April 2003 ECN-C--03-003

POSITION OF LARGE POWER PRODUCERS IN ELECTRICITY MARKETS OF NORTH WESTERN EUROPE

Report for the Dutch Energy Council
on the Electricity Markets
in Belgium, France, Germany and The Netherlands

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Acknowledgement
This report is prepared for the Dutch Energy Council (Algemene Energieraad) to provide input for a discussion among experts and members of the Energy Council on European electricity markets. The final version of this report includes some suggestions from this discussion that took place on December 16, 2002.

The authors thank Prof. Benjamin F. Hobbs of The Johns Hopkins University, Baltimore (USA), for his comments on the draft version of this report.

The report was accomplished under ECN project 7.7504.

Abstract
For a discussion among experts on the strategic behaviour of energy companies the position of large power producers in electricity markets in northwestern Europe is investigated. This report describes how power markets in European Member States are restructured due to the liberalisation process and how these markets function. Subsequently, the market positions of large power producers are analysed. In current power markets, large power producers seem to profit from the inheritance of national energy policy from the past. Furthermore, market incumbents seem to be able to maintain their position by raising market entry barriers and can gain profit from this advantageous position. The report also analyses factors that may influence the position of large power producers, such as market regulation, expansion of interconnector capacity, environmental regulation and technical innovation.

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EXECUTIVE SUMMARY

For a discussion among experts on the strategic behaviour of energy companies, the Dutch Energy Council (Algemene Energieraad) has requested ECN Policy Studies to investigate the position of large power producers in electricity markets in northwestern Europe.

This report shows that the electricity markets in Belgium, Germany, France and The Netherlands are still regional islands with different market structures and regulation models. These countries have adopted different market opening rates and unbundling types. Moreover, diverse access tariffs between network operators still persist, high levels of market power can be observed and real liquid and transparent wholesale markets are not common. In these power markets, large power producers seem to profit from the inheritance of national energy policy from the past. Furthermore, market incumbents seem to be able to maintain their position by raising market entry barriers and can gain profit from this advantageous position. The position of large power producers may be affected by a number of factors. Policy makers can influence some of these factors. The most important observations are summarized below.

New European Directive
According to the recently adopted amendment on the European Electricity Directive all electricity markets in the EU will be completely liberalized by 2007. Although a negotiated TPA system may remain in Germany, some electricity market regulation will be implemented, likely resulting in lower network tariffs. Stringent unbundling measures that lower the concentration in power generation could contribute to improving competition, but this does not automatically result in lower prices.

Market power
Vertical and horizontal integration contribute to the ability of firms to exercise market power by restricting the ease with which market parties can access the market and increasing concentration levels. While Germany and the Netherlands present relatively non-concentrated markets, the opposite is the case in Belgium and France, with their near complete monopolies. In the first two countries, however, it is still suggested that firms act strategically. In Belgium and France short-term trading is obviously not developing. In the Netherlands and Germany on the other hand, the existence of a liquid and transparent short-term market provides information and a benchmark on current and future electricity prices.

Cross-border trade
Not one single European market, but a number of single national markets exist, due to the technical characteristics of the European network (low capacity in interconnections between national networks), different levels of market opening and different regulation policies. Cross-border electricity trade between these regional markets can contribute to the system’s stability and may promote competition in the national markets. Network congestion and inefficient allocation methods, however, impede a well-functioning electricity market. If interconnection capacity between countries is increased, this will allow power to flow from regions with high market prices into regions with low market prices. The remedy of interconnection expansion is limited, however. First, the costs of expanding the interconnections could increase disproportional to the capacity increase. Transmission tariffs may not properly reflect these costs and therefore do not provide the right incentive to power markets. This could result in higher costs of the total electricity supply system. Second, expanding transmission capacity is only a short-term solution to fulfil the electricity demand in regions with scarcity of supply, i.e. high market prices. It is very likely that the export capability of all regions will decrease, because demand will increase and large power producers may discourage new investments by keeping market prices below long-run marginal costs to deter new entrants.

Large power producers gain advantage
In the last years, incumbent players in the power production sector have consolidated their positions and therefore increased the scale of their activities. It has been shown that most of the large power producers have a bigger share of capacity with low short-run marginal costs compared to other (smaller) power generating companies. In a competitive power market with sufficient generation capacity, market prices will reflect the short-run marginal costs of the most expensive plant dispatched. Therefore, large power generators will gain relatively higher revenues. Large power plants with low short-run marginal costs (hydro, nuclear, coal) are the heritage of national energy policies from the past. The ownership of these plants brings large power producers in an advantageous position compared to new market players.

Incentive for price manipulation
It is argued that current large power producers have a strong incentive for manipulating market prices in order to increase their revenues. These producers have a substantial share in base load production, which involves the plants that obtain most of the profits if market prices increase. Wholesale power markets are particularly sensitive to price manipulation because, among other things, demand is unresponsive to price variations and network constraints limit market competition. Furthermore, it is difficult to obtain evidence of this kind of strategic behaviour. While electricity prices in Belgium and France are not set via market competition, Germany and the Netherlands have relatively well functioning power exchanges that provide short-term market prices. These market prices are generally higher than the short-run marginal costs (SRMC). However, higher market prices are not only the result of strategic behaviour of power producers but can also be influenced by changes in plant availability and other factors.

New investments
In markets where new investments are essential in order to cover the (future) electricity demand, prices should reflect the long-run marginal costs (LRMC), i.e. SRMC plus capital costs. A comparison between indicative LRMC for different types of power plants with the German and Dutch spot market prices and forward prices showed that investing in new power generation capacity in these markets is currently not very attractive. This does not mean that new power plants will not be built. There may be other reasons for some (new) market players to take initiative for building new generation capacity. However, it is likely that extensive investments in new generation capacity will not occur for some time and overcapacity will tend to decrease as the electricity demand increases. For France and Belgium, the situation may be somewhat different as long as no real competition is introduced and the monopolistic market players in these countries remain responsible for supply security.

Incentive to discourage new investments
By adopting a lifetime extension strategy, large power producers will be able to cover new electricity demand and maintain their position by keeping market prices just below LRMC. Power plant data suggest that large power producers are indeed able to hold on to this strategy for some years ahead. This will impede new players from entering the market, also discouraging existing players to build new power plants. Moreover, mainly investments in renewable electricity generation will continue, because of the policy targets and relatively strong support schemes, in particular in Germany and The Netherlands.

External factors
Economic growth and fuel prices are external factors that, in principle, can influence the market position of power producers but can hardly be influenced by policy makers. Electricity demand increase correlates to economic growth. A strong economic growth will result in an earlier generation capacity scarcity in spite of a lifetime extension strategy of large power producers. A small or even negative economic growth will probably have the opposite effect. Fuel prices directly influence short-run marginal costs and thus also the market prices in a competitive power market. Only the price differences between different types of fuel may have an impact on the

positions of power plants in the supply curve and, subsequently, the market positions of large power producers. However, it is not very likely that price differences between different types of fuel will change drastically.

Environmental regulation
The European Commission proposes the introduction of a European-wide CO_2 emission trading system by 2005. This may have a significant impact on power markets, because the value of CO_2 emission allowances is related to short-run marginal costs and, therefore, may influence electricity market prices. Participants in a CO_2 emission trading system will initially receive allowances free of charge. The incumbent large power producers may yield profit from market price increases because of their relatively large share of low cost generation capacity and higher flexibility to shift between power generation plants. CO_2 emission trading may also have an impact on the import and export flows, because the impact on electricity market prices may be very different among the four countries considered. However, the effect of the introduction of a CO_2 emission trading system on the position of large power producers and cross-border trade is still difficult to predict, because details of the trading system are still unclear. Particularly the total amount of allowances for the power sector in each country and the allocation method of the allowances have not yet been determined. Likely, the two monopolistic power generators in France and Belgium will profit from increasing market prices due to the introduction of the CO_2 emission trading system, because power from nuclear (and hydro) plants have a large share in the total production of these companies. In Germany the advantageous position of coal power plants in comparison with gas-fired plants may disappear. If this occurs, it will have a strong influence on the cross-border trade with The Netherlands. Coal and gas-fired power plants may even switch position in the SRMC if gas prices are relatively low and prices for CO_2 emission allowances increase.

Technological innovations
Until 2010 technological innovations that have some impact on electricity markets can only be expected from renewable electricity production, in particular in Germany and The Netherlands, because of their policy targets and strong support schemes. Other new technologies, such as new distributed generation technologies, e.g. fuel cells and micro CHP, may have an effect on the market position of large producers, but this is not very likely to occur before 2010.

1 INTRODUCTION

With the liberalisation of European energy markets, competition is being introduced in energy production and supply. The aim of introducing competition is to enhance economic efficiency, i.e. lower costs for the energy consumer, and stimulate innovations by improving service quality. The liberalisation of energy markets in Europe began as national initiatives in England and Norway. At the European level, it started with the adoption of the EU Electricity Directive (96/92/EC) in 1996 and the EU Gas Directive (98/30/EC) in 1998. This year the European Commission published a second benchmark report on the implementation of the opening of the internal market for gas and electricity (European Commission, 2002). This report clearly illustrates the current differences between Member States in level and rates of market opening, regulation regimes, unbundling and market concentration. Recently the European Energy Council agreed upon a further enhancement of the liberalisation process. This implies, among other things, a complete market opening in 2007 in all EU Member States.

Energy companies, as a result of the market liberalisation, consolidated market positions and gained market share. Europe's largest power companies of today (EdF, Electrabel, EON, RWE, Vattenval) have strong or even dominant positions in the electricity markets in north western Europe, i.e. Belgium, France, Germany and the Netherlands. The type of assets these companies have in power production (e.g. coal, nuclear, hydro) may strengthen their strong positions. Along with the differences in market liberalisation between the countries and restrictions in cross border trade, this may hinder an effective competition. Incumbent players can maintain entry barriers and gain profits from the heritage of energy policies from the past.

For a discussion among experts on the strategic behaviour of energy companies the Dutch Energy Council (Algemene Energieraad) asked ECN Policy Studies to investigate the position of large power producers in electricity markets in north western Europe and to produce a report on this issue.

To understand the position of large power producers it is important to look at the structure of the electricity markets and how these markets are being transformed under the influence of liberalisation policy and market regulation. A short overview of the current electricity market structure in the electricity markets in Belgium France, Germany and the Netherlands is presented in Chapter 2. Furthermore, as the way power producers obtain revenues has radically changed with the introduction of competition, Chapter 2 explains how prices are set in competitive electricity markets and describes the existing markets in the four countries concerned. All of this results in a non-homogeneous picture of four national markets with very different characteristics. Also, it is explained how price differences drive cross-border trade and cause congestion on the interconnectors between these national markets.

In Chapter 3 the position of large power producers is analysed by examining the power generation assets of the large producers in the marginal supply curves of each national power market in the four countries. For large power producers and the remainder of the market the ratio between base-load and peak-load plants are compared. Chapter 3 also gives indications of price levels that are needed to attract new investments and analyses the need for these new investments by comparing the existing power generation park and electricity demand in 2010. Based on these analyses we argue that large power producers have strong incentives for maintaining their current market position and are able to do this by adopting a lifetime extension strategy.

Chapter 4 analyses a number of factors that may change the situation in the current power markets in north western Europe and which may have consequences for the position of large power producers in. Policy makers may use some of these factors to influence the position of market players with a dominant position.

The findings of this report are summarized in the Executive Summary.

2 ELECTRICITY MARKETS IN NORTH WESTERN EUROPE

2.1 Introduction

The EU Electricity Directive (96/92/EC) sets common rules to restructure the power sector in European Member States in order to achieve a single electricity market. As a result, an industry across Europe that sometime ago relied on a vertically and horizontally integrated organisational structure is now radically changing. The basic feature of the liberalisation process is the separation of the power sector in production, transmission, distribution and retail activities. Production and retail are restructured in a way so as to encourage market-based competition. Transmission and distribution, on the other hand, are regulated through different regulatory systems, as a competitive market cannot be developed, due to its natural monopoly characteristics.

The restructuring process is a significantly complex issue to put forward, especially when it intend to build a single electricity market from sectors that, due to historical, geographical and technical reasons, vary enormously. The California power crisis is the best example of the failure of the reform and has shown how costly a flawed restructuring process can result. In order to achieve a correct functioning of a liberalised electricity market a number of conditions should be accomplished. First, a competitive market in the wholesale and retail sector has to be achieved, where correct prices provide signals for efficient investment decisions in capacity. Markets with scarce capacity can generate excessive prices through scarcity rents or the abuse of market power. Second, a correct regulation of the transmission and distribution sector should be completed, providing network operators with incentives to improve investment decisions and operate efficiently while ensuring that consumers benefit from the efficiency gains and that the technical performance is maintained. These two conditions can only be fulfilled if a proper regulation in the restructured electricity sector is performed. Restructuring of the market should not by any chance mean deregulation. Instead the sector must be re-regulated.

Firms in restructured markets must adapt themselves to the new playing rules. Particularly for vertically-integrated companies, this involves unbundling, divesting of assets and allowing free and non-discriminatory entrance of new market players, particularly concerning access to the transmission and distribution networks. The central question is whether the necessary changes are taking place; whether the position of large power producers in European electricity markets is consistent with a well-functioning single electricity market; whether the exercise of market power will decrease or even eliminate the envisaged efficiency benefits of restructuring.

This Chapter analyses the European electricity restructuring in general and the power sectors of the Netherlands, Belgium, Germany and France in particular. First, it describes the electricity structures of each of the countries. Second, it analysis the wholesale side of the market, emphasising the trading arrangements in the four countries. Third, it explains the process of the transmission and distribution activities, dedicating a separate section to cross border trade. Finally, it gives a brief explanation of how firms obtain profits in the liberalised market, emphasising in particular issues in the four countries studied.

2.2 Electricity market structures

What the 96/92/EC Directive aims at, by putting forward a set of common rules, is the building of a well-functioning single electricity market. In other words, European markets with a level-playing field that provides equal opportunities for all parties. However, current evidence shows that the restructuring process is still far from reaching its objectives. The European electricity sectors are not converging into a harmonised electricity system along Member States, but are still regional islands with different models cohabiting with each other. Especially in northwestern Europe, no real level-playing field exists, as, among other things, Member States are adopting differential rates of market opening, disparities in access tariffs between network operators still persist and high levels of market power and no real liquid and transparent wholesale markets are common currency.

In order to analyse the power sector structure in north western Europe and its implications, two important issues in the industry structure are considered: vertical and horizontal integration (Glachant and Finon, 2000).

By the year 1996 (at the time when the Directive was adopted by the Council of energy ministers), the four countries showed, to different extents, vertically integrated sectors (see Table 2.1). In the case of the Netherlands, a fairly vertically integrated sector in production and transmission existed, as the four biggest generation firms (EPON, EZH, EPZ and UNA) owned the transmission grid operator. Regarding production and distribution only a large electricity supply and distribution company (Essent) owned a producer (EPZ). Belgium and France had their sectors either fairly or totally vertical and horizontal integrated (EDF and Electrabel respectively). Germany had a fairly vertically integrated power market.

Table 2.1 *Electricity market structures in north western Europe before liberalisation*

Country	Vertical and horizontal integration
Netherlands	Fairly vertically integrated in P-T and P-D
Belgium	Fairly integrated P-T-D vertically and horizontally
Germany	Fairly vertically integrated P-T-D
France	Integrated P-T-D vertically and horizontally

P = production; T = transmission; D = distribution
Source: Glachant and Finon (2000).

From the aforementioned, it can be concluded that in the past the electricity sector in the in the four countries studied was, to a higher or lesser extent, vertically integrated. This was done to solve the different difficulties presented in the execution of transactions in the electricity sector.[1] When there was no full integration, other forms were implemented that produced quasi-integrational links, such as long-term contracts, exclusive contracts with regional demarcation, exclusive co-operation in the form of closed professional clubs, and so forth. With the liberalisation of the sector, vertically integrated firms should be unbundled, as they could otherwise impede the well functioning of the market. Issues as cross subsidising and discrimination in market access restrict competition.

In order to mitigate vertical integration, the Electricity Directive pushes for a legal unbundling of the sector to allow free and non-discriminatory network access.[2] Many authors[3] argue that legal unbundling is not enough and that an ownership separation should be required among Member States instead. Table 2.2 shows the different types of unbundling implemented in the north western European MS, including the declared market opening, the market access system and the expected full opening date. France has not yet officially determined its opening date. An interesting issue, with significant implications as will be seen later, is that Germany is the only

[1] For an excellent explanation of these issues refer to Glachant and Finon (2000).
[2] In order to help to avoid the misuse of the established position of integrated utilities, the Electricity Directive 96/92/EC requires unbundling of accounts for generation, transmission, distribution and non-electricity activities of integrated electricity undertakings (Article 14). In addition, TSOs are subject to limited obligations on unbundling of management. Article 7(6) of requires that, unless the transmission system is already independent from generation and distribution activities, the (transmission) system operator shall be independent at least in management terms from non-transmission activities. At present, a similar rule does not exist in the Electricity Directive with respect to distribution system operators (DSOs), but this has been included in the amended proposal to amend the Electricity Directive (as of 27 November 2002).
[3] Newbery, 2002; Brunekreeft, 2002.

country in the EU that implemented a negotiated Third Party Access system. Network tariffs, as a result, are not regulated and published but negotiated between the network operators and consumers.

Table 2.2 *Unbundling of the electricity sector*

	Declared market opening [%]	Full opening date	Unbundling Transmission System Operator/owner	Distribution Network Operator	Market Access
Netherlands	63	2003*	Ownership	Management	rTPA
Belgium	52	2003/7	Legal	Legal	rTPA
Germany	100	1999	Legal	Accounting	nTPA
France	30	-	Management	Accounting	rTPA

* Revised planning: 2004.
Source: EC.

Table 2.1 also shows the horizontal integration of the sector. Particularly it shows that by 1996 Belgium and France had high horizontal concentration levels, while Germany and the Netherlands possessed fairly low ones. Horizontal integration is a direct threat to achieving a competitive market. Particularly at the generation side, market power issues seem to be too relevant (see also the textbox *Market Power*). According to the EC (European Commission, 2002): "the high levels of market power among existing generating companies associated with a lack of liquidity in wholesale and balancing markets which impedes new entrants, are posing particular difficulties in the functioning of liberalised electricity markets".

With the liberalisation of the sector, utilities are incentiviced to lower costs and enhance economic efficiency. Market positions, as a result, were consolidated in anticipation of competition. Particularly in the Netherlands, the government promoted an initiative to merge the four national large power producers, in order to protect them from foreign competition. However, the merger failed and subsequently, three of these four power producers were taken over by foreign companies. Particularly, two Dutch power producers were taken over by large firms from the neighbouring countries: Electrabel took over EPON and EON bought EZH. UNA was acquired by Reliant, an American company.[4] The new power producers Electrabel Netherlands and EON Benelux are subsidiary companies of the holding company in Belgium and Germany respectively. EPZ, the fourth power producer in the Netherlands, is now vertically integrated with Essent. The three large Dutch energy distribution companies, Essent, Nuon and Eneco, are also the result of a merge process. Recently, the take-over of the fourth energy distribution firm (REMU) by Eneco was announced.

Germany originally had a relatively large number of medium-sized power producers. After the electricity market liberalisation, two new large utilities were established: EON was the result of a merge between VEBA (PreussenElektra) and VIAG and RWE merged with VEW to the 'new' RWE. The Swedish utility Vattenval acquired major shares in three German utilities: VEAG, Berliner Kraft und Licht (BEWAG) and Hamburger Electricitäts Werke (HEW). Although some German electricity distribution companies (Stadwerke) were taken over by others utilities, still a significant number of distribution firms exist.

Tables 2.3 shows recent concentration indicators for the production sector in the four countries studied in this report. While Germany and the Netherlands present relatively non-concentrated markets, Belgium and France present the opposite case, with almost complete monopolies. This can clearly be seen in the share of the top 4 generators. The availability of power exchanges gives an overview of the development of short-term trading in the markets.

4 Early 2003 it was announced that Nuon, one of the large Dutch energy distribution companies, has bought the UNA power generation plants from Reliant.

In scientific literature, no mainstream approach exists concerning the levels of concentration that guarantee a reasonable level of competition.[5] Different concentration hypotheses were brought forward. Green and Newbery (Green, Newbery, 1992), for example, say that a minimum of five independent producers, each with 20% of the shares in the market, is necessary in order to discourage strategies of domination and collusion between suppliers on the wholesale market. On the other hand, Borenstein (Borenstein, et al, 1998) argue that traditional reliance on concentration measures is likely to be inadequate for the task. He mentions that the dependence upon historical data, such as energy sales and transmission congestion, is of questionable value, since the incentives of many firms will change significantly after restructuring.

Table 2.3 *Market concentration in the electricity generation sector*

	Firms with at least 5% share of installed capacity	Top 4 share [% installed capacity]*	Potential competition from imports [%]**	Power exchange
Netherlands	6	74	19	Y
Belgium	2	96	25	N
Germany	4	63	11	Y
France	1	92	12	Y

* ECN.
** Import capacity relative to installed capacity.
Source: Eurostat.

Table 2.4 shows a number of indicators concerning the retail side of the power sector. Germany, the Netherlands and in this case Belgium, show the same concentration with respect to the top 3 suppliers. France, on the other hand, concentrates all its activity in one firm.

Table 2.4 *Retail electricity market indicators*

	Number licensed suppliers	Number of suppliers independent of distribution network operator	Number with market share above 5%	Top 3 suppliers' share (all consumers) [%]
Netherlands	33	15	7	48
Belgium	16	16	3	53
Germany	1200	200	3	50
France	225	41	1	90+

Source: European Commission, 2002.

[5] Even if the electricity market is unconcentrated, significant market power can be exercised. One reason is through either genuine or artificial transmission constraints. They create situations in which only a very few generators can effectively control local markets that are created. This is important in the balancing market, when the TSO must increase and decrease generators to clear congestion. A second reason is that, as demand-side of the market is not yet well developed, price elasticities (especially day-ahead or real-time) are very low. This means that if an energy provider is 'pivotal' (that is, if they withdrew their capacity, demand could not be met), it could theoretically raise price without any limit. Thus, during peak periods even small generators can exercise market power. This was a main contributor to the California crisis; market concentration was relatively low, yet market power was still exercised.

Market Power

Horizontal integration in power markets contributes to the exercise of market power. The most important aspect of market power is the possibility that one or a group of electricity producers can raise the market price, either by restricting output, or by bidding higher prices than their original marginal costs. When one firm exercises market power it is done through a unilateral decision. Collusion occurs when a number of firms act together in order to strategically rise prices. The ability of one or a number of firms to exercise market power depends on:

- the concentration in the production (and import) sector,
- the ease with which new firms can enter the market,
- the possibility of smaller firms to expand their output,
- the likelihood of demanders reacting to the increase in prices.

Market power plays such a relevant role in the electricity market because of a certain number of characteristics that makes electricity a more susceptible market. The three important reasons are:

1. demand that is unresponsive to price because of regulatory constraints, consumer ignorance, and lack of real-time pricing programs,
2. strategic withholding of capacity,
3. exploitation of transmission physics and constraints to limit competitors' access to markets.

Market power can be a significant issue in restructured power markets. The California power crisis is the best example, as many authors argue that production firms were artificially manipulating wholesale prices (Hobbs, et al, 2002)

2.3 Electricity as a commodity: the wholesale price

With the breaking up of vertically integrated firms, the way transactions inside the sector take place change radically. In the new restructured sector electricity is treated as a commodity.[6] The prices of this commodity are determined in the different markets depending strictly on the supply and demand of power and on the functioning of the market (see text box *Short-term pricing in the electricity market*). A necessary condition to achieve a competitive wholesale market, by facilitating market entry, is the existence of a liquid and transparent short-term market that provides information and a benchmark on current and future electricity prices. A brief theoretical analysis and empirical review of the trading arrangements in the relevant countries is developed below.

Decentralised trading arrangements have been implemented in the Netherlands, Belgium, Germany and France. A decentralised market refers to the fact that market parties can voluntarily trade electricity in the different market places that were developed to satisfy the needs. Although the bulk of electricity is still traded through confidential long-term[7] bilateral contracts, electricity traded in power exchanges and the fairly transparent 'Over the Counter' (OTC) markets is increasing. Of course, the volume of traded electricity in the latter markets heavily depends on the structure of the sector. In still heavily concentrated and vertically integrated power sectors (e.g. Belgium and France), short-term trading is obviously not developing. In short, the three basic market places are:

[6] A substance, such as food, grains, and metals, which is interchangeable with other product of the same type, and which investors buy or sell.

[7] Contracts of one or more years.

- *Power Exchanges:* importance relies on increasing price transparency and reducing transaction costs. Standardised contracts traded in power exchanges, promote efficient trading by increasing transparency, price disclosure, and under certain conditions, liquidity. Participants are physical (producers and consumers) and non-physical traders (intermediaries). Buyers or sellers can, unlike in bilateral negotiations, maintain their anonymity.
- *Fairly transparent OTC market:* trading in this market place is based on bilateral transactions with custom-made contracts. Examples of contracts include day-ahead and forward contracts, swaps and options. Traders are connected with one another through phones and screens that enable them to be continuously informed about new (electricity) supply and demand contracts. Firms such as Platts, Dow Jones and Argus report information about the OTC market that they obtain from a cross-section of traders in the OTC market. This reporting is done on a voluntary basis. While the information on prices is usually reliable, information on volumes traded generally is not.
- *Opaque OTC markets:* electricity in most European electricity markets is still traded in this type of market. The (long-term) contracts are undertaken by producers and suppliers or big consumers and based on historical relationships. The price disclosure is marginal due to the commercial confidentiality.

Short term pricing in the electricity market

In a well-functioning competitive market a firm will sell electricity in a short-term period when the market price is above the avoidable or marginal costs of production. These costs are mainly dependant on the fuel costs and other variable and operating maintenance costs. As a result, in a competitive market the supply curve will equal the marginal costs of production. In the figure below the different power plants are represented as boxes. The box width represents the capacity of the power plant (MW) and the height of the box represents the short run marginal costs (SRMC). By putting the boxes in order of merit, a supply curve can be constructed. An almost vertical line represents the demand curve, since the demand for electricity is almost inelastic (i.e. most consumers do not have substitution possibilities and do not reduce demand if prices increase). The figure shows two demand curves: one for peak demand and the other for off-peak demand. The market price is realised were the demand curve meets the supply curve. The market price fluctuates between the peak and off-peak price, since demand is fluctuating continuously.

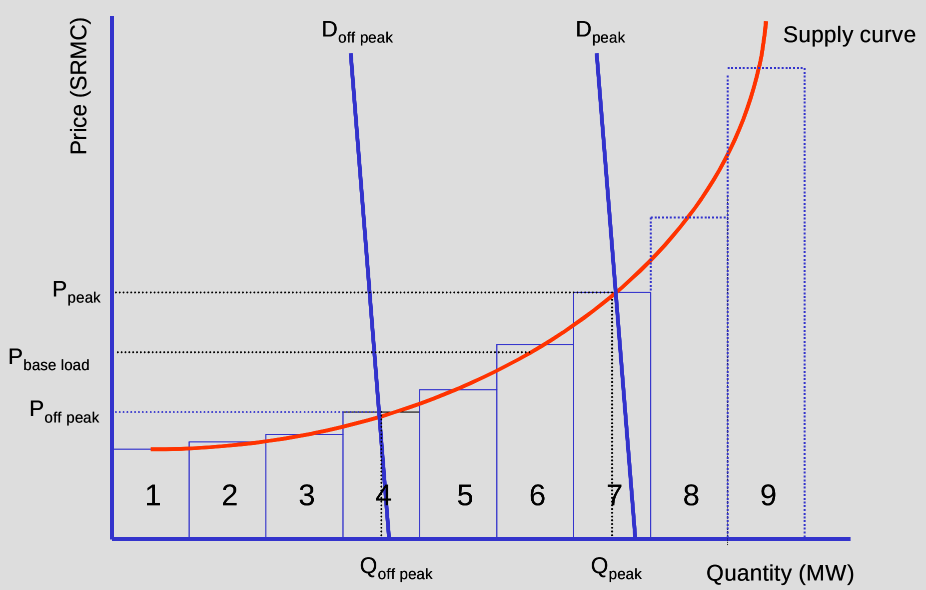

Figure 2.1 clearly shows the structural trading arrangements of decentralised power markets. The bulk of electricity is traded through long-term contracts, which can be done either through financial or physical contracts. Long-term contracts smoothes the price volatility of buyers and

sellers transactions. Furthermore, literature argues that long-term contracts reduce the ability of large producers to exercise market power (Borenstein, 1998; Lien, 2000). However, not all electricity can be traded in long-term contracts. The fact that electricity is not a storable product and that supply and demand have to match constantly, obliges market parties to constantly buy or sell electricity at very short notice to match their positions. Short-term day-ahead, intra-day and balancing markets are used for this purpose.

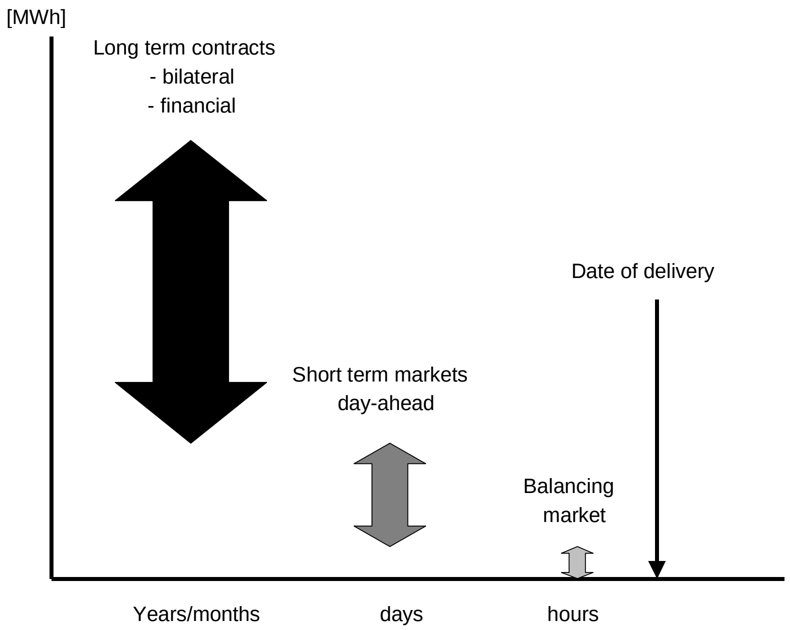

Figure 2.1 *Relative size and position of different electricity markets*

Balancing regimes are put in place to correct imbalances in the system. In order to provide market-based solutions to balance the electricity sector, balancing markets are being implemented by some Member States. In other Member States the system operator contract balancing power via bilateral contracts with producers. Depending on the regime, many market participants face new price risks from imbalance charges or their equivalent, which they will be expecting to hedge, or manage, through short-term contracts.

2.4 Trading arrangements

Although all four countries have implemented decentralised trading arrangements, trading activities differ significantly among them. A main cause of these different developments relates to the concentration and vertical integration levels in the market. In the Netherlands and Germany, as shown in Table 2.5, fairly liquid power exchanges exist, which create reference prices for the market and contribute to increasing transparency. The Dutch power market, the Amsterdam Power Exchange (APX), was created in May 1999 when its day-ahead market went alive. The volume traded increased substantially, especially since 2001, currently being around 18% of the total volume consumed. In the German market, the European Energy Exchange (EEX) resulted from a fusion between two power exchanges. It is a fairly liquid power exchange with a diverse amount of contracts traded. With respect to trading activities, an empirical study (Strecker and Weinhardt, 2000) concluded that participants in the market anticipate three substantial shifts in wholesale trading. Firstly, trading volumes are expected to increase more than twofold. Secondly, physical trading will be accompanied by financial trading, and thirdly power exchanges supplement OTC markets. The study also suggests that OTC trading will remain dominant in physical trading and the overall dominant market segment.

Table 2.5 *Some characteristics of power exchanges*

	Name	Contracts	Volume [%]*	Price volatility
Netherlands	APX	Day-ahead	18	High
Germany	EEX	Day-ahead; futures	4	Moderate
France	Power Next	Day-ahead	~0.5	Moderate

* Relative to consumption.
Sources: APX, EEX, Power Next.

The development of standardised markets in France and Belgium remain limited. In France, the 'Power Next' power exchange went alive November 26, 2001. The amount of electricity traded remains significantly low, which is mainly due to the concentration of the market in hands of EDF. Table 2.5 shows how the volume of electricity traded in France is marginal in comparison with the other two countries. In Belgium, although negotiations for a Benelux power exchange were conducted, currently no standardised power exchange exists. Electrabel publishes wholesale prices, however they are not determined by market based trading.

2.5 Transmission and distribution

As previously mentioned, while a competitive market aims at the producers' and retail side of the electricity sector, the transmission and distribution activities should remain under regulation due to their natural monopoly characteristics. The objectives of the regulatory framework are to ensure the free and non-discriminatory access of market parties to the network, while providing network operators with incentives to improve their investments and operating efficiency and to ensure that consumers benefit from the efficiency gains. However, as in the other sectors and regardless of the harmonisation process pushed forward by the European Commission, the current situation regarding regulatory methods differs significantly among countries.

The Netherlands implemented an rTPA system. To regulate tariffs, a price-cap was introduced, where maximum tariffs are set for a regulatory period of four years. The cap is, roughly speaking, determined by considering the efficiency improvements that network operators can achieve. These improvements are determined by considering the most efficient firm of the sector as a benchmark and by internalising the general technological advances of the sector. Under this regulatory system, firms that reduce costs further than dictated by the price cap are able to earn higher profits. Conversely, firms whose costs are higher than the maximum tariffs see their profits decline. Although Belgium and France also implemented an rTPA system, it is not yet clear how these systems will be implemented and affect transmission and distribution tariffs. Germany, on the other hand, has no regulated network tariffs. How transmission and distribution tariffs are established is quite complex, but basically the firms determine them through negotiations with customers.

2.6 Cross border trade between regional electricity markets

The European Union's power sector, except for the Nordpool area, still comprises a sum of national power sectors and is therefore far from being a single electricity market (Glachant and Finon, 2000). In Scandinavia, due to technical and political issues, a single market was built when policies were harmonised and electricity started being traded in the countries through a single market. In other words, transmission and energy markets were integrated. Price differential between areas still rise due to congestion, yet they are determined in a wholesale market. Electricity markets in northwestern Europe do not behave as a single market. Technical reasons, low capacity in interconnectors, different openings of markets and different policies are argued to be the main causes.

Cross border trade of electricity between Member States contributes to the system's stability and promotes competition in national markets. However, due to the fact that interconnectors lack capacity and that no implementation of a harmonised effective and efficient allocation method for congestion management has been made, the trading volume has been relatively low and inefficiencies still exist. According to the EC: "insufficient interconnection infrastructure between Member States and, where congestion exists, unsatisfactory methods for allocating scarce capacity contribute to the non-well functioning of the market" (European Commission, 2002).

The extent of potential competition from imports, as shown in Table 2.6, depends on the size of interconnectors. Price differentials between countries are the main drivers that dictate the direction of the electricity traded. Other issues that influence the trading of electricity are the opening levels and transparency of the market, and the allocation methods of interconnector capacity. Table 2.6 shows the different allocation methods of capacity among the four countries studied in this report.

Table 2.6 *Cross border trade*

	Capacity*	Allocation method	Capacity tradability	Netting**	Congested
DE - NL	2800	Auction	Yes	No	Frequently
FR - BE	2200	First come - first served / Pro rata	No	Yes	Frequently
FR - DE	2850	First come - first serve	No	No	Occasionally
BE - NL	1700	Auction	Yes	No	Seldom
NL - BE	1700	Auction	Yes	No	Seldom
NL - DE	1350	Auction	Yes	No	Seldom
BE - FR	3100	First come - first served / Pro rata	No	No	
DE - FR	2250	First come - first serve	No	No	

* ETSO winter 2001/2002.
** 'Netting' means that counter flows receive a compensation for congestion relief.
Source: EC Benchmarking report.

As previously explained, inefficient methods for congestion relief have been implemented. Specifically, congestion between the Netherlands and Germany, and the Netherlands and Belgium is managed by auctioning of aggregate transmission capability, rather than capacity of individual congested facilities.[8] Although it is the net flow through an interface that matters, these auctions generally do not give credit for counter flows ('netting' in Table 2.6). As a result, suppliers located downstream of a constraint (i.e., in higher priced zones) do not have an efficient incentive to sell power upstream (in the lower cost zones), as they do not receive revenue from relieving transmission constraints. This can occur between Germany and the Netherlands, because the latter country tends to have lower prices than the former, resulting in the frequent congestion of the interconnector between the two countries (Hobbs, et al, 2002).

Inefficiency problems that can arise from implemented transmission pricing include transactions whose real costs are greater than their benefits. In the case of no credit for counter flows, firms outside a particular country may be discouraged from competing there, thus increasing local market power. Besides transferring income from consumers to strategic suppliers, such diminished competition has two efficiency effects: a decrease in allocative efficiency and a decrease in productive efficiency[9] (Hobbs, et al, 2002).

[8] Boucher and Smeers (2001) describe some of the problems that can arise from auctions of aggregations, and from the use of different systems to manage congestion within and between countries.

[9] With capacity withholding, allocative inefficiency means that consumers do not buy some power whose true marginal cost is lower than their willingness to pay. A decrease in productive efficiency occurs as firms possessing market power will restrict output so their marginal costs are lower than the market price. They will therefore have lower marginal costs than more competitive firms whose marginal costs approach the market price.

2.7 Profits in liberalised electricity markets

With the liberalisation of the market, firms in the generation and retail sectors are no longer assured an adequate return to their activities but have to obtain profits in this new competitive driven sector. In a perfectly competitive market, the price as the earning will be cost-reflective. However, when manipulating the market, firms can receive extra rents. The abuse of market power can have particular impact in the generation and retail sectors, while the transmission and distribution sectors should, in theory remain with regulated tariffs. It could happen that vertically integrated firms try to avoid competition by denying market access to their networks.

In the Netherlands market concentration levels are relatively low and firms fairly unbundled. Abuse of market power, however, can still occur in a number of areas. For example, Electrabel, the monopolistic power producer in Belgium, is also owner of the largest power producer of the Netherlands, which can increase market power opportunities. More important is that the exercise of market power cannot only affect prices consumers pay, but also the revenues received by TSOs. In particular, suppliers may manipulate output to diminish payments in transmission capacity auctions. The interface constraining flows from Belgium to the Netherlands is sometimes fully used during daytime hours, yet the price paid is usually zero. This suggests that even though congestion is occurring, the price paid does not track differences in energy prices between the two countries. The low price for this interface may occur because there are one or two main users of that interface (Electrabel and EdF) who may have learned that they can lower their bids for that interface to zero and still obtain all of the capacity. Electrabel has essentially a monopolist position in the Belgian market, preventing arbitragers from buying and reselling power. As a result, Electrabel may be acting essentially as a monopsonist with respect to the Belgian-Netherlands interface. On the other hand, the Germany to Netherlands interfaces, which are also used to capacity most of the time, usually get a significant price in their auctions. This may be because there are more suppliers who desire that capacity, so that market is more competitive (Hobbs, et al, 2002).

Germany is a particular case. When the electricity sector was liberalised, prices decreased significantly. The existence of a large number of players together with overcapacity was generally seen as the main reason for the competitive pressure. Low prices, of course, reduced the firms profitability, which resulted in mergers of a number of power producers. The German electricity market, as a result, moved from a fragmented highly competitive market structure at the beginning of 1999 to one with increased concentration levels. However, the high concentration in generation in Germany does currently not have adverse effects on wholesale prices, but on network tariffs. More specifically, network-access charges are (excessively) high, while the profit margins at the competitive stages are low. Vertically integrated incumbents, as a result, do receive incentives to discriminate against other firms willing to access their networks. But more important, the low profit margins at the generation sector makes it unattractive for new generation to enter the market, reducing potential competition (Brunekreeft, 2002).

Belgium and France both have national monopolies. Electricity prices are therefore not determined through ‘real’ markets but between the firms and the government. It is clear that with those concentration levels energy companies would be allowed to set the prices where they maximise their profits. In this case, prices would be, politically and economically, unsustainably high.

3 POSITION OF LARGE POWER PRODUCERS

3.1 Introduction

As discussed in the previous chapter, the electricity price in a perfect competitive market will be set by the marginal costs of electricity production. When, additionally, overcapacity is assumed in this market, the short run marginal costs (SRMC) of the production park are an accurate approximation of the market prices that will be set.[10]

Even though northwestern Europe is characterised by installed overcapacity, the observed market prices seem to be not cost reflective. Apparently the existing power producers are able to raise prices above the competitive level. Especially larger power producers are able to exercise market power and also benefit the most from higher market prices, creating the incentive to do so.

This chapter argues the aforementioned by illustrating in Section 3.2 the marginal cost curves for each of the four countries.[11] It starts with an outline of the assumptions made for these supply curves. Based on these curves, the current positions of the larger power producers in each of the countries and their incentives to manipulate the market are discussed. Section 3.3 discusses how incumbent large power producers could deter new entrants. Section 3.4 deals with the future position and discusses whether investments in new capacity will be necessary in the middle term and if so, which types of investments are to be expected.

3.2 Supply curves

3.2.1 Assumptions

Generation capacity

For each of the four countries, the largest power producers are selected, based on their national market shares (see Table 3.1). These market shares include the capacity of their subsidiaries. The supply curves presented later in this chapter also take into account the capacity of subsidiaries of these firms.

The information regarding generation capacity and unit characteristics is, to a large extent, based on the World Electric Power Plants database of 2001 (UDI, 2001).[12] The database contains information on ownership, location, type of unit and fuel type among many other variables. The thermal efficiencies are estimated based on Lako and Ybema (1997). Using these efficiencies and the fuel prices, the short run marginal costs (SRMC) of the individual plants can be estimated.

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[10] Actually in a short-run competitive market, the price of electricity can be set either by the short-run marginal costs of the marginal plant or the marginal willingness to pay of consumers if plants are at capacity. Specifically, when drawing a step function supply curve, if the demand curve is not vertical it may cut the supply curve at a vertical portion of a step rather than a horizontal one, at which time price is set by the demand-side, not SRMC.

[11] In principle also one marginal cost curve for these four countries could be constructed. However, constraints in network interconnections and differences in market rules comprise a restriction for one single market price. If market prices in each of the countries are determined by the marginal cost curves these market prices will interact through electricity trade between these countries.

[12] Actually, the power plant data used for this study are derived from the database of ECN's electricity market model for northwest Europe COMPETES.

The capacities used in the supply curves are not corrected for planned and unplanned unavailability due to maintenance or outages. Corrections of this kind would decrease the available capacity in the summer on average with 10% and during winter with 5%. The capacity is based on the situation in the year 2001.

Table 3.1 *Selected large power producers per country and their market share in 2001*

Country	Power producer	National market share: For the individual power producer [%]	National market share: Total for larger power producer in the country [%]
Belgium	Electrabel SA	83	83
France	Electricité de France	90	90
Germany	E.ON Energie AG	24	
	RWE Energie AG	21	63
	Vattenfal Europe AG	10	
	ENBW Energie-Versorgung Schwaben	8	
Netherlands	E.ON NL	10	
	Electrabel NL	26	74
	Essent Energy Production BV	18	
	Reliant Energy Europe	20	

Fuel prices

The SRMC of a plant consists of the fuel and other variable operation and maintenance costs. As the fuel costs cover the largest part of the SRMC (85 to 90%), the operation and maintenance costs are left out of the supply curves here.

Table 3.2 contains the fuel prices used for calculating the short run marginal costs. The fuel prices are based on prices for the year 2000.[13] For the current analysis the relative differences between the marginal costs of the units and their merit order in the supply curve are of main interest, not so the exact level of their marginal costs. For this reason, the fuel prices of 2000 are assumed to satisfy this purpose.

Table 3.2 *Fuel prices in €/GJ including excise taxes for utilities*

Fuel	Belgium	France	Germany	Netherlands
Coal	1.31	1.31	1.59	2.04
Natural gas	3.84	3.93	4.40	3.45
Gas peak	4.73	4.90	4.46	3.95
Fuel oil	4.92	5.57	5.33	5.85
Diesel oil	7.10	8.93	8.19	9.40
Nuclear	0.65	0.52	0.65	0.65
Biomass	2.93	3.30	3.58	2.94
Waste	1.22	1.53	1.81	1.53
Lignite	6.47	1.27	1.41	6.47
Hydro	0.00	0.00	0.00	0.00

The prices in Table 3.2 show that, for example, coal in the Netherlands is more expensive than in the other three countries, whereas the price for natural gas is lower. In all countries hydro, nuclear, waste and coal belong to the cheaper fuel types whereas natural gas and diesel oil are more expensive fuels. The table distinguishes between 'Gas' and 'Gas peak' as a fuel. This dis-

[13] The fuel prices are taken from a reference scenario developed for an energy company by ECN (Oostvoorn, et al, 2001) using the PRIMES model from NTUA.

tinction is to reflect the higher gas prices for peak plants as they face higher transmission capacity costs.

A significant part of the electricity production capacity in Germany and the Netherlands consists of Combined Heat and Power units (CHP). These units differ from standard electricity production units as they also produce heat. In most cases, a CHP plant is primary built for heat supply. The decision to supply electricity is not driven by the electricity market price but by the presence of heat demand at the location. This is often referred to as the 'must-run'. The marginal costs of these CHP units should also be corrected by including the extra income received by their heat production. If this heat valuation would be taken into account, the CHP-units would be placed further down the supply curve than their current ranking. The same holds for waste incineration plants, since they are operated on a continual basis (i.e. must-run) and electricity is in fact a by-product. In this analysis, the marginal cost curves are not corrected for the specific characteristics of the plants, as it would require a more thorough study, incorporating various other particularities of individual CHP and waste incineration units, which is beyond the scope of the current assessment.

Demand and cross-border trades

Table 3.3 gives an overview of the demand and cross-border trades that are used for the analysis for 2001. For each national supply curve, a comparison with the domestic super peak demand during the winter has been made, including a correction for net imports or exports. This super peak demand and imports and exports are based on data from UCTE for the year 2000.[14] Super peak demand is defined as the maximum demand that occurs for a period of 200 hours per year. A similar comparison is made for the so-called peak demand. This peak demand is the demand load that occurs for about 1/3 of the year.[15]

UCTE data for the first half year 2001 suggests that the super peak load in the Netherlands and Belgium has increased compared to the year 2000, whereas Germany and France show no significant increases. Data on average super peak load in 2001 for Belgium and the Netherlands could not be obtained. The super peak load for 2001 in these countries is therefore assumed to equal the maximum load in 2001 according to measures of the TSOs in those countries.[16]

As the supply curves of the countries do not include production capacity that might be imported or exported, the demand should be corrected for realised cross-border trade. Assuming that this trade in 2000 and 2001 is similar, the demands per country have been corrected with the cross-border trades in 2001 retrieved from the UCTE.

Table 3.3 *Demand and cross-border trades for 2001 per country*

Country	Super peak demand [MWe]	Peak demand [MWe]	Net Exports [MWe]	Net Imports [MWe]
Belgium	12,950	11,400	-	880
France	67,450	61,610	6675	-
Germany	95,430	88,195	-	480
Netherlands	17,240	15,770	-	2540

14 UCTE, Yearly Statistical Book 2000 (www.ucte.org). The super peak load for Germany is increased with 18800 MWe and for the Netherlands with 3000 MWe as the super peak loads are based on measures at the high voltage grid. Both Germany and the Netherlands have a large share of CHP that feed in electricity at the lower voltage grids. As these units are to a certain extent, included in the supply curves, demand should also include this load.

15 More precisely the 'shoulder' demand – a time-duration curve has the shape of a shoulder – shown in the figures are retrieved from winter data. This can be assumed to be the highest shoulder demand among the four seasons. We decided to use the data from this season, as the capacity data in the supply curves are not corrected for availability.

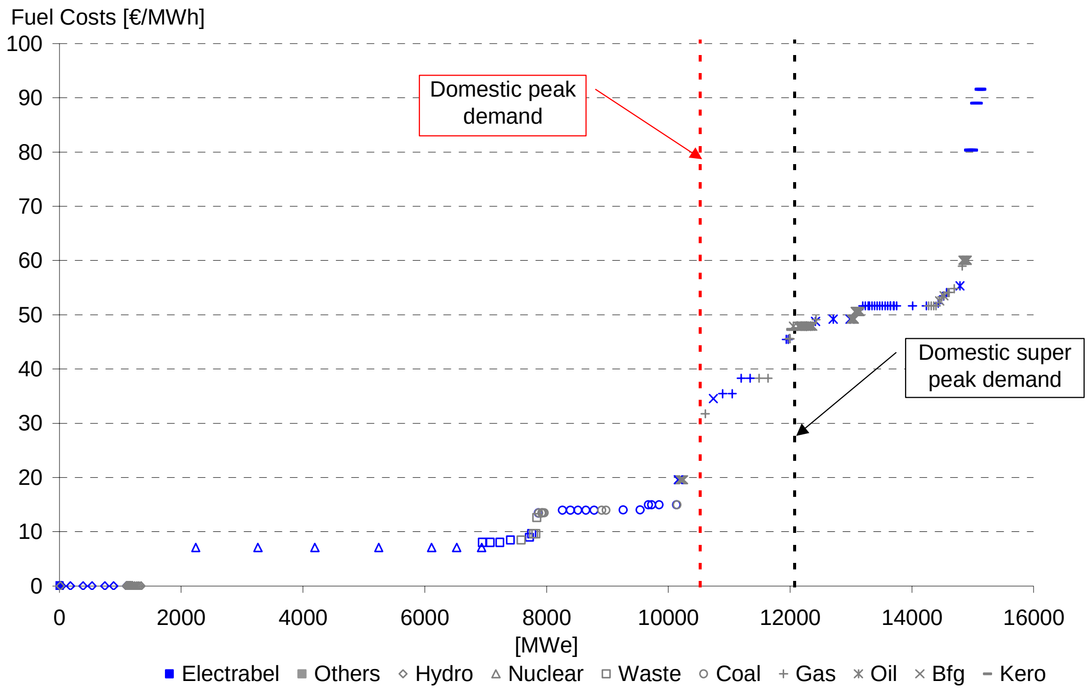
16 Transport-balans 2001, Tennet (www.tennet.nl) and Activiteitenverslag 2001, Elia (www.elia.be).

Presented supply curves
The supply curve and demand levels shown in the next sections are used to illustrate some general issues. It should be noticed that, depending on the season, fluctuations in fuel prices and other factors, supply curves and the demand levels would change. Furthermore the included marginal costs only consider fuel costs and do not include other variable costs, such as maintenance and operation and start-up costs. Therefore, firm conclusions cannot be based on the supply curves.

3.2.2 Belgium

Figure 3.1 shows the supply curve, based on SRMC, for Belgium. The curve distinguishes between capacity from Electrabel (blue) and capacity from other power producers (grey). Different markers indicate the fuel type of the generation units in the supply curve. The category hydro also includes other renewable capacity such as wind and solar.

The first part of the curve consists of hydro and renewables with marginal costs equal to zero (all indicated in Figure 3.1 as hydro). Then the nuclear plants are ranked followed by the coal plants. The end of the supply curves mainly consists of blast furnace and natural gas-fired plants. Looking at the black dotted line, representing the super peak demand in Belgium corrected for the net imports, these gas-fired plants are assumed to set the price during the peak hours.[17] All generation plants with lower SRMC that will also be invoked during the peak hours will profit from this high peak price. Figure 3.1 clearly shows that Electrabel owns most of these plants, delivering Electrabel a considerable profit.



Bfg = Blast furnace gas, Kero = kerosine.

Figure 3.1 *SRMC curve for Belgium in 2001*

[17] Note that in this conclusion one should take into account that the supply curve is not yet corrected for unavailability of plants due to maintenance. Since the comparison with winter peak demand is made, one should reckon with a 5% unavailability on average.

The significant amount of inframarginal plants owned by Electrabel, provides the firm with strong incentives to raise the market price. The above explanation uses the super peak price as an example, which only applies to around 7% of the time during a year. The so-called ‘peak price’ is therefore a better example.

The red dotted line in the figure shows the maximum demand load that occurs for circa 33% of the time, this is called the peak period. Prices during this period and during periods with lower demand load can be indicated as ‘off peak’ prices whereas prices during the other periods are so-called ‘peak prices’. In theory, the point of intersection of this demand with the supply curve will set the market price during the peak period.

Figure 3.2 shows the percentage of capacity owned by Electrabel SA, with unit cost below this peak price and above this peak price. Electrabel owns relatively more capacity (75% of its portfolio) with marginal costs below the peak price than other companies (35% on average) in Belgium. This indicates that Electrabel would profit more during peak prices than other market players. Electrabel could withhold some capacity under this peak demand inducing a shift of the supply curve to the left and an increase of the market price.

It should be noted that this explanation of market power only applies to Belgium to a certain extent as in Belgium the market is dominated by a monopolist. Electrabel is in theory able to unilaterally set the market price. However, it is expected from the government to interfere as soon as prices are above ‘acceptable’ level. The information and figures above clearly show that Electrabel has a *de facto* monopoly in Belgium.

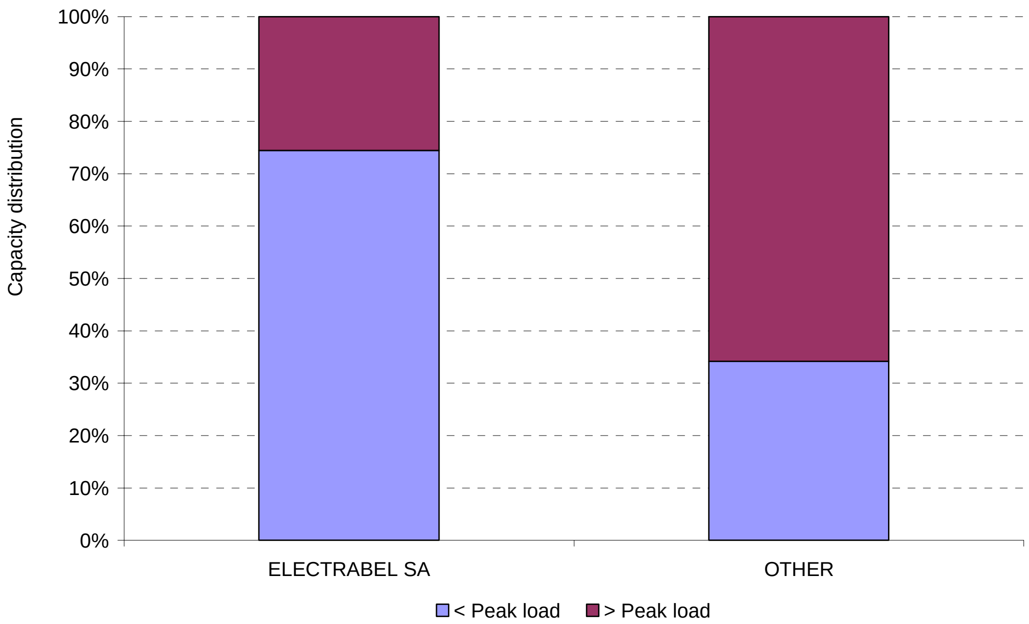


Figure 3.2 *Percentage of capacity owned by Belgian companies above or below peak load*

3.2.3 France

The French market is dominated by Electricité de France (EdF), which owns 90% of the total production capacity. Figure 3.3 shows the SRMC curve for France where the blue coloured marks indicate the power units of EdF and the grey ones correspond to units owned by other companies active in France. Most of the capacity of EdF consists of nuclear power plants.

Looking at the intersection of the supply curve with the (super) peak demand (including exports) suggests that nuclear power plants are assumed to set the peak prices. This is the case when almost all hydropower capacity is available as well as nuclear power plants. However, this usually is not the case as particular nuclear plants can be taken out of operation for a longer period (one or two years) and part of the hydropower plants is used as pump storage capacity resulting in a periodically reduced supply capacity and demand increase. Nevertheless, the curve in Figure 3.3 shows that a large amount of hydro and nuclear power should become unavailable before coal or even gas would be price setting.

Sometimes it is argued that gas or coal-fired plants are necessary to follow the volatility of electricity demand fluctuations. However, the output of a nuclear power plant can be scaled down to about 40% of its normal output. Additionally, France can vary its level of exports, depending on its domestic demand.

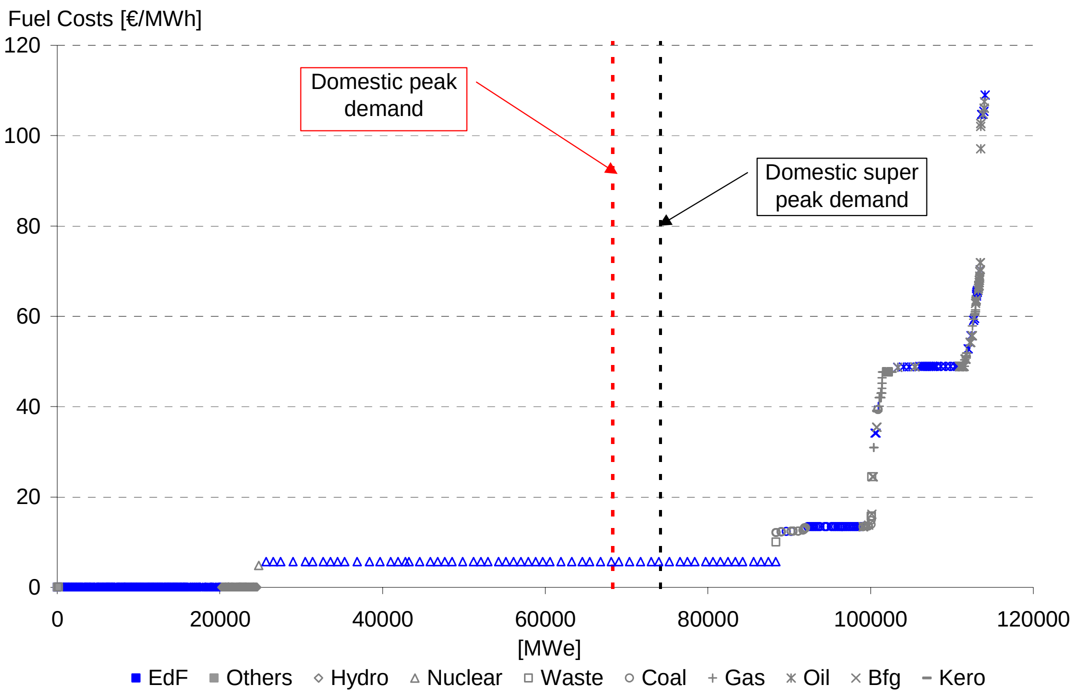


Figure 3.3 *SRMC curve for France in 2001*

Figure 3.4 shows the distribution of capacity of EdF and of the other French companies in relation to the peak demand in France. Around 62% of EdF's capacity lies below the peak demand in France, corrected for exports (68,300 MWe). In theory when some level of competition would exist on the French market these percentages would argue that EdF has more incentive to behave strategically than the other companies. Recalling the 90% market share of EdF, this analysis is rather artificial. EdF has a *de facto* monopoly on the French electricity market.

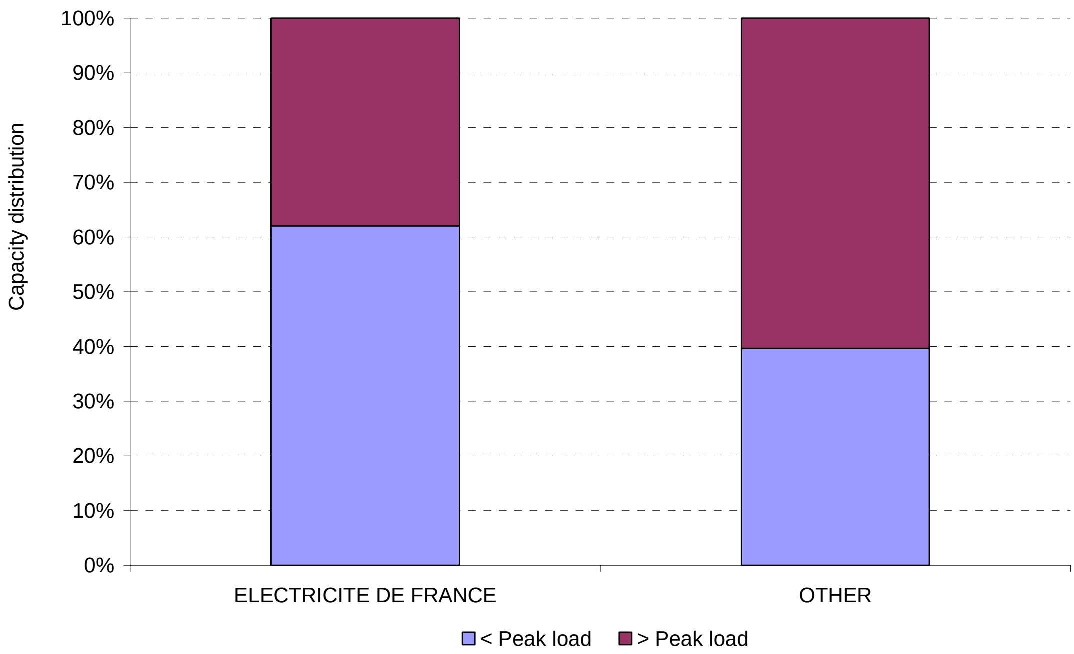


Figure 3.4 *Percentage of capacity owned by French companies above or below peak load*

3.2.4 Germany

With more than 120,000 MWe installed production capacity, the German market is the largest amongst the four countries in this study. Figure 3.5 shows the SRMC corresponding to this installed capacity.

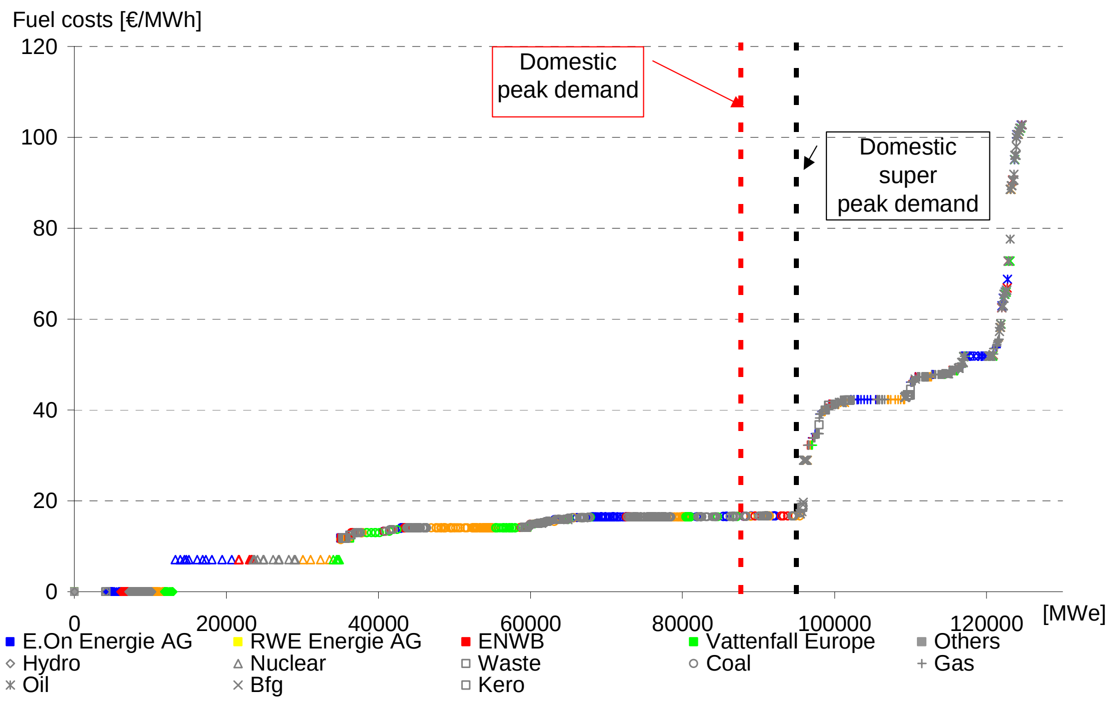


Figure 3.5 *SRMC curve for Germany in 2001*

The first thing that attracts the attention is the diversity of production companies and the diversity of fuel types. The curve distinguishes the four largest power producers (as regards their market share in production capacity) and a remaining category for the other power producers.

Again the fuel type of the units is indicated by different marks. The first part of the curve consists of hydro renewables (4200 MWe) capacity with zero marginal costs (al presented as hydro in Figure 3.5). This is followed by nuclear capacity. Clearly E.On Energie AG owns most nuclear power plants. Coal plants follow with a small increase in marginal costs and they cover the largest share of the total installed capacity. After the coal units the SRMC shows a significant increase as the gas-fired units have much higher fuel costs. The curve ends with mainly oil-fired units creating the fast increasing tail of the curve. These oil-fired plants are the real peaking plants having relatively high fuel costs and a relative low efficiency.

The diversity in power producers and type of capacity implies that the German market is more competitive compared to the Belgian and French electricity market. Moreover, the spot prices on the German market, the European Energy Exchange (EEX), suggest that the market is quite competitive. The spot prices for the year 2001 and for the first three-quarters of 2002 are shown in Table 3.4. A direct comparison with SRMC curve of Figure 3.5 is not possible since these marginal costs are based on the fuel prices for 2000 (see Table 3.2). However, for the SRMC listed in Table 3.4 these fuel prices are corrected for the price increase in 2001-2002, using IEA statistics.[18] According to this source the German (steam) coal prices have increased with 20% during that period. Table 3.4 shows that for all seasons, spot prices on the EEX are above the SRMC of the marginal unit during the winter season, which implies that during certain periods prices exceed marginal costs. Nonetheless, the intersection of the demand curve in Figure 3.5 shows that the peak and super peak price are extremely sensitive to a shift in the supply curve. As soon as unavailability of production capacity would be taken into account, the supply curve in Figure 3.5 would shift to the left and a gas-fired plant would set the super peak price (SRMC around 30 €/MWh). This accounts for the demand load the winter season. During other seasons demand will be lower and a coal-fired plant would definitely set the price.

Table 3.4 *German spot prices on EEX compared to the SRMC of the marginal unit*

		European Energy Exchange (EEX)			SRMC marginal unit**	
		Super peak	Peak	Base load*	Super peak	Peak
2001	Dec, Jan, Feb	27.79	26.09	22.52	20.7	20.1
	Mar, Apr, May	29.88	25.96	21.91	20.7	20.1
	Jun, Jul, Aug	32.96	26.66	19.98	20.7	20.1
	Sep, Oct, Nov	31.93	29.59	24.87	20.7	20.1
2002	Dec, Jan, Feb	37.49	37.93	31.24	20.7	20.1
	Mar, Apr, May	26.73	23.40	19.70	20.7	20.1
	Jun, Jul, Aug	40.85	29.76	23.13	20.7	20.1

* Base load price is the average day price.
** coal power plant.

Figure 3.6 shows the share of capacity below the peak load and above the peak load for the four largest power producers in Germany and for the remaining companies. More than 80% of the power units of Vattenfall Europe lie below this peak load. Also for E.On and RWE a significant part of their capacity is placed below this peak load. These firms will have an incentive to increase their profits by influencing the marginal unit, i.e. increasing the market price.

[18] IEA, Electricity information 2002.

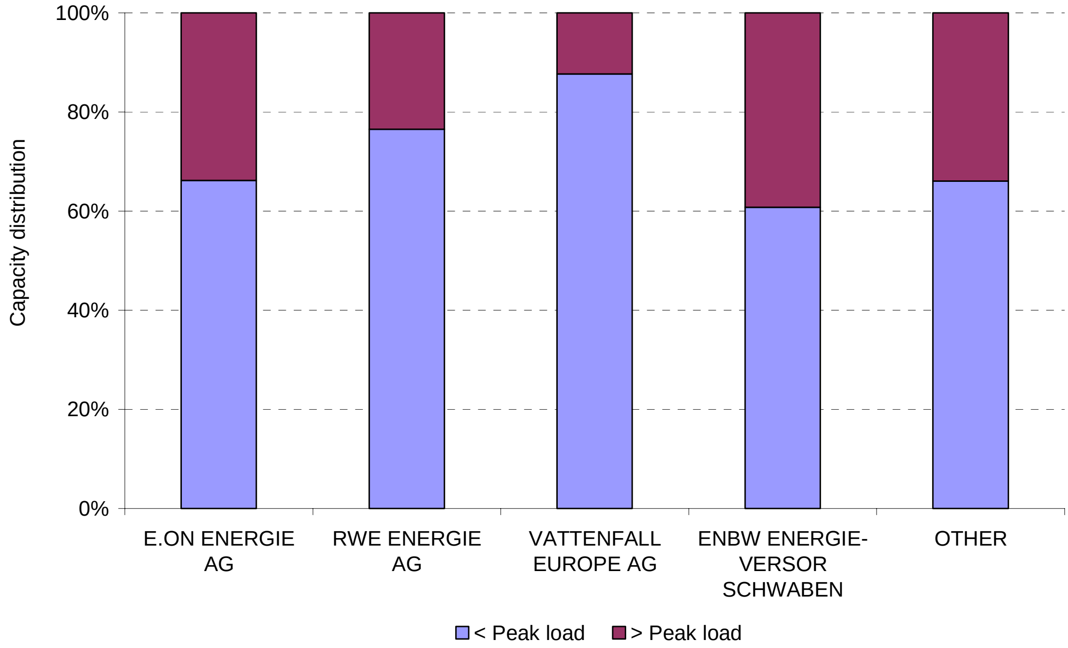


Figure 3.6 *Percentage of capacity owned by different German companies above or below peak load*

3.2.5 The Netherlands

The SRMC curve of the Dutch production park (Figure 3.7) can be approximated by an increasing linear line, in contrast to the other countries where the supply curves are more exponential. The Dutch market has a lower number of typical base-load capacity with low SRMC, such as coal and nuclear and it does not have oil-fired or kerosene-fired peak units with extremely high SRMC like the other three countries. In contrast, the Dutch market is dominated by gas-fired plants, which are used as peak plants (gas turbines) and as base load plants (combined cycles).

The SRMC for the Netherlands also illustrates that the capacity is divided between four large power producers; Essent, Electrabel NL, E.On NL and Reliant. The remaining capacity is very limited and mainly consists of CHP units owned by industries.[19]

Again the domestic super peak and peak demand are drawn in the figure. The dotted lines show these demands corrected for the imports. Under certain conditions, the intersections of these dotted lines with the supply curve would determine the market price during peak and super peak. As a reference Table 3.5 compares these points of intersection with the realised spot prices on the Amsterdam Power Exchange (APX). It shows that, although market prices sometimes approach the SRMC, on average they are higher.[20]

[19] The supply curves include all decentralised capacity in the Netherlands except the small gas engines with a capacity below 2 MWe. This comes down to an omission of almost 1500 MWe. These small gas engines can be neglected in this analysis as they cannot influence the market (price setting).

[20] Just as in mentioned in the analysis of the German supply curve, one should bear in mind that the figures shown here are results of one specific moment. During the day and the year, demand fluctuates and units are out of operation due to maintenance et cetera, which results in a different supply curve. In the current supply curve, total capacity is not corrected for unavailability. During winter, the averaged unavailability amounts to 5% of total capacity and during summer season 10%.

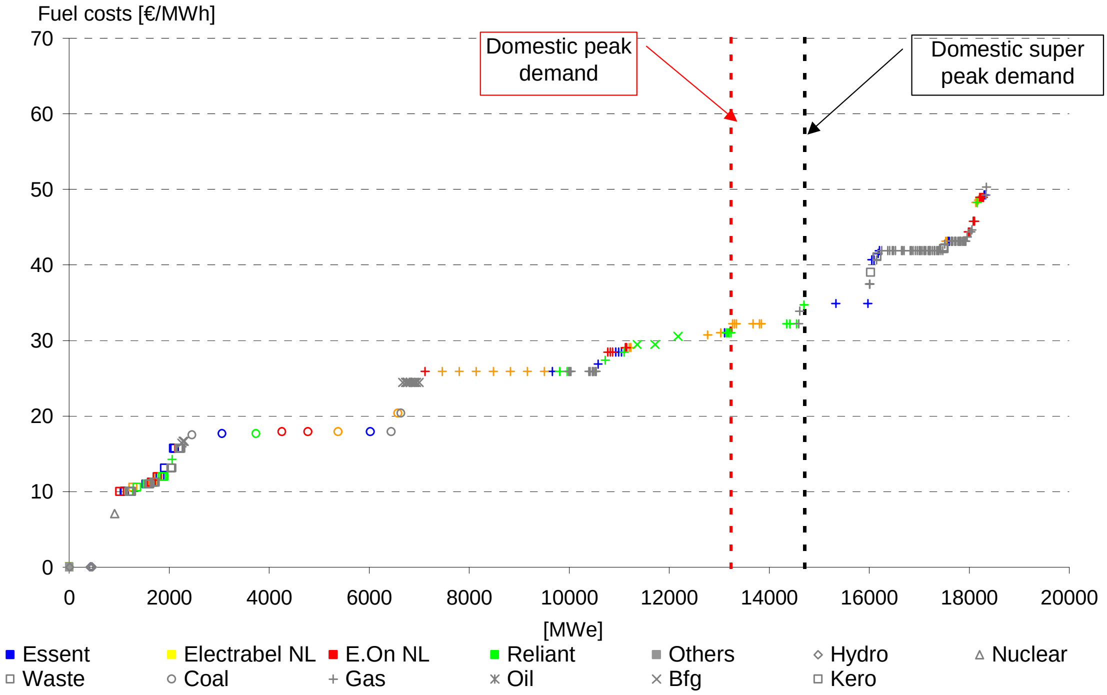


Figure 3.7 *SRMC curve for the Netherlands in 2001*

The SRMC of the marginal unit is determined by a gas-fired unit. Since the price of natural gas in the Netherlands differs per season, the SRMC in the table are corrected for these quarterly deviations of the natural gas price compared to the natural gas price of 2000 that are used for the SRMC curve (see also Table 3.2).

Table 3.5 *Dutch spot prices on the APX compared to the SRMC of the marginal unit*

		Amsterdam Power Exchange (APX)			SRMC marginal unit*	
		Super peak	Peak	Base load	Super peak	Peak
2001	Dec, Jan, Feb	41.80	48.45	36.41	48.88	43.18
	Mar, Apr, May	55.50	33.93	27.13	42.21	36.36
	Jun, Jul, Aug	122.50[21]	59.88	37.90	42.77	36.93
	Sep, Oct, Nov	62.40	42.77	31.96	39.99	34.09
2002	Dec, Jan, Feb	48.50	45.86	34.00	36.10	30.11
	Mar, Apr, May	37.50	26.67	20.85	36.94	30.97
	Jun, Jul, Aug	96.90	55.11	32.76	41.10	35.23

* Gas-fired power plant.

The distribution of capacity of the four largest producers in the Netherlands in Figure 3.8 shows again that these producers have an incentive to increase market prices, as this will increase their margin on the remaining (low unit cost) power plants that are invoked.

[21] In June 2001, high prices are observed on the APX due to the outage of two reactors in Belgium, decreasing the Belgian production capacity with almost 2000 MWe, and a reduction of 300 – 400 MWe interconnector capacity between Belgium and France. This example shows that when total supply to the Dutch market is reduced the ability to influence market prices increases (note that 122 €/MWh is very high compared to the SRMC curve). Also the number of producers that are able to supply the super peak demand is lower than the number of players that can provide off-peak capacity. This reduction in the number of suppliers also increases 'market power'. Or better: the product becomes scarce, increasing market power.

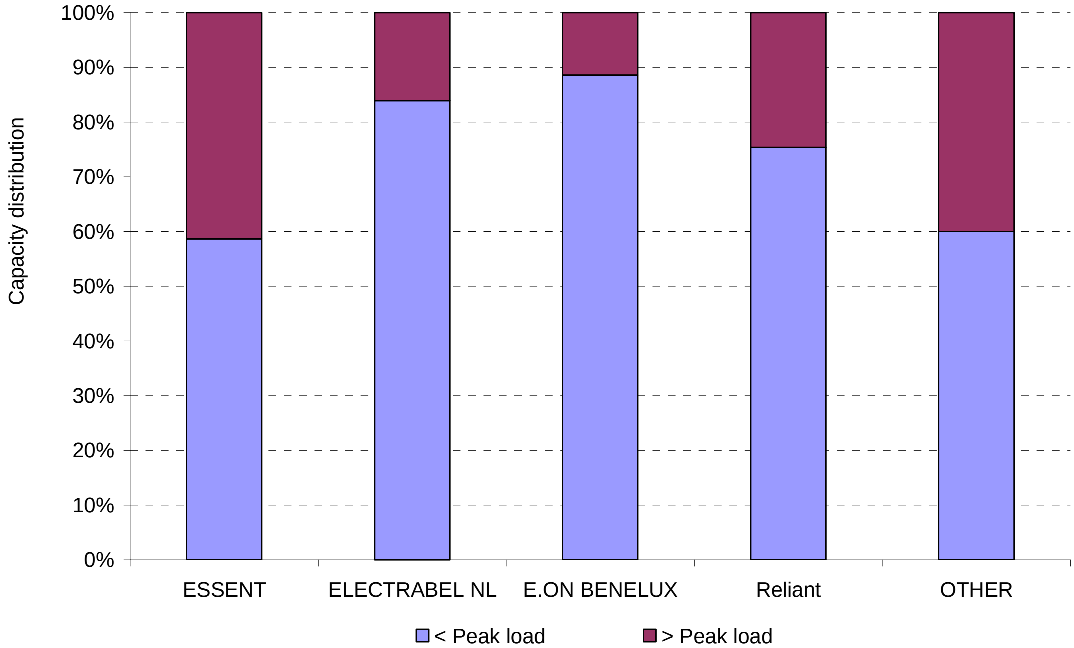


Figure 3.8 *Percentage of capacity owned by different Dutch companies above or below peak load*

3.3 Deterring new entrants

In the previous section, it was argued that the existing producers have an incentive to manipulate the market price. In principle this applies to each of the four countries. However, these incumbent producers will also try to prevent new producers from entering the market. New entrance would result in more suppliers, increased competition and lower market prices. To reduce the investment risk, new entrants would presumably build base load power plants his maximising the probability that their plant will be dispatched. A new base load plant corresponds to a shift of the supply curve to the right, decreasing the market price. Additionally, it reduces the ability for existing producers to manipulate the market. For example, withholding capacity has less impact, as the market share of an existing player in the lower segment of the supply curve will decrease.

As long as the market price is below the long run marginal cost (LRMC), new investments will be too risky, certainly for new players. The LRMC are defined as the annually fixed costs (mainly capital costs) plus the annual variable costs (i.e. the SRMC). Incumbent producers will most probably try to raise market prices up to just below this LRMC. Figure 3.9 shows the LRMC for two typical base-load plants (a nuclear and a coal-fired plant), a gas-fired peak plant (based on a gas-fired CCGT) and a typical super peak plant (based on a gas turbine). The calculations of these LRMC are based on the assumptions shown in Table 3.6.

When comparing these LRMC with the prices on the Dutch and the German spot market (APX and EEX), it shows that these spot prices are indeed below the LRMC most of the time. The super peak prices should be compared with the LRMC of the super peak plant, the peak prices with the CCGT and the base load prices should be compared with the LRMC of the coal plant.

Forward base-load for the first half of 2004 range between 24 - 34 €/MWh for the Netherlands and 25 - 26 €/MWh for Germany. The forward peak prices for the same period range between 43 - 52 €/MWh for the Netherlands and 32 €/MWh for Germany.[22] These wholesale prices are below the calculated LRMC for new power plants.

Although, Dutch wholesale prices are below LRMC for new power plants, some parties other than the four large producers have taken the initiative to build new plants.[23] These industrial CHP plants will have extra revenues from heat sales.[24] The electricity is sold to large electricity suppliers who hedge themselves against high prices in the near future. Apparently, in an unbundled market, electricity suppliers have an interest in reducing their dependency on existing large power producers.

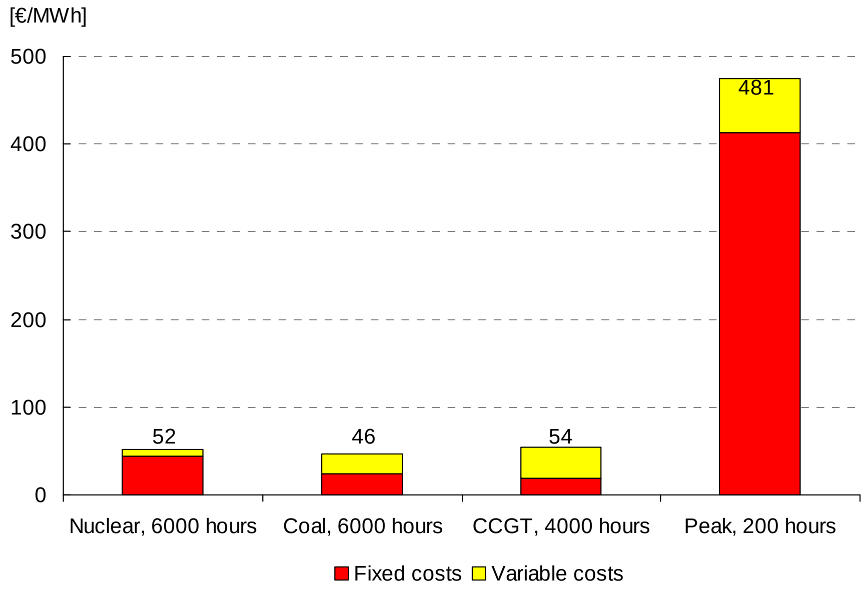


Figure 3.9 *Long run marginal costs of four typical power plants (energy prices 2000)*

Table 3.6 *Assumptions of four typical power plants*

		Nuclear plant	Coal plant	CCGT plant	Peak plant
Operation hours	[Hours]	6000*	6000	4000	200
Investment	[€/kW]	2000	1200	540	380
Economic Lifetime	[Years]	20	20	20	20
Interest rate	[%]	8	8	8	8

* In a market with a small share of nuclear power, such as the Dutch electricity market, a higher number of operation hours will be feasible resulting in lower LRMC.

3.4 Future outlook on production capacity

The strategy to deter new entrants by keeping market price below LRMC implies that prices are not significantly high for incumbent producers to invest in new capacity. In the longer term, this could lead to shortages in total supply. However, incumbent producers have the ability to extend the lifetime of their power plants. Electricity can also be supplied from other regions with an extension of import capacity, if necessary. This section discusses the alternatives of fulfilling future electricity demand. Section 3.4.1 describes the assumptions that have been made for es-

[22] Energiebeurs Bulletin, November 2002.
[23] This concerns a 800 MW CHP plant by Intergen and a 780 MW CHP plant by Delta.
[24] More information on costs and profits for CHP plants in the liberalised Dutch electricity market can be found in Rijkers, et al, 2002.

tablishing a future outlook of electricity demand and electricity production capacity in 2010. Subsequently, Section 3.4.2 compares the future demand with the current available production capacity and the expected increase of renewable energy supply (based on EU renewable electricity targets). Based on the comparison, it is discussed how future demand in 2010 could be covered in each of the four different countries, considering the alternatives of lifetime extension, (increased) import capacity and building new capacity.

3.4.1 Assumptions

The current production capacity in 2001 is expected to change, since power plants that are currently deactivated will be taken into operation again and support schemes for renewable energy will most probably stimulate investments in new renewable electricity supply.

Renewables

European Member States agreed upon national indicative targets for 2010 with respect to the contribution of electricity generated from renewable sources to gross electricity consumption (2001/77/EC). If these targets are not yet reached by the current production capacity, an increase in renewable electricity is assumed in order to comply with these EU-targets. Both Belgium and France already fulfilled these 2010 targets with their current hydro capacity. Here we assume that both Germany and the Netherlands will build additional renewable capacity in according to current renewable energy policy. However, to meet the EU target in 2010, countries can also import (part of) the renewable electricity.

Table 3.7 *National indicative targets for renewable electricity in 2010*

Country	Target in percentage of gross electricity consumption by 2010 [%]
Belgium	6
France	21
Germany	12.5
Netherlands	9

Reactivating mothball plants

Besides an expected increase from additional renewable electricity generation, the generation capacity is also assumed to increase by 2010 with the capacity currently deactivated by means of mothballing.

Electricity demand and cross-border trades

An annual growth factor for the national super peak demand is calculated using the electricity demand in 2000 and the electricity demand in 2010 forecasted by the IEA (IEA, 2002). Table 3.8 shows the resulting super peak demand and the growth factors that have been used.

Table 3.8 also indicates the projected cross-border trades for 2010 (for changes: compare Table 3.3). The second benchmarking report of the European Commission (European Commission, 2002) shows that the ratio of electricity import capacity and total installed capacity in the Netherlands is assumed to increase with circa 7.5% by 2005. This corresponds to the plans of TenneT to increase the available interconnector capacity with 1350 MW to a total capacity of 5000 MW by the end of 2003.[25] For the other three countries, a less significant (circa 2.5%) increase of the ratio between import and installed capacity is assumed for the next three years. Based on this information the net realised cross-border trade (during peak) for the Netherlands in 2010 compared to 2001 is assumed to increase with 1200 MWe. For the other countries, the net trade

[25] Currently the available import capacity for the Netherlands amounts 3650 MWe, 300 MWe is reserved to fulfil UCTE-agreements. This reservation of 300 MWe is assumed to be continued up to 2010.

between 2001-2010 is increased with the same growth factor as applied to the national electricity demand.

Table 3.8 *Demand and cross-border trades for 2010 per country*

Country	Super peak demand [MWe]	Annual growth factor [%]	Net Exports [MWe]	Net Imports [MWe]
Belgium	12533	-0.4	-	850
France	79004	1.8	7818	-
Germany	100470	0.6	-	501
Netherlands	20038	1.7	-	3740

3.4.2 How to cover future electricity demand?

One of the main issues for the future electricity market is whether there will be sufficient production capacity to cover future demand. In the previous section it was argued that current large power producers have the incentive to manipulate prices such that they maximise their margins but deter new entrants. In the extreme case, this would result in no investments in new generation capacity.

Considering the current existing power plants and assuming that they will be taken out of operation according to plan (lifetime of 25 years), the demand growth cannot be covered without building new production capacity. Figure 3.10 shows the production capacity in 2001 for each country classified according to their construction year (unknown, 1975 or before, after 1975), capacity that gets on stream after a period of mothballing and new renewable capacity. Dashes in the figure indicate the level of demand in 2010, the blue dashes showing the demand corrected for imports and exports. Note that for Belgium and Netherlands the secondary axis applies.

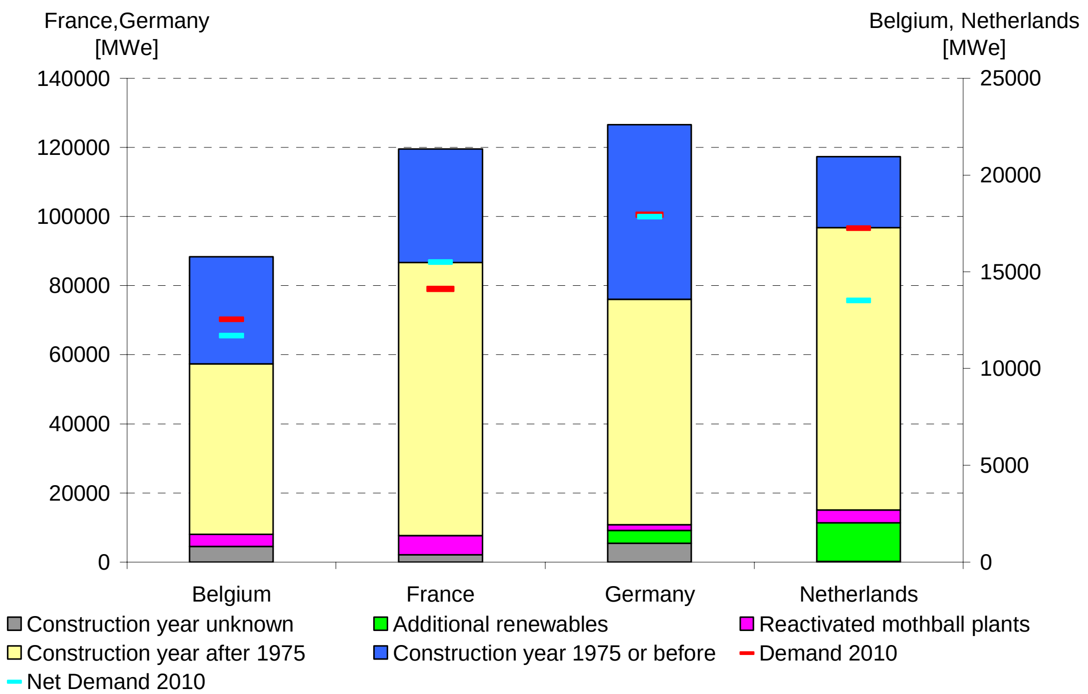


Figure 3.10 *Comparison power generation capacity 2001 with future electricity demand (net demand: domestic demand corrected with import or export)*

First, assuming that all power units built before 1975 (the blue coloured parts) will be taken out of operation. Then not one of the countries will be able to cover its 2010 demand by domestic production (i.e. looking at the red dashes). France will have some capacity left, however, recalling that the reported capacity is based on 100% availability this will not be enough for a secure supply. When taking into account imports and exports (i.e. looking at the blue dashes), the Netherlands seems to have (just) enough capacity to cover total demand. However, it should be stressed that this analysis is not suited for conclusions on supply security.

The general conclusion is that each country will need additional production capacity. Three solutions can be considered: expanding the interconnector capacity and thus increasing imports, lifetime extension of existing plants or building new capacity:

1. Increasing the import capacities is not a realistic solution as it was concluded that none of the four countries has exporting capabilities (unless other European countries should have unused capacity available, which by 2010 is not very likely). Increased interconnections should therefore not be considered as a main solution for the future shortage in production capacity.
2. The second alternative is lifetime extension by investing in renovation of existing plants. This is relatively cheap compared to new investments. It secures the current market position of incumbent producers. If market prices can be kept below LRMC, the market entry barrier for new producers is also maintained as explained in Section 3.3. Section 3.2 showed that large incumbent producers seem to have a stronger incentive for such a strategy than other smaller producers.
3. Figure 3.10 suggests that by adopting the lifetime extension strategy in the four countries considered sufficient capacity will be available to cover demand up to 2010. Without a more profound analysis, for example using a market competition model,[26] it is difficult to determine whether large power producers will be able to keep electricity market prices below LRMC until 2010 in all circumstances. As described for the Dutch power market (see Section 3.3) there may also be other reasons for market players to build new power units. Furthermore, environmental regulation may prevent lifetime extension of some old power plants.[27] Nevertheless, it is very likely that the large power generators can keep market prices just below LRMC for a certain period of time by adopting a lifetime extension strategy. This could counter act incentives for innovation and efficiency increase (except for renewable energy). Therefore, competition between incumbent power generators seems not to stimulate dynamic efficiency in the coming years.
4. At some point, new investments will be unavoidable. The extension of lifetime simply is technically restricted and plants will eventually be taken out of operation. The market prices will increase and finally reflect the LRMC of new power plants (see also Figure 3.9). It will create opportunities for new investments, as it enables investors to cover their fixed costs. This also concerns new players, creating a more competitive market: a level-playing field between incumbent and new players. Furthermore, it will stimulate dynamic efficiency: provoke innovations and increase efficiency of power plants.

For France and Belgium the situation may be somewhat different. Although the monopolistic power producers in these countries have also an interest in discouraging new market players entering the market, the governmental and political bodies in these countries may keep the monopolistic producer responsible for the security in electricity supply. Therefore, beside or instead of lifetime extension, EDF and Electrabel may start to invest in new capacity irrespective of the electricity market prices (set by these companies and not a result of market competition).

[26] For analysing strategic behaviour of power producers in Northwest European power markets ECN uses the COMPETES model. This model is based on the theory of conjecture supply functions and also incorporates the electricity grid as a linearized DC network.

[27] Here we assume that the nuclear phase out policy in Germany and Belgium will take effect after 2010.

3.4.3 Type of new production capacity

As the power production sector is liberalised and in most countries even privatised, we would presume preferences of producers dictate the type of new capacity. However, the public opinion and the policy framework (national or European) are of great importance and overrule in many cases the producer's freedom of choice. Important factors that influence the investment decision are: environment and sustainability, security of supply, and of course the financial aspect playing a role at the producer level.

In general new nuclear power will not have public support except in France. In fact, France has already announced plans to build some new nuclear power plants. In Belgium and Germany a phase-out policy is initiated and in the Netherlands nuclear power is still a sensitive subject of discussion. However, within the framework of the Kyoto-targets, in combination with the discussion on supply security, nuclear seems to become an option to consider (as also stated in the EU Green Book on security of supply, European Commission, 2000).

In Belgium, both gas-fired and coal-fired plants are an option. Considering the current greenhouse gas emission reduction targets at EU-level, investing in gas-fired units is more realistic in Belgium. In the Netherlands the CO_2 emission reduction target is also quite restrictive for the electricity production sector, which pleads for gas-fired units and renewables. At the moment, it seems even impossible to receive a licence for building a coal-fired power plant, even if power producers would like to build one.

In Germany the Kyoto targets are less restrictive for the electricity sector and as coal is one of the cheapest and best available fuels, it can be expected that - besides renewable electricity production to meet the renewable targets - coal-fired units will be the first new investments to be made on this market.

It should be noted that, when the lifetime extension strategy of large power producers is successful, large-scale investments in new power generation might only happen by the end of the current decade. By that time, the European greenhouse gas emission policy might be completely revised, including new and more severe reduction targets. This will have a strong impact on the attractiveness of certain power production options.

4 FACTORS AFFECTING THE POSITION OF LARGE POWER PRODUCERS

4.1 Introduction

In current power markets, large power producers seem to profit from the inheritance of national energy policy from the past. Furthermore, market incumbents seem to be able to maintain their position by raising market entry barriers and can gain profit from this advantageous position. This results from the combination of the relative size of the incumbents and their generation portfolio. This chapter discusses factors that may affect the position of large power producers in the market (market regulation, unbundling and market concentration; expansion of interconnector capacity; electricity demand) and the characteristics of the power plants (fuel prices; environmental regulation; technological innovations).

Policy makers can influence some of these factors but other (e.g. economic growth, fuel prices) can hardly be influenced. The discussion of these factors in this chapter can be seen as a kind of sensitivity analysis to the analysis presented in the previous chapter.

4.2 Market regulation, unbundling and market concentration

Effective market regulation is one of the necessary conditions for a successful restructuring of electricity markets. While the transmission and distribution sectors should be regulated because they are natural monopolies with market power, the generation and retail sectors also need to be closely regulated. Market power is of great concern in the competitive parts of liberalised power sectors.

It is argued that the Commission and many EU countries have largely ignored appropriate regulation of markets. In Europe, for example, electricity restructuring has tended to overlook issues of market power and instead has concentrated on introducing wholesale and retail markets in the expectation that they will be naturally competitive (Newbery, 2002). With the approval of the new proposed Directives by the Energy Council, which still have to be approved by the European Parliament in order to be adopted, important regulatory changes can take place. Among other things, it was agreed that by 2007 the opening of the market should be completed and by June 2004 all transport tariffs should be published.

Vertical integration, concentration levels, over-capacity, the market structure (industry relations) and the regulatory behaviour (pro-active or re-active, information level of the regulator, etc) can all influence the ability of firms to exercise market power. For instance, vertically integrated firms can still pose a threat to the well-functioning of the liberalised power market, by denying generators or retailers access to their network. In the case of concentration levels, it is suggested that in the generation sector, low concentration, together with adequate levels of excess capacities, can generate competitive prices (Green and Newbery, 1992; Haas and Auer, 2001).

Stringent unbundling would mainly have an impact in Germany, where the current negotiated TPA system in place seems to allow incumbent utilities to act strategically by setting high transport tariffs. Regulated tariffs mean that firms would instead have to focus on the competitive sectors in order to receive higher than competitive rents. This could result in higher wholesale or retail mark-ups. In the Netherlands, Belgium and France, to a larger or lesser extent, the existence of a regulator and published tariffs suggest that network access is not a market barrier, even though vertically integrated monopolies exist in these countries.

Governments could also implement policies to mitigate market power problems. One could be to increase the transmission capacity in order to eliminate local market power and to increase the ability of imports to discipline the market price. Another could be to require divestment or to prevent mergers that could lead to market power (as in the UK, where the regulators implemented measures to reduce the market concentration in the generation sector). Another could be to increase price elasticity by encouraging demand-bidding by large customers, real-time metering, load management programs (such as load control devices), distributed energy, and price-responsive co-generation. Lastly, selective regulation could be implemented through bid-mitigation and 'soft' market price caps.

At first sight, measures to lower concentration would mean lower prices. However, many issues in this analysis seem to dispute this conclusion. In the first case, there is the dynamic issue. Very low concentration measures, and of course over-capacity, could develop into cut-throat competition levels, which result in prices approaching short-run marginal costs. This could result in an unsustainable situation, and consequently pushing the market into a consolidation process and closure of power plants. Concentration measures would increase over time while available capacity decreases, resulting in higher prices. Another issue is whether the current monopolies abuse their dominant positions. It can be argued that, in France, EDF does not do that. What could very well happen in Belgium and France, is that a potential divestiture of the monopolists firms into an appropriate number of smaller firms could create a real market in those countries, where prices are determined by the interaction of players and not set unilaterally. However, if the markets were to stay in the hands of a concentrated oligopoly of firms, the result could be worse than under the current monopoly.

4.3 Expansion of interconnector capacity

The expansion of interconnector (and transmission) capacity, on the one hand, supports electricity liberalisation by increasing competition and, on the other hand, allows power to flow from areas with excess of supply to areas with scarce supply. In other words, an increase in trade reduces market power and helps harmonising the power balance.

Currently, trade between EU Member States has remained limited, which is, among other things, due to the fact that interconnector capacity is relatively low compared to countries' consumption levels. The importance of an increase in interconnector capacity, and thus more trade, is the promotion of competition. More transmission capacity means an increase in the number of generators competing with each other, dilutes market power and reduces the need for regulatory market intervention. Of course, the higher the price differentials between congested areas, the greater the added value of an increase in interconnectors capacity. Cross border trade is also enhanced by the agreement between European TSOs to establish a uniform tariffs for electricity transmission between countries (0.5 to 1 €/MWh).

Congestion on interconnectors will remain an issue as long as prices between national markets differ. It is very likely that this will be the case between the Netherlands and neighbouring countries (Belgium, Germany and France). Even after a large expansion of the interconnector capacity (e.g. doubled), because of the differences in power generation costs of the production parks in these countries.

An increase in transmission capacity would also reduce the need to build new capacity, and therefore increase the possibility to transport electricity from markets with excess of supply to tight markets. The risk of this action is that it is only a short-term solution. If markets do not provide the correct incentives for players to build new capacity or for the lifetime of old capacity to be extended, then a more general shortage will be the most probable outcome. The increase in trade could also result in a situation where high prices, either generated by real scarcity rents or market power, could be more easily exported. Another factor to consider is that the costs of expanding the interconnections could increase disproportional to the capacity increase. Transmission tariffs may, however, not reflect these costs properly and therefore not give the right economic incentive to the power market. The result can be higher costs of the total electricity supply system.

4.4 Electricity demand

Section 3.4 showed that electricity demand is an important factor in the need for new generating capacity. Electricity demand growth correlates to economic growth. A strong economic growth will result in a quicker increase in electricity demand. Future electricity demand can only be covered by the lifetime extension strategy for a short period of time. Electricity prices will quicker rise to LRMC levels, which will attract new investments.

A small or negative economic growth will have the opposite effect. Incumbents will be able to secure their current market positions for a longer period of time. The lifetime extension strategy can be maintained for only a certain number of years, however, because eventually power plants reach the end of the technical lifetime.

4.5 Fuel prices

Because the SRMC are to a large extent based on the fuel prices, fuel prices are very important in a well-functioning power market with sufficient generation capacity. In the short run, the electricity market price is based on the SRMC of the last dispatched power plant in the supply curve. Therefore, the fuel price for this plant sets the market price in the short-term markets.

For the position of the power generating units in the supply curve and thus also the position of power producers in the power market, the fuel price level itself is not of importance, but the price differences between the types of fuel. In particular, the price differences between coal, oil and natural gas are important. Currently, natural gas prices are generally linked to oil prices. However, these linkages may (partly) disappear if competitive gas markets arise and the price will be set by gas-to-gas competition. Table 3.2 showed that natural gas prices are up to three times higher than coal prices. Even in a well-developed competitive gas market it is not very likely that gas prices will drop to coal price levels.[28] Therefore, future changes in fuel prices will not have a large impact on the current merit order of power plants in the supply curve and the position of large power producers will be relatively unaffected by fuel price changes.

4.6 Environmental regulation

Electricity generation has several environmental effects of which emissions to the atmosphere and waste are the most prominent ones (i.e. CO_2, NO_x, SO_2, slag and ash, nuclear waste). The environmental effects strongly depend on the type of generation plant and the fuel used. Chapter 3 clearly showed that the position of power producers in the market is based on their portfolio of production plants, i.e. the different types of generation capacity. If costs for reducing emissions change, this will have a major impact on the electricity generation costs and may change the merit order of plants in the electricity supply curve.

In 2001, the European Commission submitted a draft directive on CO_2 emission trading (European Commission, 2001).[29] The directive states that each Member State has to submit an allocation plan that establishes the total amount of allowances and describes the distribution of allow-

[28] In 2001 the commodity price for natural gas was 12 €ct/m^3. In ECN's forecast for the Dutch energy market (Ybema et al, 2002) the commodity price for natural gas in 2010 will range between 7 and 12 €ct/m^3 and probably just below 10 €ct/m^3.

[29] In 2002 this Directive was accepted by the European Energy Council.

ances among participating companies and installations. Participants will be able to trade CO_2 emission allowances with each other within the EU. According to the directive, a CO_2 emission trading system should be operational in 2005.

The specific amount of CO_2 emissions of different types of electricity generation differs substantially. Nuclear plants, hydro and other renewable plants do not produce direct CO_2 emissions. In thermal combustion plants, the carbon content of the fuel and the plant efficiency determine the specific amount of CO_2 emissions. For instance, natural gas has lower carbon content than coal, and gas-fired CCGT plants have a higher efficiency than coal plants. The CO_2 emissions of combined heat and power plants (CHP) will be lower than plants producing electricity only if part of the CO_2 emissions of CHP plants is attributed to heat demand.

In a CO_2 emission trading system a power producer will receive an amount of CO_2 emission allowances, which depends on the stringency of climate policy and the allocation method. For the initial allocation of CO_2 emission allowances a grandfathering approach will be used, i.e. participants will receive allowances free of charge. For incumbents the allocation can be based on historical emissions or benchmarks. The allocation of allowances to new entrants is of importance because it can create an extra entrance barrier.[30] Participants can sell any surplus compared to actual emissions, and a deficit has to be compensated by purchase on the market. Power producers are supposed to take CO_2 reduction measures when marginal costs are lower than the market value of the emission allowances. The measures can include investments in energy efficient technology, renewable capacity or CO_2 removal. However, there is uncertainty about allowances prices. Therefore in the short term, reactions will be restricted to fuel switches and operational adjustments, e.g. from coal to gas or to renewables. Because fuel switching and CO_2 emission trading is a short-term option, the costs involved can be attributed to the short-run marginal costs.

In a well-functioning market for CO_2 emission allowances, the price of the allowances will reflect the CO_2 emission reduction costs. Because these prices may directly influence the SRMC of power production and thus also the electricity market prices, costs for CO_2 reduction will most probably be transferred to consumers. Because of this electricity market price raise the revenues of power producers may also increase. The incumbent large power producers may gain profit because of their relative large share of low costs generation capacity and higher flexibility in shifting between power generation plants. Moreover, although power producers will not receive allowances for nuclear and hydro power plants, the revenues for these plants may also increase whereas these plants often do not have the possibility to produce more power. In power markets with a large share of nuclear and/or hydropower (France and to a lesser extend Belgium and Germany) the amount paid for CO_2 emission reduction by the consumers could be relatively large compared to the actual CO_2 emission reduction, because CO_2 emission reduction may only be achieved by a small number of fossil fuel plants.

As the price for CO_2 emissions allowances increases and this price is included in the production costs (i.e. as a shadow price) the difference between generation costs of gas and coal power plants will decrease. The break-even point where generation costs for gas and coal plants becoming equal is very sensitivity for fuel cost changes.[31] Figure 4.1 show this break-even point relative to the ratio between gas and coal prices. For a gas/coal price ratio of 1.5 the break-even point is 30.85 €/ton CO_2 if only SRMC are taken into account. The break-even point for LRMC is lower (8.32 €/ton CO_2) because of the capital costs difference between both types of power plants. The corresponding SRMC and LRMC costs can also be read from Figure 1.4. The Figure

[30] Currently in the Netherlands the allocation of allowances of a CO_2 emissions trading system is discussed intensively (KPMG 2002, Van Dril 2002, Mannaerts and Mulder, 2003). However, no information is available on the national allocation plans for Belgium, Germany and France.

[31] Although to a lesser extend the break-even point is also sensitive for plant efficiencies variations. For the coal plant we used 45.4% and for the gas plant 56.5%.

is based on the power plant data listed in Table 3.6, however the operation hours for both plants are 6000 hours.

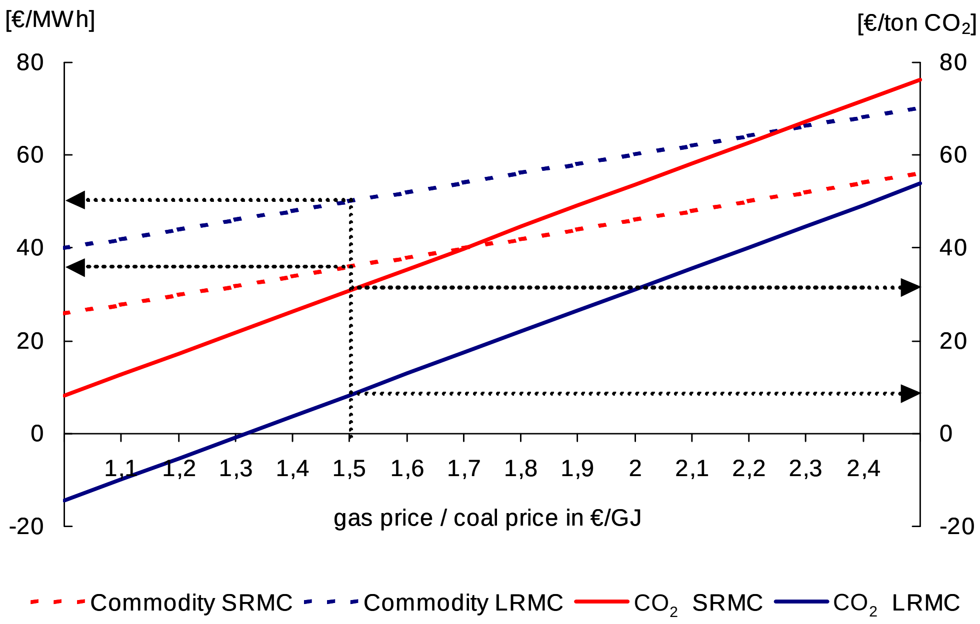


Figure 4.1 *Price for CO_2 emission allowances in case costs prices for coal and gas power plants are equal for different gas and coal price ratios*

Probably the two monopolistic power generators in France and Belgium will profit from the introduction of the CO_2 emission trading system, because power from nuclear and hydro plants has a large share in the total production of these companies. These power producers will get an even stronger incentive to export their power to neighbouring countries than they already had. In Germany, the advantageous position of coal and lignite power plants in comparison with gas-fired plants may disappear. If this happens, it will have a strong influence on the cross-border trade with the Netherlands. It is imaginable that Dutch gas fired power plants will be used to replace imports from German coal power and even export to Germany. What will happen with the position of CHP plants, particularly in the Dutch and German market, is not clear, because this is dependent on the selected allowance allocation method and valuation of the produced heat. For CHP, it is important to mention that the trading system will not apply for the medium sized and smaller plants (installations with a capacity smaller than 20 MW thermal input).

4.7 Technological innovations

Section 3.4.2 argued that by the lifetime extension strategy of incumbent market players new investments are discouraged. This applies mainly to large conventional power plants. As also indicated in Section 3.4.1 new investments are expected in renewable electricity generation because of the policy targets and implemented support schemes for renewable energy, particularly in Germany and the Netherlands.

Other small-scale power generation (so-called distributed generation - DG -, such as small and medium sized CHP plants) may be protected for direct competition with large-scale power generation through priority market access and regulated feed-in tariffs. On the Dutch electricity market DG has, however, to compete directly with large-scale generation, but receives compensated for contributing to CO_2 emission reduction and some electricity system benefits (e.g. avoided network losses). New distributed generation technologies such as fuel cells and micro CHP will initially have relative high costs and will probably not be able to compete with large power generation and with conventional CHP. During the introduction period these new technologies might be stimulated with support schemes (e.g. investment subsidies).

DG is an alternative for or at least complementary to large-scale power generation. In the long run this is only feasible if a level playing field exists between small and large-scale power generation (e.g. proper valuation and allocation of electricity system costs and benefits).[32] Studies show that this is currently not the case (Connor and Mitchell, 2002). Such a level playing field requires adaptation of the current regulatory framework and network innovations regarding control and management of distribution networks. Adoption of a new approach in electricity regulation and the introduction of new DG technologies will take time. If started in the next years the impact on the electricity market until 2010 will presumably still be marginal. However, after 2010 the impact may become substantial. Initially, if new demand is covered completely by new DG (and RES) the large power producers can probably maintain their position in large-scale power generation. Distributed generators will probably first act as price takers and large power producers will still be able to set the market price. Eventually, this situation may change when new so-called 'virtual' utilities, that aggregate distributed power supply, start trading on the wholesale market. Therefore, only in the long run these DG technologies may affect the position of incumbent players in the power generation market.

[32] We assume that DG and RES will be compensated for external effects beyond the level playing field, such as CO_2 emission reduction as long as these effects are not internalised.

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