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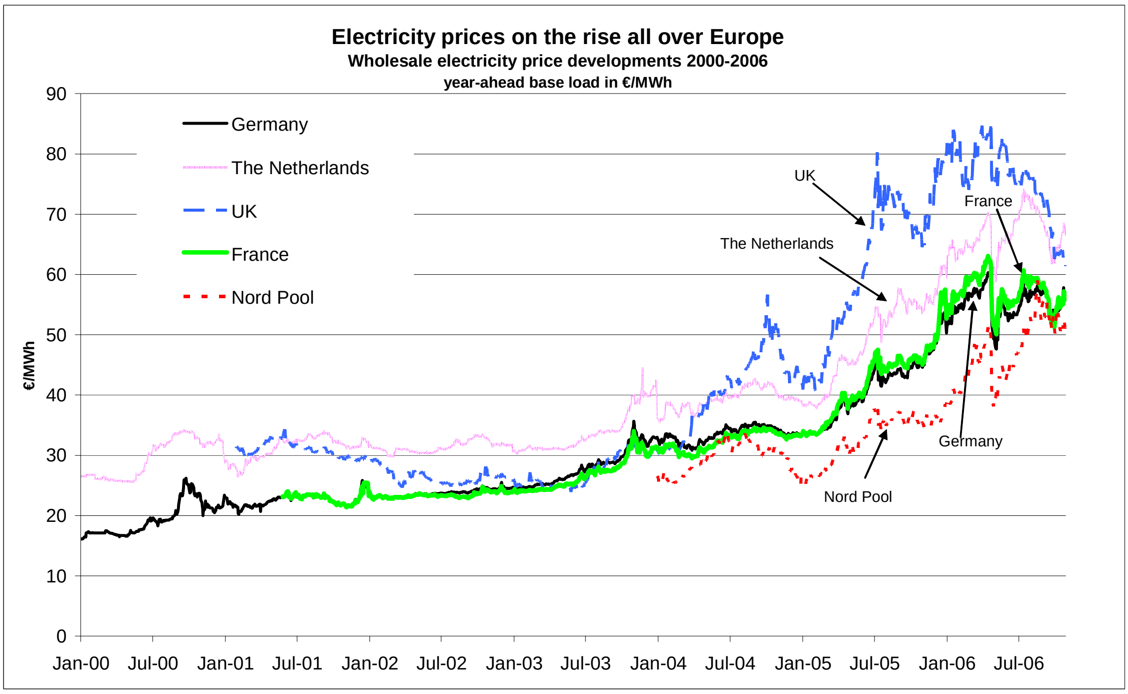
Inquiry pursuant to Article 17 of Regulation (EC) No 1/2003 into the European gas and electricity sectors (Final Report)

{COM(2006) 851 final}

b. ELECTRICITY

I. Introduction

Figure 38



Source: information received within the scope of the Sector Inquiry from Argus Media, Platts[1], and Nord Pool.

(315) Following market liberalisation, electricity wholesale prices were initially relatively stable[2].

(316) 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.

(317) 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.

[1] Data from Platts a division of The McGraw-Hill Companies 2006- all rights reserved.

[2] Prices for certain end users even showed a downward trend after 2000.

I.1. Main market features

I.1.1. Overview

(318) 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[3]. 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. Primary fuels for electricity generation are of course often imported.

(319) Within the EU, cross-border trading of electricity is more important than exchange with third countries. Luxembourg, Latvia and Hungary have net imports of respectively 62%, 51% and 22% of their domestic consumption. At the other end of the spectrum 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, at 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, have grown 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 being the third largest net importer.

(320) 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[4]. Hence, electricity generators rely heavily on competitive gas markets. Malfunctioning gas markets thus adversely affect the price of electricity.

I.1.2. Essential features of electricity markets

(321) 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.

(322) Prior to liberalisation, vertically integrated companies executed these activities serving exclusively certain regions or even a whole Member State, and prices were regulated. This has profoundly changed with European-wide market opening and the electricity business has been split up into regulated and competitive segments. Because transport

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[3] Eurogas, Annual Report 2004-2005, p. 27.

[4] Eurogas, Annual Report 2004-2005, p. 28.

activities are considered to be a natural monopoly, they remain regulated. However, generation, wholesale trading, and retail supply have been progressively opened to competition. A number of Member States have, however, retained regulated supply tariffs.

(323) 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.

(324) An important feature of electricity is that, unlike gas, 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. Also the price elasticity of the electricity demand is very low, especially over the short term, i.e. price fluctuations do not give rise to large changes in electricity consumption.

(325) 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 resulting in different cost structures (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).

(326) All these features render 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 B.b.II.1).

(327) As electricity cannot be stored, balancing and reserve regimes exist to settle market participants' real-time imbalances resulting from discrepancies between scheduled and actual electricity demand, and production[5]. Although the volumes involved are relatively small compared to overall consumption, properly operating balancing markets are crucial for proper functioning of the electricity market as a whole. These markets tend to be as or more concentrated as the underlying wholesale markets, as balancing requires additional technical characteristics of plants that some plants are not equipped to meet. As such, balancing markets are potentially exposed to the exercise of market power as much as wholesale markets, although the exercise of market power in balancing markets may be considerably more complicated, since oversupply is potentially as costly as undersupply. The balancing markets will be analysed in more detail in the chapter C.c.II.

(328) Various business models as well as various structures due to the liberalisation process exist on electricity markets in the EU, ranging from stand-alone generators and independent supply companies to fully integrated utilities. In more recently liberalised Member States vertically integrated companies, or very strong ownership and/or contractual links between generators and suppliers, are predominant. In areas that were liberalised earlier, such as the UK and Nord Pool, business strategies seem to be somewhat more diverse. In the UK, as well as the larger integrated companies, a number of independent generators with their own business strategies exist. On the Nordic

[5] Producers can create imbalances as well as consumers if the supply more or less than they have scheduled in advance.

market(s) consisting of Norway, Sweden, Finland and Denmark independent suppliers are relatively important.

(329) Typically, within fully integrated utilities, specialised affiliates are dedicated to the different activities, such as generation, trading, supply and network operations. Usually, the entire output of the generation affiliate is sold under intra-firm arrangements to the affiliated trading entity[6] which in turn manages the undertaking's overall portfolio i.e. sells electricity to the supply affiliate(s) and sells it 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

(330) EU energy policy pursues three objectives: (1) the achievement of an efficient and competitive integrated energy sector (higher growth rates and increased competitiveness); (2) maintaining an adequate level of security of supply; and (3) increasing the effectiveness of environmental protection. The creation of the internal market is expected to contribute strongly to all of these objectives and this section provides a brief description of the relevant EU legislation in this area.

I.2.1. Liberalisation

I.2.1.1. The beginning of the liberalisation process:

(331) The first important piece of Community legislation aimed at liberalising the electricity sector was Directive 96/92/EC[7] ("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).

(332) 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 creating competitive markets. To address these concerns, further measures were proposed by the Commission leading to the adoption of Directive 2003/54/EC[8] ("Second Electricity Directive") and Regulation (EC) No 1228/2003[9] ("Cross Border Electricity Trading Regulation").

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6 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 section B.b.I.3.4).

7 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).

8 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).

I.2.1.2. The Second Electricity Directive

Full market opening

(333) The Second Electricity Directive aimed at complete market opening. It required that all non-household electricity customers became eligible by 1 July 2004. This will be followed by the opening of the electricity markets for all household customers by 1 July 2007[10]. This approach will remove the discrepancies in the level of market opening between Member States.

(334) Market opening by legislation does not, however, automatically lead to the introduction of competition in supply markets 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 while others (Italy) went so far as to require capacity divestiture. In the UK, the existing state owned generation company was split up into competing undertakings, which facilitated the creation of competitive markets.

Regulated third party access and creation of regulators

(335) 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 sufficiently mitigate the market power of networks owners, vis à vis the alternative of regulated third party access regimes.

(336) 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 governments). The regulators must monitor the overall activities of the network companies, deal with complaints, and control network tariffs[11], a key element in creating competitive conditions.

(337) Some market participants raised concerns that, despite this, 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.[12]

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9 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).

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

11 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.

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

Unbundling

(338) 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. However a holding company is still entitled to approve the annual financial plan and to set global limits on the level of indebtedness.

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

(340) The Directive does not impose that the network operator must own the network assets or that there is ownership unbundling[13] 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.

(341) 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. However, this form of vertical integration may violate EC competition law (antitrust rules or state aid rules).

Conclusion

(342) The Second Electricity Directive, where Member States have properly implement it – not only in form, but also in spirit, has significantly contributed to the creation of a common electricity market. The Commission is actively pursuing the lack of adequate implementation of the Directive in certain Member States.[14]

(343) 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

(344) 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

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

[14] IP/06/430 of 4 April 2006 and MEMO/06/152 of the same day.

and the allocation of cross border capacity. The Regulation entitles the Commission to adopt and amend legally binding guidelines for more detailed rules.

(345) The Regulation's rules on congestion management[15] are of central importance, as mechanisms to allocate congested interconnection capacity play a crucial role in market integration[16]. The Regulation requires that congestion problems on interconnectors be addressed through non-discriminatory, market-based solutions. The Guidelines on congestion management[17] have recently been amended, and the new Guidelines identify both explicit and implicit auctions as methods complying with this requirement[18]. The Preliminary Report's chapter on market integration examines these methods in more detail.

(346) 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

(347) 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 balance between supply and demand 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 more comprehensive set of rules regarding this matter.

(348) 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[19] and that stable and transparent market based rules are in place regarding any action taken to balance supply and demand. In addition, networks must set

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[15] 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.

[16] 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.

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

[18] 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.

[19] 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

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 February 2008.

I.2.3. Environmental protection

(349) 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.

(350) Pursuant to Directive 2003/87/EC[20] (the "Emissions Trading Directive"), Member States must ensure that all plants with a rated thermal input exceeding 20MW emitting CO2 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. Allowances are normally allocated free of charge although a small proportion may be sold in an auction process. 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 which allows for internalising external costs and in particular the alleged effects on electricity prices is discussed below in the chapter on price formation.

(351) Directive 2001/77/EC[21] (the "Renewable Electricity Directive") is an important step in the development of power generation from renewable sources. It mandates that Member States set national targets to meet the Community target of increasing the share of electricity consumption from renewable sources to 21% by 2010[22]. It also encourages Member States to apply various support mechanisms[23] 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 as the operation of the national systems permits. Directive 2004/8/EC on the promotion of cogeneration[24] 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[25], 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.

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20 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).

21 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).

22 An analysis of progress reports of Member States shows that measures currently in place will probably lead to a 19% of renewable share on electricity by 2010. Report on the progress in renewable electricity of 10 January 2007.

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

24 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).

25 OJ 2001 C 37/3.

(352) In 2006 the Community adopted a Directive on energy end-use efficiency and energy services[26] to address environmental concerns relating to energy consumption. According to the Directive, Member States will 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.

I.3. Electricity wholesale markets

(353) 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

(354) Competitive wholesale markets generate efficiencies in the overall performance of the electricity sector by providing price signals to market participants[27]. 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;

2. **efficient investment and improved security of supply**, because competitive wholesale markets provide price signals for both demand and supply and, for example, encourage new investment when necessary and give the signals to potential investors on the type of investment (e.g. base-load or peak) or choice of technology 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 hedge their portfolio of electricity at a minimum volume and price risk if markets have sufficient depth; 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.

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26 Directive 2006/32/EC of the European Parliament and of the Council of 5 April 2006 on energy end-use efficiency and energy services.

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

6. **unsustainability of subsidies and other inefficiencies** as the decision making process is driven by economic considerations.

I.3.2. Basic features of wholesale markets

I.3.2.1. Wholesale market participants

(355) 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).

(356) 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 can hedge themselves against spot price drops.

(357) 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 rises in spot prices.

(358) In comparison to generators and retailers, (financial) traders buy and sell to exploit price differences, e.g. between two geographical areas (arbitrage). Traders also may 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.

(359) 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

(360) 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').

(361) Power exchanges are organised and standardised marketplaces. Market participants transact anonymously using the exchange as central counterparty. 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.

(362) 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.[28] Transactions are carried out bilaterally and counterparty risk is born by the market participants. Increasingly, transactions on traded OTC electricity markets are also 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 the inquiry are GFI, ICAP, Prebon, Spectron and TFS. The prices of such transactions are reported/estimated on an anonymous basis by industry price reporting companies.

(363) 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. The prices for these types of transactions are usually not reported.

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

(364) 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.

(365) Typical spot products on continental European 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.

(366) 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.[29] 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.

28 e.g. 'Standard Electricity Contract' of the European Federation of Energy Traders.

29 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.

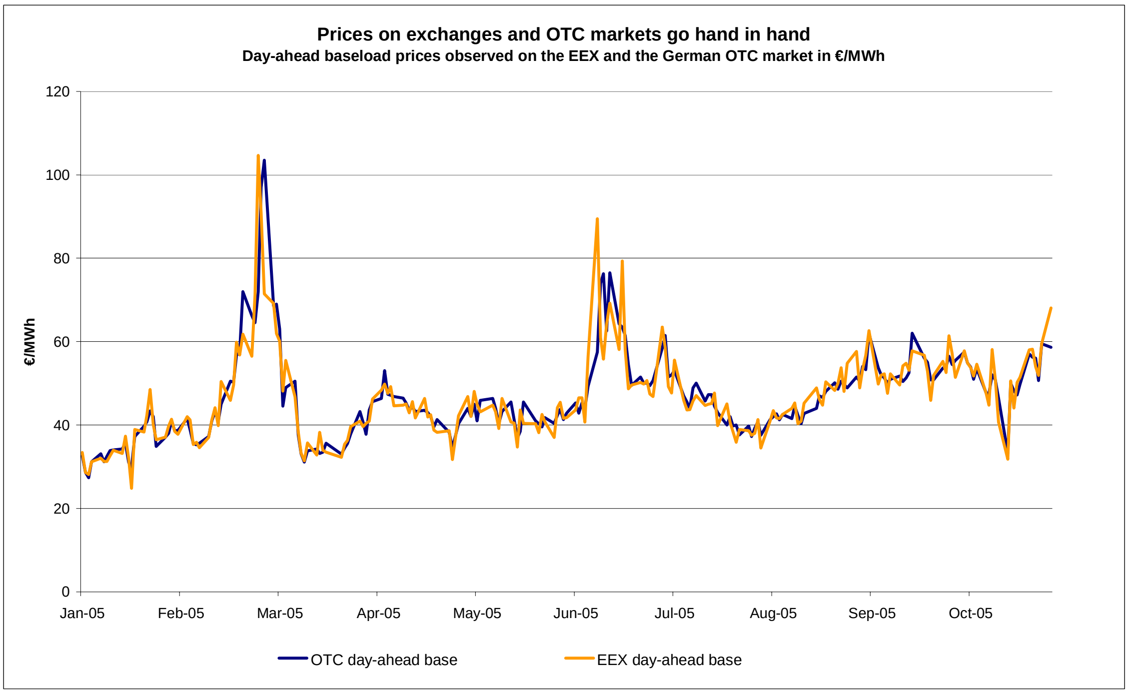
Table 15

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[30]*, Powernext*

(367) As a result of continuous arbitrage, prices of identical products traded on different marketplaces (i.e. on power exchanges or OTC markets) develop in parallel. 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 very 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

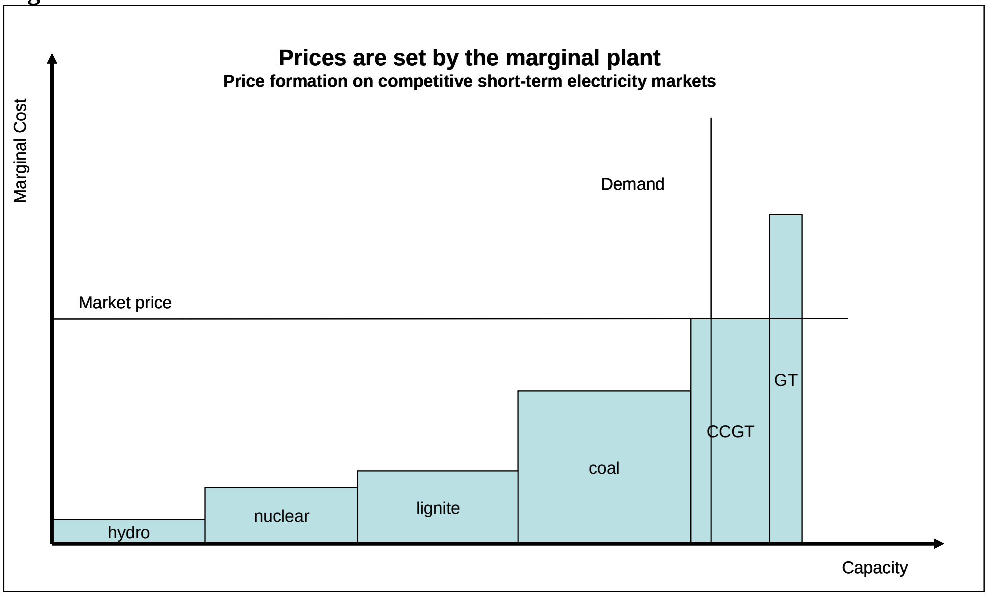
(368) As noted above electricity can be produced in many ways using a variety of fuels and applying different technologies. This diversity also results in different cost structures. Generation technologies that use low-cost fuels (e.g. nuclear fuel, lignite) often require relatively large capital investments[31]. 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.

30 Data from Platts a division of The McGraw-Hill Companies 2006- all rights reserved.
31 Including run-of-river plants that do not use fuels to generate electricity

(369) On 'perfectly competitive' short term (day ahead/spot) markets, and in absence of generation capacity constraints, economic theory suggests that prices would be set by the short run marginal cost (‘SRMC’) of the plant producing the last unit of electricity required to meet demand at that time of day. 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[32]. As a consequence, it can be expected that nuclear or lignite fired power plants will be dispatched continuously and serve as base load units. They may set prices at off-peak period, for example during the night. For other periods the marginal and therefore price setting units – depending on the market in question, would be expected to be fuelled by natural gas, light fuel oil, or black coal.[33]

(370) 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[34] associated with base load generation. Figure 40 also explains this concept graphically using a schematic ‘merit order’.[35]

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.

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

33 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

34 As regards fixed costs, some comments made in the public consultation point to the “specific situation” of peak plants operating during a limited number of hours. They argue that the price at which the power of such plants should be offered could not be strictly based on the marginal costs of the plants but should take in account that the fixed costs can only be amortised during those hours where these plants are among the last one called along the merit curve.

35 The term ‘merit order’ refers to the sequence of generating units according to their SRMC.

(371) Spot prices on power exchanges are usually set in auctions, separately for 24 individual hours.[36] 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.

(372) 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

(373) 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 certificate prices. Prices in the long run are predominantly determined by forward fuel prices, (new) cost of generation capacity (or capacity retirement), water reservoir levels, weather trends, interconnector capacities, CO2 prices and economic growth.

(374) Whereas forward prices are or should be primarily 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[37]. 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 B.b.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.

(375) In addition, 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 fewer buyers will be likely to rely on spot transactions and turn to forward markets instead.

(376) Therefore, generators with market power on spot markets have ample opportunity to also exercise their influence on forward prices. For example dominant operators could

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

37 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.

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 seem costly for generators, it could be outweighed by higher revenues on their total portfolio.

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

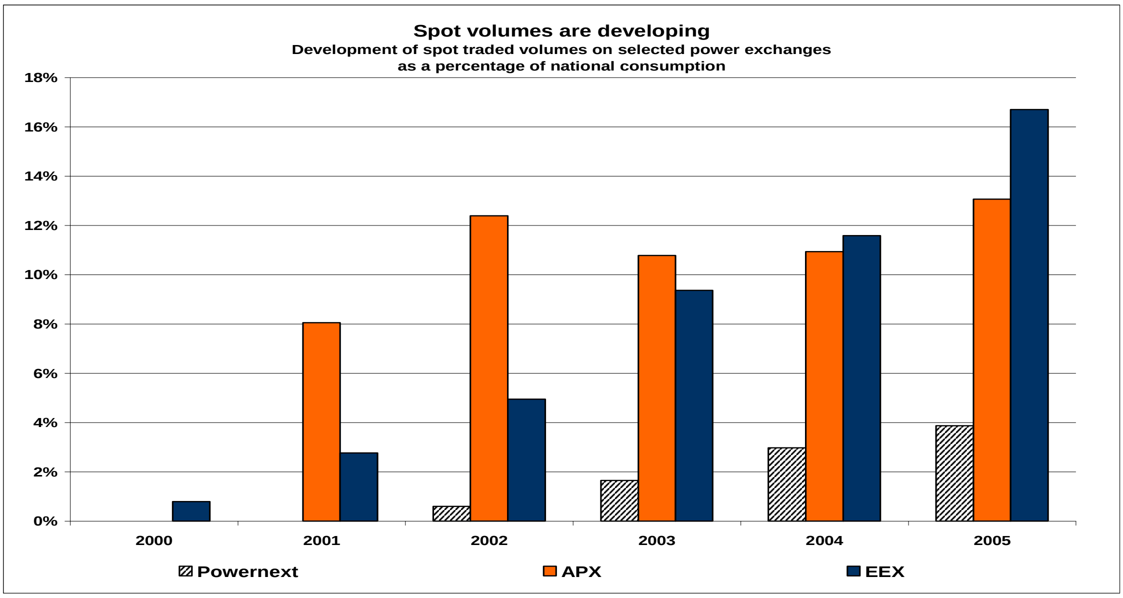
(377) Especially in Member States where generators sell a considerable part of their generation months or even years ahead of actual delivery and where traded forward markets exist (e.g. Germany, France, UK, The Netherlands), it is a common practice for suppliers to offer fixed price supply contracts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

(378) 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 also for the future. 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.

(379) 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

(380) 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.[38]

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.

(381) 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 obligation or incentive to trade via the exchange (OMEL,

38 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

GME, Nord Pool).[39] In the second group exchange members have no such incentives or obligations. 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.

(382) From this table it also emerges that traded spot volumes on exchanges are larger than brokered spot markets in most of the Member States 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

(383) 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[40]. 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 (2005)	196%	327%*	523%
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.

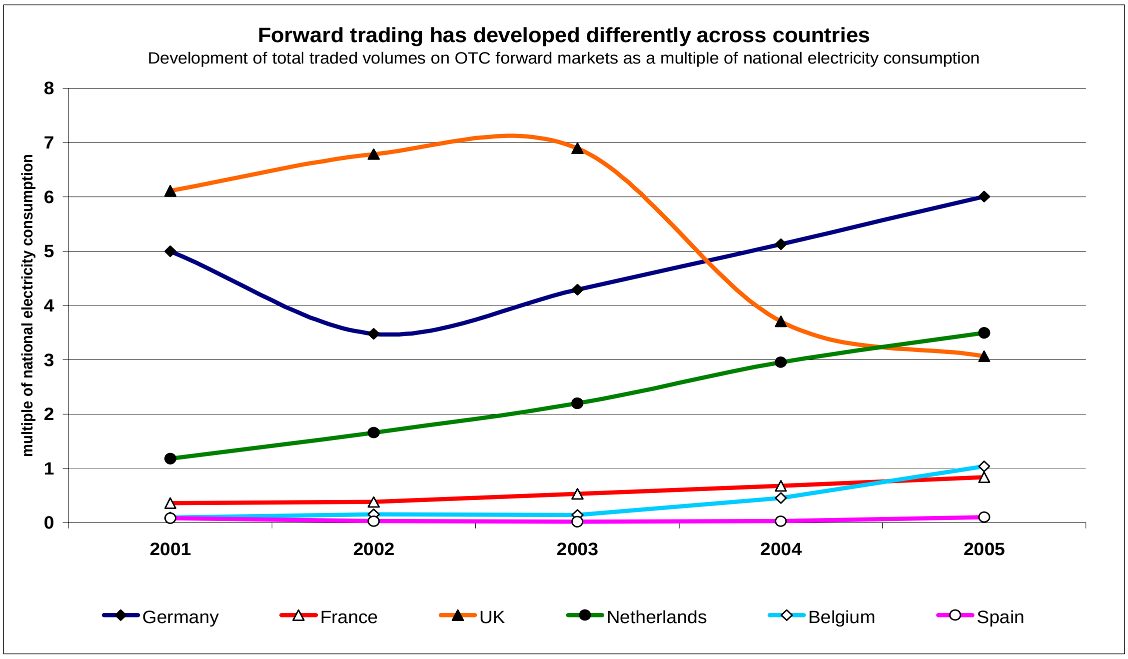
** This figure only includes bilateral contracts cleared by Nord Pool*

(384) 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.

39 In the period reported upon, in Spain only electricity traded via OMEL was entitled to receive capacity payments. The situation has changed in the meantime and new rules have resulted in a lower percentage of total consumption being traded on Omel at the time of publication of this report. 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.

40 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.

(385) 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

(386) Wholesale markets do not only need electricity for their functioning but also a large number of market participants trading actively. The numbers in Table 18 are based on the data 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.

(387) 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 Member States 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.

(388) 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 such 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.

(389) 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

(390) 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 B.b.II.1.

II. Issues

(391) 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, policy makers, professional observers and analysists, that significant efforts are still needed to create a competitive common market for electricity.

(392) 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

(393) 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) 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 exercising market power and disputed that the prices were at competitive levels.

(394) The following customers' views on the functioning of the spot and forward markets illustrate their concerns and allegations about concentration:

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 the power exchange] 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."

(395) 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 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 and further indicators related to concentration and its impact on price formation are provided in chapters B.b.II.1 and C.c.III.

(396) 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, section 5 presents 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

(397) The relevant product market in this analysis is wholesale trade in electricity. Previous analysis of the Commission[41] has defined 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.

(398) Some market participants have indicated that product markets could be further narrowed 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. However, for the purpose of this report it is not necessary to take any position on further refinements of the relevant product market.

(399) 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.

[41] 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

(400) 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[42], but that they may sometimes be smaller[43] or larger[44].

(401) 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[45]).

(402) Annex A that is attached to this report includes a preliminary analysis of the regional scope of certain wholesale markets. A complete analysis would have to include further assessment of supply and demand substitution, 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 possible to do such an assessment only for some markets, without prejudice to the conclusions that could be reached by further investigation in individual cases on these and other markets. All in all, on the basis of the analysis carried out for this report (including analysis detailed in chapter B.b.II.1 and the corresponding annex), all markets will be considered to be national in scope, except Denmark and Italy, where sub-national regional markets clearly exist.

II.1.3. Concentration in generation

(403) 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 most expensive of the offers selected in power exchanges. According to market participants generators can influence prices in two main ways[46]:

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

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

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

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

45 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.

197 This does not preclude other practices: some comments in the public consultation underline that dominant operators can also deter entry by selling at low prices or even below costs during certain hours in the day to affect the prospects of a business case for a new power plant. Obviously, one can also not exclude the possibility of anti-competitive agreements by market participants to raise prices or efforts by market participants to increase prices by purchasing significant volumes at times when the market is expected to be tight (see section on forward markets).

(404) 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 more than compensate the lost profit from not running a plant[47] and create substantial additional profits from the generation assets being used. Assessing overall concentration of generation assets thus helps to identify the scope for such profitable withdrawals of capacity.

(405) 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, or in certain locations in the network. The higher the concentration in the relevant parts of the merit curve concerned the greater is the scope for influencing prices[48] (as presented in chapter B.b.I.3). Comments made in the public consultation point at the level of concentration of certain categories of plants (by fuel and technologies) in certain market, as these will represent a specific segment of the merit curve. This will be elaborated later in this chapter.

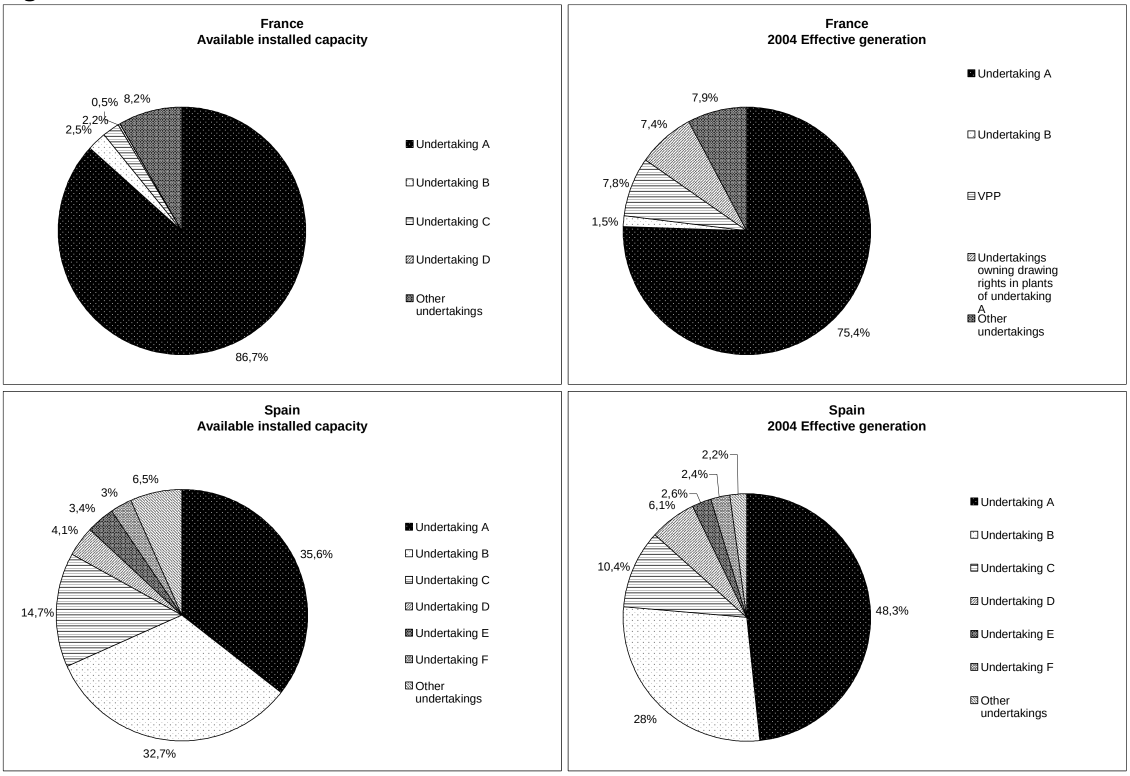
(406) Although the extent to which generators may successfully influence the price level, may not (always) correlate with the level of concentration, it is a necessary element of the analysis of electricity markets across Member States. Figure 43 shows the share of available capacity and of effective generation of the main operators in France[49] and Spain. Charts for other Member States can be found in annex B.

[47] The plant which is not run will likely not be one of the cheapest plants but a more expensive one (typically some mid-merit plant) to minimise the cost of the withdrawal.

[48] Some comments in the public consultation also note that when generation is concentrated in the hands of a single or few operators, then such operators can also impose directly higher prices in the bilateral contracts that are negotiated outside of the power exchange.

[49] 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.

Figure 43



Source: Energy Sector Inquiry 2005/2006

(407) 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[50], especially in the initial liberalisation phase. In the past few years some new gas-fired plant has been constructed in Italy, Spain and the UK and investment of this type is now being planned in other Member States. In addition, some new wind and other renewable generation facilities have shown significant growth in Spain, Italy, Germany, and Denmark.[51]

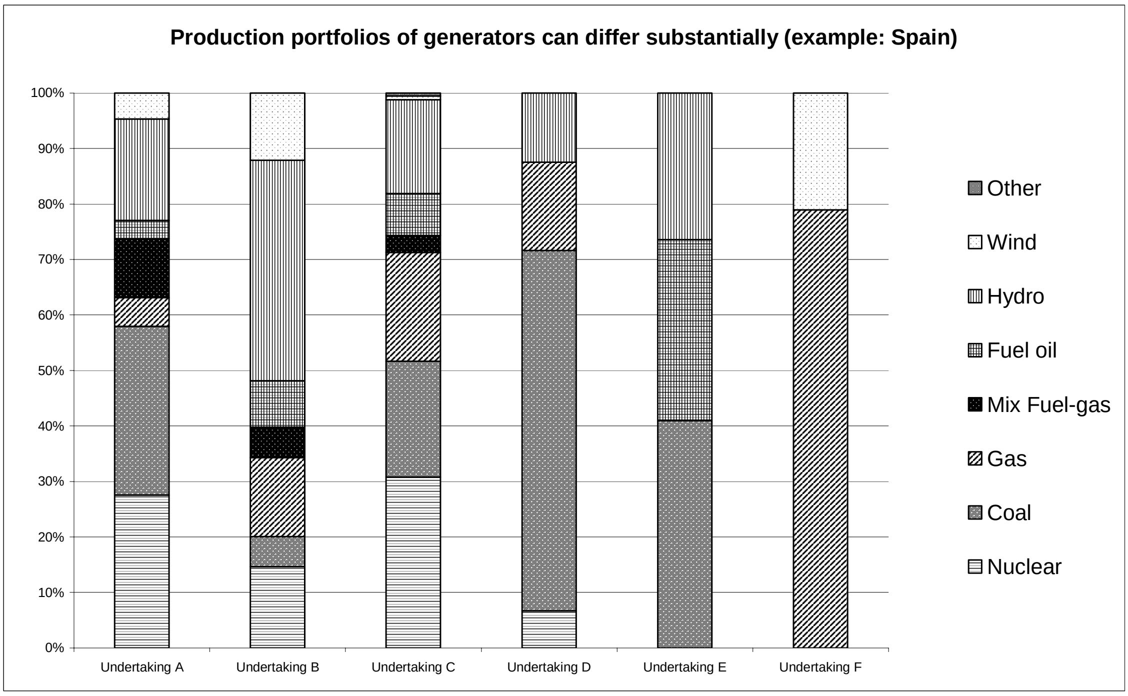
(408) The charts also point to the possibility that companies with a limited share in generation capacity might have market power at certain moments. For instance, in Spain, the second largest operator has almost the same size of installed capacity as the largest one (and both of them represent one third 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, this indicates that the largest producer might have scope for profitable withdrawals of capacity according to the first scenario mentioned above, whereas the

[50] Some market participants have noted that a number of factors contribute to a lack of investment: the lack of visibility on the long-term for the EU ETS mechanism, the availability of sites, etc.

[51] New wind power represents 33% of the new electricity generating capacity in the EU.

second largest operator might rather have scope for charging high prices at times of peak load[52].

Figure 44



Source: Energy Sector Inquiry 2005/2006

(409) 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 B.b.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.

(410) 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 is being 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.

52 The operator concerned has commented in the public consultation that it would not have market power, but its statement cannot be reconciled with the results of the analysis of bidding on the power exchange, as will be shown in section cII.1.5.1.

II.1.4. Concentration in trade

II.1.4.1. Introduction

(411) 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. Further, the spot market outcome is decisive for the forward market according to a number of market participants, as it constitutes the market of last resort for purchases of electricity[53] and will thus set the direction for forward prices. So these markets serve as an important means of sale and purchase and develop reference prices.

(412) 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

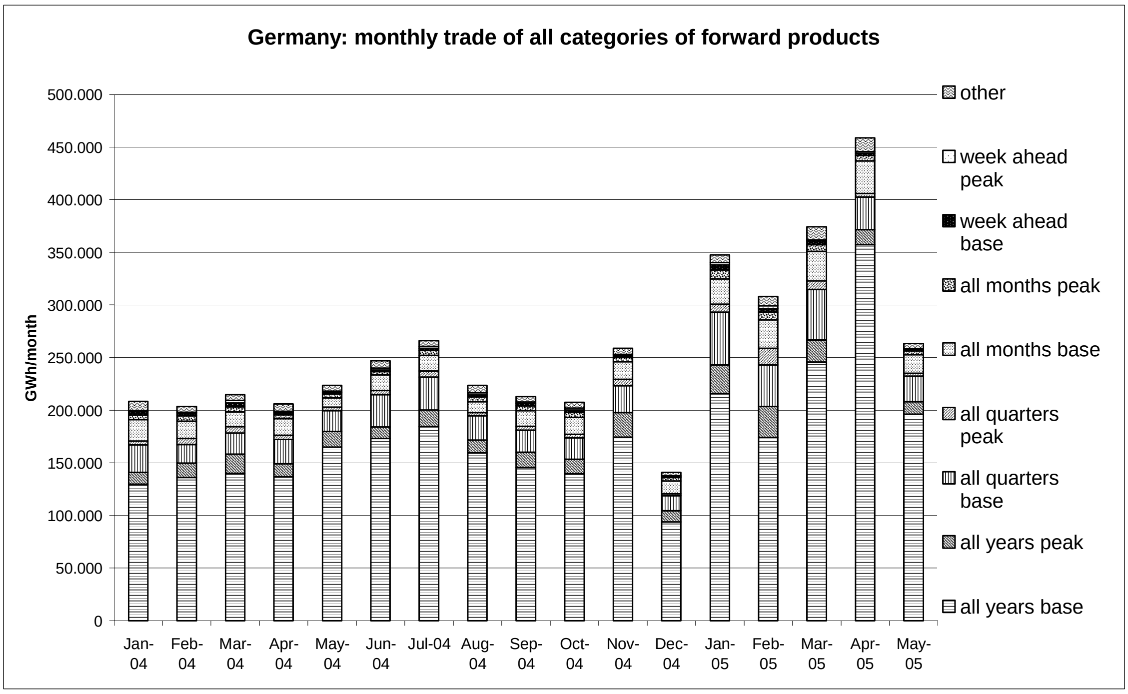
(413) The most traded product by far on forward markets is the yearly contract for base load hours. An exception is the UK market where products for different seasons are the most traded products[54]. Figure 45 shows for example the proportion of trade of the different forward products in Germany. Further, the yearly forward prices are the main forward price indicator in all markets, for both wholesale and downstream retail contracts.

(414) 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 assessed separately.

[53] This is true for many new entrants who are short of electricity (i.e. they have less electricity generation capacity than they need to supply to final customers) as is shown in the chapter cII.2.

[54] 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

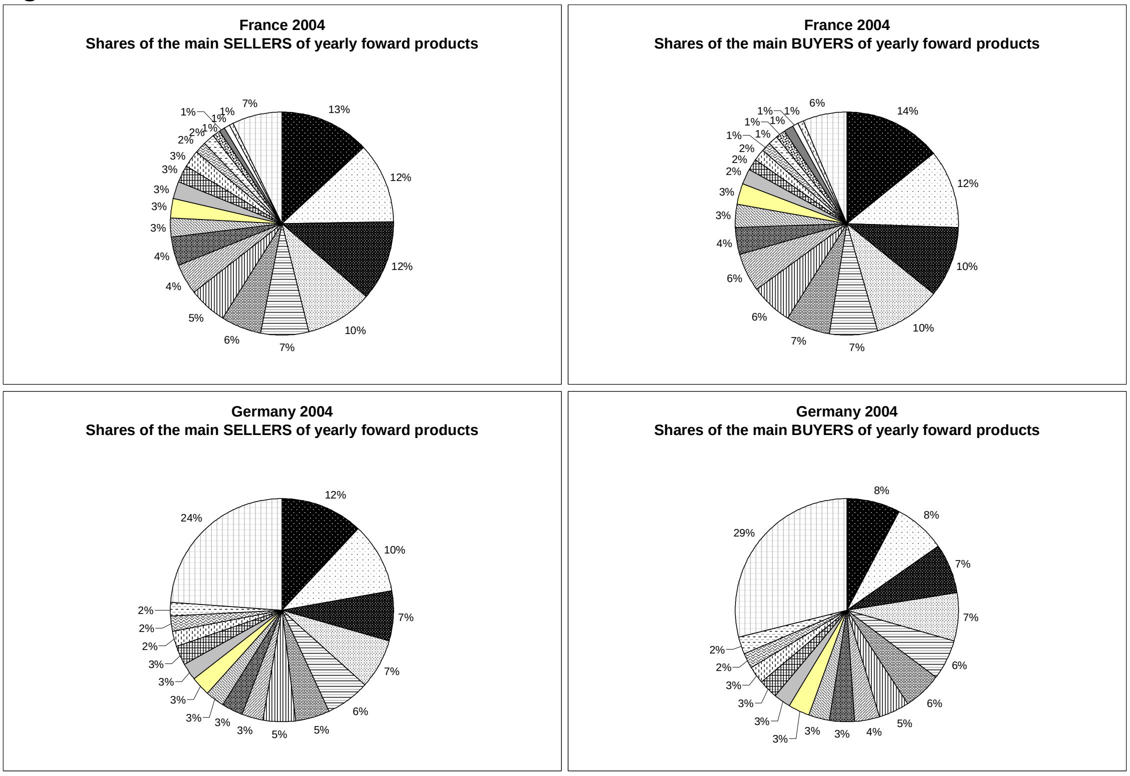
(415) Figure 46 illustrates for France and Germany in 2004 the trade in yearly forward contracts (indicating the shares of the main sellers and the main buyers separately[55]). Charts for other forward markets can be found in Annex C. The charts represented here and in the annex show that, except for 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.

(416) 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”[56]. 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.

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

56 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.

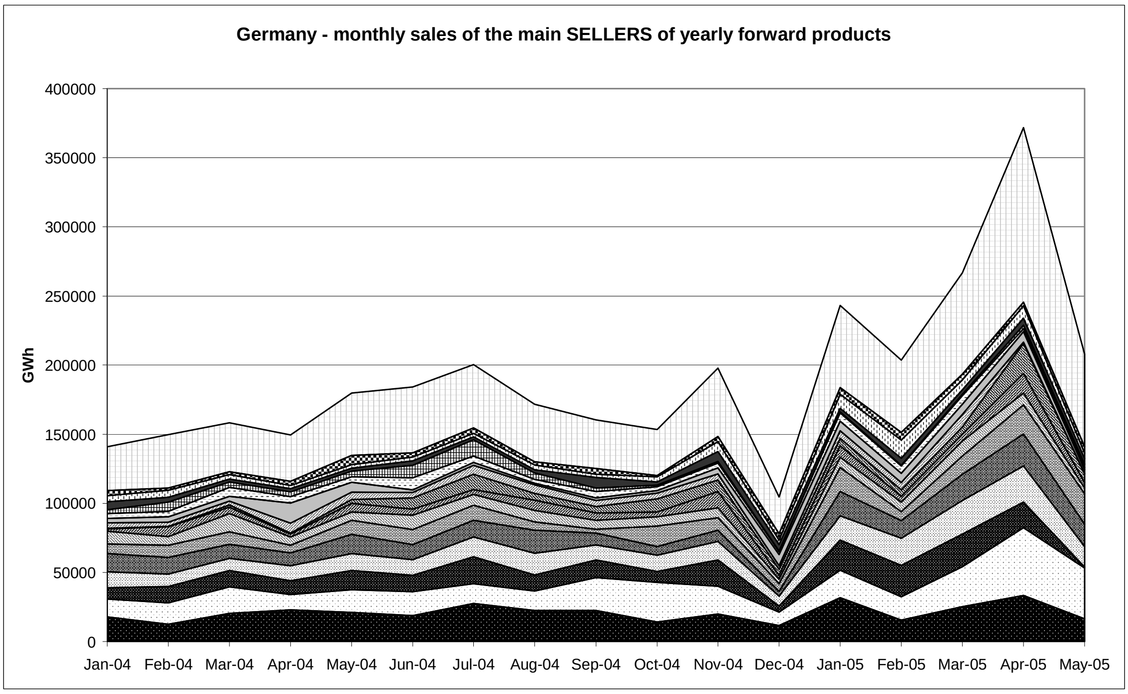
(417) An important result, shown in the charts, is that shares in trade do not reflect shares in generation. Furthermore, for the markets analysed, almost no trading platform has been identified where operators systematically have a dominant position on supply or demand as is claimed by a number of market participants[57].

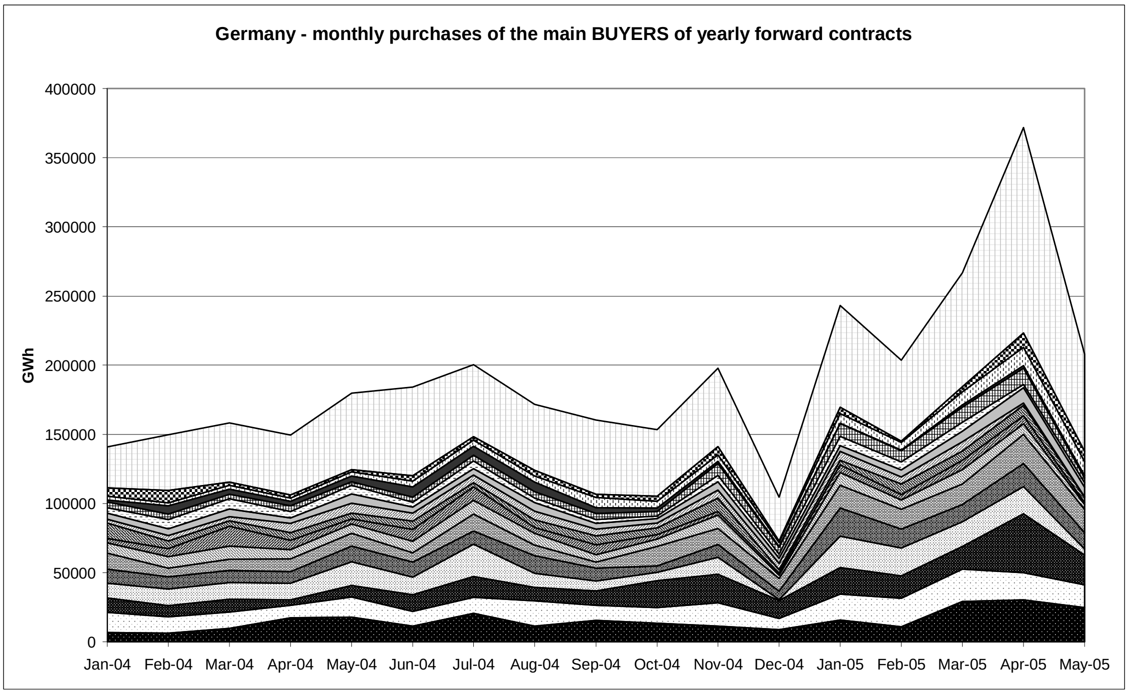
II.1.4.2.2. Evolution of concentration in forward trade over time

(418) 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.

[57] 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.

(419) The monthly evolution of relative trading positions for the annual contract during the period January 2004 – May 2005 shows that, except in Belgium[58] 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

[58] 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 are becoming 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.

(420) 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.

(421) 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[59]. 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. Chapter B.b.II.2 confirms that only a limited number of operators have excess generation compared to their retail sales (they have a "long position") and thus control the supply of the market. It remains to be seen if the generators in those markets could affect the trade in forward products by changing abruptly their net positions.

II.1.4.3. Concentration in spot markets

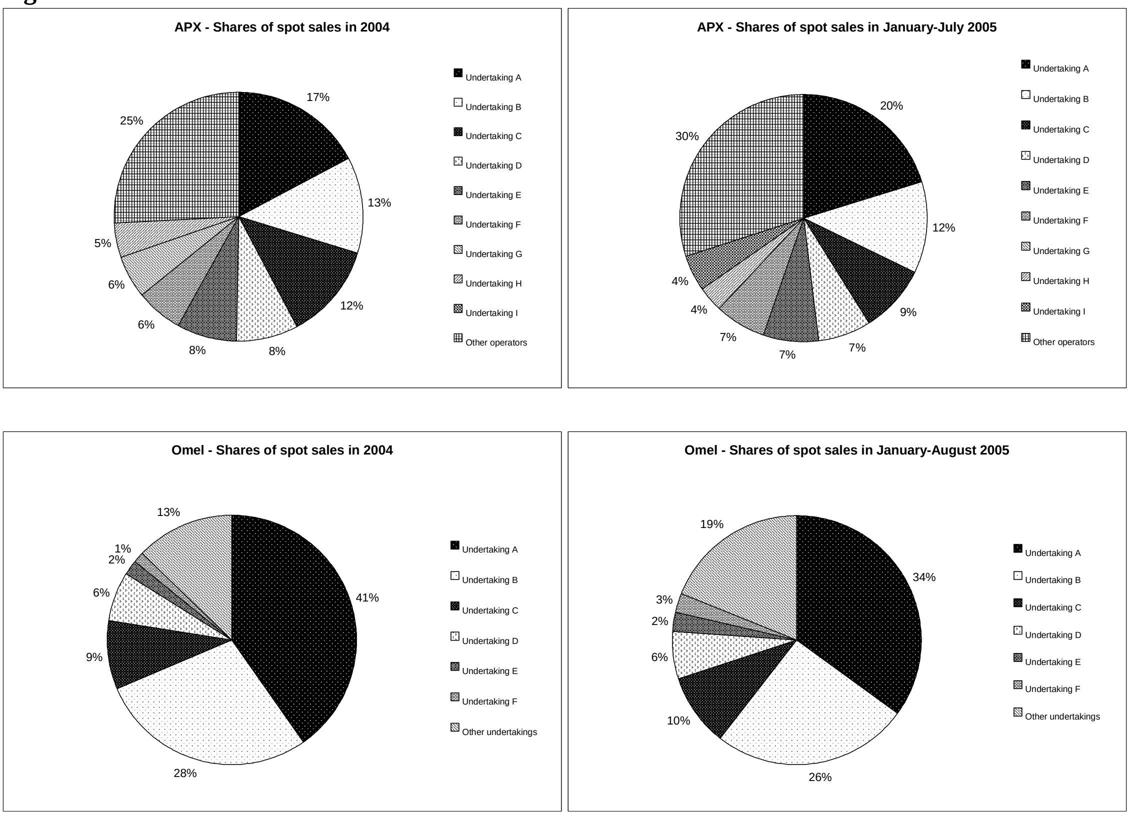
(422) Power exchanges, where one can trade day-ahead on an hourly basis, often functions as a last resort to close an open contractual position before gate closure. Alternatively one may be exposed to balancing market prices that in some Member States are highly unpredictable and are reported as (economically) punitive by certain market participants. See section C.c.II on electricity balancing mechanisms. 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 exercising market power. Some market participants

[59] The inquiry has 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 B.b.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.

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.

(423) 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

(424) 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[60]. This situation does not reduce the concerns that there is scope for market power.

60 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 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.

(425) 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 exchanges for the different operators[61]. However further assessment in the form of additional indicators is necessary.

II.1.5. Additional indicators

(426) 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)[62].

(427) 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 certificates, constraints on interconnections, etc), as explained in other chapters. These factors and constraints make it more difficult to identify the final effect of an anti-competitive practice as some of these constraints 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

(428) 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[63]. 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.

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[61] 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.

[62] As indicated earlier, some market participants note that the scope for excessive pricing may also exist outside exchanges in case a single generator dominates the market and is able to impose directly higher prices in contracts negotiated bilaterally with other operators. Such comments by market participants particularly relate to markets which do not have a power exchange or whose exchange represents only a low percentage of total consumption.

[63] 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. Further, some market participants underlined in the public consultation that the price of the offers made by generators on an exchange may not be exactly equal to the marginal cost of the plant (operating costs including fuel cost) that they intend to run as some plants may have high start-up costs to be added to the marginal costs or may benefit from some subsidies: this is taken into account in the analysis presented because it deals with offers made rather than the underlying costs.

II.1.5.1.1. Price setting frequency

(429) As a first rough measurement of concentration at the right end of the merit curve, in all exchanges for each operator the number of hours were identified when this operator "set the clearing price", meaning the hours when its selling bid was equal to the clearing price[64]. This does not mean that this operator has unilaterally set the price of the market (which is determined by the aggregated supply and demand curves[65]) but this gives an indication of how often an operator makes selling bids at the 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.

(430) 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 most frequent price setting company 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[66]. 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.

(431) 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[67]. 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

64 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.

65 In that respect, there is also a "price setter" in the same meaning on the demand curve, i.e. an operator buying energy whose price bid is equal to the clearing price of the market. The analysis in this chapter is focused on the supply curve.

66 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.

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

plants of the main generator(s)[68]. 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[69].

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%.

68 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 B.b.II.1.3, depending on the possibilities of arbitrage between markets.

69 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.

(432) 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[70], 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[71]. 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 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.

(433) 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

(434) 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.

(435) 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[72].

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70 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).

71 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".

72 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).

(436) 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 seems 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).

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

(437) 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).

(438) 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.

(439) 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, a similar calculation has been done[73]. It has produced graphs similar to those below (please see annex I) but their interpretation is less straightforward as one must take into account the maintenance schedules of the plants.

(440) 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[74]. The load factor is then equal to the effective measured output during the period divided by its (potential) maximum.

(441) 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.

(442) 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.

(443) 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.

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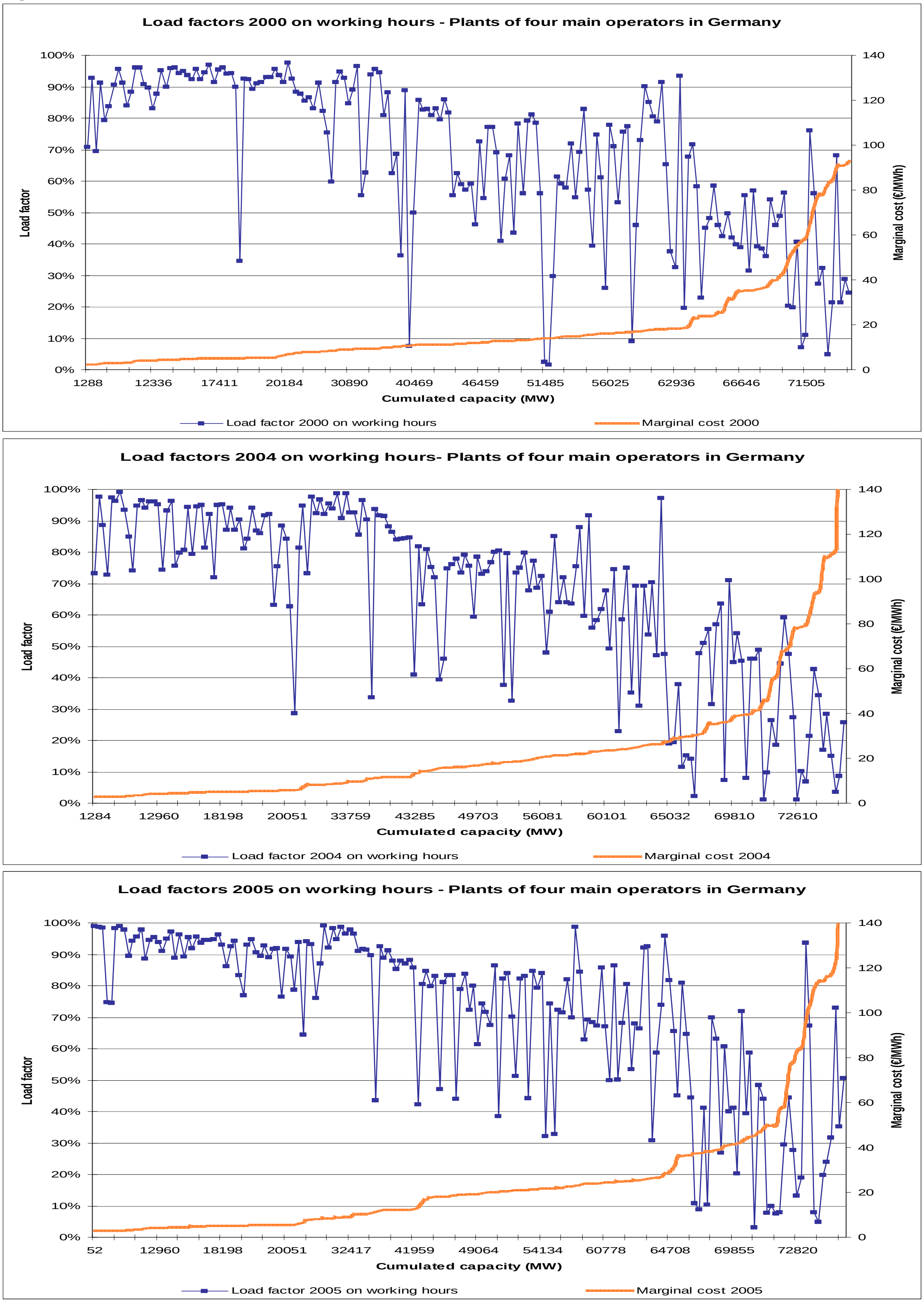
73 Whilst the calculation of load factors for full withdrawals have been made in relation to "all hours of each year", the partial withdrawals calculations were made on "working hours" only.

74 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

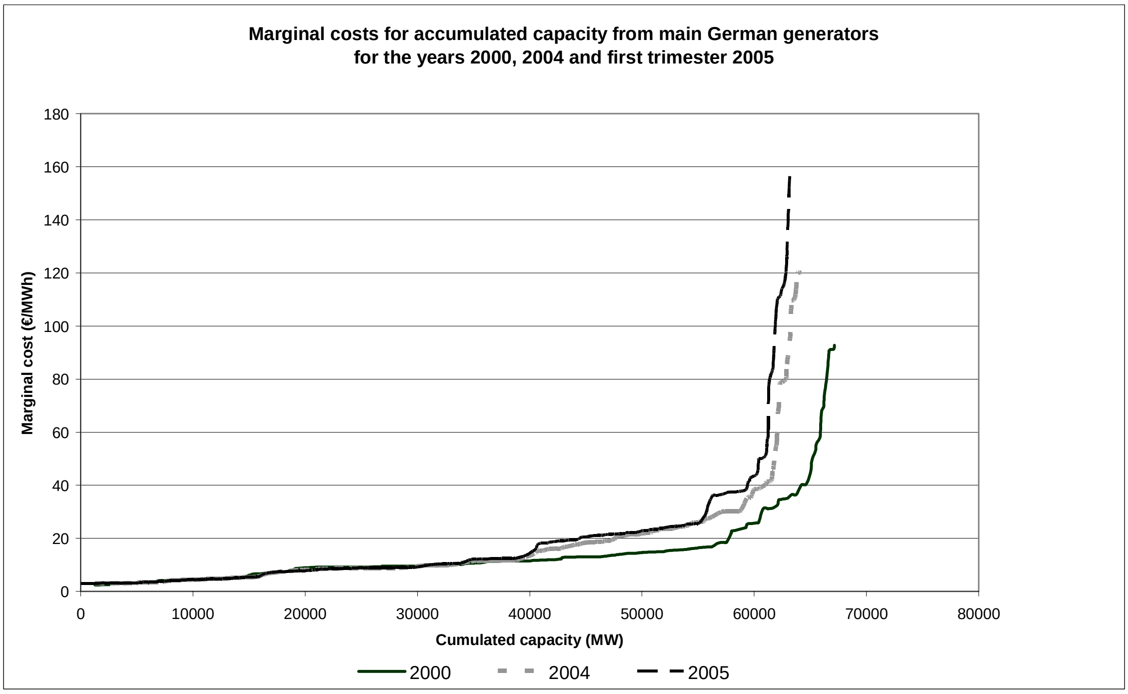


Source: Energy Sector Inquiry 2005/2006

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.

(444) Figure 50 shows the same calculations as those in Figure 49, 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.

Figure 50



Source: Energy Sector Inquiry 2005/2006

(445) 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 2149MW (addition of 960MW of capacity, and retirement of 3109MW of capacity). The retirement of a plant may be explained by the age of the plant and the need for an operator to replace its old plants. In that respect it is to be noted that in the preceding years some new plants were switched on by these operators, although net additions in the preceding years were still of a lesser scale than these retirements[75]. In any event, this decrease of total capacity is likely to have had 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 (2679MW) 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%.

(446) 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. They show a similar situation in terms of increased usage of the plants but are different in terms of the overall merit curve due to the specificity of the operator's portfolio. Some respondents in the public consultation note in that respect that this operator has retired

[75] In the year 1999, the four operators added little net capacity, but in 2000 they added around 1500MW.

some less expensive coal-fired plants in the period 2000-2005 while de-mothballing some more expensive fuel oil fired plants.

(447) More generally as regards withdrawals of capacity, some comments made in the public consultation argue that certain power exchanges may have enough resilience to withstand a withdrawal of capacity. In that respect, one power exchange computed that 500MW of additional demand during a given winter month (January 2006) would have generated an averaged increase of a bit less than 4€/MWh. Whatever conclusions are drawn from this figure, it could be useful for regulators and competition authorities to know what kind of resilience power exchanges have in order to identify the scope for withdrawals of capacity.

(448) Further indices are presented in chapter C.c.III.

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. Concentration is a key factor in the proper analysis of the price developments. Other factors are the developments in fuel prices and the impact of the EU Emission Trading System.

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 on forward markets where electricity can be traded several times before delivery. However, all spot and forward markets, even the most developed forward markets, remain dependent on the few players which enjoy a net excess of generation compared to their retail supplies.

Further, an analysis of who determines the clearing price at certain power exchanges indicates that there is scope to directly influence prices by excessive bidding prices for operators in Italy, Spain and Denmark. Possibilities to move prices might also exist in other markets.

In addition to excessive bidding, large operators can push up prices by withdrawing capacity. In that respect, it appears that load factors of generation units have increased over time in Germany and in France suggesting higher efficiency levels and a tighter supply/demand balance. However, 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.

II.2. Vertical foreclosure and vertical integration[76]

(449) 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.

(450) 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

(451) 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[77].

(452) 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).

(453) 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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76 The title was chosen in order to ensure consistency with the gas part. Contrary to gas the chapter mainly deals with vertical integration.

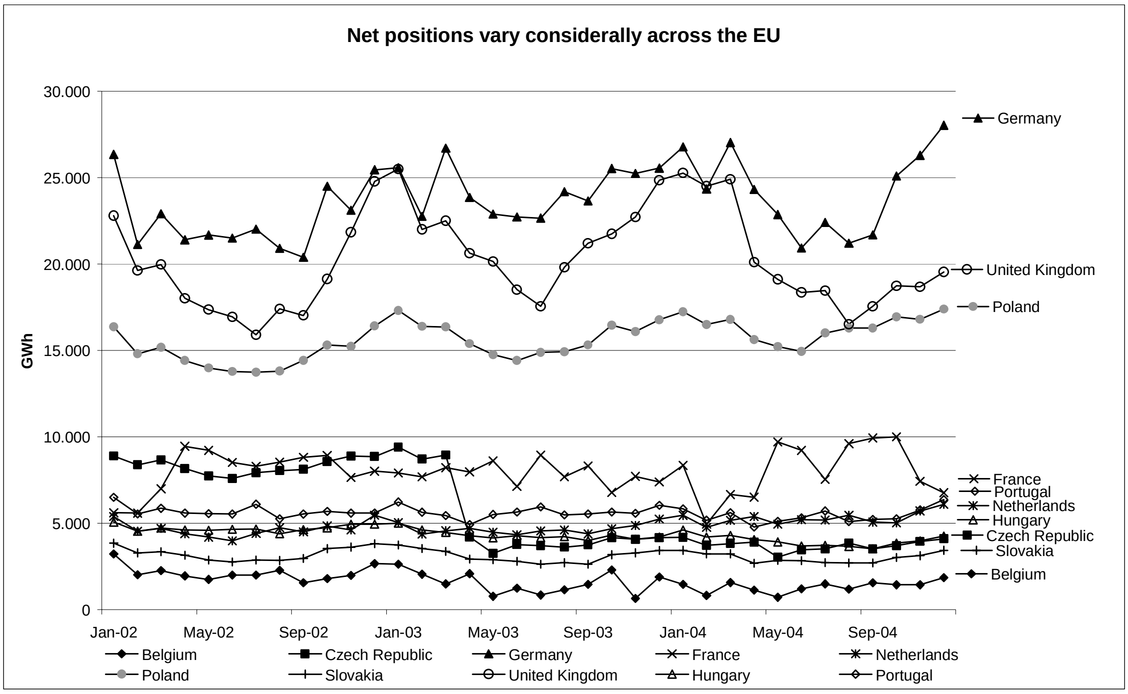
77 Vertically integrated companies continue to have incentives to trade on the wholesale markets, in particular to optimise their generation portfolios. A vertically integrated company that owns the generation capacity to produce all the electricity needed to cover its customers requirements will benefit 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. For “pools” see footnote 79 below.

(454) 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 portfolio, but can choose to enter as purely 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

(455) 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[78] 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.[79]

Figure 51



Source: Energy Sector Inquiry 2005/2006

(456) 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

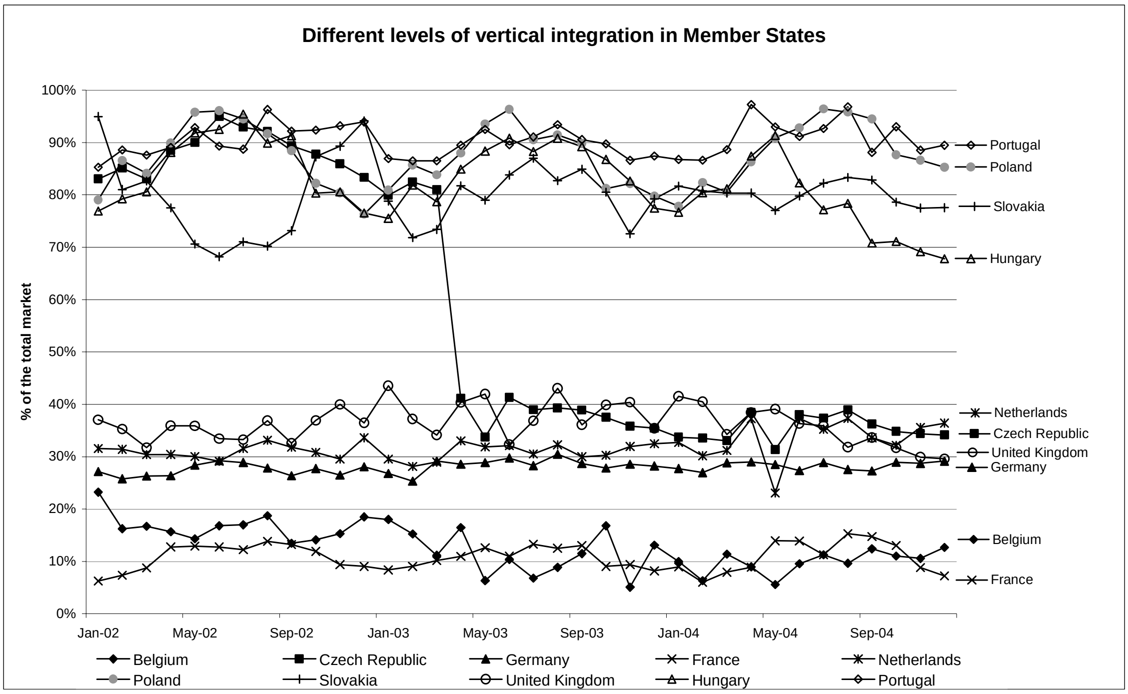
78 The analyses here cannot be directly translated to the manner in which contracts are traded (OTC, power exchange, bespoke bilateral contracts) or the time horizon over which contracts are traded (a given long or short position can be closed immediately before gate closure or any time before.)

79 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.

(457) 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[80], 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

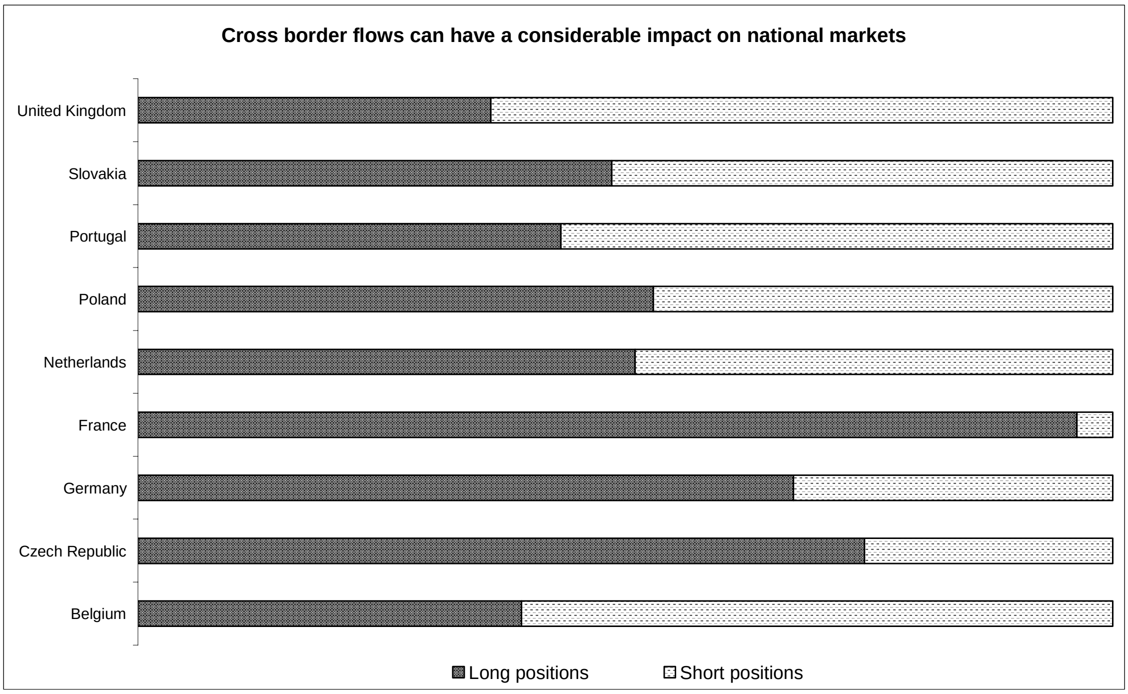
(458) In Poland, the positions to be cleared by trading almost equal the total size of the Polish market, i.e. hardly any generators were selling to final customers. This is however primarily due to the Government's previous policy not to allow vertical integration. The same comment can be made as regards 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 a single buyer regime at the wholesale level.

(459) 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

80 In its comments to the Preliminary Report, CEZ a.s., the Czech incumbent, informed that as of 1 January 2006 its generation and retail activities are carried out by two separate entities: CEZ a.s. and CEZ Prodej s.r.o., respectively. The latter entity is acting as a retail arm of CEZ a.s. and maintained that it would source, on an independent basis, all its electricity needs from the wholesale market. However in the context of the Sector Inquiry it was not possible to verify whether the separation is effective in practice.

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 Member States 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.[81]

Figure 53



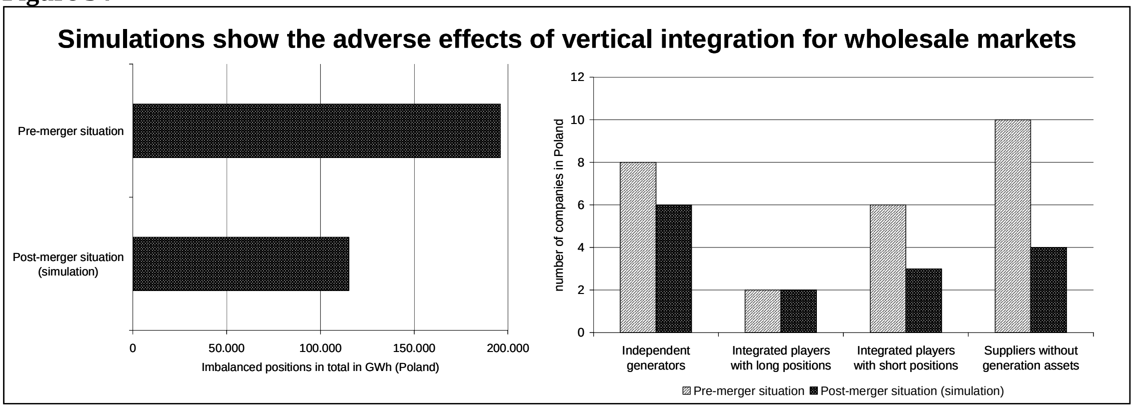
Source: Energy Sector Inquiry 2005/2006

(460) 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.

(461) 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).

[81] 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

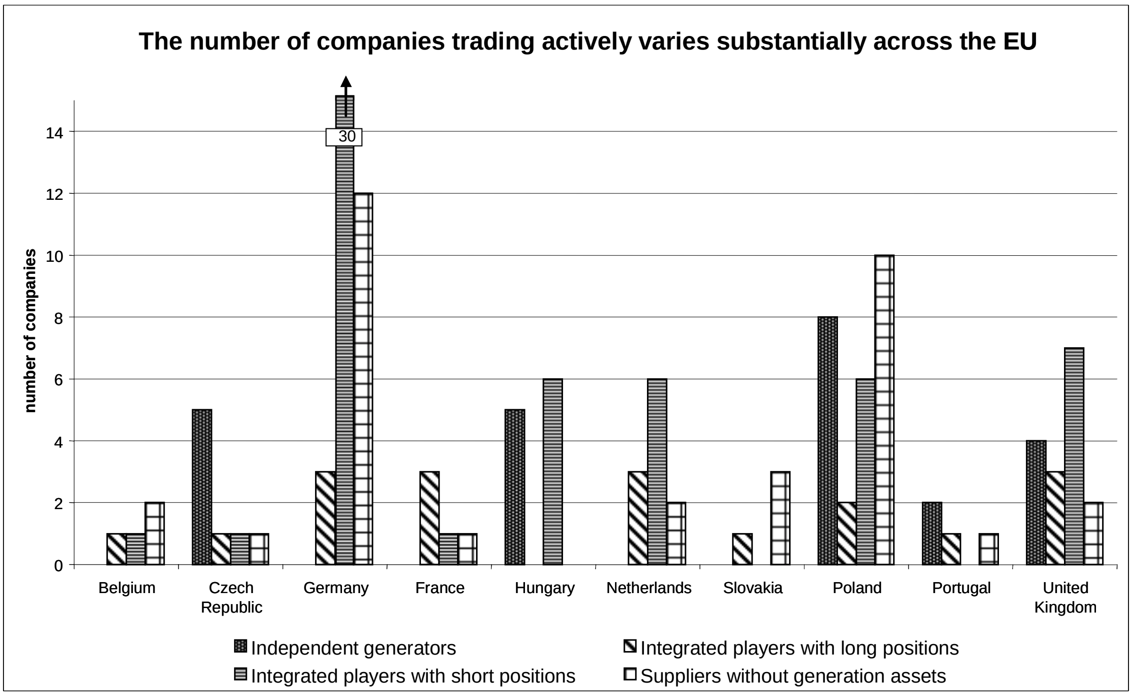


Source: Energy Sector Inquiry 2005/2006

II.2.1.3. Market participants

(462) 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

(463) Figure 55[82] 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.

(464) 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 its own supplies from the electricity wholesale markets. Therefore, if an integrated company is net short, its generating branch has less or no 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[83].

(465) 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.

(466) For the purpose of calculating the concentration levels, indices based on sums of squares[84] 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[85] 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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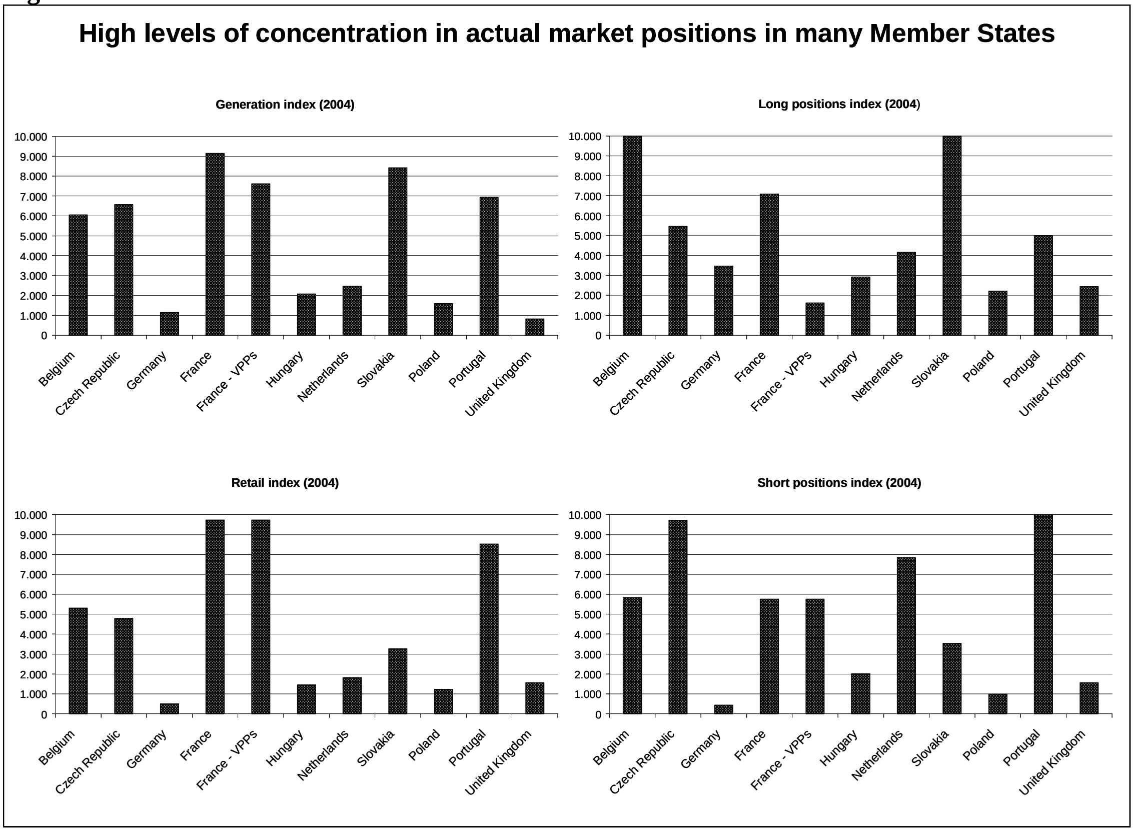
82 Figure 55 does not include suppliers with the annual sales (to final customers) below 1TWh and those of independent generators which have less than 250MW of capacity.

83 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.

84 The mathematical formula 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.

85 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

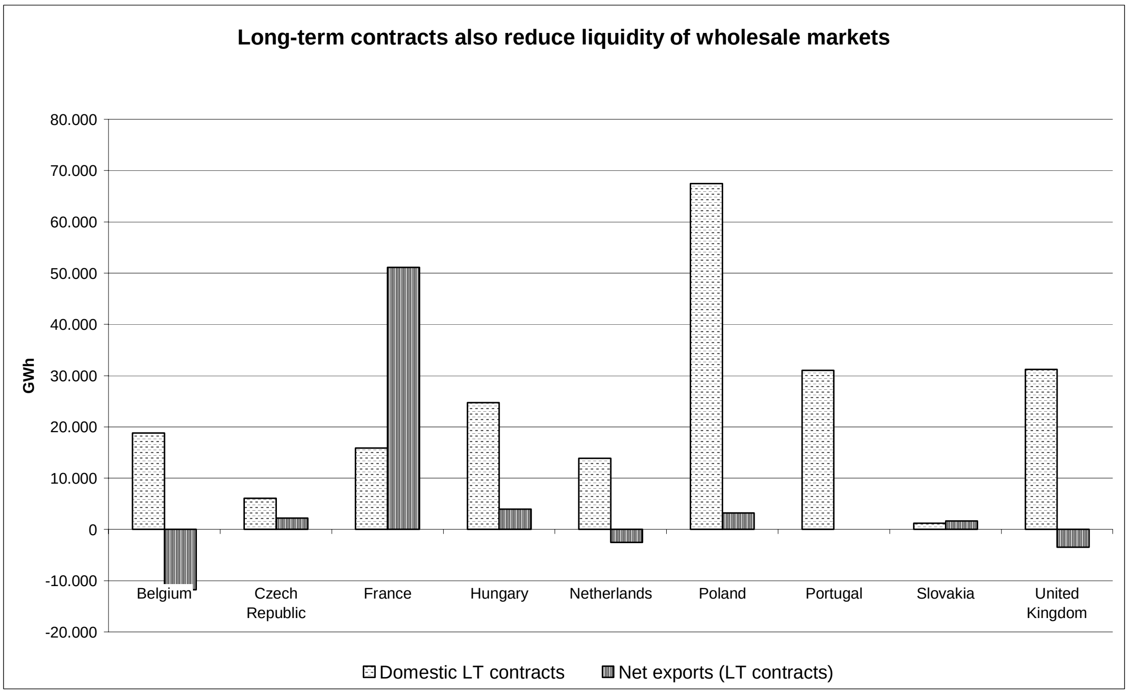
II.2.1.4. Long-term power purchase agreements

(467) 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[86] is also traded. But it has only a limited effect on the price formation process on spot 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).

(468) 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 tend to 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 contracts, mitigating the effects long-term contracts may have on these countries. In France, the opposite is true.

[86] 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

(469) 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.

(470) 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.

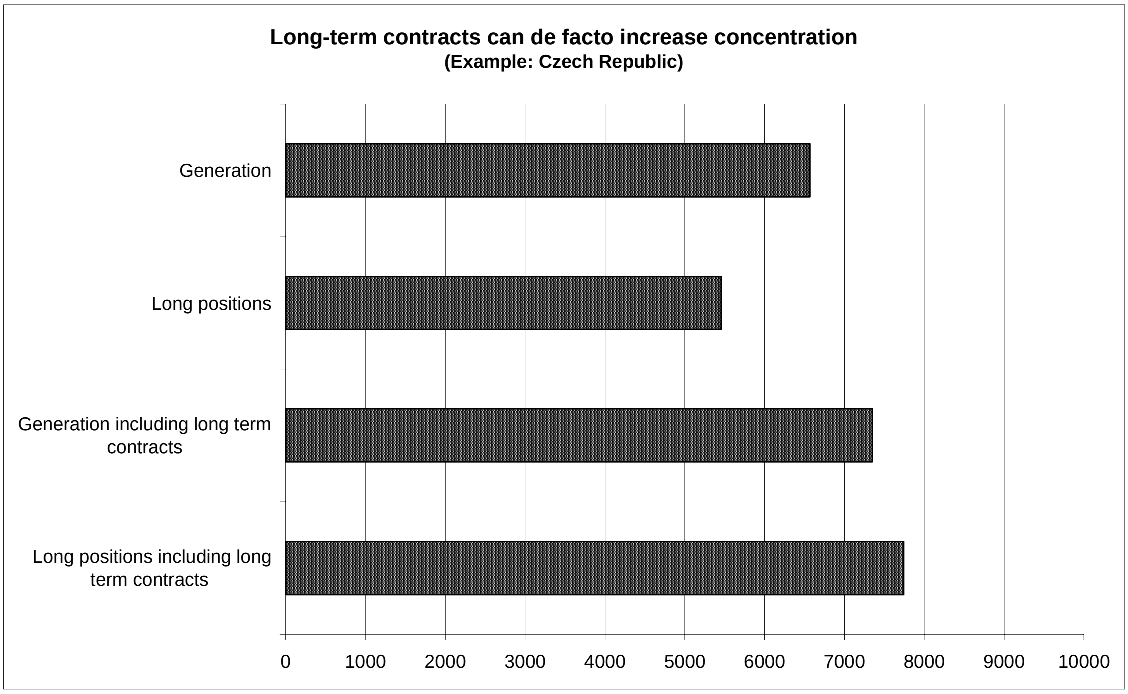
(471) In Poland, the long-term arrangements have predominantly a domestic character. A large number of long-term contracts exist, which were signed mainly in the 1990s between generators and the former national incumbent company, Polskie Sieci Energetyczne ('PSE'). PSE resells this energy to the local 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.

(472) A similar situation exists in Hungary, where Magyar Villamos Művek ('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 Member State'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.

(473) Potentially traded volumes appear to be less affected by the long-term contracts signed in Member States 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[87].

Figure 58



Source: Energy Sector Inquiry 2005/2006

II.2.2. Vertical integration between supply and network activities Inefficient unbundling

(474) 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. Competitors thus need effective access to the existing network.

87 In the public consultation of the Preliminary Report, CEZ a.s., the Czech incumbent, informed that, in 2006, the electricity volumes tied in its upstream PPAs with the independent power producers decreased by 24 per cent in comparison with the year 2005. CEZ also referred to two contracts signed for indefinite periods that must be extended for the following calendar year by means of a revision. In the company's view, these two contracts should not be classified as long-term PPAs. As regards of the Sector Inquiry analysis, the exclusion of the two contracts in question would only result in a slight shortening of the two bottom bars in Figure 58 and thus would not alter the paragraph's general conclusion.

(475) A company active in electricity generation and/or supply that owns at the same time transmission or distribution network assets has, however, an incentive to use its monopoly position as network owner to prevent or limit 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 and render market entry more difficult. This in turn can reinforce the market power of incumbent generators/suppliers. With the same token the market power of incumbent operators can be prolonged through the failure to invest in network expansion.

(476) It is to limit the risk of such behaviour from occurring that the Second 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 1 July 2007. They can also decide not to impose certain unbundling obligations on distribution companies that have less than 100.000 customers.

(477) Unbundling requirements for gas and electricity companies are essentially the same. To avoid further repetition, reference is therefore made to the Chapter on vertical foreclosure in the gas part, which contains a more detailed description of what full implementation of the unbundling rules entails.

(478) As regards TSOs most Member States have by now implemented the Second 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 DSOs, compliance is less advanced[88]. It is true that Member States only have to comply fully with the unbundling requirement for DSOs by 1 July 2007. However, at the time when the Preliminary Report was written a significant number of Member States still has 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[89]. For those Member States, for which the Commission reached the view that they had not respected the obligations under the Directive, infringement procedures were launched in April 2006.

(479) 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 group. 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

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

[89] 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).

('DSOs') will no longer have the incentive to favour affiliated companies –since there are none-, but can focus on optimising the use of the networks.

(480) This chapter mainly describes the obstacles to effective unbundling as reported by market participants in reply to the Commission's information requests of summer 2005. In reaction to the Preliminary Report certain operators – particularly vertically integrated companies opposing ownership unbundling - claimed that the information presented in the report is outdated taking into account that the unbundling provisions under the Electricity Directive were only implemented into national law shortly before the Inquiry. Accordingly it is also maintained that only little experience existed with the new unbundling regime and more time should be given to prove that the unbundling regime foreseen in the Second Electricity Directive works in practice.

(481) In this respect it suffices to say that the Commission services continued to gather information about existing unbundling practices also after the Preliminary Report. The new information confirmed the earlier assessment that the current level of unbundling is insufficient (for details see below). In certain areas the concerns expressed earlier were even reinforced. It is therefore submitted that the behaviour described below still reflects current realities.

(482) This subsection is structured as follows: In its first part it sets out a number of practical problems with unbundling as reported to the Commission. The chapter then goes on to describe the obstacles for market participants with new generation projects to connect their power plants to the net (essentially to the TSO network). It concludes that vertically integrated companies have an incentive to delay market entry and in practice take certain measures leading at least to delays for new power projects. The third part deals with access to the network from the perspective of network users (e.g. traders). Again the incentive structure for vertically integrated companies is at the heart of the findings. The fourth part deals with obstacles to switching at the distribution level. For all parts (as well as the parts described in other chapters) it transpired from the analysis that the current level of unbundling is not satisfactory and calls for further action.

II.2.2.1. Practical problems in the implementation of the unbundling provisions

(483) Taking into account the historic development of vertically integrated electricity companies it is not surprising that legal and functional unbundling of network activities and supply/generation activities is taking significant time and efforts to implement in practice. There are a number of obstacles of a practical nature.

(484) For example, the Sector Inquiry confirmed that the unbundled network and supply branches are - in many instances - still located in the same building. This also means that the personnel of the supply branches have "better access" to the employees working in the network branch. The employees of these branches still share a large number of common facilities. For instance they go to the same company restaurant, which allows for an informal exchange of views. They also attend the same training programmes/facilities allowing for the same exchange of information. In certain companies network and supply/generation branches also share the same IT services[90]. All these seemingly small

[90] Vertically integrated companies maintain however that Chinese Walls exist within the IT system. As a consequence employees of the supply branch do not have access to the data stored for the network business.

factors contribute to the continuation of a close cooperation between the formally unbundled branches (special relationship). In some instances it has been confirmed that the "special relationship" leads to a (systematic) copying of e-mails to the other formally unbundled, but affiliated branch (lack of "information unbundling"), whilst obviously third parties do not get access to such information or only at a later stage.

(485) Another important concern stems from the fact that the personnel still perceives themselves as employees of one and the same group, and that there are a number of factors reinforcing the group identity. It was thus brought to the attention of the Commission that in certain companies the head of TSOs systematically participates in the strategic discussions of the holding company. Accordingly he/she is well informed about the group's generation and supply interests and can/will report about them to his colleagues in the network business. At the same time the management of these vertically integrated companies are not limited in their career prospects to the branch, for which they currently work. Moving from one affiliated branch to the other seems to be current practice and will have an impact on the decision making process in the network branch. It will certainly not give the management in the network operation the incentive to take decisions, which are likely to harm the generation and supply interests of the group or favour new entrants over the affiliated branches. The obligation to have compliance programmes and annual reporting in place has not adequately changed the assessment.

(486) In the light of the above described practical problems regulatory oversight is very difficult. Particularly in Member States with a high number of transmission and distribution companies it is virtually impossible for the regulator to verify in all companies that the unbundling provisions are fully respected, even if the Directive is correctly implemented into national law. Generally the regulator will simply not have the resources to ensure that unbundling requirements are complied with.

II.2.2.2. Grid connection for new power plants

(487) In order to replace Europe's ageing generation facilities significant investments into new power plants will be needed in the coming years. Taking into account that in many Member States the Sector Inquiry has confirmed a high degree of concentration in generation, it would clearly be preferable for the future market structure if new power projects were not only developed by incumbent operators, but also – or even primarily - by new entrants[91]. However the Sector Inquiry has confirmed the existence of a number of obstacles to connecting new plants to the TSO network. When the network is owned and operated by vertically integrated electricity companies, the TSO is unlikely to have an incentive to connect potential competitors in the generation/supply business to their network.

(488) 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 were submitted. With this qualification, it is fair to say that blatant refusals for access to networks appear rare. In this respect it is important

[91] For the avoidance of doubt it should be underlined that the investment into a new power plant located in Member State A by incumbent from Member State B would also be considered to be a market entry by a "new entrant".

to underline that network operators can only refuse access to their networks if no or insufficient capacity exists.

(489) This does not mean however that the access to networks is unproblematic. Despite an 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.

(490) 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 any project unviable. The request by a TSO for compensation for network reinforcements is particularly problematic, if the alleged congestions cannot (exclusively) be attributed to the new plant(s).

(491) 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.

(492) Nonetheless the Sector Inquiry confirmed that in a Benelux country a project to build generation capacity was abandoned solely because the compensation demand from the developer to remedy capacity constraints rendered the project unviable. Allegedly, no insight was however provided by the TSO as to the causes of this congestion. Similar allegations have been made against German TSOs as well as one regional network operator.

(493) Obstacles can also stem from delays in the grid connection process caused by/attributable to the TSO. Market participants have reported that TSOs require significant documentation before a first application for grid connection for the new power plant can be made. This is time consuming and cost intensive at an early stage of a project. Others have maintained that grid connection can only be applied for once all necessary administrative permits have been received. It has also been reported that the assessment of the first application can take many months (up to 18 months), which delays the planning process. Finally it has been maintained that TSOs only agree to the final connection of the new plant to the network after all congestion is removed, even if the generation company has paid the required amounts in this respect. These delaying tactics are of a particular concern in the light of the fact that new power plants are reported in some countries to receive free emissions allocations only if they are up and running by the end of 2012 (end of NAP II).

(494) Often the works related to building new network connections can only be undertaken by the network operator itself, who also chooses the best geographical location of the grid connection. A vertically integrated network operator has no incentive to choose the shortest connection or 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 compared 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[92].

(495) Whilst the main focus of this chapter was connection to TSO networks it should be stressed that similar issues have been raised with regard to the connection to distribution networks. In this respect it needs to be underlined that decentralised generation capacity (linked to distribution networks) which permits a certain degree of auto-production having also a stabilising effect on grids, is expected to increase in the coming years.

II.2.2.3. Access to the TSO networks

(496) Article 20 of the Second Electricity Directive lays down the requirements for non-discriminatory access to networks at regulated tariffs. A refusal to grant access is only possible in case of capacity constraints and must be duly substantiated. Third party access is thus a statutory obligation, which can only be refused under specific conditions. However it should not be forgotten that TSOs also have other means than straight forward refusals which can amount to obstacles for other network users to use the existing network.

(497) Supply companies and traders complained in particular about problems relating to interconnectors. Issues brought to the attention of the Commission services in the framework of the Sector Inquiry included: (1) the lack of adequate investments into interconnectors; (2) use of allocation procedures that do not bring about maximum use of interconnector capacity; and (3) long-term capacity reservations in favour of incumbent operators. These issues are reported in more detail below, but the examples demonstrate that vertically integrated network operators, in practice, appear to favour the interests of the affiliated generation/supply interest.

(498) A particular problem is related to the lack of incentives for vertically integrated TSOs to remove bottlenecks in the network (most prominently at cross-border points), if these bottlenecks are assumed to favour the supply branches of the network operator. Following the adoption of the Preliminary Report a number of examples were brought to the attention of the Commission services demonstrating this. Amongst other things it was maintained that certain interconnector expansions did not take place or were delayed despite repeated requests from third parties to expand the capacity. The situation only changed after the vertically integrated supply branch itself expressed an interest in interconnector expansion. The expansion which was previously reported to be impossible was then achieved within a few months. It has also been suggested that vertically integrated companies carry out a detailed study on the financial implications of any expansion for its affiliate supply business.

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92 Experience in the UK has shown that, in order for this to function properly, arrangements have to be made to ensure that TSOs (and DSOs if connections are at medium or low voltages) 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 the Gas and Electricity Markets Authority to accept commitments pursuant to section 31A(2) of the Competition Act 1998 of 27 October 2005.

(499) Traders/network users also expressed concerns with respect to the provision of information. It was argued that information was only available to vertically integrated companies or was made available to them at an earlier stage, which undermined the level playing field and/or increased risks for new entrants. Obviously these concerns could be addressed by stricter unbundling rules. For further details on transparency reference is made to the chapter B.b.II.4 below.

(500) Concerns were also raised with respect to allegedly excessive access tariffs, which raise competitors' costs. In this respect it is noteworthy that network tariffs differ significantly between Member States, even though they are subject to regulatory oversight. Even if in some instances there might be a valid explanation for the discrepancies, it would appear unlikely that the differences can be fully explained by them. The fact that tariffs have historically been too high has also been confirmed by the decisions of regulators to reduce the tariffs submitted for approval by TSOs. For example, the German regulator reduced the requested tariffs of the German TSOs by up to 18% in summer 2006.

(501) 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.

(502) It seems fair to conclude from the above that vertical integration of network and supply activities strongly influences the incentive structure for network operators. Despite the obligation not to discriminate between network users there is a risk that investments do not take place if they would favour competitors of the affiliated supply branch. For a concrete example see the ENI case referred to in chapter B.a.II.2. Vertically integrated TSOs also have an incentive to favour their affiliated supply branch when it comes to the provision of information (transparency) or the fixing of network charges.

II.2.2.4. Access to distribution networks

(503) Problems with respect to effective unbundling between network and supply also exist at the distribution level. This is also reflected in the relatively low level of switching rates.

(504) In the framework of the Sector Inquiry, DSOs were asked to provide information on the new connections to their networks during 2004. The Sector Inquiry confirmed that the vast majority of these customers, which happen to be the most likely to accept offers from alternative suppliers due to low "switching costs", concluded a supply contract with the affiliated supply branch of the network operator.

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.

(505) Even if the figures in Table 22 should be taken with some caution, it is clear that the "switching rates" are very low. Only in the UK, and to a lesser extent, the Netherlands, did newly connected customers chose suppliers unaffiliated to the DSO to which it was being connected.

(506) 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 may well be attributed to this factor. In this respect it is emphasised that in view of these low switching rates, any barrier, even those that do not immediately appear to be significant, may nonetheless have significant effects on entrants' ability to acquire customers. It is therefore very important that switching procedures work properly and do not impose barriers to customer changing supplier.

(507) 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.

(508) 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. 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, which should help to improve the situation.

(509) 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. For example, such rules exist in Belgium. However, contractual relationships are geared towards the interest of the network monopolies in ways that effectively mean that non-compliance does not have any consequences for the

DSO and shifts 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. In reaction to these complaints, the network operators in Flanders have now committed to performance standards.

(510) 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. The lack of Chinese walls between the supply and network branch was also largely criticised in the public consultation.

(511) Examples have also been provided where distribution companies appear to have deliberately withheld historical consumption data to companies competing with their supply affiliates. In the Walloon region of Belgium, many DSOs still 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 currently has privileged access to information on customers, even those of its competitors. A similar situation continues to exist in Germany. Information advantages can also be abused in other ways. Late, or even, no announcement 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[93].

(512) 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 thing, customers were not invoiced the entire network charges due as long as the customer was supplied by the supply company affiliated to the DSO.

(513) 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 customers that may be more easily acquired by entrants.

(514) 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. On the basis of the new energy law the German regulator (including the regional regulators) should however now have adequate powers to set appropriate network tariffs which would remedy this situation.

93 The new German energy law should limit these possibilities in future.

(515) 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.

II.2.2.5. Way forward

(516) It is fair to conclude that unbundling measures required under the current Directives 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 (including investment decisions). 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 Second Electricity Directive.[94]

(517) 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, for instance, Belgium (where vertically integrated and ownership unbundled DSOs coexist) confirmed that the DSOs that are ownership unbundled perform significantly better in facilitating competition[95] than those that are still part of a vertically integrated company.

(518) Similarly, some network companies have expressed the view that ownership unbundling contributed to clarifying their role and purpose as grid operators towards market players. Through ownership unbundling, independent network operators would indeed have greater incentives to maximise the use of their infrastructure and to invest into further expansions. They would have less incentive to favour certain network users over others. Only incumbent operators contest this view, whilst a number of regulators support the call for full ownership unbundling.

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[94] 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.

[95] Belgium's 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 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.

Vertical integration of supply and network (transmission and distribution alike) reduces the economic incentives for the network operator to facilitate third parties access and to expand the network in the interest of all network users. In the views of many respondents the existing rules on legal unbundling do not ensure that vertically integrated companies do not engage in practices favouring their supply affiliates to the detriment of their competitors.

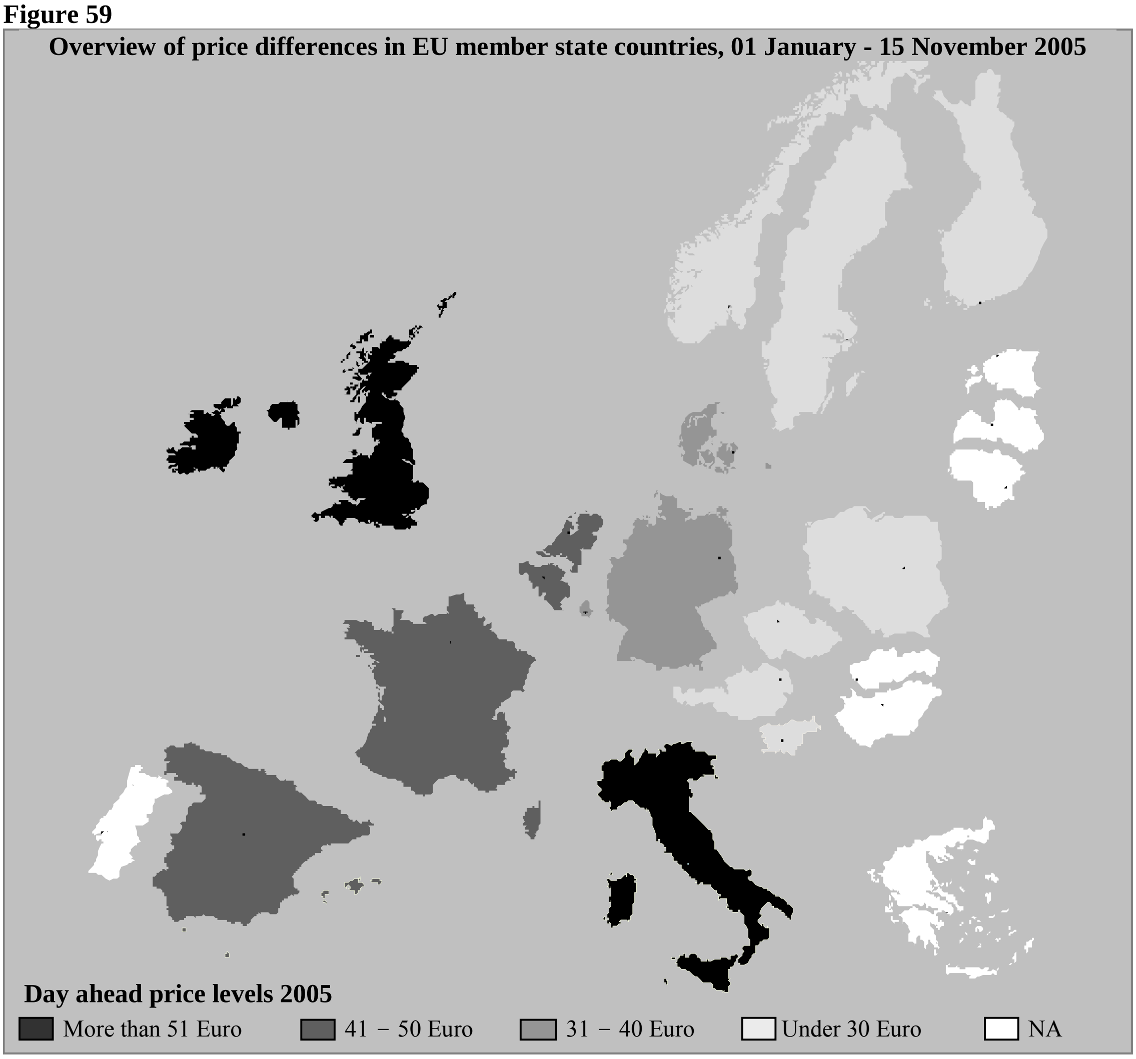
With respect to transmission networks, a number of respondents raised concerns as regards obstacles to connect new power plants to the network. No means exists to verify whether claims of congestion or costs for network reinforcements are valid. With respect to the distribution networks, respondents 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

(519) Interconnectors are essential for market integration. Through interconnectors generators and suppliers on both sides of the border are exposed to an additional source of 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, as illustrated in Figure 59, prices differed substantially during 2005 between geographical regions. The figures for 2006 also reflect significant divergence.

Figure 59



Source: Platts[96], Power exchanges.

(520) 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 has, as yet, hardly been observed in EU Member States.

[96] Data from Platts a division of The McGraw-Hill Companies 2006- all rights reserved.

(521) The Sector Inquiry leads to the preliminary findings that the lack of electricity market integration[97] 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

(522) 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[98] area includes 22 countries (also non-Member States). Another synchronous zone is the NORDEL area in Scandinavia. Additional DC-links (direct current-links) connect (other) grids further.

(523) Today the role of interconnectors has changed significantly. Under third party access rules, participants must now be able to access interconnector capacity in order to deliver power in neighbouring countries, trade on wholesale markets in other Member States 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.

(524) It is important to remember that the overall flow load pattern in the EU integrated synchronized network is not determined by the contractual arrangements but results from production and consumption locations, and network topology. The combined decisions made by generators, traders, suppliers and consumers result in electricity transports from one region to another. TSO manage these flows through a set of administrative rules, most importantly requesting players in the market to report in advance their expected production and load schedules, as well as the extent to which they intend to use interconnectors. This enables the TSOs to manage commercial transactions and physical flows in a secure manner in the high voltage grids.

(525) 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.

[97] At this stage cross border market power issues have not yet been assessed.
[98] Synchronous meaning that all members of UCTE work on the same 50 Hz frequency.

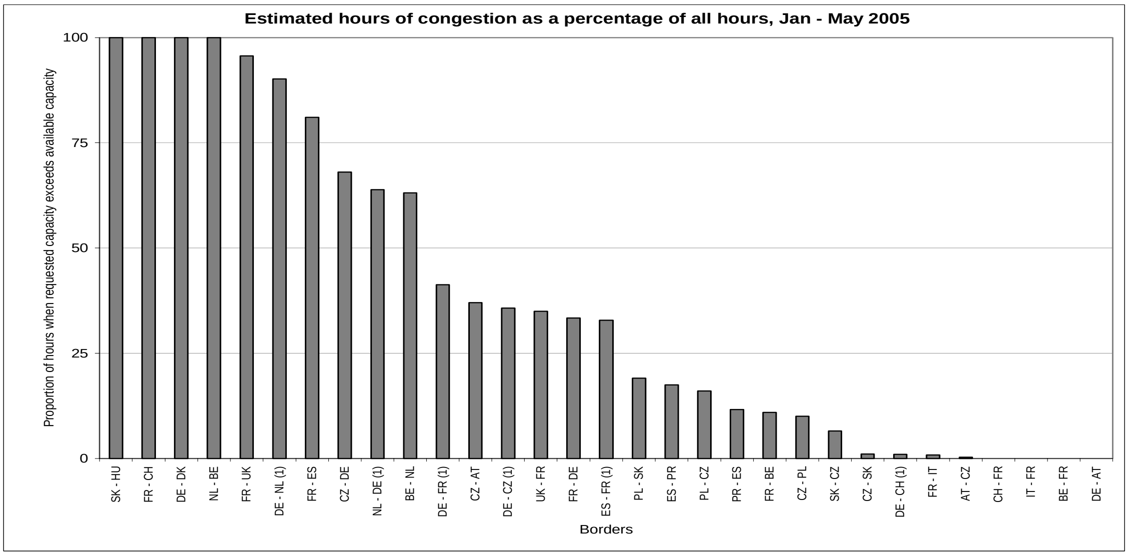
II.3.3. Insufficient interconnecting infrastructure

(526) 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. This process will shift the generation pattern in the grid toward lower cost production facilities.

(527) Demand for interconnector capacity at many borders has increased and often exceeds the available transmission capacity. This level congestion is illustrated in the subsequent Figure 60 per border. The bars, for each border, show the number of hours (sorted in ascending order) reported by TSOs when capacity requested exceeded the available capacity as a percentage of all hours in the period January – May 2005. Note that this situation can be independent from the physical flows in the grid.

(528) 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 were 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.

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.

(529) 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.

(530) It is likely that persistent price differences between Member States markets are amongst the main causes for congestions. Changes in wind speed can also cause unforeseen flows that might reduce the capacity available and increase congestion.

Table 23

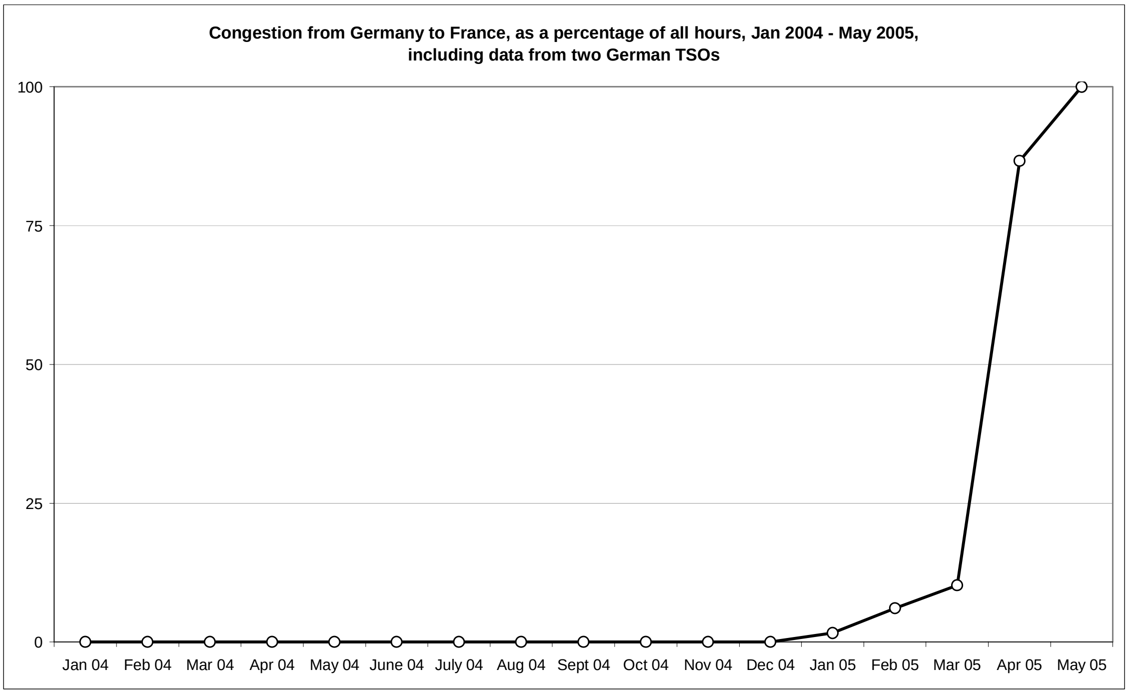
Hours with congestion as a percentage of all hours (selection of borders)

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.

(531) 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.

Figure 61



Source: Energy Sector Inquiry 2005/2006.

(532) The consequence of the substantial and increasing congestion 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.

(533) 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?
- How can the problem of lengthy and bureaucratic authorisation procedures be solved?

II.3.4. Level of interconnector capacity

(534) 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.

(535) The Barcelona Council 2002 set a broad 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[99], 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, Denmark, which has a relatively high level of interconnection, still has in some circumstances high levels of concentration in generation and scope for the exercise of market power as shown in the chapter Concentration and Market Power.

Table 24

Average hourly total import capacity 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

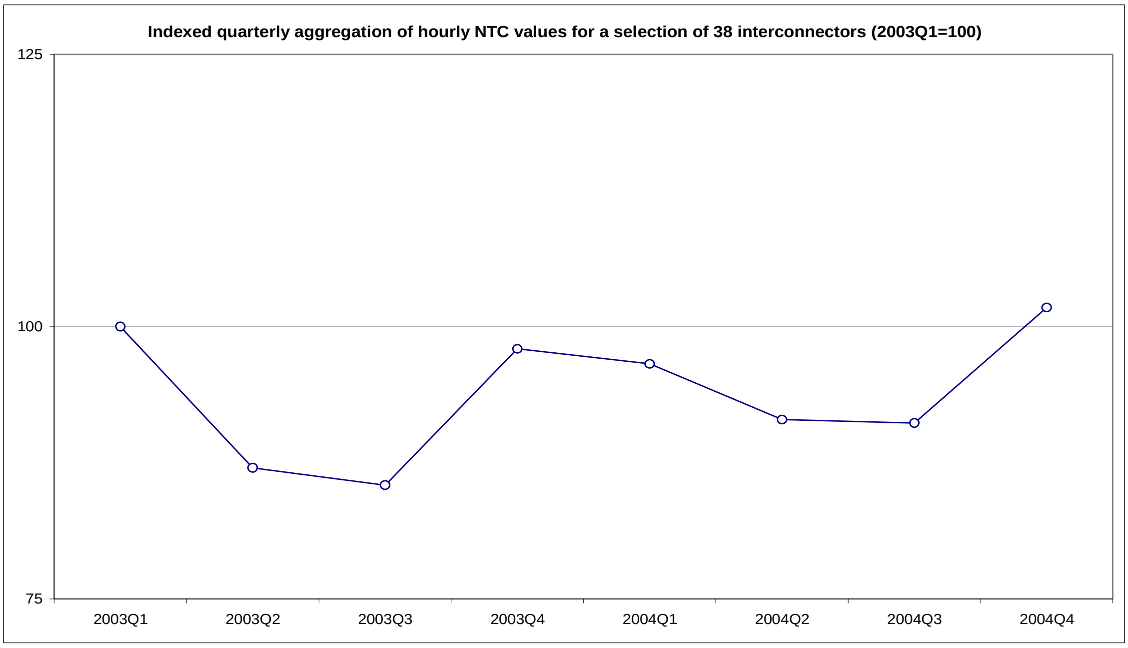
Source: Energy Sector Inquiry 2005/2006, UCTE and ETSO.
Note :(1) NTC values from ETSO used for calculation
(2) For Italian-French NTC value is estimated
(3) For Polish-German NTC and Czech-German NTC is estimated.

(536) 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

99 Import capacity from Switzerland is excluded.

remained almost unchanged over the last 30 months. The movements of the curve relate to expected capacity in summer and winter periods. NTC values may also change on a short term basis 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.

Figure 62



Source: Energy Sector Inquiry 2005/2006.

(537) 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 different treatment of congestion on internal lines and interconnectors. Table 25 shows at first glance that such an assessment may be relevant since a low level of congestion on internal lines may be indicate that the problem is being pushed to the border. 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, whether it is done for sound cost efficient reasons.

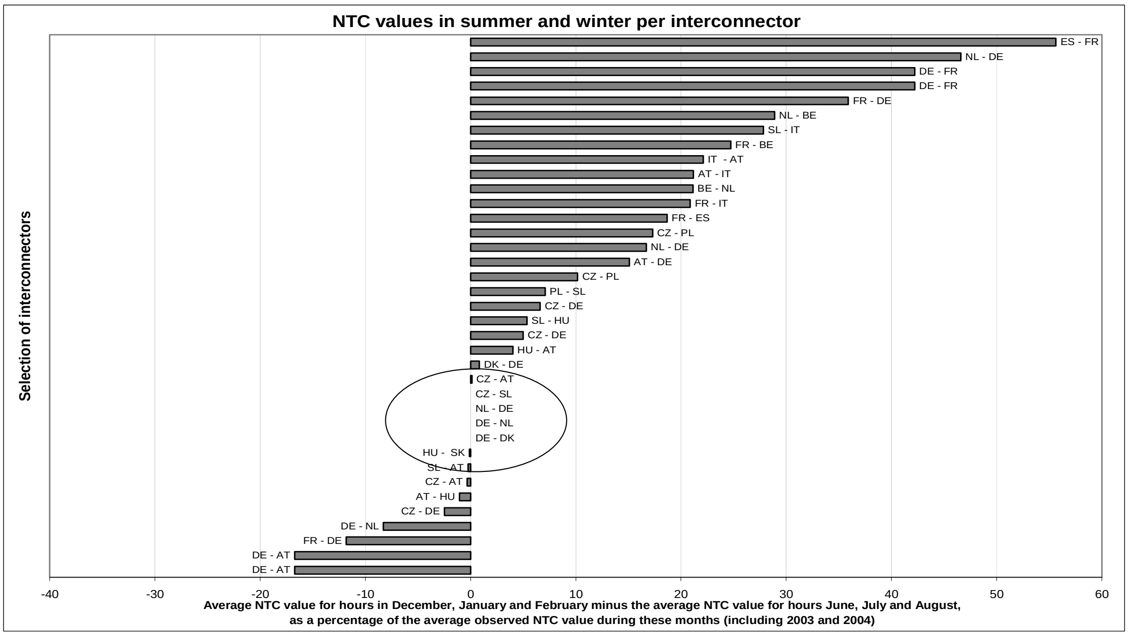
Table 25

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.

(538) 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.

(539) 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. For instance, maintenance on the network occurs often off winter periods. Additionally 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

(540) A precondition for building additional interconnector capacity is that incentives to expand the net are properly set by regulators both for “regulated” and “merchant lines”(unregulated lines) which may arise from estimated future revenues primarily reflecting the absolute price differences between adjacent geographical wholesale markets.

(541) TSOs, who in the past had a monopoly on building additional interconnectors, are likely to be the main developer of new or additional interconnection, especially for regulated lines, and hence it is important that TSOs have correct incentives. For example, 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 shows that many TSOs obtain congestion revenues[100] and that these revenues are not fully invested on projects to increase interconnector capacity.

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.

(542) 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.

(543) 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 in the importing Member States 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.

(544) 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 capacity would be low compared to the efforts required. The replies to the Sector Inquiry also confirmed that planning procedures for building new interconnectors are complicated, not least due to local resistance as regards visual impact and fears of electro-magnetic fields. This is partly due to the fact that in many cases increasing the level of cross border capacity also requires substantial internal grid reinforcements.

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

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

(545) The congestion mechanisms to allocate existing 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. Alternatively, each successful bidder pays the amount 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 power exchange 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

(546) Mechanisms that allocate interconnection capacity which 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. For example, 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.

(547) 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.

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 France - Spain (3)
First come - first serve	France - Switzerland (4)

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) Per January 2006 the allocation mechanism has been changed from "first come first serve" to an explicit auction principle. It will be coordinated with the Spanish TSO before the end of the first semester of 2006 according to RTE.

(4) This relates to a border between the EU and a third country. It is planned to implement an explicit auction by the end of 2006.

(548) In addition, 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.

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

(549) From a legal point of view these ongoing grandfathered capacity 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.

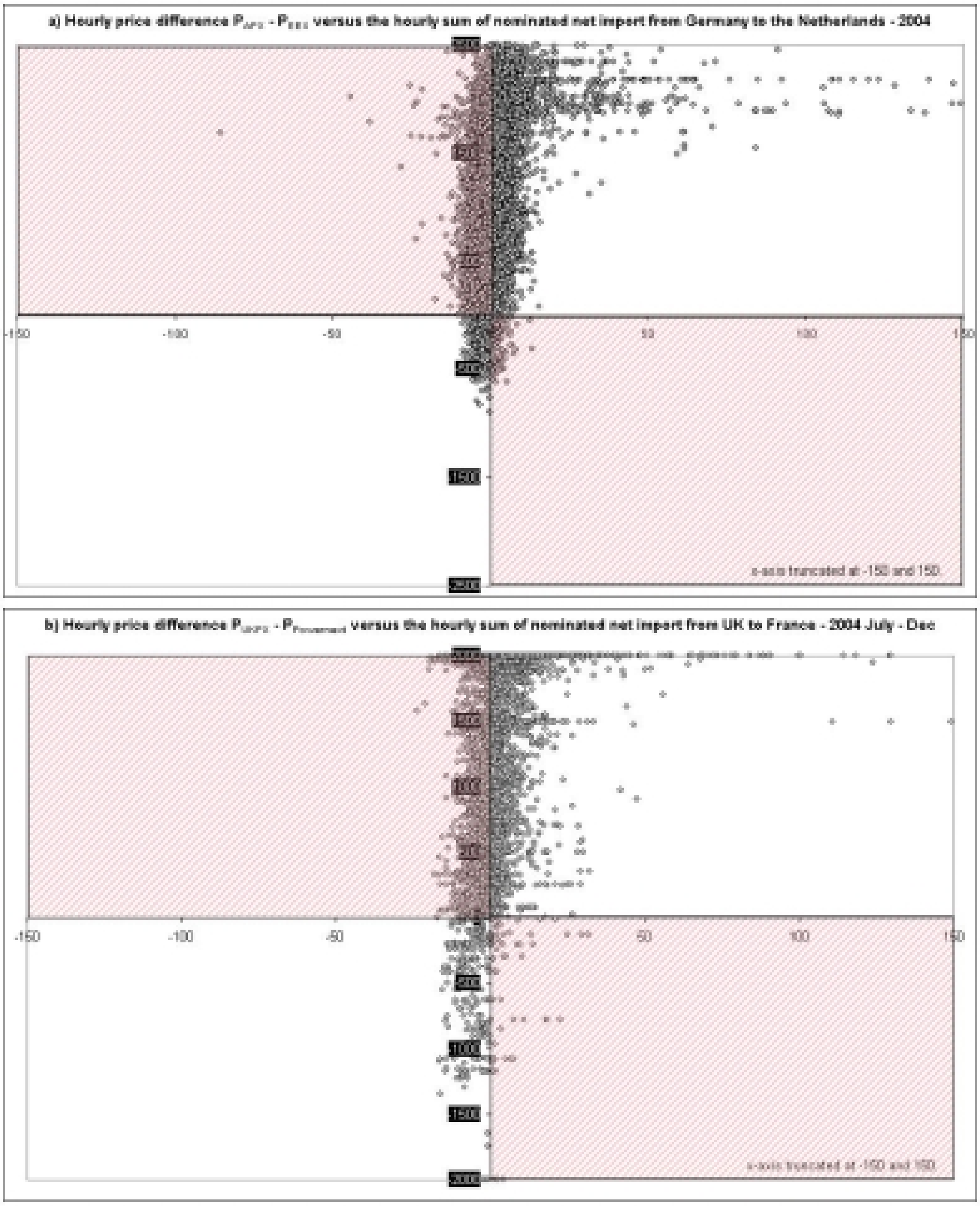
(550) It cannot be excluded that long-term contracts could result in efficient allocation as secondary trade could in theory employ efficient redistribution means. However the holder of the contract would still profit from the money paid in the secondary market and, more importantly, the conditions to obtain these long-term contracts in the past were largely unequal. 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, both the Court and the Commission has concluded that long-term contracts should, with certain exceptions, be disqualified as a method for allocating scarce interconnector capacity. In April 2006 the Commission launched a number of infringement cases against Member States which were still allocating capacity on the basis of long-term reservations. Recent reports indicate that efforts to dismantle these contracts are in progress. For example, 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. A similar decision has now been taken in Germany.

II.3.5.3. Market based methods

(551) On many congested interconnectors TSOs make use of explicit auctions for 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.

(552) 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 a 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 (non-economic) outcome. The area in the bottom-right (also marked) also represents irrational outcome.

Figure 64



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

(553) 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 especially if allocation sessions are not co-ordinated with the deadlines for trading.

(554) From the responses from the questionnaires market participants confirm that they face uncertainty due to the fact that they have to place auction bids based on expected wholesale market prices. As intraday and balancing markets (after the day-ahead stage) are often illiquid, players cannot, if the outcome is different to that expected, easily resell acquired electricity in the market A where they initially had bought the electricity, and buy in the market B where they would have liked to use the acquired electricity. This would be desirable if they had anticipated a positive price difference in an hour between two markets, but after market closure it turned out that the price difference was negative.

(555) In addition, although it might appear to be unreasonable for transactions to be nominated in two directions if the price spread between the two energy markets was small, participants might even 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.

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

(557) 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 capacity worth 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. Also this result does not include cost of the losses of the DC transfer nor cost for balancing.

(558) Furthermore, 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 financial loss is also significant on this border.

(559) The result of the above analyses illustrates that, although explicit auctioning is theoretically and with perfect foresight an efficient mechanism and it is in practice compatible with Regulation 1228/2003, it has efficiency deficits compared to implicit auctioning especially where intraday and balancing markets are illiquid. With implicit auctions results of trade are less likely to have economically irrational use of the interconnector capacity as is the case for explicit auctions as demonstrated in Figure 64.[101]

(560) An additional advantage of implicit auctions is that netting, which has not been discussed in this chapter, will become more 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

(561) 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.

[101] 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.

(562) 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

(563) 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

(564) 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 vertically integrated incumbents is first shared with affiliates and not necessarily at all with other market participants, which undermines 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.

(565) 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 a situation where 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.

(566) 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. For example, the Florence Forum[102] concluded at its September 2005 meeting that "participants also highlighted the need for increased transparency, in view of creating a functioning and fair market". Specific action to improve transparency was agreed following the meeting in September 2006 and there is a growing consensus on this subject.

(567) 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 26 June 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.

(568) Eurelectric state[103] 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

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

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

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 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".

(569) The European Transmission System Operators (ETSO) published a paper on transparency[104] 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.

(570) The European Federation of Energy Traders (EFET) state[105] "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".

(571) 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

(572) It has been noted that 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

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

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

published to all market participants on an aggregated basis, the risk of facilitating collusion – whilst requiring monitoring- does not outweigh the benefits of more transparency.

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

(573) 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[106] 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).

(574) 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.

(575) 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.

[106] 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
Czech Republic *	17
Belgium	17
Netherlands	16
Greece	16
France	14
Ireland	13
Austria	12
Slovakia	8
Estonia	1
Latvia	0
Luxembourg	-
Cyprus	-
Malta	-

Source: Energy Sector Inquiry 2005/2006
*Note: * Information received from the Czech Republic following the publication of the Preliminary Report*

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

(576) 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

(577) 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[107] 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 Inquiry2005/2006

(578) 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)

(579) 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.

(580) 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. Disregarding the situation of a tight oligopoly (risk of collusion) 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

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

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.

(581) It should be noted that in the most liquid and efficient wholesale electricity 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

(582) 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

(583) EC financial services rules, in particular the Markets in Financial Instruments Directive (MiFID)[108], the Prospectus Directive[109], the Transparency Directive[110] and the Market Abuse Directive (MAD)[111] and its implementing rules[112], impose various transparency obligations on financial markets.

(584) 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[113] is.

(585) 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

(586) 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).

(587) 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

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108 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 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..

109 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.

110 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.

111 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.

112 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).

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

conditions to trade on the financial market. 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 200MW. Participants possessing such information may not trade on Nord Pool until the relevant information has been disclosed to the market by Nord Pool[114].

- 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"[115].

(588) Experience of enforcement of these rules appears to be extremely limited, with the exception of Nord Pool which 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 have been carried out.

114 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.

115 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.

II.4.9. Developments since the Preliminary Report was prepared

(589) Since the Preliminary Report was prepared, there have been significant developments in transparency in electricity wholesale markets due to the revised congestion management guidelines, the revised EC financial sector rules, voluntary initiatives from electricity generators, and an intensive exchange of views between market participants, TSOs and regulators on precisely what information should be published, when and at what level of detail.

(590) The Commission Decision C(2006)5303 of 9 November 2006 amended the annex to Regulation (EC) No 1228/2003 on conditions for access to the network for cross-border exchanges in electricity. The amended annex obliges TSOs to provide significant information to the market including: network availability, access and use; a report on where congestion exists and the methods applied to manage the congestion; cross-border transmission capacity available to the market; total capacity allocated and an indication of prices paid; total capacity used; aggregated commercial and physical flows; information on planned and unplanned outages; forecast and actual demand; forecast and actual generation. Market participants shall provide TSOs with the relevant data where necessary.

(591) Implementing provisions for the MiFID were adopted in August 2006. Commission Regulation (EC) No 1287/2006, in particular in Articles 37 and 38, will help to clarify the scope and effect of the MiFID and related financial service legislation with regard to electricity wholesale markets.

(592) On a voluntary basis, the four largest electricity generators in Germany decided to publish information on installed capacity, available capacity and actual quantities generated each hour at the EEX electricity exchange from April 2006. Even though this step was widely seen as a progress, it was claimed that it is still not sufficient as the information is only published in an aggregated form and not complete for all of the country but only for a part of generation. In June 2006, the conference of German Economics Ministers in both the Federal and Länder Governments welcomed the publication of this information and called for further work on the issue of transparency in the electricity wholesale markets. In September 2006 it was announced that Austrian electricity generators would publish at the EEX similar information to the German electricity generators.

(593) Finally, ETSO[116], Eurelectric[117], ERGEG[118] and EFET[119] have all published detailed proposals for the information that they believe should be published by market participants, the time at which it should be published (eg in advance, in real time, or afterwards) and the appropriate level of aggregation. The Florence Forum of 7 and 8 September 2006 concluded that the Commission would organise a working group to discuss guidelines on transparency, on the basis of the ERGEG proposal, and how best to

116 List of data European TSOs need to pursue optimal use of the existing transmission infrastructure of December 2005.

117 Eurelectric Position Paper on market transparency of 16 February 2006.

118 ERGEG Guidelines for Good Practice on Information Management and Transparency in Electricity Markets of 15 March 2006.

119 EFET updated position on transparency of information about the availability and use of infrastructure and the promotion of competition in European wholesale power markets of May 2006.

implement them quickly, possibly on a voluntary basis at first. The working group met for the first time in November 2006.

(594) The voluntary publication of information in Germany and Austria and the rapid development of a detailed debate on the precise information that need to be published show how the issue of transparency in electricity wholesale markets has received greater priority since the launch of the Sector Inquiry and in particular since the preliminary report was published. This is a welcome first result of the Sector Inquiry and it is hoped that further improvements, for example the adoption of guidelines on transparency, will occur soon.

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 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 ensure that all market participants publish more information, which may require Community legislation (e.g. clarification or modification of existing legislation or new legislation), also in line with the recent ERGEG advice on that issue in October 2006. Transparency requirements can also have a role as remedies in competition cases, given that improved transparency can help to limit the possibility to abuse market power.

Since the Preliminary Report was prepared, there have been significant developments in transparency in electricity wholesale markets. Some of these improvements appear to be a result of the Sector Inquiry, and it is hoped that further improvements, for example the adoption of guidelines on transparency, will occur soon.

II.5. Price issues

(595) 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)[120]. Secondly, the effects of publicly set supply tariffs for competitive electricity wholesale and retail 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.

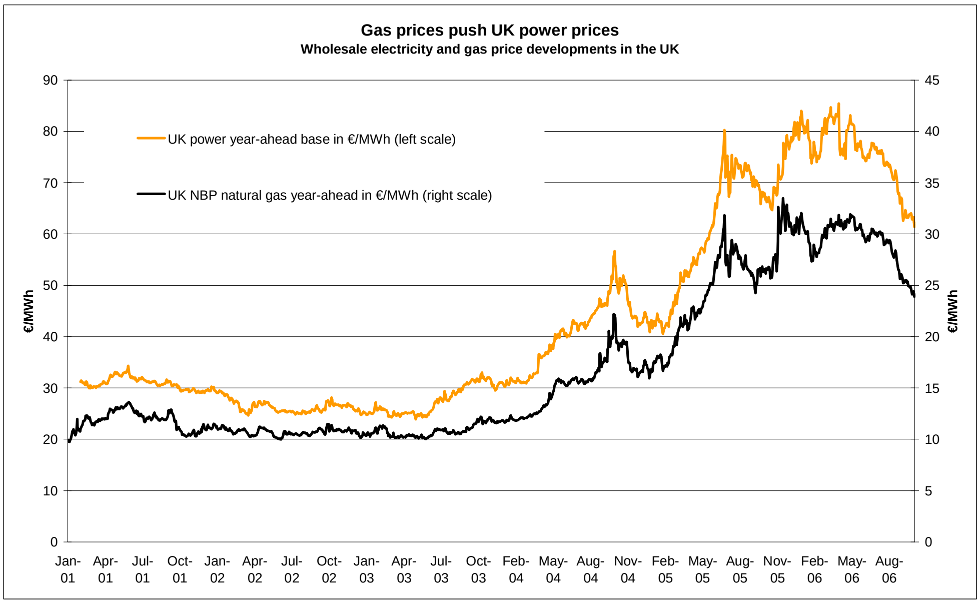
II.5.1. External factors possibly explaining price increases

II.5.1.1. Electricity prices and fuel price developments

(596) 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.

(597) 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



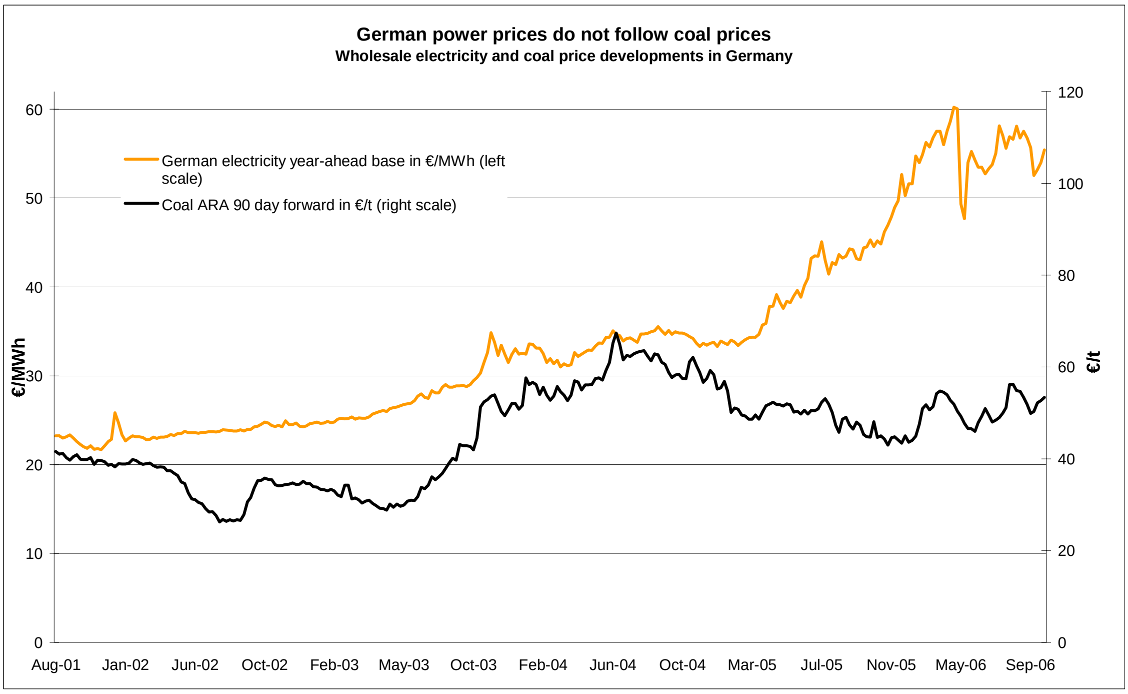
Source: information received within the scope of the Sector Inquiry from Argus Media, and Platts[121].

[120] For further details on this issue see also chapter C.c.III on the Electricity Study

[121] Data from Platts a division of The McGraw-Hill Companies 2006- all rights reserved.

(598) In other parts of Europe coal (instead of gas) plays a major role in electricity generation. It is generally understood that coal is often used by generators operating on the margin (e.g. in Germany). 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 63 €/t in July 2004 to 51 €/t in September 2006), the year-ahead base load electricity price has risen significantly in Germany (from 34 €/MWh in July 2004 to 56 €/MWh in September 2006). 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 require some explanation (see also C.c.III Electricity Study). 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 Energy Sector Inquiry from Argus Media, and Platts[122]

II.5.1.2. Electricity prices and CO2 certificates

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

(600) 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. Most argue however that the value of the allowances is at least partially priced in. A study by the Energy Research Centre of the Netherlands[123] concluded that in the Netherlands between 39% and 44% of the value is priced in at peak times and

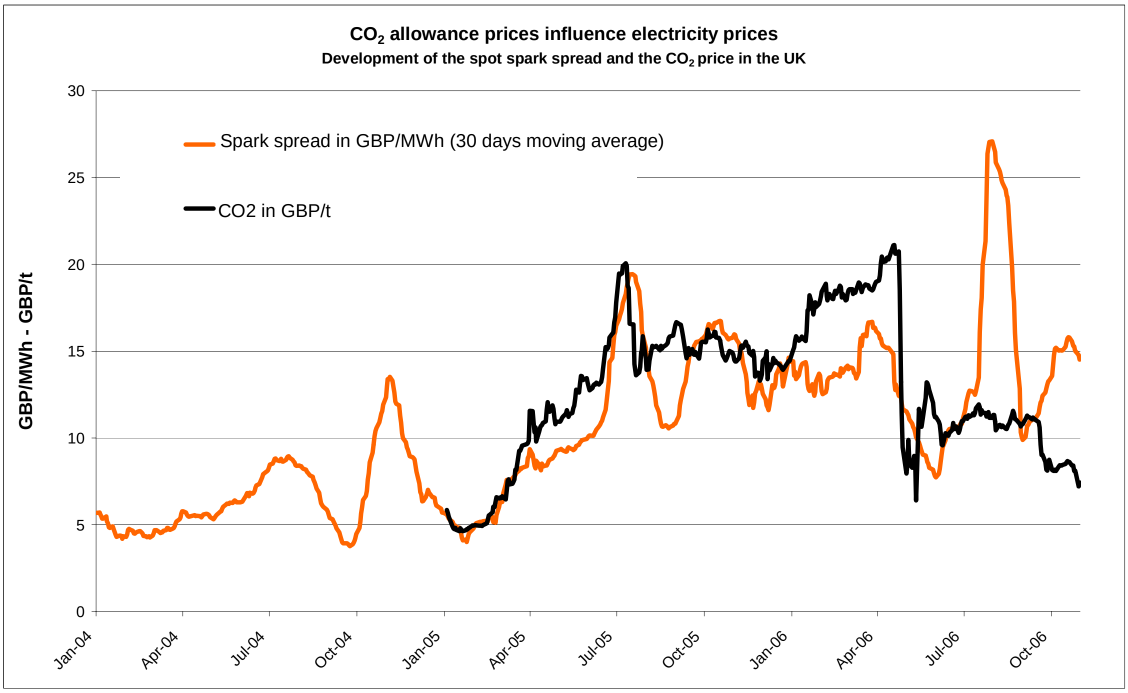
[122] Data from Platts a division of The McGraw-Hill Companies 2006- all rights reserved.
[123] 'CO2 price dynamics: The implications of EU emissions trading for the price of electricity', Energy Research Centre of the Netherlands, September 2005.

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. Other studies reached higher figures showing pass-on rates of up to 100% which is in line with the statements received from generators in the context of the Energy Sector Inquiry.

(601) The European Commission Directorate-General for Environment closely follows the overall impact of the EU Emission Trading Scheme. It commissioned and published two corresponding studies in this respect.[124] The Commission also adopted a communication with the title: Building a Global Carbon Market – Report pursuant to Art. 30 of Directive 2003/87/EC[125], which summarises the first experiences with the ETS.

(602) The possible impact of CO2 certificates trading on power prices – all other factors being equal – can be demonstrated using the concept of spark spreads (see also Chapter C.c.III). The spark spread is the difference between the price of one unit of electricity and the price of the same 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.

124 '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.

125 COM(2006) 676 final of 13 November 2006.

(603) Figure 67 shows that the spot spark spread in the UK remained low and relatively stable (apart from a short period with tighter margins 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 certificates price development suggesting that generators – at least to some extent - include the value the CO2 allowances into their pricing decisions.[126]

(604) 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 certificate prices as can be seen in Figure 67. The prices remained high, at close to 30€ per ton, until April 2006, when they suddenly fell sharply to around 12€ per ton. The reason was the publication of emission data for 2005 by Member States, which were lower than expected. Subsequently prices for CO2 allowances have fallen below 10€ per ton CO2 (state of play November 2006).

(605) 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 the 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. Industrial companies also request a differentiated allocation between sectors, with a view to taking into account the external aspects of competitiveness. Critics mention that the vast majority of the allowances were given for free to generators. 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'.

(606) Furthermore companies that intend to enter the generation market are concerned that the current allocation scheme favours incumbents over new entrants, for example if old plants (normally owned by incumbents) are closed and replaced by a new plant with less emissions, this may lead to an excess of allocations. 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. New entrants argue, however, that some insecurity still persists in some Member States as to the extent of the allocation methods and the likely amounts to be attributed.[127] In the public consultation on the preliminary report it was also underlined by a number of commentators that the period post-2012 is crucial for any investment decision in new generation, and that therefore further clarity on this aspect is important. Moreover some commentators called for a harmonisation of rules between Member States to ensure a level playing field. Finally, some commentators argued for a change in the allocation procedure. A possible alternative would for example be the full auctioning

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

[127] The new national allocation plans for the period 2008 to 2012 which are in the process of being reviewed/approved by the Commission should address these concerns.

of CO2 allocations for the post-2012 period.[128] All these issues will be addresses in the EU ETS review.

(607) 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 and long 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. If the value of the CO2 allowance would not be taken into consideration the generator on the margin would lose revenues that it could realise if it decided not to generate but sell the CO2 allowances and buy the electricity instead (opportunity cost principle)[129]. In any event pricing in costs for CO2 allowances would be in line with the objectives of the EU ETS.

(608) It can be noted in this respect that the German competition authority is currently investigating whether German electricity producers are entitled to pass on the price for CO2 allowances to their customers or whether such pricing practice amounts to an abuse of dominant position. No final decision has, as of 10 January 2007, been taken.

(609) 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. It also takes note of the recommendations of the High Level Group on competitiveness, energy and the environment on the issue of the EU ETS[130] in the context of the ongoing EU ETS review process. In this respect it supports in particular the requests of new entrants that the EU ETS must not create barriers for market entry.

II.5.2. Regulated supply tariffs

(610) 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[131] (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 the level implied by 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.

(611) 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. Whilst there may be short run benefits to (certain categories of) consumers, such supply tariffs have adverse effects for competition and

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128 The Commission will pay particular attention to put in place a more harmonised allocation method beyond 2012. See in this context the Commission Communication "Building a Global Carbon Market" COM(2006) 676 final of 13 November 2006.

129 This argument is not entirely convincing as it takes a rather static approach. The generator has to consider that it will also need allowances for the next period. If all allowances were sold during the reference period, the generator would be obliged to buy new allowances in the subsequent period. In addition, if all generators were to sell simultaneously their allowances on a large scale, this would have a depressing impact on the price of the allowances given that the electricity sector represents more than half of total CO2 allowances.

130 http://ec.europa.eu/enterprise/environment/hlg/hlg_en.htm

131 See also Second Electricity Directive, Art.3, Public service obligations and customers protection. Another issue is the exclusive rights or compensation granted to incumbents to supply within regulated markets.

thus for consumers in the longer run. New suppliers with no access to own generation are effectively squeezed out from the market, as they can no longer market electricity purchased on wholesale markets. Accordingly no competition based on merits can take place for these customers freezing the market position of incumbent operators. Also the tariffs distort the necessary price signals for investment into new generation capacity and are consequently damaging to security of supply. Many commentators in the public consultation as well as electricity suppliers, in particular from Spain and France, complained about the level of regulated tariffs being too low and their effects for the wholesale markets[132].

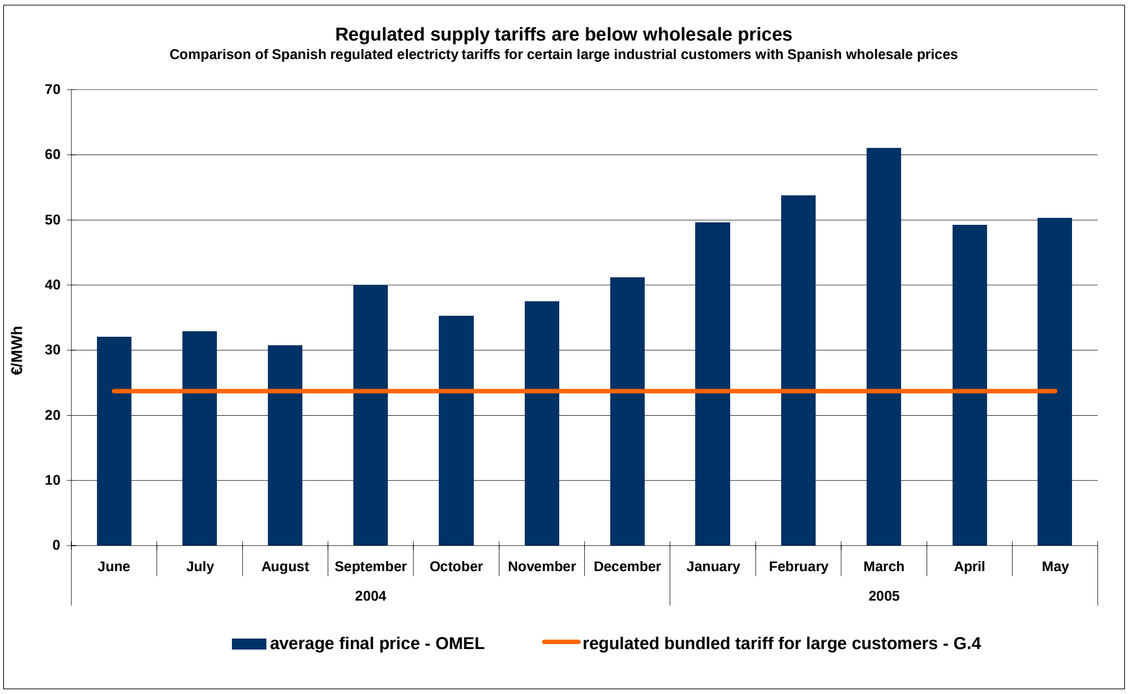
(612) In May 2006 the UK operator Centrica, which had gained significant market share in the eligible customer segment in Spain, lodged a formal complaint to the Commission concerning the regulated electricity tariffs in Spain, and the corresponding tariff deficit system (compensation scheme for loss making local distributors supplying on the basis of public tariffs). In the view of Centrica, the Spanish system has squeezed out their Spanish subsidiary and other newcomers from the electricity supply market. The Commission is currently analysing whether any violations of state aid or antitrust rules have taken place.

(613) In April 2006 the Commission opened infringement proceedings against a number of Member States for failure to correctly implement the Second Electricity and Gas Directives[133]. The inexistent or inadequate justification for regulated tariffs – in particular for eligible customers – was one of the key elements for certain of these infringement procedures. Taking into account the adverse effects of regulated tariffs for competition in particular for the non-household segment, it is recommended that these tariffs are discontinued without delay.

132 It can be noted that the French Constitutional Council on 30 November 2006 declared non-conform with the French Constitution the Amendments to the Energy Sector law 13 July 2005 with respect to regulation of energy and gas prices.

133 Commission Press Release IP/06/430 of 4 April 2006.

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

II.5.3. Special support schemes for energy intensive users

(614) In the light of increasing electricity prices a number of Member States are also 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 for energy intensive users under criteria set by national legislation. The consortia would enter into long-term supply contracts with electricity producers. Essentially the consortium would make a significant initial down payment corresponding to the investment costs for a new power plant in return of continuous supplies of base load electricity on a marginal cost basis. These purchasing consortia may give rise to antitrust and possibly also state aids concerns.

(615) From an antitrust point of view the main questions are: a) Do the long-term contracts have foreclosure effects? This may be the case if the companies which acquire electricity under long-term contracts account –together with other customers- for a good part of the overall electricity demand in the market concerned and if the selected supplier has a dominant position in the market (for further details on this issue cf. chapter C.c.I.b). Are the participants in the consortia free to market the electricity? The electricity supplier or the consortium might have an interest in preventing the buyers from marketing unused electricity at low prices (as a quid pro quo to the electricity generator). However, such a use restriction may also raise competition concerns.

(616) The major concerns as regards state aid are that any such aid exceeding the *de-minimis* thresholds would be viewed as operating aid which is normally not compatible with EU state aids rules. 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.

(617) 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 the price increases observed. Analysts cannot yet agree to which extent the value of CO2 allowances is priced into electricity prices. It needs to be ensured that the ETS does not amount to an entry barrier for companies that want to become active in power generation.

Industrial users claim that electricity producers should not be entitled to factor in the value of CO2 allowances, as they were largely distributed for free. Generators claim that the value of CO2 allowances is an opportunity cost, which can be factored in legitimately. An antitrust investigation is ongoing in Germany dealing with this question.

Public tariffs for electricity supply have adverse effects for the development of competitive markets if set very low compared to wholesale prices and if they cover a large part of the eligible customer market. 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.