to close open contractual position before gate closure. Alternatively one may be exposed to balancing market prices that in some Member States are highly unpredictable and are reported as (economically) punitive by certain market participants[204]. Hence, in contrast to forward markets, there are fewer possibilities to substitute away from the product concerned, e.g. by delaying the purchase. Therefore high levels of concentration on power exchanges may indicate substantial scope for

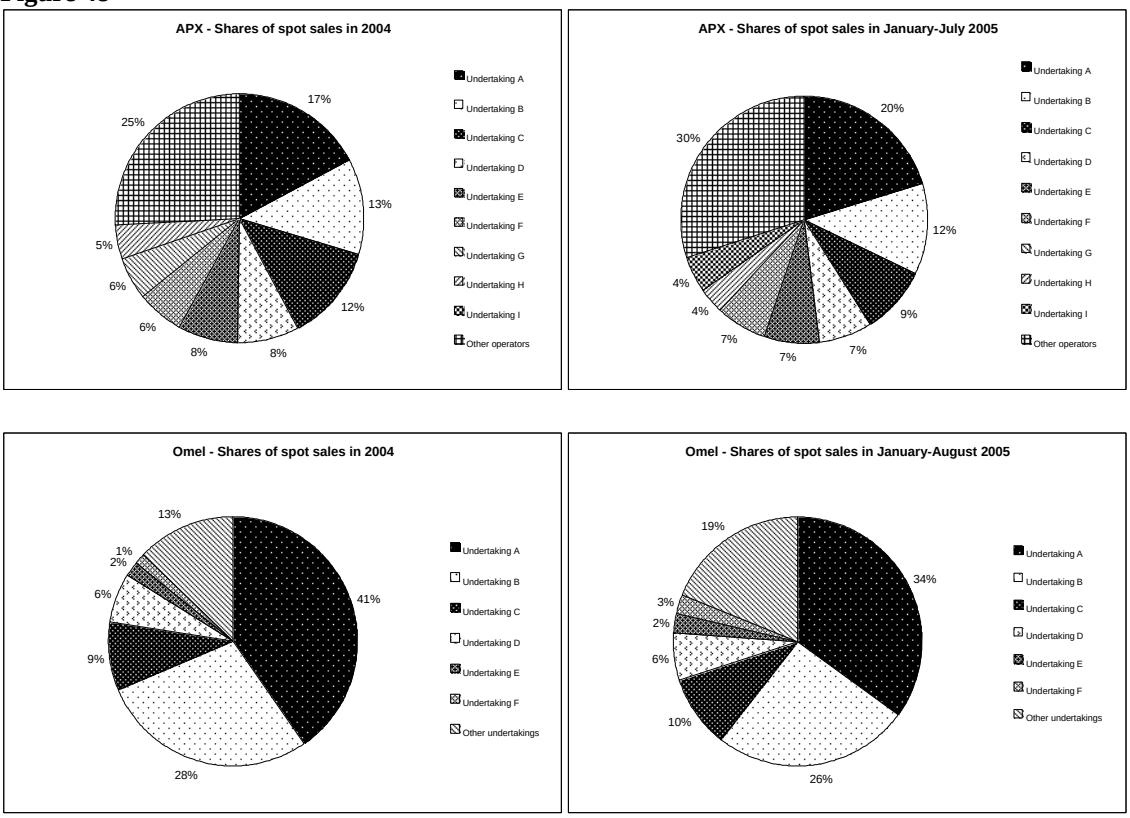
[203] We have in particular studied the evolution of the cumulative net position up to the moment of delivery, for instance the cumulative net positions (sales-purchases) of each operator in yearly forward products all through the year 2004 until all Calendar 2005 products have either been physically delivered or turned into shorter-term contracts. The graphs presenting the evolution of the cumulative net positions show three categories of operators in all markets during 2004: first there were a number of operators (usually retailers with or without generation) who gradually increased their net buying position during the year, second there were a few operators (usually generators) who increased gradually their net selling position during the year, and thirdly there were a number of operators whose net position varied in both directions but who remained (except for a few of these "traders") in absolute terms usually far below the cumulative net value of the operators in the two other categories. This seems to indicate that there was a rather cautious approach on both the buying and selling side during 2004, which avoided the rush that would happen if for instance all buyers had increased their net purchases at the same time. That being said, some of the net positions in trading did not correspond to the net positions studied in the chapter II.2 on vertical foreclosure. Further, in a number of markets, the categories and the behaviours were much less straightforward in the first half of 2005.

[204] Further work on balancing regimes will be considered in the next part of the sector inquiry.

exercising market power. Some market participants have also claimed in their answers that generators may "dictate prices" on power exchanges. Thus, this section measures the level of concentration on power exchanges.

(396) As explained above, it is important to keep in mind that not all power exchanges with spot markets have the same underlying design. Some thrive on regulatory constraints (OMEL, GME, Nord Pool), others are of a more voluntary nature (APX, EEX, Powernext). Thus the volumes traded on the respective market places might vary considerably. Figure 48 shows the degree of concentration of the various power exchanges in 2004 and during the first five months of 2005 (further graphs in Annex E).

Figure 48



Source: Energy Sector Inquiry 2005/2006

(397) In the first category of power exchanges (Spain, Italy and Nord Pool) the concentration in generation finds – with one exception (Italy's North zone) - direct expression in a rather stable equivalent concentration in the power exchanges[205]. This situation does not reduce the concerns that there is scope for market power.

(398) In the second category of power exchanges (France, Germany and Netherlands) the power exchanges display a lower level of concentration and also less correlation with concentration in generation. Also the stability of the shares is low in these power

205 For this analysis, it is necessary to take into account the electricity sold by TSOs on certain exchanges (TSOs appear as a separate undertaking in the corresponding graphs). Electricity is sold by TSOs on exchanges in particular in Italy and Denmark. Regulation in Italy mandates the TSO to sell on the power exchange the large amounts of electricity sold under regulated pre-liberalisation contracts (so-called "CIP 6" contracts). In Denmark, the TSOs sell wind power on the exchange: the corresponding amount of electricity has varied substantially between 2004 and 2005.

exchanges for the different operators[206]. However further assessment in the light of the comments on additional indicators is necessary.

II.1.5. Additional indicators

(399) In this section a more detailed analysis is presented of the scope for market power on power exchanges (possible excessive pricing) and generation (possible withdrawals of capacity).

(400) In this respect it should be kept in mind that there are a number of objective factors that may influence electricity prices (cost of fuels, pricing-in of CO2, constraints on interconnections, etc), as explained in other chapters. These factors and constraints make it more difficult to identify the effect of an anti-competitive practice as some of these constraints (e.g. CO2 emissions) are reported to have a very large impact on prices. The assessment that follows does not at this stage aim to quantify the impact of such practices, but tries to identify whether they were possible.

II.1.5.1. Possible scope for excessive pricing

(401) As indicated above, a relatively low market share on a power exchange does not necessarily mean that an operator cannot influence the price level. Indeed, it all depends on the price level of offers of the other operators. For instance, if one operator owned most of the more expensive plants required to meet demand at times of higher demand (concentration in the right of the merit curve), this operator would make most of the offers determining the clearing price at times of peak demand and would face few competitive constraints[207]. In other words, the residual demand is supplied by a few or just one operator. The focus of the assessment below aims to identify for all exchanges whether some operators are in such a position. Accordingly, it is the aim at this stage to identify if the operators had the scope for excessive pricing but not to check if they actually used it.

II.1.5.1.1. Price setting frequency

(402) As a first rough measurement of concentration in the right of the merit curve, we have identified in all exchanges for each operator the number of hours when this operator "set the clearing price", meaning the hours when its selling bid was equal to the clearing price[208]. This gives an indication of how often an operator makes selling bids at the

206 It shows in particular in the difference of aggregated shares between 2004 and 2005. It has also been checked that variations month by month and the variations of shares of sales of generators month by month are larger in this second category of power exchanges.

207 In that respect it is important to note that the merit curve will not be perfectly reflected in the power exchanges: especially in smaller exchanges, it is only a very small part of the merit curve that is reflected by the offer curve in the power exchange. However, since generators usually try to optimise their most expensive plants on the basis of spot prices, the right of the merit curve will be much better reflected in the offer curve on the power exchange than the left of the merit curve.

208 Depending on the clearing system used by the power exchange, the price for a given hour may be established by interpolation between selling bids. In such cases, the "operator setting the price" was defined as the operator(s) whose selling bid had a price closest to the clearing price. It may also be possible that several operators had the same selling price equal to the clearing price or were as close to the clearing price: this leads to totals exceeding 100% in a few cases. Finally, during some hours all sellers who had been selected had made offers at zero (the price was then not equal to zero because of interpolation with the first bid at a non-zero price): in those cases no operator was identified.

clearing price. Hypothetically, if only one operator "sets the price" most of the time, it means that there are very few, if any, alternative offers around the clearing price most of the time. The operator builds-up knowledge about the inelasticity of demand on a specific part of the supply curve where he operates by comparing his bids with the exchange clearing price. If demand is relatively inelastic, he can increase his selling price without the risk (or with little risk) of being replaced by another operator.

(403) The frequency of price-setting on the main EU exchanges has been checked month by month for 2004 and for the first eight months of 2005. Table 20 shows the frequency of price setting of the three main "price-setters" in each of the exchanges (or area of the exchange when the relevant market is smaller) in the first eight months of 2005; the number of operators with an average frequency above 5%; as well as the maximum percentage of the number 1 operator in any given month during 2005. For zones in Nord Pool and GME, the frequency is calculated only on hours during which the zone is isolated from other zones[209]. This naturally produces higher figures than for other exchanges. In order to provide a complete picture for Nord Pool, the calculation has also been made for the most common aggregation of zones (all zones together), which leads to lower percentages.

(404) This indicates that in EEX, APX and Powernext, there are a fairly large number of operators making offers of electricity resulting in setting the clearing price. The figures for 2004 in those exchanges further show that the shares of the main operators vary over time and that even the positions of the main operators have varied. The figures presented in the above table are usually similar but sometimes higher when only including peak hours[210]. The fact that there are many operators involved in price setting despite concentration in generation is possible because there are smaller generators which apparently have "marginal plants" and because a number of market participants have bought electricity from the main generators in VPP auctions or own drawing rights in plants of the main generator(s)[211]. Also, some of the price-setters are traders which arbitrage between market segments such as spot exchanges and OTC trade. This measurement does not indicate thus that there was a single operator very much influencing the spot price in those markets, although the situation may need some further monitoring, particularly for Powernext. In addition, it would be important to verify also the buying side as generators may also influence the price through purchases[212].

209 The zones selected are the ones in the EU which are most often isolated (Sweden is almost never isloated) as well as South Norway (another often-isolated zone) for comparison purposes.

210 Peak hours have been defined for that purpose as the hours covering the period 8:00-20:00 on working days.

211 These operators are different from traders who do not have any retail business in a given market. Such traders, have to sell the electricity that they still have remaining the day before delivery (e.g. if they have bought that electricity in the forward market), either in the spot trading of the market where they bought it or in the spot trading of a neighbouring market if they can export the electricity or sell it OTC. Accordingly, such traders are present in the statistics of price-setting usually less than in those of shares of sales presented in II.1.3, depending on the possibilities of arbitrage between markets.

212 Indeed, generators often combine buying and selling bids as part of their optimisation process: for instance, an undertaking A with a 50MW plant of a marginal cost of 15 €/MWh, a 50MW plant of a marginal cost of 35.1 €/MWh and needing 150 MW for its retail needs would place a buying bid for 100MW up to the price of 35MW and 50MW above. In other words, that operator would make no selling bids. If the clearing price was (due to interpolation), say, 35.05€/MWh, the measurement above will determine that it is another operator that "set the price", whereas at least both operators influenced the price.

Table 20

Frequency of "price setting" in the main exchanges in 2005					
	N°1	**N°2**	**N°3**	**Number of operators above 5%**	**Maximum percentage in one month**
Omel	32%	25%	10%	5	44%
GME Nord	86%	5%	5%	3	100%
GME Centre South	96%	2%	1%	1	97%
GME Sardinia	80%	19%	1%	2	98%
GME Sicilia	87%	10%	2%	2	98%
Nord Pool WDK	50%	10%	2%	2	89%
Nord Pool EDK	60%	3%	1%	1	100%
Nord Pool SNO	40%	30%	21%	10	63%
Nord Pool FIN	85%	12%	3%	2	100%
Nord Pool all zones together	34%	35%	27%	15	57%
EEX	17%	13%	11%	8	25%
APX	15%	14%	9%	8	18%
Powernext	20%	15%	12%	7	33%

Source: Energy Sector Inquiry 2005/2006
Note: all percentages are rounded, totals can exceed 100%.

(405) On the other hand, in all macro-zones of GME, in West Denmark, East Denmark, and Finland, when they were isolated, there was in 2005 one operator which set the clearing price almost all the time[213], meaning that there was very little alternative offer around the clearing price. With one exception (Sardinia) the figures were roughly the same for 2004. The same statistics were also calculated for the period of peak hours and it provided similar results[214]. This means that there might be room for the main price-setter in each zone to increase its price without having the fear to be replaced by another operator, in other words there seems scope for market power. In the case of Omel, as expected in the section on concentration in generation, the largest price setter happens to be the second

213 The percentages for the main price setter are much higher than the largest share of trade (seen in 2.4.1.3). This is possible because other participants have less expensive plants (as explained in the Spanish case under 2.1.3), or because some other participants even bid at zero (so-called "price takers"). Bids at zero maybe due to the fact that a plant is heat-driven or due to regulatory constraints (the TSO sells into the power exchange wind-power in Denmark and the TSO sells into the power exchange the large amounts of electricity produced under regulated legacy contracts "CIP6" in Italy).

214 The proportion remained the same between operators but, in certain zones the percentage of the main operator in "peak hours"could be one or two points above or below that for "all hours".

largest operator in terms of total capacity, i.e. the one with by far the largest amount of hydro power. Furthermore, the percentage of price setting of this operator reached high proportions (up to 58%) during the summer months of 2005. This would at least give some scope to this operator to exercise market power.

(406) All in all, the price setting frequencies indicate a substantial scope for influencing the prices on certain power exchanges.

II.1.5.1.2. Quantity offered around the clearing price

(407) In addition to analysing who set the clearing price, the sector inquiry analysed in more detail which operators placed bids around the clearing price. For this purpose the interval +/-10 percent around the clearing quantity along the power exchange supply curve was analysed to establish whether any operator offered more than 50% of the quantity in that interval. This goes further than the previous measurement by checking how much the largest operator on the right of the merit curve controls of the bids. This approach is rather conservative given that the +/-10 percent interval represents 20% of the clearing quantity and that some of these exchanges represent a fairly large part of total consumption. For zones in Nord Pool and GME, the frequency is calculated only on hours during which the zone is isolated from other zones. This naturally produces higher figures than for other exchanges. In order to provide a complete picture for Nord Pool, the calculation has also been made for the most common aggregation of zones (all zones together), which leads to lower percentages.

(408) The results shown in Table 21 confirm that the largest price setters in Omel, in the Nord Pool zones included in the table when they are isolated, and in all GME zones except Sardinia are also those placing most bids around the clearing price. At certain levels of demand (particularly in certain months), the main price-setter seems to be in a position to raise prices, provided that it can forecast well enough the separation of zones in the cases of Nord Pool and GME[215].

(409) The same analysis was also carried out on other exchanges. It revealed that in EEX, the concentration around the clearing price has been increasing rapidly in 2005, reaching levels of up to half of the peak hours in a month. This may be a sign that the growth of EEX is now leading to similar characteristics as discussed for OMEL where a larger part of the "peak plants" are being optimised through power exchanges. A similar trend seem to be occurring in Powernext, though at much lower level as the largest price-setter there started in the summer 2005 to offer more than 50% of the quantity around the clearing price for a non-negligible percentage of the time (up to 17% of peak hours).

[215] In general, it can be said that such a forecast is easier when the isolation of the zone occurs frequently (e.g. more than 45% of the time for West Denmark, Sardinia or Sicilia) than when it occurs less frequently (8% of the time for Finland and 11% of the time for East Denmark in 2005).

Table 21

Percentage of peak hours when the largest "price setter" controlled more than 50% of the offers of electricity offered at a price around the clearing price				
	Maximum in a month in 2004	Monthly average in 2004	Maximum in a month in 2005	Monthly average January-August 2005
GME Nord	68%	42%	66%	28%
GME Centre South	100%	100%	100%	100%
GME Sardinia	79%	41%	11%	4%
GME Sicilia	55%	36%	56%	40%
Omel	50%	17%	66%	33%
Nord Pool WDK	100%	80%	100%	87%
Nord Pool EDK	100%	74%	100%	92%
Nord Pool SNO	83%	32%	88%	50%
Nord Pool FIN	73%	27%	95%	31%
Nord Pool all zones together	63%	25%	100%	50%
APX	12%	6%	10%	5%
EEX	25%	11%	52%	25%
Powernext	1%	0%	17%	6%

Source: Energy Sector Inquiry 2005/2006
Note: all percentages are rounded.

II.1.5.2. Impact of generation on prices: a preliminary assessment of the possibilities to withdraw capacity

(410) Generators, due to the characteristics of electricity markets, may also be able to influence prices through withdrawals of physical capacity. This can be done by fully withdrawing a plant or, more discreetly, by making it produce at less than its capacity (partial withdrawals).

(411) The analysis focuses thus on the level of utilisation of power plants of the main generators over a sufficiently long time period. Disregarding special circumstances one would expect plants with relatively low marginal costs to run all hours and plants with relatively (very) high marginal costs only to run at (super) peak hours. If this relation between marginal costs and utilisation does not appear from the data one may suspect that competitive pressure is too low, and that (partial) withdrawal of generation to manipulate the price level during some hours must be further investigated.

(412) In order to identify plants which are not run at their maximum capacity (partial withdrawals), so-called load factors have been calculated (see the definition below) of the main generators for a number of years in Germany and France. In order to identify full withdrawals, one must also take into account the maintenance schedules. At this stage, this has not been done.

(413) The load factor of a plant is the ratio between effective production and the maximum amount of electricity that this plant could have produced in a period, all market terms remaining equal. For this purpose, for each plant and in each period, the number of hours were calculated when it was generating electricity. Multiplying these effectively operational hours with the plant's maximum capacity yields the maximum potential output[216]. The load factor is then equal to the effective measured output during the period divided by its (potential) maximum.

(414) Figure 49 shows the results of the calculations for the main operators in Germany and cover the years 2000, 2004 and the first trimester of 2005. The year 2000 corresponds to the beginning of liberalisation, the year 2004 and the first trimester of 2005 represent the situation after liberalisation and before the full effects of CO2 emission trading were felt. The first line which starts low and increases continuously is the aggregated merit order of all plants of the four main German generators, i.e. the line ranking the marginal costs of all the existing plants. The second line shows the load factor for each plant in the order of their marginal cost (so that points on both curves correspond to one another vertically). The horizontal axis provides the aggregated value of capacity of the plants in the order of their marginal cost.

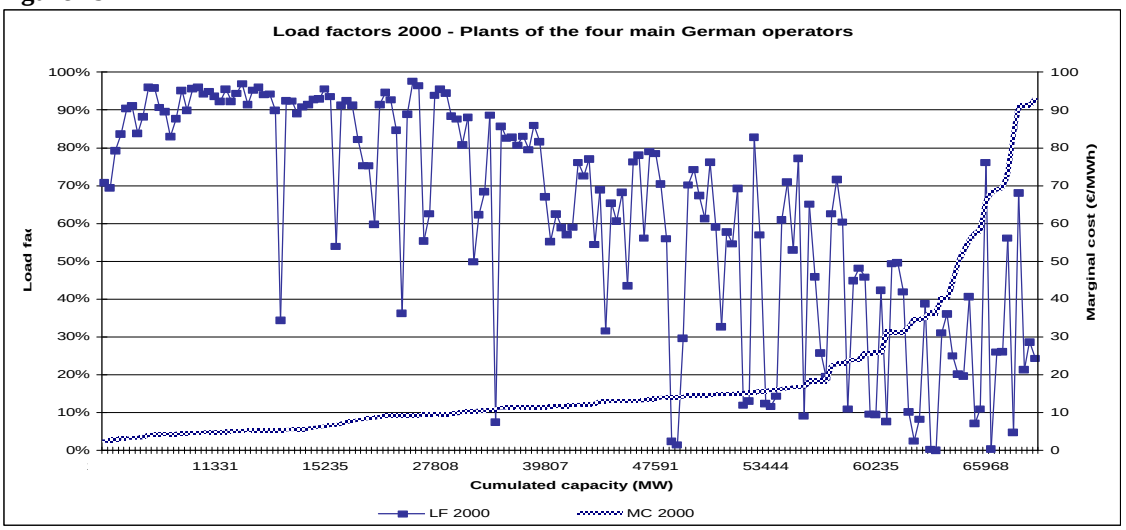
(415) Figure 49 indicates that the correlation between marginal costs and load factors has increased overall throughout the period investigated. Especially, the load factor of the relatively low marginal cost plants is overall on the rise.

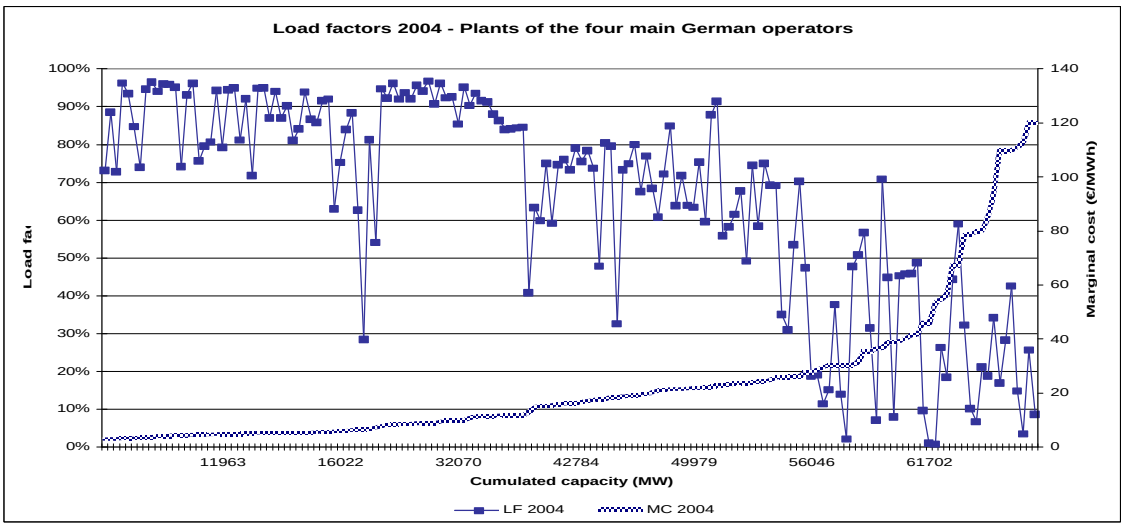
(416) Figure 49 shows that within the groups of plants with marginal costs usually below the spot market level (on average around 28-30€/MWh in 2004 and around 36-38€/MWh in the first trimester of 2005) some were used extensively whilst others were characterised by low load factors. In other words, some plants ran significantly more than other plants with similar or higher marginal cost. There is a variety of possible explanations for this phenomenon: for instance, a plant may be producing heat as well as electricity and needs to run according to the need to produce heat.

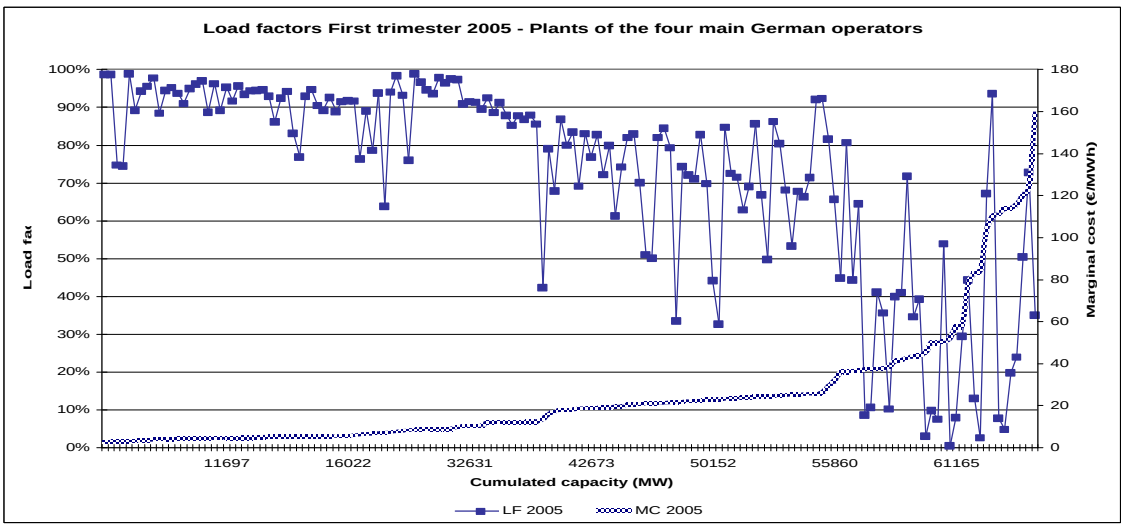
(417) Figure 50 shows the same calculations as those in Figure, but it plots the marginal costs to compare the merit curve across the years (with on the horizontal axes the accumulated capacity for the main German operators). One should keep in mind that, in this chart the plants on the horizontal axis need not necessarily be the same for all years.

[216] This maximum capacity is usually the capacity stated by the generator in its answer to DG COMP questionnaires. However, in a number of cases (especially the cheap plants), the plant is run for a very large number of hours above the nominal capacity. In those cases, the maximum capacity the maximum output of the plant during the period is taken.

Figure 49



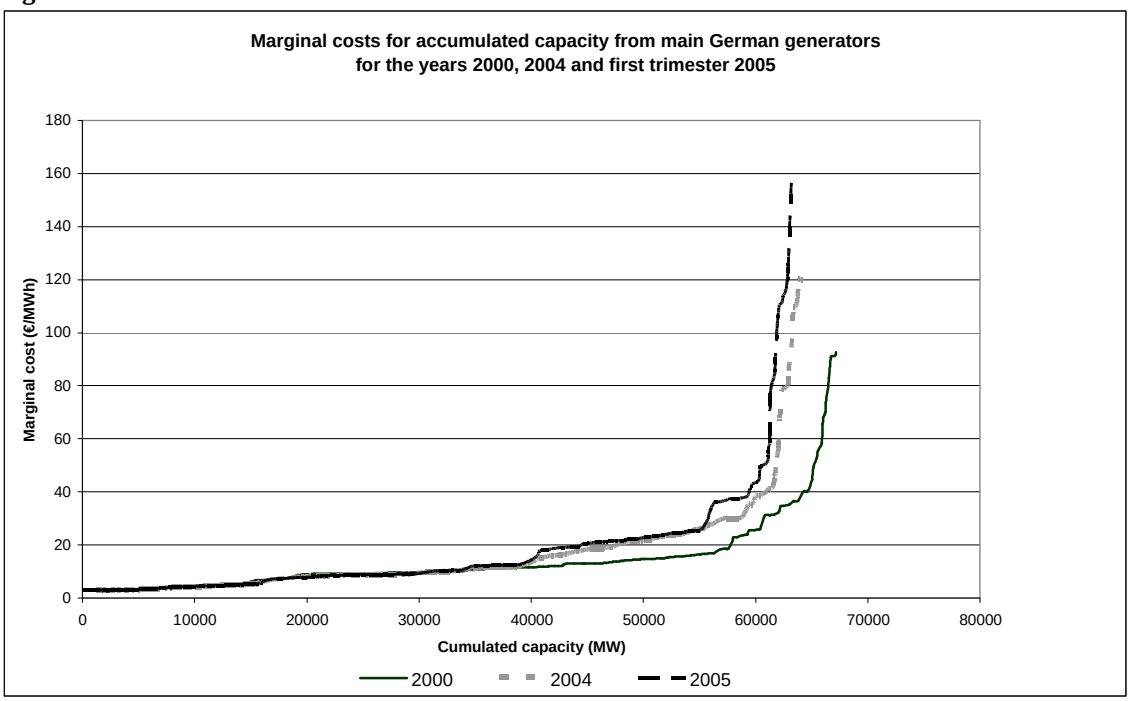




Source: Energy Sector Inquiry 2005/2006

Note: Some corrections have been made to the values of the marginal costs of certain plants to protect confidentiality, but it still gives a fair and representative picture of the actual situation.

Figure 50



Source: Energy Sector Inquiry 2005/2006

(418) As regards the shifts to the left of the merit curve over the years, the evolution of the portfolio of the main generators has been studied. It is interesting to note that the total generation capacity of the four main German generators decreased between 2000 and early 2005 by 4166MW (addition of 1350MW of capacity, and retirement of 5516MW of capacity). This is likely to have an adverse effect on the balance of supply and demand. Furthermore, out of all the plants which have been retired, most of the capacity retired (3753MW) had low variable costs. This had an impact on the merit curve. At the same time – according to Eurostat - there was an increase in overall demand in Germany from 2000 to 2004 of approximately 5.5%.

(419) Similar graphs have also been prepared for France. However these graphs cannot be reproduced as there is one main operator and the graphs would reveal its costs.

Conclusion

Customers have little trust in the functioning of wholesale markets. They suspect market manipulation on the spot and forward markets by large generators to be the main reason for recent price increases. However there are a number of other factors that might explain price increases that require further investigation.

Most wholesale markets have remained national in scope. The level of concentration in generation has remained high in most Member States giving generators scope for market power. The level of concentration in trading markets is less striking than in generation, particularly when analysing shares of operators on yearly forward products. The level of concentration on spot markets reflects more closely the level of concentration in generation, although at a lower level. When analysing who determines the clearing price at certain power exchanges it appears that there is scope to influence prices for operators in Italy, Spain and Denmark. The situation on the French, Dutch and German exchanges will be further assessed.

When analysing whether there is scope to withdraw physical capacity, it appears that load factors have increased over time in Germany suggesting higher efficiency levels and a tighter supply/demand balance. Significant generation capacity – most of it with low marginal costs – was retired in Germany despite slowly increasing demand. Also, certain plants with rather low marginal costs did not operate fully at all times. Further investigation is foreseen for the subsequent phase of the sector inquiry to disentangle the different reasons for price increases.

II.2. Vertical foreclosure and vertical integration[217]

(420) Vertically integrated electricity companies have traditionally been active in generation, network and retail activities. This chapter assesses the effects of this vertical integration. It starts with vertical integration of generation and retail activities and continues with vertical integration of network and supply activities. The sector inquiry confirms that both forms of vertical integration, whilst also bringing about certain economic benefits, have adverse effects for the liberalisation process. The magnitudes of these adverse effects are empirically assessed.

(421) Exclusive long term contracts may also result in vertical foreclosure. They have similar effects to vertical integration of generation and retail activities, as independent suppliers have (almost) no access to uncommitted generation and independent generators cannot supply electricity directly to the wholesale market. This will also be assessed.

II.2.1. Vertical integration between generation and retail activities

II.2.1.1. Introduction

(422) Vertical integration of generation and retail within the same group reduces, all other things being equal, the need to trade on wholesale markets. In turn, this can lead to a reduction of liquidity of wholesale markets. In a market without any vertically integrated companies, all electricity will necessarily be traded between generators and suppliers. In contrast, when all companies are vertically integrated, each vertically integrated group in the sector would meet (part of) its respective demand from final customers with own generation capacity and so would have less need to enter into wholesale transactions[218].

(423) Lack of liquidity can have many negative effects, such as: high volatility of prices, which increases costs for hedging (this can be an important barrier to entry) and a lack of trust that the exchange price reflects the overall supply and demand balance in the wholesale market (reduced reliability of the price signal).

(424) A lack of liquidity may also initiate a vicious circle by creating further incentives to vertical integration because operators do not want to rely on the wholesale market for their electricity supply. New entrants face higher risks when markets are volatile and consequently may not be able to match, at least not in the short run, market offers from their vertically integrated competitors and may only be able to attract capital at higher costs. Similarly, incentives to integrate vertically may result from balancing markets where the regime foresees an economic penalty for imbalances. In such cases, incentives for self-balancing (i.e. to vertically integrate) also exist. Thus, vertical integration limits exposure to volatile wholesale markets and balancing markets.

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217 The title was chosen in order to ensure consistency with the gas part. Contrary to gas the chapter mainly deals with vertical integration.

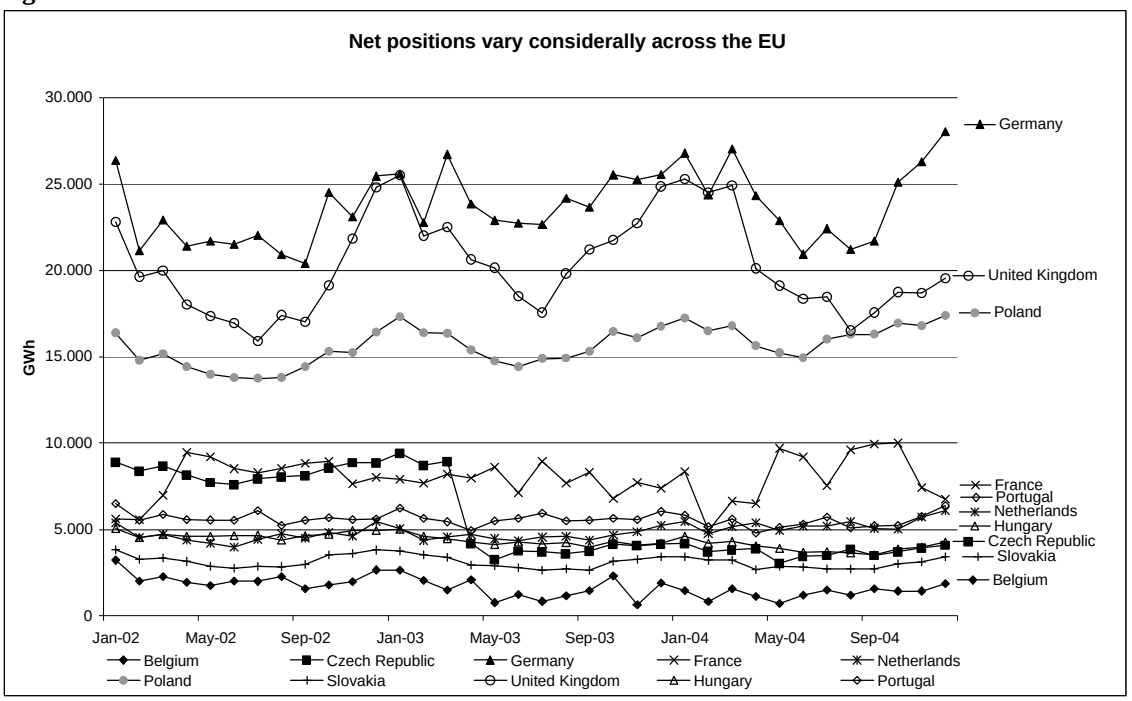
218 Vertically integrated companies continue to have incentives to trade on the wholesale markets, in particular to optimise their generation portfolios. A vertically integrated company that owns the generation capacity to produce all the electricity needed to cover its customers requirements will benefit from buying instead of producing electricity if the wholesale market electricity price is lower than the short run marginal cost of the last generation unit in the merit order of its own generation capacity.

(425) Cross-border entry in electricity markets is facilitated to an important degree if entrants do not have to enter as vertically-integrated companies acquiring simultaneously generation capacity and a customer port folio, but can choose to enter as a supply company or generation company. This reduces the risks and costs of entry. However, this is only possible if a liquid wholesale market exists. Liquid wholesale markets are therefore key for the erosion of incumbent's market power.

II.2.1.2. Comparison of net positions

(426) An undertaking can have a long or a short position, meaning that it, respectively, produces more electricity than is required to supply its retail customers or, less. In both cases a company will have to trade[219] in order to balance its position. The sum of long and short positions ("net positions") of all market participants represents the minimum amount of sale and purchase transactions that must be concluded in order for all short and long positions to clear.[220]

Figure 51



Source: Energy Sector Inquiry 2005/2006

(427) Figure 51 shows that the aggregated net positions vary significantly from Member State to Member State. At one extreme there is the German market with some 25 TWh/month of positions that need to be closed. At the other extreme there is Belgium, where this volume has been below 2 TWh/month for most of the period analysed. It must be noted

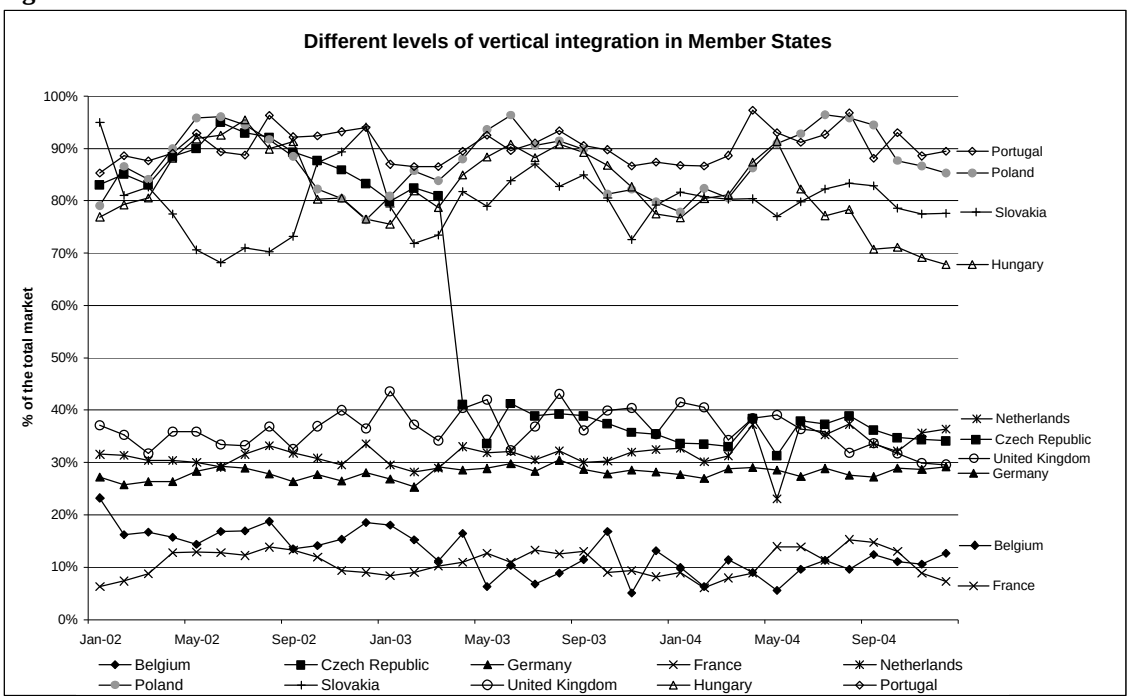
219 The analyses here cannot be directly translated to the manner in which contracts are traded (OTC, power exchange, bespoke bilateral contracts) or the time horizon over which contracts are traded (a given long or short position can be closed immediately before gate closure or any time before.)

220 The design of certain wholesale markets, in particular the Spanish organised market OMEL and to a lesser extent the Italian organised market, GME and Nord Pool result in vertically integrated companies trading all or part of the their generation output through the (organised) wholesale market only to purchase subsequently on the same market the amounts needed for their retail operations. For this reason, the analyses performed in this chapter are not pertinent for these market places.

that the existence of the French VPP programme contributes strongly to liquidity on the French market. Indeed, the auctioned 6000 MW capacity translates into about 3.5 GWh/month.

(428) To demonstrate the real extent of vertical integration between generation and retail per Member State, the figures on net positions have been compared with the total size of respective national markets (see Figure 52). The inquiry reveals that in countries such as the Czech Republic, Netherlands, Germany and United Kingdom, the positions that need to be cleared by trading electricity represents 25-40% of the market. In Belgium and France, this percentage is substantially lower.

Figure 52



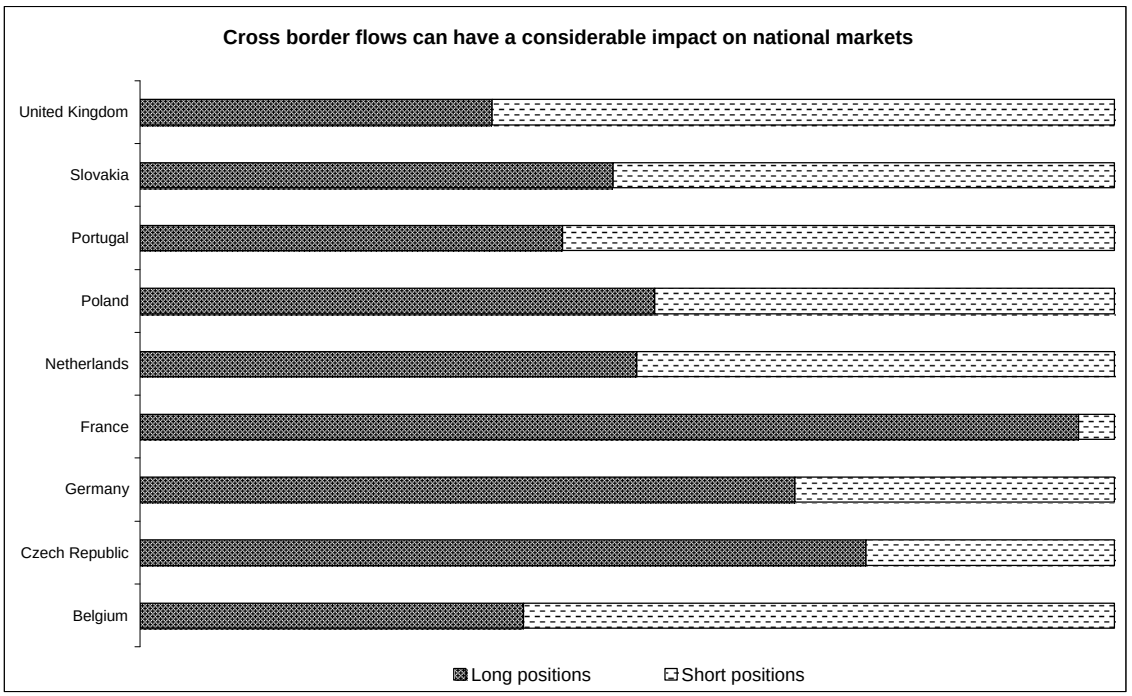
Source: Energy Sector Inquiry 2005/2006

(429) In Poland, the positions to be cleared by trading almost equal the total size of the Polish market, i.e. hardly any generators were selling to final customers. This is however primarily due to the Government's previous policy not to allow vertical integration. The same comment can be made as regards the markets in Hungary and Slovakia, where generation companies are, in general, not active at the retail level (for further comments on these markets see below). For Portugal, the picture is disturbed due to the existence of the single buyer at the wholesale level.

(430) In a closed system, where neither imports nor exports take place, one would expect to observe that the total amount of long positions equals the total amount of short positions. In a liberalised market with cross border flows this equilibrium no longer exists. However, undertakings in the exporting countries need to have overall larger positions because (a part of) this energy will flow to foreign customers. For the importing countries, the opposite is true. In many instances, this theoretical pattern is confirmed by the Figure 53. The pattern is visible in countries like France and the Czech Republic, which are large exporters, or Belgium, where substantial quantities of energy are sourced from abroad. On the other hand, some of the existing discrepancies in Figure 53 can be

explained by the fact that the Commission inquiry did not cover entities falling below certain thresholds.[221]

Figure 53



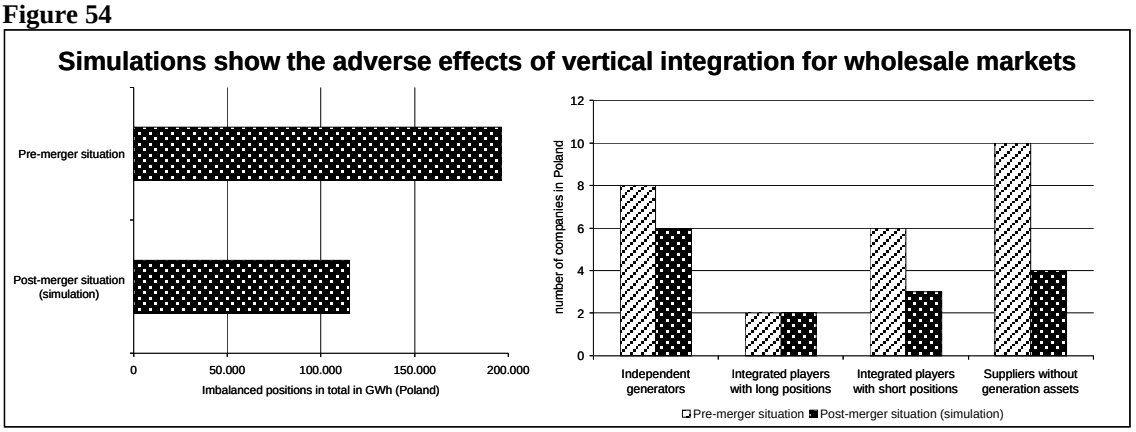
Source: Energy Sector Inquiry 2005/2006

(431) The impact of vertical integration on the net positions can be demonstrated by the Czech example. In 2003 the Czech incumbent, CEZ, acquired control over five of the seven retail companies active at the time. The integration of long (CEZ) and short positions (retail companies) within the same group led to a 40-50% drop in the net positions. On the other hand, the widely held belief by market participants that the drop in wholesale market liquidity in the United Kingdom is related to an increased vertical integration could not be confirmed by this analysis.

(432) The current discussion in Poland about the envisaged vertical integration is another interesting example. It shows that that the level of net positions would drop dramatically (40%) if the planned restructuring around the two largest groups active predominantly in generation goes ahead (see Figure 54).

[221] Suppliers with the annual sales to final customer below 1TWh were not obliged to reply to the questions relevant for this chapter. This in particular means that small retailers in countries like Germany (for instance, smaller 'Stadtwerke') or small independent generators from the UK are not included in the study.

Figure 54

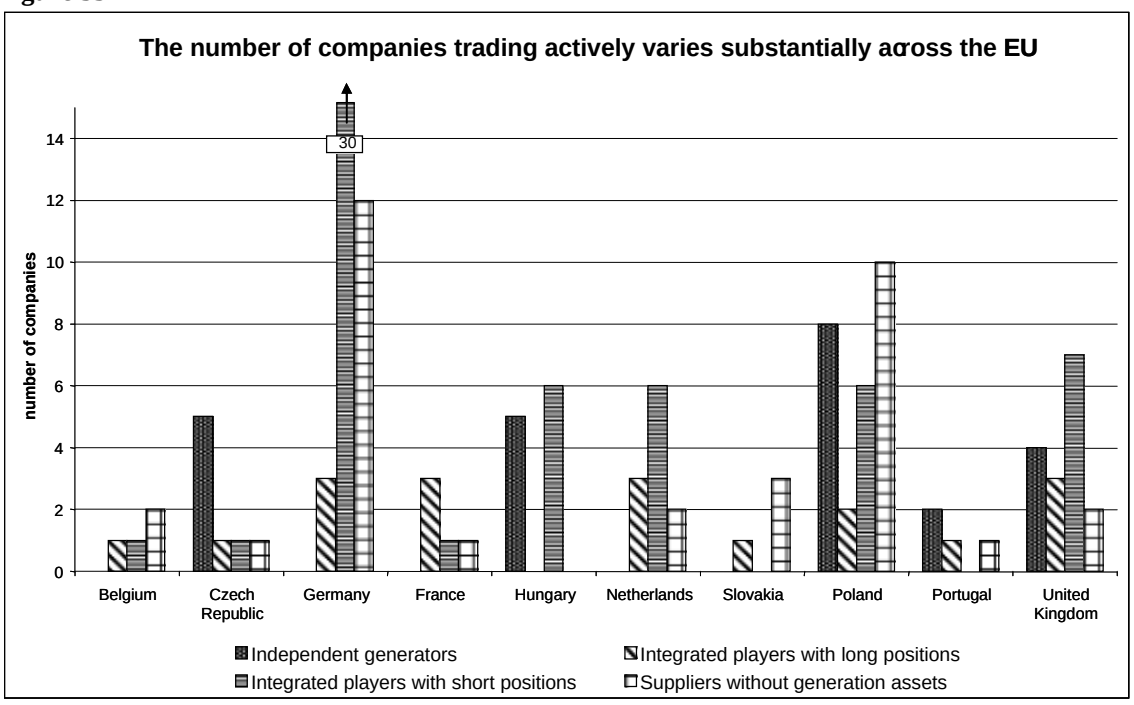


Source: Energy Sector Inquiry 2005/2006

II.2.1.3. Market participants

(433) Vertical integration not only reduces the overall volumes of net positions but may also have an impact on the number of actively trading companies and the size of long or short positions of the remaining active participants. This is important because, as a general rule, it can be said that the more actively trading players on the supply and demand side of the electricity wholesale market the more liquid the wholesale markets. Moreover, non-physical or financial players are, all other things being equal, more inclined to participate in markets with higher numbers of physical participants.

Figure 55



Source: Energy Sector Inquiry 2005/2006

(434) Figure 55[222] provides a first indication how entrants might evaluate the risks that they would be exposed to when entering a market by assessing the number of established generators and suppliers operating with short or long positions in the market. From Figure 55 it may be deduced that the situation in the UK is relatively favourable, whilst for Germany the situation is less advantageous for new suppliers, in particular due to the lack of independent generators.

(435) The likelihood that an undertaking has an interest in increasing electricity prices on spot markets also depends on whether it is long or short as a group. A group that is normally short has to source part of it own supplies from the electricity wholesale markets. Therefore, its generating branch has limited incentives to increase artificially wholesale prices as the company as a whole would not benefit from such a strategy. Figure 55 illustrates that, ultimately, the number of companies in a given market that may have incentives to raise prices above the competitive level is fairly limited[223].

(436) An even better indicator for new entrants to assess their risks when entering new markets is the "concentration levels" in net positions, in other words an analysis that not only takes into account the number of players that are short or long, but also the degree to which they are long or short. In this respect it goes without saying that a high degree of concentration in long positions is not a favourable condition for competitive wholesale markets. A high concentration in short positions is also not conducive to competitive markets although the impact of 'buying power' may be of less immediate concern from a pure competition point of view.

(437) For the purpose of calculating the concentration levels, indices based on sums of squares[224] have been calculated on total production and retail sales as well as the long and short positions of market participants. In almost all cases, the indices calculated on the basis of market positions have higher values than the respective indices calculated on the basis of generation or retail shares (see Figure 56). On the supply/long positions side, the most striking is the effect of this analysis in Belgium and Slovakia. It must also be noted that this analysis affects strongly the German situation. On the demand/short positions side of the market, the effects on the Czech, French, Dutch and Portuguese[225] markets stand out. Furthermore, it should be noted that due to the capacity auctioned under the VPP, the index calculated for long positions in France dropped considerably.

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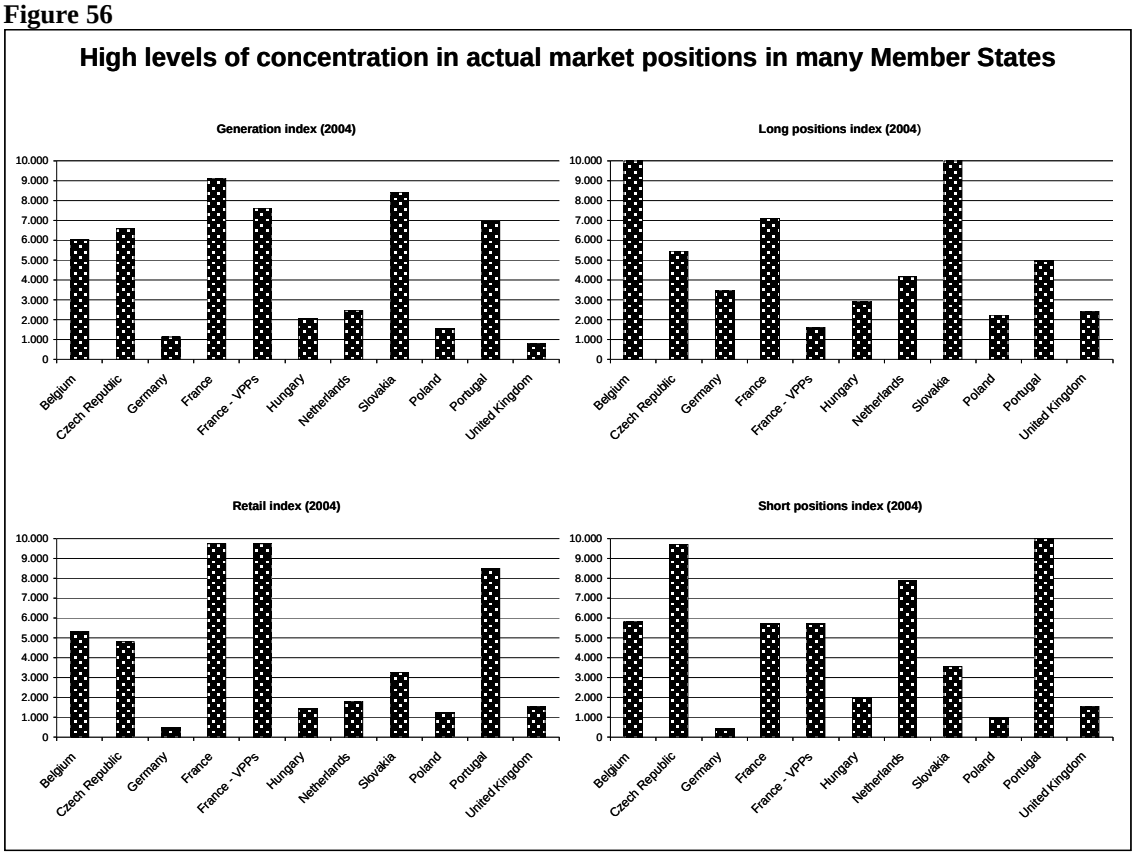
222 Figure 55 does not include suppliers with the annual sales (to final customers) below 1TWh and those of independent generators which have less than 250MW of capacity.

223 This observation depends on downstream contractual relations. The disincentive for vertical integrated companies to use market power in spot markets disappears if retail prices are largely dependent on short-term wholesale prices. However, although spot market indexed supply agreements exist, the sector inquiry shows that contracts with final customers normally have a fixed price. Moreover, no strong link between wholesale prices and those for final consumers can exist where retail prices for non-eligible customers remain regulated.

224 The mathematical algorithm used is the same as in the Herfindahl-Hirschman Index ('HHI index'). Indices have therefore the well-described mathematical properties of the HHI index and can take values from 0 to 10,000, where the latter value indicates that all "observations" are attributed to one source. The term 'HHI' has however been avoided in the main text as the indices are here used in a context where they are usually not applied. Moreover concentration and therefore the HHI index is not a very appropriate indicator for the electricity sector, where, for reasons explained elsewhere, market power can exists at lower levels of concentration then in other industries. Having said that, the figures presented here can certainly provide guidance about a Member State's relative position. For the use of HHIs in the context of competition law application, see the Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings, (OJ C 031 , 05/02/2004 p.5-8) which provide some guidance as to the meaning that can be attached the value of the index.

225 As regards Portugal, the present situation can be explained by the existence of the single buyer at the wholesale level.

Figure 56



Source: Energy Sector Inquiry 2005/2006

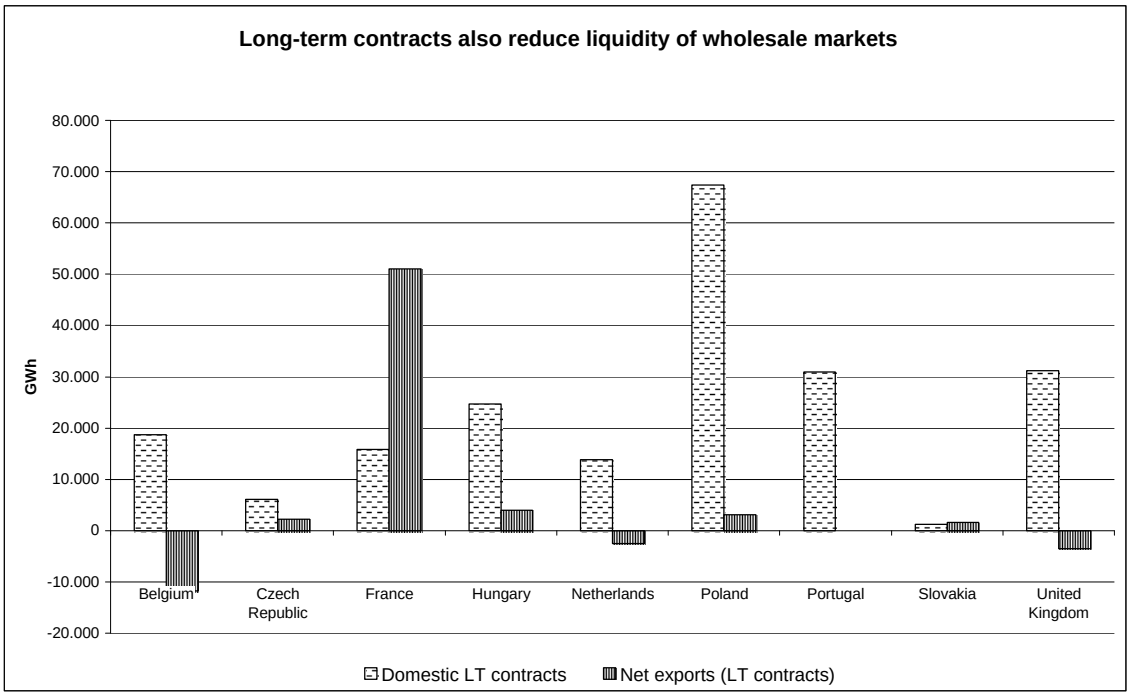
II.2.1.4. Long term power purchase agreements

(438) Long term power purchase agreements (PPAs) are another factor which may affect the volumes that are traded on a regular basis on wholesale markets. Clearly, electricity sold under longer term contracts[226] is also traded. But it has only a limited effect on the price formation process on electricity wholesale markets. In certain countries PPAs are believed to be among the main causes for the low volumes of electricity traded on the wholesale markets. The effects of such agreements were therefore analysed for a selection of countries (see Figure 57).

(439) First of all, it must be noted that not just the existence but also the nature of long term contracts plays a role here. Long term contracts between parties with opposite market positions in the same Member State will always reduce the amount of open long and short positions that need to be closed by wholesale market trading. Import and export contracts however will add or reduce the amount of electricity that is available for trading in a given Member State. Import contracts may therefore mitigate the effects of domestic contracts whereas long term export agreements may aggravate them. In the table below these distinctions are therefore analysed. In particular the Belgian and Dutch markets, considering their size, benefit from imports under long term contacts, mitigating the effects long term contracts may have on these countries. In France, the opposite is true.

226 For the purposes of this analysis, long term contracts were taken to mean contracts of a duration longer than three years and/or that are tacitly renewed.

Figure 57



Source: Energy Sector Inquiry 2005/2006

(440) In France the bulk of long-term contracts are export contracts, which further increased the impact of the domestic contracts. As such a large proportion of potentially traded volumes in France are apparently unavailable for the price formation process, the volumes auctioned under the VPP remain the only significant source of liquidity on this market.

(441) In Portugal, Rede Eléctrica Nacional ('REN') is the single buyer at the wholesale level. It purchases electricity mainly on the basis of long-term 'PPAs' signed with the domestic generators. This energy is sold to non-eligible clients connected predominantly to the distribution network of the EDP group. As long as the present situation prevails, the scope for wholesale trading in Portugal will remain very limited.

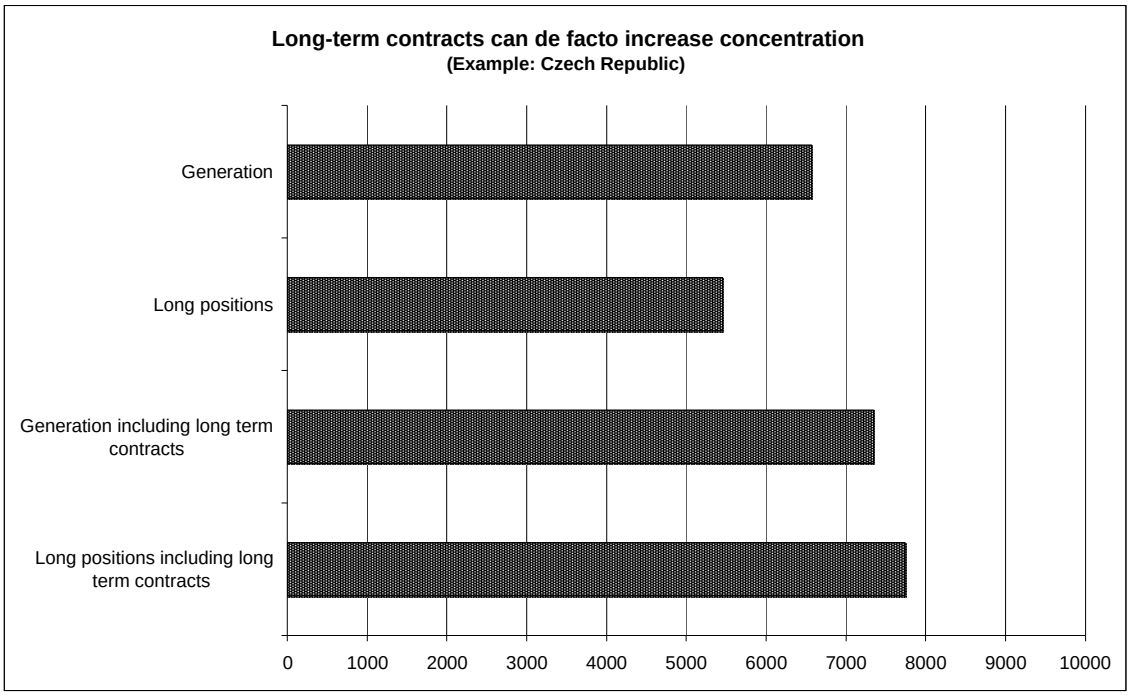
(442) In Poland, the long-term arrangements have predominantly a domestic character. A large number of long-term contracts exist, which were signed mainly in the 1990s between generators and the former national incumbent company, Polskie Sieci Energetyczne ('PSE'). PSE resells this energy to the local distribution companies, who are under obligation to buy each year from PSE a certain percentage of their own sales to non-eligible customers. The fact that power is sold on a long term basis to the incumbent downstream operators means that the relatively favourable picture drawn above as regards volumes available for wholesale trading must be qualified. Even if the degree of vertical integration in Poland stays for the time being very low, 'PPAs' restrict severely the volume of electricity that contributes to the price formation process. Hence, they may well constitute a significant barrier to the development of the Polish wholesale market, even if the currently discussed vertical integration should be abandoned.

(443) A similar situation exists in Hungary, where Magyar Villamos M•vek ('MVM') is the public utility wholesaler and acquires electricity by means of long-term PPAs that is subsequently sold to the local retailers. The Hungarian PPAs cover the vast majority of the country's electricity needs (see Figure 57), which may have effects on wholesale

trading similar to, or even going further than, those described above in the context of the Polish wholesale market.

(444) Potentially traded volumes appear to be less affected by the long-term contracts signed in countries like the Czech Republic or United Kingdom. However, in the former case, such a conclusion may be partly misleading. The Czech PPAs were concluded between the vertically integrated incumbent and independent generators, and their impact was further upstream. Consequently, although these contracts do not immediately affect the volume of electricity that needs to be traded they do affect the number and degree of parties with long positions and add to the already high degree of concentration at the generation level, as is shown by Figure 58.

Figure 58



Source: Energy Sector Inquiry 2005/2006

II.2.2. Vertical integration between supply and network activities

(445) Effective access to the existing network is considered indispensable for competition to develop. This is due to the fact that the network generally constitutes a natural monopoly, that is uneconomic to duplicate.

(446) A company active in electricity generation or supply that also owns transmission or distribution network assets may, however, have an economic interest in using its monopoly position as network owner to prevent or hinder competition in other areas of the value chain. This can happen in many ways such as: raising rivals' costs, price squeezes, withholding essential information and by providing the information only to affiliated companies. All of these practices distort a level playing field.

(447) It is to limit the risk of such behaviour from occurring that the Electricity Directive contains unbundling rules for transmission and distribution networks. The transmission system operator ('TSO') must be independent at least in terms of its legal form,

organisation, and decision making from other activities not relating to transmission. For distribution system operators ('DSO') the rules are similar. However, Member States are not obliged to implement fully the unbundling rules until July 2007. They can also decide not to impose unbundling on distribution companies that have less than 100.000 customers. Unbundling requirements for gas and electricity companies are essentially the same. To avoid repetition, reference is therefore made to the Chapter on vertical foreclosure in the gas part for a more detailed description of what fully implementing the rules entails.

(448) As regards TSOs most Member States have by now implemented the Electricity Directive's requirements for unbundling. Approximately half of them have gone further than the legal obligations and implemented forms of ownership unbundling. As regards distribution system operators, compliance is less advanced[227]. It is true that Member States only have to comply fully with the unbundling requirement for DSOs by 2007. However, a significant number of Member States still have not introduced accounting and management unbundling. Management unbundling was supposed to be implemented by 1 July 2004 whereas accounting unbundling was already required by the first electricity directive of 1996 and had to be implemented by 19 August 1999 by most Member States[228].

(449) It is interesting to note that the conduct discussed in more detail below concerns without exception TSOs and DSOs that have, even if unbundled in accordance with the legal requirements, remained part of a vertically integrated company. Indeed, unbundling measures may render discriminatory practises in the exploitation of the network monopoly more difficult, but do not eliminate the incentives for vertically integrated companies to engage in such conduct. The experiences of full ownership unbundling suggest that it significantly changes the behaviour of the network undertaking: fully unbundled Transmission System Operators ('TSOs') and Distribution System Operators ('DSOs') will focus on optimising the use of the networks.

II.2.2.1. Vertical integration between generation and the transmission network

(450) Article 20 of the Second Electricity Directive lays down the requirements for non-discriminatory access to networks at regulated tariffs. Refusal of access is only possible in case of capacity constraints and must be duly substantiated. Two types of access refusal can be distinguished. Access for potential generators which want to inject their electricity into the grid and access by supply companies, which want to use the net to supply customers.

(451) The first phase of the sector inquiry focussed primarily on the most blatant forms of refusal of network access. Various categories of respondents were requested to report on applications for network access and their treatment. For this report, which deals primarily with wholesale markets, the main focus was grid access for generators. However the report also looked into concerns raised by supply companies (see below).

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227 Source: Communication from the Commission to the Council and the European Parliament: 2005 Report on the Implementation of the Gas and Electricity Internal Market

228 See Art. 27 of Directive 96/92/EC of the European Parliament and of the Council of 19 December 1996 concerning common rules for the internal market in electricity. (OJ L 027 30/01/1997 p. 20, - 29).

(452) The actual number of network access applications by owners of new generation assets was relatively low during the period investigated, (2000 to 2005). In fact, during this period only few investment projects in generation capacity were undertaken and so only a few applications for network access. With this qualification, it is fair to say that blatant refusals for access to networks are apparently rare. This does not mean however that the access to networks is unproblematic. Indeed, a number of respondents reported practises that hindered network access in various ways.

(453) In this respect it is important to underline that network operators can only refuse access to their networks if no or insufficient capacity exists. However, despite the legal obligation to motivate such refusals, the existence, location, and degree of congestion is often not transparent. Respondents in Belgium, Ireland, and Germany claimed that it was impossible to verify whether and to what extent the congestion that was claimed to exist by the network operator was real.

(454) When constraints exist in the network, applicants can often only be connected if they are ready to compensate the network operator for the costs of reinforcing the net, measures that have allegedly be introduced by certain vertically integrated TSOs. Costs for reinforcing networks can be substantial when compared with the overall investment in generation capacity and may render the project uneconomic.

(455) Evidently, a lack of transparency as regards network constraints combined with the obligation on applicants to contribute to network reinforcement creates considerable leeway for vertically integrated companies to raise their rivals costs for bringing new capacity online or even to make this *de facto* impossible without an outright refusal of network access. In principle it is a task of national regulatory and competition authorities to address these issues.

(456) Nonetheless the Sector Inquiry confirmed that in a Benelux country a project to build generation capacity was abandoned solely because compensations to remedy capacity constraints rendered the project uneconomic. Allegedly, no insight was however provided by the TSO as to the causes of this congestion. The generation branch of the TSO was competing with the applicant on the same project. Similar allegations have been made against a German TSO as well as a regional network operator.

(457) Often the works related to building new network connections can only be undertaken by the network operator itself. Evidently, a vertically integrated network operator has no incentive to make attractive offers for building network extensions and reinforcements that will serve its competitors. Indeed, concrete examples from Ireland suggest that costs for network connections by the network operators were significantly, (between 17 and 51%) higher than to earlier connection offers or offers to execute the building works made by third companies. Repeatedly respondents made calls for rendering the building of network extensions and reinforcements contestable, i.e. providing the applicant for a network connection with a choice to contract construction work with a third party. A network operator's ability to raise costs for its rivals would then be curtailed by the existence of competing bids[229].

[229] Experience in the UK has shown that, in order for this to function properly, arrangements have to be made to ensure that DSO's provides technical information concerning the point of connection (needed to design the network extensions) and design approvals in a non-discriminatory manner. (See for instance, SP Manweb – Decision to accept

(458) Supply companies also complained about problems with respect to access to transmission networks. They mentioned in particular problem relating to interconnectors and the provision of information (as described in more detail below in the chapters concerning market integration and transparency). Concerns were also raised with respect to allegedly excessive access tariffs, which would raise competitors cost, but the regulatory oversight foreseen in the Second Electricity Directive should help addressing these concerns. Finally reference is made to the issues set out in the next section dealing with the distribution networks. The issues raised there apply *mutatis mutandis* to transmission networks.

II.2.2.2. Vertical integration between supply and distribution system network

(459) In the framework of the Sector Inquiry, DSOs provided information on the new connections to their networks during 2004 and, among these, the percentage of connections that concluded a supply contract for electricity with any of the supply companies that were affiliated to the DSO. The interest of looking at new connections lies in the fact that these customers are probably least affected by switching costs and, therefore, represent those most likely to switch electricity supplier.

Table 22

Even new customers conclude supply contracts with the supply branch of the DSO	
% of new connections contracting with a supply company affiliated to the DSO	**Member State**
97,5% - 100%	France, Poland, Slovakia, Luxembourg, Greece, Ireland, Estonia
95% - 97,5%	Austria, Germany, Spain
90% - 95%	Italy
< 90%	Netherlands, United Kingdom

Source: Energy Sector Inquiry 2005/2006
Note: The figures in this table cannot be compared with those published in Commission Communication of progress in creating the internal gas and electricity market, COM (2005) 568 and technical annex (SEC(2005) 1445) as the latter are cumulative and use different customer categories.

(460) Even if the figures in Table 22 should be taken with some caution, it is clear that among those end-consumers able easily to choose another supplier, the vast majority conclude contracts with a supply company affiliated to the DSO to whose network the customer is connected. Clearly, even in this category, rates are very low in most Member States. Only in the UK, and to a lesser extent, the Netherlands, do customers choose suppliers unaffiliated to the DSO to which it is connected.

(461) Low switching rates can be due to various factors. Indeed, in the chapter on prices below it will be discussed how the co-existence of regulated tariffs with market based prices may eliminate probably the most important incentive to switch supplier: price. The low rates reported here for France may well be attributed to this factor. Here it is emphasised that in view of these low switching rates, any barrier, even those that do not immediately

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the Gas and Electricity Markets Authority to accept commitments pursuant to section 31A(2) of the Competition Act 1998 of 27 October 2005.

appear to be significant, may nonetheless have significant effects on an entrants' ability to acquire customers. It is therefore very important that switching procedures work properly and do not impose barriers to customer switching.

(462) In a number of Member States, however, substantial problems have been reported with respect to the exchange of customer data needed for switching. In particular, information needed for connection and billing purposes was not provided within the statutory deadlines or not at all, or was simply wrong in a significant number of cases. Such problems have been reported for many countries, including Finland, Spain, Italy, the Netherlands, Belgium, and Germany. Such problems may be inevitable to a certain degree during a transition to liberalised markets, especially in the mass market segments. However, these problems appear to remain as yet unresolved in Belgium and Germany.

(463) Many German respondents reported very heavy administrative procedures, information exchange protocols and payment conditions, so onerous in certain cases that they appear designed to increase switching costs. In Germany, procedures of a voluntary nature existed that were claimed to be inadequate and, in addition, widely disregarded by DSOs. The legislation that was recently adopted in Germany provides powers to the German energy regulator to impose data exchange procedures and protocols. Negotiations are currently underway to finalise a number of procedures and protocols that should improve this unsatisfactory situation. The German regulator intents to render these procedures and protocols obligatory by formal decision for all market participants.

(464) Even if rules exist, however, they may not be sufficient. Most Member States have legislation on, for instance, the maximum duration of switching procedures and the respective responsibilities of parties. Such rules also exist in Belgium. However, contractual relationships are geared towards the interest of the network monopolies in ways that effectively render non-compliance without any consequences for DSO and shift the associated costs and risks to suppliers. As a result, even if statutory rules exist, much metering data in Belgium is still communicated later than the statutory deadlines or is wrong. Many Belgian respondents complain and have substantiated that for a significant number of connection points no metering data is received before the statutory deadline. The Flemish regulator now seeks to extend the liability for the DSO by introducing a flat rate financial compensation to suppliers if statutory deadlines are not respected.

(465) Respondents have also expressed significant concerns about discriminatory conduct in switching procedures. In Belgium and Germany, but also Finland and Austria, there are allegations about preferential information for affiliated supply companies. Repeatedly, respondents complain that affiliated supply companies approach customers with improved offers when their intention to switch is reported to the network branch. Examples have been provided where companies appear to have deliberately withheld historical consumption data to companies competing with their supply affiliates. In Belgium, DSOs representing approximately 80% of all connections have subcontracted operational matters to a subsidiary of the incumbent. The latter manages these operations on the same IT systems that are used by its supply affiliate which therefore has privileged access to information on the customers of its competitors. Over 2006 some structural improvements are expected. Information advantages can also be abused in other ways. Late or even no announcements of changes on network charges to competing suppliers also unduly increase administrative costs and commercial risks for competitors. Such practices have been reported in Belgium and Germany.

(466) German, Polish and Czech respondents also report cases where network related charges were increased when a customer switched or where, which amounts to the same, customers were not invoiced the entire network charges due as long as the customer was supplied by the supply company affiliated to the DSO.

(467) German and Portuguese respondents mention practises rendering it difficult if not impossible for customers that are new to the network to be supplied by parties other than the supply company affiliated to the DSO. These practices may be particularly harmful as they concern customer that may be more easily acquired by entrants.

(468) Inadequate unbundling also maintains the incentives for vertically integrated companies to raise costs for competitors. Respondents have provided detailed information on a very substantial number of German distribution network companies that are said to cross-subsidise supply activities with revenues from (monopoly) network charges. The German regulator recently acquired powers to set appropriate network tariffs which may remedy this situation.

(469) The fact that of the approximately 150 supply companies that entered the German market when customers became eligible in 1999, only a handful have survived until now was attributed by a market participant to the damaging impact of the various practices on the German market reported above.

(470) In more general terms it can be said that unbundling measures may render discriminatory practices in the exploitation of the network monopoly more difficult, but do not eliminate the incentives for vertically integrated companies to favour the affiliated supply branch in network issues. Indeed, it must be noted that the conduct described above concerns without exception TSOs and DSOs that have remained part of a vertically integrated company. Moreover, it regularly concerns DSOs and TSOs that are already unbundled in accordance with the requirements in the Electricity directive[230].

(471) Respondents to the questionnaires therefore often argued that changing DSO's and TSO's incentive structures by introducing ownership unbundling would be the preferred solution to address the issues. A number of respondents from Belgium (where vertically integrated and ownership unbundled DSOs coexist) for instance substantiated that the DSOs that are ownership unbundled perform significantly better in facilitating competition[231] than those that are still part of a vertically integrated company.

[230] Two of the three TSOs referred to are unbundled in accordance with the Second Electricity Directive. Six out of the ten Member States from which allegedly unfair conduct by DSOs was reported have already completely transposed the unbundling requirements for DSOs.

[231] Belgium is transposition of the Second electricity Directive has not postponed the implementation of legal unbundling for DSOs until 2007. Similarly Belgium did not make use of the 100.000 connections threshold to exempt smaller DSOs from the unbundling requirements. For more details see : Newbury (2005) Electricity Liberalisation in Britain: The quest for a satisfactory wholesale market design. The Energy European Special Issue, IAEE, 2005.

Conclusions

Vertical integration of generation and retail reduces the incentives to trade on wholesale markets. This might lead to a drying up of wholesale markets. Illiquid wholesale markets are a barrier to entry as they are characterised by higher price volatility. Volatile wholesale markets might oblige new entrants to enter as a vertically integrated generator and supplier, which is more difficult.

The degree of vertical integration between generation and retail differs significantly between Member State. In most Member States there are few companies with long positions leading to high "levels of concentration". VPPs (auction of electricity) assist in some Member States (e.g. France) to improve the level of concentration. Long term power purchase agreements (PPAs) have similar effects to vertical integration.

According to respondents', vertical integration of supply and network (transmission and distribution alike) reduces the economic incentives for the network operator to grant third parties access. In the views of many respondents the existing rules on legal unbundling do not ensure that vertically integrated companies do not engage in practices favoring their supply affiliates to the detriment of their competitors.

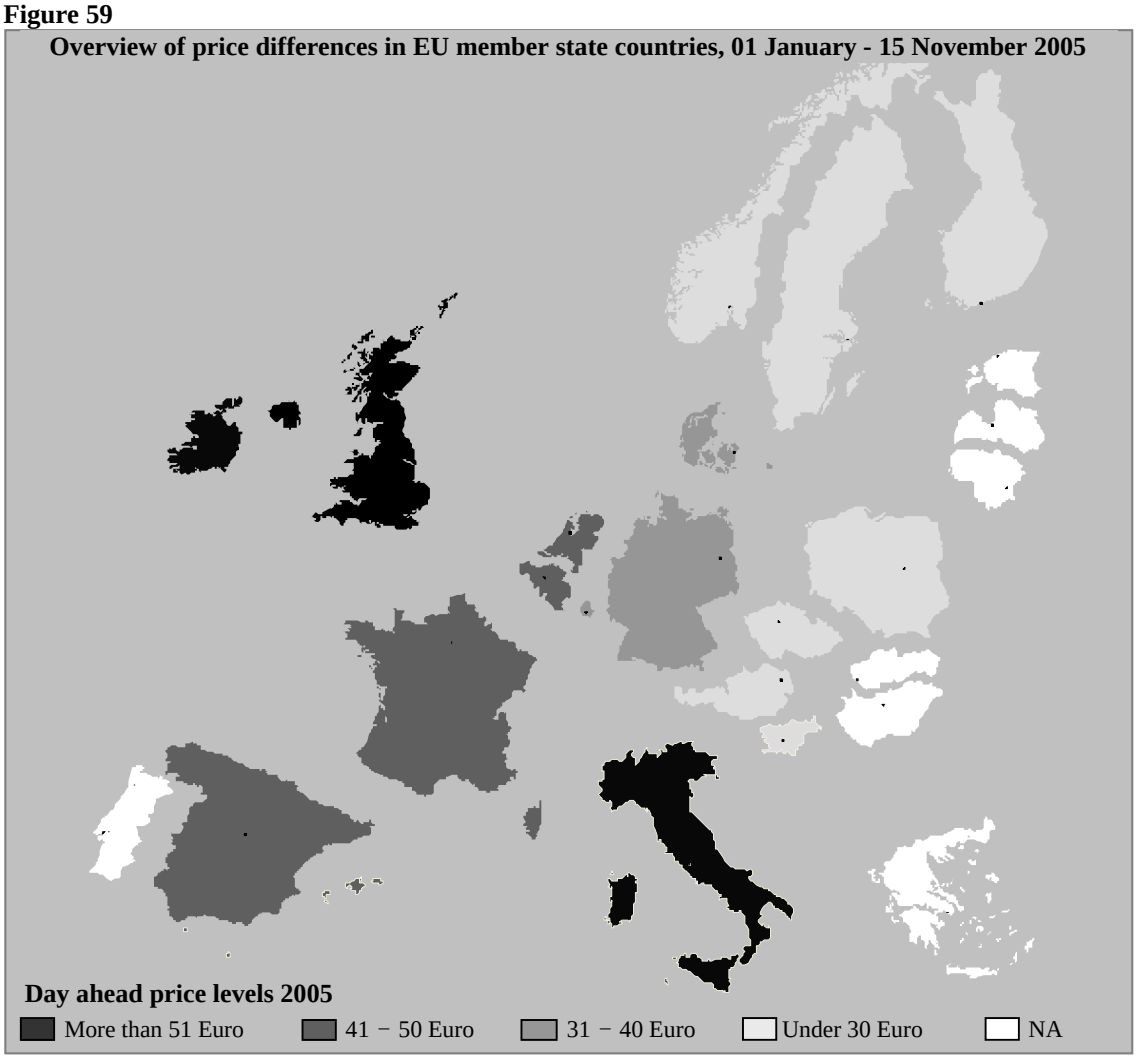
With respect to transmission networks, a number of respondents complained about significant costs to connect new power plants to the network. No means exists to verify whether claims of congestion or costs for network reinforcements are valid. With respect to the distribution networks, respondents reported amongst other things inappropriate switching procedures, a lack of Chinese walls between network and supply branches and discriminatory access tariffs.

II.3. Market integration

II.3.1. Introduction

(472) Interconnectors are essential for market integration. Through interconnectors generators and suppliers on both sides of the border are exposed to competition. Imports should drive prices down to the level of the minimum required cost to serve the required electricity in all EU Member States. However, today prices differ substantially between geographical region in the EU. This is illustrated in Figure 59.

Figure 59



Source: platts, Power exchanges.

(473) Imports should also play a role in eroding the market shares of major generation companies in wholesale electricity markets. However, in most Member States the incumbent's market shares have remained high. The need for imports is even more important knowing that market entry by new players who started supply or generation activities in countries in which they were previously not present was hardly observed in EU Member States during the liberalisation.

(474) The Sector Inquiry leads to the preliminary findings that the lack of electricity market integration[232] mainly results from:

- insufficient interconnecting infrastructure between national electricity systems,
- insufficient incentives to improve cross border infrastructure,
- inefficient allocation of existing capacities, and
- incompatible market design (e.g. differences between balancing regimes, nomination procedures, differences in opening hours of power exchanges) between TSOs and/or spot market operators.

II.3.2. Institutional setting

(475) Before liberalisation, integrated companies, who where responsible for supply of customers and their electricity grids, decided to connect their grids through cross border links (interconnectors) in order to be able to assist one another in case of temporary shortages caused by unexpected high demand or generation outages. For continental Europe the UCTE-synchronous[233] area includes 22 countries (also non-EU members). Another synchronous zone is the NORDEL area in Scandinavia. Additional so-called DC-links (direct current-links) connect (other) grids further.

(476) Today the role of interconnectors has changed significantly. In many Member States participants can access interconnector capacity in order to trade on wholesale markets and hence potentially benefit from price differentials between regions. In order to facilitate the use of cross border capacity by participants several procedures have been introduced. This topic will be examined later.

(477) The load pattern in the EU integrated synchronized network results from production and consumption locations, and net topology. Transactions made by generators, traders, suppliers and consumers result in electricity transports from one region to another. Due to the characteristics of electricity (explained earlier) demand and supply have to be balanced at all times. Introduction of a set of administrative rules, most importantly requesting players in the market to report in advance which (contractual) transactions they want to carry out, should enable the TSOs to manage commercial transactions and physical flows in a secure manner in the high voltage grids.

(478) The TSOs' main task is to provide a secure and stable grid facilitating the integrated electricity market. This includes activities to balance the equilibrium between supply and demand in their so-called control area and between control areas of other TSOs. Ensuring that the TSOs perform their work at minimum cost is commonly the task of regulators who are part of the institutional setting in the EU. Clearly, any change in the (administrative) rules may alter the extent to which cross border trade in the EU is possible.

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232 At this stage cross border market power issues have not yet been assessed.

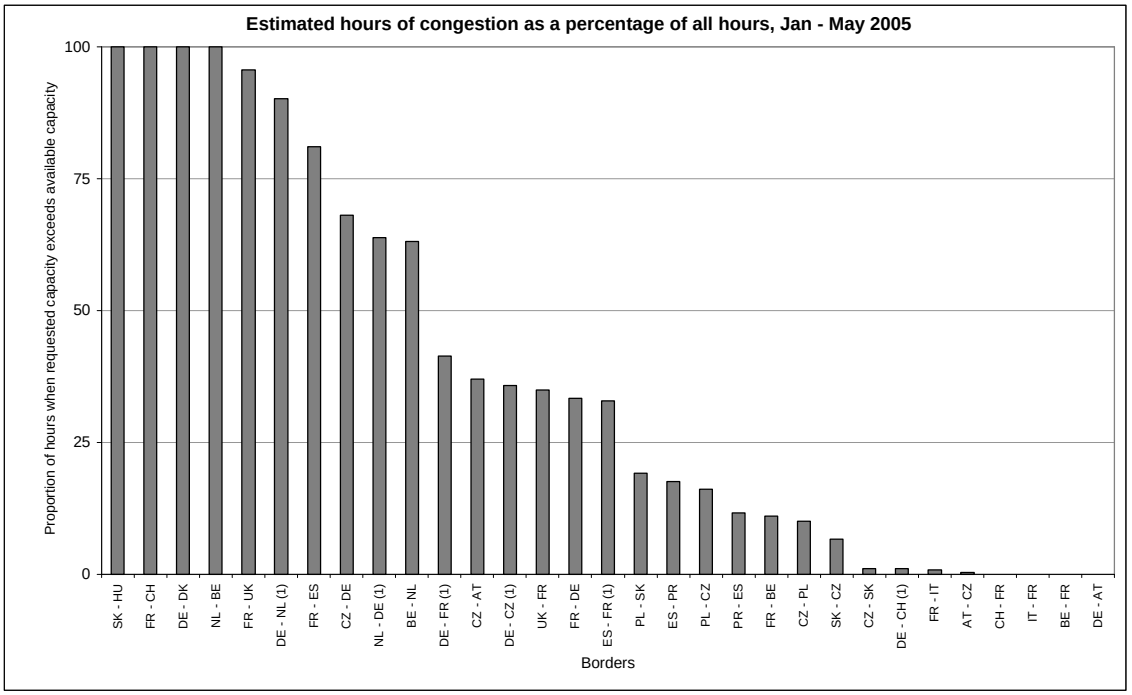
233 Synchronous meaning that all members of UCTE work on the same 50 Hz frequency.

II.3.3. Insufficient interconnecting infrastructure

(479) Since the liberalisation of the electricity markets the need for interconnector capacity has increased substantially. This is of particular importance for players who have entered other markets and become active in cross border trade. Their arbitrage activities constitute buying (in low price regions) and selling (in high price regions) of electricity in different markets. As a result they shifted the traditional generation pattern in the grid. Moreover the generation pattern was also changed due to investments in generation technologies such as wind power. This injects more variable power flows into the grid compared to for instance a coal fired power plant - caused by changes of the wind speed (possibly reducing available cross border capacities). More interconnection is needed to facilitate companies extending their activates into other regions outside their traditional areas in order to increase competition.

(480) Demand for interconnector capacity at many borders increased and often exceeds the available transmission capacity. This congestion is illustrated in the subsequent Figure 1 per border. The bars show number of hours (sorted in ascending order) per border reported by TSOs when capacity requested exceeded the available capacity as a percentage of all hours in the period January – May 2005. This situation can be independent from the physical flows in the grid. The bars represent a specific direction.

Figure 60



Source: Energy Sector Inquiry 2005/2006.
Note: Most TSOs reported congestion per interconnector, but some TSOs reported congestion aggregated over several interconnectors between adjacent markets. In some cases the reported data deviate per border between TSOs. This means that the involved TSOs do not have a common clear statement whether the requested capacity exceeded the available capacities or not. This suggests that the approach to capacity allocation is not sufficiently coordinated and needs improvement. (1) Refers to an average of more than one interconnector between two adjacent borders.

(481) Figure 60 reveals that almost all borders are congested to some degree, except a small number of borders such as e.g. IT to FR, BE to FR and DE to AT. Congestion depends of

course on the direction since there is a clear incentive for traders to deliver electricity from low to high price regions. Some borders are congested in all hours during the first five months of 2005. Examples are the interconnectors from SK to HU, DE to DK, NL to BE and FR to CH.

(482) Congestion has increased on most borders. Table 23 compares the percentage of congested hours in the first five months in 2004 with 2005. Congestion increased on almost 60 percent of the listed borders. The cause of increasing congestion has to be further studied. It is likely that persistent price differences between Member States markets cause congestions. The relative marginal costs e.g. from CO2 emissions might also reduce congestion and unforeseen changes in wind speed cause unforeseen flows that might reduce the capacity available and increase congestion.

(483) At some borders the increase of congestion has been dramatic. For instance, from the Germany to France congestion has increased from almost 0% in January 2004 to 100% in the month May 2005. Figure 61 shows this development of congestion per month between January 2003 and May 2005. Further investigation is required to explain the differences in the level of congestion between the period before and after January 2005.

(484) The consequence of the substantial and increasing congestions on interconnectors between Member States is that many electricity markets are separated from each other. As a result imports are limited and their ability to counter market concentration in national markets and exert competitive pressure on (dominant) generators is reduced and consumers pay more for their electricity than strictly necessary.

(485) The questions that arise from the above are:

- Is existing interconnector capacity used efficiently?
- Are incentives to invest in new interconnector capacity set properly and what are other obstacles to increasing interconnection capacities?

II.3.4. Level of interconnector capacity

(486) Investing in the expansion of interconnector capacity is one way to lower congestion on the borders between Member States. At present the level of interconnectors as a percentage of installed capacity is listed in Table 24.

(487) The Barcelona Council 2002 set a target for (import) interconnector capacity of at least 10% of production capacity per Member State by 2005. Using the Sector Inquiry data the current percentages for some MS have been calculated. The results (average 2004 NTC value as a percentage of installed generation capacity) are shown in Table 24. It confirms earlier reporting by the Commission that several countries, such as Italy, Portugal, Spain, Ireland and UK, do not meet the 10% threshold. However, meeting the "Barcelona" target does not necessarily result in resolving congestion and concentration in generation. For instance, the Dutch interconnector remains congested though the import capacity is 17%. Neither does this target resolve concentration in generation. For instance, in Denmark which has a relatively high level of interconnection still has, high levels of concentration in generation and scope for the exercise of market power as shown in the chapter Concentration and Market Power.

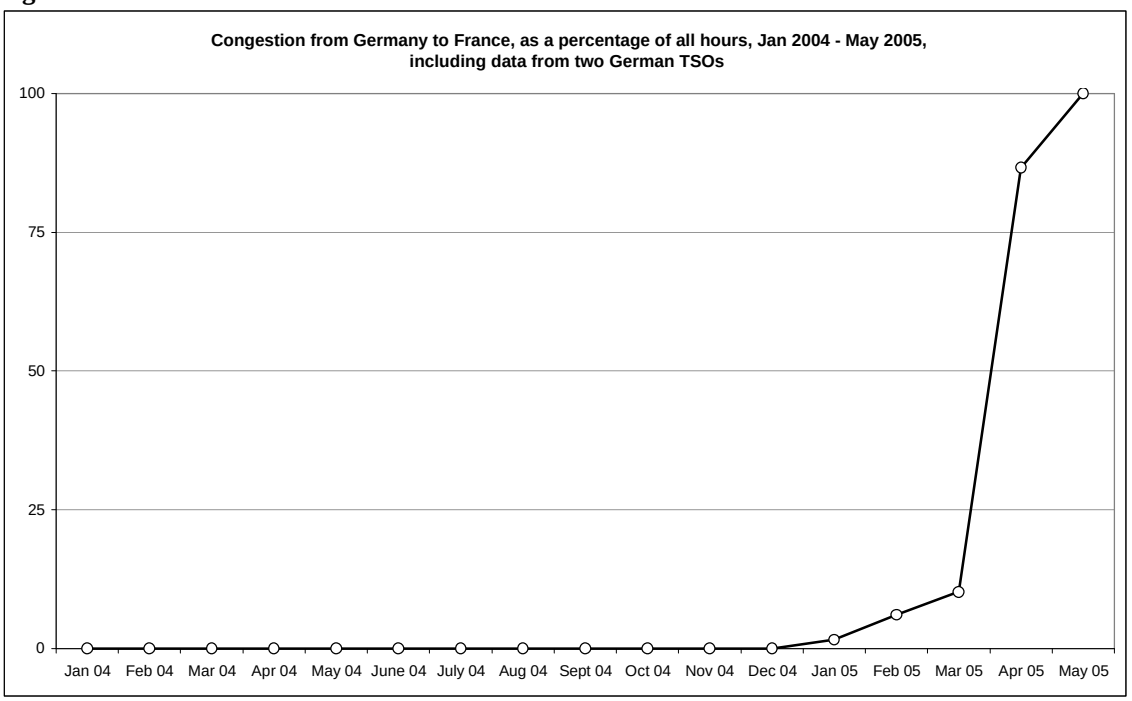
Table 23

Hours with congestion as a percentage of all hours (selection of borders)		
Border	**2004** Jan-May	**2005** Jan-May
SK --> HU	100,0	100,0
FR --> CH	100,0	100,0
DE --> DK	99,3	100,0
NL --> BE	96,4	100,0
FR --> UK	94,6	95,6
DE --> NL (1)	87,9	90,1
FR --> ES	34,6	81,1
CZ --> DE	69,2	68,0
NL --> DE (1)	62,9	63,9
BE --> NL	63,3	63,1
DE --> FR (1)	0,0	41,3
CZ --> AT	0,0	37,0
DE --> CZ (1)	30,0	35,7
UK --> FR	31,5	35,0
FR --> DE	48,4	33,3
ES --> FR (1)	30,0	32,8
PL --> SK	0,0	19,1
ES --> PR	7,8	17,5
PL --> CZ	15,8	16,1
PR --> ES	26,7	11,7
FR --> BE	30,4	11,0
CZ --> PL	0,2	10,1
SK --> CZ	1,4	6,6
CZ --> SK	2,1	1,1
DE --> CH (1)	0,0	1,0
FR --> IT	0,7	0,8
AT --> CZ	0,0	0,3
CH --> FR	0,0	0,0
IT --> FR	0,0	0,0
BE --> FR	0,0	0,0
DE --> AT	0,0	0,0

Source: Energy Sector Inquiry 2005/2006.

Note: Hours when requested capacity exceeded available cross border capacity as a percentage of all hours. The arrows indicate the direction per border, in some cases reported by different TSOs. (1) Refers to an average of more than one interconnector between two adjacent borders.

Figure 61



Source: Energy Sector Inquiry 2005/2006.

(488) Availability interconnector capacity is related to the performance of TSOs who are responsible for system integrity in their control area and hence calculating the NTC (Net Transport Capacity) for import and export. Figure 62 illustrates that the values have remained almost unchanged over the last 30 months. The movements of the curve relate to summer and winter periods. NTC values may also change as a result of production factors such as changes in wind speed, outages and (unforeseen) maintenance of power plants or internal grid outages. In addition consumption factors, such as changes in demand, may affect the level of NTC values.

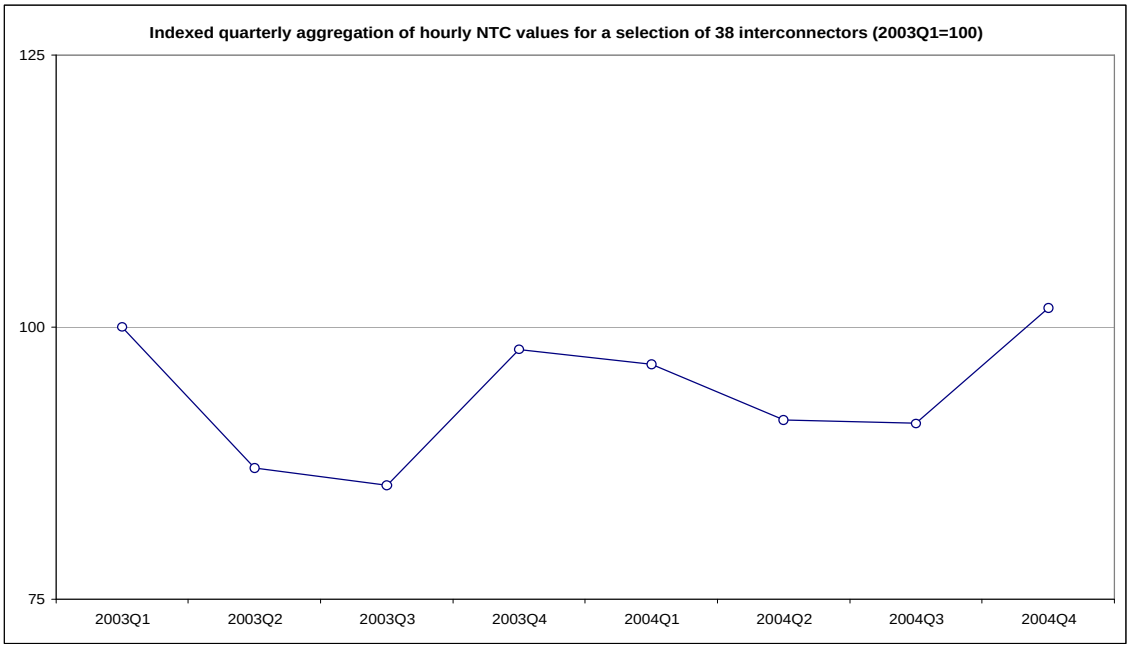
(489) NTC-levels may be affected by the way TSOs manage grid congestion in their control area. At this stage no assessment has been made of TSO's behaviour regarding the treatment of congestion on internal lines and interconnectors. Table 25 shows at first glance that such an assessment may not be required since only Austrian and Italian TSOs state that they have lines in their grid that suffer from congestion for at least 10% of all hours. Other TSOs reported that they have congested lines, though not meeting the threshold of 10 %. It is unclear at this stage if TSO's relieve congestion on their internal lines at the expense of lower cross border capacity, and if so if it is done for sound cost efficient reasons.

Table 24

Average hourly NTC relative to installed generation capacity for a selection of countries, 2004	
Country	**%**
UK	2
Italy	6
Spain	6
Ireland (1)	6
Portugal	9
Poland (1)	10
Greece (1)	12
Finland (1)	14
France (2)	14
Germany (3)	16
Netherlands (1)	17
Czech Republic (1)	23
Austria (1)	24
Belgium	25
Sweden (1)	29
Hungary (1)	38
Slovakia (1)	39
Denmark (1)	50
Estonia (1)	66
Slovania (1)	68
Luxembourg (1)	90

Source: Energy Sector Inquiry 2005/2006, UCTE and ETSO.
Note :(1) NTC values from ETSO used for calculation
(2) For Italian-French NTC value is estimated
(3) For Polish-German NTC and Czech-German NTC is estimated.

Figure 62



Source: Energy Sector Inquiry 2005/2006.

Table 25

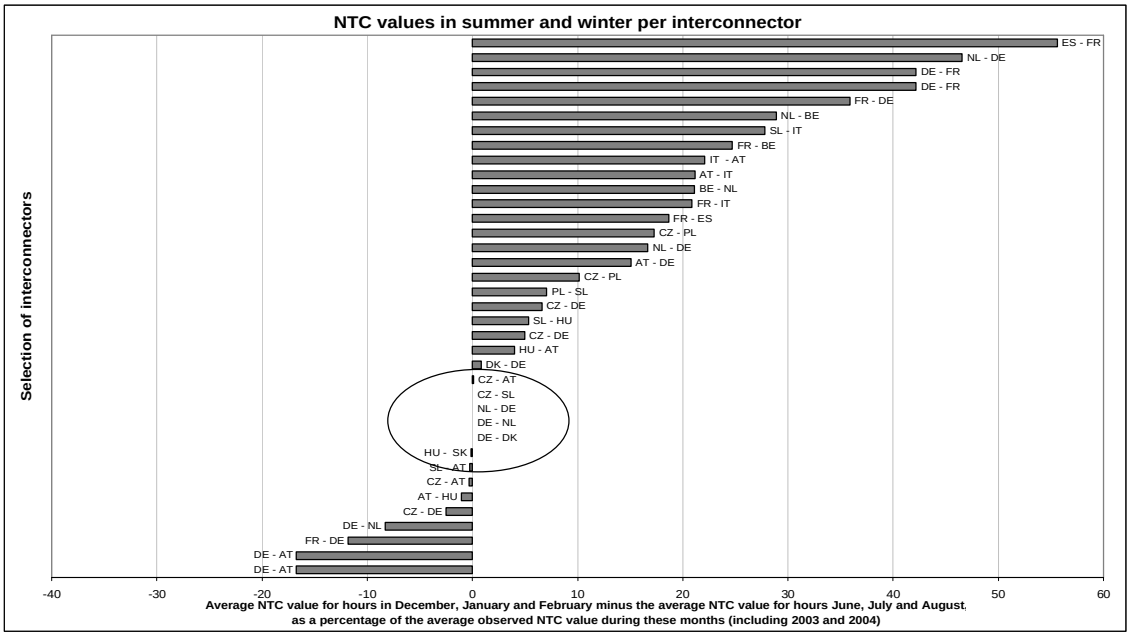
Congestion of lines other than interconnectors, selection of TSOs	
Country	**Number of lines congested for more than 10% of the hours in one calendar year during 2003 - May 2005**
Austria	none
Austria (1)	4
Denmark	none
Denmark	n.a
France	none
Germany	none
Germany	none
Germany	none
Germany	none
Italy (2)	5
Netherlands	none
Spain	none
United Kingdom	none

Source: Energy Sector Inquiry 2005/2006.
Note: Some countries appear more than once because they have several control areas.
(1) 2003.
(2) April 2004 – March 2005.

(490) During relative cold months, ignoring other factors, NTC values may increase compared to relatively warm periods due to the physical characteristics of electricity wires. Several TSOs explain this in their answers to the questionnaires. Figure 63 demonstrates that the performance of TSOs to maximise the amount of cross border capacity delivered to the

market differ substantially between TSOs. For instance the difference in the NTC value for the Spanish – French border between winter and summer month exceeds 55 percent. This is positive for the market as during relatively cold periods more capacity is available for cross border trade. However, at some borders (marked area in Figure 63) the NTC values seem to be insensitive to temperature changes and remain at the same level throughout the year.

Figure 63



Source: Energy Sector Inquiry 2005/2006.
Note: Differences between the average Net Transport (NTC) in relative cold and warm months relative to the average NTC value in % - 2003 and 2004. In some cases borders appear two or three times in Figure 63 which is due to the fact that each TSO reports on export and import NTC values per interconnector.

(491) The results for some interconnectors in the marked area of Figure 62 are difficult to explain. They seem to suggest that there was very little difference in the level of NTC values between summer and winter. The results of negative bars (below the marked area in the figure) are also difficult to explain since they show that during winter periods the NTC values are lower than in summer periods. However, it is important to note that there are also other factors than outside temperature that affect NTC levels. As is explained above, local generation and consumption events play an important role determining NTC levels. These may have a stronger effect than the temperature. However, the figures illustrate that the differences between the performances of the TSOs are substantial. Clearly, on borders where high price differences persist the need to optimise the level of available interconnector frequently is more important than elsewhere.

II.3.5. Incentives for TSOs to build more capacity

(492) A precondition for building additional interconnector capacity is that incentives to expand the net are properly set by regulators who set the (regulatory) framework. Incentives for building merchant lines (unregulated lines) may arise from estimated future revenues primarily reflecting the absolute price differences between adjacent geographical wholesale markets. Market design changes or new generation investments are hard to predict over a long period. The replies to the Sector Inquiry also confirmed

that planning procedures for building new interconnectors are complicated, not least for environmental reasons.

(493) TSOs, who in the past had a monopoly on building additional interconnectors, may also invest in new or additional interconnection (regulated lines), and hence it is important that TSOs have correct incentives. Table 26 shows that many TSOs obtain congestion revenues[234] and that these revenues are not fully invested on projects to increase interconnector capacity. Article 6 (6) of the Regulation 1228/2003 states that revenues resulting from the allocation of congested interconnector capacity shall be used for: (a) guaranteeing the actual availability of the allocated capacity; (b) network investments maintaining or increasing interconnector capacities, or; (c) as an income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs, and/or in assessing whether tariffs should be modified.

Table 26

Congestion revenues and total investments in interconnectors during 2001 - 2005 in mln-euro		
TSO	**Congestion Revenues (2001 - 06/2005)**	**Interconnection Investments (2001 - 06/2005)**
A	200-300	25-35
B	0-20	0-10
C	80-150	0-10
D	200-300	0-10
E	200-300	50-100
F	80-150	0-10
G	20-80	0-10
H	80-150	80-150
J	0-20	10-40
K	0-20	10-40
Total	**1000-1300**	**200-300**

Source: Energy Sector Inquiry 2005/2006.
Note: Excluding spending on congestion relief.

(494) The table shows that only about one quarter of the congestion revenues is used to build new interconnections or to reinforce existing grid elements. This result from the Sector Inquiry demonstrates that incentives need improvement.

(495) According to answers from TSOs these revenues are mainly used to reduce national grid tariffs. Since the existing interconnections were financed in the past by tariffs paid by the local consumers it could be justified to allocate the welfare resulting from auctions to these consumers. On the other hand consumers would also profit from increased generation efficiency gained from additional cross border trade and enhancement of the markets. That being said, it should be clear that based on current (cross border electricity) regulation TSOs are allowed to spend congestion revenues on lowering transmission tariffs for electricity in their control area.

(496) In the Sector Inquiry some TSOs also provided information on recent studies on new interconnection lines. Most of these studies conclude that building a new line is a difficult and lengthy procedure and in some cases the impact on the available interconnector

[234] Congestion revenues refer to the additional revenues (e.g. auction proceeds) the TSOs receive due to congestion for the interconnectors.

capacity would be low compared to the efforts required. This is partly due to the fact that in many cases increasing the level of cross border capacity also requires substantial internal grid reinforcements.

Congestion revenues of German TSOs in 2001 to 2005 and use of the revenues

In the period 2001 to 2005 three German TSOs managing interconnectors generated congestion revenues of [400-500] million Euro. Of these revenues only [20-30] million Euro were used to reinforce/build new interconnectors (one TSO said that it does not know how much of the investment into the net had the effect of reinforcing interconnectors). All TSOs maintained that the remaining revenues were used to reduce the transmission tariffs. One TSO declared that the extension of a 380 KV line with a length of 50 km and a capacity of 1400 MVA costs [1-10] million Euros. The building of new lines or subsea cables is significantly more expensive.

II.3.5.1. Utilisation of existing interconnector capacity

(497) The congestion mechanisms to allocate interconnector capacity play an important role in market integration. The word (congestion) mechanism refers to a set of actions and measures that are applied to handle network access in the presence of congestion. Table 27 lists from the questionnaires the most commonly used mechanisms and divides them into market based and non-market based methods. Table 27 also explains briefly the different mechanisms.

Table 27

Overview of the most common interconnector allocation mechanism	
Not market based, discriminatory and often not transparent methods	**First-come-first-served** (Priority list) Capacity is allocated according to the order in which the transmission requests have been received by the TSO. Starting from the earliest request, all requested amounts of capacity are fully granted until the available capacity is used up. **Pro-rata rationing** All requests are partially accepted so that each applicant is granted a fixed share of his requested capacity amount, the share being equal to the amount of available capacity divided by the sum of all requested capacity amounts. **Retention** A proportion of the available capacity is granted in long term contracts (also) based on grand father rights
Market based and non-discriminatory methods	**Explicit auction** Along with the requested capacity amount, the applicants have to declare how much they are willing to pay for this capacity. These bids are ordered by price and allocated starting from the highest one until the available capacity is used up. Usually the price for the capacity is set to the bid price of the lowest allocated bid. **Implicit auction** Transmission capacity is managed implicitly by two or more neighbouring spot markets: network users submit purchase or sale bids for energy in the geographical zone where they wish to generate or consume, and the market clearing procedure determines the most efficient amount and direction of physical power exchange between the market zones. Hence, separate allocation of transmission capacity is not required, cross border capacity and energy are traded together.

Source: Energy Sector Inquiry 2005/2006.

II.3.5.2. Non market based mechanisms

(498) Mechanisms that allocate interconnection capacity using methods that are not market based, discriminatory and not (always) transparent result in inefficient use of interconnector capacity. This is due to the fact that in contrast to auctions, first-come-first-served, pro-rata rationing and retention do not necessarily allocate capacity to participants that value interconnection capacity the highest. Partly it could be allocated to some who do not value it at all.

(499) Quite a number of questionnaire responses criticize the existence of non-market based mechanism not only because they are not market based and discriminatory, but also because they are often not transparent resulting in unclear allocation and sometimes favouring incumbents. In addition these methods are anyway incompatible with Regulation 1228/2003, but still seem to be practised for certain interconnectors as is shown in Table 28. This table lists the different allocation mechanisms per interconnector through which existing interconnector capacity is commonly allocated to the market – excluding long term contracts.

(500) Table 29 illustrates that a significant proportion of existing interconnector capacity is still allocated on the basis of priority rights or "pre-liberalisation" contracts. These capacity reservations often relate to some of the most congested interconnectors.

(501) From a legal point of view the existing grandfather rights are problematic. The ECJ stated in a recent case (C-17/03, Vereniging voor Energie, Milieu en Water, judgment of 7 June 2005) that a preferential treatment for pre-liberalisation capacity reservations is incompatible with the Electricity Directive 96/92/EC if the Member State concerned failed to request an exemption pursuant to Article 24 of that Directive. Pre-liberalisation contracts may also be assessed under Articles 81 and 82 EC and recently the Commission received requests for guidance on this important issue. Responses from some large energy consumers indicate that they would be interested in booking capacity on interconnectors. However, most customers consider that transaction costs are too high for them to become directly involved in cross-border trade.

(502) It cannot be excluded that long term contracts could result in efficient allocation as secondary trade could in theory employ efficient redistribution means. But the holder of the contract would still profit from the money paid in the secondary market and, more importantly, the conditions to obtain these long term contracts in the past were often not equal. Also it is often not transparent who "owns" the capacity and how long the underlying contracts last. This raises search cost (transaction costs) for any player interested in buying this interconnector capacity, since "secondary capacity markets" remain immature. This raises barriers to entry and may harm liquidity in several wholesale markets. Hence, long term contracts should with certain exceptions be disqualified as a method for allocating scarce interconnector capacity. Recent reports indicate that efforts to dismantle these contracts are in progress. For exemple, the Netherlands have directly reacted to the ECJ decision and the French Regulatory Authority decided not to grant priority rights any more for long term contracts on the interconnection with other EU Member States.

Table 28

Overview of allocation mechanism of the main EU interconnectors - selection	
Allocation mechanism	**Border**
Explicit auction	Denmark - Germany United Kingdom - France Germany - Netherlands Germany - France Poland - Germany Poland - Czech Republic Czech Republic - Austria Czech Republic - Germany Austria - Hungary Austria - Slovenia (1) France - Italy (2) Belgium - Netherlands France - Belgium
Implicit auction	Sweden - Finland Denmark - Sweden
First come - first serve	France - Switzerland France - Spain (3)

Source: Energy Sector Inquiry 2005/2006.

Notes:(1) On this border Slovenia has been exempted from Regulation 1228/2003 (requiring that cross border capacity is to be allocated using a market based method) until 2007. The explicit auction here is just conducted for the Austrian half of the interconnection capacity.

(2) For the French - Italian border there does not exist a joint capacity allocation. The explicit auction is just conducted for the French half of the interconnection capacity.

(3) On the French side export capacity is allocated on a daily basis and in blocks of 25 MW based on a priority list subject to satisfying minimum use factors to maintain the position in the list, and the allocation of import capacity is based on a pro-rata method. On the Spanish side the capacity is shared between bilateral contracts and market transactions and after that implicit auctions organised by OMEL are applied.

Table 29

Long term reservations on a selection of interconnectors, 2005								
Border	France-Spain	Spain - France	France - Italy	Czech Rep. - Austria	Austria - Italy	Czech Rep. - Germany	Poland - Slovakia	Slovakia - Hungary
Current NTC value (1)	[1-1000]	[1-700]	[1-2300]	[1-600]	[1-190]	[1-950]	[1-800]	[1-1000]
Long term contracts as % NTC	60-70%	70-80%	60-70%	60-70%	50-60%	20-30%	40-50%	30-40%

Source: Energy Sector Inquiry 2005/2006.

Note: (1) The NTC values used for percentage calculation represent 2004 data, since for 2005 they were not available for the entire year.

II.3.5.3. Market based methods

(503) On many congested interconnectors TSOs make use of explicit auctions for day-ahead allocations. Examples of interconnectors that are explicitly auctioned are listed in Table 28 and include e.g. NL – DE and FR – UK. This mechanism is considered not to be satisfactory by a number of respondents in the sector inquiry, because it suffers from the time lag between capacity allocation and wholesale market clearance.

(504) Figure 64 focuses on these comments. It shows for each hour in 2004 the spot price differences between the Netherlands and Germany, e.g. APX price minus the EEX price (horizontal axis) and correlates the sum of nominations from Germany toward the Netherlands (vertical axis). Each dot in the figure represents an unique hour with a price difference and the result of the nomination. It reveals that in many hours (40 percent of all observed hours) during 2004 capacity was nominated from Germany to the Netherlands while prices in Germany where higher than in the Netherlands. This result is intuitively not rational since the wholesale electricity price in the Netherlands is typically higher than in the German wholesale market. Such an arbitrage 'mistake' is shown in the upper left area (diagonally marked) in Figure 64. All markers in this area constitute an irrational (economical) outcome. The area in the bottom-right (also marked) also represents irrational outcome.

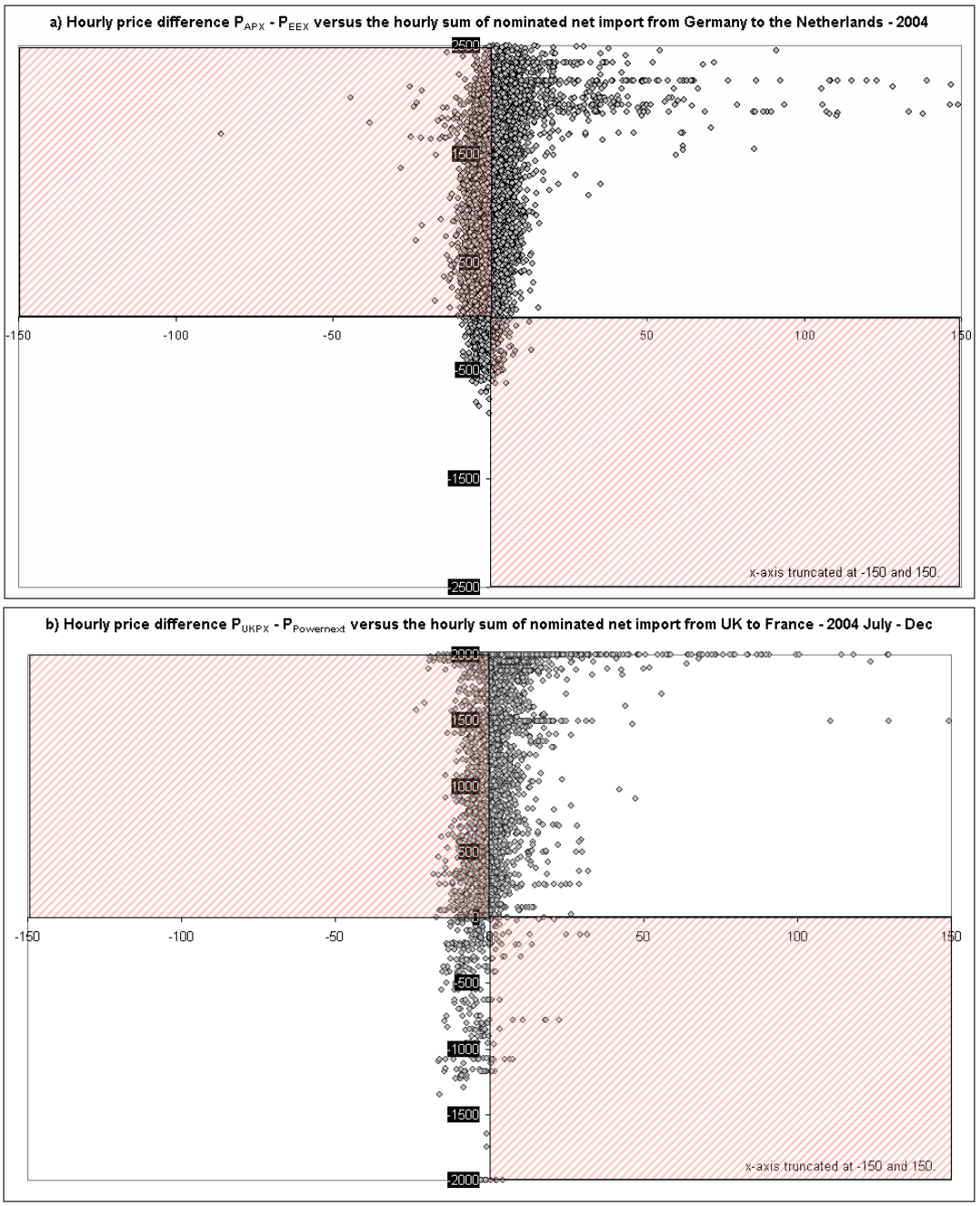
(505) One of the explanations for these economically inefficient outcomes is that the deadline for the day ahead interconnector auction ends before the German (EEX) and Dutch (APX) energy market clears. A similar coordination issue occurs on the interconnector between France and the UK (England and Wales), where the deadline for interconnector nominations occurs after the French (Powernext) energy market clears, while the UKPX (the leading UK power exchange) is open and prior to gate closure in respect of the UK balancing mechanism. The consequence is that explicit auctions do not lead to an optimal use of scarce interconnector capacity.

(506) From the responses from the questionnaires market participants confirm that they face uncertainty due to the fact that they have to place bids based on expected prices. As markets after the day-ahead market are illiquid players cannot easily resell acquired electricity in the market where they initially had bought the electricity, and buy in the market where they would have liked to use the acquired electricity. They would have a preference for that if they had anticipated a positive price difference in an hour between two markets, but after market closure it turns out that the price difference is negative.

(507) In addition, it might be unreasonable for transactions to be nominated in two directions if the price spread between the two energy markets was small, however participants might prefer to transfer electricity from the high to the low prices markets in order to avoid exposure to balancing prices. This is particularly relevant where interconnectors connect relatively illiquid markets.

(508) Due to the arbitrage errors systematically made by the market participants incorrect signals prevail regarding the value of interconnector capacity. This leads to incorrect incentives to attract new investments into interconnector capacity.

Figure 64



Source: Energy Sector Inquiry 2005/2006, ECB Exchange rate Pound vs Euro.

(509) Table 30 shows that the financial loss resulting form underutilisation plus incorrect utilisation (wrong sign nominations) of interconnector capacity is significant per border. For instance, in 2004 almost 50 million Euro was not utilised in the Dutch - German border which is 46 percent of the total value (107 million Euro) of this interconnector capacity. Due to the relatively high Dutch spot price volatility in 2003 the result in 2003 was more than 20 million euro higher. A similar calculation is done for the French-UK border. The results are presented in Table 30.

Table 30

Estimated value of unused cross border capacity (selection) ***in mln. euro***		
Borders	**2004**	**2003**
NL to DE	49,4	70,8
UK to FR	64,4 (1)	…
FR to ES	41,8	140,3

Source: Energy Sector Inquiry 2005/2006.
Note: The estimated amounts are calculated as follows. For each hour the estimated day ahead available import capacity is reduced with nominations. This is the estimated unused capacity. Summed with wrong sign nominations they are multiplied with the absolute hourly spot market price difference. NTC values day ahead used in this figure represent an ex-ante estimation of the seasonal transmission capacities of the joint interconnections on a border between neighbouring countries, assessed through security analyses based on the best estimation by TSOs of system and network conditions for the referred period. (1) Includes July 2004 – May 2005.

(510) Further there remain a few borders where the allocation of interconnector capacity is not carried out according to a harmonised and economic-based mechanism. The French – Spanish border is an example and Table 30 shows that also on this border financial loss is significant.

(511) The result of the above analyses illustrates that, although explicit auctioning is theoretically with perfect foresight an efficient mechanism and it is in practice compatible with Regulation 1228/2003, it has efficiency deficits compared to implicit auctioning. With implicit auctions results of trade are not likely to have economically irrational use of the interconnector capacity as is the case for explicit auctions as demonstrated in Figure 64.[235]

(512) An additional advantage of implicit auctions is that netting, which has not been discussed in this chapter, will become feasible. For instance, on the Dutch – German border import and export capacity is auctioned separately. Hence, introducing implicit auctions may increase the available capacity significantly.

II.3.6. The need for harmonization

(513) One of the key complaints from the respondents in the sector inquiry is that parties involved in arbitrage between borders face important differences between the administrative rules underlying the electricity markets. For instance the imbalance settlement period (for TSOs to balance the market) limits the possibility to alter schedules. These differences in settlement periods result into increased risks and are therefore barriers to trade. The different time periods for which imbalances are settled are shown in Table 31.

[235] In this context is should be mentioned that new important congestion management guidelines are currently being discussed (see http://europa.eu.int/comm/energy/electricity/legislation/doc/congestion_management/cm_guidelines_en_v1.pdf)

Table 31

Different time windows in which imbalances are settled by control area - 2004	
Country, responsible TSO(s)	**Time unit**
Netherlands (TenneT) Italy (GRTN) Austria (APG, TIRAG, VKW-UNG) Germany (EnBW TNG, E.On Netz, RWE TS, Vattenfall ET) Belgium (Elia) Luxembourg (Cegedel)	15 minutes
France (RTE) England & Wales (NGT)	30 minutes
Poland (PSE-Operator) Sweden (SK) Norway (Statnett) Denmark (Energinet.dk) Slovenia (ELES) Spain (REE) Greece (HTSO/DESMIE)	60 minutes

Source: ETSO (2004), DG Comp.

(514) The rules for nominating transactions and the rules relating to changes (if needed) of nominations before gate closure also differ between countries. Because of these differences, nominations for cross border transactions - if possible - require separate administrative procedures per border. Conditions for nominations also differ between countries. These differences increase the complexity for market players to trade across borders and may reduce the scope for competition.

Conclusion

Imports do not yet adequately play their role to counter market concentration in national markets and exert competitive pressure on incumbent operators. Hence consumers may pay more for their electricity than strictly necessary. Important reasons for inadequate market integration include:

- Insufficient levels of cross border capacity,
- Inefficient congestion management methods (including explicit auctions),
- Important differences in rules that manage the electricity markets administratively within and between control areas,
- Long term cross border capacity reservations, partially given under discriminatory conditions, and
- Lack of adequate incentives to invest in additional capacity.

II.4. Transparency

(515) Efficient wholesale electricity markets can bring significant benefits to the electricity sector, in terms of greater operational efficiency, improved signals for investment, greater security of supply, better allocation of risks and increased scope for competition.

II.4.1. Transparency is needed for electricity markets to develop

(516) For efficient wholesale markets to develop it is essential that all market participants have access to the information considered necessary to trade, in particular as regards expected demand, supply and network issues. The sector inquiry confirms, however, that there is a lack of transparency in most Member States. There is a general perception that generation data of incumbents is sometimes first shared with affiliates, which undermines the confidence in the wholesale markets. The inquiry also revealed examples where operators seem to have withheld information regarding generation outages until after markets have closed, which may have allowed them or their affiliates to trade on electricity markets on an unfair basis.

(517) More transparency is needed essentially for three reasons. First the publication of more information would allow all players to take informed action on the markets, which minimises their commercial risks and reduces entry barriers. Secondly it ensures a level playing field by avoiding that certain parties have access to commercially sensitive information (e.g. from generation affiliates), but others do not. If the transparency obligations are not sufficiently strong, some market participants will be able to profit unfairly at the expense of other market participants. Thirdly, lack of transparency undermines the trust in the wholesale markets and with it its price signals as a reliable benchmark.

(518) The need for transparency to promote the development of the wholesale markets is not only the view of the European Commission but has been widely recognised, both in answers to the questionnaires and outside the context of the sector inquiry. The Florence Forum[236] concluded at its September 2005 meeting that "participants also highlighted the need for increased transparency, in view of creating a functioning and fair market".

(519) European Energy Regulators (CEER) emphasise that the transparency of information about the physical situation of the European electric system is one of a number of conditions that must be met to facilitate the development of a single energy market, as specified by the directive of June 26, 2003. Although some initial progress has been recorded in many Member States, the degree of transparency of information about the physical situation of the European electric system remains weak.

(520) Eurelectric stated[237] that "the development [of wholesale electricity markets] must be underpinned by solid involvement by all market participants and by a common body of available information. (…) It is essential that market places fulfil at least the following criteria: (…) provide transparent access to common sets of market information." In the same report it went on to say "another prerequisite for the development of liquid

[236] Conclusions of the Florence Forum of 1-2 September 2005, section 2(d), page 4.

[237] Eurelectric report of June 2005 "Integrating Electricity Markets through Wholesale Markets: Eurelectric Road Map to a Pan-European Market".

wholesale markets is the trust of the market participants in the market. Therefore, market transparency and information exchange in the wholesale markets must be harmonised to ensure that all market participants have the same information at their disposal".

(521) The European Transmission System Operators (ETSO) published a paper on transparency[238] which focuses on the provision of information to TSOs to allow them to manage the network as efficiently as possible. However, in the paper it also states that "ETSO believes that data from generators and market participants is of particular importance to achieving improvements in transparency and facilitating fair and efficient markets". It should be noted in this context that the full implementation of the congestion management guidelines that are currently being adopted should increase transparency as regards cross-border congestion.

(522) The European Federation of Energy Traders (EFET) stated[239] "an efficient wholesale market for power is crucial to meeting the aims of liberalisation and offers the prospect of considerable benefits to consumers. The development of an efficient wholesale market, however, is currently being hindered by the lack of information being released to the market".

(523) Barclays Capital, an important electricity trader, stated in its reply to the sector inquiry questionnaires "information release is the key non-structural measure that could be implemented to improve competition in EU electricity markets. Greater information release would allow participants to understand the underlying supply and demand events that drive prices which in turn facilitates better price forecasts, increased liquidity and hence an increased ability for a wider range of participants to compete to supply customers. Greater information release will also result in better price signals for maintenance, closure and investment decisions which in turn enhances system reliability and security of supply". It further went on to say that "the cost to EU energy consumers of poor information transparency alone is therefore likely to run into tens of billions of Euros". This figure seems very high at first glance, but it represents just over 5 percent of the total turnover in the electricity sector in the EU of approximately €180 billion in 2004 (and with significant increases since).

II.4.2. The risk of collusion does not outweigh the advantages of more transparency

(524) There is a risk that excessive transparency, particularly in an oligopolistic market as many electricity markets are, could facilitate collusion between the major suppliers. However, given the current state of the electricity markets and the low level of transparency in many markets, this does not in practice appear to be a likely at this stage. Indeed, the principal problem at the moment is that the lack of transparency in most markets undermines the development of the wholesale markets. In any case, the risk of facilitating collusion could be reduced by only publishing figures on an aggregated rather than individual basis (at least in advance of trading). Therefore, in the current state of the electricity markets and as long as where necessary information is published to all market participants in an aggregated basis, the risk of facilitating collusion – whilst requiring monitoring - does not outweight the benefits of more transparency.

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238 ETSO paper "List of data European TSOs need to pursue optimal use of the existing transmission infrastructure" of December 2005.

239 EFET Position Paper: "Transparency and Availability of Information in Continental European Wholesale Electricity Markets", July 2003.

II.4.3. The level of transparency varies widely between Member States

(525) Despite the widespread recognition of the need for transparency in order for wholesale markets to develop, the sector inquiry has provided evidence that the level of transparency in the wholesale markets in the EU is not satisfactory. It is also widely divergent. In the context of the sector inquiry national regulators were asked whether adequate information was made publicly available in their Member State on 49 precise issues[240] covering:

- technical availability of TSO network (10 issues covering inter alia frequency and causes of congestion, net and available transfer capacity, prices and physical flows)
- technical availability of interconnectors (11 issues addressing similar issues to those asked regarding the TSO network)
- load (5 issues covering inter alia day ahead and week ahead aggregated load forecasts and actual load)
- balance and reserve power (5 issues covering inter alia demand for balancing power, system balance status and actual use of reserve power)
- generation (production) (4 issues covering inter alia actual generation and outages)
- generation (capacity) (14 issues covering inter alia production portfolios).

(526) 21 national regulators replied. According to the regulators, information is published in the Member States on between zero and 38 of these issues. On average information was published on just under 20 issues. Table 32 shows the range of information published in the Member States according to the regulators.

(527) It can be seen from Table 32 that the markets in which most information is published (eg Nord Pool and the UK) are generally perceived as more competitive than those where little information is published.

[240] The list of 49 issues is attached in annex H.

Table 32

Number of issues for which information is published by Member state	
Member State	**Issues for which information is published (out of 49)**
UK	38
Spain	34
Denmark	31
Finland	30
Sweden	27
Portugal	26
Poland	25
Lithuania	24
Germany	23
Slovenia	21
Italy	20
Hungary	18
Belgium	17
Netherlands	16
Greece	16
France	14
Ireland	13
Austria	12
Slovakia	8
Estonia	1
Latvia	0
Czech Republic	-
Luxembourg	-
Cyprus	-
Malta	-

Source: Energy Sector Inquiry 2005/2006

II.4.4. Market participants not satisfied with level of transparency

(528) In the sector inquiry, suppliers were asked about the information that must be available to trade within acceptable risk levels on electricity wholesale markets. For each of the 49 issues suppliers were asked whether information was made publicly available, and were asked how important this issue was. Table 33 summarises their replies:

Table 33

Suppliers' views on whether information is available	
suppliers saying that "indispensable" information was not available	43%
suppliers saying that "important" information was not available	16%
suppliers saying that "useful" information was not available	25%
suppliers saying that "all useful" information was not available	17%

Source: Energy Sector Inquiry 2005/2006.

In a nutshell more than 80% of market participants are not content with the current level of transparency arguing that indispensable, important and useful information is not made available.

II.4.5. The information that market participants believes ought to be published

(529) At its meeting in September 2005 the Florence Forum considered the need for more transparency. ETSO undertook to provide a list of the data TSOs need to ensure an optimal use of the existing infrastructure. At the same meeting "Eurelectric agreed to provide a list of information that it considers market agents need to have in order to trade efficiently, where possible in co-ordination with traders, power exchanges and customers"[241]. The ETSO paper has been published and the Eurelectric paper is expected to be published in early 2006. It should not only address the question of what information needs to be published but also when (eg in advance, in real time or with a certain delay).

(530) The replies to the sector inquiry indicate the broad types of information that market participants believe should be made public. The questionnaires sent in the context of the sector inquiry to generators, traders and suppliers ("suppliers") asked them to identify how they assess the importance/relevance of different issues to trade. Table 34 summarises[242] their replies (on the same of a comprehensive analysis of the replies to sector inquiry).

Table 34

Importance of information according to suppliers				
	indispensable	**important**	**useful**	**not useful**
TSO network	36.1%	24.5%	34.6%	4.8%
Interconnectors	30.5%	30.8%	30.5%	8.2%
Load	24.8%	32.9%	36.9%	5.5%
Balancing	22.2%	30.1%	38.4%	9.3%
Generation (production)	20.0%	33.5%	32.7%	13.8%
Generation (capacity)	26.7%	29.9%	37.5%	5.9%

Source: Energy Sector Inquiry

(531) Table 34 suggests that for market participants the issues on which information is most important are (in decreasing order):

1. Technical availability of interconnectors
2. Technical availability of TSO network
3. Generation (capacity)
4. Balancing and reserve power
5. Load
6. Generation (production)

(532) It is surprising that generation (production) is stated to be the least important issue. This could be because currently this information is not widely available and so market participants are not used to receiving it. Another possible explanation is that the information is perceived as commercially sensitive by the generators concerned. In this respect it is interesting to note that almost all suppliers who said that generation (production) information was "not useful" were local or regional incumbents, who might be expected to be able to benefit from the refusal to release the information, whilst possibly sharing relevant information between affiliates.

241 Conclusions of the Florence Forum of 1-2 September 2005, section 2(d), page 4.

242 Information on the views of suppliers on the importance of each of the 49 precise issues is attached in annex H.

(533) In a similar vein, some market participants have stated that they should not be required to publish confidential information. Instead they propose that in advance they should only reveal the information to a third party (normally the TSO or a power exchange) who should publish the information in an aggregated form combining similar information from parties in the same position. This would not seem to pose a problem as long as more detailed information on a disaggregated basis was published once the trading had taken place. In any event, there is a strong presumption that as much information as possible should be published, because otherwise market participants possessing market sensitive information would be able to profit from this information. As this profit would be at the expense of other market participants, acceding to the request not to publish this information would increase risks for market participants and confuse the price signals from the market.

(534) It should be noted that in the most liquid and efficient wholesale markets, including in particular Nordpool and the UK, the transparency requirements are high and so commercially confidential information is limited. It should also be noted that in Nordpool (as stated below) market participants with insider information are not allowed to trade until the relevant information has been disclosed to the market. This suggests that if an exemption for confidential information is to be allowed it must be very restricted. It could, for example, be to allow some very sensitive information to be published in aggregated form in advance and the detailed information to be published following an appropriate delay rather than in real time. This would still allow the possessor of the information to benefit from it, but replies to the sector inquiry indicate that even delayed publication of information is of importance to market participants as it allows them to understand price movements in the past and so to model price movements in the future.

II.4.6. Responsibility for publication of information

(535) Responsibility for revealing relevant information should primarily lie on the market or network participant responsible for the relevant activity. For example, generators should ensure that the required information on generation capacity and actual generation is revealed, and TSOs should ensure that the required information on congestion is revealed. However, in some cases, it might be appropriate for a third party to be responsible for the publication of the information. For example, if it was decided that information on generation schedules should only be published in an aggregated form before gate closure then generators might be made responsible for providing the TSO or another third party with their generation schedule and the TSO would be responsible for publishing aggregated figures. This issue should be further considered by the European Commission and the market participants during the discussions on precisely which information should be published and when.

II.4.7. The transparency requirements under EC law

(536) EC financial services rules, in particular the Markets in Financial Instruments Directive (MiFID)[243], the Prospectus Directive[244], the Transparency Directive[245] and the Market

[243] Directive 2004/39/EC of the European Parliament and of the Council of 21 April 2004 on markets in financial instruments amending Council Directives 85/611/EEC and 93/6/EEC and Directive 2000/12/EC of the European Parliament and of the Council and repealing Council Directive 93/22/EEC (OJ 2004 L 145/1). The MiFID allows investment firms, banks and exchanges to provide their services across borders on the basis of their home country

Abuse Directive (MAD)[246] and its implementing rules[247], impose various transparency obligations on financial markets.

(537) The aim of these Directives is to regulate the trade of securities, including derivatives on commodities, and related financial services. Commodity trading, including electricity and gas trading, is generally not covered by these Directives unless it is considered to be trading in derivatives on commodities. Some but not all power exchanges and brokers platforms in the EU are covered by the national rules implementing these directives. For example, in the Netherlands the APX exchange is not seen as falling within the scope of the directives, while Endex[248] is.

(538) Furthermore, the sector-specific rules only impose limited transparency obligations on electricity wholesale markets or their participants.

II.4.8. Transparency requirements under national law or market conditions

(539) In addition to the requirements under EC law, there exist transparency requirements under national law or self-imposed transparency requirements in individual markets (e.g. it can be a condition of trading on the market concerned to subscribe to certain transparency rules).

(540) The following examples from the most important wholesale markets are representative.

- Trading in Nord Pool is subject to regulation both by the authorities in accordance with national law and by Nord Pool pursuant to the private law market conditions. In particular, Nord Pool prohibits insider trading under its conditions to trade on the financial market (although there is no statutory prohibition against insider trading in Norwegian law). Market participants must notify Nord Pool of any insider information, which is defined as "any matters related to the relevant entity's business in the electricity markets that is likely to have a substantial impact on the prices in listed products". This is further specified to include any planned outages or maintenance concerning more than

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authorisation. The Directive also harmonizes the requirements for the provision of investment services and the operation of regulated markets by imposing several pre-trade and post-trade transparency requirements..

244 Directive 2003/71/EC of the European Parliament and of the Council of 4 November 2003 on the prospectus to be published when securities are offered to the public or admitted to trading and amending Directive 2001/34/EC (OJ 2003 L 345/64). The Prospectus Directive lays down several requirements for the prospectus to be published when securities are offered to the public or admitted to trading on a regulated market.

245 Directive 2004/109/EC on the harmonisation of transparency requirements in relation to information about issuers whose securities are admitted to trading on a regulated market and amending Directive 2001/34/EC (OJ 2004 L 390/38). The Transparency Directive covers periodic and ongoing information requirements for issuers whose securities are admitted to trading on a regulated market.

246 Directive 2003/6/EC of the European Parliament and the Council of 28 January 2003 on insider dealing and market manipulation (market abuse) (OJ 2003 L 96/16). The main aim of the MAD is to establish harmonised rules prohibiting market abuse, in particular insider dealing and market manipulation which harm the integrity of financial markets and public confidence in securities and derivatives.

247 In particular Commission Directive 2003/124/EC of 22 December 2003 implementing Directive 2003/6/EC of the European Parliament and of the Council as regards the definition and public disclosure of inside information and the definition of market manipulation (OJ 2003 L 339/70) and Commission Directive 2004/72/EC of 29 April 2004 implementing Directive 2003/6/EC of the European Parliament and of the Council as regards accepted market practices, the definition of inside information in relation to derivatives on commodities, the drawing up of lists of insiders, the notification of managers' transactions and the notification of suspicious transactions (OJ 2004 L 162/70).

248 Endex European Energy Derivatives Exchange operating an electricity futures exchange.

200MW. Participants possessing such information may not trade on Nord Pool until the relevant information has been disclosed to the market by Nord Pool[249].

- In the UK the main transparency requirements are imposed in accordance with the Grid Code and the Balancing and Settlement Code. Compliance with these codes is a condition for obtaining a licence as generator or supplier. Implementation is monitored by the regulator OFGEM. The existing rules require market participants to publish information such as intended generation, contractual positions and outage plans to National Grid Company (NGC), the TSO. Most of this information is circulated to market participants via the internet. NGC also circulates its outage plans to market participants. With respect to unplanned events, participants must provide an oral and written account, the latter within two hours of receiving original notification of the event.

- In Germany it appears that the main transparency requirements as regards trading on EEX are due to national legislation (national competition law and the German Securities Trading Act supervised by the EEX trade monitoring office, the State Ministry for the Economy and Labour in Saxony and the German Financial Supervisory Authority (BaFin)). The TSOs also impose transparency obligations including use of interconnectors and congestion problems.

- In France, the national and EC legislation on market abuse is not applied to Powernext. However, Powernext has inserted provisions into its market rules to prohibit market abuse. Furthermore, the national legislation has recently been amended to grant the regulator the power to carry out surveillance of "transactions carried out on organised electricity markets as well as on the interconnectors"[250].

(541) Experience of enforcement of these rules appears to be extremely limited, with the exception of Nord Pool. Nord Pool has carried out eight detailed investigations since 2000, and in a number of cases found that the rules had been breached. In the UK there have been no formal investigations in the generation market relating to competition law or OFGEM's regulatory controls since 2001 (although there were previous investigations into the pool prices). The Financial Services Authority investigated the trading activity of an energy producing and trading company in 2003 but found that allegations that its conduct in the short term power markets may not have been for legitimate commercial purposes were unsubstantiated. In France there have been no allegations of breaches of rules on proper market conduct. In Germany no formal investigations were carried out.

[249] Nord Pool Market Conduct Rules (in particular, section 4.1) and Disclosure Rules (in particular, section 2.1). Furthermore, Nord Pool Ethical Guidelines state that market participants shall never compete in an unfair manner.

[250] Article 3 of the Law of 10 February 2000 on the modernisation and development of the public service of electricity as modified by article 51 of Law 2005-781 of 13 July 2005 on the orientation of energy policy.

Conclusions

The need for greater transparency is widely recognised and has been identified as the key non-structural measure that could improve competition in EU electricity markets. Lack of transparency amounts to an entry barrier, undermines the level playing field between market participants and adversely affects the trust in the functioning of the wholesale markets.

In practice in most Member States the level of transparency remains low. There are also significant differences between Member States undermining the level playing field. More than 80% of all market participants are not satisfied with the current level of transparency arguing that not all indispensable, important and/or useful information is made public. More information should be published on technical availability of interconnectors and TSO networks, on generation, balancing and reserve power and load.

The EC financial services legislation, even when it applies to electricity wholesale markets, imposes only limited transparency obligations on these markets or their participants. The same applies to the sector-specific rules.

The transparency requirements under national rules or market conditions appear to be widely divergent, with for example only Nord Pool explicitly banning trading before the relevant information has been passed to the market. Furthermore, experience with enforcement of the national rules and the market conditions are even more divergent, with only Nord Pool having a broad experience enforcing its rules

There is therefore an urgent need to require all market participants to publish more information. The Commission will consider whether there is a need for Community legislation in this area (e.g. clarification or modification of existing legislation or new legislation). The Commission will also consider imposing transparency requirements as remedies in competition cases, given that improved transparency can help to limit the possibility to abuse market power.

II.5. Price issues

(542) Whilst the formation of electricity prices on wholesale markets has already been explained in some detail in this report, three issues relating to the overall price level of electricity deserve particular attention. First, it needs to be analysed which external factors might explain – wholly or in part – the price increases over the last years such as increases in fuel costs or the introduction of the CO2 emission trading scheme (ETS). Secondly, the effects of publicly set supply tariffs for competitive electricity wholesale markets need to be assessed. And thirdly, special support schemes – currently under consideration in certain Member States - to support large energy intensive users are presented and assessed.

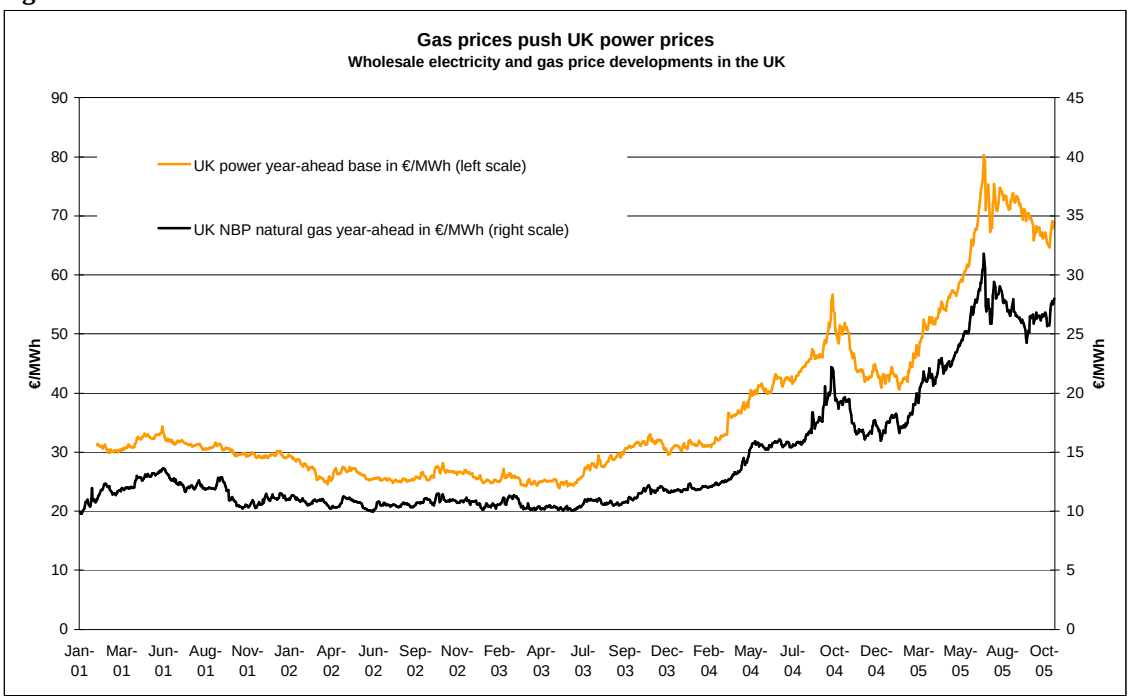
II.5.1. External factors possibly explaining price increases

II.5.1.1. Electricity prices and fuel price developments

(543) Coal and natural gas are commonly used primary energy sources to generate electricity throughout Europe. It can therefore be expected that their price development will affect electricity prices.

(544) Recent strong price increases of natural gas (themselves subject of the gas sector inquiry) had a significant impact on wholesale electricity prices especially in the UK, where natural gas constitutes the fuel that is predominantly used by generators on the margin. Figure 65 demonstrates this relationship showing the development of the UK forward natural gas and electricity prices. It is characterised by a high correlation between the price levels.

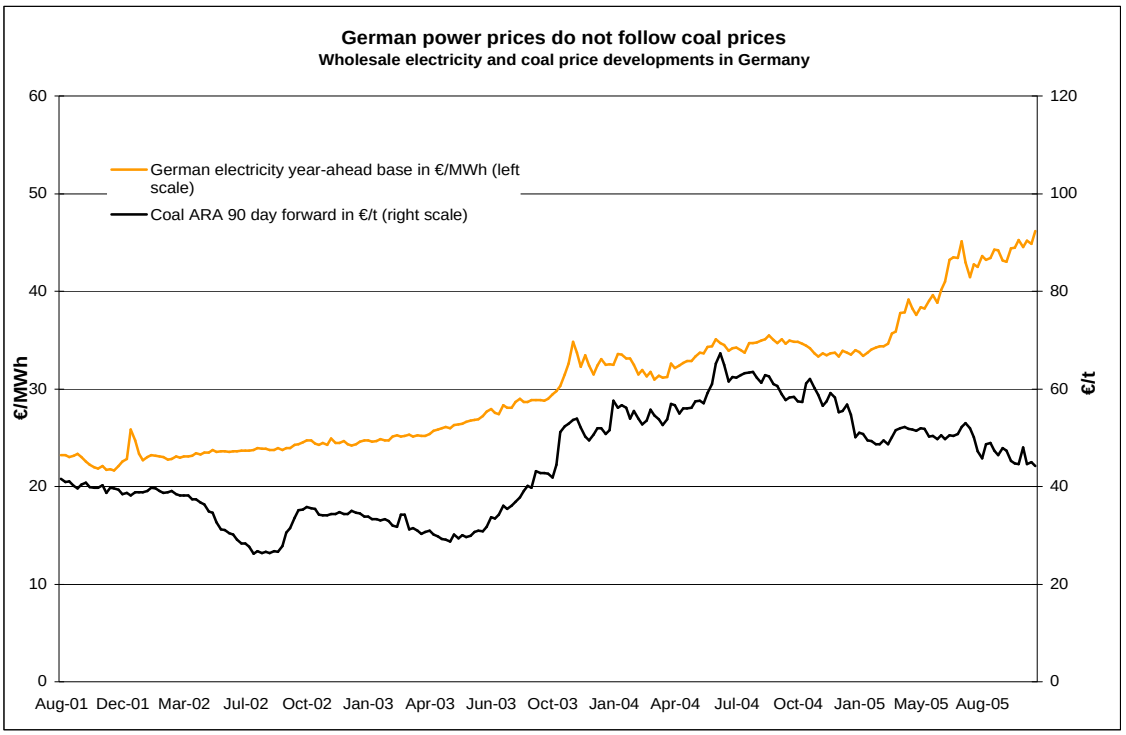
Figure 65



Source: information received within the scope of the Sector Inquiry from Argus Media, and platts

(545) In other parts of Europe coal (instead of gas) plays a major role in electricity generation. It is generally understood that (e.g. in Germany) coal is often used by generators operating on the margin. Thus coal price developments – all other factors being equal – should have a major impact on electricity prices. However, this was not the case in recent years. Whereas the relevant benchmark coal price has decreased (from 60 €/t in January 2005 to 44 €/t in December 2005), the year-ahead base load electricity price has risen significantly in Germany (from 34 €/MWh in January 2005 to 52 €/MWh in December 2005). Although electricity prices are also influenced by factors other then fuel prices (e.g. CO2 prices, trade with other countries) the reasons for this development will have to be studied in more detail. This is all the more important since the German market lacks the transparency that would allow market participants to identify the marginal generator or take an informed view on the development of supply fundamentals. Figure 66 shows the development of forward electricity and coal prices in Germany.

Figure 66



Source: information received within the scope of the sector inquiry from Argus Media, and platts

II.5.1.2. Electricity prices and CO2 price developments

(546) In addition to rising natural gas prices generators – as they explain in their answers – started to factor in the value of the CO2 allowances in their pricing decisions as an additional factor of production.

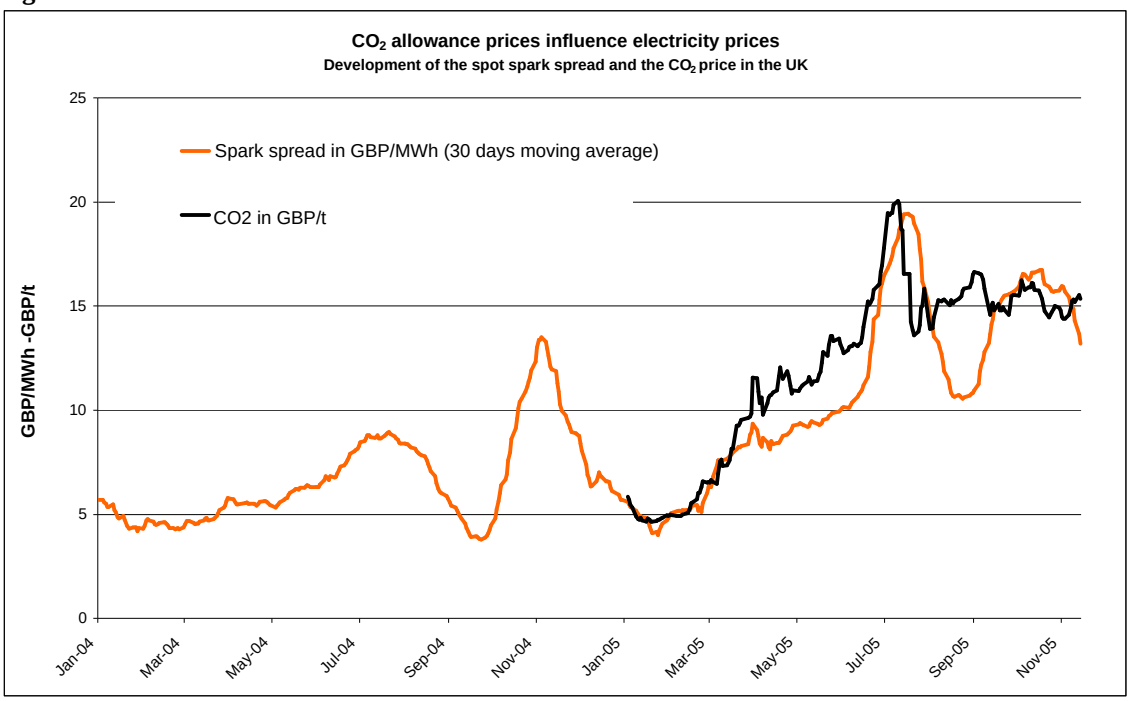
(547) There is no consensus yet among analysts to what extent prices for CO2 allowances are included in wholesale prices and/or whether in all Member States the same developments can be observed. Some argue however that the value of the allowances is at least partially priced in. A recent study by the Energy Research Centre of the Netherlands[251] concluded

[251] 'CO2 price dynamics: The implications of EU emissions trading for the price of electricity', Energy Research Centre of the Netherlands, September 2005

that in the Netherlands between 39% and 44% of the value is priced in at peak times and between 47% and 55% at off-peak times. In Germany between 42% and 46% of the value is priced in during off-peak times and between 69% and 73% during peak times. The European Commission Directorate-General for Environment closely follows the overall impact of the EU Emission Trading Scheme. It commissioned two corresponding and recently published studies.[252]

(548) The possible impact of CO2 trading on power prices – all other factors being equal – can be demonstrated using the concept of spark spreads. The spark spread is the difference between the price of one unit of electricity and the price of one unit of gas (adjusted for plant efficiency). It gives an idea about the revenue of generators burning gas and selling the generated electricity on the market. As long as gas constitutes the marginal fuel in a market one would expect a relatively stable development of the spark spread (apart from possible price distortions or short term supply/demand imbalances). A spark spread graph thus allows isolating the impact of the gas price on the electricity price.

Figure 67



Source: information received within the scope of the sector inquiry from Argus Media
Note: for the calculation of the spot spark spreads we used spot NBP prices and adjusted them for 50% plant efficiency. The spark spread is not corrected for the value of CO2.

(549) Figure 67 shows that the spot spark spread in the UK remained low and relatively stable (apart from a short period with tighter margin between demand and available capacity) during 2004 and started to rise from the beginning of 2005. This is also when the 1st phase of the EU Emission Trading Scheme began. It can be observed that the spark spread followed the pattern of the CO2 price development suggesting that generators – at

252 'Review of EU Emissions Trading Scheme: Survey Highlights', European Commission Directorate-General for Environment, McKinsey & Company, Ecofys, November 2005
'Interactions of the EU ETS with Green And White Certificate Schemes', European Commission Directorate-General Environment, NERA Economic Consulting, 17 November 2005

least to some extent - include the value the CO2 allowances into their pricing decisions.[253]

(550) CO2 allowance prices rose sharply during the first half of 2005 tracking the development of rising gas prices relative to coal prices. Because of high gas prices generators preferred to burn coal instead of gas to produce electricity. Since power plants using coal emit approximately twice as much CO2 as those burning gas as primary fuel, increased coal usage raised the demand for additional CO2 allowances. This in turn resulted in rising CO2 prices as can be seen in Figure 67.

(551) The practice of including the value of CO2 allowances in the cost calculations is seen - by certain industrial customers - as evidence for generators' market power (predominantly in Germany) and non-functioning of electricity markets. The critics underline that companies subject to global competition are not able to pass on costs associated with CO2 allowances to their customers (e.g. steel or aluminium producers, whilst electricity producers can do so). Critics also mention that the vast majority of the allowances were given for free to generators (generally between 95% and 100% of their demand). Customers claim further that generators would not only benefit from higher electricity prices for their marginal plant but for their entire production portfolio resulting in 'windfall profits'. Furthermore they are concerned that the current allocation scheme favours incumbents over new entrants into generation. However it needs to be mentioned in this context that the allocation plans of all 25 Member States as approved by the Commission for the period 2005-2007 contain new entrant reserves. This implies that new power plants will be given free allowances in accordance with the rules governing these reserves.

(552) However, in the view of electricity generators and traders, CO2 allowances are like any other variable factor of production. As such, CO2 allowance prices have to be included in the short run marginal cost calculation of the generating units. In this context – generators argue - it would not matter whether CO2 allowances were allocated for free or had to be bought on the market. It is claimed that the market value of the allowance is what ultimately matters (similarly to a house that was inherited but would be sold on the property market for market prices). If this value would not be taken into consideration the generator on the margin would see revenue that it could realise if it decided not to generate but sell the CO2 allowances and buy the electricity instead (opportunity cost principle). In any event pricing in costs for CO2 allowances would be in line with the objectives of the CO2 ETS.

(553) The Commission will continue to monitor the effects of the EU ETS (including the effect of the ETS on electricity prices), which is a major element in its strategy to achieve the Kyoto obligations

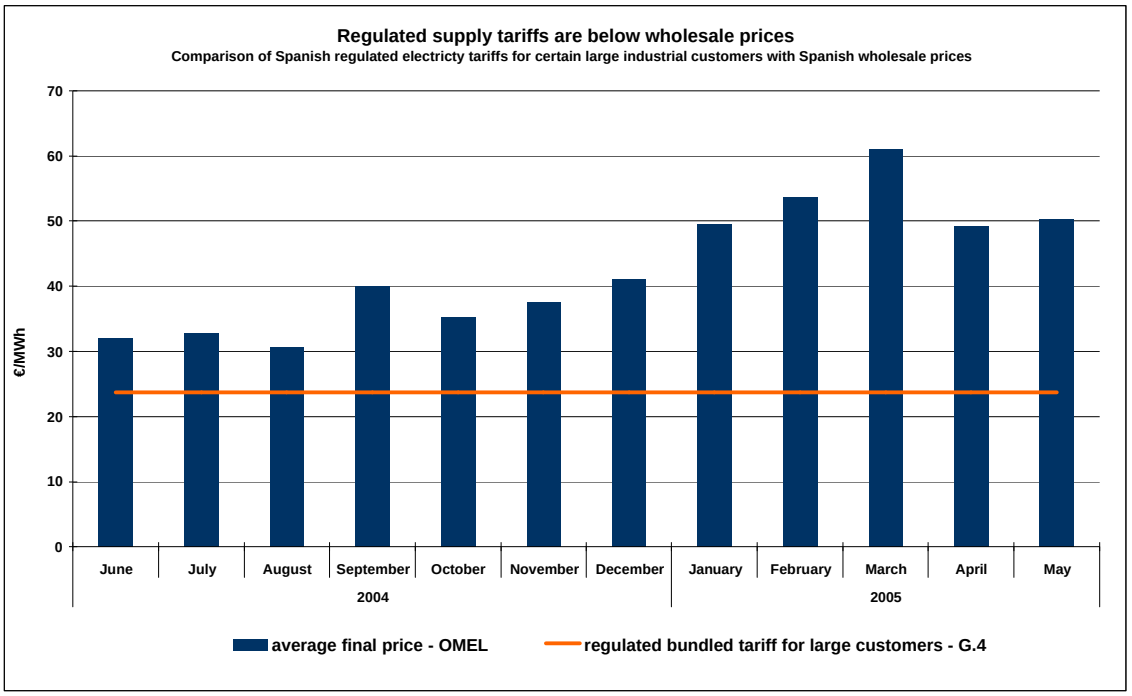
[253] Similar trends can be observed when analysing forward spark spreads.

II.5.2. Regulated supply tariffs

(554) In a number of markets that have been examined, the liberalised supply market with its freely negotiable energy prices between suppliers and customers coexists with a system of regulated final customer tariffs[254] (e.g. Portugal, France, Italy, Spain, Hungary, Poland). Parallel regimes are no threat to a liberalised supply market and its participants as long as regulated energy prices are comfortably above wholesale market price levels. This differential allows for (new) suppliers without any local generation to source on the wholesale market and make attractive supply offers compared to the regulated energy tariff.

(555) However, Member States could be tempted – especially in periods of rising wholesale prices – to set the supply tariffs below the corresponding wholesale benchmark to ensure lower price levels for customers. An adverse effect of such tariffs is however that new suppliers with no access to own generation are squeezed out from the market. Electricity suppliers, in particular in Spain and France, complained about the level of regulated tariffs being too low.

Figure 68



Source: OMEL, CNE (Spanish Regulator)
Note: The G.4 bundled tariff depends on a capacity and consumption element and also includes network usage

254 See also Second Electricity Directive, Art.3, Public service obligations and customers protection. Another issue is the exclusivity granted to incumbents to supply within regulated markets.

II.5.3. Special support schemes for energy intensive users

(556) In the light of increasing electricity prices a number of Member States are considering special support schemes for large energy intensive users. Whilst a number of different concepts seem to exist, one of the most advanced relates to the formation of purchasing consortia under criteria set by national legislation. The consortia would enter into long term supply contracts with electricity producers guaranteeing lower electricity prices for the members of the consortia. These purchasing consortia may raise antitrust and possibly also state aids concerns.

(557) From an antitrust point of view the main questions are: a) How are the purchasing consortia formed? The underlying issue is that the possible exclusion of certain companies from consortia can put them at a competitive disadvantage compared to those being part of the consortium benefiting from the lower electricity prices. b) Do the long term contracts have foreclosure effects? This may be the case if the companies which acquire electricity would account for a significant proportion of the overall electricity demand in the market concerned. And c) Are the participants in the consortia free to market the electricity? The electricity supplier might have an interest in preventing the buyers from marketing unused electricity at low prices. However, such a contractual restriction may be problematic use restriction.

(558) The major concerns as regards aid are that any such aid exceeding the de-minimise thresholds would be viewed as operating aid which normally is not allowed in the EU. It would in any case not be possible for the Commission to authorise such aid based on any existing State aid guideline. It can also be questioned whether there would be a need to provide such aid since the mere effect of the establishment of a consortium is supposed to trigger a reduction in price.

(559) Further analysis will be required as regards these special support schemes.

Conclusion

In certain Member States the recent increases of electricity prices can be explained by the rise of gas prices used in marginal plants. However coal prices have remained relatively stable thus not explaining any price increases. Analysts cannot yet agree to which extent the value of CO2 allowances is priced into electricity prices.

Industrial users claim that electricity producers should not be entitled to factor in the value of allowances, as they were largely distributed for free. Generators claim that the value of CO2 allowances are opportunity costs, which can be factored in legitimately. The Commission will closely monitor the effects of the ETS.

Public tariffs for electricity supply can have an adverse effect on the development of competitive markets. Support schemes for large energy intensive users – currently considered in a number of Member States – need to be compatible with antitrust and state aid rules.

D CONCLUSIONS

(560) The overall objective of the Inquiry is to address the barriers currently impeding the development of a fully functioning open and competitive EU wide energy market as a basis for competitive prices for the final consumer, more efficient allocation and use of resources and supply, more openness for renewable energies and an economically sustainable basis for security of supply. The wider context has been set out in the Commission's Communication to the 2006 Spring Council concerning the renewed Lisbon strategy that puts the formulation of an efficient and integrated energy policy at the heart of the Commission's priorities[237]. This context will be further developed in the announced Green Paper on energy policy to be submitted by the Commission in early March.

(561) The launch of the Inquiry into the functioning of the European energy markets in June 2005 was prompted by dramatic rises in gas and electricity wholesale prices and persistent complaints about barriers to entry and limited consumer choice. The energy sector inquiry is a competition investigation based on Art. 17 of Regulation 1/2003 which aims at assessing the competition conditions on European energy markets and establishing whether current indications of energy market malfunction result from breaches of competition law.

(562) At this stage of preliminary findings and on the basis of the further assessment of the data received during the Inquiry, the overall conclusion is that the main problems areas identified in the Issues Paper[238] have been confirmed. Main findings at this stage can be summarised as follows.

(563) Market concentration

- *Gas:*

Access to gas for new entrants is essential for the future development of European gas competition. There are three main sources from which gas may be sourced: imports, domestic production and wholesale trading. Gas incumbents remain dominant in their national markets by largely controlling gas imports and/or gas production. Control of imported gas is mainly exercised through long term gas purchase contracts with upstream producers. Although incumbents trade only a small proportion of their gas on Continental hubs they nevertheless dominate trading on most hubs.

There has been little new entry into the European gas markets. The overall picture for new entrants is one of dependence on incumbents for services throughout the supply chain. This includes access to gas, networks and storage. When combined with the lack of transparency, ineffective wholesale markets and in the absence of effective regulation this dependence affirms the dominant position of incumbents and is seriously impeding the development of competition.

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237 In the Communication the Commission proposes the promotion of more competition on the electricity and gas markets as a major goal (Action 4: "Moving towards an efficient and integrated EU energy policy*")"taking account of the Commission's sector competition enquiry"*.

238 Energy Sector Inquiry – Issues Paper of 15 November 2005, available at DGCOMP's website, Sector Inquiries.

Electricity:

Customers have little trust in the functioning of wholesale markets. They suspect market manipulation on the spot and forward markets by large generators to be the main reason for recent price increases. However there are a number of other factors that might explain price increases that require further investigation.

Most wholesale markets have remained national in scope. The level of concentration in generation has remained high in most Member States giving generators scope for market power. The level of concentration in trading markets is less striking than in generation, particularly when analysing shares of operators on yearly forward products. The level of concentration on spot markets reflects more closely the level of concentration in generation, although at a lower level. When analysing who determines the clearing price at certain power exchanges it appears that there is scope to influence prices for operators in Italy, Spain and Denmark. The situation on the French, Dutch and German exchanges will be further assessed.

When analysing whether there is scope to withdraw physical capacity, it appears that load factors have increased over time in Germany suggesting higher efficiency levels and a tighter supply/demand balance. Significant generation capacity – most of it with low marginal costs – was retired in Germany despite slowly increasing demand. Also, certain plants with rather low marginal costs did not operate fully at all times. Further investigation is foreseen for the subsequent phase of the sector inquiry to disentangle the different reasons for price increases.

(564) Vertical foreclosure

- *Gas:*

Vertical integration of operators active at different levels of the supply chain and long-term supply agreements seem to foreclose the availability of crucial inputs for actual or potential competition:

Access to gas

New entrants can procure gas either directly from producers, or on national wholesale markets. Incumbents have long-term import contracts in place with producers, which cover the production of almost all existing gas fields from which gas can be transported to Europe by pipeline. New entrants are therefore largely foreclosed from procuring gas directly from the producers. At the same time, most national wholesale markets are not liquid enough to provide confidence about gas availability or that hub prices reflect the underlying supply/demand dynamic. This lack of liquidity is aggravated by flexibility clauses in the incumbents' long-term supply contracts which avoid situations of excess or shortage of gas, thereby reducing the incumbents' need to trade gas at national wholesale markets.

Access to storage

Access to storage is seriously foreclosed by long-term reservations. In some cases booked storage is not being fully used. Moreover, separation of suppliers from affiliated storage operators is unclear, leading to concerns about non-discrimination.

Insufficient unbundling of networks

Legal and organisational unbundling as foreseen by the Second Gas Directive is not yet fully implemented and incumbent suppliers still have access to network information through representation on the Supervisory or Administrative Board of vertically integrated companies. Suppliers and networks often share names/logos, buildings and IT systems. A number of allegations of discrimination by network operators in favour of affiliates have been received.

- *Electricity:*

Vertical integration of generation and retail reduces the incentives to trade on wholesale markets. This might lead to a drying up of wholesale markets. Illiquid wholesale markets are a barrier to entry as they are characterised by higher price volatility. Volatile wholesale markets might oblige new entrants to as a enter vertically integrated generator and supplier, which is more difficult.

The degree of vertical integration between generation and retail differs significantly between Member States. In most Member States there are few companies with long positions leading to high “levels of concentration”. VPPs (auction of electricity) assist in some Member States (e.g. France) to improve the level of concentration. Long term power purchase agreements (PPAs) have similar effects to vertical integration.

According to respondents', vertical integration of supply and network (transmission and distribution alike) reduces the economic incentives for the network operator to grant third parties access. In the views of many respondents the existing rules on legal unbundling do not ensure that vertically integrated companies do not engage in practices favoring their supply affiliates to the detriment of their competitors.

With respect to transmission networks, a number of respondents complained about significant costs to connect new power plants to the network. No means exists to verify whether claims of congestion or costs for network reinforcements are valid. With respect to the distribution networks, respondents reported amongst other things inappropriate switching procedures, a lack of Chinese walls between network and supply branches and discriminatory access tariffs.

(565) Market integration

- *Gas:*

Cross-border sales do not currently exert any significant competitive pressure in EU wholesale markets. The concentration of the historical incumbents in their domestic markets is mirrored by their lack of sales in other markets. Swaps are not a marginal phenomenon and can substitute physical transport of gas. However, they are largely tools used by incumbents. New entrants are unable to secure *primary* transit capacity on key transit routes due to the predominance of long-term contracts signed between incumbent TSOs and, typically, their supply affiliates. This situation is expected to persist for the term of the pre-liberalisation legacy contracts (typically fifteen to twenty years of duration) but also potentially beyond this time due to the existence of provisions allowing these contracts to be extended.

On a number of the most congested transit pipelines the volume of requests for additional capacity (much of it from new entrants) is material in comparison to the existing technical capacity of these pipelines, indicating a significant level of unsatisfied demand for transit capacity.

Even in instances where the capacity of particular transit lines has been increased, the resulting new capacity has, for the most part, ended up in the hands of the companies that already controlled the pre-existing primary capacity. The current process for financing new investment risks cementing market shares in destination markets and forming a barrier to smaller players participating in the market.

Moreover, access to *secondary* transit capacity, which should be in theory open to new entrants, has in reality not been obtained by them, with the majority being secured by incumbent suppliers from other countries or large gas producers. Due to the lack of effective congestion management mechanisms on the majority of transit pipelines, it is seldom possible for new entrants to secure even smaller volumes of short-term, interruptible capacity.

- *Electricity:*

Imports do not yet adequately play their role to counter market concentration in national markets and exert competitive pressure on incumbent operators. Hence consumers may pay more for their electricity than strictly necessary. Important reasons for inadequate market integration include:

- Insufficient levels of cross border capacity,
- Inefficient congestion management methods (including explicit auctions),
- Important differences in rules that manage the electricity markets administratively within and between control areas,
- Long term cross border capacity reservations, partially given under discriminatory conditions, and
- Lack of adequate incentives to invest in additional capacity.

(566) Transparency

- *Gas:*

Network users request more transparency on access to networks and transit capacity, as well as on storage. Users would like to see more detailed information than is currently provided for by the minimum requirements set by the Gas Directive and the Guidelines annexed to it. Notably, network users question the "three or more" rule and favour the enhancement of secondary trading by the publication of unused capacity. A number of new entrants would welcome the creation of a single transparent and integrated web platform providing information on available capacity for all transit pipelines. As far as storage is concerned, users underline the need for detailed information.

- *Electricity:*

The need for greater transparency is widely recognised and has been identified as the key non-structural measure that could improve competition in EU electricity markets. Lack of transparency amounts to an entry barrier, undermines the level playing field between market participants and adversely affects the trust in the functioning of the wholesale markets.

In practice in most Member States the level of transparency remains low. There are also significant differences between Member States undermining the level playing field. More than 80% of all market participants are not satisfied with the current level of transparency arguing that not all indispensable, important and/or useful information is made public. More information should be published on technical availability of interconnectors and TSO networks, on generation, balancing and reserve power and load.

The EC financial services legislation, even when it applies to electricity wholesale markets, imposes only limited transparency obligations on these markets or their participants. The same applies to the sector-specific rules.

The transparency requirements under national rules or market conditions appear to be widely divergent, with for example only Nord Pool explicitly banning trading before the relevant information has been passed to the market. Furthermore, experience with enforcement of the national rules and the market conditions are even more divergent, with only Nord Pool having a broad experience enforcing its rules.

There is therefore an urgent need to require all market participants to publish more information. The Commission will consider whether there is a need for Community legislation in this area (e.g. clarification or modification of existing legislation or new legislation). The Commission will also consider imposing transparency requirements as remedies in competition cases, given that improved transparency can help to limit the possibility to abuse market power.

(567) Price formation

- *Gas:*

Prices in most European long-term supply contracts are currently linked to heavy and light fuel oil.

Companies from the Netherlands, Norway and Russia, three of the major gas producers in Europe, all sell long-term gas with a price which is principally linked to heavy and light fuel oil. Companies from the UK and other intra-EU producing countries have a more mixed indexation in their pricing formulae, including an element of hub gas prices.

Whilst the price paid for gas under long-term contracts by companies from Western and Eastern Europe are principally indexed to oil derivatives, in the UK hub gas prices are the most important variable in determining the prices paid by companies purchasing gas under long-term supply contracts.

The overall price level of gas is similar for all gas producing regions. The interquartile range of long-term gas contract prices seems to be dependent on the amount of hub gas price indexation present in the contract.

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 is being paid by the wholesaler to the producers.

Long term gas contracts exhibit a constant price throughout the period January 2003 to December 2004, whereas hub prices are much more volatile. In particular, hub prices change significantly from the summer to the winter, due to increased demand for energy. These price signals are not incorporated into the pricing mechanism of most long-term gas supply contracts.

Long-term contracts with prices indexed mainly to gas also display seasonality, but on a volume weighted basis their price level tends to be in line with that of long-term contracts indexed to oil, which do not display any seasonality or response to demand signals. This is because contracts indexed to hub gas prices are more expensive during the peak winter months when most gas is consumed.

A number of Member States have some form of regulated prices which may have negative effects on competition, where these prices are set too low.

- *Electricity:*

In certain Member States the recent increases of electricity prices can be explained by the rise of gas prices used in marginal plants. However coal prices have remained relatively stable thus not explaining any price increases. Analysts cannot yet agree to which extent the value of CO2 allowances is priced into electricity prices.

Industrial users claim that electricity producers should not be entitled to factor in the value of allowances, as they were largely distributed for free. Generators claim that the value of CO2 allowances are opportunity costs, which can be factored in legitimately. The Commission will closely monitor the effects of the ETS.

Public tariffs for electricity supply can have an adverse effect on the development of competitive markets. Support schemes for large energy intensive users – currently considered in a number of Member States – need to be compatible with antitrust and state aid rules.

E WAY FORWARD

In the Issues Paper the Commission services had announced that it would discuss and propose any necessary *structural, regulatory and competition law based remedies*, once the assessment of the findings of the Inquiry and the parallel reviews of implementation of the Liberalisation Directives had been concluded. It is therefore too early to draw conclusions at this stage and comments are solicited during the forthcoming two months consultation period following the publication of the report and the wider debate in the context of the forthcoming Green Paper, which will allow the Commission to reach conclusions at the end 2006. Nevertheless, from the point of view of the Commission services a number of preliminary remarks can be made now.

Competition law

The Commission is pursuing infringements of Community competition law in the sector wherever the Community interest so requires, in accordance with the regulations in place and in close cooperation with National Competition Authorities. Even before the completion of the Inquiry, the current findings will help to carry forward procedures with full knowledge of the market environment and to orient priorities towards the most serious problem areas.

(1) *Market Concentration* has been identified as the major problem and this makes the Community's action under the merger regulation essential. While each merger case is assessed according to its specific characteristics, the Inquiry helps to identify the most relevant criteria and the most efficient remedies in the given market environment.

(2) *Vertical foreclosure: Tying of downstream markets*. The Inquiry has confirmed that foreclosure of the downstream market by long-term contracts is an immediate priority for review of case situations under competition law. During the forthcoming phase of the Inquiry, the data collected will be further screened and any foreclosure effect closely analysed.

(3) *Market integration: access to capacity on pipelines, gas storage and on interconnectors* has been found to be a major stumbling block towards more market integration and should be the other immediate priority for review in terms of anti-competitive conduct.

The findings indicate that the use of market partitioning clauses continues in a number of Member States. This will need further attention during the final phase of the Inquiry.

Besides these priority actions focusing on market concentration, downstream market foreclosure, and market integration, other case situations of anti-competitive and exclusionary conduct deserve immediate attention, such as inhibiting customers from switching suppliers.

The issuance of guidance on the application of Articles 81 and 82 EC to various practices in the sector may be envisaged. The Commission welcomes comments on the need for such guidance during the consultation.

Regulatory

The Commission has undertaken to review on a Member State by Member State basis the implementation of the gas and electricity liberalisation directives during 2006, and to submit proposals by the end of the year[242] .

While more time will, therefore, be needed to reach conclusions in this field, from a competition perspective a number of issues already seem to emerge from the preliminary findings .

(1) A main finding is that *transparency* is insufficient in the sector. There seems to be broad consensus that this issue should be addressed by strengthening transparency obligations, be it under regulation or under competition law.

(2) There are substantial indications that the remaining *"grandfathering rights"*[243] seriously impede effective entry of competitors and therefore undermine the pro-competitive operation of the market.

(3) Whilst progress has been made in fixing common rules regarding the interconnectors between national grids, much more needs to be done. While there are a number of schemes between national regulators in place or being set up concerning coordination in this area, the findings suggest that purely voluntary cooperation schemes between regulators are unlikely to provide the investment certainty and regulatory protection that is needed to develop international pipelines and interconnectors in a stable environment and keep them open.

There are a number of other regulatory issues that have been raised by both market participants and regulators and which will have to be further considered during the ongoing reviews of the implementation of regulation in the sector. It seems that in a number of Member States, the powers of national regulators should be increased in a number of areas. For example, one area appears to be the surveillance of the conditions and prices for Third Party Access for competitors in order to make pro-competitive markets work and allow consumers to benefit.

Issues under review

There are a number of issues on which it would be premature to take position at the current stage of the assessment but on which comments are solicited:

– price setting practices on electricity wholesale markets including power exchanges

– the competitive assessment of the gas / oil price linkage in many contracts

– the exemption from Third Party Access provisions in the gas directive (in cases of new investment in pipelines, storage and LNG terminals)

242 Commission Report on Progress in Creating the Internal Gas and Electricity Market, 15 November 2005.

243 Capacity rights stemming from pre-liberalisation monopoly contracts.

– a possible more generalised use of gas and electricity release programmes under regulation, in order to reduce the effect of concentration in the upstream supply level and inject liquidity into the market, as well as other measures reducing the effects of concentration,

– further measures to reduce upstream supply concentration, and

– the impact of the Emission Trading System (ETS) on prices in the electricity market. The Emission Trading System is central to a cost effective attainment of the Kyoto green house gas reduction goals and therefore must be seen in a wider policy context. The Commission has committed to undertake a review of the functioning of the scheme before the end of the year.

Structural

While the measures and issues set out above and submitted for consultation would address a number of the key problems found at this stage of the Inquiry, the findings of the inquiry suggest more and more strongly that a real breakthrough towards effective competition in the gas and electricity markets by 1st July 2007 will not be possible unless the root causes of the market malfunctioning are addressed. The market structure suffers from a systemic conflicts of interest resulting from the vertical integration, in many cases, of the supply, transport and distribution level.

This situation dates from the pre-liberalisation period and prevents the advantages of an efficient competitive market reaching the final consumer in a meaningful manner. It makes the Community's energy system less receptive to the introduction of new forms of energy such as renewables due to the stake holders' interest at all three levels of the value chain; and it prevents an effective diversification of supply, which is an indispensable element towards more security of supply.

The provisions of the second electricity and gas Directives on unbundling need to be fully implemented, not just in their letter but also in their spirit. If real progress in this respect does not develop and a true level playing field result, further measures such as full structural unbundling (i.e. separation on the supply and retail business from monopoly infrastructures) should be considered[244].

Comments on this issue are also welcome during the consultation period.

[244] Member States are addressing the issue of unbundling under the existing Directives and national regulation along different routes. Certain Member States have introduced full “ownership unbundling”.

F PUBLIC CONSULTATION

This Inquiry must be seen in the context of the current wider overhaul of the Community's energy policy and the positions that will be set forth in the Green Paper on energy policy. It is intended to proceed to the final phase of assessment of the Inquiry after a two month consultation period that will start with the public presentation of the Preliminary Report on 16 February 2006. Comments are solicited before 1 May 2006 and should be sent to comp-energy-sector-inquiry@cec.eu.int.