FACTORS AFFECTING GEOGRAPHIC MARKET DEFINITION AND MERGER CONTROL FOR THE DUTCH ELECTRICITY SECTOR

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FINAL REPORT

NON-CONFIDENTIAL VERSION

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Contents

1 Introduction and Executive Summary

The NMA asked us to analyse:

1. Factors that would affect geographic market definition for the purpose of merger control in the Dutch electric power industry.
2. The competitive effects of some specific (hypothetical) mergers in that industry.

Note that this study does not refer to any actual merger proceedings, and NMa have not asked us to analyse any mergers of which they have been notified. All mergers analysed are hypothetical.

We have performed this study using both statistical analysis of historical data, and results from our comprehensive model of the European power market, BAM. We use standard tools of competitive analysis, including the so-called SSNIP test for geographic market definition, and measures of concentration (market shares, HHI indices, Pivotal Supply Index) for merger analysis, as well as more sophisticated economic modelling (e.g., Cournot model).

Product Markets

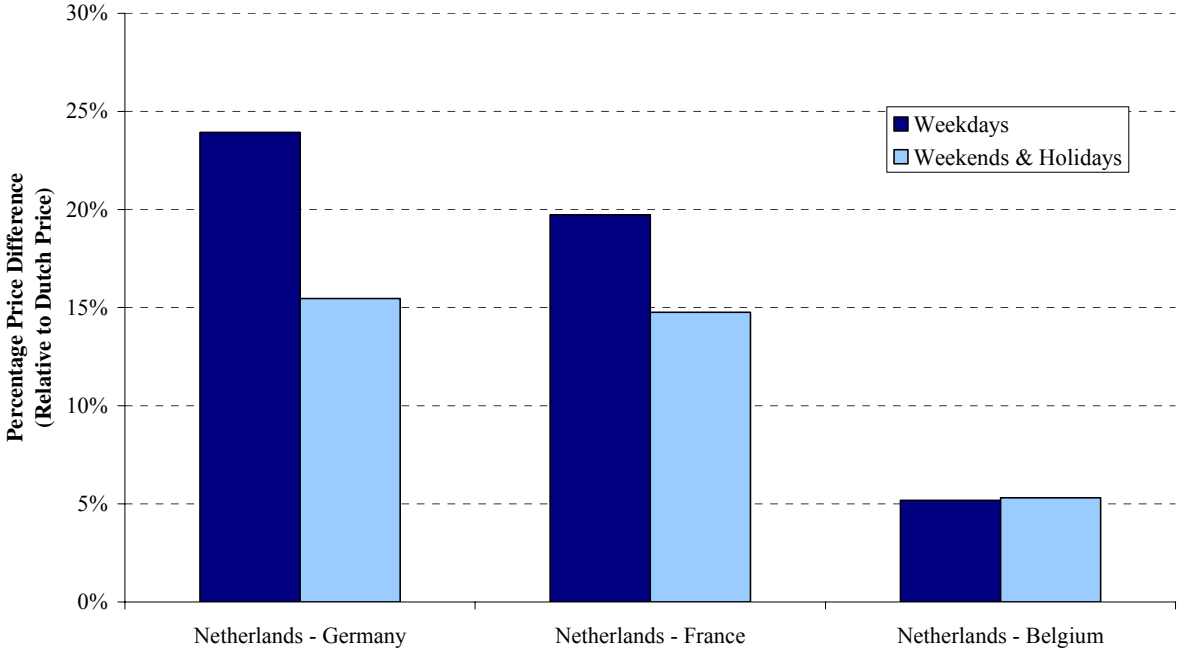
Product market definition was not the focus of our study. However, for the purposes of our competitive analysis we have considered the following product markets:

- Wholesale electricity, subdivided into:
    - Peak electricity and;
    - Off-peak electricity;
- Balancing electricity;
- Electricity bought at the retail level.

Geographic Market Definition: Evidence from Historical Data

Analysis of historical price data shows that Dutch prices have been consistently higher than those in neighbouring countries for many years, as shown in Figure 1. In 2005 Dutch prices were more than 5% above German prices for 60% of the hours in the year, and more than 5% above Belgian prices more than 40% of the hours. The existence of significant and persistent cross-border price differences (unrelated to transportation costs) is strong evidence that generators outside of the Netherlands do not represent a competitive constraint on Dutch generators, and therefore argues for a national geographic market.

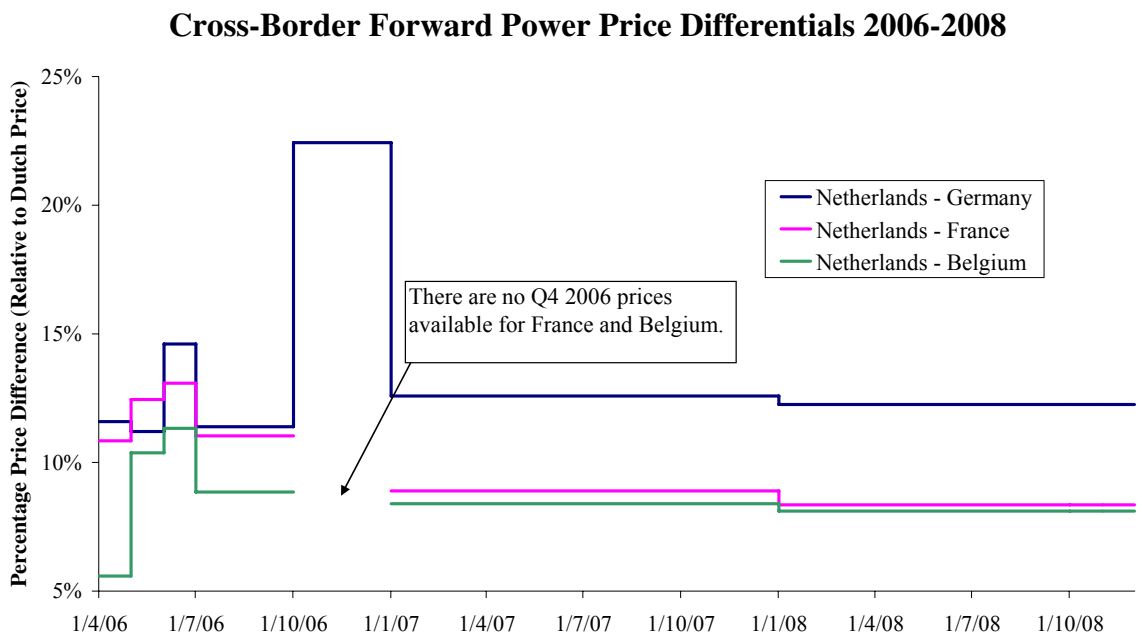
Figure 1: Average Price Differences



Source: Platts.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country.

Prevailing forward prices imply that these price differences are expected to persist for a number of years, as shown in Figure 2. Our analysis shows that cross-border price differences reflect differences in underlying costs, in particular because Dutch prices are generally set by gas-fired generation while in neighbouring countries coal and nuclear are more significant. Since forward prices and other forecasts foresee that gas-fired generation is likely to remain costly relative to other types for some years, it is likely that Dutch prices will continue to exceed those in neighbouring countries.

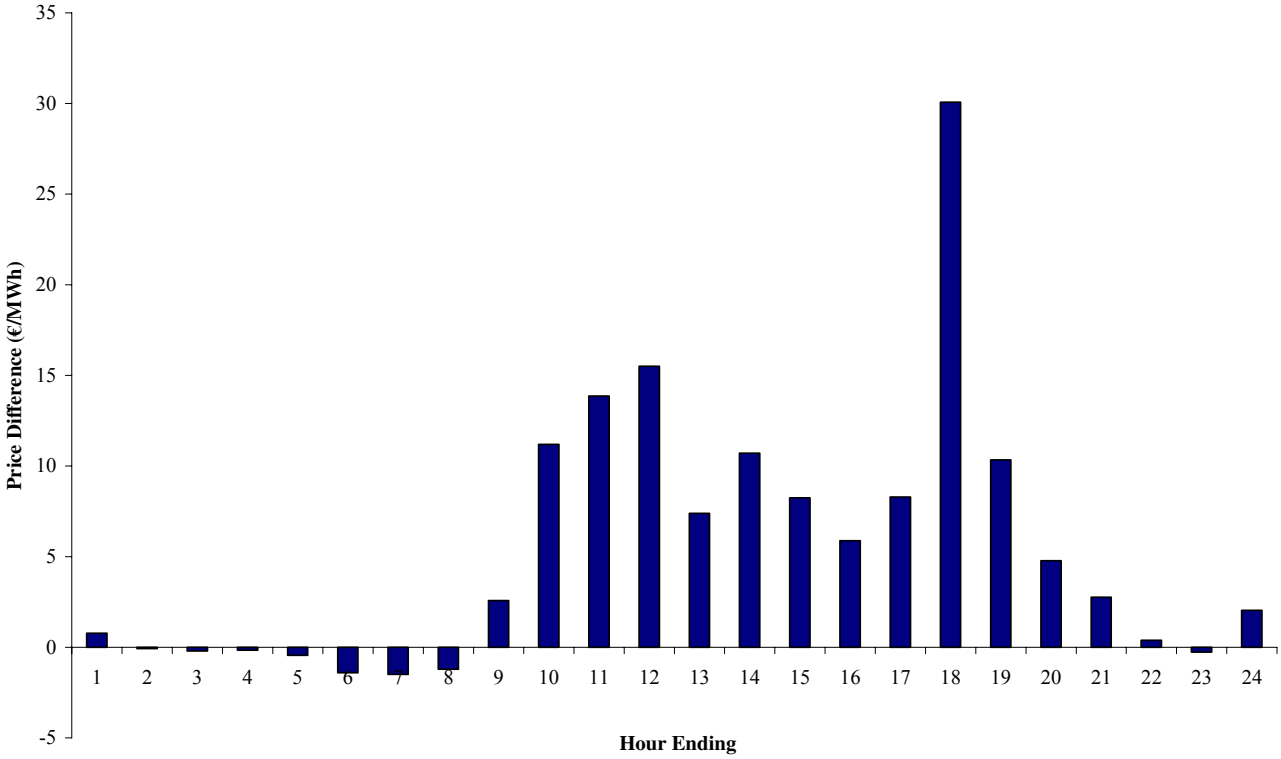
Figure 2: Forward Prices



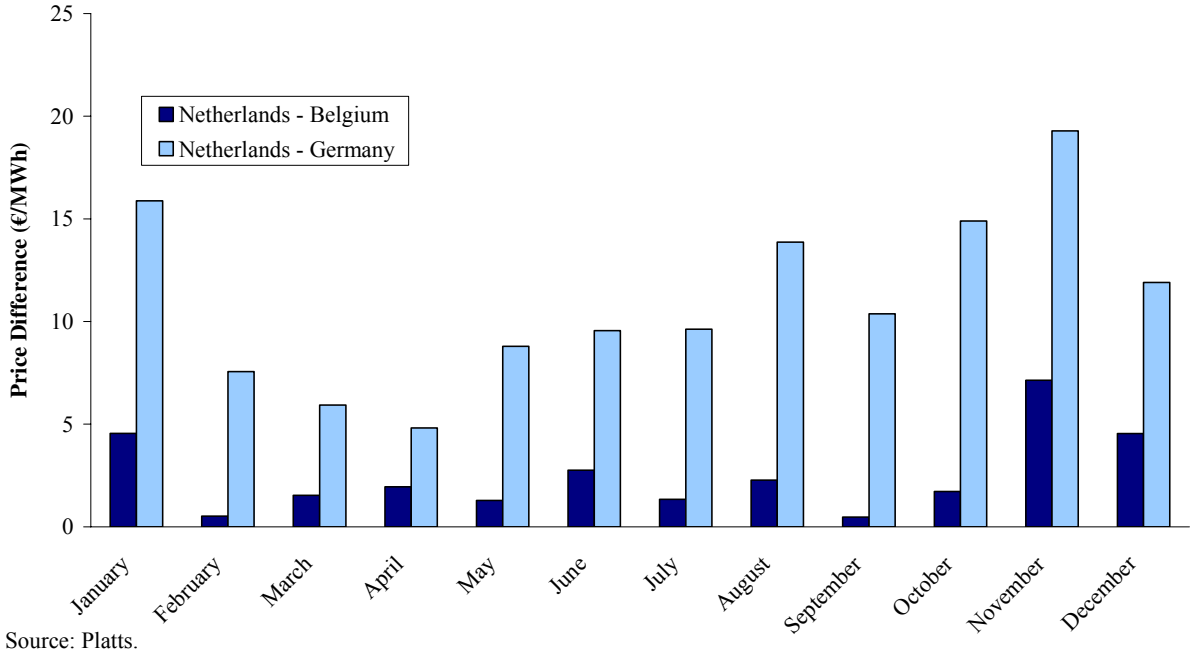
Source: Platts European Power Daily, March 21, 2006.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring countries.

Closer analysis shows that these differences vary significantly by time of day, and also by season, as illustrated in Figure 3 below.

Figure 3: Price Differences



Source: APX, EEX.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in Germany.



Source: Platts.
Notes: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country. Netherlands - Germany data are for 2000-2005. Netherlands - Belgium data are only available for 2004-2005.

Geographic Wholesale Market Definition: Evidence from computer modelling

We have used a computer model (BAM) to perform SSNIP tests on peak and off-peak Dutch wholesale electricity markets in 2008. Note that we assume a 700 MW NorNed cable in our

analysis. We find that at gas prices of around 20 €/MWh (similar to current gas prices) and expected coal and carbon prices *the Netherlands defines a separate geographic market for peak electricity for the purposes of merger control*. Lower gas prices will reduce price differences between the Netherlands and the surrounding countries, relieving constraints on interconnectors. However, we find that even assuming a gas price of 7 €/MWh (or equivalent coal and carbon prices), the Netherlands defines the peak market. We conclude that *changes in input prices will not expand the peak market beyond the Netherlands* for the foreseeable future.

The willingness of Dutch generators to operate at a loss in off-peak hours (to avoid start up costs and to make profits in peak hours) complicates the SSNIP test for off-peak electricity. Our market model, which does not account for start-up costs, indicates that a 5-10% price increase in the off-peak market would be profitable. However, we find that a small increase in prices of off-peak electricity elicits a large loss of off-peak sales for a hypothetical Dutch monopolist. This would increase start-up costs and reduce profits. This result, combined with the current absence of price differences in off-peak hours, makes it unlikely that a 5-10% increase in off-peak prices would be profitable. The majority of imports that off-peak price rises motivate come from Germany. It would therefore be appropriate to increase the geographic test market by adding Germany to the Netherlands, so that the likely geographic extent of the off-peak market is at least the Netherlands and Germany.

To expand the peak market beyond the Netherlands, we find that TSOs would have to increase the import capacity available to the market between Belgium/Germany and the Netherlands from its current level of 3,600 MW to around 6,500 MW at current and likely fuel prices. Note that physical interconnector capacity would need to increase to significantly more than 6,500 MW (since currently only around 75% of Net Transfer Capacity is made available to the market), and that our analysis already assumes market coupling. The absence of market coupling may require up to 15% further expansion of interconnector capacity. Depending on which border interconnector capacity was added, either Germany and the Netherlands or Belgium and the Netherlands could define a separate geographic market for peak power.

We also investigate market definition for a super-peak product – which we define as the four hours with the highest prices in the Netherlands. If a hypothetical monopolist can profitably increase prices of a peak product, it will certainly be able to increase the price of a super-peak product, since in super-peak hours the interconnectors are more heavily constrained and there is less scope for imports to defeat any price increases. Our calculations confirm this. We also calculate that interconnector capacity between Belgium/Germany and the Netherlands would have to be expanded to around 9,000 MW to expand the geographic extent of a super-peak product market beyond the Netherlands. All our conclusions are robust under a reasonable range of own-price demand elasticity assumptions.

The most likely way to achieve additional effective interconnection (either through more efficient use of existing capacity or through additional physical investment) is through coordinated action by national regulators at a regional level. It would be helpful if this was mirrored by regional coordination at TSO level. Making this effective is likely to require additional European legislation, to address the "regulatory gap" identified by the European Regulators (that is, the mismatch between the purely national competences accorded by Member States to national regulators, and the need for co-ordinated action at supra-national level for

example in relation to increasing interconnection).[1] The potential for such legislation should be assessed in light of the ongoing policy discussions following the February 2006 Green Paper.

Conclusions on Geographic Market Definition

Evidence from both current market prices, forward prices and our computer model indicates that, for the purpose of merger control, the Netherlands defines a geographic market for peak power. With regard to computer modelling, our conclusions are valid for a wide range of fuel, carbon price, plant efficiency and demand elasticity assumptions. There is strong evidence that the market for off-peak power is larger than the Netherlands. The current interconnection capacity to the Netherlands would need to be increased by several thousand MW to expand the peak market beyond the Netherlands.

Analysis of Hypothetical Mergers in the Wholesale market

Our market structure analysis indicates that in a peak market defined by the Netherlands, a merger of Nuon and Essent would, according to the Commission's guidelines as applied to other product markets, likely cause an unacceptable increase in concentration in the absence of appropriate remedies. While expanding the market to include Belgium would lesson the effect of the merger, it would nevertheless still increase concentration to an unacceptable degree. We note that with both these geographic definitions of the peak market, a company such as RWE could takeover Essent without causing an increase in concentration, since RWE is not currently active in any significant way in either the Netherlands or Belgium. A peak market defined by the Netherlands and Germany would allow a merger of either Essent and Nuon or RWE and Essent without divestment.

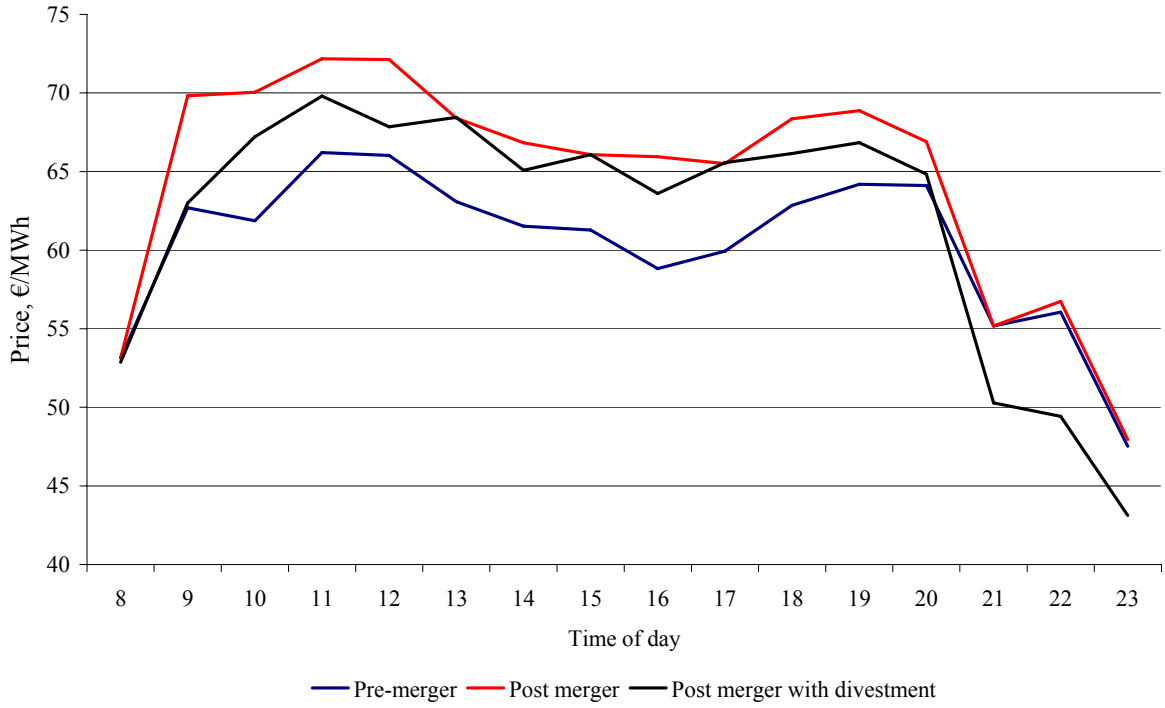
In an off-peak market that includes at least Germany and the Netherlands, a merger of either Essent and Nuon or RWE and Essent would, according to the Commission's HHI and market share guidelines, be possible without any divestment. Note, however, that the former would run into objections as it would impact the peak market as well.

We calculate that, to comply with the Commission's HHI merger guidelines, Nuon-Essent would need to divest around 1,900 MW. However, we calculate that even after meeting the Commission's guidelines, a merged Nuon-Essent would remain pivotal for around 24% of peak hours. Since the Pivotal Supplier Index is arguably a more accurate measure of market power in electricity markets, the results indicate that concentration may remain unacceptable even after complying with HHI guidelines. We calculate that Nuon-Essent would need to divest a total of 4,200 MW to avoid being a pivotal supplier post-merger.

We have also used a merger simulation model based on the Cournot model of oligopolistic behaviour, the results of which lend support to our HHI and pivotal supplier analysis. Our model forecasts that the merger could lead to price increases of around €4/MWh on average, as shown in Figure 4 below. The model also predicts that a divestment of 1,900 MW would be insufficient to bring prices back to pre-merger levels.

[1] See "The Creation of Regional Electricity Markets, An ERGEG Conclusions Paper", Feb 2006.

Figure 4: The increase in prices predicted by a Cournot model following a Nuon-Essent merger, with and without divestment



It seems likely that NMa could define narrower product market definitions than the peak market – for example a super-peak market, defined as power sold between a relatively small number of hours when electricity prices are typically very high. However, there seems little point in defining narrower product markets until interconnector capacity has been expanded sufficiently. For example, if the Netherlands defines a market for peak power, it must also define a market for super-peak power. Similarly, as we include all plant in our peak-market HHI calculation, the HHI for a peak and a super-peak market are identical; the level of divestment required to meet HHI targets for a super-peak market is identical to that required for a peak market. The issue of narrower product market definitions becomes relevant if interconnectors were expanded. For example, with interconnector capacity between Belgium/Germany and the Netherlands of 8,000 MW, the Netherlands would not define a geographic market for peak power, but would still define a separate geographic market for super-peak power (as we define it). Accordingly, at this point it would be appropriate to investigate the existence of a smaller super-peak product. However, until the interconnectors are expanded, the peak product market definition is representative of all narrower product market definitions.

Balancing Market

At present, parties from outside the Netherlands are unable to supply balancing power to Dutch consumers and producers. Accordingly, the Netherlands defines the geographic market for balancing power. We find that the balancing market is concentrated, with five players having similar shares of the market, and that any merger between two players would result in an unacceptable increase in concentration. However, in contrast to the wholesale market, behavioural remedies – such as a commitment by the merged entities to offer a certain quantity

into the balancing market at an approved price – might be more appropriate to deal with a concentration in the balancing market. Structural remedies may be disproportionate, and fail to reduce concentration in the balancing market.

Retail Market

We conclude that the Netherlands defines the relevant geographic market for the retail sector. Since it is not possible for consumers to buy retail power from market players outside of the Netherlands, the relevant market cannot be larger than the Netherlands. Hence, the issue is if the relevant market is the Netherlands or a smaller geographic area, such as a region. We argue that the Netherlands defines the retail market geographically, for two reasons. First the main Dutch retailers are all involved in retailing on a national basis, and the lack of price differences between incumbents and entrants implies that each incumbent experiences competitive pressures. Second, it seems that the conditions of competition are homogeneous nationally. These considerations argue in favour of a national definition for the retail market.

We calculate an HHI for the Dutch retail market of about [2,200 – 2,300],[2] which indicates a high level of concentration. Moreover, the ability of potential entry to act as a competitive constraint is at best unproven (and the low price differentials between incumbents and existing entrants would suggest that new entry is unlikely to be attractive), and tacit collusion may also be a concern. In common with the wholesale market analysis, we have analysed a hypothetical merger between Essent and Nuon, and find a post-merger market share of [50 – 60%] and an HHI of [3,900 - 4,000] (an increase of [1,600 – 1,700] points). Accordingly, the merger would create or strengthen a dominant position for the two firms concerned, and in our view this hypothetical merger could not be approved without significant remedies.

One possible type of remedy might involve the merged company "divesting" customers, for example by selling off some parts of its retail business. As a minimum, it would appear necessary to lose [0 – 10%] market share, to get the post-merger market share below 50%, but it would not seem at all unreasonable to require more divestiture. We estimate that if Nuon/Essent were to divest market share to a single brand new company, it would have to divest [10 – 20%] to keep the post-merger-and-divestment HHI in line with the Commission's guidelines.

Vertical Effects

When considering a vertical merger, competition authorities must weigh up two competing factors. A vertical merger could reduce liquidity, increase the difficultly in entering the wholesale and retail markets and reduce the number of potential entrants. In a counterfactual case (*i.e.* without the merger) there could be more market entry, greater competition and reduced prices. On the other hand, the merger will likely reduce costs in the short-term, which may reduce prices for consumers today.

NMa would need to judge how likely entry is in the absence of the merger i.e. in the counterfactual case, and whether such entry would have a material effect on prices. If entry is not likely in the counterfactual case, or if it would have little effect on prices, there would be few

[2] To avoid revealing confidential data, the NMA has replaced certain numbers in this report by ranges (indicated by square brackets as above).

grounds for preventing the vertical merger. To block a vertical merger a competition authority would need to rely on a counterfactual case of additional future entry in the absence of the merger, and this would necessarily be speculative in nature, whereas the benefits of the merger would be immediate and tangible.

2 Background to market definition

2.1 Background to market definition

The objective of merger control is to protect consumers from the potential loss of competition arising from a merger. Market definition is designed to aid in that task, by helping identify the presence or absence of competitive constraints that would act against any potential anti-competitive results of the merger. Product market definition looks for constraints in the form of alternative products that may act as substitutes for the products produced by the merged entity. Geographic market definition looks for constraints that arise from substitution by production (or consumption) from another location. The point of geographic market definition is to identify the area that contains potential alternative sources of production that can constrain price rises. Put another way, an area defines a geographic market if production outside it cannot sufficiently constrain price rises within the area. The area, which defines a geographic market, must rely on production within the geographic market to restrain prices. Geographic market definition is therefore a tool used as part of a process whose purpose is the protection of consumer interests.

2.2 SSNIP Test

The "workhorse" methodology for carrying out market definition is the so-called "Small but Significant and Non-transitory Increase in Price" ("SSNIP") test, promulgated in the United States Department of Justice 1982 Merger Guidelines, and adopted by the European Commission in its 1997 "Notice on the definition of the relevant market for the purposes of Community competition law", where it is described as follows:

> *The assessment of demand substitution entails a determination of the range of products which are viewed as substitutes by the consumer. One way of making this determination can be viewed, as a thought experiment, postulating a hypothetical small, non-transitory change in relative prices and evaluating the likely reactions of customers to that increase. The exercise of market definition focuses on prices for operational and practical purposes, and more precisely on demand substitution arising from small, permanent changes in relative prices. This concept can provide clear indications as to the evidence that is relevant to define markets.*
>
> *Conceptually, this approach implies that starting from the type of products that the undertakings involved sell and the area in which they sell them, additional products and areas will be included into or excluded from the market definition depending on whether competition from these other products and areas affect or restrain sufficiently the pricing of the parties' products in the short term.*
>
> *The question to be answered is whether the parties' customers would switch to readily available substitutes or to suppliers located elsewhere in response to an hypothetical small (in the range 5%-10%), permanent relative price increase in the products and areas being considered. If substitution would be enough to make the price increase unprofitable*

> *because of the resulting loss of sales, additional substitutes and areas are included in the relevant market. This would be done until the set of products and geographic areas is such that small, permanent increases in relative prices would be profitable.*

In reality the SSNIP test is a more or less practical methodology, depending on the circumstances around a particular case. For wholesale power markets, the fact that bulk power is a relatively homogeneous product, with price data widely available, and with price formation relatively well-understood and susceptible to modelling makes the SSNIP test rather useful, and it is the basic approach used in this report.

2.3 Cellophane fallacy

The "cellophane fallacy" refers to the observation that if a market is already subject to the exercise of significant market power, then the SSNIP test may give results that are for some purposes misleading. The phrase arises from the 1950s DuPont case, where the Supreme Court of the US accepted the argument of DuPont that although it sold over 75% of the cellophane purchased in the US, the relevant product market included aluminium foil, "saran wrap" ("clingfilm" in UK English) etc, thus giving it a market share of less than 20%. This reasoning is widely regarded as flawed: although it is true that a small increase in DuPont's prices would not have been profitable, this was because the prices were already at the monopolist's profit-maximising level. In other words, by engaging in abuse of its dominant position in the cellophane market, DuPont had made other products substitutes even though they are in fact rather poor substitutes for cellophane.

However, there is a key difference here between (in European terms) merger control and Article 81 and 82 cases. The sole purpose of merger control is to prevent harm from the merger. It cannot be used to address pre-existing problems. From the point of view of merger control, it is a fact that under the existing conditions in the DuPont case, the other products were a competitive constraint that would prevent any further price rises. If (hypothetically) DuPont had wished to merge with a competing producer of cellophane, then correct application of the legal standards (at least those relevant for the purposes of this report) would have entailed recognising that the other products were indeed a constraint that would prevent the merged entity from raising cellophane prices post-merger.

This point is recognised, albeit rather vaguely, in the Commission's 1997 Notice:

> *Generally, and in particular for the analysis of merger cases, the price to take into account will be the prevailing market price. This might not be the case where the prevailing price has been determined in the absence of sufficient competition. In particular for investigation of abuses of dominant positions, the fact that the prevailing price might already have been substantially increased will be taken into account.*

Other commentators are more explicit. For example, a 2001 Office of Fair Trading discussion paper observes that:[3]

> *2.25 […]Before discussing the cellophane fallacy, it is important to note a fundamental difference between the nature of analysis undertaken in merger inquiries and that undertaken in dominance inquiries.*
>
> *2.26 In merger inquiries, the competitive concern is whether the merger will create or strengthen a dominant position – or to put it in economic terms - will the merger result in an increase in prices above the prevailing level? This is likely to be the case where a merger results in the elimination of an important competitive constraint on the current pricing behaviour of the merging parties. Hence, merger inquiries are forward-looking and are concerned with the identification of the competitive constraints that exist at current prices.*

While a senior member of the Irish Competition Authority has written that:[4]

> *Applying the SSNIP test ignores the fact that a firm may already have market power. However, such considerations are not relevant for defining a market in merger cases. In assessing the competitive impact of a merger the crucial issue is not whether one of the merging parties already enjoys a degree of market power, but whether, as a result of the merger, the degree of market power would increase. Thus the SSNIP test defines the market correctly for the purposes of merger analysis.*

Applying the SSNIP test to carry out market definition for the purposes of merger control should therefore be based on an assessment of the ability of the hypothetical monopolist to raise prices relative to prevailing, pre-merger prices. It is therefore fundamentally different from the approach that may be applied in cases relating to abuse of dominance (or infringements of Article 81), such as for example the Danish Competition Authority's recent *Elsam* decision, which chose not to use prevailing prices for the purpose of geographic market definition so as to avoid the cellophane fallacy.

2.4 Other potential fallacies in market definition

Companies and commentators sometimes argue that Europe (or regions of Europe) should be considered as a "single energy market", because of factors such as:

- Common market institutions and rules (resulting inter alia from the transposition of Directives and application of Regulations)
- Regulatory harmonisation (e.g., for grid fees)

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[3] Office of Fair Trading, "The role of market definition in monopoly and dominance inquiries", July 2001, United Kingdom.

[4] Patrick Massey, "Market Definition and Market Power in Competition Analysis: Some Practical Issues", The Economic and Social Review, Vol. 31, No. 4, October 2000.

- Market coupling
- Cross-border capital flows, in particular the growth of pan-European utilities such as Eon, RWE, EdF and Suez, with activities stretching across many Member States.

However, such factors are not relevant to geographic market definition for the purpose of competition law except to the extent that they affect the ability of different geographic areas to impose competitive constraints. For example, while the Netherlands and Malta have both implemented the liberalised market framework enshrined in European law, clearly there is little opportunity for supply or demand-side substitution between the two countries. A producer in the Netherlands could not defeat a price rise by a Maltese monopolist. Therefore, the Netherlands and Malta are not part of a single market for the purposes of competition law.

In relation to merger control, the loss of competition arising from a merger in either the Netherlands or Malta would not be mitigated by increasing competition from the other. In other words, proposing to divest plant in Malta would not be an effective remedy for a merger between two electricity producers in the Netherlands; the two countries are not in the same geographic market, even thought both are subject to the same EU laws. Considering the Netherlands and Malta, or any other two countries that have a very limited amount of interconnection, to be part of a single geographic market is mistaken, and inconsistent with the underlying aim of protecting consumer interests.

Similar considerations apply in relation to grid fee harmonisation and market coupling. Both are relevant to the extent that they facilitate cross-border competition, but in themselves cannot guarantee that one country can impose sufficient competitive constraints on another. In particular, although market coupling is likely to enhance cross-border trade, if interconnectors are frequently constrained then the ability of market coupling to ensure competitive conditions may be very limited. The notion that market coupling creates a single market is seductive but, from the point of view of competition law and the protection of consumers, is mistaken.

It should also be recognised that companies can merge across borders without creating a single market. For example, while German and French companies own three of the main UK utilities, limited import capacities mean that power generated in Germany or France does not present a significant competitive constraint on UK power prices. To consider the UK to be part of the same market as France and/or Germany would therefore be a mistake that could lead to incorrect decisions in merger analysis, to the detriment of consumers. Convergence to a single European capital market is no guarantee of competition at the level of products or services.

Sometimes a more sophisticated argument is made: that focus on national markets has allowed for consolidation of the industry at European levels, to the overall detriment of competition. The idea here (often implicit) is that cross-border M&A has led to the consolidation of companies that were potential entrants and competitors in each others' markets. For example, Eon, RWE and EdF might have chosen to enter the UK market directly (building new generation, setting up their own retail operations) if they had been precluded from acquiring existing UK firms.

Such concerns can and should be incorporated into competitive analysis, including geographic market definition. Our own analysis in this report takes into account the possibility that companies inside and outside of the Netherlands may in the future become direct competitors

as a result of changing market conditions, even if today they do not compete directly because of limited cross-border trade capacities. However, the standard of proof is quite high: competition authorities will need to provide objective evidence that a firm is a likely entrant in a new market, or that current barriers to trade will diminish enough to change the geographic market scope.

Finally, it is sometimes argued that competition law fails to protect relatively small regional or national utilities from acquisition by large pan-European utilities. However, this kind of argument fundamentally misunderstands the aim of modern competition law, by confusing the protection of competition for the benefit of consumers with the protection of indigenous producers or "national champions".

3 Relevant product markets

A detailed definition of product markets is beyond the scope of the current study. However it is not possible to define geographic markets without first having a working definition of the relevant product markets. If one does not know what the product is, then one cannot analyse the geographic scope of competition in that product.

We propose three potential product markets on which to perform our analysis:

- The wholesale market (subdivided into peak and off-peak hours)
- The retail market
- The balancing market (subdivided into upward and downward balancing or regulation).

We discuss these choices briefly below.

3.1 The wholesale market

The wholesale market consists, on the supply side, mainly of electricity generators and importers, and on the demand side large consumers and retailers who buy power to sell-on to smaller consumers. Persistent differences in average peak prices[5] and average off-peak prices indicates that peak and off-peak power may be separate products. If they were not, then presumably consumers would substitute peak and off-peak power until the prices of the two products came closer to one another. Accordingly, we perform separate geographic market definition exercises for peak and off-peak power. We also consider the possibility of a separate 'super-peak' product (power consumed during a sub-set of peak hours) and the effect that the existence of such a product would have on our conclusions.

We do not define separate wholesale market products according to how far in advance deals are struck to buy and sell power, or by duration of contract. In other words we assume power bought day-ahead and power bought on a one-year (or longer) contract occupy the same market. The reasoning is that buyers facing increased prices of power sold in one year contracts could switch at low cost to buying power in shorter term contracts, and even to power sold in the day-ahead market if required. It may be that, for reasons of risk aversion, buyers would be prepared to pay a 5-10% premium for power bought on e.g. one-year contracts relative to day-ahead power, but an empirical analysis of the issue is outside of the scope of this report.

We do recognise that very long-term contracts effectively remove that amount of capacity from the discretion of the generators who have signed such contracts, and these contracts may also pre-empt some part of the interconnector capacity, to the extent that it is effectively must run, and will therefore reduce the amount of interconnector available to defeat price rises within the importing country (the Netherlands). These issues are discussed further in section 6.

[5] We adopt the standard definition of peak power in the Netherlands as power consumed on working weekdays (i.e. excluding public holidays and weekends) from 07:00 up to but not including 23:00. For example, power consumed at 23:30 on a weekday is off-peak; power consumed at 22:30 on a weekday is peak power. Off-peak power is power consumed at all other times.

Similarly, we do not assume that power bought via different institutions define separate product markets. For example, we assume that power bought over-the-counter (OTC) and power bought on the exchange (APX, Endex) are good substitutes for one another, can be easily arbitraged and therefore occupy the same product market. The very close correlation between APX prices and OTC prices supports this assumption (see Appendix XI). In addition we consider that the market for financial products (options etc.) is separate from the market for physical electricity –we only study the latter.

3.2 The retail market

Domestic and small commercial customers buy their power from retailers, and are therefore one step down the supply chain from the wholesale market. Accordingly, a concentration between electricity retailers could affect retail prices, even if wholesale prices remained competitive. Small consumers would be unable to defeat an increase in retail prices by buying power on the wholesale market without incurring significant costs. Similarly, it is possible to imagine significantly different levels of profit margin in the retail market and wholesale market, as a result of differences in market structure. Therefore, we consider electricity bought at the retail level as a separate product than wholesale electricity.

3.3 The balancing market

Balancing market prices are consistently different from both wholesale and retail electricity prices, which indicates that balancing electricity may be a separate product than electricity bought at the wholesale or retail level. Nevertheless, it is possible to imagine substitution between wholesale and balancing electricity; if day-ahead prices were very high, a customer could chose not to buy wholesale electricity and go out of balance instead, in effect buying balancing power. Similarly, if balancing prices for generators who were short of power were very high, generators could buy an 'excess' of wholesale power and, so that even in the event of a plant failure they could still avoid having to buy balancing power. In a compulsory gross Pool market design such as that in England and Wales until 2001, all available plant is bid into a single market, and the System Operator can then use bids for balancing, congestion relief and energy demand as appropriate and without defining separate products in advance. In a decentralised Power Exchange with physical bilateral contracting as in the Netherlands such aggregation is no longer easy. While substitution between the various markets (day-ahead and balancing) is possible both on the demand and supply side, for the purposes of this report we treat balancing energy and wholesale electricity as separate products to motivate an analysis of the balancing market. More detailed work, which is beyond the current scope of this report, would be required to demonstrate that wholesale and balancing power are or are not separate products.

We also consider upward balancing electricity (which market participants must buy when they are short of power) and downward balancing electricity (which market participants must sell when they have an excess of power) as separate products, since they are clearly not substitutes for one another.

3.4 Precedent for relevant products

Our choice of potential product markets finds support in recent merger investigations by the European Commission. For example, in the most recent electricity supply industry merger investigated by the Commission, it noted that:

> *"In previous decisions concerning the electricity sector, the Commission has considered that the following product markets should be distinguished:*
>
> *(i) generation and wholesale supply of electricity,*
>
> *(ii) transmission,*
>
> *(iii) distribution,*
>
> *(iv) retail supply,*
>
> *(v) possibly, the provision of regulating/balancing power services."*[6]

While transmission and distribution are separate products, we do not consider them in this study. These products are in any case heavily regulated, as they are recognised as 'natural monopoly' activities. Effective regulation of transmission and distribution severely limits the ability of merging parties to exercise market power in these product markets. Accordingly, they are of limited interest in merger investigations, although maintaining a sufficient number of comparator distribution-firms may be important from a regulatory perspective.

With respect to the issue of whether the regulating/balancing power is a separate product from wholesale electricity, the Commission said specifically that:

> *"The market investigation indicates that balance regulation may constitute a separate product market. However, for the purpose of this decision [Sydkraft/Graninge] it can be left open whether balance regulation constitutes a separate product market as well as whether primary and secondary balance regulation constitute separate segments within this product market, since the proposed transaction will not create any competition concerns under either market definition."*[7]

In other words, the Commission is undecided as to whether regulating/balancing power is a separate product from wholesale electricity. For completeness, we assume that regulating/balancing power is a separate product from wholesale electricity, consistent with the current market design in the Netherlands.

We note that the Commission has made no explicit reference to separate peak and off-peak wholesale markets in its product definitions. However, in several decisions, the Commission has implicitly acknowledged a distinction between peak and baseload electricity. For example, in the investigation of the EdF/EnBW merger the Commission stated that:

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[6] Commission Decision of 9.12.2004 declaring a concentration to be incompatible with the common market (Case No COMP/M.3440 EDP/ENI/GDP) §31.

[7] Case No COMP/M.3268 - Sydkraft/Graninge Article 6(1)(b) Non-opposition 30/10/2003 §51.

> *"Competitors which want to supply eligible customers in France need to provide base load as well as peak load. Where such competitors are not able to satisfy peak demand themselves, they need arrangements with other suppliers for peak load, in particular Swiss suppliers. The proposed concentration will considerably restrict the choice of Swiss peak load supply for such suppliers."*[8]

In its decision on the VEBA/VIAG merger which led to the creation of E.ON the Commission calculated ownership of peak load, medium load and base load plant.[9] This implies that the Commission has recognised that differences in ownership of peak, medium and base load plant is important, because they produce different products.

Most recently, in its investigation of the GDP/EDP/ENI merger, the Commission stated that "coal plants tend to set prices mainly to address the base load demand whereas hydroelectric plants, gas-fired plants and occasionally oil-fired plants, tend to dominate during peak periods."[10]

Turning to competition authorities other than DG COMP, the UK Competition Commission, in its investigation of license conditions for GB generators noted that:

> *"In the extreme, therefore, each half-hour could be considered a separate market. This presents difficulties, however, for the standard approach to market definition, which asks whether a modest but significant increase in prices—usually 5 or 10 per cent—would be sustainable if there were only one supplier. The reason for this is that it would not be practicable for a generator to have a separate supply response, and hence to adopt a different bidding approach, for a single half-hour period on a single day. It might therefore seem better, for market definition purposes, to aggregate both over half-hour periods within the day (while still distinguishing between peak and off-peak) and also over a number of days."*[11]

The UK Competition Commission's statement provides support for the assumption of separate peak and off-peak wholesale products.

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[8] Commission Decision of 7 February 2001 declaring a concentration to be compatible with the common market and the EEA Agreement (Case COMP/M.1853 — EDF/EnBW) (notified under document number C(2001) 335), §83.

[9] Commission Decision of 13 June 2000 on the compatibility of a concentration with the common market and with the EEA Agreement (Case COMP/M.1673 VEBA/VIAG) (notified under document number C(2000) 1597), p.14.

[10] *Loc. cit*. footnote 6 §292.

[11] AES and British Energy: A report on references made under section 12 of the Electricity Act 1989, Presented to the Director General of Electricity Supply, December 2000, §2.107.

4 Statistical analysis of wholesale price differences

We use historical data on wholesale power prices in the NL and its neighbours to look at cross-border price differences. Persistent and material price differences, beyond what can be explained by transportation costs, are prima facie evidence of distinct geographic markets (although not a substitute for the SSNIP test). In a single market, and abstracting away from search costs and other such issues that are clearly of no relevance here, consumers can choose to buy from the lower priced supplier and arbitrage therefore equalises prices. Conversely, the persistence of price differences implies that supply of the product in one area is not a competitive constraint on its supply in the other. That conclusion is reinforced if the price differences go along with congestion on interconnectors (in the case of electricity), since in that case it is clear that even larger price differences (as in a SSNIP test) could not induce additional imports.

Obviously the use of historical data is a retrospective exercise, while merger control is inherently prospective. Rather than extrapolate blindly it is therefore better to see whether changing circumstances might make the future different from the past. We analyse historical data to examine the factors that appear to drive cross-border price differences. We can then consider the likely future evolution of those factors that we have identified as the chief drivers of price differences, and see whether that evolution is likely to lead to geographic convergence or continued separation.

Our statistical analysis of price-difference drivers focuses on supply-side factors. As is well-known, there is very limited potential for geographic demand-side substitution in electricity markets. While price differences might drive some cross-border shifts in the location of production for energy-intensive industrial users, it is mostly a long-term phenomenon and in any case would only represent a small part of the wholesale market. Our analysis does not capture the potential for increased interconnection to reduce price differentials, but this issue is discussed extensively elsewhere in the report.

It is worth noting for the avoidance of any possible confusion that transportation costs do not play a role in driving price-differences. Capacity for cross-border transportation of electricity is sold via auction, and the auction price therefore reflects but does not cause cross-border price differences. This is because the only value of holding interconnector capacity is that it allows parties to capture cross-border price differences, by producing or buying electricity on one side of the border and selling it on the other. If (absent the auction) prices were the same on both sides of the border, then there would be no incentive to pay a positive amount of money for the interconnector capacity, and the auction price would be zero.

Data issues

There are a number of sources for pricing data for the NL and its neighbours: “trade press” assessment of prices arising in bilateral (“Over-The-Counter” or OTC) trades, power exchange (PX) prices, and the Belgian Power Index published by Electrabel. We expect that the OTC and PX prices should be very similar, and analysis in Appendix XI confirms this to be the case. The wholesale products traded via OTC and via power exchanges are very similar, with only minor differences concerning time-of-trade, contractual terms etc, and arbitrage should therefore ensure very similar prices. However, the differences are material enough to warrant checking our analysis against both sources, and we have done so (for ease of exposition we have attached much

of this analysis in Appendix XII). Moreover, the PX prices (other than for Belgium) include pricing for hourly products, allowing us to examine differences between peak and off-peak times of day. Additional detail on this is provided in Appendix XI. In general we have a preference for using OTC prices, as it is more liquid than the APX.. The BPI is also the product of an arguably "artificial" system. By contrast, OTC price represents the outcome of genuinely voluntary transactions (albeit imperfectly reflected in reported "assessments").

4.1 Prices and cross-border price differentials

As background, Table 1 describes (daily) prices in the Netherlands and its neighbours (including France as an "honorary neighbour"). It confirms that, as is well-known, Dutch prices are considerably higher than in neighbouring countries.[12]

Table 1: Daily prices
Daily Day-Ahead OTC Prices (€/MWh)

	Netherlands		Germany		Belgium		France	
	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays
First Observation	2-Jan-00		2-Jan-00		6-Jan-04		30-May-01	
Using All Available Data								
Minimum	11.50	10.00	7.73	5.00	18.50	11.50	7.50	6.25
Maximum	300.00	67.75	275.00	59.75	155.00	62.00	232.50	68.50
Mean	46.01	25.74	32.31	21.71	45.11	29.24	34.85	22.22
Median	37.10	23.88	29.03	20.00	38.50	27.13	30.51	20.50
Standard Deviation	26.67	9.66	17.11	8.86	19.60	10.02	17.81	9.67
2004								
Minimum	22.75	12.75	16.73	12.25	18.50	13.00	16.75	12.50
Maximum	85.00	37.00	45.50	31.63	70.00	31.50	44.00	32.00
Mean	36.49	23.38	31.76	21.61	34.64	22.15	31.28	21.43
Median	34.50	23.38	31.75	22.00	33.30	22.19	31.25	21.58
Standard Deviation	7.81	4.54	3.84	4.45	7.01	4.13	3.85	4.42
2005								
Minimum	30.25	17.00	27.00	11.38	24.50	11.50	28.75	11.50
Maximum	157.50	67.75	140.00	59.75	155.00	62.00	151.50	68.50
Mean	59.62	38.64	51.48	34.49	55.67	36.41	51.67	35.13
Median	50.25	36.63	46.50	33.83	47.00	35.25	45.75	33.94
Standard Deviation	23.91	10.00	18.80	8.22	22.37	9.07	20.45	10.04

Source: Platts
Note: All prices used in calculations are midpoints between daily high and low.

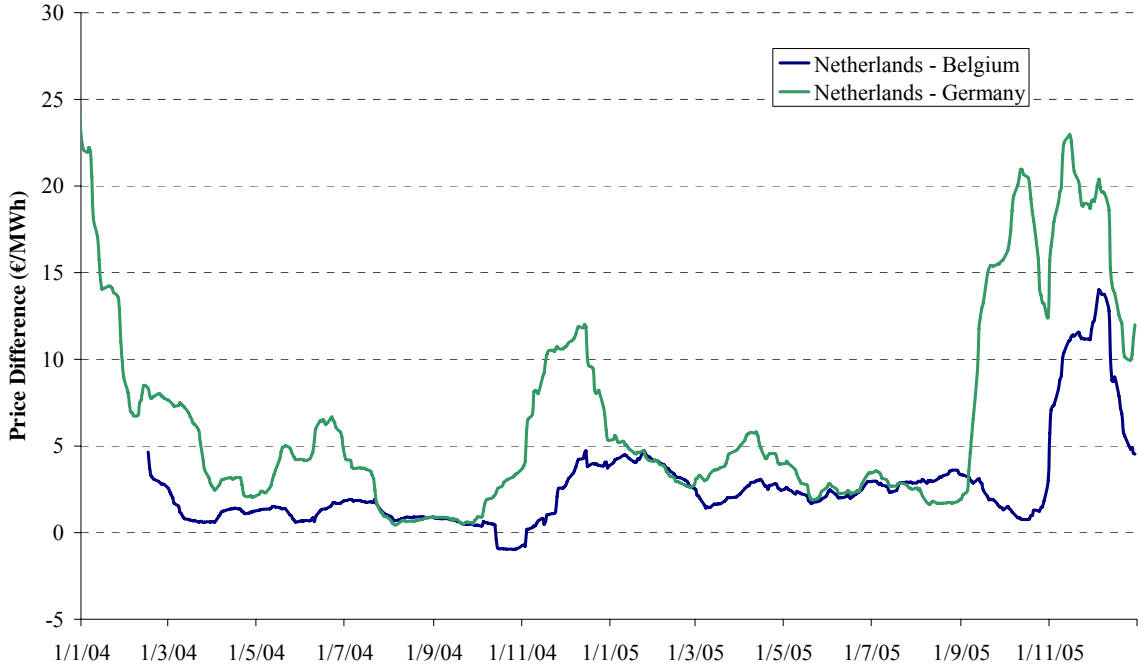
Given the very small differences between German and French prices in the period considered (confirmed by more detailed examination, see Appendix XII) we have generally omitted France from the analysis presented here (but see Appendix XII for additional detail).

Cross-border price differentials

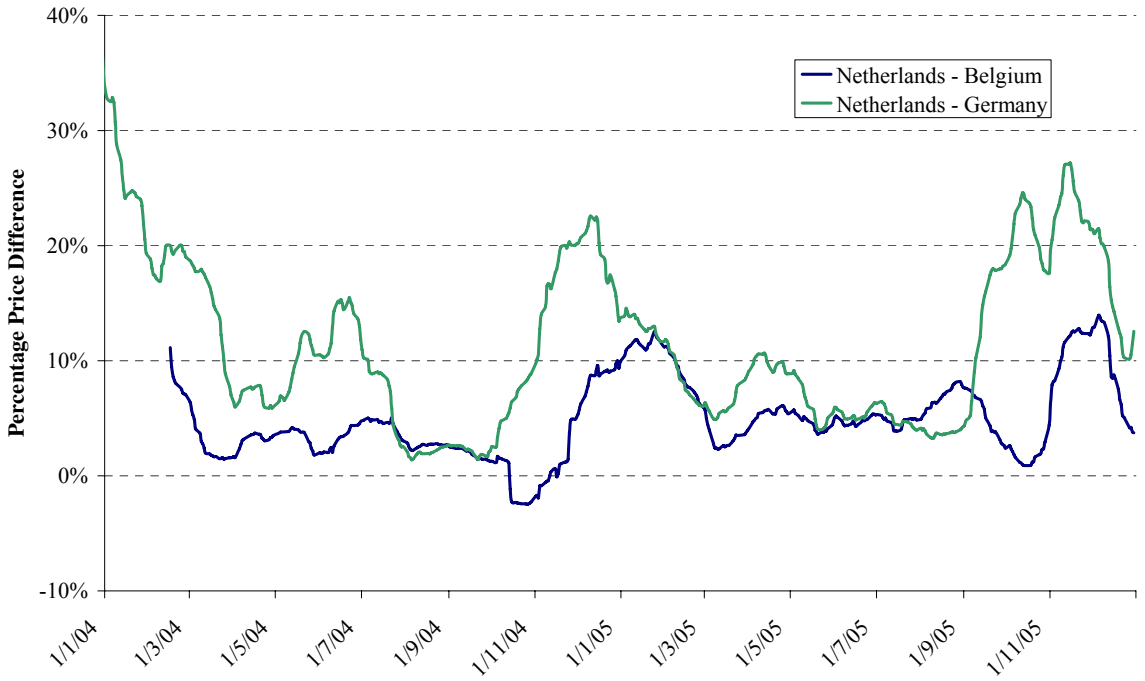
Figure 5 shows the (weekday) cross-border price differences, in absolute and percentage terms. Simple inspection shows that the differences are significant and persistent.

[12] Note that the figures presented using "all available data" cover different time periods for different countries (as indicated in the table, the data for the NL begin in 2/1/00, for France in 30/5/01, for BE in 6/1/04) and are therefore not directly comparable with each other.

Figure 5: Daily weekday day-ahead price differences (30-day Moving Average)



Source: Platts
Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country.



Source: Platts.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country.

Table 2 shows the differences in greater detail[13]. We note one perhaps surprising feature, which is that in percentage terms the differences are similar for weekdays and for weekends.

Table 2: Daily day-ahead price differences

Daily Day-Ahead Price Differences (€/MWh)
The Netherlands vs. Germany, Belgium and France

	Netherlands OTC Prices		Netherlands - Germany		Netherlands - Belgium		Netherlands - France	
	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays
First Observation	2-Jan-00		2-Jan-00		6-Jan-04		30-May-01	
Using All Available Data								
Minimum	11.50	10.00	-17.50	-7.00	-26.00	-6.13	-17.50	-13.00
Maximum	300.00	67.75	194.68	29.13	82.50	16.00	181.30	29.05
Mean	46.01	25.74	13.70	4.02	2.78	1.82	11.32	3.78
Median	37.10	23.88	6.16	3.00	1.23	0.88	5.00	2.86
Standard Deviation	26.67	9.66	21.89	4.08	6.61	3.12	19.08	4.16
2004								
Minimum	22.75	12.75	-0.63	-1.63	-26.00	-3.00	-0.50	-2.50
Maximum	85.00	37.00	57.20	7.25	30.00	6.25	57.80	7.63
Mean	36.49	23.38	4.73	1.77	1.79	1.16	5.22	1.95
Median	34.50	23.38	2.50	1.43	0.75	0.69	3.00	1.50
Standard Deviation	7.81	4.54	6.77	1.86	4.08	1.76	6.95	1.89
2005								
Minimum	30.25	17.00	-6.00	-0.75	-6.50	-6.13	-17.50	-13.00
Maximum	157.50	67.75	107.75	16.00	82.50	16.00	112.50	15.58
Mean	59.62	38.64	8.14	4.15	3.78	2.48	7.95	3.52
Median	50.25	36.63	3.25	2.75	2.00	1.50	4.00	2.63
Standard Deviation	23.91	10.00	13.51	3.65	8.32	3.96	13.98	4.51

Source: Platts
Note: All prices used in calculations are midpoints between daily high and low.

[13] The mean differences quoted in Table 2 may not match exactly the differences between the means listed in Table 1 for NL-BE and NL-FR. This is because a difference cannot be calculated for days when data is missing for either Belgium or France. Some figures may also appear slightly off due to rounding.

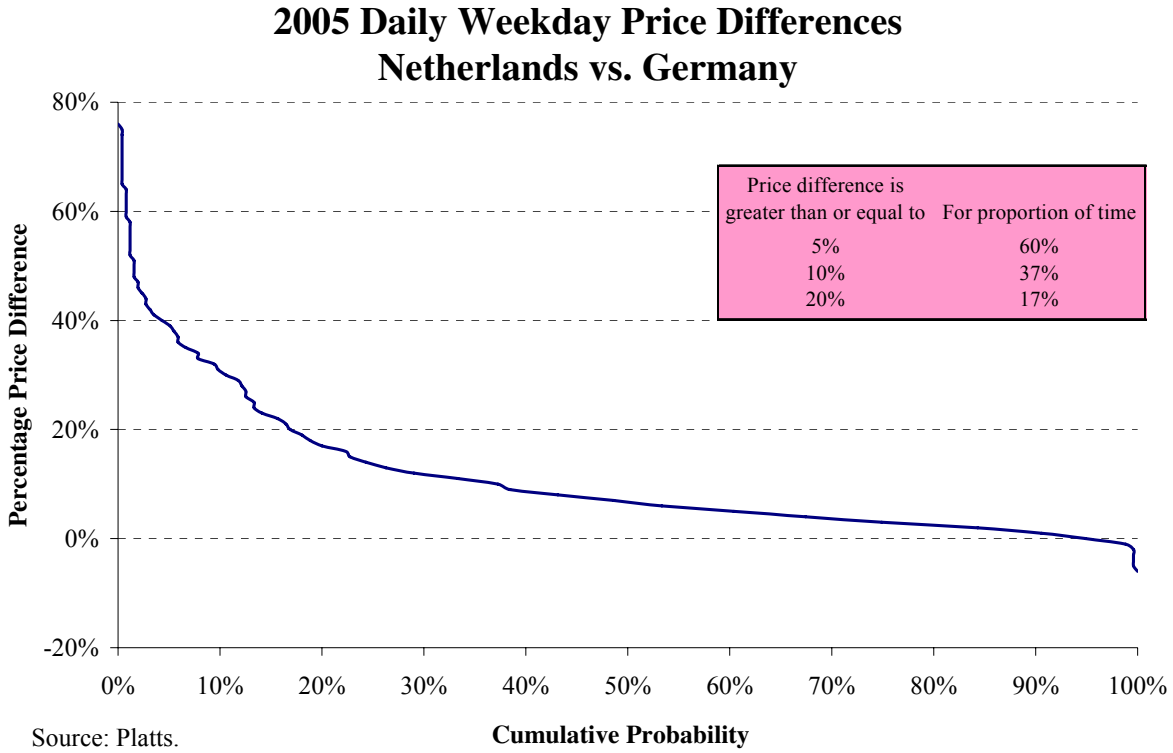
Daily Day-Ahead Percentage Price Differences
The Netherlands vs. Germany, Belgium and France

	Netherlands - Germany		Netherlands - Belgium		Netherlands - France	
	Weekdays	**Weekends & Holidays**	**Weekdays**	**Weekends & Holidays**	**Weekdays**	**Weekends & Holidays**
First Observation	2-Jan-00		6-Jan-04		30-May-01	
Using All Available Data						
Minimum	-25%	-54%	-67%	-22%	-27%	-54%
Maximum	91%	65%	58%	32%	87%	65%
Mean	24%	15%	5%	5%	20%	15%
Median	17%	13%	3%	3%	14%	13%
Standard Deviation	22%	15%	9%	8%	18%	14%
2004						
Minimum	-2%	-10%	-67%	-17%	-1%	-11%
Maximum	67%	33%	51%	27%	68%	28%
Mean	11%	8%	4%	5%	12%	8%
Median	7%	6%	2%	3%	8%	6%
Standard Deviation	12%	8%	9%	7%	12%	8%
2005						
Minimum	-5%	-2%	-10%	-22%	-17%	-32%
Maximum	76%	33%	58%	32%	79%	39%
Mean	11%	10%	6%	6%	11%	9%
Median	7%	8%	4%	4%	8%	8%
Standard Deviation	13%	7%	9%	9%	13%	10%

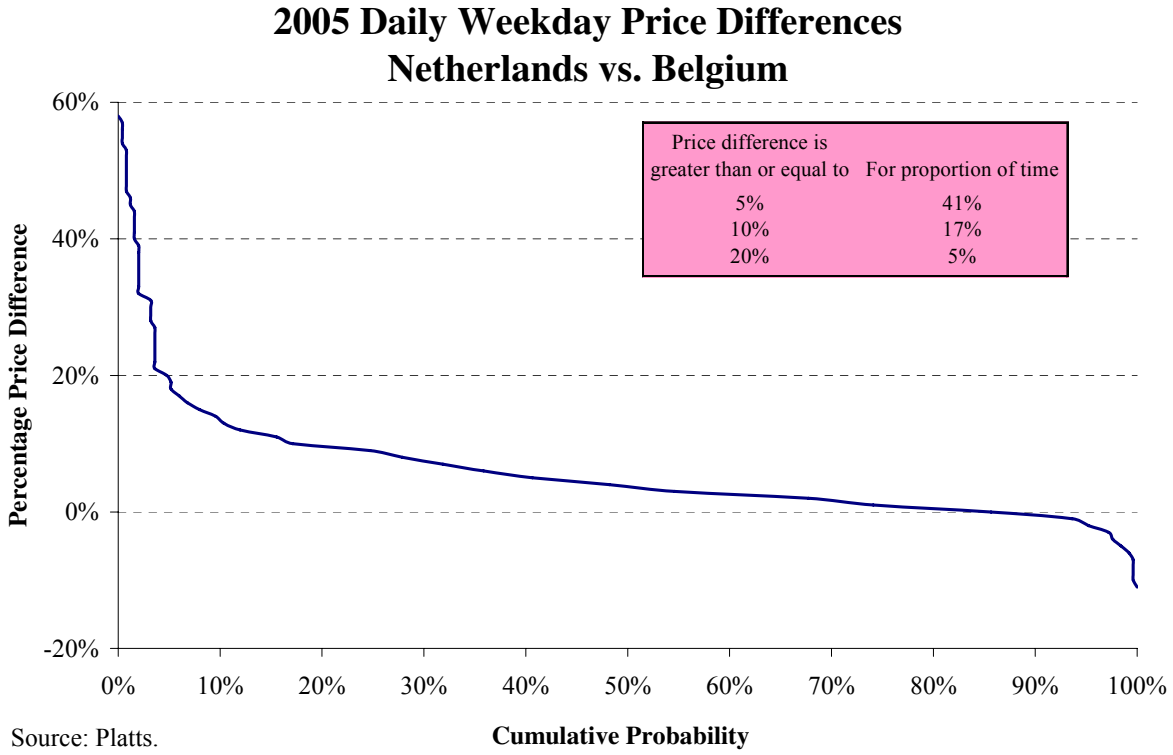
Source: Platts
Note: All prices used in calculations are midpoints between daily high and low.
*: Percentage difference is relative to the price in the Netherlands.

In particular, the mean differences with Germany and France have for half a decade been consistently greater than 10% for weekdays, and close to or greater than 10% on weekends. Looking at the distribution (for 2005) more closely, Figure 6 shows that the weekday difference for daily baseload prices was greater than 5% for 60% of the days, and greater than 10% for 37%.

Figure 6: Weekday price differences 2005 (daily prices)



Source: Platts.



Source: Platts.

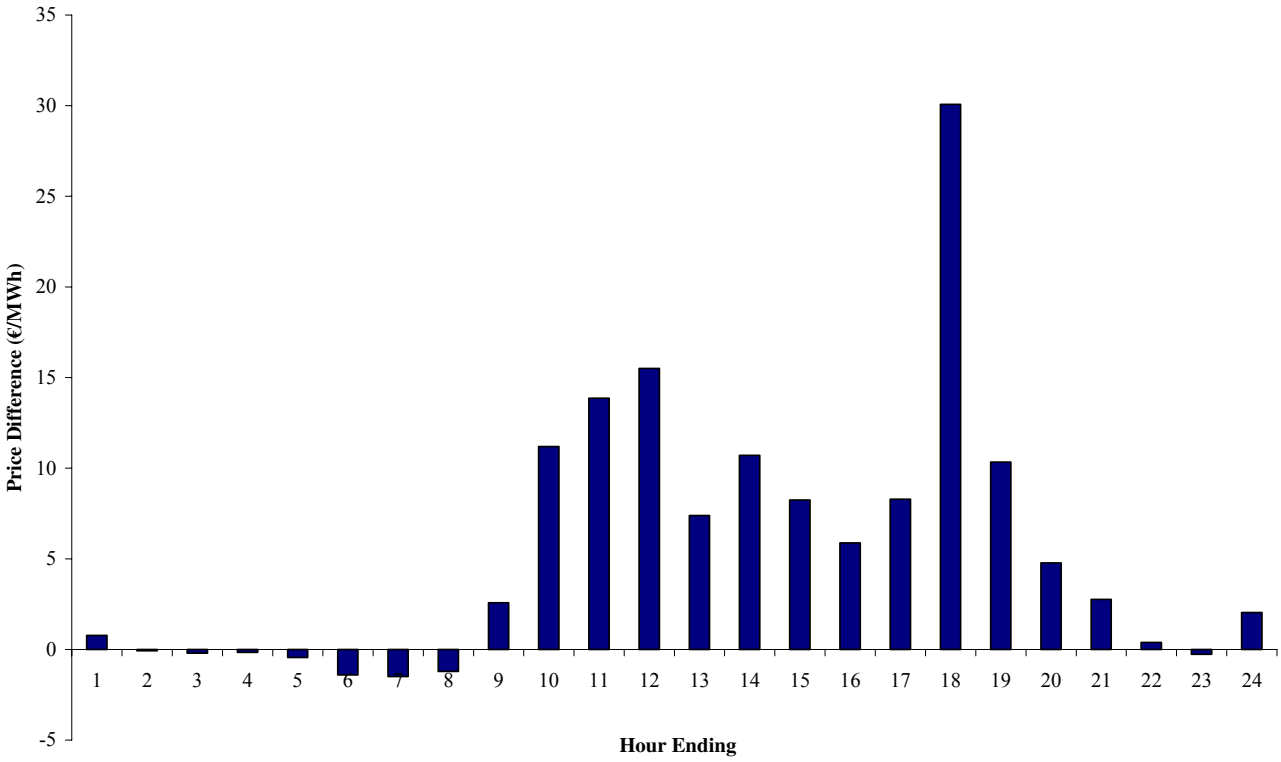
It is natural to conclude that the NL and Germany/France have been separate geographic markets. However, this conclusion needs to be caveated since examination of hour-by-hour price differences later in this chapter suggests a more nuanced outcome.

For Belgium, the mean difference of around 5% is less material, and Figure 6 shows that the difference was less than 5% on a majority of days. Nonetheless one might argue (in the spirit of the SSNIP test) that if imports from Belgium can not reduce the price difference below 5%, they would not be able to prevent a "hypothetical monopolist" in the NL from adding 5 or 10% to the prices.

Hourly Differences

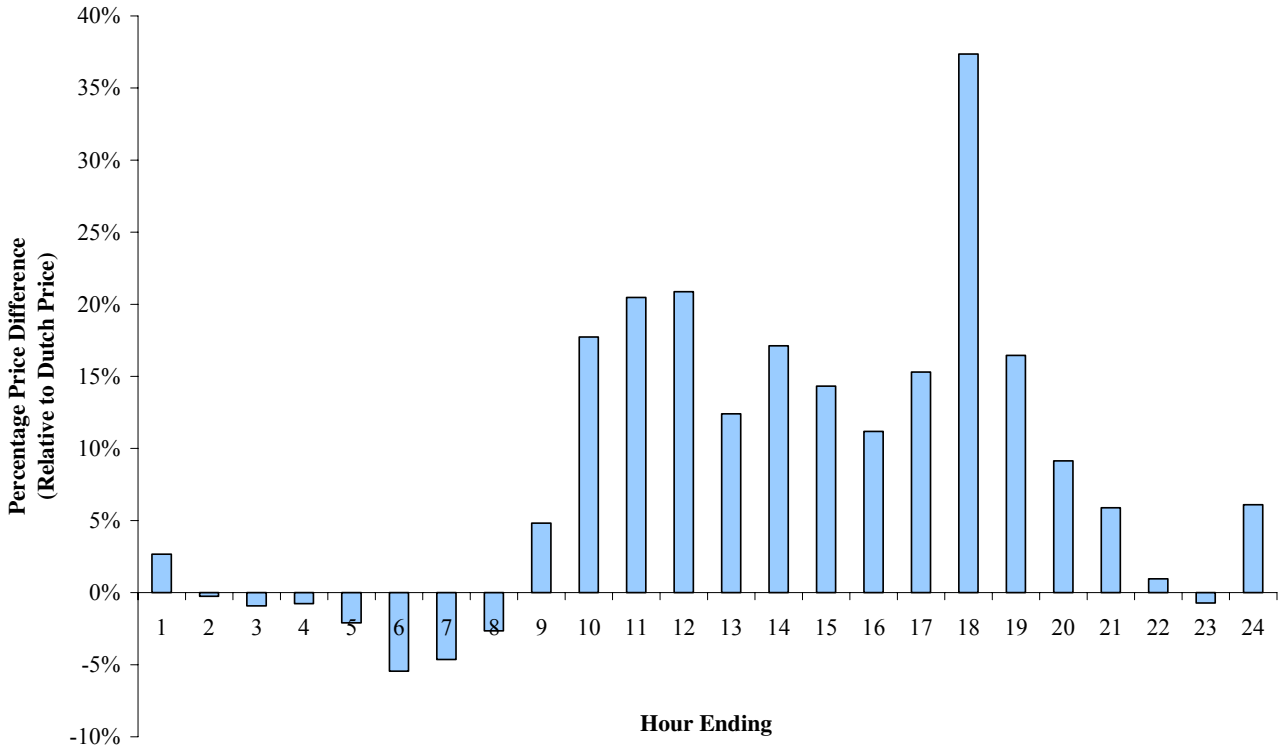
We have also looked at cross-border price differences on an hour-by-hour basis, between NL and DE (there are no hourly prices in BE). Figure 7 shows the results in both absolute and percentage terms. They show a pattern where the NL is more expensive during the day, but at the same price or even cheaper in the early morning hours. This presumably reflects the well-known issues around start-up costs for NL generators, which mean that they are effectively "must-run" plant in some hours. Obviously one possible implication is that these are separate markets in peak hours, but not in off-peak (weekday) hours.[14]

Figure 7: 2004 – 2005 Hourly average price differences, NL-DE



Source: APX, EEX.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in Germany.

[14] It might be thought that the rather dramatic pattern seen in Figure 7 reflects the influence of a few outliers, but this is not the case: removing outliers in the data does not produce significant changes in the results. For instance, we removed five of a total of eight observations with price differences in excess of 500 €/MWh. These five observations were all in hour 18. Removing the observations changed the average price difference in hour 18 from 30.06 €/MWh to 23.67 €/MWh. Figure 7 does not have outliers removed.

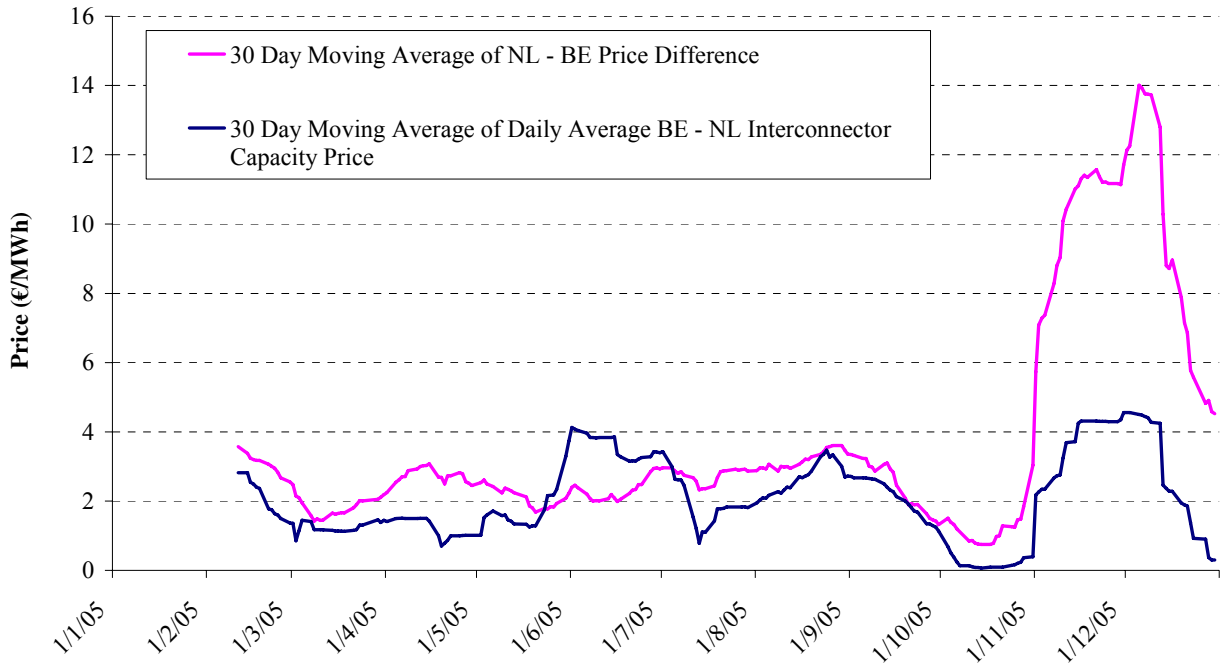


Source: APX, EEX.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in Germany.

In the absence of hourly power prices for Belgium, we have used hourly interconnector auction prices as a proxy. This is by no means ideal, as there are significant differences between interconnector prices and cross-border price differences (reflecting the inefficiency of explicit auctions relative to market coupling, and also some commentators would argue the dominant position of Electrabel in Belgium). Figure 8shows the data for 2005, confirming both that there is a reasonable correlation for much of the year, and that there are significant differences toward the end of 2005, where the interconnector auction clearly fails to capture most of the relevant rents. [15]

[15] Note that Figure 7 compares the NL-BE price difference (Dutch price minus Belgian price) to be BE-NL interconnector price (capacity from BE to the NL). These "ought" to be the same. If the Dutch price is e.g. €5/MWh higher than the Belgian price, then a trader should be willing to pay up to €5/MWh for capacity from BE to NL.

Figure 8: Cross-border daily price differences and interconnector capacity prices BE-NL, 2005



Source: Platts, TSO.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in Belgium.

Figure 9 shows the average hourly price of capacity from BE to NL, in terms of €/MW and as a percentage of the Dutch price in that hour. We see that the dramatic pattern in the hourly NL-DE price difference is mirrored in the price for interconnector capacity, but the numbers involved are much smaller.

Figure 9: 2005 Average Price of BE – NL Interconnector Capacity

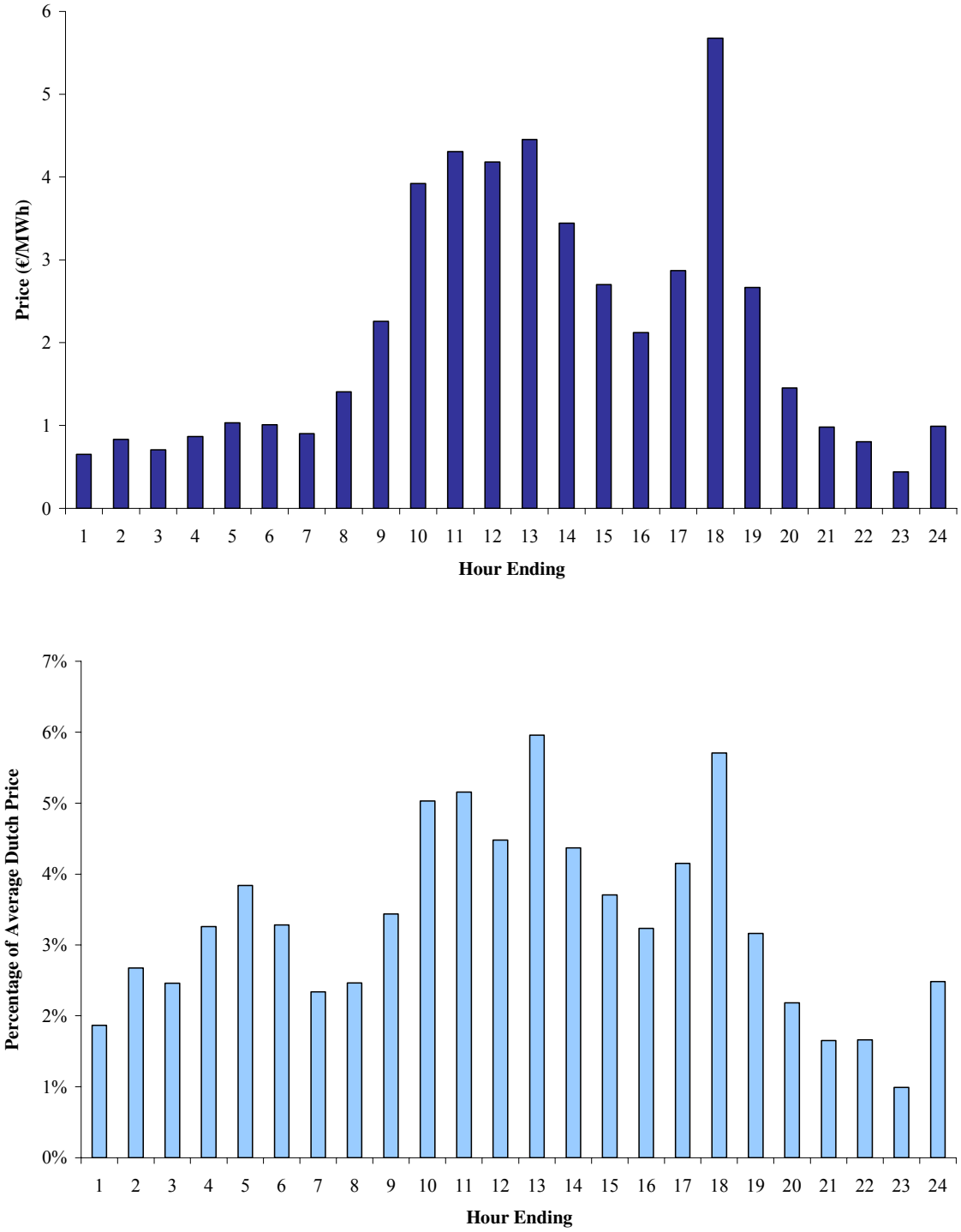
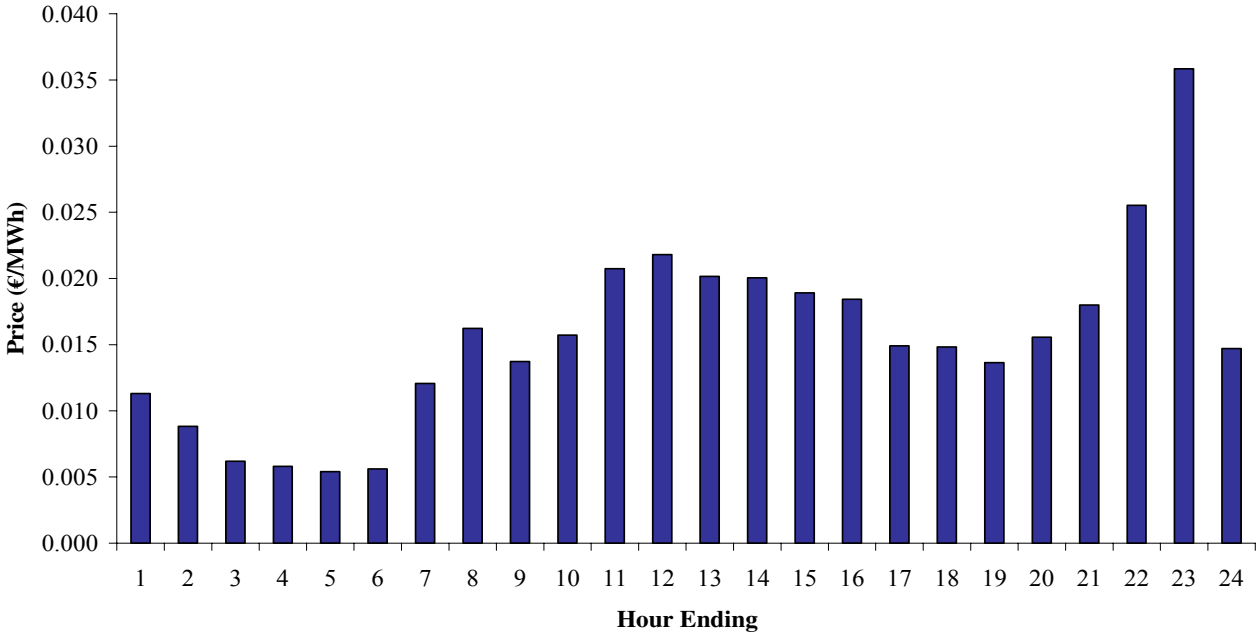
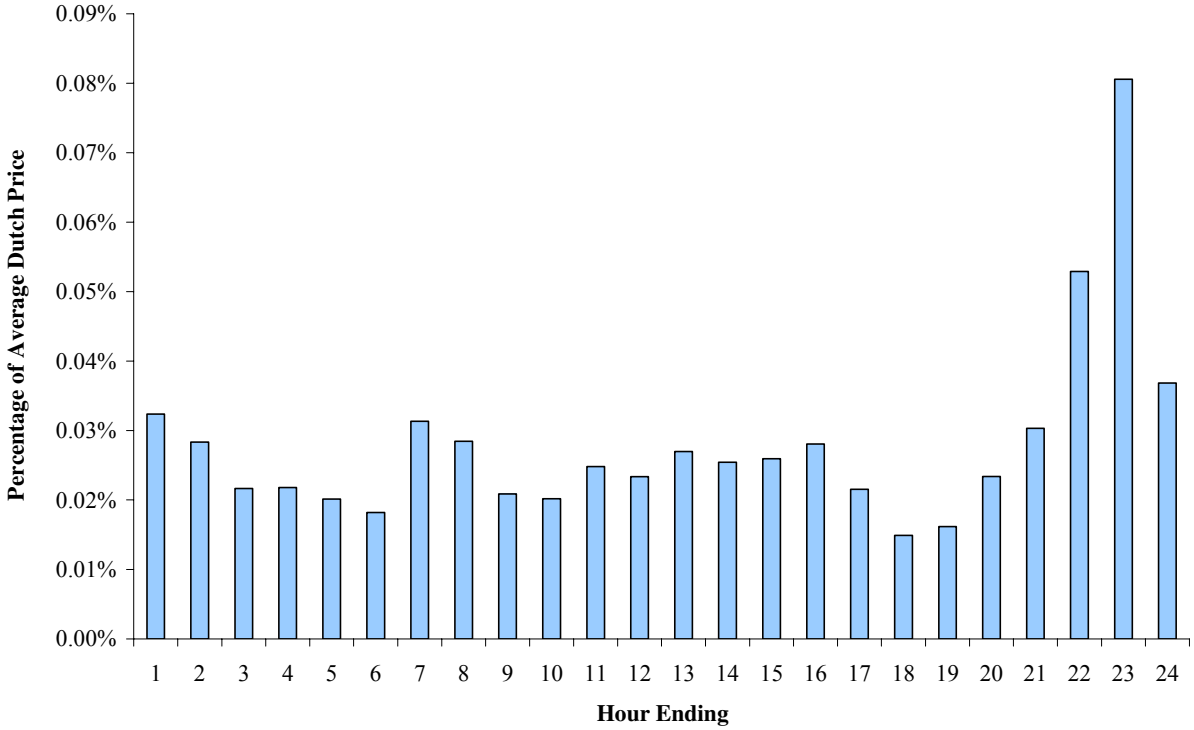


Figure 10 depicts the average hourly price of capacity from NL to BE. As expected given the persistent pattern of Dutch prices exceeding Belgian prices we observe that the price of capacity from NL to BE is negligible.

Figure 10: 2005 Average Price of NL – BE Interconnector Capacity



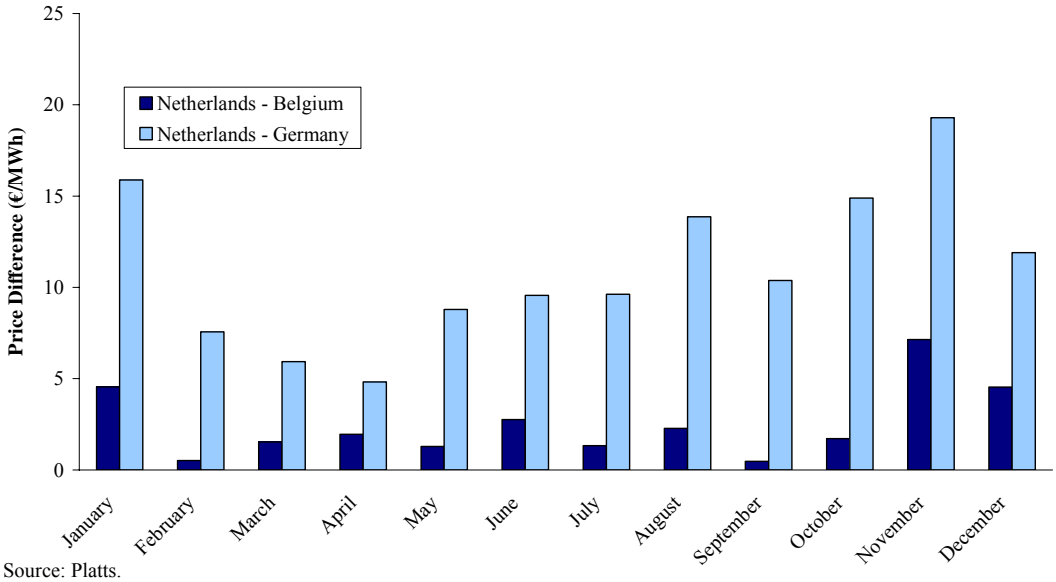


The interconnector capacity price between BE and NL therefore do not provide strong evidence for a time of day difference in geographic scope.

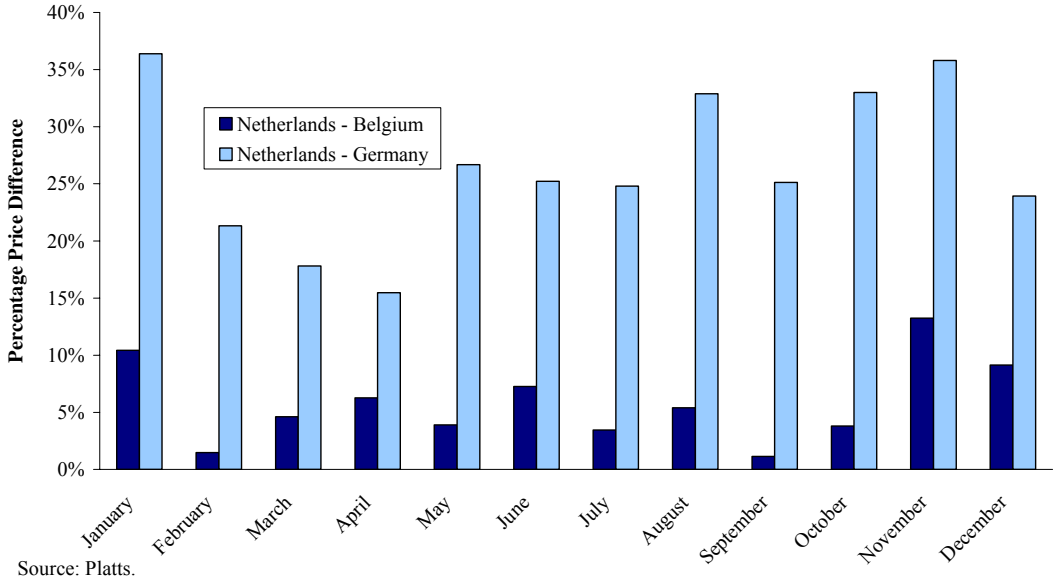
Seasonal Differences

We have also examined average price differences broken down by month. Figure 11 shows the results. Clearly there is strong seasonality in the price differences, particularly across the German border. Note that there is no significant difference in interconnector capacity between different seasons—the seasonality presumably reflects seasonality in demand (with lower demand giving lower prices and price differences).

Figure 11: Average Price Differences by Month



Source: Platts.
Notes: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country. Netherlands - Germany data are for 2000-2005. Netherlands - Belgium data are only available for 2004-2005.



Source: Platts.
Notes: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country. Netherlands - Germany data are for 2000-2005. Netherlands - Belgium data are only available for 2004-2005.

Seasonal and Hourly Differences

Finally, we have examined average NL-DE price differences broken down by time of day and season. From examination of the results above, it seems appropriate to distinguish the period 0900-2100 from 2100-0900, and the months April-August from the months Sept-March.[16] Table 3 shows the results. Clearly there is strong seasonality in the price differences across the German border in the 0900-2100 period.

Table 3: Average NL-DE price differences by time of day and season weekdays 2004 - 2005

Hours	April - August	September - March
09.00 - 21.00	8.02%	22.57%
21.00 - 09.00	-0.72%	0.67%

Source: APX, EEX.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in Germany.

Forward Prices

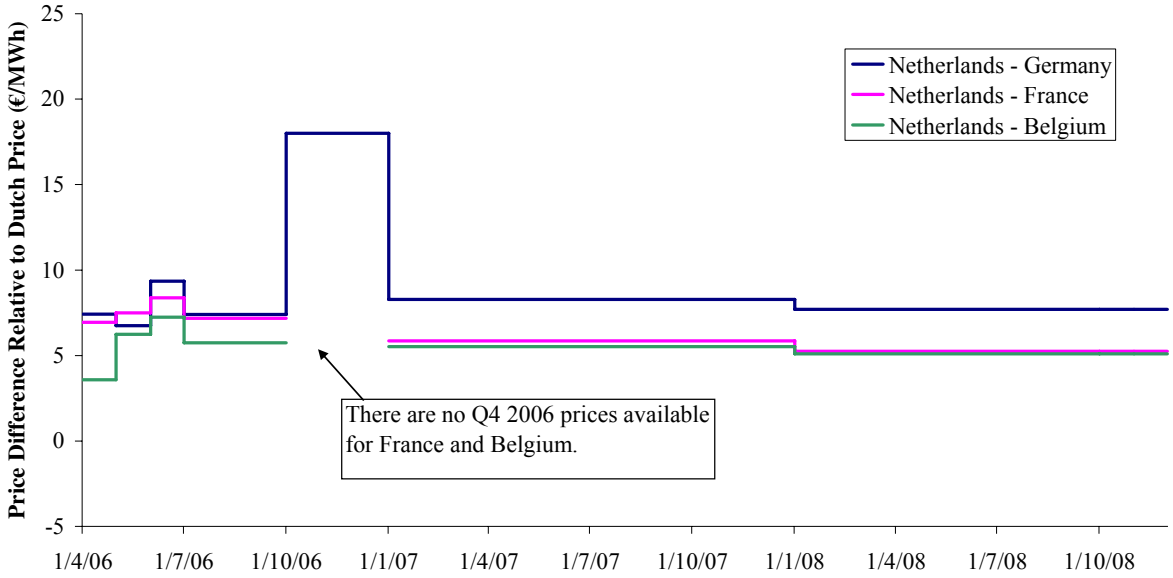
We can use forward prices to ask whether these historical cross-border price differences can be expected to continue into the future.[17] Figure 12 shows the expected cross-border differences, based on Platts forward price assessments as of 21 March 2006, both in €/MWh and as a percentage of the Dutch price. It seems that the markets are not anticipating large increases in interconnector capacity that would equalise prices between the Netherlands, France, Germany and Belgium.

[16] Note that the time period chosen is different from the 0700-2300 "peak hours" definition. As noted above, our choice here is based on examination of the data in Figure 7.

[17] These comparisons are based on baseload prices (i.e., 24 hours). Unfortunately it is not possible to compare peak or off-peak prices. The forward peak products traded are for different time periods in different countries (e.g., 0700-2300 in the NL, 0800-2000 in DE), making such comparisons misleading.

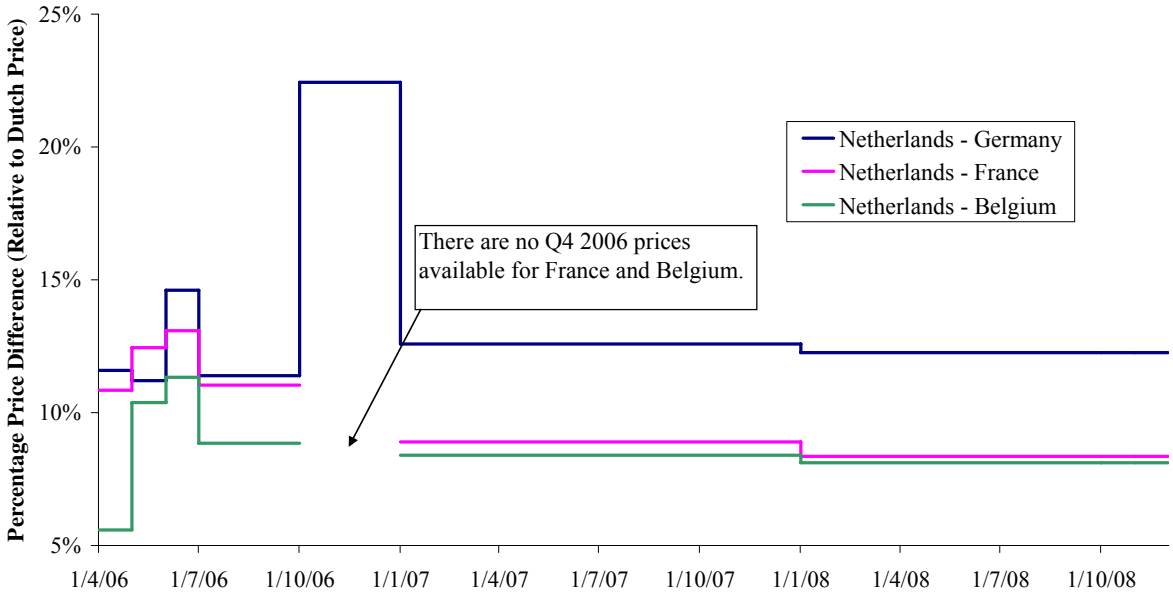
Figure 12

Cross-Border Forward Power Price Differences 2006-2008 (€/MWh)



Source: Platts European Power Daily, March 21, 2006.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring countries.

Cross-Border Forward Power Price Differentials 2006-2008 (%)



Source: Platts European Power Daily, March 21, 2006.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring countries.

Price Correlations

In looking at geographic market definition it is often useful to look at the correlation of prices between different regions. In this case that exercise is of very limited value, for two reasons. First, power prices largely reflect the costs of inputs that tend to have the same price in different

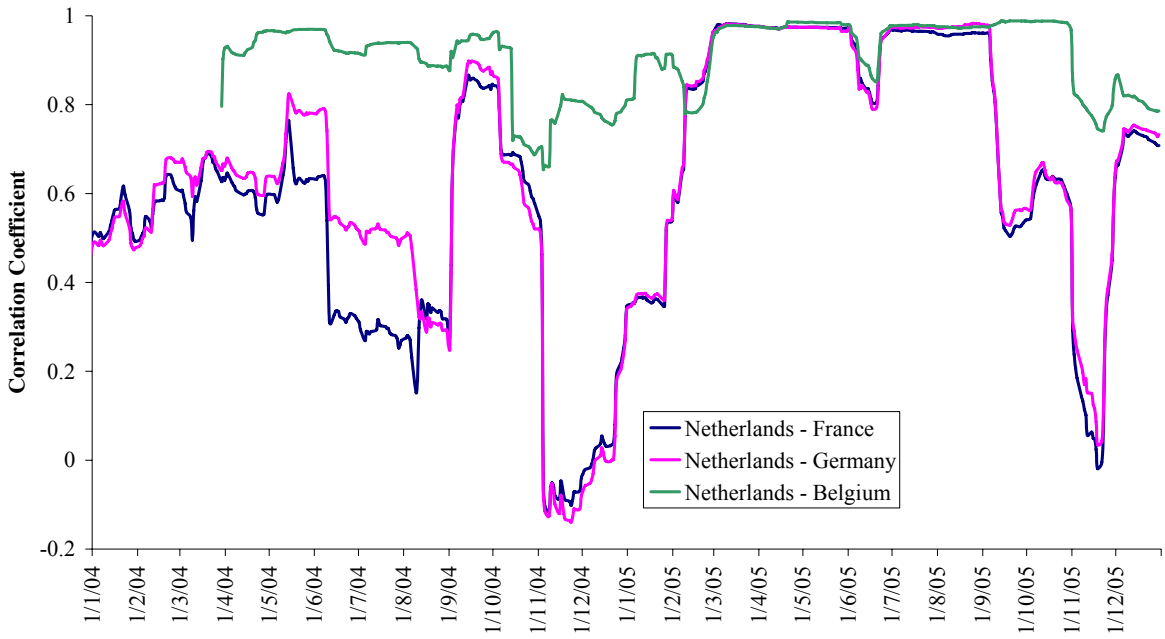
parts of Europe, either because they are freely traded (carbon allowances, coal, spot gas to a limited extent) or because of more complex institutional factors (in the case of gas bought under traditional oil-indexed contracts). They therefore will tend to be quite highly correlated even if there is little or no potential for cross-border trade.

This problem could be addressed through the use of sophisticated statistical techniques that attempt to factor out these common drivers. However, the second drawback is that in this case at least there is limited value in applying those techniques because we can easily observe the cross-border price difference, which is a more useful indicator than the cross-border price correlation.

Nonetheless, for completeness sake we have undertaken some analysis of the cross-border price correlations. Figure 13 shows the 60 day trailing cross-border price correlations (i.e., we calculate for each weekday the correlations between Dutch and neighbouring countries' daily prices over the preceding 60 working weekdays, i.e. approximately three months).

Figure 13

60-Day Moving Correlations of Daily Weekday Price Differences



Source: Platts.

The only conclusion we draw from this analysis is a negative one—there is no sign of any trend toward greater correlation over time between Dutch prices and those in neighbouring countries.

4.2 Determinants of prices and price differences

We now analyse the data to see what drives wholesale prices and cross-border price differences in NW Europe. The "conventional wisdom" is that:

- A very high proportion of Dutch capacity is gas-fired, especially among the price-setting plant, as can be seen from the merit order shown in Figure 14.

- Dutch power prices are therefore largely driven by gas prices.
- For neighbouring countries a very high proportion of capacity is coal and nuclear, again especially among the price-setting plant.[18]
- Power prices in neighbouring countries are therefore largely driven by coal prices and the cost of nuclear generation.
- Cross-border price differences will therefore tend to increase with the price of gas, and decrease with the prices of coal and carbon.

Below we present some data that elaborates on these propositions. We focus on the German-Dutch price differences, where the evidence is by far the clearest. We look at the generation park in each country, represented by the "merit order". We then proceed to calculate "clean spark spreads" and "clean dark spreads" (see below) to see how much can be explained by looking at the prices of gas, coal and carbon. We also use our modelling results (from later in the paper) to estimate a "clean spread" that is the difference between the actual price and our estimate of the system marginal cost (largely derived from gas, coal and carbon costs).[19] Finally, we look at whether the *difference* between Dutch and German prices seems to be reasonably closely related to the *difference* between system marginal costs.

Clean spark and clean dark spreads

The "clean spark spread" is defined as the difference between the wholesale power price and the costs of natural gas and EU ETS carbon allowances for a gas-fired generation plant of given thermal efficiency. The "clean dark spread" is the equivalent figure for a coal-fired plant of given thermal efficiency. We use thermal efficiencies for both gas and coal derived from our database of estimated plant efficiencies.[20]

The Netherlands: generation park and power prices

Figure 14 below shows the Dutch merit order (including imports) as well as minimum and maximum domestic demand. It confirms that gas-fired plant will be marginal a large proportion (although not all) of the time, and thus defines the system marginal cost (SMC) for a large proportion of the time.[21]

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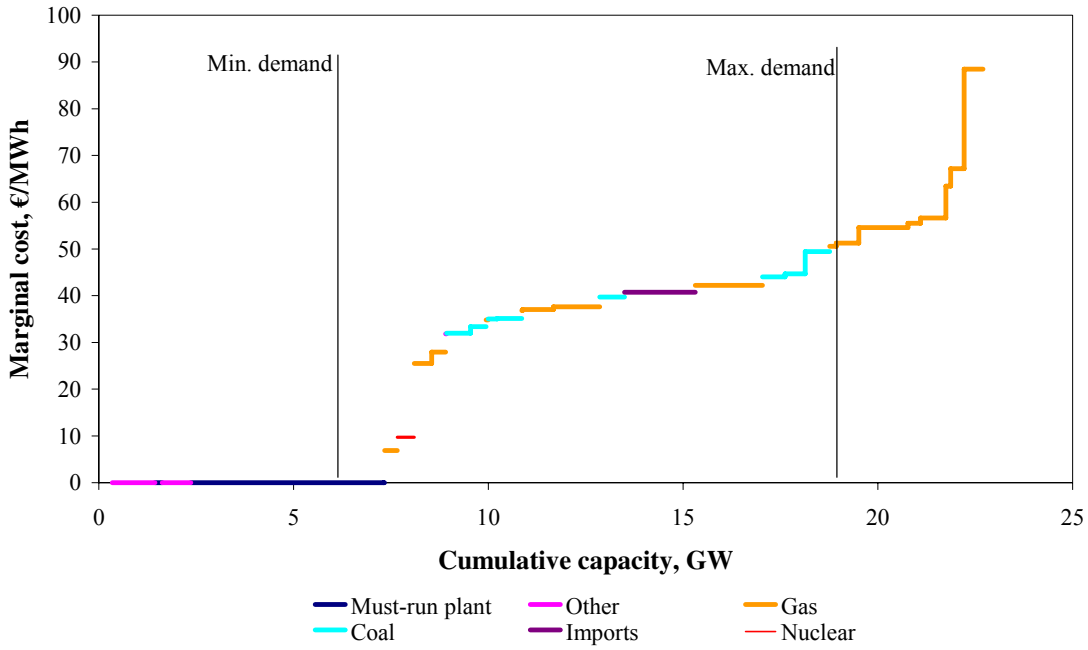
[18] The European Commission sector inquiry also notes that coal is generally believed to be the main marginal fuel for Germany in its Preliminary Report (Feb 2006n), see p.177.

[19] Note that this is the only part of this chapter's analysis that uses results from our model.

[20] For the NL, we look at the thermal efficiencies of each gas-fired plant and calculate spreads based on the efficiency of the median plant (i.e., the plant that has the median MW of capacity). This gives a thermal efficiency of 45% (the 5th and 95th percentiles are 34% and 57% respectively). For DE we do the same for coal plants. The median thermal efficiency is 39% (the 5th and 95th percentiles are 32% and 44%).

[21] The SMC is defined at any point in time as the marginal cost of the highest marginal cost plant that is running at that time.

Figure 14: Dutch merit order including imports (2005)



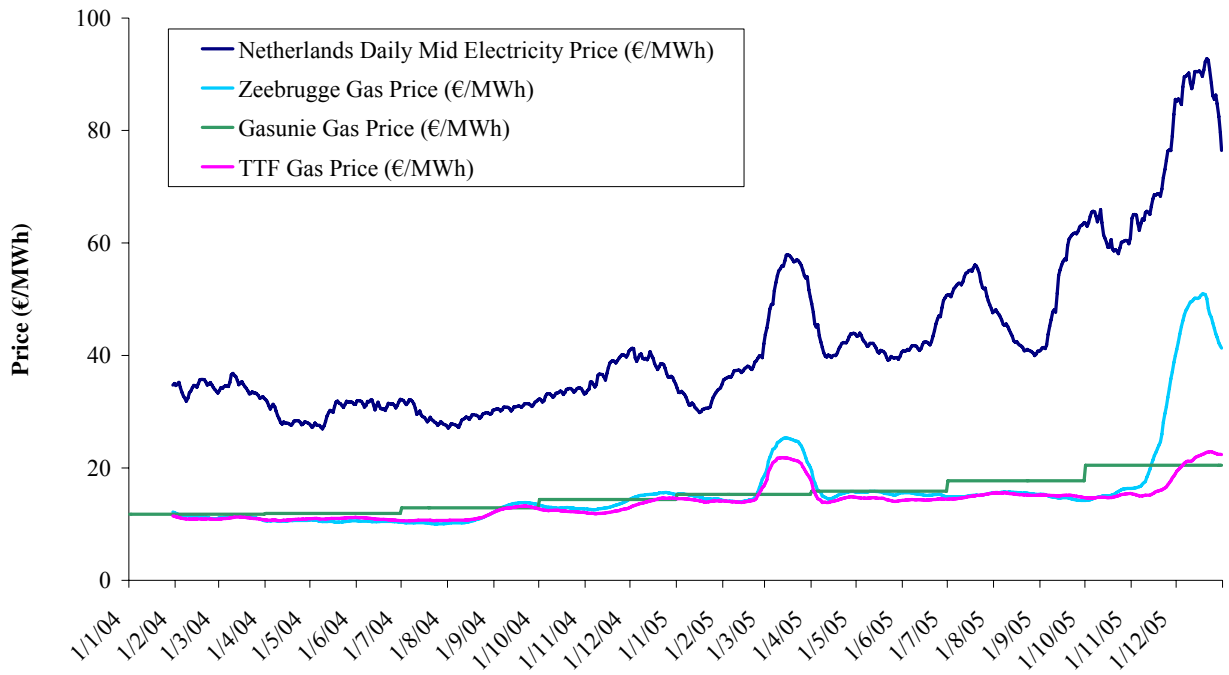
It is therefore of great interest to calculate the "clean spark spread" for the Netherlands, i.e., the difference between the power price and the fuel and carbon cost of a "typical" Dutch gas-fired generator.[22] This is a measure that is widely used in the industry.

One methodological question is whether the relevant gas price for calculating the Dutch spark spread is that from "traditional" oil-indexed gas supply contracts, or that from a trading hub (TTF or Zeebrugge). Figure 15 shows Dutch power prices and three different gas price series: TTF, Zeebrugge and a gas price based on a formula published by Gasunie Trade & Supply, which is a reasonable representative of traditional oil-indexed pricing.[23]

[22] I.e., for a given thermal efficiency we calculate how much gas the plant burns, and how much CO2 it produces, in producing 1MWh of electricity, and look at the difference between the price achieved for that electricity and the costs of the gas and the EU ETS carbon allowances used up in producing it.

[23] The Gasunie formula is used to calculate quarterly gas prices. It is an oil-indexed formula and can be expressed as follows: (0.0175 x P) + (0.03102 x G) + 2.498, where P represents the value of heavy fuel oil with a sulphur content of one percent by weight and G represents the value of gasoil. Both G and P are averaged over the 6 calendar months immediately preceding the quarter to which the gas price applies, and are based on the arithmetic average of the high and low monthly quoted prices as published by Platts Oil gram Price Report in USD per ton under Barges FOB Rotterdam. TTF gas prices are gas prices quoted for the Dutch Title Transfer Facility. The TTF is a virtual gas hub and a trading point of the national gas transmission system operator Gas Transport Services B.V. We received TTF prices from Argus Media.

Figure 15: Dutch power prices, Zeebrugge and oil-indexed gas prices



Note: All prices except for the Gasunie gas price are 30-day moving average prices.

It is clear from the graph that the Gasunie price is too flat to explain any of the volatility in power prices. The Zeebrugge and TTF series have spikes corresponding to some of the power price spikes, but as the next graph demonstrates, neither can adequately explain power prices toward the end of 2005.

Figure 16: 30-day moving average of Dutch clean spark spreads

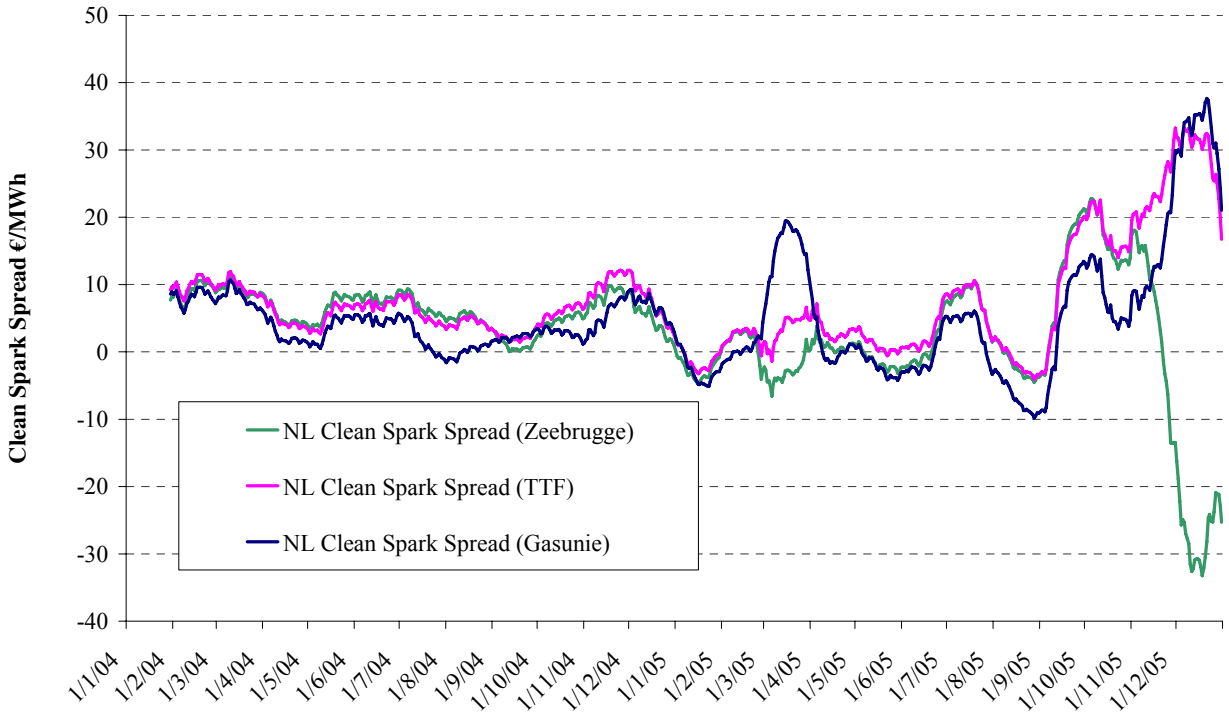


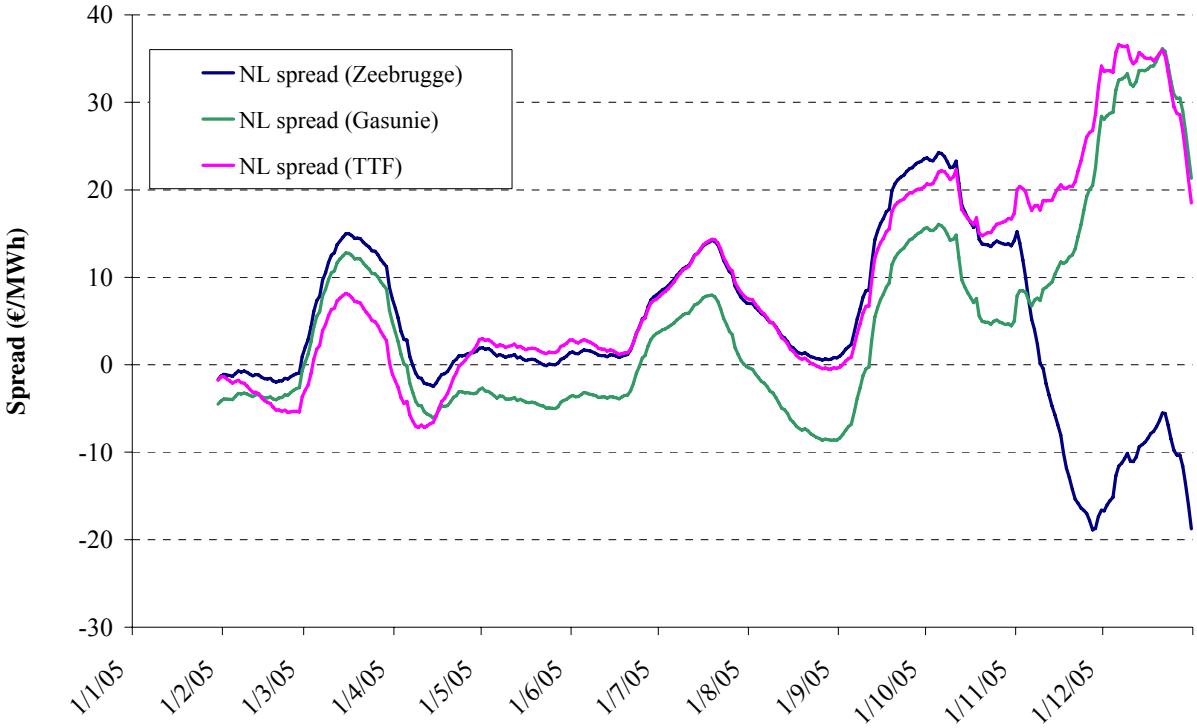
Figure 16 above therefore shows the "clean spark spreads" for the NL, based on each of the three gas price series. In general it suggests a fairly stable relationship between Dutch power prices and the inputs to a gas-fired plant. We believe that the most appropriate spread to look at is the one based on Zeebrugge gas prices (and for modelling purposes in the rest of this paper we have chosen the Zeebrugge price). That is because (a) the Zeebrugge price performs better than the Gasunie price and at least as well as the TTF price in explaining historical price data; and (b) from our own experience in the Dutch market we understand that generators now view Zeebrugge as the reference price for the opportunity cost of gas (in part because the TTF remains rather illiquid)..

The data shown here demonstrate that the NL (Zeebrugge) clean spark spread appears to be stable through most of 2004-05. However, the stability appears to break down toward the second half of 2005, especially in 4Q05. Here power prices increase way ahead of marginal costs as measured by Gasunie or TTF gas prices, but not high enough to compensate for the dramatic increase in Zeebrugge prices. It is outside the scope of this paper to explain this episode in any detail. One can speculate that the high prices at Zeebrugge (reflecting UK 2005 winter prices) induced as much gas export as possible from the Netherlands, so that at the margin it was not always possible to export additional gas to Zeebrugge (e.g., due to contractual or physical congestion). The true marginal value of gas to Dutch generators would then have varied from day to day and possibly from generator to generator, depending on their access to transportation capacity from the NL to Zeebrugge, and this would have led to a time series somewhere between Zeebrugge and TTF prices. This would be consistent with the observed data, but of course is only speculation.

It might also be asked whether it is misleading to look only at gas-fired marginal costs, since there is also a significant amount of other plant that sometimes is marginal in the NL. We have therefore estimated a spread equal to the difference between the historical price and an hour-by-hour estimate of the system marginal costs (again, fuel and carbon allowances), taken from our BAM model.[24] Again we perform the exercise three times, to take account of the three different gas price series available.

[24] Note that this is the only place in this chapter where we use modelling results.

Figure 17: 30-day moving average of Dutch BAM-spreads

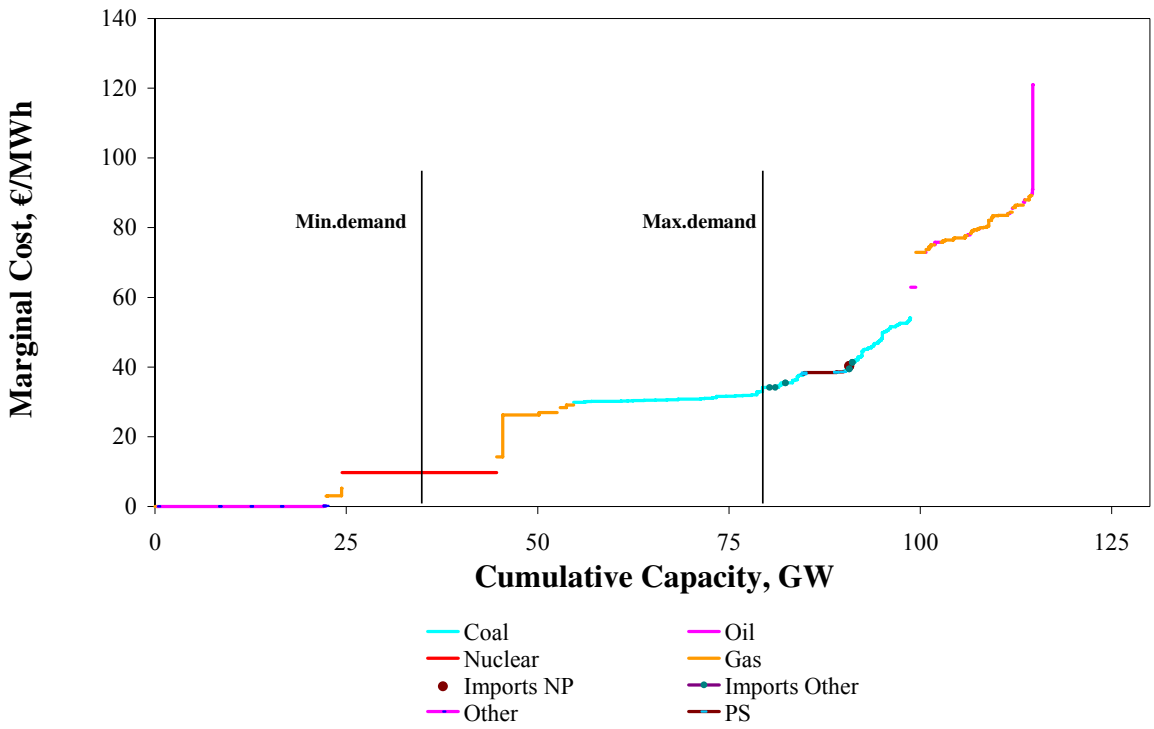


If this last exercise appeared to do a much better job than the clean spark spread in explaining Dutch power prices, then we might question whether it is safe to generalise that gas prices largely drive Dutch power prices. However, the results are qualitatively similar to those using the clean spark spread, and we therefore conclude that this is a reasonable generalisation. Note that we do *not* argue that Dutch prices are or are not at competitive levels—our report makes no assessment of this question—simply that in general gas and carbon prices are the key explanatory variables for Dutch power prices.

Germany: generation park and power prices

Figure 18 below shows the German merit order as well as minimum and maximum domestic demand. It confirms that coal-fired plant will be marginal a large proportion (although not all) of the time, and thus defines the system marginal cost (SMC) for a large proportion of the time.

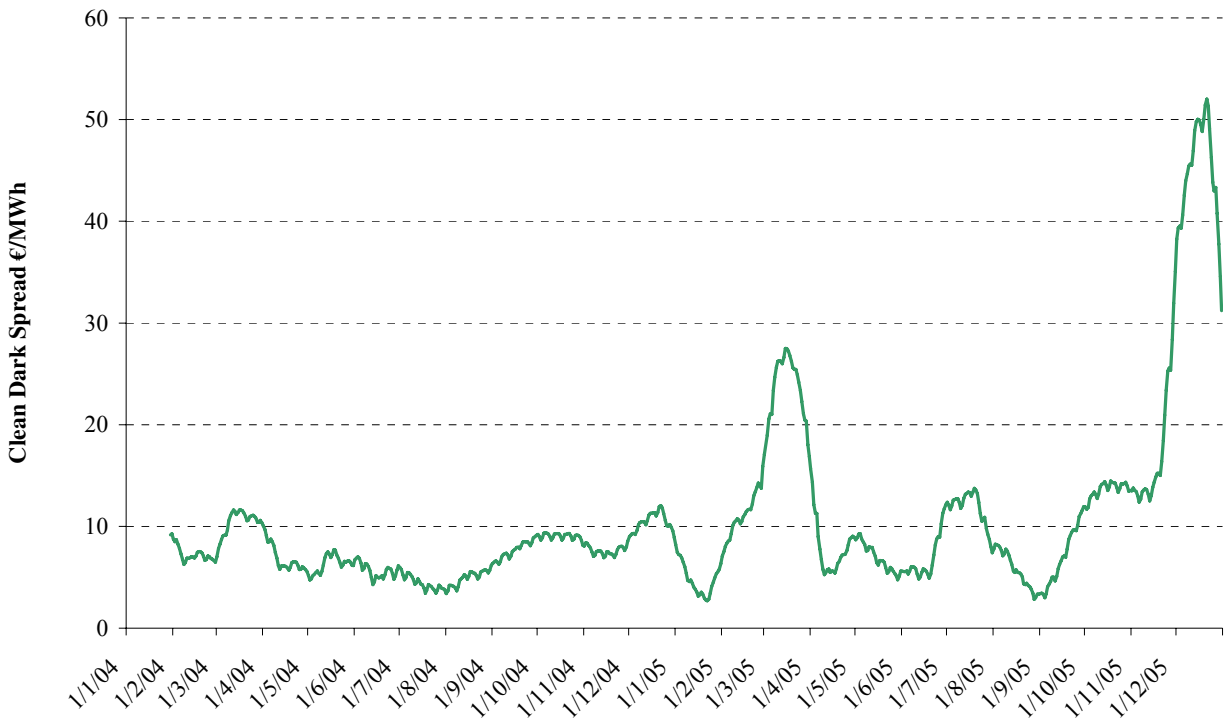
Figure 18: German merit order including imports (2005)[25]



We therefore examine the German clean dark spread, shown in Figure 19 below.

[25] See also European Commission sector inquiry's Preliminary Report p.133 on DE merit order, but note that it only covers the capacity of "main" German generators and is therefore not directly comparable.

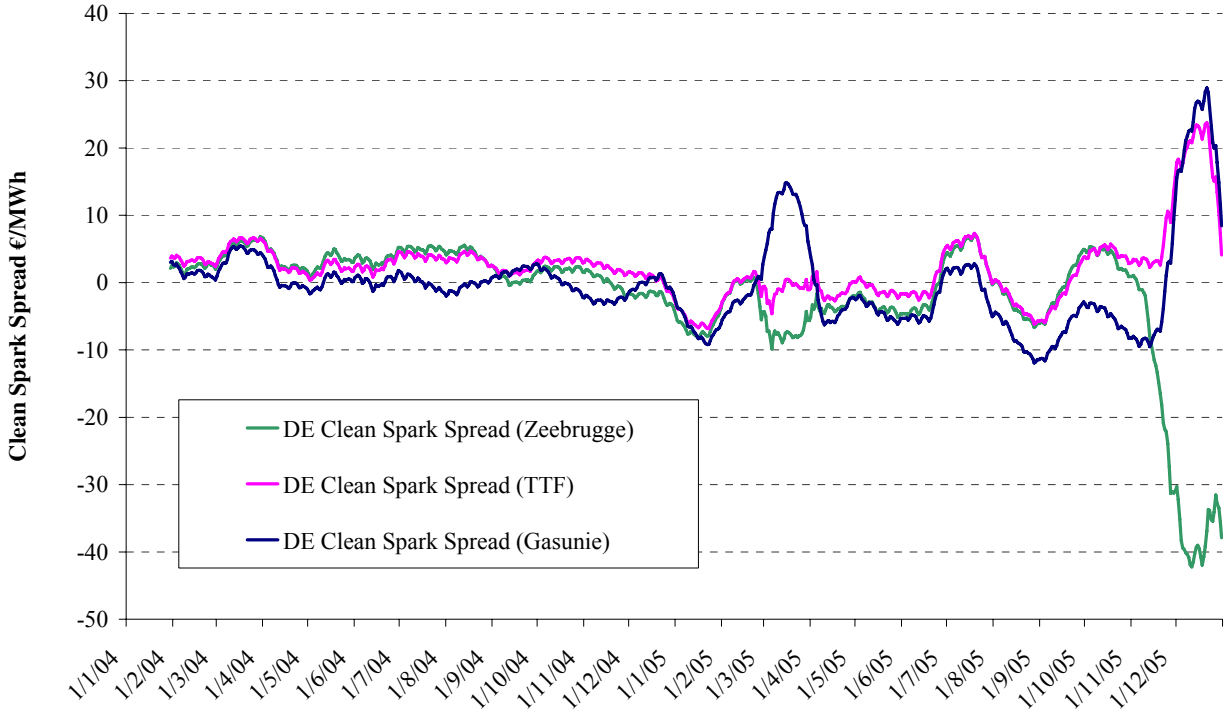
Figure 19: 30-day moving average of German clean dark spread



The spread shown suggests that coal prices appear to do a reasonable job of explaining German spot power prices, until the end of 2005, where there appears to be a major disconnect.[26] One possible explanation for this disconnect would be if German power prices in winter 2005 reflected spiking gas prices. Of course it is possible that gas-fired plant is marginal in Germany at times (depending in part on the evolution of gas prices). However, given the relatively small amount of gas-fired capacity in Germany it is hard to see how gas could be responsible for a very large part of German prices. Nonetheless, to examine this hypothesis we have calculated a German spark spread shown in Figure 20 below.

[26] Note the possibly related observations in the DG Comp Sector Inquiry, concerning the apparent disconnect between 2005 coal prices and the 2005 German year-ahead baseload contract price (p.177).

Figure 20: 30-day moving average of German clean spark spreads



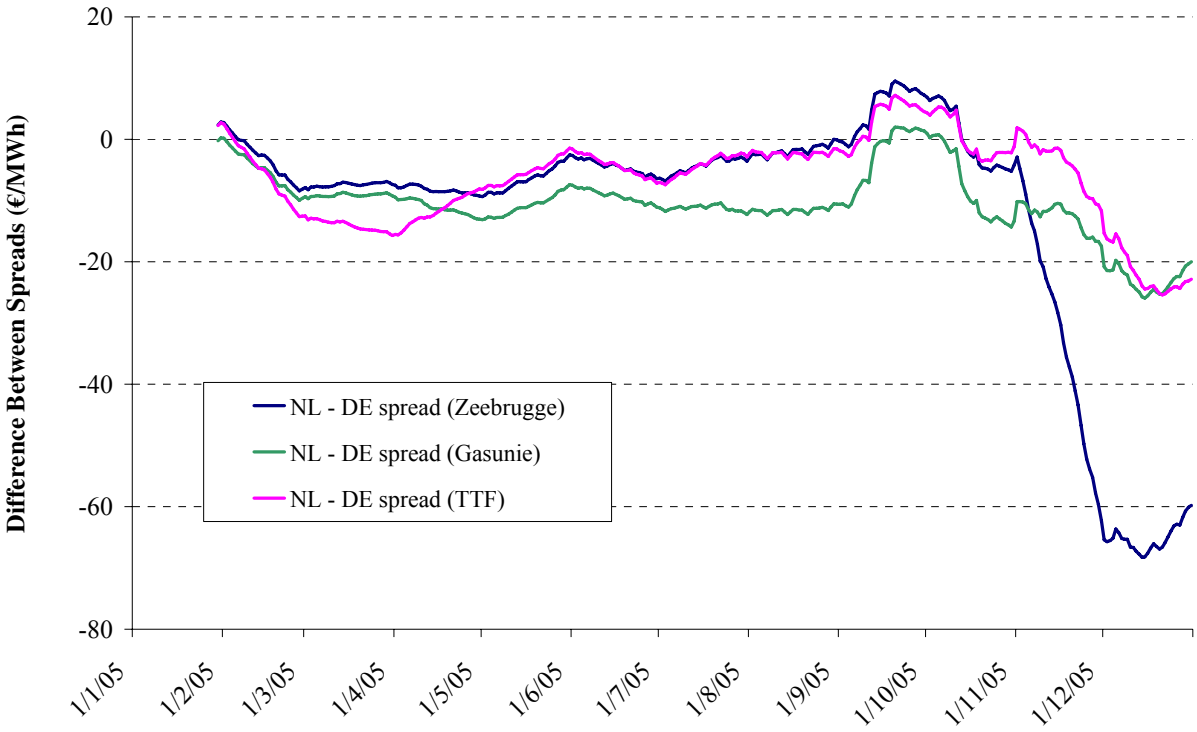
Price differences and differences in marginal costs

Finally, Figure 21 shows the difference between

- The NL-De price difference; and
- The difference in BAM-estimated system marginal costs between NL and DE

Again we have shown the results three times, based on the three difference gas price series.

Figure 21: 30-day moving average of difference between NL-DE price difference and BAM-estimated NL-DE cost difference



As previously, the relationship appear to be rather stable expect for the last quarter of 2005. The data therefore provide a reasonable level of support to the fundamental hypothesis that we have examined in this section. **Key drivers of the NL-DE price difference are gas, coal and carbon prices.**

Forward Prices

It is therefore valuable to look at forward prices, as shown in Table 4.

Table 4: Forward Gas and Coal Prices

	Zeebrugge Gas (€/MWh)	Central Appalachian Coal ($/ton)
Historical Prices		
Winter 04 (Oct. 04 - March 05)	15.96	
Summer 05 (April 05 - Sept. 05)	15.21	
Q4 2005	32.54	
Forward and Futures Prices		
Apr-06	23.70	54.00
May-06	21.37	53.50
Jun-06	21.62	53.50
Q3 2006	22.81	54.25
Winter 06 (Oct. 06 - March 07)	42.47	54.38
Summer 07 (April 07 - Sept 07)	23.10	54.50
Winter 07 (Oct. 07 - March 08)	35.00	54.50

Sources: Gas data are from Platts, coal data are Nymex futures from the Bridge database.

Forward prices are rather flat for both gas and coal. There is no reliable forward price for carbon (at least in part because of uncertainty about EU ETS Phase II allowance allocations). However, gas-coal switching will almost certainly remain the main source of carbon reduction in Phase II and flat gas and coal forwards therefore place some limits on the potential for significant changes in carbon prices.

We conclude that the key drivers of NL-DE price differences are set to remain stable over the coming few years, and therefore that historical price differences are likely to remain in place, in the absence of major structural changes (e.g., changes in market power or interconnector capacity).

5 SSNIP tests for the wholesale market

As outlined in section 1, the method of market definition generally accepted by competition authorities is the SSNIP test. In essence, if a hypothetical monopolist can profitably raise prices by 5-10% within a given geographic area, then that area defines a market. If it is not profitable to raise prices, then we expand the geographic area of the monopolist and repeat the experiment.

Since the SSNIP test assumes a hypothetical monopolist (which does not exist in reality), to perform the SSNIP test we must rely on a computer model of the electricity market which can simulate the profits of a hypothetical monopolist. Moreover, in defining the markets it is interesting to see that the market definition is valid for the foreseeable future, to discount the possibility that the definition could change substantially *e.g.* next year. Accordingly, we perform the SSNIP test for the expected conditions in 2008.

In this section, we perform a SSNIP test for the peak market. We explain why the presence of start-up costs complicates the results of the SSNIP test for the off-peak market. While we cannot perform a full SSNIP test, we provide a partial analysis. In the following section, we investigate what factors could change the geographic extent of the markets.

5.1 Methodology

The BAM model

We use the Brattle Annual Model (BAM) for all the electricity market simulations described in this report. For example, we use the BAM model to calculate prices in each country modelled, the profits of generators and the flows between countries. Appendix II contains details of the functioning of the BAM model, but we give a brief overview of the model below.

The BAM model is essentially a simple despatch model, which calculates the system marginal prices and cross-border flows based on plant data, fuel prices *etc*. Unlike some more complicated models, it does not predict the level of market power, or the increase in generator offer prices above marginal costs – the model user must input these parameters. On the other hand, this kind of despatch model is simple, transparent, relatively easy to understand, and creates unique solutions. This is in contrast to more some more complex models (such as Supply Function Equilibrium or SFE models) which can produce several solutions. In sum, there is a trade-off between sophistication and transparency; we argue that in competition proceedings transparency is the more important, and a simple model is therefore more appropriate. We discuss alternative modelling approaches in more detail in Appendix VI.

The main inputs to the BAM model are: a list of installed plant in each country, and details such as the capacity of the plant, fuel type, thermal efficiency *etc.*; the cost of the fuels used to generate electricity; demand in each country; and the capacity of interconnection between countries. For details of installed plant, we have used a variety of public and private sources. We derive fuel costs from purchased data from Platt's Argus and other reputable data sources. We use historical demand data either from TSO websites or data published by UCTE. To forecast future demand, we use demand-growth rates from TSOs. We derive current interconnector capacity from ETSO, and update to account for announced interconnector capacity increases as

appropriate. Appendix III contains tables summarising the input values we have used in our modelling.

In essence, BAM calculates the marginal cost of generating electricity for each plant by reference to the assumed fuel and carbon prices and the technical efficiency of the plant (BAM also includes an amount for other variable costs like maintenance, but the vast majority of variable costs are due to fuel and carbon permits). For nuclear plant we use a marginal cost based on the approximate variable cost of fuel re-processing, and we use a small (approximately 1 €/MWh) variable cost for wind turbines to reflect variable maintenance costs. Note that wind and distributed generation (like combined heat and power plant or CHP) do not set the price, since there are always higher marginal-cost plant required to meet demand. However, wind and CHP do influence the price in the model, by reducing the need for more expensive plant. For example, every MWh served by wind power reduces the need for a MWh to be served by the most expensive marginal plant.

As a result of these calculations, BAM has a merit order for each country *i.e.* it can calculate the marginal cost of electricity for any level of demand. Changes in assumed fuel prices will lead to changes in the marginal cost and merit order. Changes in assumed plant efficiency will also lead to changes in the marginal cost. Using the assumed level of demand and the merit order, BAM begins by calculating the price of electricity that would result in each country, without any imports or exports. Next, if the electricity price in country A is higher than in country B, then BAM will 'send' exports from country B to country A. BAM will continue this process, until either desired exports meets the maximum capacity of the interconnector, or prices between the two countries are equal. This is similar to the process which occurs under market coupling, where the market operator clears the coupled markets and allocates interconnector capacity until prices are equal or the interconnector is constrained.

BAM allows generators to offer power at a price above their marginal cost (*i.e.* at a mark-up). The appropriate level of mark-up is discussed in more detail below.

BAM can generate prices for every hour of a year, but to save computation time we generally use a characteristic weekday for each month. The main outputs of the BAM model are the prices in each country, the flows between countries, and the costs, revenues and profits of each plant. BAM also does not include start-up costs, since this would considerably increase the computational time of the model, without significantly increase the accuracy of the results.

BAM 'calibration' for 2005

We use our electricity market model (BAM) to perform SSNIP tests (which involve forecasting prices and generator profits) in 2008. To ensure that the results of the SSNIP tests are credible, we have ensured that our model can reliably re-create prices for 2005. This section describes the main choices and tests in this 'calibration' exercise.

Accordingly, one of the main tasks in calibrating the model is to set mark-ups which accurately re-produce historical prices in the Netherlands, and predict realistic levels of imports and exports. However, one expects generators to apply higher mark-ups when the demand-supply

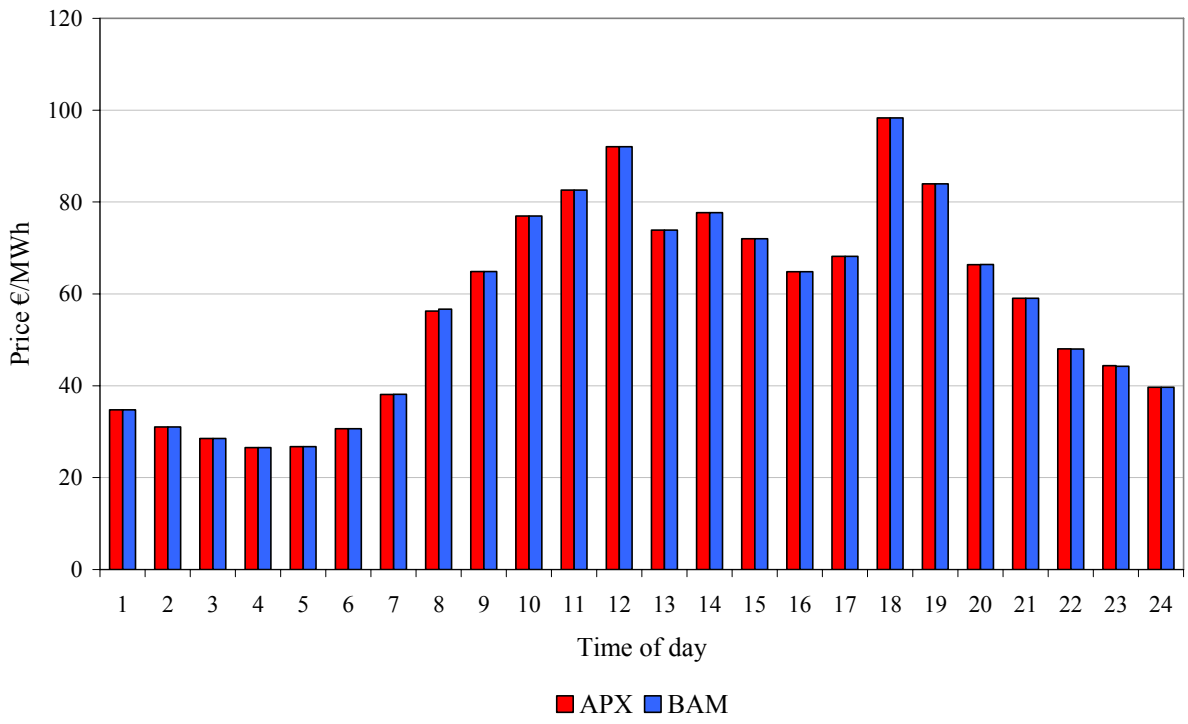
balance is tight. Therefore, a further test is that the mark-ups we use should increase as the reserve margin declines.[27]

To calibrate the model, we compare the marginal costs and prices produced by BAM to APX prices in 2005. However, because BAM assumes market coupling by default, but there was no market coupling in 2005 in the Netherlands, we remove BAM's market coupling assumption by fixing imports/exports to and from the Netherlands at historical 2005 levels. These historical imports are derived from UCTE data.

One of the key choices in the model is which gas prices to use for generators in north-west Europe: TTF prices; 'Gasunie' prices (*i.e.* oil-index gas prices that vary according to the old Gasunie Trade & Supply formula); or Zeebrugge prices. As explained on page 36 in section 4.2 we chose to use Zeebrugge gas prices mainly because these best explain the historical movements in the Dutch electricity price

To calibrate mark-ups, we follow an iterative process. We adjust mark-ups (*i.e.* set offer prices above marginal cost), run BAM to calculate prices, and compare these prices to observed APX prices. We then adjust the mark-ups to reduce the difference and repeat (an iterative process is required, since the change in mark-ups will cause marginal costs in each hour to change slightly). We stopped this process when the prices predicted by BAM match APX prices (Figure 22 illustrates that BAM prices almost exactly match APX prices at the end of the calibration exercise). Note that we carry out the same calibration exercise for all the countries surrounding the Netherlands.

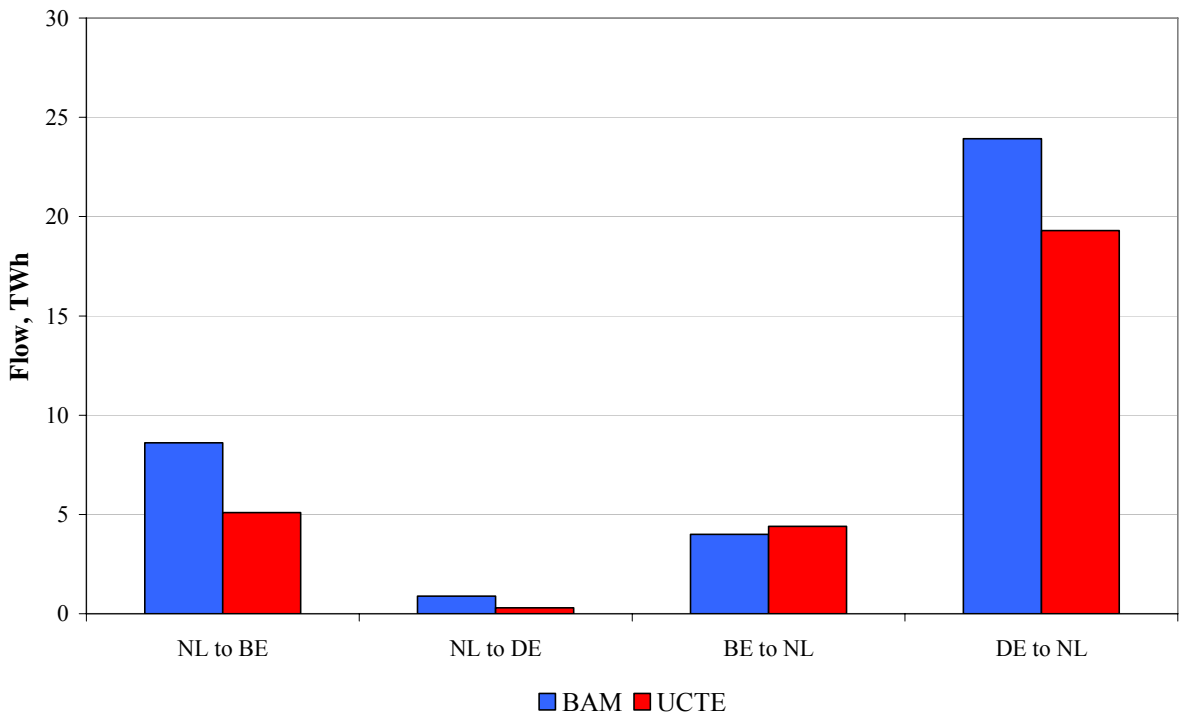
Figure 22: Comparison of APX hourly prices and prices produced by BAM, averaged over 2005



[27] We define the reserve margin as (available capacity minus demand)/demand.

The second calibration 'test' is that BAM produces realistic levels of imports and exports. Figure 23 illustrates that the levels of cross-border flows predicted by BAM match the UCTE physical flows reasonably well. Unfortunately, the two numbers are not directly comparable, as UCTE indicate that their numbers include 'loop' flows *i.e.* non-contractual physical flows, whereas BAM predicts contractual flows. This could account for the differences observed (in particular loop flows from FR to DE via BE and NL would explain lower physical than contractual flows from NL to BE and from DE to NL, consistent with Figure 23). Nevertheless, Figure 23 gives some confidence that BAM is predicting realistic levels of cross-border flows for 2005, and hence congestion forecasts should be accurate.

Figure 23: Comparison of 2005 cross-border flows predicted by BAM and reported by UCTE



Finally, we check that the mark-ups used to match APX prices and predict cross-border flows are reasonable *i.e.* that mark-ups increase as the reserve margin decreases. As we do not have reliable data on the level of plant availability throughout the year, we use demand as a proxy for the reserve margin.[28] Figure 24 shows the average mark-ups for each hour plotted against average hourly demand. The mark-ups we use exhibit most of the properties one would expect. They are negative at off-peak hours, (this is because some Dutch generators are prepared to operate at a loss during off-peak hours to avoid start-up costs), and increase with demand.

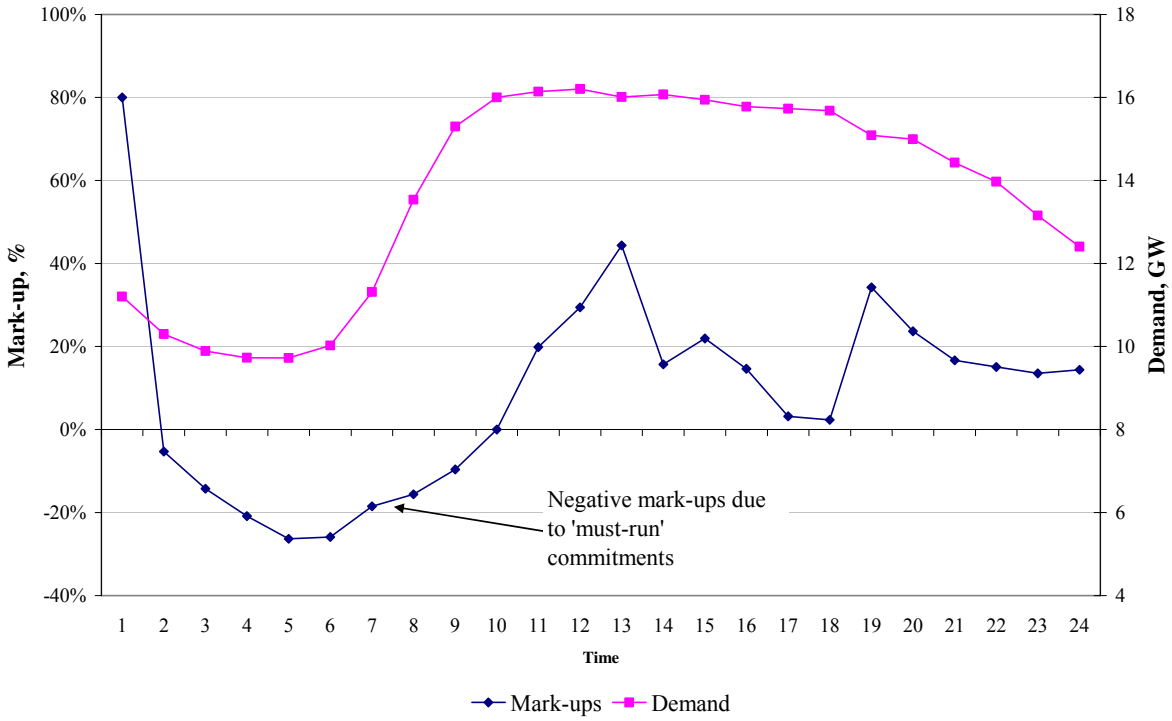
The average mark-up we use is 4.6%. This is very close the level of mark-ups that DTe found (3.4% to 4.9%, depending on whether APX or OTC prices were used) in its recent market

[28] We note that even if we had availability data for Dutch plant, and so were able to calculate a Dutch reserve margin, this still leaves the problem of foreign plant outages. For example, the failure of several plants in Belgium could cause a large increase in demand for Dutch generation and higher mark-ups, which would not correlate with the Dutch reserve margin.

monitoring exercise.[29] The mark-ups we use are significantly less than those calculated in an earlier study commissioned by DTe, which found mark-ups of 16% to 28% during 2004.[30]

Note that lower mark-ups are in some ways similar to using lower gas prices – they will lead to less congestion on the interconnectors (since prices will be closer to German and Belgian prices) and leave more room for imports. This will make prices rises less profitable, and make it more likely that the Netherlands does *not* define a market for a given product. In other words, low mark-ups are more likely to lead to a larger geographic market definition. If the Netherlands defines a separate geographic market with relatively low mark-ups, it will definitely define a separate market with higher mark-ups.

Figure 24: Mark-ups as a percentage of marginal cost vs. Dutch demand



In sum, the BAM model reproduces 2005 prices and cross-border flows, using mark-ups that have a sensible relationship with demand. Therefore, we expect the BAM model to be able to give accurate predictions of prices and generator profits in 2008.

Main assumptions for modelling 2008

Table 5 summarises the main input assumptions of our model for 2008, and how these relate to conditions in 2005. We have included all the main factors that could affect market definition in 2008. Appendix III gives more detail on the inputs used in our modelling, and we discuss interconnector capacity in more detail below. Note that with respect to the import capacity, we

[29] DTe Market Monitor: Development of the Electricity Wholesale Market 2004 – 2005 Results and Recommendations The Hague, July 2005, Table 2-3 p.38.

[30] *Ibid*. §2.4.3 p.37.

assume that the capacity currently set aside for the so-called SEP legacy contracts is, by 2008, available to the rest of the market.[31]

Table 5: Changes in the main input parameters for market definition between 2005 and 2008

Interconnection		2005	2008	Change, %
Capacity available, BE+DE to NL, GW		3.6	3.6	
NorNed capacity, GW		-	0.7	
Total interconnection capacity, GW		3.6	4.3	19%
Dutch Demand				
Peak demand, GW		18.4	19.6	6%
Energy demand, TWh		112.5	119.5	6%
Installed 2008 capacity, GW				
	Wind	1.4	1.8	
	Coal	4.3	4.3	
	Gas	14.9	14.7	
	Ind gas	0.0	0.3	
	Nuc	0.4	0.4	
Total installed capacity, GW		21.1	21.7	3%
Average gas price, €/MWh		19.4	17.3	-11%

Countries are the relevant building blocks for geographic markets in NW Europe

At present, wholesale electricity prices do not vary *within* the countries that we examine (principally the Netherlands, Belgium, France, Germany and the relevant part of Norway). In other words, there is only one price for wholesale electricity in the Netherlands. Of course, the price of delivered electricity may differ within a country, because the price includes transmission and distribution costs. But the product we are interested in – wholesale electricity – does not vary with location. Accordingly, it is logical to take a country as a starting point for a geographic market definition exercise.

In contrast, some countries (for example the USA and Denmark) have electricity markets where wholesale prices differ within the country, because of significant (and un-socialised) internal transmission constraints. Accordingly, in such markets it would be possible to define a geographic market for electricity that is relatively small. If such markets were ever introduced into countries that could form a geographic market with the Netherlands, then the SSNIP test would have to take this into account.

[31] In the 'Report on monitoring reliability of supply, 2004 – 2012' 29 April 2005 Tennet show the SEP contracts ending in 2009. However, rather than model the SEP contracts in 2008 we prefer to better represent the longer-term situation by allocating the SEP capacity to the market already in 2008.

Elasticity of demand

Although consumers in the Netherlands will substitute Dutch electricity for imported electricity, as the price of the former rise, our model assumes that consumers' demand for all electricity (*i.e.* both imported electricity and electricity produced in the Netherlands) is fixed in the short term. In reality, we recognise that if the price of electricity goes up, people will buy less of it (*i.e.* demand is elastic). Therefore in carrying out the SSNIP test we make an adjustment to the results of the model, to allow for the reduction in demand for all electricity that would result from price rises. For example, if our model predicts that a price increase of 5% would result in monopoly profits of €1000 million, and that total demand for electricity would fall by y% for every 1% increase in the price, we reduce the calculated profits by $5 \times y$%. In our results, we always report profits adjusted for the reduction in total demand that would occur as a result of the price rise. Appendix IV discusses the assumed elasticity of demand in more detail, and demonstrates that none of our main conclusions change using the range of elasticity assumptions found in the economic literature.

Interconnector assumptions

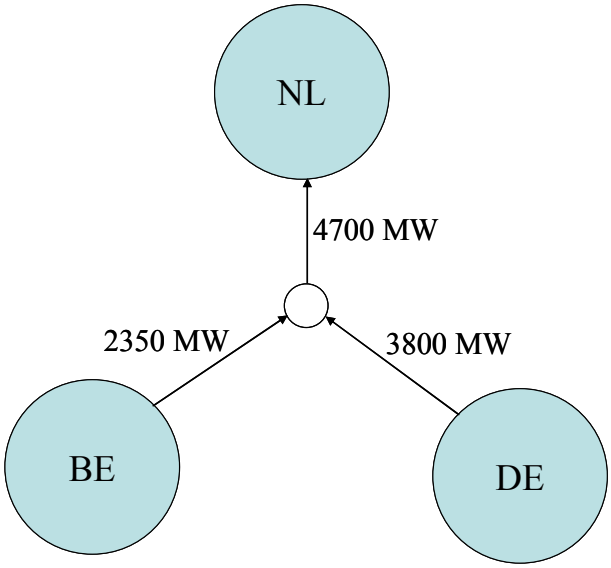
Because price increases in a country are mainly defeated by imports,[32] assumptions regarding interconnector capacity are crucial to the results of any SSNIP tests. The association of European Transmission System Operators (ETSO) publishes information on interconnector capacity, including the various definitions of interconnector capacity. Hence, we use the ETSO-published interconnector capacities as our starting point, specifically the Net Transfer Capacities (NTC), which is the total interconnector capacity less a margin to cope with emergency exchanges.

Unfortunately, the modelling of interconnector capacity between the Netherlands and neighbouring countries is complicated by two factors. First, Belgium and Germany face a common export constraint which is less than the sum of their individual interconnections. Figure 25 illustrates that while the sum of German and Belgian NTC to the Netherlands is 6,150 MW, the two countries have a maximum NTC to the Netherlands of 4,700 MW. Accordingly, increasing *e.g.* the interconnector capacity on the Dutch Belgium border by 300 MW might increase the capacity of the 4,700 MW common constraint by less than 300 MW. Only highly qualified and well-informed electrical engineers can determine the relationship between expanding capacity on a specific border and the effect on the common interconnector constraint.[33]

[32] When we say imports 'defeat' a price rise, we mean that it is no longer profitable to increase prices by between 5-10%. Note that imports are able to respond even to short-term price changes, since while much interconnector capacity is sold up to a year in advance, flows are not nominated until often one day before despatch.

[33] For more detail in the interdependency of NTC values, see the ETSO publication 'Definitions of Transfer capacities in liberalised markets' April 2001.

Figure 25: 2005 ETSO Net Transfer Capacities to the Netherlands



Second, because of differences in pattern of flows anticipated when the ETSO NTC values were calculated, and actual flow patterns, *there is a difference between the published ETSO NTC values and the capacity that is made available to the market*.[34] We base our interconnector capacity assumptions on a 2005 document published by Tennet.[35] While the interconnector capacity available to the market (via auctions) varies over the year due to changes in the predictability of loop flows, Tennet has previously estimated that on average 3,600 MW of capacity from Belgium and Germany to the Netherlands will be available to the market in 2008. Since starting this study, Tennet has increased its estimate of available import capacity available from Germany and Belgium to about 4,200 MW (although the amount varies according to the assumptions Tennet makes).[36] This means that our assumption of 3,600 MW of capacity from Germany and Belgium will slightly over-estimate the profitability of prices increases in the Netherlands, since it now seems likely that more imports would be possible than we assume. However, later in this report we investigate the consequences of up to 9,000 MW of interconnector capacity being available from Germany and Belgium; we conclude that increasing the level of interconnector capacity from our base case assumption of 3,600 MW to 4,200 MW would not be sufficient to expand the relevant geographic market beyond the Netherlands. Accordingly, our base case assumption does not lead to an erroneous conclusion. We also include 700 MW of interconnection from Norway to the Netherlands (the Norned cable) in our model.[37]

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[34] See *Ibid*. §4.1 for more details of why NTC values differ form the capacity made available to the market.

[35] Tennet, 'Report on monitoring reliability of supply, 2004 – 2012' 29 April 2005.

[36] 'Kwaliteits en Capaciteitsplan 2006-2012' Tennet.

[37] We note that there is the potential for additional capacity on the Dutch-German border (although increased wind generation in Germany may reduce the potential of this capacity to be used for cross-border trading). Hence, the assumption of 3,600 MW may slightly underestimate 2009 interconnector capacity. However, we address this possibility by investigating the consequences of much larger NTCs later in this report.

5.2 SSNIP Modelling results

Significant price differences between peak and off-peak prices in the Netherlands indicate that the peak market may be a separate product market. Therefore, we have modelled increased peak prices for a hypothetical Dutch monopolist in 2008, and calculated the change in profits which result. Figure 26 illustrates that a hypothetical Dutch monopolist could profitably increase peak prices by between 5-10%. Accordingly, (under the relevant assumptions) **the SSNIP test implies that for the purposes of merger control the Netherlands defines a separate geographic market for peak wholesale electricity in 2008.**[38]

Figure 26: SSNIP test for a Dutch peak market, 2008

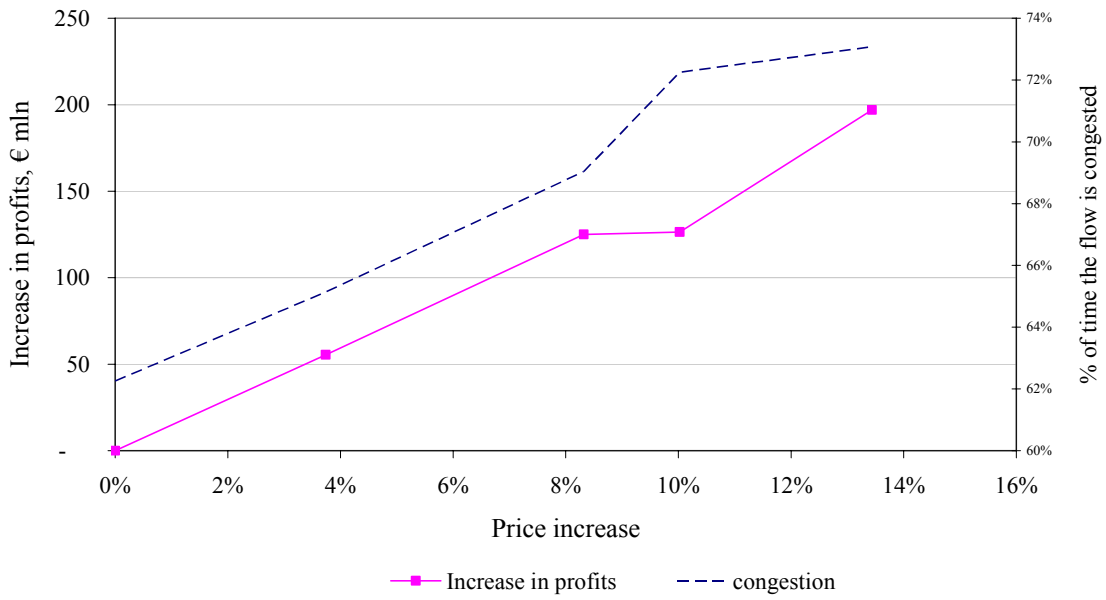


Figure 26 also illustrates that the interconnector is congested for about 60% of peak hours before any price rises, and the interconnectors are congested for over 70% of peak hours as the hypothetical monopolist raises prices by over 10%. When the interconnector is congested, the main restraint on a hypothetical monopolist with respect to increasing prices is the demand response (*i.e.* the ability of consumers to switch consumption to other, non-congested hours) and the threat of regulatory intervention. However, the question of which peak hours are substitutes for one another is beyond the current scope of this work, and so we are unable to say whether a

[38] Our model predicts the percentage of time that interconnectors will be congested, for a range of prices. The predicted congestion will differ from congestion numbers presented in the European Commission's Draft sectoral inquiry report ('Preliminary Report - Sector Inquiry under Art 17 Regulation 1/2003 on the gas and electricity markets', February 16 2006) because a) our congestion numbers are for 2008, whereas the Commission's numbers are for 2004 and b) we define an interconnector as congested if no more power can flow over the interconnector, whereas the Commission measures congestion according to traders willingness to pay for interconnector capacity. Under Commission definition, an interconnector can (and often is) simultaneously congested in both directions, which is impossible under physical definition. The two measure may differ, because traders might pay for interconnector capacity (causing congestion under the Commission's measure) but then not fully use it (meaning the interconnector is not congested according to our measure) Note the use-it-or-lose rules do not address this problem completely, since there is no mechanisms to 'lose' unused daily capacity.

hypothetical monopolist would be able to profitably increase prices during a specific hour when the interconnector is congested.

The off-peak Dutch market

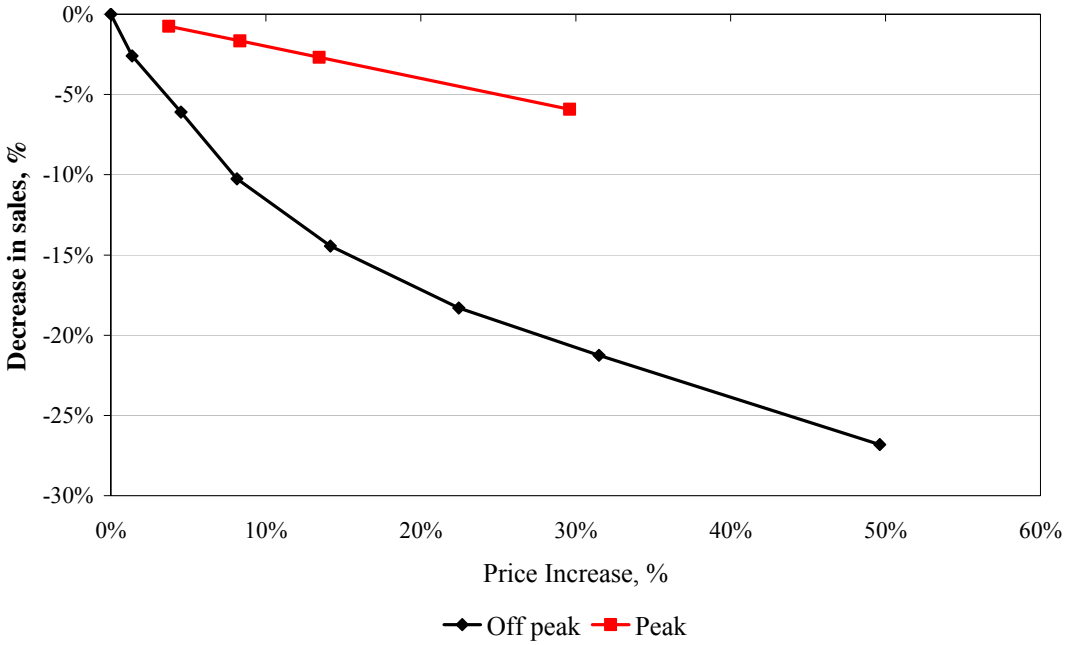
Section 4 demonstrated that, in 2005, prices between the Netherlands and neighbouring countries are rather similar during off-peak hours, indicating a lack of congestion and the scope for more imports. Our model also predicts that the interconnector is congested for only 32% of the time during off-peak hours, compared to congestion 62% of the time for peak hours. This suggests that the Netherlands may not define a separate market for off-peak wholesale electricity.

Performing a SSNIP test on the off-peak market is complicated, because our model indicates that Dutch generators are actually charging less than their marginal cost for electricity during most off-peak hours (see Figure 24). That is, if profit is measured simply as electricity revenue less marginal cost, generators are actually making a loss during off-peak hours. This behaviour is nevertheless rational; by continuing to run even at prices that are below marginal cost, generators avoid the expense of closing down and starting up again. They would lose more money if they shut down plant overnight and started it up again in the morning.

If a hypothetical Dutch monopolist were to raise off-peak Dutch prices, it would lose sales volumes quite rapidly. However, since the monopolist is making a loss on off-peak sales, losing sales volumes actually increases its profits. Hence, our model predicts that profits appear to increase as the monopolist raises prices. However, this conclusion is misleading. As the Dutch monopolist lost off-peak sales volumes, it would be forced to shutdown plant and incur start-up costs. Assuming that the monopolist was minimising its costs before the price increases, the loss of sales must cause the monopolist's costs to increase. However, modelling the increase in costs caused by additional start-up costs is difficult, as they occur in a 'lumpy' fashion, once a plant is forced to run at below its minimum load. While we can say that the loss in sales will increase the monopolist's costs, we cannot say by how much. Accordingly, we cannot predict if the price increases would more than offset the increase in costs, making off-peak price increases profitable.

A better test of market definition for the off-peak market may be the change in sales volumes as a function of the increase in price. Figure 27 illustrates that off-peak sales decline far more significantly than declines in peak sales for the same price rise. This is because off-peak imports have the ability to increase substantially in response to Dutch off-peak price increases, which indicates that increasing off-peak Dutch prices is unlikely to be profitable.

Figure 27: Decline in sales as a function of price increases for the Dutch peak and off-peak markets



The empirical evidence detailed in section 4, combined with the results of our modelling, suggests that the Netherlands does *not* define a geographic market for off-peak electricity for the purposes of merger control. Price differences between the Netherlands and its neighbours are generally small during off-peak hours; and interconnectors from the Netherlands are not heavily congested during off-peak hours, so that any attempt to raise Dutch off-peak prices would attract a large increase in imports.

We calculate that 85% of the extra imports that an increase in off-peak Dutch prices would cause come from Germany. Accordingly, Germany would be the most logical country to add to the Netherlands to test for a separate geographic market. In practise, such a test would still face the difficulties we have seen in the Dutch off-peak SSNIP test of including hard-to-measure-start-up costs.

However, we can still conclude that:

- It is likely that the geographic scope of the off-peak wholesale market for the purposes of merger control is at least as large as Germany and the Netherlands i.e. it is significantly larger than the peak market. This implies that analysis of the effects of a Dutch merger would tend to be focused on peak hours (since the off-peak market is larger and hence more competitive).
- There seems little scope for the exercise of market power in off-peak hours; mark-ups in off-peak hours appear to be negative, indicating over-capacity and an absence of market power.
- We also note that our model predicts that, following the construction of the NorNed cable, Dutch generators will be exporting to Nordpool during off-peak hours. In

effect, NorNed will increase off-peak demand, meaning that generators will not have to reduce output as much as at present during off-peak hours. Therefore, the NorNed cable is likely to increase off-peak power prices and mark-ups. However, given that the planned size of the NorNed cable is less than 10% of even off-peak demand, this effect is unlikely to be very significant.

- Qualitatively, the NorNed cable will also make the exercise of market power in the off-peak market more profitable, since (with NorNed) a hypothetical monopolist will have more room to turn down plant without incurring start-ups costs than without NorNed.

6 Factors that could expand the wholesale market

The SSNIP tests in the previous section indicated that the Netherlands defines the geographic market for peak power, but the off-peak market is probably larger than the Netherlands. In this section we investigate factors which could expand the peak market beyond the Netherlands. Specifically we investigate the combinations of fuel prices that would be required to expand the peak market, and the additional interconnector capacity required to do the same. All calculations assume market coupling is already in place. As explained later, the introduction of market coupling will tend to expand the relevant geographic market relative to the use of an explicit auction mechanism.

Having found the factors that would expand the peak market beyond the Netherlands, we go on to investigate the geographic extent of the 'expanded' peak market. In addition, we investigate the additional interconnector capacity that would be required to expand the market for a 'super-peak' product beyond the Netherlands. Finally, we discuss the effect on geographic market definition of market coupling and of a mechanism to create a single price area without increasing interconnector capacity. All cases assume that the Norned cable will be introduced in 2007.

Peak market sensitivity – gas prices

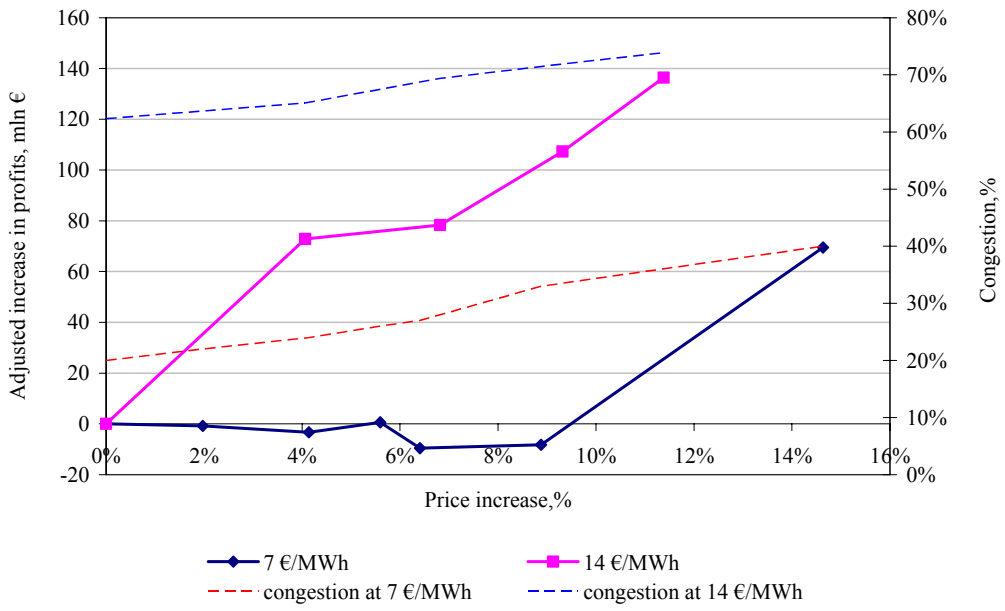
The Netherlands has a high proportion of gas-fired plant, relative to Germany which has more coal-fired plant. Accordingly, changes in the gas price affect Dutch electricity prices more than prices in Germany (Belgian prices are somewhat between Dutch and German prices in terms of their sensitivity to gas prices). Our base case assumes a gas price of around €17/MWh. That compares to a Zeebrugge gas price today of about €28/MWh, and a Zeebrugge forward gas price for winter 2007 of approx. €33/MWh.[39] A higher gas price would make Dutch electricity even more expensive than German prices in the base case, and increase congestion further on the Dutch German and Dutch-Belgian borders. Increased congestion would leave less room for imports that could defeat a Dutch price rise. With a higher than €17/MWh gas price, Dutch price increases would be even more profitable than in the base case. The Netherlands would remain a separate market for peak wholesale electricity. Hence, our assumption of a gas price of €17/MWh is conservative, in that it is likely to result in a larger geographic market for peak power than the Netherlands.

While low by current gas prices, our base-case gas price is relatively high by recent historical standards, and may be above the long-run average price of European gas. For example, we estimate that between January 1999 and April 2000 the average price of gas in the US (Henry hub) was less than €7/MWh. Lower gas prices would reduce Dutch electricity prices relative to Germany and Belgium, reduce interconnector constraints and leave more scope for imports that could render any Dutch price increases unprofitable. To test this theory, we have performed a SSNIP test for the Netherlands for average gas prices of €14/MWh and €7/MWh. Figure 28 illustrates that reducing gas prices to around €7/MWh reduces interconnector congestion into the Netherlands significantly; with €14/MWh gas the interconnector is congested for around 60% of peak hours, but congestion falls to about 25% with €7/MWh (€2/MMBtu) gas. As a result, with

[39] Taken from Platts European Natural Gas report, 10 March 2006,

gas at €7/MWh, smaller prices increases are unprofitable, because they attract imports and the monopolist loses market share. However, even with very low gas prices, prices increases above 10% are profitable, and the Netherlands defines a separate market. It would require gas prices even lower than €7/MWh to expand the Dutch peak market. As such low prices seem implausible, we conclude that it is not feasible that changes in input prices could expand the peak market beyond the Netherlands.

Figure 28: SSNIP test for the Dutch peak market for lower gas prices

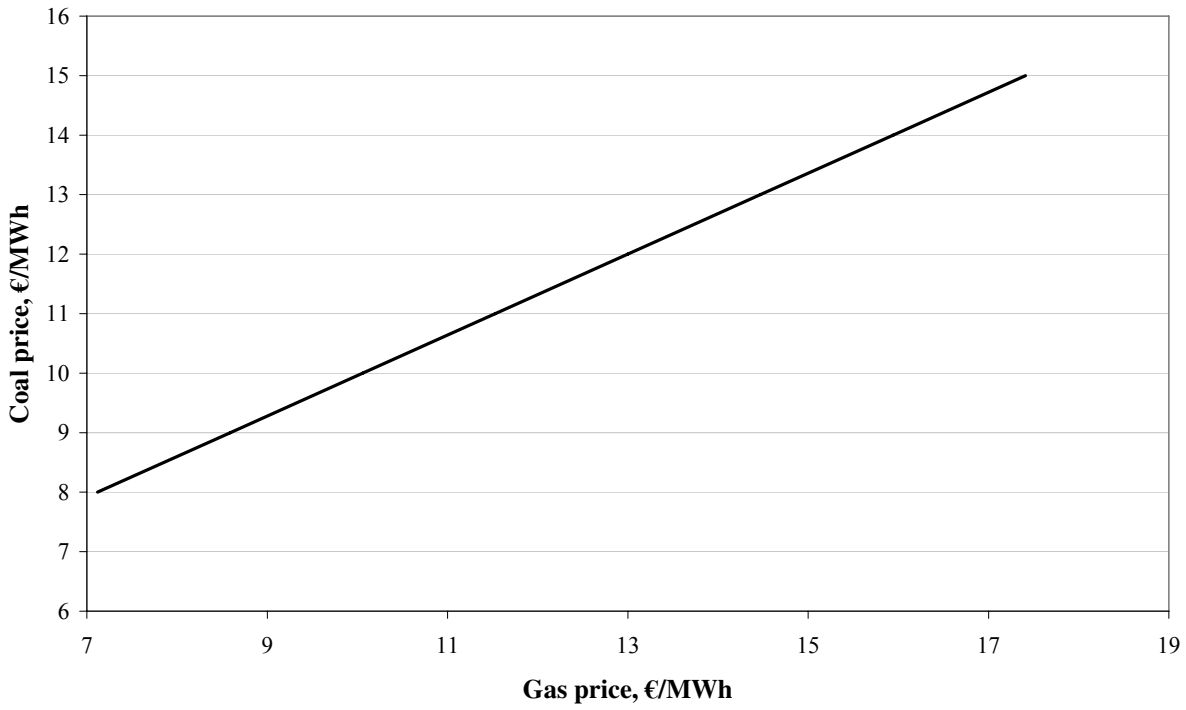


While our sensitivity is for lower gas prices, what is important is the relative price of the fuels used by price-setting plant in the Netherlands, Belgium and Germany – in practise gas and coal. Hence, our sensitivity for low gas prices could equally be read as a sensitivity on relatively high coal prices, or a high carbon price (which would make coal-fired plant more expensive relative to gas-fired plant). Either high coal prices or high carbon prices could potentially expand the peak market beyond the Netherlands.

For example, Figure 29 shows the combinations of gas and coal prices that would give approximately the same price difference between Dutch and German electricity as a 7 €/MWh gas price, our base-case coal price of 8 €/MWh and a carbon price of 28 €/tonneCO2. Figure 29 illustrates that at a gas price of 17 €/MWh, coal prices would have to increase to more than 15 €/MWh to expand the peak market beyond the Netherlands. Similarly, Figure 30 illustrates the combinations of gas and carbon prices that would give approximately the same price difference between Dutch and German electricity as the 7 €/MWh scenario in Figure 28 above. For example,

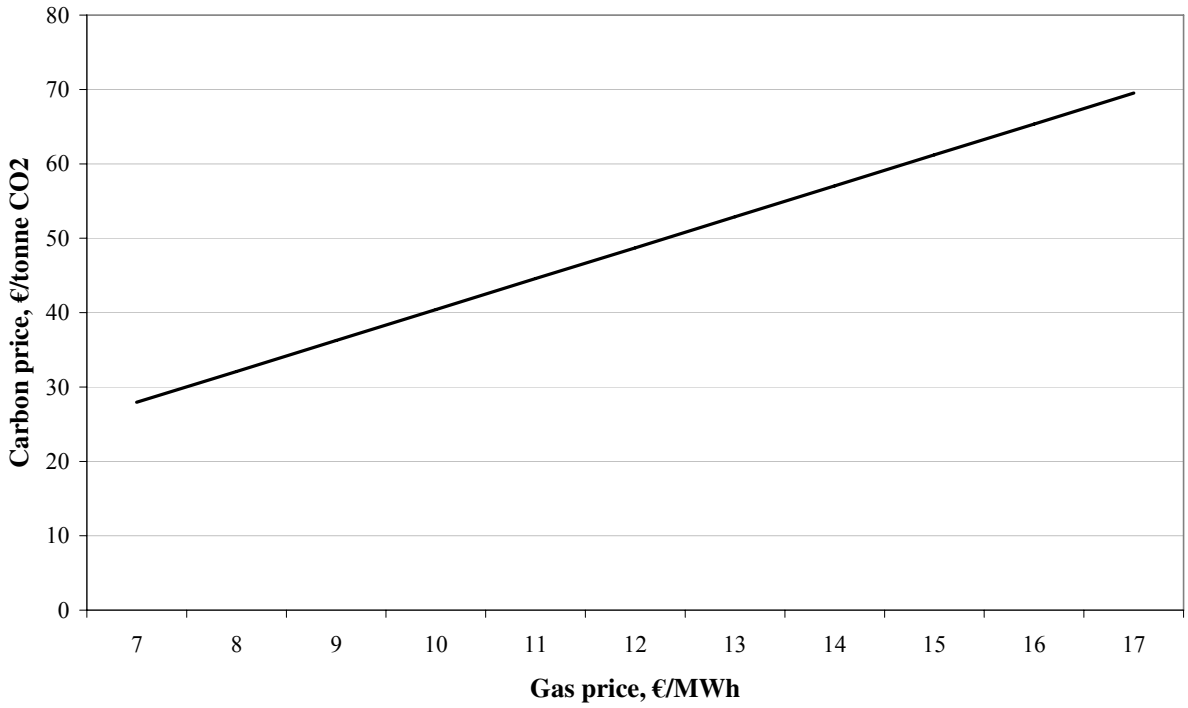
with a gas price of 17 €/MWh, carbon prices would have to reach over 70 €/tonneCO2 to expand the market beyond the Netherlands.[40]

Figure 29: Combinations of gas and coal prices that give the same price difference as 7 €/MW gas and 8 €/MWh coal for a carbon price of 28 €/tonneCO2



[40] In reality, the prices of coal, gas and carbon are interrelated, so that it is unlikely that e.g. the price of coal and gas would vary while the price of carbon remains constant. Nevertheless, holding one of the three prices constant allows the plotting of a two dimensional graph.

Figure 30: Combinations of gas and carbon prices that give the same price difference as 7 €/MW gas and 28 €/tonne CO2 for a coal price of 8 €/MWh



6.1 Expanding interconnector capacity

Increasing the capacity of the interconnectors would allow more imports, and eventually render peak-price increases unprofitable. We have repeated the SSNIP test for the peak Dutch market, for a range of higher capacities of the common Belgian-German export constraint to the Netherlands (see Figure 25 for an illustration on the interconnector constraints).

Figure 31: Peak market SSNIP test for a range of interconnector capacities between the Netherlands and Germany/Belgium

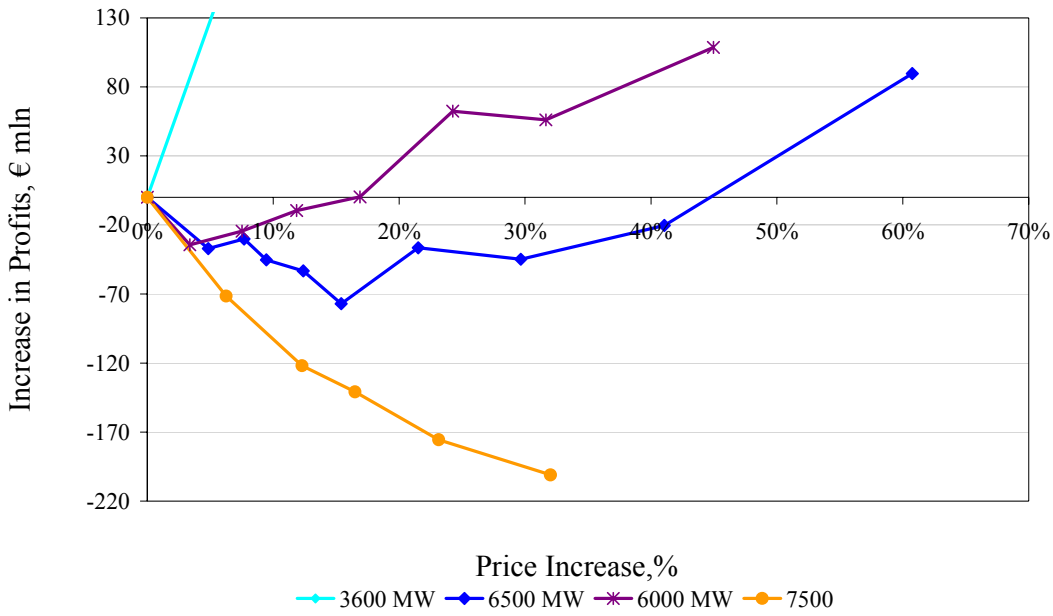


Figure 31 illustrates that for an interconnector capacity from Germany/Belgium to the Netherlands of around 3,600 MW, price increases of between 5-10% are profitable. Increasing the interconnector capacity to 6,000 MW means that price increases in 5-10% range become unprofitable.

However, Figure 31 raises an interesting issue regarding the application of the SSNIP test, since it shows that with 6,000 MW of capacity, price increases above about 17% are profitable. Similarly, for an interconnector capacity of 6,500 MW price rises of about 45% are required for the hypothetical monopolist to increase profits. The 'standard' SSNIP test specifies that price rises of 5-10% should be profitable for the area to define a geographic market. Therefore, following the 'standard' SSNIP reasoning 6,000 MW would be sufficient to expand the market, since price rises of between 5-10% are not profitable with this level of interconnection. The SSNIP test does not explicitly specify whether the price rise should fall within the 5 - 10% range or must be of a magnitude at least 5-10%. In many product markets, if a price increase of between 5-10% is unprofitable, then higher price rises are even less profitable. This is presumably the logic behind a specific 5-10% price increase in the SSNIP test. The assumption is if price increases are unprofitable, it is because customers buy less of the product at a 5-10% price increase, and they would buy even less of the product at higher price increases.

Electricity is different to many standard products. The main loss of the monopolist's sales comes not from consumers buying less electricity (Appendix IV discusses that electricity demand is relatively insensitive to the price), but from losing sales to foreign competition. Moreover, there are very definite limits on the amount of capacity that foreign competitors can import, and these limits are not easily or quickly expanded. Once foreign competitors are importing at the

maximum rate (*i.e.* interconnectors are constrained), the domestic monopolist can increase prices with relatively minor reductions in sales, and price increases will be profitable. Accordingly, even if price increases of 5-10% are not profitable, some higher level of price increase will be.

Anti-trust experts in the US have addressed this issue. For example, Law Professor Herbert Hovenkamp states that "[i]t would be anomalous to draw a market in such a fashion that a 10% price increase were unprofitable but a price increase by some greater amount were profitable. So the relevant question is whether the profit-maximising price increase would be 10% *or more*." (emphasis in original text)[41]

Accordingly, as some level of price rise will always be profitable for a firm with a hypothetical monopoly over generation, it seems reasonable to say that an area defines a geographic market if a hypothetical monopolist can sustainably and profitably raise prices by an amount that is unlikely to provoke *ex-post* regulatory intervention in the three year time horizon typical for merger decisions. Given the volatility of prices, and more importantly mark-ups in the Dutch electricity market, increases in the mark-ups due to the exercise of market power could be difficult to spot in the midst of all the other 'noise'. For example, we calculate that margins (*i.e.* price minus marginal cost, including carbon cost, divided by cost) in the Netherlands varied from -32% to over 112% over the two years 2004 and 2005.[42] Given this variability in margins, even sustained price rises might be difficult to detect.

One study indicates that margins between 27% and 39% were sustainable for at least four years in the old (pre-NETA) England & Wales electricity market (the pool).[43] While there will be a certain subjectivity as to what level of price rises are sustainable for a period of three or more years, it seem likely that price increases in the region of 17% could be possible for a period of several years.

Hence, even with an interconnector capacity of 6,000 MW, the Netherlands defines a geographic market for peak electricity because price rises of around 17% are profitable and quite possibly sustainable. Only if the price rises required to yield an increase in profit were so large as to be unsustainable without detection and censure would the market expand beyond the Netherlands. For example, Figure 31 illustrates that an interconnector capacity from Germany/Belgium to the Netherlands of 6,500 MW, the hypothetical monopolist would need to raise prices by about 45% to increase profits. It seems likely that such price rises would not be possible without attracting the attention of competition authorities. Accordingly, **interconnector capacity from Germany/Belgium to the Netherlands of 6,500 MW would expand the peak electricity market beyond the Netherlands**.

Note that this assumes the additional capacity is fully available. Significant reductions in its effective availability, due for example to maintenance or absence of market coupling, would

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[41] 'Federal Antitrust Policy' Herbert Hovenkamp, 2nd ed, West, 1999, Chapter 3, 'Market power and Market definition' §3.2 'Estimating the relevant market' pp. 84-86.

[42] -32.0% is the minimum and 112.57% the maximum 30-day average margin during the 2004-2005 period.

[43] Sweeting, A., Market Power in the England and Wales Wholesale Electricity Market 1995-2000, 2004.

mean that more than 6,500 MW of "nameplate" capacity was needed to achieve the required effect.

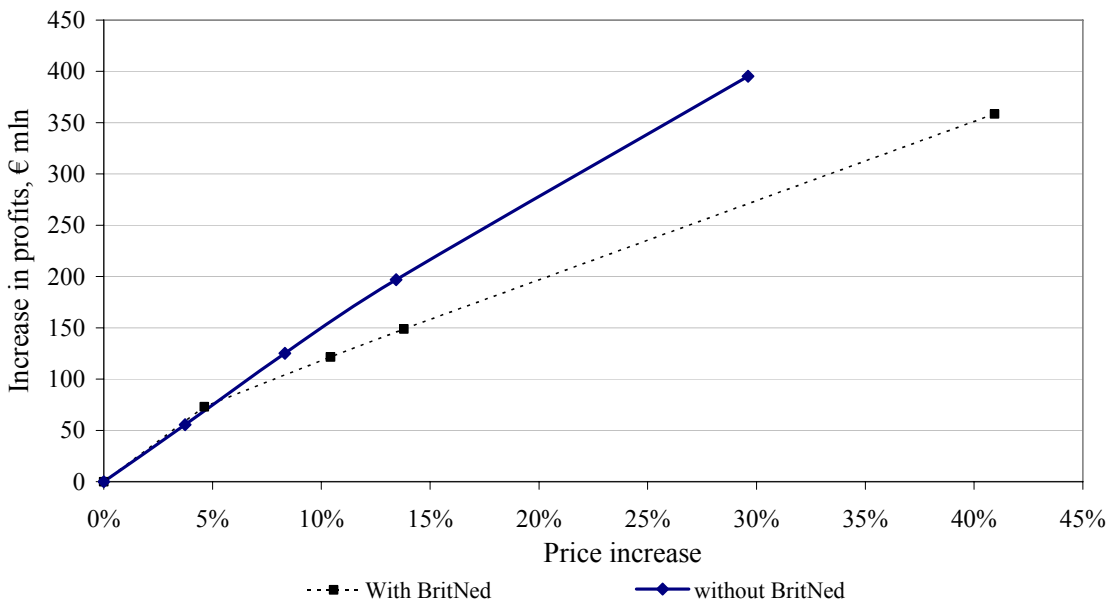
BritNed

While we think it is unlikely to be constructed, there is a possibility that a new interconnector will be installed between the Netherlands and Great Britain (the BritNed cable). The effect of BritNed on the definition of the Dutch peak electricity market depends on the relative price of electricity in the Britain and the Netherlands. If gas – and therefore peak electricity – prices in Britain are high, BritNed will export power from the Netherlands to the Britain. This will reduce the supply for Dutch consumers, and make it easier to profitably increase prices. Conversely low gas and electricity prices in Britain will increase the volumes of electricity that would arrive in the Netherlands if a hypothetical monopolist raised prices – the monopolist would lose more market share than without BritNed, and price rises would be less profitable.

Nationals Grid's latest seven year statement anticipates that the BritNed cable would (if built) reach 800 MW capacity by 2008/09 and in reality the date could be significantly later. There is therefore significant uncertainty as to what will be the relative level of gas and electricity prices in Britain and the Netherlands when the BritNed cable goes into service. In our analysis, we have modelled a case where peak electricity prices in Britain are lower than those in the Netherlands, so that BritNed is exporting heavily towards the Netherlands. Therefore, our SSNIP analysis represents the greatest effect that BritNed could have on restraining Dutch price rises, and increasing the geographic scope of the Dutch peak market.

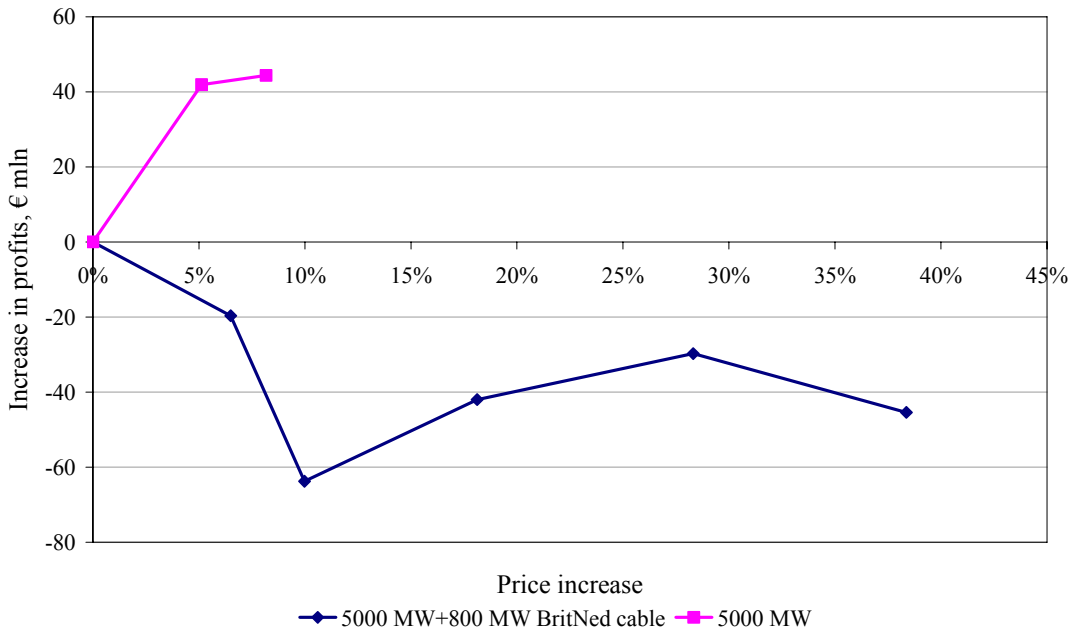
We have repeated the SSNIP test for the peak product market, including an 800 MW BritNed cable. Figure 32 illustrates that, while the increase in the profit of a hypothetical monopolist is lower with the BritNed cable, the cable does not expand the peak market beyond the Netherlands.

Figure 32: Peak market SSNIP test with and without the BritNed cable



We have also investigated the effect of an 800 MW BritNed cable on the interconnector capacity required to expand the market beyond the Netherlands, under the same assumptions as described above concerning relative prices in the UK and NL. Figure 33 illustrates that although price increases were profitable with 5,000 MW of interconnection between the Netherlands and Belgium/Germany *without* the BritNed cable, the BritNed cable makes the price rises unprofitable. Hence, with the BritNed cable, even 5,000 MW of interconnection would be sufficient to expand the Dutch market. This suggests that in this scenario (lower prices in the UK than in the NL) the UK is a strong source of competition for the Netherlands, since an increase of 800 MW of interconnection with the UK reduces the interconnection with Belgium/Germany required to expand the Dutch market by more than 800 MW. However the results are obviously highly dependent on the underlying assumptions, and again must be interpreted as an upper bound on the potential impact of BritNed.

Figure 33: Peak market SSNIP test for 5,000 MW interconnector capacity between the Netherlands and Germany/Belgium, with and without the BritNed cable

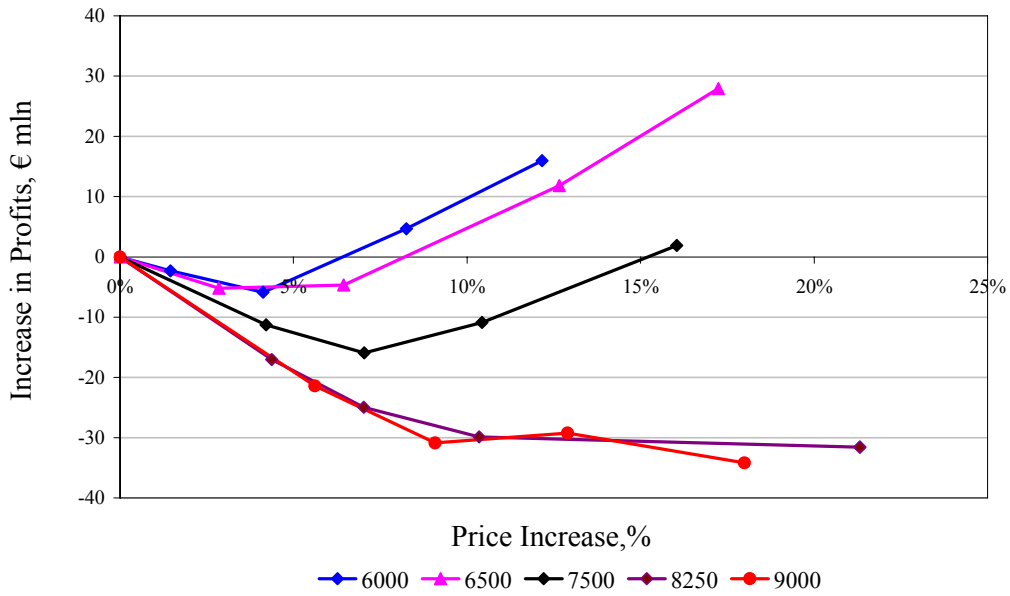


The geographic market for a 'super-peak' product

We have adopted the standard peak-product market definition of electricity supplied between 07:00 and 23:00 on weekdays. However, this definition of a peak product contains several hours in which electricity prices in the Netherlands are not especially high, and interconnectors are relatively un-congested. If one defined a separate, super-peak product, which contains only the hours of highest demand, it would be more profitable for a hypothetical monopolist to raise the price of this product than it would to raise the price of a peak product by the same percentage. Similarly, the TSOs would need to add even more interconnector capacity to expand a super-peak market beyond the Netherlands.

Figure 34 shows the results of a SSNIP test for our super-peak product (which we define as power consumed between 17:00 and 20:00 on weekdays), for a range of interconnector capacities between Germany/Belgium and the Netherlands. Although an interconnector capacity of 6,500 MW from Germany/Belgium to the Netherlands is sufficient to expand the peak market beyond the Netherlands (see Figure 31), a hypothetical monopolist could profitably raise the price of super-peak power with this level of interconnection (Figure 34 shows that price rises over 8% would be profitable for a monopolist with 6,500 MW of interconnection). The interconnector capacity from Germany/Belgium to the Netherlands would need to be around 8,250 MW to make price increases of a super-peak product unprofitable.

Figure 34: Super-peak market SSNIP test for a range of interconnector capacities between the Netherlands and Germany/Belgium



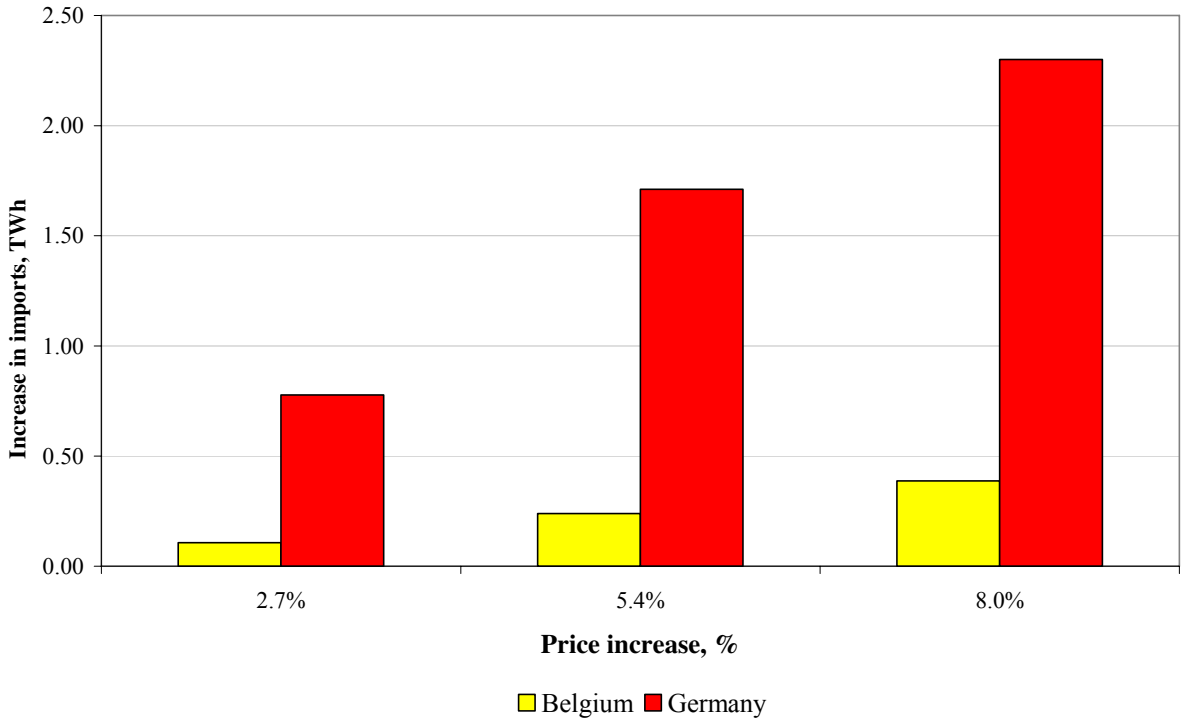
Dutch-Belgian SSNIP test

In the absence of a combined constraint as described in Figure 25, we would increase the interconnector capacity between the Netherlands and a neighbouring country, until imports from the neighbour are sufficient to defeat a price in the Netherlands. We would then add that country to the test geographic market, and perform another SSNIP test. However, in the presence of a combined constraint, we must add import capacity simultaneously to both Germany and Belgium. Consequently, when import capacity is eventually large enough to defeat Dutch peak price rises, it is not clear which of Belgian or Germany should be added to the test geographic market.

Figure 35 suggests that as most of the additional imports prompted by increases in Dutch peak prices come from Germany, then perhaps Germany is the logical country to add first to the test geographic market. However, if the increase in the combined Belgian/German flow constraint actually came from a physical increase in capacity on the Dutch-Belgian border it would seem

reasonable to add Belgium first to the test geographic market. In the absence of a compelling reason to first add either Belgium to the Netherlands or Germany to the Netherlands, we perform SSNIP tests for both a peak Dutch-German market and a peak Dutch-Belgian market.

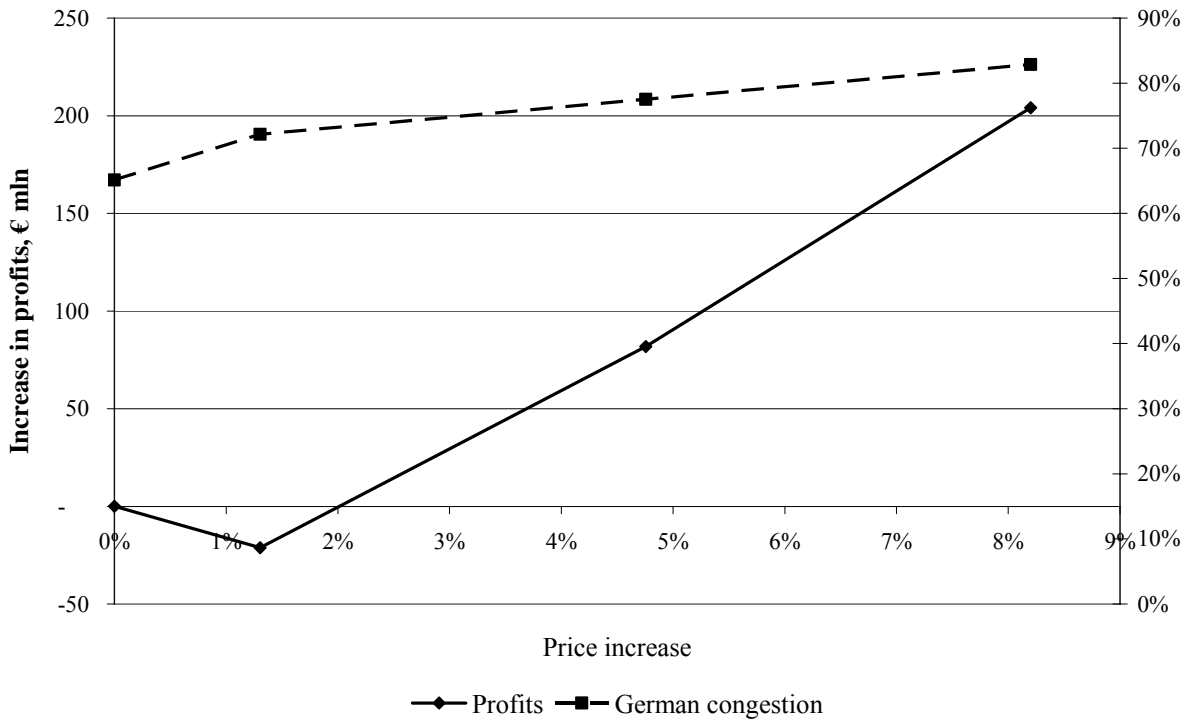
Figure 35: Increase in German and Belgian imports as a function of Dutch peak price increases



To perform a SSNIP test for the Netherlands and Belgium, we first expand the interconnector capacity between the two countries in the model, to ensure that prices in Belgium and the Netherlands are the same.[44] We then increase this price and measure the change in profits for a hypothetical Dutch-Belgian monopolist. Figure 36 illustrates that while a 1% price increase is unprofitable, increased constraints on the interconnectors from Germany and France make further price increases in the range of 5-10% profitable. Accordingly, if there was sufficient interconnection capacity between Belgium and the Netherlands, these two countries would then define a geographic market for peak electricity.

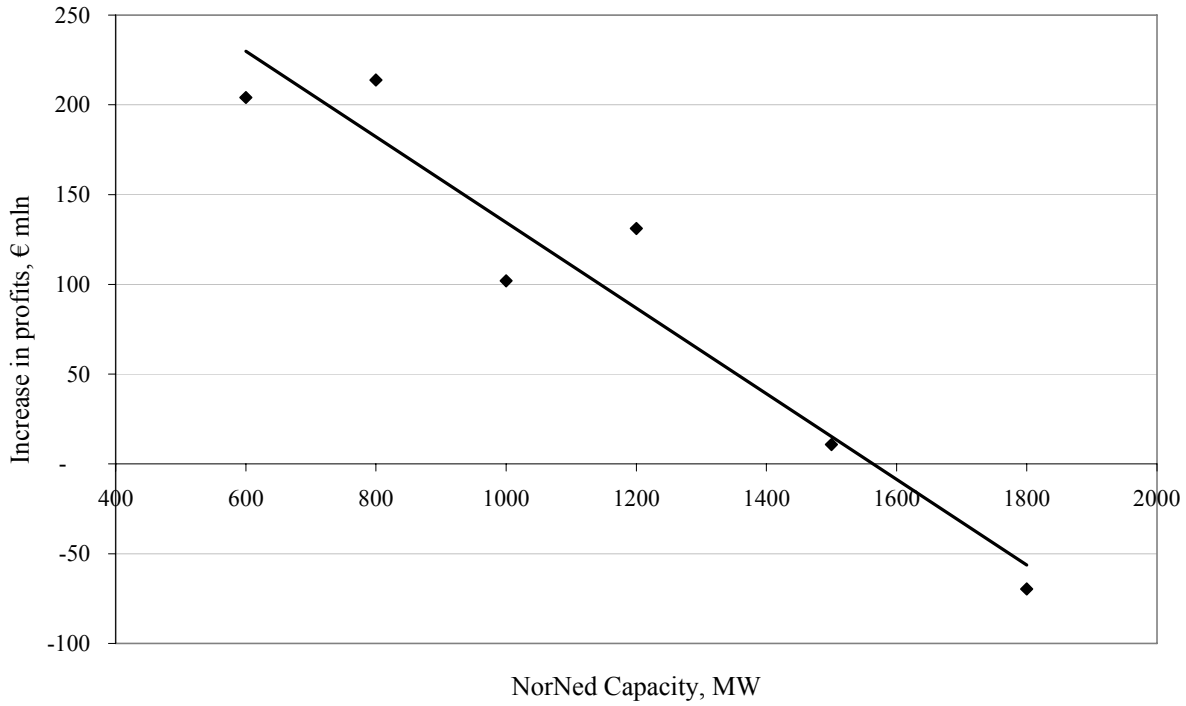
[44] As we explained earlier, although the published ETSO NTC between Germany/Belgium and the Netherlands is 4,700 MW, in practise only 3,600 MW is available. However, it is not clear how this reduction (from 4,700 MW to 3,600 MW) in NTC affects the individual interconnector capacities from Germany to the Netherlands and Belgium to the Netherlands. For example, the ETSO NTC from Germany to the Netherlands is 3,800 MW, but presumably less than 3,800 MW is available, since less than 4,700 MW is available for the combined German/Belgian flows. How much less is available is not clear. Accordingly, we assume that the full 3,800 MW is available from Germany to the Netherlands. As the Netherlands and Belgium define a peak market with this maximum level of NTC from Germany, they will certainly define a peak market with a lower NTC. Similarly, we assume an NTC from Belgium to the Netherlands of 2,400 MW when testing a German-Dutch peak market.

Figure 36: Peak market SSNIP test for the Netherlands and Belgium (assuming no NL-BE constraints)



We have also investigated how much additional capacity would be required from the NorNed cable, to make peak price rises unprofitable for a Dutch-Belgian market. Figure 37 shows that the NorNed cable would have to be expanded by about 1,000 MW (*i.e.* from 700 MW to 1,600 MW) for Norwegian plant to defeat peak price rises of between 7-9% in the Netherlands. However, this may still not be sufficient to expand the market, since higher price increases (*e.g.* 15%) may still be profitable and sustainable. Moreover, expanding the NorNed cable (after the first cable has been built) would be a very expensive undertaking, and it seems likely that expanding other (land-based) interconnectors would be more cost-effective (although an analysis of this issue lies outside the scope of this study).

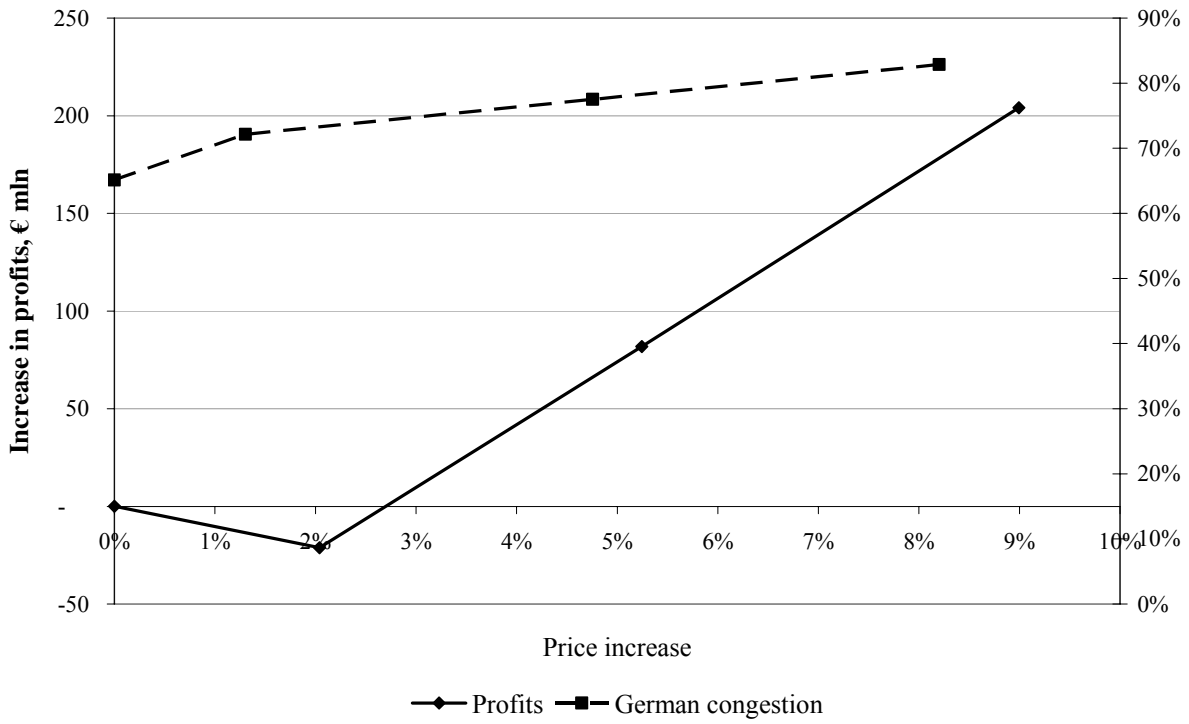
Figure 37: Increase in the profits of a hypothetical Dutch-Belgian monopolist for peak price rises of between 7-9% as a function of NorNed capacity



Dutch-German SSNIP test

Figure 38 illustrates that peak price rises of between 5-10% are profitable for a hypothetical Dutch-German monopolist, so that Germany and the Netherlands would define a geographic market for peak electricity.

Figure 38: Peak market SSNIP test for the Netherlands and Germany (assuming no NL-DE constraints)



Conclusions on geographic market modelling

Our results suggest that, with expected 2008 interconnector capacities, **the Netherlands defines a separate market for peak power for the purposes of market definition**. Increased interconnector capacity could expand the peak market beyond the Netherlands. The country that should be added to the test geographic market following interconnector expansion depends on which border interconnector expansion took place. If the Dutch-Belgian interconnector was expanded then, since Belgium would be the source of competing imports that defeated a Dutch price rise, it would make sense to expand the market by adding Belgium. Similarly, one would add Germany if the Dutch-German interconnectors were expanded.

Our results indicate that, with suitable interconnector expansion, either the Netherlands and Belgium or the Netherlands and Germany would define a separate market for peak power. However, the two market definitions would have quite different implications for mergers. A Dutch-German market would be sufficiently large that a merger of two Dutch players would have little effect on market concentration. A Dutch-Belgian market would place greater restrictions on mergers of Dutch market players.

6.2 The effect of market coupling

Market Definition

In 2005, the TSOs allocated interconnector capacity on the Dutch borders via an explicit auction. Traders must first buy interconnector capacity at the auction, and then they offer power on the market. In contrast our model (and most computer models that we are aware of) assumes an implicit auction or market coupling between the Netherlands and neighbouring countries. With market coupling, flows across interconnectors and market prices are determined at the same time.

Wholesale electricity prices in connected countries are the same if there are no constraints on the interconnector, and diverge when interconnectors become constrained.

We would expect flows and prices to be slightly different under the two different auction mechanisms, because market coupling is a more 'efficient' mechanism. For example, under an explicit auction, traders must buy interconnector capacity and nominate flows *before* they know what prices will be in the connected markets. This can result in sub-optimal flows *i.e.* flows from a high price area to a low price area in some hours. There could be 'un-arbitraged' price differences between countries, because even though traders see the price difference, it is too late for them to buy interconnector capacity and transport electricity.[45]

In contrast, with market coupling flows across interconnectors and market prices are determined at the same time; electricity will always flow from the low price area to the high price area. Electricity will flow until either price differences are arbitrated away to zero, or the interconnector becomes constrained. In sum, we would expect market coupling to induce more flows, and to reduce average price differences between neighbouring countries.

A further difference between market coupling and explicit auctions is the ability to 'net out' flows fully. Netting is generally considered to be easier with a market coupling mechanism that with alternative interconnector capacity allocation mechanisms such as an explicit auction. This means that increasing prices is less profitable with a market coupling mechanism than without out it. Since the geographic market definition depends on the ability of a hypothetical monopolist to profitably increase prices, *if the Netherlands defines a separate market with market coupling in place then it will also define a separate market with an explicit auction*, since prices rise with an explicit auction are even more profitable.

The more difficult case is if one determines that, with geographic market is larger than the Netherlands with market coupling since this raises the possibility that the Netherlands may define the geographic market with an explicit auction (since price rises would be more profitable). However, we only find that the off-peak market may be larger than the Netherlands with market coupling. While it may be true that the Netherlands defines the off-peak market with an explicit auction mechanism, this would be hard to test since the off-peak market is anyway complicated by the presence of start-up costs.

Generally, the difference between market coupling and an explicit auction will be greatest when the difference in prices between two countries changes frequently. In contrast, if the price in one area is always higher than the price in another area, then even with an explicit auction traders would know to always export from the low price country to the high price country. Appendix VII illustrates that in the absence of the exercise of market power, market coupling increases cross-border flows by around 15%.

[45] In its Draft Sectoral inquiry report, DG Comp also remarks on the problem of trying to trade across borders before knowing the prices in the relative markets, and the inefficiencies that can result. DG Comp estimates that around €50 mln of interconnector capacity on the Dutch-German border was unused in 2004 as a result of inefficient trading. See 'Preliminary Report - Sector Inquiry under Art 17 Regulation 1/2003 on the gas and electricity markets', February 16 2006, §II.3.5.3 p.163.

The effect on interconnector capacity required to expand the Dutch market

In section 5.2, we concluded that, assuming market coupling; TSOs would have to increase the common flow constraint between the Netherlands and Belgium/Germany to about 6,500 MW. Because market coupling would improve the effectiveness of interconnector capacity, the absence of market coupling could necessitate the construction of even more additional interconnector capacity to expand the peak market beyond the Netherlands.

As noted above, the difference in the level of extra imports that one would expect with market coupling, relative to explicit auctions, depends on the average price difference between two markets. The larger average price differences, the less difference market coupling will make.

In Appendix VII we calculate that in 2005, at prevailing prices, market coupling would have increased peak flows by around 15%. As we raise prices in the Netherlands during the SSNIP test, the increase in flows as a result of market coupling would be less than 15%, because the price differences are larger; flows under market coupling and explicit auctions would look increasingly similar. It is possible that, at the 5-10% price increases seen under the SSNIP test, market coupling and explicit auctions would give exactly the same level of imports.

Therefore, we conclude that if 6,500 MW of interconnector capacity is required with market coupling to expand the peak Dutch market, then with an explicit auction *at most* they would require 7,500 MW.[46] In sum, market coupling will reduce the amount of additional interconnector capacity required to expand the market by an amount that—although material—represents only a relatively small part of the total required.

We also note that, in reality, some hybrid of market coupling and explicit auctions is likely to emerge. For example, rather than dedicate the entire interconnector capacity to market coupling, it seems more likely that some portion of the interconnector (most likely that which is currently sold as daily capacity) would be used for market coupling.

6.3 Specific factors affecting market definition

In the previous section, we discussed that the interconnector capacity to the Netherlands from Germany and Belgium would need to be expanded to around 6,500 MW to expand the peak market beyond the Netherlands. This implies that the present interconnector capacity of around 3,600 MW would need to be almost doubled. Some factors could help achieve this interconnector expansion and others would hinder it. For example, we understand that large amounts of wind generation in Germany have significantly changed the pattern of electricity flows in North West Europe, and decreased the effective interconnector capacity to the Netherlands. Further increases in wind generation could further reduce the interconnector capacity to the Netherlands from Germany and Belgium.

On the other hand, we understand that the German TSOs plan to increase interconnector capacity on the Dutch-German border. For example, RWE has announced that it is exploring

[46] If market coupling increases imports by around 15%, then 6,500 MW of extra interconnector capacity is equivalent to about 6,500 MW x 1.15 = 7,475 MW ≈ 7,500 MW of extra interconnector capacity with an explicit auction.

various alternatives with Tennet to increase interconnector capacity on the Dutch-German border by 1,500 MW.[47] Whether this will actually lead to a net increase in transmission capacity between the two countries relative to the present depends mainly on the increase in wind generating in Germany. Extra transmission capacity may just be sufficient to cope with additional 'loop' flows caused by wind generation, rather than adding any net capacity. In addition capacity has been expanded on the French-Belgian interconnector by 700 MW,[48] and there are plans to increase capacity on the Dutch-Belgian border by 300 MW. All these developments would contribute to expanding the Dutch market.

Increasing the capacity of the Norned cable to expand the Dutch market does not seem a practical alternative to increasing capacity from Germany and Belgium, for two reasons. First, it seems likely to be more expensive, given that the Norned cable is a sub-sea cable and must cover a very large distance relative to the interconnectors from Germany and Belgium. Second, Nordpool prices vary strongly with rainfall –in a dry year prices in Nordpool can be high relative to the Netherlands. In such years, even if the Norned cable were expanded, there would be no cheap imports available from Nordpool to defeat price rises in the Netherlands. In contrast, prices in Germany and Belgium are more closely correlated to prices in the Netherlands. If interconnector capacity from Germany and Belgium was expanded so that the Netherlands no longer defined a separate market, changes in fuel prices would be less likely to render German and Belgian imports uncompetitive.

In section 2.4, we mentioned several factors which are sometimes cited as creating a 'single market' – for example common trading arrangements and institutions, or the harmonisation of grid fees – but we noted that these factors are not relevant to geographic market definition for the purpose of competition law except to the extent that they affect the ability of different geographic areas to impose competitive constraints. For example, differences in grid access fees will not generally inhibit the ability of foreign generators to compete with domestic generators. Similarly, differences in balancing prices would not affect the market definition for the wholesale market under our analysis since we assume that balancing electricity is a separate product. Accordingly, harmonisation of balancing mechanisms will not do anything to integrate wholesale electricity markets.

Finally, expanding the interconnector capacity to around 6,500 MW would likely require a very considerable investment by the TSOs. Careful consideration should be given as to whether the benefits of a larger peak market would justify the large cost of such an expansion.

6.4 Trading mechanisms to create a single market

Our analysis has focused on expanding interconnector capacity to remove frequent physical constraints between the Netherlands and its neighbours. This would expand the market beyond the Netherlands, because in the absence of constraints, prices in the Netherlands and surrounding countries would be the same.

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[47] Speech by RWE CEO, 23rd February 2006.

[48] European Power Daily, Volume 8, Issue 09, 13 January 2006, p.2.

An alternative way to achieve the identical prices in the Netherlands and one or more neighbouring countries is to change the way cross-border constraints are managed. At present, (and also with a market coupling mechanisms) a constraint has different prices on either side of it. 'Cheap' plant on the upstream side of the constraint would like to sell more electricity into the expensive area, but cannot because of transmission constraints.

An alternative approach is to use re-despatch to create a single price area. Consider the following example, of a hypothetical single price area including the Netherlands and Belgium. Suppose Generator A in Belgium offers 500 MWh of electricity to both Dutch and Belgian consumers at 35 €/MWh. Suppose also that the marginal plant in the Netherlands has a cost of 50 €/MWh; as a result, generator A exports 500 MWh from Belgium into the Netherlands. Now imagine that the interconnector between Belgium and the Netherlands becomes constrained. Generator A would like to export 500 MWh to the Netherlands but cannot. Under market coupling, the marginal Dutch plant sets the price of 50 €/MWh, and there are different prices in Belgium and the Netherlands.

However, under a single price mechanism, the market operator (MO) calculates the market price ignoring the constraint. The MO calculates the price assuming that 500 MWh flows from Belgium to the Netherlands – we assume this price is 45 €/MWh, less than the cost of the marginal Dutch plant and more than the offer price of the Belgian plant. Of course, the interconnector is constrained, and so the power cannot really flow. Accordingly, the Belgian plant does not produce the 500 MWh, but rather it is 'constrained off' *i.e.* it cannot run as it would like to because of transmission constrains. The MO pays the Belgian plant the market price (45 €/MWh) minus the Belgian plant's offer price of 35 €/MWh, for the 500 MWh it was unable to despatch *i.e.* €5,000. At the same time, the MO instructs a Dutch plant (downstream of the transmission constraint) to produce 500 MWh 'on behalf of' the Belgian plant. The Dutch pant is said to be constrained on, since it is producing only because another plant is constrained off. The MO pays the constrained-on Dutch plant the difference between its offer price, which we assume is 65 €/MWh (the constrained on plant's offer price will be above the market price – if it was not, the plant would already be running) and the market price. The net result is that there is a single price between Belgium and the Netherlands of 45 €/MWh. The MO makes constrained off payments of €5,000 and constrained on payments of €2,500 *i.e.* €7,500 in total. The cost of these payments are usually recovered from all electricity users via a surcharge on transmission tariffs.

Most European TSOs already use a form of the mechanism described above to deal with transmission constrains within their control area. In this way, TSOs achieve a single price in the control area, despite the presence of some transmission constraints.[49]

One advantage of a single price mechanism is that it guarantees a single price, even when there are transmission constraints present. A single price mechanism could be advantageous between two countries where transmission constraints are rare, but the possibility of separate prices disproportionately increases transactions costs of trading between the two countries. In this case, it might be efficient to adopt a single price mechanism.

[49] This need not always be the case – markets that use a Locational Marginal Pricing (LMP) system can have a different price for each node on the transmission network – constraints are fully accounted for.

However, where constraints are frequent (*e.g.* between Germany and the Netherlands) a single price mechanism could be inefficient. The MO would make up large constrained off payments to German generators, and large constrained on payments to Dutch generators. Consumers in the Netherlands would not face the true marginal cost of generating electricity, and could consume an inefficiently large amount of electricity as a result. Moreover, a single price mechanism can be vulnerable to abuse by market players; for example, generators in the Netherlands could submit very high offer prices, in the knowledge that the MO will have to accept them to solve the transmission constraint. In addition, there would be no observable price signal of the value of additional interconnector capacity.

In sum, a single price mechanism may be efficient to 'smooth over' occasional constraints, but will result in inefficiencies if it is used as a substitute to interconnector expansion on transmission routes that are frequently constrained.

Long-term contracts and geographic market definition

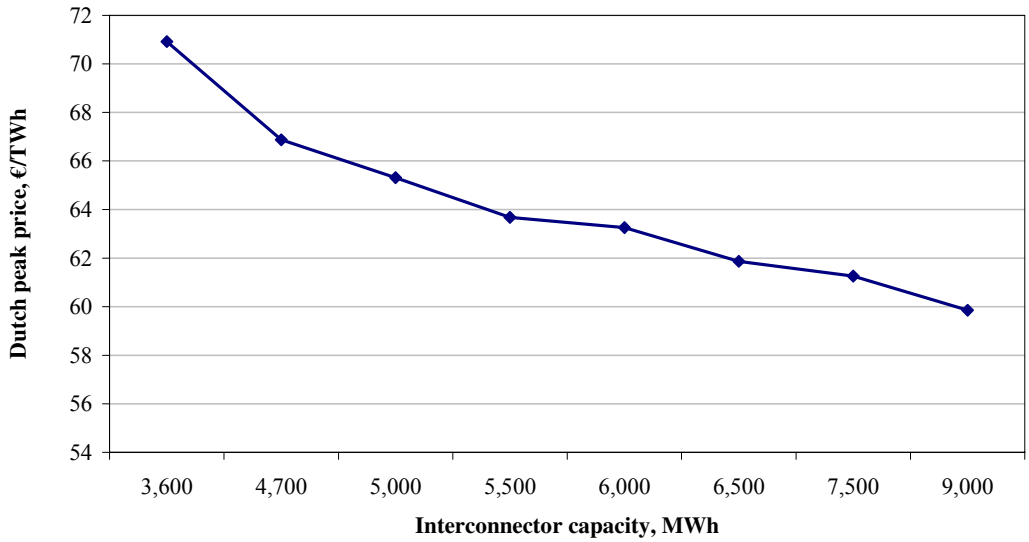
Long-term contracts could have at least two possible effects on geographic market definition. First, long-term import contracts (such as the SEP contracts) reduce the amount of capacity available to discipline incumbents in the Netherlands. The SEP contracts in effect reduce the amount of interconnector capacity available to the market, and this could 'shrink' the market (or make it harder to expand the market beyond the Netherlands). However, we understand that the preferential interconnector access for the Sep contracts has not applied since September 2005, and so this should not be an issue.

Second, the presence of very long-term contracts could make price rises in the spot market unprofitable, depending on how these contracts were indexed. In our standard SSNIP test, we have assumed that any price rises are sustainable (non-transitory in the language of the SSNIP test) and would therefore feed through to longer-term contracts after one or two years. The presence of longer-term (*i.e.* 1-2 year) contracts would slightly reduce profits from price rises (by deferring them) but the effect would not be significant. However, if parties signed very long-term contracts of 10-15 years duration, in theory any spot-price rises could take such a long time to feed through to the contract price that spot price rises become unprofitable. However, we think it more likely that such contracts would either be partly indexed to spot prices (so that spot price rises would feed through rapidly to the contract) or the contracts could be re-opened if the contract price diverged sharply from spot prices. Such clauses are common in long-term gas supply contracts. Therefore, it seems unlikely that the presence of long-term contracts would make any difference to market definition.

6.5 Market expansion: who would need to act?

Our analysis to now has shown that the Dutch wholesale power market is currently national in scope, at least for peak power. In the absence of increased interconnection it is likely to remain so, since the difference in underlying input prices (coal, gas, carbon) is unlikely to change in the direction that would favour Dutch generation. This section of the report therefore considers what types of action would be needed to increase interconnection, and who would be best placed to lead in this area.

Figure 39: Peak prices in the Netherlands in 2008 as a function of interconnector capacity between the Netherlands and Germany/Belgium



Our analysis of market definition indicates that increasing the capacity that could flow from Germany and Belgium to the Netherlands to around 9,000 MW would reduce average Dutch peak prices from around €71/MWh to €60/MWh (see Figure 39). Clearly, these lower prices would benefit Dutch consumers, although the benefit would be offset either partially or completely by the cost of expanding the interconnectors, which Dutch consumers would (partly) have to pay for, presumably via increased transmission charges. However, in this report we do not analyse the net benefit of increased interconnection is desirable, either in terms of a social cost-benefit analysis or broader policy goals (e.g., the "Lisbon agenda" and its commitment to 10% interconnection between neighbouring Member States). Those questions fall outside the scope of this report.

There are a number of possible types of action that could lead to increased interconnection:

- Market coupling, which is already under way, should lead to more efficient use of existing interconnection capacity;
- It may also be possible to get increased interconnectivity (greater effective capacity) from existing infrastructure through better co-ordination between TSOs, and/or through the provision of greater financial incentives;
- Of course it is also possible to add additional physical capacity.

The main possible actors in this regard are TSOs, regulators and governments. In each case, they can act at national, regional or EU level. For example, market coupling is being progressed at regional level, under the joint leadership of CRE, CREG and DTe.

More capacity from existing infrastructure

With regard to improved co-ordination, it is clear that the availability of cross-border capacity is a function of both TSOs' actions. Greater co-ordination could therefore lead to increased availability. National regulators could encourage this co-ordination on a bilateral or regional basis. Similarly, TSOs could co-operate either bilaterally or regionally. With regard to regional co-operation, it may be of interest to look at the Regional Transmission Organisations in place in the US (and in Great Britain, where one TSO operates the transmission networks of National Grid, Scottish Power and Scottish and Southern).

At European level, co-ordination could be fostered through CEER/ERGEG, and through ETSO and/or UCTE. The proposals in the European Commission's recent Green Paper for a European Centre for Energy Networks, a European Grid Code, and potentially a European regulator would clearly allow for EU-level action in this regard, but of course would not be in place for some years.

However, this leaves open the question of the incentives facing TSOs with regard to network expansion. Here relevant issues include:

- Unbundling: without adequate unbundling, there may be a conflict between the desire for greater interconnection and the interests of the TSO's parent company. This issue is well-known and we do not address it further here.
- Congestion rents: at present congestion rents go to TSOs, who according to the Electricity Regulation are required to use them either to fund interconnector expansion, or to reduce rates. The Sector Inquiry Preliminary Report estimates (p.159) that during the period 2001 to 6/2005, TSOs obtained congestion revenues of €1,000 to €1,300 million, and invested just €200 to €300 million on interconnectors (excluding spending on congestion relief). Of particular relevance to the NL, the Report notes that "three German TSOs managing interconnectors generated congestion revenues of [400-500] million Euro. Of these revenues only [20-30] million Euro were used to reinforce/build new interconnectors". Previously there has been no German regulator to verify that the rest of these revenues have been used to lower tariffs, although this may now change since a German regulator has been created.
- Financial certainty: clearly TSOs facing regulated tariffs will not wish to take on uncompensated risks in building interconnectors. NRAs can help here through the development of effective, transparent and stable procedures for tariff-setting, that give appropriate levels of comfort to investors. Again this is a well-known set of issues that does not need further discussion here.
- Incentives for efficient system operation: TSOs incentives at present may bias them against maximising interconnector use, either because they wish to avoid increasing internal congestion (for operational or financial reasons) or because there is no counter-incentive that would appropriately balance the desire for ever-greater system security against the economic value of making additional capacity available to the market.

Incentives for efficient system operation

The last point is worth expanding upon. There may be trade-offs between internal congestion and congestion at borders, and in the absence of countervailing incentives it is natural for a TSO to sometimes "push the problem to the border". Moreover, decisions about the amount of interconnector capacity that can be made available to the market inevitably involve a trade-off between security and economic value. Making more capacity available allows the TSO(s) less flexibility in operating their system, and reduces the level of security. Tempting as it may be to endorse slogans of the form" you can never be too safe", in reality no system is 100% secure. For modern transmission systems of the kind found across Europe the level of system security is—rightly—extraordinarily high.

It is therefore worth asking whether the provision of appropriate financial incentives might induce TSOs to find additional interconnection capacity from existing infrastructure, without inappropriately reducing system security. UK experience suggests this may be possible. Ofgem has for some years provided "System Operator incentives" to the natural gas network operator Transco, that provide strong incentives for increasing the system's throughput capacity (measured in this case by entry capacity) both in the short term, through more efficient operation of the entire transmission system (e.g., making appropriate trade-offs between congestion at the border and internally) and in the long term, through increased investment. With regard to electricity transmission, Ofgem also provides "System Operator incentives". Although there is no direct analogue for the GB transmission system to the creation of additional interconnection, it is noteworthy that in general the SO incentives in electricity have had a very major impact in reducing the costs of operating the system, while security has continued to rise. Ofgem notes that:[50]

> *NGC has been subject to incentives to control the costs of balancing the system since 1994. Prior to the introduction of incentives, these costs were passed straight through to consumers and, over the course of the four years since Vesting, these costs had doubled in real terms to £509 million. Between April 1994 (when the first incentive scheme was introduced) and the introduction of NETA, NGC reduced the annual costs of system operation by more than £400 million.*

Clearly it would be open for DTe to introduce such incentives at the national level. However, while these might encourage more efficient system operation by TenneT, it would be difficult for TenneT alone to increase cross-border capacity, since as noted above this requires co-operation from other TSOs. There would therefore seem to be a good argument for the coordinated introduction of such incentives at the regional level. This would require co-operation among the relevant NRAs (at least BNA, DTe, CREG).[51]

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[50] "NGC system operator incentive scheme from April 2004, Initial consultation document", Ofgem, December 2003.

[51] Of course there is also an issue as to whether a state-owned company such as TenneT will respond effectively to financial incentives. In principle this might be achieved through providing appropriate incentives to senior management at TenneT.

Additional Physical Capacity

Again this requires coordination between the two TSOs, and they must be incentivised to act appropriately. The barriers to expansion include all the issues listed above. In addition, there is a serious problem of obtaining permits etc. The difficulty of obtaining relevant permits is a major issue. However, it should be noted that a motivated TSO can work with government at all relevant levels to facilitate the processes. The converse is also true.

Possible measures to expand capacity include:

- National regulators could place requirements on TSOs to expand capacity, either acting individually or in a coordinated way—probably regionally. The nature of these requirements would require definition. It might comprise a numerical goal ("MW of additional capacity"), or a requirement to carry out some kind of cost-benefit assessment and act on the basis of its conclusions.
- There would be a difficult issue of enforceability—in particular, an unwilling TSO could use technical problems and permitting issues as excuses for failure to meet its goals. It might be possible for NRAs to penalise TSOs by removing the congestion revenues, although this would presumably require new legislation in most if not all MS.
- Given the difficulties of imposing penalties, it would be useful/necessary to complement any such goals with positive incentives: the TSO would earn additional revenue for meeting its goals.
- For this to happen it may be necessary to expand the powers and obligations of the relevant NRAs. While individual Member States could do this, it is likely to require additional EU legislation. It should therefore be seen in the light of the currently ongoing process around the Commission's Green Paper, the discussion over an EU regulator, and the alternative concept of "ERGEG-plus".

In sum, the most likely way to achieve additional effective interconnection (either through more efficient use of existing capacity or through additional physical investment) is through coordinated action by NRAs at regional level. It would be helpful if this was mirrored by regional coordination at TSO level. Making this effective is likely to require additional European legislation, to address the "regulatory gap" identified by the European Regulators (that is, the mismatch between the purely national competences accorded by Member States to national regulators, and the need for co-ordinated action at supra-national level for example in relation to increasing interconnection).[52] The potential for such legislation should be assessed in light of the ongoing policy discussions following the February 2006 Green Paper.

6.6 Conclusions on factors affecting geographic market definition

Evidence from both current market prices, forward prices and our computer model indicates that, for the purpose of merger control, the Netherlands defines a geographic market for peak power. With regard to computer modelling, our conclusions are valid for a wide range of fuel, carbon price and demand elasticity assumptions. There is strong evidence that the market for off-

[52] "The Creation of Regional Electricity Markets, An ERGEG Conclusions Paper", Feb 2006.

peak power is larger than the Netherlands. The current interconnection capacity to the Netherlands would need to be expanded by several thousand MW to expand the peak market beyond the Netherlands.

7 The effect of possible mergers on wholesale competition

Mergers modelled

In this section of the report, we examine the implications of our geographic market definition findings for mergers. We investigate two hypothetical mergers: a merger of Nuon and Essent (a 'Dutch-Dutch' merger) and a takeover of Essent by RWE (a 'Dutch non-Dutch' merger). We chose Essent and Nuon for the Dutch-Dutch merger because these firms are the only two major players who have the vast majority of their business in the Netherlands, and so are the only candidates for the creation of a 'Dutch national champion' (the other two large players, E.ON and Electrabel have the majority of their generation activities outside of the Netherlands). For the Dutch non-Dutch merger, RWE is an interesting hypothetical buyer of Essent for two reasons. First, it is not currently active in the Dutch electricity market in a significant way. If we had chosen either E.ON or Electrabel as a buyer of Essent, the acquisition would look similar to an Essent-Nuon merger, because it would result in the merger of two players that are active in the Netherlands. Second, RWE is a large player in a market (Germany) that could become part of the relevant geographic market for peak electricity, with sufficient interconnector expansion. Hence, it is interesting to see the effect of expanding the geographic market from the Netherlands to the Netherlands and Germany on such a merger. Choosing a buyer in a country that will never likely become part of the same geographic market as the Netherlands would have little effect; the plant would simply change its label, from Essent to the new owner. There would be no effect on competition.

We do not consider a non-Dutch non-Dutch merger, because we cannot imagine such a merger that is both likely to happen and would have a significant effect on Dutch electricity consumers. A non-Dutch non-Dutch merger would only have a significant effect on Dutch consumers if it happened in market that is, or could become, part of the relevant geographic market for Dutch electricity producers (*e.g.* Germany and Belgium). For example, a merger of two large German generators would likely affect the off-peak market for Dutch consumers, and if the interconnector was expanded would also affect the peak market for Dutch consumers. However, the German market is already relatively concentrated, and it is difficult to imagine a merger of *e.g.* RWE and E.ON being allowed, especially given recent comments from the German competition authorities (to the effect that it was a mistake to allow the mergers that created E.ON and RWE).[53] In Belgium the incumbent player has, in effect, no-one to merge with. A merger in a country that is not part of the relevant geographic market for Dutch electricity producers (*e.g.* two players in Nordpool) would only effect Dutch consumers via the control of interconnector capacity. For example, two players might control 400 MW of interconnector capacity each prior to the merger, so that post-merger they potentially control 800 MW. However, existing rules limiting the maximum interconnector capacity one party can control would already address this issue. In sum, there are no likely mergers that would have an effect on Dutch consumers.

[53] See Platts European Power Daily, 15 Feb 2006.

Alternative measures of competition

Market shares and Hirschmann-Herfindahl Indices (HHIs which are used to examine horizontal issues in competitive analysis)[54] are commonly accepted measures of competition in Europe, and are used extensively in the European Commission's horizontal merger guidelines.[55] Clearly any competition analysis for the purpose of merger control must include these measures. However, there are several reasons why they are often poor indicators of competition in electricity markets. For example, it is difficult to store electricity, and the demand for electricity is very inelastic. Accordingly, even a player with a small market share can exercise market power in any given instant, if that player must produce some power to satisfy market demand *i.e.* even the output of all other players combined cannot satisfy the market. Similarly, due to inelastic demand, an electricity market can have a relatively low HHI, and still experience market power problems if the demand-supply balance is tight. The problems experienced in the Californian electricity market provide evidence of this.[56] On the other hand, the use of market shares and HHI are well understood and accepted by most competition authorities, including DG COMP.

Economists have developed alternatives to market share and HHIs for analysing competition in electricity markets. These include the use of computer models that simulate competition between electricity generators taking into account demand levels and elasticity of demand. In Appendix VI we describe several alternative modelling approaches for the analysis of mergers and competition, and their advantages and disadvantages. However, these computer-based methods, while more accurate, are less transparent than concentration measures. They are more difficult to explain to a non-technical audience, and moreover there is little precedent for their use in competition cases.

In this report we combine several forms of analysis. We use a 'traditional' concentration analysis, which calculates market shares and HHIs. We also calculate Pivotal Supplier Indices (PSI) (based on the geographic market definitions developed earlier),[57] which are somewhat between an HHI index and a Cournot model in terms of sophistication. PSI analyses are a standard feature of proceedings to allow so-called Market Based Rates (MBRs, which are rates for selling power that are not approved by a regulator) in the US, but are less commonly used by European regulatory and competition authorities (Appendix X describes the application of PSI

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[54] The HHI is the sum of the square of the market shares. For example, if there were four players in the market, each with a 25% market share, the HHI would be calculated as $25^2 + 25^2 + 25^2 + 25^2 = 2{,}500$. The HHI has a foundation in the Cournot economic model of competition, where players compete by setting output or capacity, rather than price.

[55] Guidelines on the assessment of horizontal mergers under the Council Regulation on the control of concentrations between undertakings (2004/C 31/03).

[56] For a detailed discussion of the short-comings of 'traditional' concentration measures in electricity markets, and the California electricity market in particular, see 'Market Power in Electricity Markets: Beyond Concentration Measures' Severin Borenstein, James Bushnell, and Christopher R. Knittel February 1999, working paper of the Program on Workable Energy, University of California Energy Institute.

[57] The PSI measures the percentage of time that a supplier is pivotal. A producer is pivotal if demand cannot be met without some output from that producer. For example, producer A would be pivotal in a given hour if demand was 20 GW, and the supply of all other producers *except* producer A is 18 GW; some output (2 GW) would be required from producer A, and hence producer A has an ability to exercise market power.

analysis in the US in more detail). Finally, we use a computer simulation of a Cournot model, in which generators vary their power production so as to maximise profits. The Cournot model does not need to use geographic market definitions, since it explicitly models the effect of interconnector constraints *etc.* Hence, the Cournot model can assess if, for example, plant in Germany will constrain a generator in the Netherlands from raising market prices, and in which hours. We explain the Cournot-model approach in more detail below.

7.1 Market structure analysis

In our previous analysis, we concluded that the Netherlands defined a market for peak power, but the geographic extent of the off-peak market is likely to be larger than the Netherlands. Because the geographic scope of the peak and off-peak markets are different, we analyze the peak and off-peak markets separately. We begin by assuming that the Netherlands defines the peak market, and go on to investigate a case of a peak market defined geographically by the Netherlands and Germany, and by the Netherlands and Belgium. We assume that Germany and the Netherlands defines the off-peak market. We do not conduct a separate analysis for an off-peak geographic market defined by Germany, the Netherlands and Belgium; both mergers we examine would be acceptable with an off-peak market defined by the Netherlands and Germany; adding Belgium would create an even larger market, further reducing any negative effects of the mergers.

While the Netherlands defines a geographic market for peak power (for the purposes of merger control), foreign generators can still provide power to Dutch consumers via the interconnectors. Hence, the supply-side participants in the peak market are Dutch generators *plus power imported via the interconnectors*. When we say that the Netherlands defines a market, this actually means that generators in the Netherlands plus interconnector capacity defines the supply-side of the peak market, and market shares should be calculated accordingly. Similarly, the demand-side of the market is all consumption in the Netherlands plus any net demand over the interconnectors.

If the interconnector between Germany and the Netherlands was expanded sufficiently, then Germany and the Netherlands would define the geographic extent of the market. Supply-side participants in the peak market would be Dutch and German generators and interconnectors to both Germany and the Netherlands. But we would not include the interconnector between Germany and the Netherlands, since this no longer represents a significant constraint; that is why the two countries now occupy the same geographic market.

Peak market shares and HHIs

The HHI is based on a Cournot model, in which generators vary their output to maximize profits. In the HHI calculations, we consider it correct to consider all capacity that generators could vary to maximize profits (*e.g.* flexible gas and coal-fired plant). We also include plant that, while it may not be flexible enough to withdraw, gives generators an incentive to withdraw plant because it will enjoy the benefits of any high prices achieved (*e.g.* nuclear). For example, a generator might own a flexible gas plant and a nuclear plant. The generator might withdraw output from the gas-plant to raise prices. The generator would then earn increased profits from electricity sales from both the gas-plant and the nuclear plant. Both plant play a role in the generators profit-maximisation strategy, and hence we include both plants in our HHI calculation.

Accordingly, for the purposes of calculating market shares and HHIs, we consider that, on the supply side, all Dutch generating capacity participates in the peak market *with the exception of wind generation*. The output of wind generation cannot be easily controlled (for the purposes of manipulating market prices) and it is unpredictable whether it will be running (so that it could benefit from high prices). Moreover, renewable or green energy often enjoys a different price and tariff from conventional power. For these reasons, we exclude wind generation from the market share and HHI calculations.

Note that we calculate market shares (and hence HHIs) on the basis of capacity (MW) rather than energy sold (MWh). The reason is that for the analysis of competition, we are interested in the ability of players to produce electricity and hence influence prices, and installed capacity is the best measure of this. In contrast, examining market shares on a produced – energy basis simply tells us about market players' historic decisions to produce energy, and could be misleading because it tells us little about producers' ability to influence prices. For example, a generator could produce relatively little energy, but have a large amount of capacity which it withdraws strategically to raise market prices.

In general, we have made assumptions which will tend to underestimate the HHI. For example, we assume that holdings of Stadwerke plant in Germany are held very diversely, and that imports are not all allocated to large incumbent players.

In Germany in particular, plants often have several owners. However, in all countries examined we calculate a 'simple' HHI *i.e.* we allocate 100% of the profits and control of a plant to one company (usually the operating company if this is known, or otherwise the majority shareholder), rather than calculate an HHI which accounts for the actual shareholding of each plant. We do not expect that using a simple HHI rather than a more complex HHI will have a significant effect on the results.

Table 6 shows our calculations of peak market shares, before and after an Essent/Nuon merger, for the case that the Netherlands defines the geographic extent of the peak market. Appendix VIII contains the detailed market share calculations for all players.

Table 6: The effect of a Nuon/Essent merger on the peak market shares of the main players (Netherlands defines the peak market)

Electrabel	22%
Essent	21%
Nuon	16%
E.ON	9%
Delta	4%
Others (including imports)	29%
Nuon/Essent share post merger	37%

In its guidelines for horizontal mergers, the European Commission states that it has found mergers in which the merged entity has a market share of "between 40 % and 50 %, and in some

cases below 40 %" which have led to the creation or strengthening of a dominant position.[58] The Commission also states that "where the market share of the undertakings concerned does not exceed 25%" the merger is likely to be approved without remedies being required.[59] While the Commission makes clear its guidelines are just an initial screening device – they do not mean a merger will be approved or otherwise – they provide a useful benchmark that we apply in the remainder of this section.

Table 6 illustrates that Nuon/Essent would have a peak-market share of 37%, above the 25% 'cut-off' cited by the Commission and close to the 40% share at which the Commission would likely investigate a merger, and possibly require remedies. Table 6 indicates that, if the Netherlands defines the peak market, on the basis of market share data and using the Commission's indicative market share numbers, a Nuon/Essent merger could well necessitate mitigation measures, especially given that electric power markets are particularly susceptible to abuse. With the peak market defined by the Netherlands, a takeover of Essent by RWE would have no effect on market shares or the HHI, since RWE is not active in the Dutch generation market. Essent plant would simply become RWE plant, and the HHI would remain the same.

Table 7 shows the effect if the peak market was expanded to include Belgium. The market share of Nuon-Essent in this case would be below the 25%. Similarly, if the peak market was expended to include Germany, according to the Commission's guidelines neither a Nuon-Essent merger nor an RWE-Essent merger would be cause for concern. Nuon-Essent would have a peak market share of only 8%, and RWE-Essent a market share of 20% (see Table 8), well below the 'soft' 25% threshold cited by the Commission.

Table 7: The effect of a Nuon/Essent on the peak market shares of the main players (Netherlands and Belgium defines the peak market)

Electrabel	41%
Essent	13%
Nuon	10%
E.ON	6%
SPE	3%
Delta	2%
Eneco	2%
Others (including imports)	24%
Nuon/Essent post merger	22%

[58] *Loc. cit.* footnote 55 §17.

[59] *Ibid*, §18.

Table 8: The effect of mergers on the peak market shares of the main players (Netherlands and Germany defines the peak market)

E.ON	19%
RWE	16%
Vattenfall	12%
STADTWERKE	8%
Electrabel	4%
Essent	4%
STEAG AG	4%
Nuon	3%
KRAFTWERK	3%
EnBW	2%
Others (including imports)	26%
Nuon/Essent post-merger	8%
RWE/Essent post merger	20%

With respect to HHIs, the Commission states that it is:

> *"unlikely to identify horizontal competition concerns in a market with a post-merger HHI below 1 000. Such markets normally do not require extensive analysis. The Commission is also unlikely to identify horizontal competition concerns in a merger with a post-merger HHI between 1 000 and 2 000 and a delta below 250, or a merger with a post-merger HHI above 2 000 and a delta below 150"*[60]

We note that the Commission's guidelines are less stringent than those employed by the US Department of Justice (DoJ). DoJ states that mergers which result in an HHI of 1,800 or less and increase the HHI by 100 points potentially raise significant competitive concerns; mergers which result in an HHI of over 1,800 and increase the HHI by 50 points potentially raise significant competitive concerns; and if the change in HHI exceeds 100, DoJ presumes that the merger is likely to create or enhance market power.[61] In our remedies analysis we use the Commission's guidelines, but note that NMa is in no way bound to use these guidelines and if it were to employ the DoJ's standards then further divestment would be required.

Table 9 illustrates our HHI calculations for the peak market. With the peak market defined by the Netherlands (which would have installed capacity in 2008 of about 21.7 GW), a Nuon-Essent merger would have a significant effect on the peak market HHI, increasing it by 655 points from 1,328 to just under 2,000. According to the Commission's Guidelines, such a merger may require "extensive analysis". Similarly, with a Dutch-Belgian peak market (which would have installed capacity in 2008 of about 34.8 GW), a Nuon-Essent merger would increase the HHI to above 2,000 and increase the HHI by 242 points – more that the 150 point increase that the Commission would find notionally acceptable. Interestingly then, a Nuon-Essent merger in a Dutch-Belgian peak market would 'pass' on market share criteria, but 'fail' on HHI grounds. However, if the

[60] *Ibid*, §§19-20.

[61] U.S. Department of Justice and Federal Trade Commission, Horizontal Merger Guidelines, issued April 2, 1992, revised April 8, 1997 (DOJ/FTC Merger Guidelines).

peak market is expanded to include Germany and the Netherlands (which would have installed capacity in 2008 of about 115.7 GW), a Nuon-Essent merger results in an HHI of less than 1,000; even if the HHI increased to just above 1,000 (due to *e.g.* different assumptions on the allocation of interconnector capacity) the merger would not increase the HHI by more than 250 points. Therefore, a Nuon-Essent merger in a geographic market defined by the Netherlands and Germany is unlikely to cause concern according to the Commission. Similarly, with a Dutch-German peak market, even an RWE-Essent 'merger' would result in an HHI of less than 1,000 (and increase the HHI by less than 250), and may also be approved. Note that as RWE has little activity in either Belgium or the Netherlands, a RWE-Essent merger would not affect the HHI of a peak market defined by either the Netherlands or the Netherlands and Belgium.

Table 9: The effect of mergers on the peak market HHI

Geographic market	HHI with no merger	HHI post Nuon-Essent merger	Increase in HHI post Nuon-Essent merger	HHI post RWE-Essent merger	Increase in HHI post RWE-Essent merger
Dutch market	1,328	1,983	655	1,328	-
Dutch-German market	841	876	35	963	122
Dutch-Belgian market	2,059	2,301	242	2,059	-

We note that our calculated HHI for the Netherlands is lower than previous HHI estimates made by NMa-DTe. This is mainly because the treatment of imports; the NMa-DTe did not include imports in one of its HHI calculations, whereas we include imports and assume an allocation of import capacity that tends to lead to a lower HHI (Appendix VIII gives details of the allocation of interconnector capacity assumed). Moreover, our HHI calculation is for 2008, and so includes the new capacity from the NorNed cable, which lowers the HHI relative to today.

Peak market PSI analysis

The PSI is the percentage of hours that a generator is pivotal; a generator is pivotal if demand cannot be met without some of their output. Summing the hours in which the generator is pivotal and converting this into a percentage of all hours creates an index. The main difference between a PSI analysis and an HHI analysis is that the former accounts for the level of demand relative to supply.

For example, suppose that the supply side consisted of many small generators with total capacity of 80 GW, and one generator A with 20 GW of capacity. The HHI of this market is about 400 – indicating that it is a relatively competitive market. Suppose also that if all generators offered electricity at a competitive price (i.e. at their marginal cost) then demand was always 90 GW. Now suppose that generator A decides to withdraw 13 GW of its capacity, so that total supply is now only 87 GW, and there is a 'shortfall' of 3 GW. With the inelastic demand typical of electricity markets, the withdrawal of plant by generator A could cause prices to far exceed the competitive level. In other words, generator A is pivotal, because by withdrawing capacity it can set the price above the competitive level. The PSI for generator A would be 100%.

Hence, the PSI shows the effect that a tight supply-demand balance can have on market power, because demand is very inelastic. In this sense, the PSI analysis is somewhat between the HHI analysis and the Cournot analysis that we will present later, in that the PSI accounts for the

supply-demand balance, and also examines each hour separately. The key additional feature of the Cournot analysis is that it models several pivotal players simultaneously, it reports the price achieved by the exercise of market power, includes elasticity of demand and accounts for the incentive of players to exercise market power, as well as their ability. Appendix IX explains the difference between the PSI and a similar index, the Residual Supplier Index.

Note that while we exclude wind generation in our HHI calculations for the reasons explained earlier, we do account for wind generation in our PSI analysis by subtracting average wind output from demand. Hence, increased amounts of wind generation help to reduce the PSI by reducing net demand.

Table 10 illustrates the effect of our PSI calculations for a peak market defined by the Netherlands. Pre-merger, only Essent is pivotal for 6% of peak hours. However, with a peak market defined by the Netherlands, a Nuon-Essent merger would result in the merged entity being pivotal for over 70% of peak hours.

The Commission has not described any guidelines for the PSI with respect to mergers. However, the Federal energy regulator in the US (the Federal Energy Regulatory Commission or FERC) will not allow the electricity prices to be set without price controls (so called Market Based Rates) if it finds that a supplier is pivotal for any of the 14 'typical' demand periods it examines.[62] Accordingly, FERC would not allow a merged Nuon-Essent to set market based rates. In other words, a finding that Nuon-Essent is pivotal for 71% of hours indicates a very significant level of market power.

Table 10: The effect of mergers on the peak market PSI defined by the Netherlands

Firm	Fraction of hours firm is pivotal
Essent	6%
Nuon	0%
Nuon/Essent merged	71%

Table 11 shows the results of our PSI analysis for a peak market expanded to include Belgium. In this larger peak market, Nuon-Essent is pivotal for 55% of the time, less than for a peak market defined by the Netherlands alone. We have also checked for when Nuon-Essent is joint-pivotal. By joint-pivotal, we mean that there are two firms in the same hour *either of which* could withdraw power and increase prices. Joint pivotal does not mean that the firms need to collude to raise prices; it means that either firm could independently withdraw power and raise prices. Table 11 shows that Electrabel is pivotal for *all* peak hours in a peak market defined by the Netherlands and Belgium. In other words, while Nuon-Essent is pivotal for 55% of peak hours, Electrabel is also a pivotal supplier in these hours. However, having two joint pivotal suppliers can make competition worse, not better, relative to having only one pivotal supplier. At

[62] The FERC examines supply and demand conditions for 14 representative periods, for example a winter peak, summer off-peak, summer shoulder period *etc.*

first glance it might seem surprising that if there are two firms that are pivotal rather than one, the price cost margin is likely to be higher, as one might casually argue that two competing firms are surely better than a single firm. This is, however, a mis-description, and it might be more accurate to say that with two pivotal firms facing a competitive fringe, there is one fewer competitive firm than if a single pivotal firm faces a competitive fringe. Appendix IX explains this line of reasoning in more detail.

Table 11: The effect of mergers on the peak market PSI defined by the Netherlands and Belgium

Firm	Fraction of hours firm is pivotal
Essent	11%
Nuon	2%
Nuon/Essent merged	55%
Electrabel	100%
Electrabel and Nuon/Essent joint pivotal	55%

Table 12 illustrates out PSI analysis for a peak market expanded to include the Netherlands and Germany. In contrast to the situation with a Dutch-Belgian peak market, a merged Nuon-Essent would not be pivotal in a Dutch-German peak market. Even a merged RWE-Essent would be pivotal only 1% of peak hours, and during these hours it would be joint pivotal with E.ON.

Table 12: The effect of mergers on the peak market PSI defined by the Netherlands and Germany

Firm	Fraction of hours firm is pivotal
Essent	0%
Nuon	0%
Nuon/Essent merged	0%
RWE	0%
E.on	1%
RWE/Essent merged	1%
E.ON and RWE/Essent joint pivotal	1%

Off-peak market shares and HHI

Broadly speaking, one can define two types of plant: baseload plant, which runs in both peak and off-peak periods; and peak plant, which does not generally run in off-peak periods. Accordingly, we wish to exclude peak plant from our off-peak market share and HHI calculations.

One could define peak plant as plant that only operates in peak periods. However, this is rather a narrow definition. As Figure 40 shows, our computer model indicates that only a few plants sell 100% of their output exclusively during peak hours; most plant also sell some output in off-peak hours. However, for the Dutch generating park, there is a clear group of plants that

produce significantly more power in peak periods. Specifically, there is a jump between plant that produce 59% of their output in peak hours (similar to a 'baseload' plant), and plant that produce at least 75% of their output in peak hours. Accordingly, we subjectively (but not unreasonably) take the mid-point of this break as the dividing line between peak and off-peak plant.[63] In other words, we define peak plant as that which produces more than 67% of its output during peak hours. We include plant that produce less than 67% of their power in peak hours in the supply-side of the off-peak market.[64]

Figure 40: Fraction of output in peak hours for Dutch plant according to BAM computer simulation

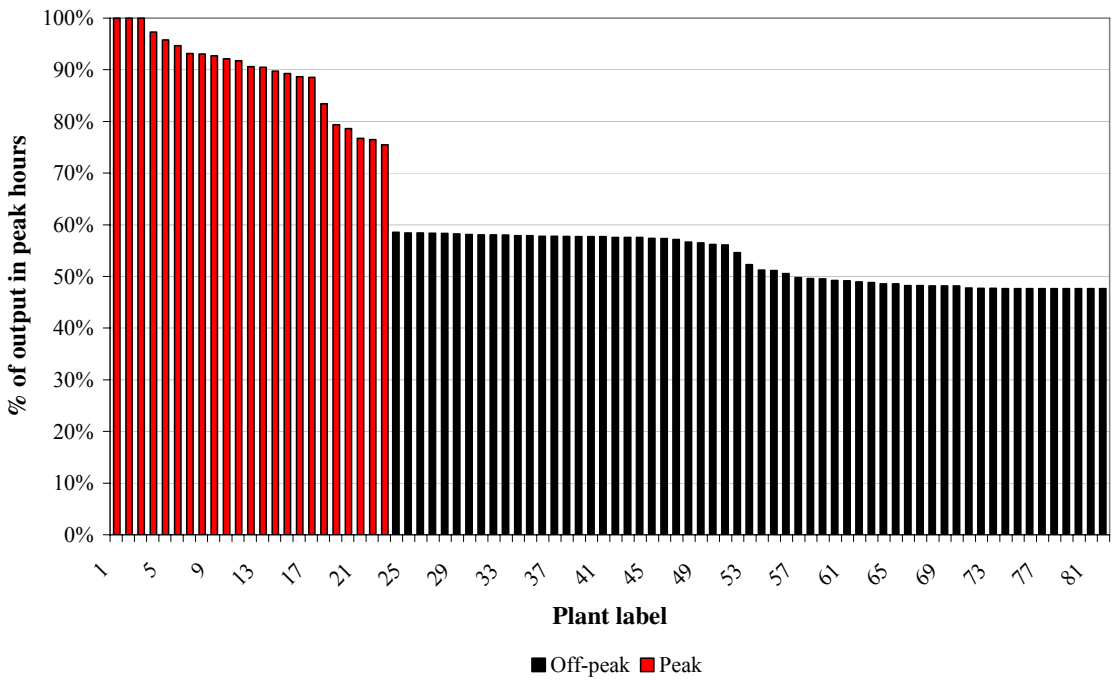


Figure 41 illustrates the equivalent analysis for the German generating park. Unlike in the Netherlands, there is no clear break between peak and off-peak plant. Hence, to be consistent with the definition applied for the Netherlands, we simply exclude plant that produce more than 67% of their production in peak hours from the supply-side of the off-peak market.

[63] We note that most market definition exercises involve decisions which, while they may be reasonable and consistent, are nevertheless subjective. A case in point is the subjective 5-10% level of price rise typically applied in the SSNIP test.

[64] In many markets, an alternative and reasonable definition of off-peak plant could be derived by assuming that off-peak plant are plant with a variable cost of less than the average off-peak price plus 5-10%. However, as off-peak prices in the Netherlands tend to be below the variable cost of most plant (*i.e.* mark-ups are negative) the use of this definition could result in a very small group of plants being defined as off-peal. If off-peak prices were sufficiently low, there would be no off-peak plant using this definition. Hence, we prefer to define plant according to the expected output in off-peak and peak periods, rather than looking at price and cost data.

Figure 41: Fraction of output in peak hours for German plant according to BAM computer simulation

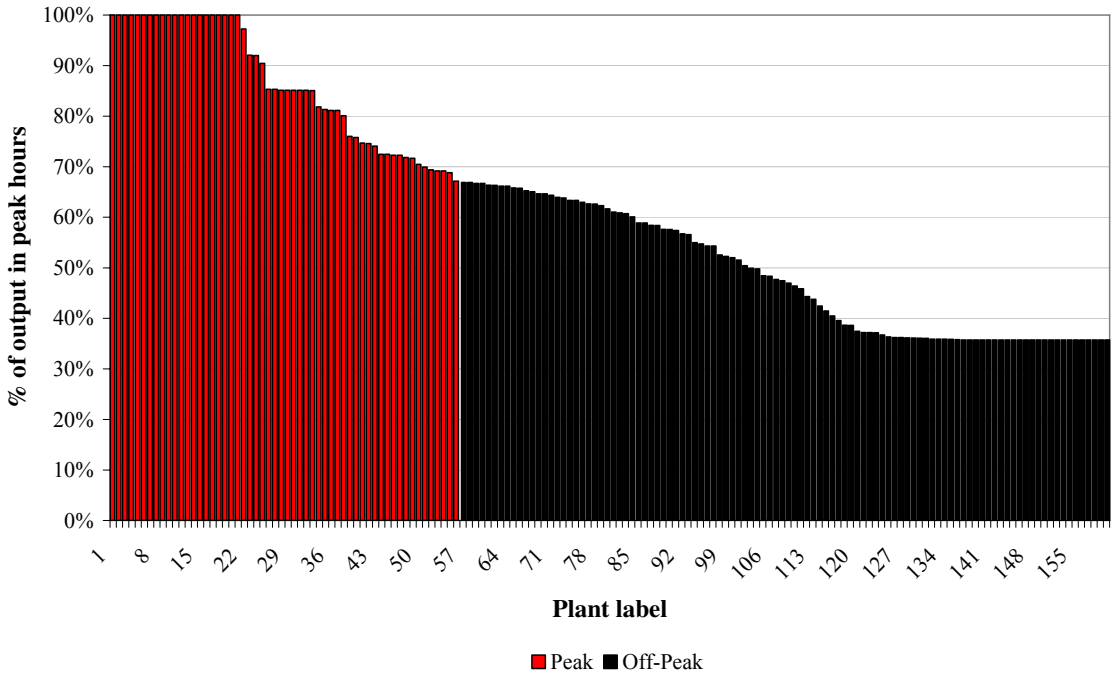


Table 13 illustrates that, if the geographic extent of the off-peak is at least as large as the Netherlands and Germany, neither a Nuon-Essent merger not a RWE-Essent merger would result in a market share over 25%. Therefore, it would be unlikely to cause competition concerns according to the Commission's merger guidelines.

Table 13: The effect of mergers on the off-peak market shares of the main players (Netherlands and Germany defines the peak market)

E.ON	20%
RWE	15%
Vattenfall	10%
STEAG AG	4%
Essent	3%
STADTWERKE	7%
Electrabel	3%
Nuon	2%
KRAFTWERK	3%
EnBW	1%
Other (including imports)	32%
Nuon/Essent post merger	6%
RWE/Essent post merger	18%

Similarly, a merger of either Nuon-Essent or RWE-Essent would not result in an HHI of over 1,000 (see Table 14) in the off-peak market, and would therefore be unlikely to cause concern.

Table 14: The effect of mergers on the off-peak market HHI

HHI with no merger	HHI post Nuon-Essent merger	Increase in HHI post Nuon-Essent merger	HHI post RWE-Essent merger	Increase in HHI post RWE-Essent merger
785	800	15	887	102

Off-peak market PSI analysis

Table 15 illustrates the results of our PSI analysis for the off-peak market. Our analysis reveals that no supplier is pivotal in the off-peak market for a significant number of hours either before or after the mergers considered.

Table 15: The effect of mergers on the off-peak market PSI

Firm	Fraction of hours where firm is pivotal
Essent	0.0%
Nuon/Essent	0.0%
RWE	0.0%
E.ON	0.3%
E.ON and RWE joint pivotal	0.0%
RWE/Essent	0.1%
RWE/Essent and E.ON joint pivotal	0.1%

Possible market entry

The above analysis has assumed no significant new entry into the market by independent players (excluding imports). Given that our analysis is for 2008, this seems entirely reasonable, since any potential new entrant would have to be already building plants in 2006 for these plants to be active in 2008, and this has not happened. More generally, we note that there has been little structural change in the Dutch generating market since before market liberalisation. At that time, there were four larger generators (EPON, EZH, EPZ and UNA), and although their ownership has changed, there are still four large generators today (Nuon controls UNA's old assets, and similarly, E.On corresponds to the old EZH, Electrabel to EPON and Essent to EZH). Based on the history of the last eight years, there seems little reason to suppose that there will be significant new entry in future.

Conclusions on market structure analysis

Our market structure analysis indicates that in a peak market defined by the Netherlands, a merger of Nuon and Essent may, according to the Commission's guidelines and the results of the PSI analysis, cause an unacceptable increase in concentration in the absence of appropriate remedies (bearing in mind that the Commission's guidelines are a screen rather than a rule or recommendation, but also that the HHI analysis may underestimate market power in electricity markets). While expanding the market to include Belgium would lesson the effect of the merger, it would nevertheless still increase concentration significantly. We note that with both these

geographic definitions of the peak market, a company such as RWE could takeover Essent without causing an increase in concentration, since RWE is not currently active in any significant way in either the Netherlands or Belgium. A peak market defined by the Netherlands and Germany would allow a merger of either Essent and Nuon or RWE and Essent without divestment.

Using a narrower definition of a 'super-peak product' (*e.g.* power sold between 17:00 and 20:00 on weekdays) would not change our conclusions. If the Netherlands defines the market for peak power, then it will also define the market for a super-peak product; a geographic market smaller than the Netherlands is not possible for wholesale power. The supply-side participants in a super-peak market will be identical to the supply-side of a peak market. Hence, our analysis would be unchanged, and the required remedies (which we discuss below) would be the same. The only effect of using a narrower product definition is that more interconnector capacity would be required to expand a super-peak market beyond the Netherlands than a peak market.

In an off-peak market which includes at least Germany and the Netherlands, a merger of either Essent and Nuon or RWE and Essent would, according to the Commission's HHI and market share guidelines, be possible without any divestment.

It is also worth noting the impact of such a merger on incentives with regard to use of cross-border capacity. Clearly the merger would give RWE-Essent an incentive to withhold cross-border capacity so as to raise prices in the NL market, to the benefit of its Dutch units. We do not argue that RWE-Essent would do so, simply that economic analysis indicates that such behaviour would be unprofitable pre-merger but might be profitable post-merger (Eon already has similar theoretical incentives as a result of its position in the Dutch market).[65]

Such behaviour would represent an abuse of market power. It is important to note the difficulties it would involve. First, the limits on the amount of import capacity that any one party can hold, plus use-it-or-lose it mechanisms, would limit the feasible amount of withholding. Second, compared to other forms of market abuse this would be relatively easy for authorities to detect, since they can compare booked capacity with nominations. Nonetheless, it would probably be rather difficult to bring an Article 82 case, given the high hurdles of competition law.

An additional and arguably greater concern would be the disincentive on RWE-Netz to maximise/expand cross-border capacity. Again the same issue is already present for E.on. It is clear that this problem will persist in the absence of effective unbundling—in particular, unbundling that prevents the parent company from exercising any formal or informal control over system operation and investment decisions.

7.2 Cournot modelling of the Netherlands

We have simulated the effect of a Nuon-Essent merger in a computer based Cournot model of the Netherlands during peak hours. We do not simulate the effects of the RWE-Essent merger in the Cournot model, since we expect that for almost all peak hours the Dutch-German interconnector is constrained, and so price rises in one market will not affect prices in the other

[65] It is also worth noting that any party that holds capacity into the Dutch market can in theory profit by taking a "long" position in traded markets and then withholding capacity.

market. With the Dutch-German interconnector constrained, if a merged RWE-Essent attempted to raise prices in the Netherlands, there would be no effect on the prices RWE-Essent received for its electricity in Germany. Accordingly, RWE-Essent could ignore the effect of Dutch prices rises on its German operations, just as Essent would have ignored the effect of Dutch prices on RWE's German operations before the merger. In other words, with a constrained interconnector, Essent faces the same profit maximisation problem before the merger with RWE as after it. Therefore, the results of a Cournot model of the Netherlands would give the same results before an RWE-Essent merger as after it.

The Cournot model is a standard workhorse of micro-economics. In essence it is a generalisation of the standard "textbook" model of monopolistic behaviour, where the monopolist withholds capacity from the market to increase prices. In a Cournot model each firm takes into account that it can affect prices by withholding output from the market, and therefore makes its production decisions on a "strategic" basis, taking into account that producing more or less affects profits through the impact on price, rather than acting as a pure price-taker as in the paradigm of perfect competition.

Our model differs from the standard Cournot model in two ways (both intended to capture more accurately the real world situation being modelled). First, not all firms in our model act strategically: we allow for the presence of a 'competitive fringe' *i.e.* a number of smaller players who act as price-takers rather than setting output taking into account the effect on prices (these can be thought of as a combination of small players in the market being considered, and potential imports from neighbouring markets). Second, we also assume that generators have sold a certain amount of their output in advance (forward) at a fixed price. Generators in that situation still have incentives to raise prices. Raising spot prices not only increases profits on that part of their output that is not forward-contracted, but will also cause forward contracts to be renewed at a higher price when they expire. However the incentives are less powerful than for generators with no forward contracting, since they must sacrifice output to raise prices, but will not enjoy the benefits of higher prices directly for the output which they have sold forward.

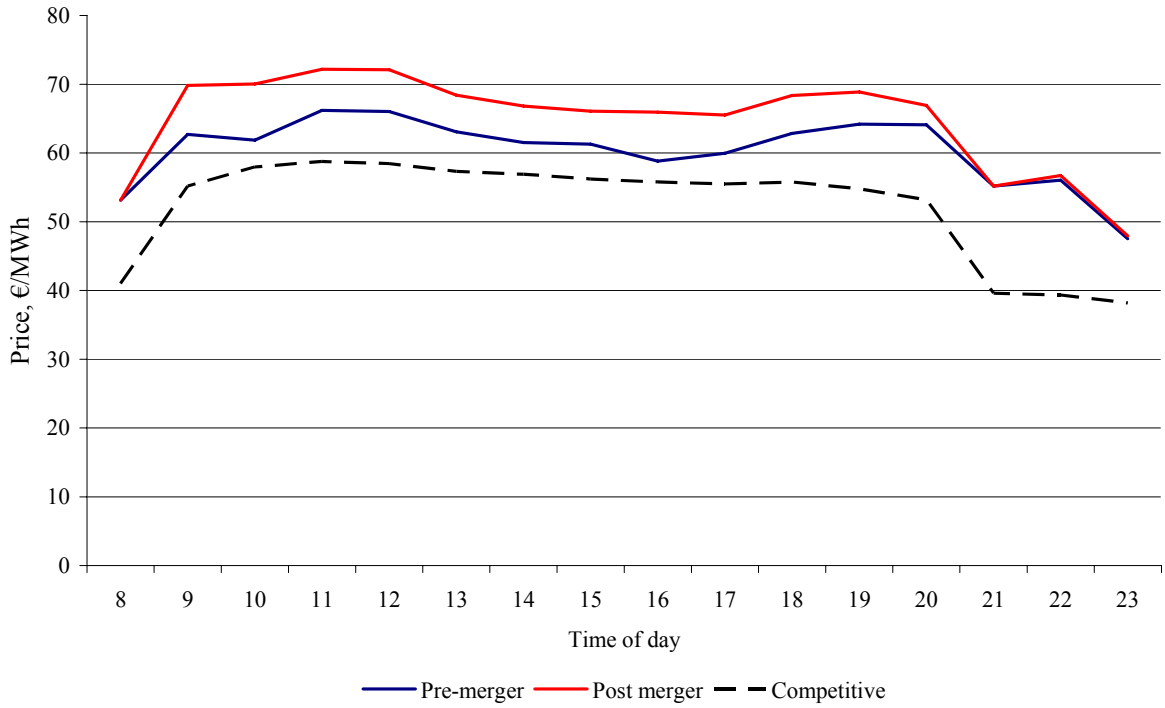
Appendix II describes and explains our Cournot model in more detail. It is worth noting that, unlike an HHI analysis, with a Cournot model there is no need to define the geographic extent of the market. This is required in an HHI analysis, since one must define the market before calculating market shares. With a Cournot model, there is no need to define market shares. Imports from other areas will constrain the prices the Cournot players achieve where possible, and when interconnectors constrain imports the prices Cournot players can achieve will rise. Hence, the market definition exercise – where one calculates if imports can render price rises unprofitable or not – is an integral part of the Cournot model. Moreover, one does not need to define peak and off-peak products, since the Cournot model treats every hour as a separate event. In a sense, every hour is a separate product, because the model assumes no substitution between hours.

Results

Figure 42 illustrates the average hourly prices the Cournot model predicts before and after a Nuon-Essent merger. The model predicts that, on average, prices between 07:00 and 23:00 would increase by over €4/MWh, or just over 7%. In some hours, prices increase by over €8/MWh. The

chart also shows for purpose of comparison estimates of competitive prices provided by this model (rather than the BAM model).

Figure 42: Dutch prices predicted by the Cournot model before and after a Nuon-Essent merger



7.3 Co-ordinated effects

The previous analysis is conservative in the sense that it does not model the possibility of co-ordinated effects or collusion. Rather, the HHI and other Cournot-based models simply assume strategic interaction between players, but do not assume explicit collusive agreements between market parties.

Economists have developed a well-accepted literature on the particular attributes of an industry that contribute to the likelihood of tacit collusion in that industry, as well as attributes that inherently hamper tacit collusion. The industry factors that promote tacit collusion include: products that are homogeneous, high degrees of concentration, transparent information on sellers' output and prices, frequently repeated trading, symmetries among firms in the market (such as market shares, costs, technological knowledge, capacities, etc.), high entry barriers, contractual and structural links among competitors, and highly inelastic demand. The features associated with a low probability of successful tacit collusion are asymmetries in cost or capacity shares, cyclical or unpredictable demand, and a high degree of innovation and product differentiation.

The electric power industry happens to have nearly all of the attributes of an industry that is highly susceptible to tacit collusion and few of the features that tend to discourage it. Electric power is a very homogenous product that has experienced little product differentiation or innovation in many years. For security and reliability reasons, information about sellers' output, costs, and capacities is often readily observable. Electric markets also often trade in centralized "pools", which increase the gains from tacit collusion and make prices highly observable.

Electricity is traded repeatedly by the same traders, sometimes over periods as short as one hour, facilitating coordination (again particularly in a centralized pool). Finally, demand is highly inelastic, increasing the profitability of tacit collusion when it occurs.

Moreover, the large sunk costs of entering the generation market make the threat of entry less of a constraint than in some other industries. Even if entry does occur, it will typically take several years, which time significant harm could be done to consumers. Since merger analysis typically looks a three to five year period, in most circumstances competition authorities cannot rely on entry to mitigate the effects of market power. A dominant or collectively dominant group of generators could raise prices above the competitive levels for several years without attracting entry.

In sum, we note that the electricity power industry has a number of features which make it susceptible to collusion, and that a merger which increased concentration could increase the likelihood for collusion. This would lead to higher price rises than predicted by Cournot-based models.

7.4 Possible Remedies

Of course any merger has to be the subject of detailed scrutiny on the basis of the facts known at the time, taking proper account of the arguments presented by all relevant parties including the merging companies. However, our own view of a hypothetical merger of Nuon and Essent is that it could not be approved without significant remedies at least to be compatible with the Commission's merger guidelines. Remedies for the effects of a merger on the wholesale market could take two forms: structural remedies, in which the merged entity divests plant; and behavioural remedies, in which the merged entity commits to e.g. offer a certain amount of electricity at a certain price.

Behavioural remedies are generally inferior to structural remedies, for three main reasons. First, the regulator or other relevant authority must commit to monitoring the merged entity to ensure that it abides by the behavioural remedies. This can be costly and use significant regulatory resources. Second, enforcement can be difficult, both because deviations from any commitments the merged entity made can be hard to detect, and if they are detected then sanctions can involve costly legal proceedings. Finally, the remedies themselves may distort the market. For example, the authorities may require the merged entity to offer a given amount of power at a set price, but this may be quite different from the competitive market outcome, and distortions and inefficiencies could result. In contrast, structural remedies require no monitoring and enforcement and, if well-designed, should approximate the level of competition before the merger. Consequently, remedies for a Nuon-Essent merger should be structural in nature, focusing on plant divestment.

As a further indicative exercise, Table 16 illustrates our calculations for the divestments that a merged Nuon-Essent would need to make to satisfy the Commission's HHI guidelines (i.e. to keep the HHI increase under 150 if the post-merger HHI is above 2,000, and under 250 if the post-merger HHI is between 1,000 and 2,000), in either a Dutch peak market or a Dutch-Belgian peak market. We calculate that in a Dutch peak market, Nuon-Essent would need to divest just under 1,900 MW of capacity to satisfy the Commission's HHI guidelines; they would have to divest less capacity (1,000 MW) with a Belgian-Dutch peak market. Note that in our calculations,

we have divested capacity on a plant-by-plant basis (rather than assuming some form of virtual divestment). We also take the case that Eneco, which currently has little generating capacity, acquires Nuon-Essent's divested plant. That the smallest current generator acquires the divested plant reduces the divestment required to meet the HHI guidelines. If a market player with a larger current generating capacity (such as E.ON or Electrabel) acquired some of the divested plant, more divestment would be required. Conversely virtual divestment[66] may require less capacity to be divested to achieve the required HHI. This is because many smaller players, who are not currently active in generation (*e.g.* small electricity suppliers) can hold 'virtual' capacity. Diverse holdings of divested capacity held by new market players will result in a lower HHI than the same MW of plant divested physically.

Table 16: The effect of divestment on concentration in a Dutch peak market and a Dutch-Belgian peak market following a Nuon-Essent merger

	Dutch peak market	Dutch-Belgian peak market
Nuon/Essent capacity, no divestment, MW	8,484	8,724
Nuon/Essent capacity, after divestment, MW	6,590	7,705
Nuon/Essent capacity divested, MW	1,894	1,019
Pre-merger HHI	1,328	2,059
Post-merger HHI no divestment	1,983	2,301
Increase in HHI no divestment	655	242
Post-merger HHI with divestment	1,575	2,210
Increase in HHI with divestment	246	150
Nuon-Essent market share no divestment	37%	22%
Nuon-Essent market share with divestment	28%	20%

However, we calculate that even after the 1,900 MW of divestment designed to meet the Commissions' HHI guidelines, Nuon-Essent would remain a pivotal supplier in a peak market defined by the Netherlands for 24% of the time. Similarly, in a peak market defined by the Netherlands and Belgium, after the 1,000 MW of divestment designed to meet the Commissions' HHI guidelines, Nuon-Essent would remain a pivotal supplier for 38% of the time. In other words, the parties would still have market power even if they met the Commission's guidelines. The PSI analysis indicates that Nuon-Essent would need to divest about 4,200 MW of plant to avoid being a pivotal supplier in a Dutch peak market, and nearly 5,300 MW in a Dutch-Belgian peak market. We also note that the PSI analysis is probably a better indicator of market power in the electricity wholesale market than the HHI.

That Nuon-Essent has to divest more in a Dutch-Belgian market to avoid being pivotal than it must divest in a Dutch market, even though Nuon-Essent is pivotal for less of the time in the

[66] In virtual divestment, acquirers typically buy the right to despatch up to a given number of MW at a set price per MWh. These are often called Virtual Power Plants or VPPs. In effect, they act like an option, as the owner has the right but not the obligation to buy power.

Dutch-Belgian market, may seem counter-intuitive. One might think that the amount of capacity a firm needs to divest to avoid being pivotal should be proportionate to the percentage of time that the firm is pivotal; if the firm is pivotal for more hours under an alternative market definition, it seems like it would need to divest more capacity under the alternative market definition. In Appendix IX we explain how the relationship between divestment and the percentage of hours pivotal depends on the pattern of demand. If the pattern of demand is different in two different markets, then a firm which is pivotal for less time under market 'A' than market definition 'B' may actually need to divest more capacity to avoid being pivotal under market definition A than definition B.

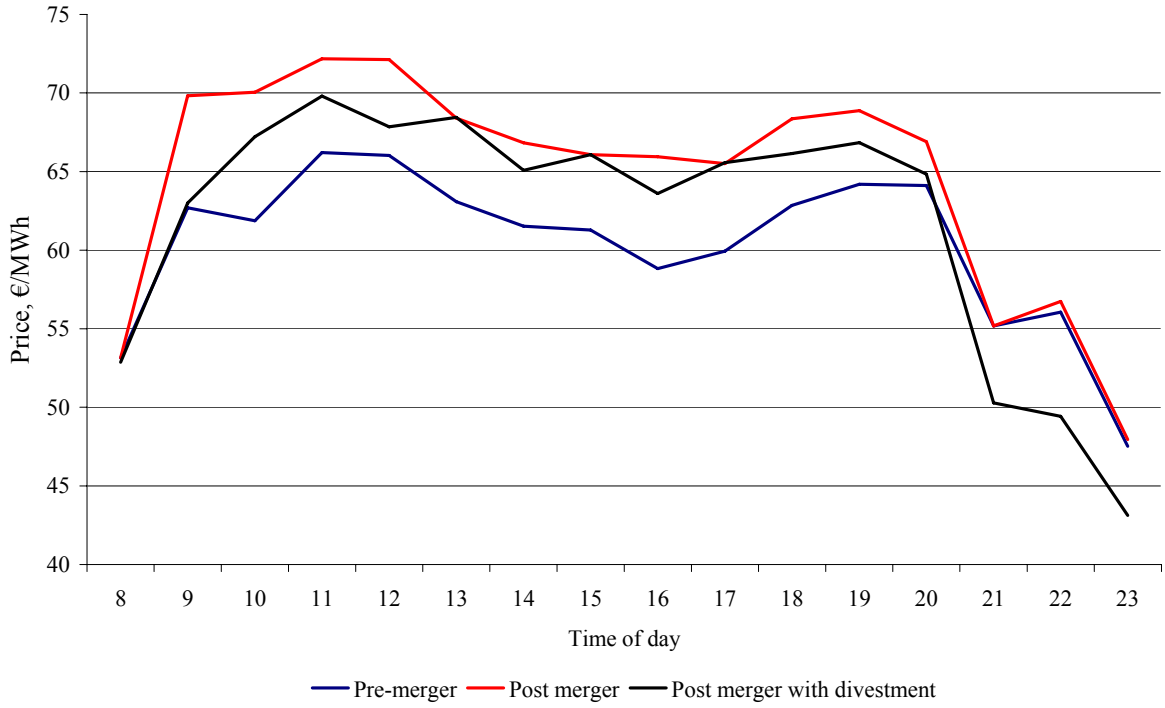
We have also analysed the (approximately) 1,900 MW divestment suggested by the HHI analysis in our Cournot model.[67] Divestment will reduce Nuon-Essent's ability and incentive to exercise market power in a Cournot game: they will have less marginal plant to withdraw; and they will have less inframarginal that would benefit from any price increases which they achieve.

Figure 43 illustrates that if the merged Nuon-Essent divested about 1,900 MW, average peak prices would increase by €1.6/MWh, (or about 3%) relative to the pre-merger prices. Hence, divestment reduces the price increases resulting from the merger, but does not quite bring prices back to the pre-merger level. This is line with the HHI analysis; since the HHI has still increased by around 250 points after divestment, relative to the pre-merger HHI. Since the HHI has a close theoretical relationship to the Cournot model, one would expect the changes in the HHI and the price changes predicted by a Cournot model to correspond.

We note that our list of divested plant was chosen to represent a reasonable mix of baseload and peak plant. In practise, the effects of divestment are sensitive to the precise plants chosen, and in an actual merger case this is an area to which the competition authority should pay careful attention.

[67] Specifically, we assume that a merged Nuon-Essent would divest: Hemweg HW-7 (585 MW); Lage Weide LWE6(235 MW); Merwedekanaal MK11 (95 MW); Moerdijk (MD-1) (339 MW) Purmerend (60 MW) Borssele BS12 (Coal) (400 MW); DEL1 (180 MW).

Figure 43: The increase in prices predicted by a Cournot model following a Nuon-Essent merger and following a Nuon-Essent merger with divestment



Note that our market power analysis is based on *average* conditions. There could be circumstances, such as the unavailability of plant due to hot weather or other unusual conditions, which temporarily increase the ability of large players in the Dutch market to exercise market power.

8 Balancing electricity

So-called Program Responsible Parties or PRPs in the Netherlands must submit a programme to Tennet describing the amount of electricity that they intend to produce or use over the next day. Deviations from the programmes must be made up in the balancing market. On the supply side of the balancing markets, participants submit offers to Tennet to either increase their production (or reduce their consumption) of power to make up net shortfalls in power production, or reduce their production of power (or increase their consumption) to absorb excesses of electricity production. While the supply side of the balancing market is open to both producers and consumers of electricity, in practice producers (*i.e.* generators) supply almost all balancing electricity and for a variety of reasons this is unlikely to change within the relevant timeframe for merger control. Hence, we discount the role of consumers in the balancing market in our analysis.

We define two balancing products: upward regulation (where a generator increases power production); and downward regulation (where a generator decreases produced power).[68] To provide upward regulation, a plant must be able to change output at reasonably short notice (which means that it must be already operating and have a reasonably good rate of production increase or ramp-rate), and it must be running at less than its maximum capacity (so that it can increase production further). To provide downward regulation a plant must be running, and able to reduce output reasonably quickly.

Given the way upward and downward regulating power are produced and used, they are not substitutes for one anther. Therefore, it is appropriate to define upward and downward regulation as separate products.

We begin by explaining why, even without doing a SSNIP test, the Netherlands defines a market for balancing electricity, before going onto calculate market shares in the upward and downward regulating markets, and the effect of mergers.

8.1 The Dutch balancing market is currently national in scope

At present, Tennet does not allow imports to correct temporary imbalances between supply and demand. Consistent with this requirement, cross-border exchanges are programmed a day in advance, for each hour of the following day (*i.e.* flows should remain roughly constant over an hour). Therefore, with the current rules, it is not possible for a generator in one control area to provide balancing power to another control area, because the generator would not be able to anticipate the imbalance one day-ahead. Moreover, in the Netherlands imbalances are defined over 15 minute time periods. As imports are programmed for an hour at a time, it would not be possible for a foreign generator to provide a set amount of imbalance power for only 15 minutes. In sum, the provision of balancing power can only come from generators within a control area. Generators (and for that matter consumers) from outside of the Netherlands have no ability whatsoever to provide balancing services to the Netherlands. Accordingly, Tennet's control area (*i.e.* the Netherlands) defines the geographic market for balancing power.

[68] In practice, there are several different forms of balancing power, for example regulation and different types of reserve power, but we consider all of them occupy the same product market.

While we also conclude that the Netherlands defines a market for peak electricity for the purposes of merger control, there is an important difference between the peak market and the balancing market. Imports can compete with domestic generators for sales of peak electricity, whereas, for reasons described above, foreign generators cannot provide balancing power to the Netherlands. Accordingly, the peak wholesale market is the Netherlands plus interconnector capacity, whereas the balancing market consists only of Dutch generators. Since Tennet anticipates that there will be around 4.3 GW of interconnector capacity, compared to around 21 GW of domestic generation in 2009, the inclusion of foreign imports makes an important contribution to the degree of competition in the market. Moreover, only relatively flexible plant can participate in the balancing market, which shrinks the pool of participants further – we estimate that in 2009, less than 17 GW of capacity would be suitable to participate in the balancing market (*i.e.* over 4 GW of plant will be CHP, nuclear or other non-flexible plant). In sum, while around 25.3 GW of capacity can participate in the peak wholesale market, only around 17 GW can participate in the Dutch balancing market. This creates the potential for a more concentrated Dutch balancing market, depending on the degree of concentration of ownership of flexible plant relative to that of all plant.

8.2 Market shares in the Dutch balancing market

Table 17 illustrates market shares in the Dutch balancing market, derived from data provided by Tennet. Ideally, one would like to define market shares according to players' capacity or ability to provide upward or downward balancing power. For example, for upward regulation, we would like to measure the difference between a player's power production in any hour and their maximum power production possible; for downward regulation, it would simply be the capacity of plant running in an hour that the player could withdraw from the market. Unfortunately, such data is not publicly available. Moreover, it is difficult to predict by modelling, since most computer simulations of the wholesale market (including BAM) will model a plant as either running at full capacity or not at all. To make such predictions would involve a detailed dynamic model that would be extremely computationally intensive.

In the absence of data quantifying players' ability to produce balancing power, we have used historic offers into the balancing market to define market shares, on the grounds that there is likely to be a good correlation between a players ability to produce balancing power and the number of offers they have accepted in the balancing market. Since there are 96 balancing periods per day, we restricted our sample to three separate weeks in 2003 (*i.e.* approximately 860 balancing periods), covering different seasons, rather than sample a longer period of time. As imbalances are by definition random, there is no reason to think that supply and demand in the balancing market follows any particular pattern, and the sample of data we use should be representative. Note that Tennet have replaced the names of the market participants with letters to protect the confidentiality of the offers made.

Table 17 illustrates that only five players provide power to the upward and downward regulating markets; there is no participation by smaller players or the large power consumers. The HHI of both the upward and downward markets is 2,300 (it seems to be a pure coincidence that both have the same HHI—note that the distribution of market shares is quite different in the two markets). Most economists would regard this as a concentrated market. We note that a PSI analysis of the balancing market would be complicated by the volatile nature of demand in the balancing market.

Table 17: Shares of the Dutch upward and downward (average of three weeks data)

[Confidential data]

It also seems significant that there are only five major players in the balancing market, and this is similar to the number of large players in the wholesale market. We have calculated the share of Dutch generators of flexible (*i.e.* gas and coal-fired) plant in the Netherlands, and ranked the participants in order of those shares (highest share first). We then rank the anonymous parties by their share of the upward and downward regulating market in Table 17. Finally, we assume that the party with the largest share of the flexible capacity market corresponds to the party with the largest share of the balancing market – for example that Electrabel corresponds to party C in the balancing market. We then plot market shares of the capacity and balancing markets by participant in Figure 44. Figure 44 shows that there seems to be a reasonable degree of correlation between a market party's share of flexible capacity and their assumed share in the balancing market. Hence, it seems likely that the degree of participation in the balancing market is roughly proportional to shares of flexible plant. Smaller capacity owners do not seem to participate in the balancing market.

Figure 44: Market shares in the balancing market compared to shares of flexible capacity

[Confidential data]

The effect of a merger

With such a concentrated market, any merger is likely to lead to an unacceptable increase in concentration according to the Commission's guidelines. Table 18 illustrates that even if the two smallest participants were to merge, the HHI would increase by over 300 points to around 2,600. However, in mitigation, entry into the balancing market is easier than entry into the generation market, since on the supply side generators (with the right kind of plant) can easily switch between providing balancing power and providing power in the wholesale market.

Table 18: Shares of the Dutch upward and downward following a merger between the two smallest players

[Confidential data]

Possible remedies

A merger of any of the five main balancing participants would raise concentration in the balancing market to an unacceptable level. In section 7.4 we argued that structural remedies – divestment – were superior to behavioural remedies. However, in the balancing market divestment of flexible plant faces three problems. First, in the absence of any new entrants into the balancing market, the lowest HHI divestment could achieve would be 2,500. This is still 200 points above the pre-merger HHI. Second, typically only a small part of a plant's capacity will be used in the balancing market – there are no dedicated balancing plants. Hence, to divest *e.g.* 50 MW of balancing power may in practice require the divestment of 500 MW of flexible capacity. This may be regarded as a disproportionate level of divestment for the problem it solves, although this would require additional analysis of the potential price impact of increased concentration in the balancing market, which goes beyond the scope of this paper. Finally, even if the merging parties were required to divest plant to increase competition in the balancing market, the acquirer

may chose not to use the plant to provide balancing power. Hence, the divestment would result in an increase in concentration in the balancing market. In contrast, divestments designed to address concentrations in the wholesale market will be effective, since the acquirer will use most of the plant's output in the wholesale market. In sum, the acquirer will use most or all of a divested plant's output to provide wholesale market power, but may not use any of the plant's output to provide balancing power.

Accordingly, for the balancing market behavioural remedies may be preferable to structural remedies. NMa could seek a commitment from the merged entity to offer a fixed amount of upward and downward regulation to the balancing market subject to a price ceiling approved by NMa/DTe, and reviewed at regular intervals to accommodate changes in fuel prices *etc.* Alternatively, NMa could require the merged entity to offer 'virtual' balancing power plants. These would be similar to virtual power plants, but able to be despatched at short notice and only allowed to offer into the balancing market. The use of virtual balancing plants could negate the need to control offer prices, although the 'call' price of the virtual plant would still need to be regulated. At the same time, NMa should encourage Tennet to increase the pool of active balancing market participants, by for example encouraging more demand-side participation. However, we acknowledge that Tennet has made ongoing efforts in this direction with little apparent success.

8.3 An expanded balancing market

While the Netherlands currently defines a market for balancing power, future changes could create a larger balancing market. In the 'roadmap' for regional market integration, the energy regulators of the Netherlands, Belgium and France (DTe, CREG and CRE respectively) expressed a preference for the integration of balancing markets based on a model of TSO to TSO balancing trade *i.e.* where only the TSOs are responsible for the management of cross-border balancing trade. The regulators have asked that by 1st January 2007, the Dutch, Belgian and French TSOs should submit a joint proposal for cross-border balancing trade based on the TSO-TSO model. Once approved by the regulators, implementation of this cross-border balancing scheme shall be effective no later than the 1st of July 2007.[69]

In the case of cross-border balancing trade, the issue as to whether the Netherlands defines a separate balancing market would be similar to those for the wholesale market. The answer would depend in large part on the amount of interconnector capacity that the TSOs had set aside for the trading of balancing energy, and the respective costs of providing balancing on either side of the interconnector. However, there are very major differences between the wholesale markets and the balancing markets that must be kept in mind in any attempt to perform a SSNIP test for the balancing markets than for the wholesale markets.

Balancing markets are difficult to simulate, as demand is by definition random, and the offers made to the TSO tend to be "complex", including both variable costs and start-up costs over a short number of hours. For example, a firm may offer to increase production at short notice, but needs to start up another unit to do so. Since the firm may only be required to run for 15 minutes,

[69] 'Regional market integration between the wholesale electricity markets of Belgium, France and the Netherlands - a road map prepared by CRE, CREG and DTe', December 2005, §4.3 p.7.

it would need to recover the unit start-up costs in its balancing offer price. This can lead to very high balancing offer prices, and large differences in offer prices as 'lumpy' start-up costs are included.

Accordingly, balancing markets are not susceptible to the kind of modelling that we performed for the wholesale markets. On the other hand, the balancing markets are smaller and transparent, in that the TSOs see all offers made and accepted, and there is no possibility for flows from outside the control area. Therefore, the best approach to a SSNIP test would be for NMa to rely on an analysis of *historical* offers and demand in the balancing market. Taking the example of a single Dutch-Belgian control area, NMa (in co-operation with the TSOs) could look at offers from Belgian and Dutch generators, the amount of capacity set aside for balancing trades between the two countries and demand. NMa could then increase the price of all the Dutch offers by 10%, and see if this would be profitable for a hypothetical Dutch monopolist given the price of competing Belgian balancing offers and the amount of capacity available for balancing power flows from Belgium. We note that this would only be possible if there was a sufficient history of offers and bids in a single Benelux control area.

9 Electric retail markets

Analysis of retail markets must focus on issues that are specific to retailing, and avoid repeating analysis that has already been carried out for wholesale markets. In practice, many competitive problems in markets for retailing electricity and gas arise from various forms of foreclosure, either in wholesale markets or in network access. Thus the relevant question for analysis of geographic market definition for retail markets is whether there are barriers that prevent companies in one area entering another area, other than barriers in the wholesale market. In practical terms for the Netherlands this means for any given area: if an out-of-area company can obtain power and ancillary services (balancing power) in the wholesale market on non-discriminatory terms, are there any barriers that prevent it from entering as retailer in that area.

Potential barriers are of two kinds:

- Incumbent retailers in many places are able to restrict entry through their ownership and control of the distribution network, for example by introducing slow and cumbersome procedures for customer switching, responding slowly to requests for switching, setting high charges etc
- Incumbent retailers enjoy a legacy of benefits of which the greatest is simply the inheritance of the customer base (others include brand awareness and knowledge of the market)
- For the Netherlands we do not believe that the first of these is likely to be relevant. Consumers of all sizes have been free to switch in the Netherlands for many years (even small consumers have been free to switch since 2001, albeit until 2004 this was only to green electricity). While problems with customer transfer, provision of metering information etc are not unheard of, the Netherlands is in the process of implementing a strict unbundling policy, and also has an effective regulatory system and agency in place that will provide additional safeguards against any residual discrimination.
- Experience from other retail markets indicates that the second type of barrier is highly relevant for small consumers (households and small commercial), but not for other types. Liberalised markets with reasonably open access to wholesale markets and networks have typically seen rapid and successful entry in retailing to medium and large size consumers. For example, this has been the experience of the Netherlands itself, Spain and the United Kingdom.

Our focus therefore is on retailing electricity to domestic and small commercial consumers. In the rest of this chapter we use the term “retail market” to refer to this activity.

9.1 Background: the Dutch retail market

Market opening occurred in July 2001 for green electricity, and in July 2004 all consumers became fully eligible. Both incumbents and entrants offered green tariffs following the 2001 opening, and a very high proportion of consumers switched to green tariffs (which attracted large subsidies). However, most of those who switched tariff did not switch supplier. By July 2004

about 9% of consumers had switched away from their historic supplier to a different supplier offering a green tariff, and we understand that in the vast majority of cases this involved switching to one of the firms that entered the Dutch retail market as "green retailers" (e.g., Greenchoice, Oxxio, RWE).[70]

With the introduction of general retail competition in 2004 switching appears to be moving at rates comparable to the more successful EU markets (see below). Latest data indicates that annual switching rates for 2005 were about 6% in both electricity and gas.[71] The main incumbent retailers (Nuon, Essent, Eneco) are investing significantly in branding, using national advertising campaigns (even after unbundling the retailers will share a common brand with the distribution companies). Entrants make use of door-to-door sales and telemarketing.

In the Netherlands as in other Member States, the retail market is characterised by rather low switching rates. Table 19 shows cumulative switching rates for household and small businesses in EU15 Member States (i.e., cumulative switching since market opening).[72] We note that in some cases the existence of retail price controls may deter competitive entry, particularly if they are set at unrealistically low levels. Nonetheless, the data confirm the commonly held view that small energy consumers are "sticky" in their choice of retailer. Experience in other markets (e.g., the United States) also indicates low levels of switching by households.[73]

[70] Unless stated otherwise, information in this section concerning the Dutch retail market was provided by NMa-DTe.

[71] Source: newsletter B-con nieuwsbrief 15, 26-01-2006.

[72] Data for the EU10 accession states omitted, but indicates no switching to date.

[73] See for example "Les marchés de détail dans le secteur électrique : un tour d'horizon", J.M. Glachant, Working Paper of Florence School of Regulation, 2005.

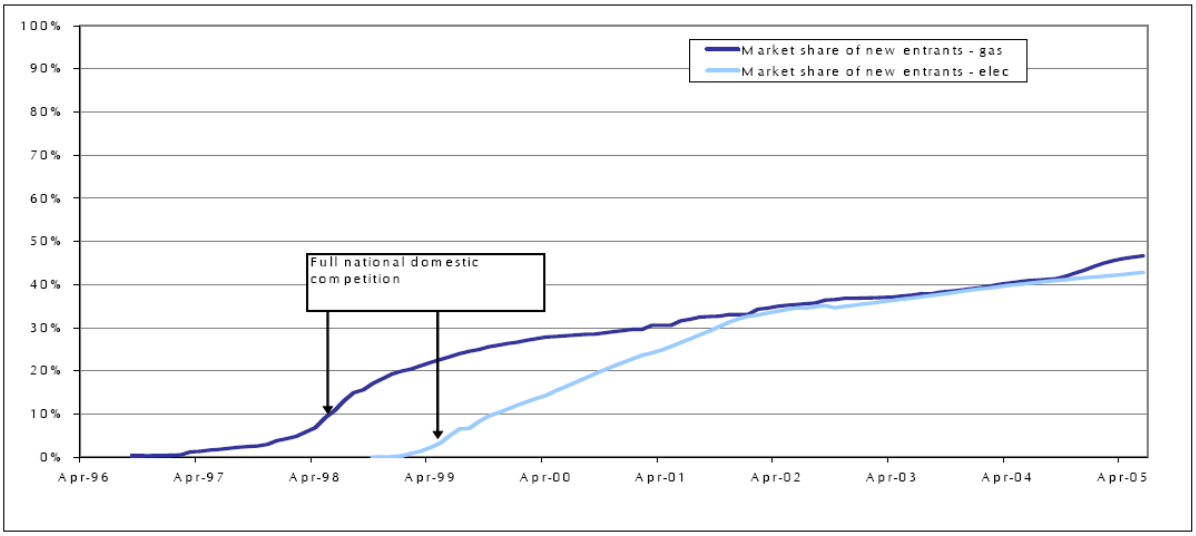
Table 19: Switching Rates in EU15 + NO (Electricity, Very Small Businesses and Households)

Country	Switching (by volume)
Austria	4%
Belgium	10%
Denmark	c. 15%
Finland	30%
France	0%
Germany	5%
Greece	0%
Ireland	9%
Italy	-
Luxembourg	0%
Netherlands	11%
Portugal	16%
Spain	19%
Sweden	29%
UK	48%
Norway	44%

Source: European Commission, Report on Progress in Creating the Internal Gas and Electricity Market, Dec 2005, pp.38,39,40.

While Dutch experience to date is relatively limited, the data shown above on switching rates in the Netherlands are clearly in line with experience elsewhere. Similarly, the combined market share of new entrants in the Dutch retail market currently stands at around [10 – 20%]. Figure 45 shows the rate of new entrant penetration in UK retail market (also for small consumers). If we take market opening date as July 2004 then new entrant penetration has been rather slower in the NL than in the UK, since the graph indicates that after about 18 months new entrant market shares in the UK were around 20% in electricity.

Figure 45: Market shares of new entrants in UK domestic retail[74]



[74] Ofgem, Domestic Retail Market Report - June 2005, February 2006, p.6.

DTe regulation of retail markets

Retail margins in the Netherlands are subject to a form of *ex post* regulation by DTe (according to Art. 95(b) of the Dutch Energy Act). DTe has a cost model and can set maximum retail tariffs. However, it is important to understand the nature of this regulation. DTe takes a "light-handed" approach to retail regulation, in the belief that competition between retailers can provide significant benefits to consumers that are hard to replicate with regulation. It therefore does not publish maximum retail tariffs. Instead it monitors retail tariffs and intervenes if it believes that they entail an excessively high retail margin.

The key advantage of this approach is that it can foster competition by reducing the risk of implicit collusion between retailers. Publishing maximum retail tariffs runs the risk that all companies set their tariffs at this level (in terms of economic theory, the maximum tariff would become a "focal point" for implicit collusion). Competition between retailers also has advantages for example in relation to quality of service (e.g., metering, billing) and innovation (e.g., new contract structures).

There is some evidence that the approach is successful: current retail margins are generally below the level that induces DTe intervention. It follows that a merger could harm consumers if it reduced the level of competition. It is therefore necessary and appropriate in performing merger control to consider the impact of a merger on retail markets.

Pricing in the Dutch retail market

A key feature of the Dutch retail market is that prices between entrants and incumbents have converged rather rapidly since liberalisation. Table 20 shows the range of prices available from incumbents and the two major new entrants in the Dutch retail market, based on the most recent data available.

Table 20: Dutch retail prices, Jan 2006

Dutch Retail Market Grey Energy Price

	Variable Price		Fixed Price	
Contract Length	Incumbents	Entrants	Incumbents	Entrants
No contract	217 - 236	229 - 232		
1 year				238
2 years				233
3 years				207 - 230

Notes: Incuments companies are ENECO, NUON and Essent. Entrant companies are OXXIO and RWE.
The prices above exclude taxes, transmission and distribution charges

Dutch Retail Market Green Energy Price

	Variable Price		Fixed Price	
Contract Length	Incumbents	Entrants	Incumbents	Entrants
No contract	234	263 - 266		
1 year	225 - 293			233 - 278
2 years				198 - 278
3 years				192 - 241

Note: Incuments companies are ENECO, NUON and Essent. Entrant companies are OXXIO and RWE.
The prices above exclude taxes, transmission and distribution charges

This is in clear contrast to experience in some other MS. For example, in the UK, where the retail market has been fully open since 1999 (and there have been no price controls in place since 2002) there still remains a large gap between the price charged by incumbent retailers and the prices charged by entrants.

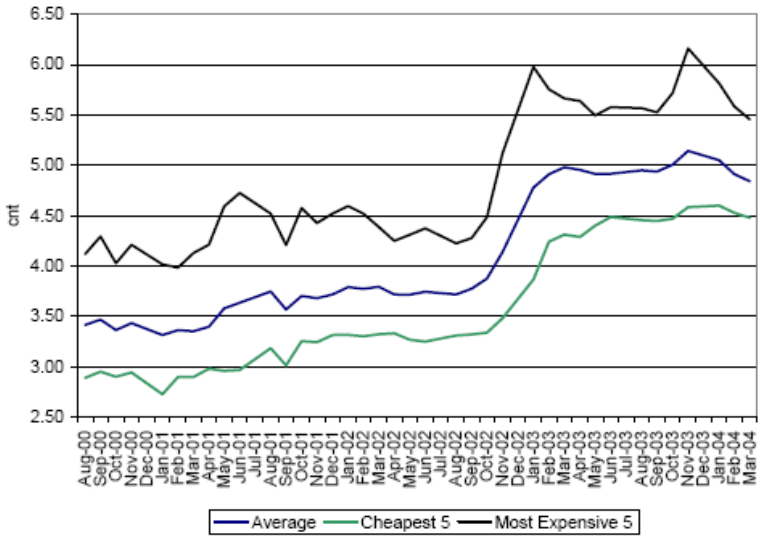
Table 21: GB savings relative to incumbent (February 2004)

Consumption	Min Saving (%)	Max Saving (%)	Medium Saving (%)
Electricity			
Low	0-5	4-16	2-10
Medium	0-6	8-18	3-13
High	0-8	8-22	4-12
Dual Fuel			
Low	0-4	11-18	4-11
Medium	2-5	11-17	8-12
High	2-5	13-18	7-12

Source: Ofgem, Domestic Competitive Market Review, Dec 2004, pp.107,112

Similarly, evidence from Finland, where the market has been open since 1998, shows a very marked dispersion between the highest prices (charged by the local incumbent) and others, as shown in Figure 46 below (note that these prices refer only to the supply portion of the bill).

Figure 46: 5000 kWh end-user offer price ranges, cnt/kWh, Finland[75]



This difference is important for geographic market definition (in countries where prior to liberalisation there were multiple utilities, each with a regional monopoly franchise). All else being equal, the ability of the incumbent in a given region to charge a significant premium tends to argue in favour of a regional market definition, since it appears that competitive pressure from incumbents from other regions is rather limited. However, the evidence shown above does not support such a conclusion for the Netherlands.

Another possible exercise would be to look at regional market shares. However, this is a much weaker kind of evidence, since even if regional incumbents retain very high market shares in their "home" region, players in other regions might well represent potential competition that has a significant restraining effect on pricing.

Geographic market definition

For the purposes of retail market definition we do not see a reliable way to perform a SSNIP test. Simulating the impact of a permanent 5-10% increase would require a dynamic model of consumer switching, with estimates of the distribution of switching costs across the population, which would in turn require (or imply) some assumptions about competitive responses (extent of entry, speed, level of marketing effort etc). Such an exercise would be challenging in any circumstances, but at present the short history of retail liberalisation and consequent absence of relevant experience and relevant data make it impossible.

We therefore turn back to the underlying definition of geographic market given in the Commission guidelines: [76]

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[75] Source: Analysing the relationship between wholesale and end-user prices in the Nordic electricity market, Vaasa, April 2004, Philip E. Lewis, Tor A. Johnsen, Teemu Närvä, Salman Wasti, p.48. Notes in square brackets added by us.

[76] Commission Notice on the definition of the relevant market for the purposes of Community competition law, 1997.

> *The relevant geographic market comprises the area in which the undertakings concerned are involved in the supply and demand of products or services, in which the conditions of competition are sufficiently homogeneous and which can be distinguished from neighbouring areas because the conditions of competition are appreciably different in those areas.*

This contains three criteria. With regard to the first ("the area in which the undertakings concerned are involved in the supply and demand of products or services"), the main Dutch retailers are all involved in retailing on a national basis. It seems clear (despite the lack of precise data) that each has its customer base heavily concentrated in its former franchise area, but as discussed above the lack of price differences between incumbents and entrants implies that each incumbent experiences competitive pressures,[77] or at least is consistent with that claim. In fact the Commission guidelines foresee such a situation, noting that "[c]ompanies might enjoy high market shares in their domestic markets just because of the weight of the past…"

With regard to the second ("the conditions of competition are sufficiently homogeneous"), it seems that the conditions of competition are homogeneous nationally. For entrants this is a reasonable supposition (although again the absence of regional data is problematic). For incumbents, again the lack of major price differences argues against, or at least fails to provide evidence for, a major competitive advantage in their home region.

With regard to the third ("can be distinguished from neighbouring areas"), it is clear that consumers in the Netherlands cannot buy power from a retailer in another Member State; for example, a retailer active in Germany would need to establish a Dutch subsidiary in the Netherlands to supply customers there.[78]

These considerations argue in favour of a national market definition, although on the basis of rather limited evidence. In contrast, a regional market definition would imply that the Dutch incumbent retailers have limited ability to compete in each others' areas and in the absence of strong evidence, such a conclusion seems perverse for reasons noted above. We therefore believe that on the basis of the available evidence, in particular the lack of a significant price difference between incumbents and entrants, a national market definition is most appropriate for the Netherlands.

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[77] It is also relevant that incumbents' pricing is—as discussed earlier—generally below the "ceiling" that would induce intervention by DTe. Otherwise the lack of price differences would simply be an artefact of regulation, rather than reflecting competitive pressures.

[78] Obviously in our example that option is open to the hypothetical German retailer. However, the Commission guidelines on market definition note that "[s]upply-side substitutability may also be taken into account when defining markets in those situations in which its effects are equivalent to those of demand substitution in terms of effectiveness and immediacy. This requires that suppliers be able to switch production to the relevant products and market them in the short term without incurring significant additional costs or risks in response to small and permanent changes in relative prices", and that in other circumstances, constraints from supply side substitution should be taken into account not in market definition but in the competitive assessment stage.

Merger control: general considerations

Table 22 shows the current market structure and HHI for the Dutch retail market, based on the most recent (2006) DTe estimates of the number of small customers (residential and small business).[79] The HHI indicates a high level of concentration, as does the combined market share for the three largest firms of [80 – 90%].

Table 22: Dutch Retail Market Shares

Firm	Market Share
Eneco	[20-30%]
Nuon	[30-40%]
Oxxio	[0-10%]
RWE	[0-10%]
Essent	[20-30%]
Others	[0-10%]
HHI	[2,200-2,300]

In assessing the impact of a merger, it is important to bear in mind the effect of potential competition. In markets where entry is relatively easy, even significant concentrations may not have major negative effects on competition. For the Netherlands, we believe the evidence on entry is ambiguous. Experience in other MS suggests that entry into retail markets is generally difficult. However, there are two noteworthy differences between the NL and (for example) the UK.

On the positive side, the NL has a few examples of apparently successful entry by new firms, in the form of OXXIO, RWE and Greenchoice, with between them a combined market share of [10 - 20%] (although some of this success may reflect a unique set of circumstances, the government decision to heavily subsidise green retail packages). On the negative side, in other countries the main entrant into electricity retailing has been the gas incumbent (e.g., Centrica in the UK, Gas Natural in Spain), and vice-versa. In the Netherlands this is not possible as the main regional distribution companies are already dual fuel companies. Overall it is hard to conclude that future entry in the NL market is likely to be more successful than in other Member States.

A further consideration is whether a merger would facilitate tacit collusion ("coordinated effects"). Here the legacy of a market divided upon regional lines is rather significant. It suggests that tacit collusion is already a significant risk. When firms are mostly active in different areas, it is relatively simple for each to understand that if they refrain from aggressive sales outside their own area then their competitors may be willing to do the same. Since such understandings are easier with fewer players, a merger between two Dutch incumbents might well facilitate tacit collusion. However, such an outcome is only sustainable if it is immune to entry: in this case, an agreement between the Dutch incumbents would be ineffective if it allowed firms such as Oxxio to win significant market share by under-cutting the incumbent price. As discussed above, the current evidence on entry is somewhat ambiguous and it is therefore difficult to draw firm conclusions.

[79] We understand that the data is of variable quality, and in particular the number for […] is an older estimate.

The general conclusion is therefore that the Dutch retail market is already highly concentrated, the ability of potential entry to act as a competitive constraint is at best unproven (and the low price differentials between incumbents and existing entrants would suggest that new entry is unlikely to be attractive), and tacit collusion may also be a concern. Any merger in this market would therefore have to be subject to very close scrutiny.

Hypothetical merger

As in section 7.4, we have analysed a hypothetical merger between two Dutch utilities, Essent and Nuon. Table 23 shows the impact on market shares and HHIs. Based on the [50 – 60%] post-merger share, the merger would clearly create or strengthen a dominant position for the two firms concerned, according to usual standards/case law. Similarly, the post-merger HHI and the increase in HHI are at levels that would normally give rise to serious concern. Of course any merger has to be the subject of detailed scrutiny on the basis of the facts known at the time, taking proper account of the arguments presented by all relevant parties including the merging companies. However, our own view of this hypothetical merger is that it could not be approved without significant remedies, based on the general considerations outlined above together with the market share and HHI data.

Table 23: Dutch Retail Market Shares post Nuon/Essent merger

Firm	Market Share
Eneco	[20-30%]
Nuon	[30-40%]
Oxxio	[0-10%]
RWE	[0-10%]
Essent	[20-30%]
Others	[0-10%]
Nuon/Essent post-merger	[50-60%]
HHI pre-merger	[2,200-2,300]
HHI post-merger	[3,900-4,000]
HHI increase	[1,600-1,700]

One possible type of remedy might involve the merged company "divesting" customers, for example by selling off some parts of its retail business.[80] As a minimum, it would appear necessary to lose [0 - 10%] market share, to get the post-merger market share below 50%, but it would not seem at all unreasonable to require more divestiture. For example, NMa might take the view that in this case 40% market share was sufficient to constitute a dominant position, and therefore require the merged company to lose at least [10 - 20%] market share. As a further

[80] A requirement to divest retail customers was imposed on Philadephia Electric ("PECO", now part of Exelon), not in connection with a merger but as part of the settlement of a stranded cost case in the late 1990s. PECO entered into an agreement to ensure that a considerable number of "Standard Offer" residential customers did in fact switch to retail suppliers. This guarantee was set up in terms of targets for customers that had "switched" which had to be met after the first, second, etc. years of retail access. The targets were not met by the natural growth of retail competition among small customers. PECO held an auction, in which a certain large numbers of residential customers were sold off. Unfortunately it is hard to judge the success of this programme as it was disrupted by subsequent unrelated events (arising from the bankruptcy of Enron).

indicative exercise, we have calculated the market share that would have to be lost in this way in order to limit the HHI increase to 150,[81] in line with the Commission's HHI screen (bearing in mind that it is a screen rather than a rule or recommendation, and that the HHI is only one measure of concentration and competitive impact), We estimate that if Nuon/Essent were to divest market share to a single brand new company, it would have to divest [10 - 20%] to keep the post-merger-and-divestment HHI increase down to 150 (the post-merger HHI would then be [2,400 – 2,500]). Divesting to Eneco would not do what is required: if all divestment were to be to Eneco, then at a minimum the post-merger-and-divestment HHI increase would be [1,000 - 1,100].

Other possible remedies could include ceding the company's brand name to a new entrant, or behavioural remedies such as a commitment to a particular set of prices for a certain number of years.

[81] The figure in the Commission Guidelines, given a post-divestiture HHI over 2,000.

10 Vertical Effects

In this section we consider the implications of a vertical merger between a player active on the supply side of the wholesale market (*i.e.* a generator) and a player active on the supply side of the retail market. We describe the main positive and negative effects of vertical mergers in the Electricity Supply Industry, and the likely steps a competition authority would need to take to analyse a vertical merger.

The most plausible and 'pure' vertical integration that could occur in the Netherlands at present would involve a merger between Eneco (which has relatively little generation capacity) and Electrabel (a generator which has little activity in the retail market in the Netherlands). While Electrabel is active in retail in Belgium and other countries, our work to date suggests that these activities take place in a separate geographic market from Eneco's retail business.

10.1 The pros and cons of vertical mergers

The main negative effects from a vertical merger represented by an Electrabel-Eneco merger would be:

- A reduction in liquidity in the wholesale market, since the merged entity would buy and sell more power 'internally'.
- The removal of a potential entrant from the supply-side of the wholesale market (Eneco) and the removal of a potential entrant from the supply business (Electrabel).
- The generator (Electrabel) would gain access to contracts that the supplier (Eneco) has with other generators. This could give the merging generator an informational advantage (because it knows more about the operations of its horizontal competitors) which might reduce the effectiveness of competition.
- The main positive effect from a vertical merger is that the merger would presumably reduce the costs of supplying electricity to consumers (since if it did not there would be little motivation for the merger). In the presence of sufficient competition in the retail market (which the merger would not affect directly) any reductions in transaction costs should be passed through to consumers, resulting in lower prices.

We expand on the main negative point of a vertical merger (the reduction in liquidity) below.

Reduction in liquidity

A reduction in liquidity would make wholesale prices a less reliable indicator of supply and demand fundamentals, since the prices would be based on fewer transactions.

Moreover, a reduction in liquidity is likely to increase wholesale price volatility and hence the risks suppliers and generators face who are not vertically integrated. This could result in a wave of further vertical integrations, resulting in further reductions in liquidity. Eventually, liquidity could be reduced to such an extent that it becomes difficult to enter either the supply-side of the wholesale market (by building generation) or the retail market. Plant developers would be more wary of making investments on the basis of volatile and less reliable price signals. Similarly,

vertically integrated companies may be reluctant to sell to competing suppliers, who would lose a potential source of upstream supply.

The England & Wales experience with respect to vertical electricity mergers is instructive, because the industry was re-structured with complete vertical separation between several generating companies and 12 distribution and supply companies knows as Regional Electricity Companies or RECs. Since re-structuring, the RECs first acquired equity interests in new independent power stations, and then many of the RECs were acquired by the generating companies. The UK competition authorise raised few objections relating to purely vertical effects.

For example, in its analysis of a vertical merger in the UK, the Monopolies and Mergers Commission (the MMC, which was the predecessor of the UK Competition Commission) recognised that reduction of liquidity was a negative effect, but judged that it was not (in the case examined) sufficient to damage consumer interests. In 1996, the MMC analysed the merger of Powergen, which was principally a power generator (although it did have a reasonable share of the market for supply to eligible customers) and Midlands Electricity plc. (MEB, one of the 12 RECs). MEB had an equity interest in several Independent Power Producers.

The MMC noted that:

> *"It has been put to us that the merger would reduce the size of the CfD market [i.e. the market for electricity contracts, similar to the Dutch OTC market], making entry by both independent generators and independent suppliers more difficult. We agree that a small CfD market would inhibit entry. However, we believe this market will be larger in 1998 than it is now even if the merger proceeds and that it will be in the interests of both the generation and supply businesses of the merged company to continue to contract with third parties. That the CfD market after 1998 would probably not be as large as it would be without the merger is, in our view, unlikely to lead to effects adverse to the public interest."*[82]

The MMC ultimately found that the merger, as proposed, was not in the public interest, but allowed it on the condition that MEB disposed of its equity interests in power stations and ring-fenced information from its power purchase agreements that could give an advantage to Powergen.

10.2 Analysis of vertical mergers

When considering a vertical merger, competition authorities must weigh up two competing factors. A vertical merger could reduce liquidity, increase the difficultly in entering the wholesale and retail markets and reduce the number of potential entrants. In a counterfactual case (*i.e.* without the merger) there could be more market entry, greater competition and reduced prices,

[82] PowerGen plc and Midlands Electricity Plc: A report on the proposed merger Presented to Parliament by the Secretary of State for Trade and Industry by Command of Her Majesty April 1996, §1.10 p.4.

although clearly any counterfactual case will be rather speculative.[83] On the other hand, the merger will likely reduce costs in the short-term, which may reduce prices for consumers today. Clearly, the bulk of the NMa's work would be in quantifying the negative effects of the merger, *i.e.* the reduction in liquidity and the negative effects thereof.

NMa could estimate the reduction in liquidity that might result from a merger by looking at the parties' net short and long positions before and after the merger. In other words, pre-merger the supply company must buy its power on the market, and the generator must sell its power on the market. Post-merger, the merged entity will only need to buy or sell the difference between what the generation division produces and the supply division sells. The competition authority could then compare the likely traded volumes after the merger to those currently traded on the market, to see if the merger materially reduces liquidity. This would provide some basis on which to make a judgement as to whether the merger will significantly raise entry barriers.

NMa would also need to judge how likely entry is in the absence of the merger *i.e.* in the counterfactual case, and whether such entry would have a material effect on prices. If entry is not likely in the counterfactual case, or if it would have little effect on prices, there would be few grounds for preventing the vertical merger. In sum, to block a vertical merger, a court might require the competition authority to show that:

- entry is likely without the merger, and that this entry would result in a non-negligible price reduction to consumers;
- that the merger reduces liquidity significantly, and this in turn significantly reduces the likelihood of entry;
- the positive effects of the merger (which would be easier for the merging parties to estimate, and provide tangible evidence of) do not compensate for the above effects.

In contrast to horizontal issues, there are no 'brightline' tests for vertical mergers. To block a vertical merger a competition authority would need to rely on a counterfactual case of additional entry in the absence of the merger, and this would necessarily be speculative in nature. Accordingly, without compelling evidence of the effect of the merger on entry, it would be difficult for a competition authority to block a 'pure' vertical merger.

We also note that even with reduced liquidity, it may still be possible for a vertically integrated party to enter the market (although this would be more complicated, since the entrant would have to establish a supply business and a generation business simultaneously).

[83] Moreover, one point of view is that prices are a 'public good' which firms produce by trading bi-laterally. It would seem difficult for a competition authority to prevent a vertical merger because the merging entities would produce less of a public good for which they are not rewarded.

Appendix I : Lists of Tables and Figures

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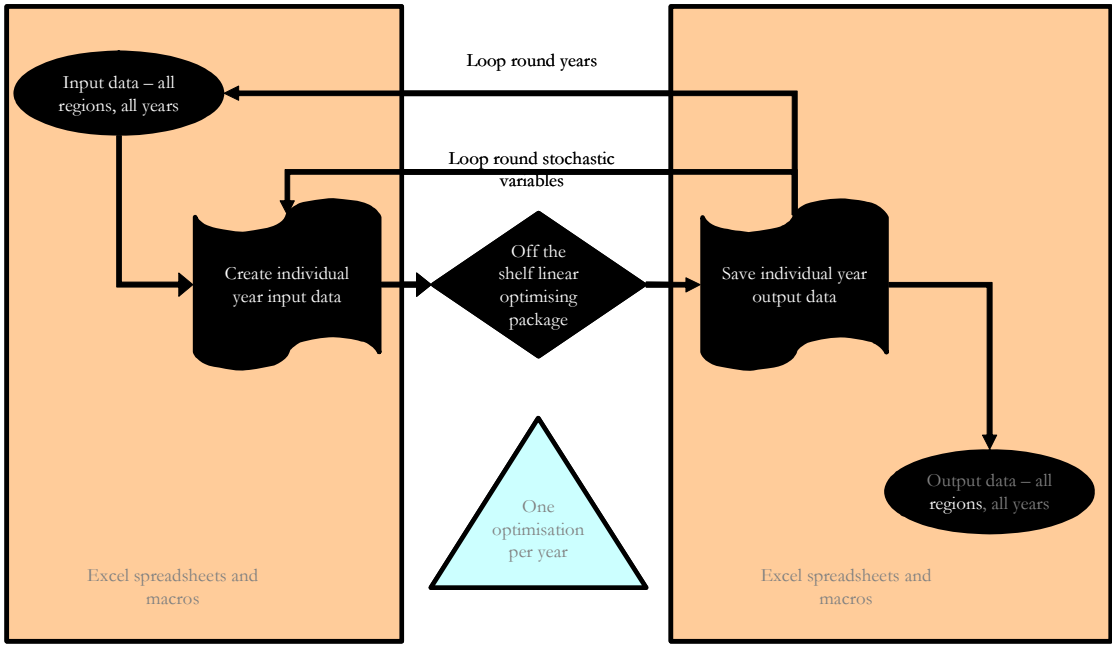
Appendix II : Details of the BAM and Cournot models

At the heart of BAM is a cost-minimising plant scheduler that, in conjunction with a sophisticated fixed-cost recovery module, enables marginal costs and prices for any number of interconnected countries (or regions) to be modelled. The model can be run in two modes: (a) fast – deterministic runs with simplified approaches to forced outages, to demand variations and to wind output patterns to provide initial indications of prices or to model longer periods and (b) detailed – stochastic representation of these variables using a random number generator to give a more detailed insight into prices and their volatility but taking longer to run. This is illustrated in Figure 47.

Figure 47: Outline of model structure



Model inputs

The generic types of required input data include

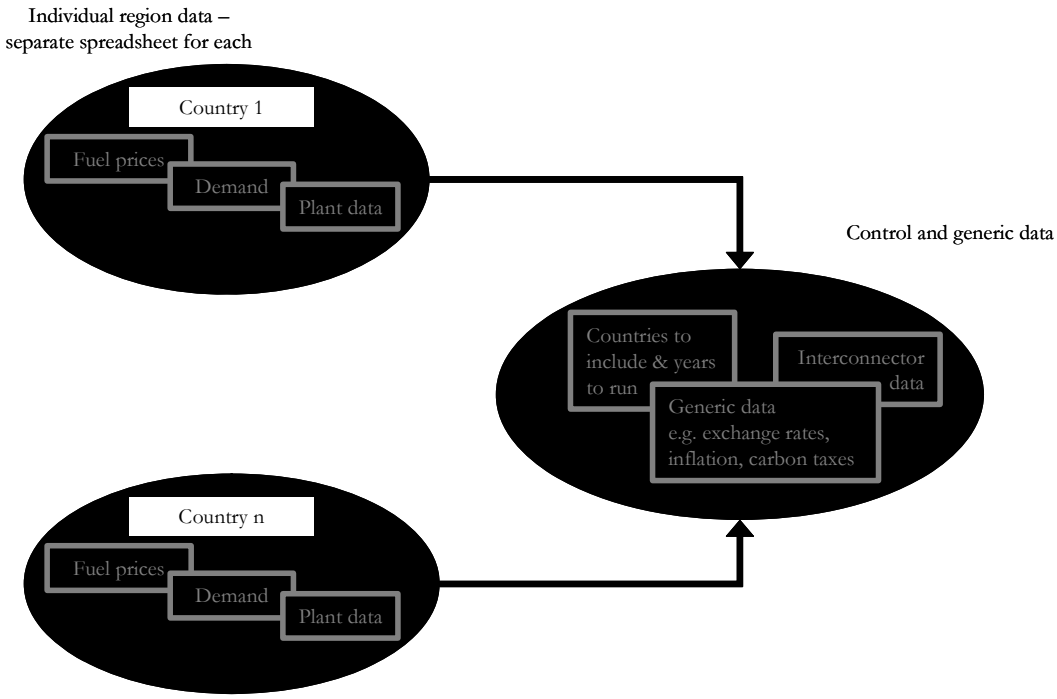
- Fuel prices: generic international prices for coal and oil products and country specific domestic fuel prices,[84] and taxes;
- Fuel characteristics: calorific values, carbon, sulphur and nitrogen content;
- Current plant capacities, retirement of existing plant and entry of new capacity, including renewables;

[84] In addition to allowing gas contract prices to be linked to other fuel prices and inflation, it will be possible to include indexation to the previous year's electricity prices.

- Other plant characteristics (fuel blending requirements, maintenance requirements, environmental measures e.g. flue gas desulphurisation levels, forced outage levels, thermal efficiency etc.);
- Plant costs: fuel transport costs, non-fuel variable costs (e.g. coal milling costs, variable O&M costs, market power uplifts etc.), fixed costs; transmission loss factors;
- Electricity demand profiles and growth;
- Contractual arrangements (physical bilateral contracts, must-take fuel contracts);
- Environmental constraints and costs: plant and country/regional emissions limits and costs,
- Financial parameters: exchange rates and inflation rates;
- Inter-regional data: monthly capacities in both directions, losses etc;

These data are required for each country (or region within a country where market splitting occurs) to be included within the model. The model can accommodate varying numbers of countries, with all the data specific to a particular country grouped into an individual Excel spreadsheet. Generic and control data are held in a separate spreadsheet, as shown in Figure 48.

Figure 48: Data structure



The model utilises a characteristic day representation of demand with 3 characteristic days for each month (weekday, Saturday, Sunday) being used to represent the demand over a year. Since the countries modelled will have electrical connections to other countries, it is important to incorporate the impact of flows into and out of the model area. The model can incorporate historical net flows from each surrounding country as zero-priced flows, which effectively forces these to take place, using ETSO data. However, the model structure allows any number of import

and export flows to be incorporated (with separate volumes and prices for each flow for each month and distinguished between day and night). Thus, a simplified step-wise approximation to the marginal cost curve in a country can be used to define several tranches of import (or export) flows. Whilst this method is more flexible, it effectively requires modelling the surrounding countries (at least to some extent) in order to produce an appropriate marginal cost curve. It is for this reason that we suggest using a simpler approach initially.

Outputs other than prices

In addition to detailed price data, the model also produces information on the output, revenues and costs of each generating plant, the flows across interconnectors (both within the model area and to countries outside it), fuel consumption and emissions levels.

Cournot model

It is useful to distinguish between the Cournot model from a conceptual point of view (i.e., the ideas underlying the model) and from a computational point of view (i.e., what is the algorithm that the computer uses to implement the conceptual model). We begin by explaining the conceptual basis of the model, and then describe the computational algorithm.[85]

To understand the conceptual basis it is helpful to go in three stages: "one-player Cournot", "multi-player Cournot", and "multi-player Cournot with fringe".

"One-player Cournot" (i.e., monopoly)

The "one-player Cournot" model has just one firm that sets its output to maximise profits, taking into account the impact of its output decision on pricing. This is of course the standard model of monopoly that forms part of any introduction to microeconomics.[86] As former students will recall, the mathematical solution involves the firm setting output such that marginal cost equals marginal revenue. Note that the "marginal revenue" from increasing output by one unit has two components: the additional revenue on that one unit (equal to the prevailing price), less the lost revenue on all the firm's output that arises because the increased output lowers prices. In contrast, under perfect competition the firm sets output such that marginal cost equals price.[87]

Key points from the standard monopolist model are that output is less than is socially efficient (there is so-called "deadweight loss"), prices are above the competitive level (detriment to consumers), and the magnitude of these effects depends on the elasticity of demand. If demand is

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[85] See also Severin Borenstein and James Bushnell, 'An Empirical Analysis of the Potential for Market Power in California's Electricity Industry', *Journal of Industrial Economics*, 1999, vol. 47, issue 3, pages 285-323. Borenstein and Bushnell use a computer-based Cournot model that has many features in common with ours to simulate the California electricity market.

[86] A description of the monopolistic and Cournot models can be found in any microeconomics textbook. See for example '*Intermediate Microeconomics: A modern approach*', Hal R. Varian, Fifth Edition, W W Norton & Co Ltd, ISBN 0-393-97370-0, p.477, §27.4.

[87] That is, in both cases the firm sets output such that marginal cost equals marginal revenue, but under perfect competition the firm acts as a "price-taker", i.e., it assumes that marginal revenue equals price, whereas under monopoly the firm takes into account the second component of marginal revenue identified above.

highly inelastic (as is the case for electricity, especially in the short run) then the impact of price rises on output is rather small, so that the monopolist is able to raise prices significantly without losing too much volume of sales.

"Multi-player Cournot"

With more than one firm, the Cournot model assumes that each firm attempts to maximise its profits, given the output decision of the other firms in the market. If we consider the "reaction function" of any single firm in this model, it therefore looks very similar to that of a monopolist: it sets its output to maximize profits, taking into account that if it produces less the price will increase. The difference between the monopoly situation and a multi-player Cournot game is that in the latter case a Cournot firm does not have 100% market share. If it withholds output to increase prices, all the cost of withholding (i.e., lost profits on the withheld output) are incurred by the firm that withholds. However, part of the benefits (higher prices) "leak out" to other firms, since there is a single market price. The incentive to withhold output is therefore smaller than for a pure monopolist (and more generally it is smaller, all else being equal, the smaller a firm's market share).

Note that the multi-player Cournot model is one of unilateral effects (each player takes the others' actions as given), and does not claim to capture any inter-firm coordination or "concerted effects".[88] Note also that the key points listed above from the monopolist model carry over: output is less than is socially efficient (there is so-called "deadweight loss"), prices are above the competitive level (detriment to consumers), and the magnitude of these effects depends on the elasticity of demand (in qualitatively the same way as for the monopolist).

"Multi-player Cournot" with fringe

Our model differs from the standard Cournot model in that there are two types of firm: "strategic players" (as in the standard Cournot model), and a so-called 'competitive fringe' *i.e.* a number of smaller players who act as price-takers rather than setting output taking into account the effect on prices. These players have different "reaction functions" from the strategic players: for a given market price, they set output such that they are producing up to the level where marginal cost equals that price.[89] The presence of a competitive fringe in our model is intended to capture more accurately the real world situation being modelled. It also leads to significantly easier computation.

The presence of fringe players reduces the incentive on strategic players to withhold capacity, because part of the effect of withholding capacity is compensated for by increased output from the fringe. Since the fringe players are price-takers, their output increases (relative to the competitive outcome) as a result of the increase in prices arising from withholding by strategic players.

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[88] See "The Economics of Unilateral Effects", Ivaldi, Jullien, Rey, Seabright and Tirole (IDEI, Toulouse), November 2003, Interim Report for DG Competition, European Commission: "under individual rivalry firms take their competitors' behaviour as in some sense given, and not open to influence by the firm's own actions".

[89] Or producing at maximum output, if that involves marginal cost less than price.

The key points from the monopolist model carry over again to this model: output is less than is socially efficient (there is so-called "deadweight loss") and prices are above the competitive level (detriment to consumers). However, the presence of a competitive fringe mitigates these negative effects. Again the magnitude of these effects depends on the elasticity of demand (in qualitatively the same way). Note that we assume the same level of demand elasticity (-0.2) as in our market definition analysis.

Forward Sales

Our model also differs from standard Cournot models in allowing for forward sales. This is a more significant departure from the standard model than is the addition of a competitive fringe. Again, it is intended to capture more accurately the real world situation being modelled. We assume that generators have sold a certain amount of their output in advance (forward) at a fixed price. Generators in that situation still have incentives to raise prices. Raising spot prices not only increases profits on that part of their output that is not forward-contracted, but will also cause forward contracts to be renewed at a higher price when they expire. However the incentives are less powerful than for generators with no forward contracting, since they must sacrifice output to raise prices, but will not enjoy the benefits of higher prices directly for the output which they have sold forward.

Features of Equilibrium

In Cournot models, the "equilibrium" outcome corresponds to the so-called "Nash equilibrium": each firm optimises taking the others' strategies as given.[90] This is the case for both standard Cournot and Cournot with competitive fringe. The only difference is that players in the competitive fringe optimise against a price that they assume is not affected by their actions. Equilibrium in the model with a fringe therefore consists of a market price and a set of output levels (one per firm), such that:

- The level of demand corresponding to the market price is equal to the sum of firm outputs
- Each competitive fringe player is producing at a level where its marginal cost equals price
- Each strategic player is maximising its profit given the levels of output of the other firms

Note also that there are two possible types of equilibrium in this model:

1. The competitive fringe is producing at price equals marginal cost. However, note that this does not imply that the equilibrium is socially efficient: the strategic players are still producing too little (and the fringe players too much) relative to the socially efficient outcome, and prices are too high.
2. The competitive fringe is producing at its maximum output. Same comments apply as in the previous point (expect that it is possible that the fringe also produces at

[90] Sometimes called the "Cournot-Nash equilibrium" on the basis that the Cournot model was the first example of this concept.

maximum capacity in the socially efficient outcome—however in any case the strategic players are producing too little and prices are too high).

Computational Algorithm

The computer algorithm to solve the Cournot model is essentially as follows:

1. The computer solves for the competitive outcome, i.e. it models all players as price-takers. The model assumes that the demand curve has constant elasticity, and the actual elasticity of demand is a model parameter. The model also calibrates the demand curve by assuming that the curve goes through the (quantity, price) point given by the corresponding BAM equilibrium.[91]
2. For each strategic player, the computer calculates the profit-maximising level of output assuming that the other players are producing at the levels given in step 1. It does so by looking at a finite set of different possible levels of output for the player in question, and choosing the one that gives the highest profit.
3. For each fringe player, the computer calculates the profit-maximising level of output given the price taken from step 1.
4. Steps 2 and 3 give a new set of outputs, and a new price. The computer then iterates steps 2 and 3 relative to this new data.
5. Iteration continues until the model converges (to within pre-specified limits).

Note that to implement this algorithm the Cournot model uses the same underlying dataset as the BAM model (with the addition of an elastic demand curve).

For the analysis in this report we first undertook some "calibration" of the model using as a calibration parameter the percentage of demand covered by forward contracts. We set this parameter so that the pre-merger Cournot runs give price predictions that are a reasonable match to actual prices. This gave us a value of 20% for the percentage of demand covered by forward contracts. However it is important to interpret this parameter correctly. In reality the impact of forward contracts is complex—as discussed in the main report, the fact that a generator has a forward contract does not remove the incentive to raise spot prices, since raising spot prices not only increases profits on that part of their output that is not forward-contracted, but will also cause forward contracts to be renewed at a higher price when they expire. The figure of 20% is therefore best interpreted not as an estimate of the percentage of demand covered, but of the impact of forward contract coverage on the incentive to raise prices. So for example, suppose that in reality that generators have sold (say) 40% of their output forward, on contracts of a range of durations (days, weeks, months, years). That complex set of contracts may give generators the same incentives to raise spot prices as they would have if they had sold 20% of their output forward on contracts of unlimited (in effect infinite) duration.

[91] For a given elasticity of demand ε there is an infinite family of "constant elasticity of demand curves", each of the form $q = Ap^{-\varepsilon}$ (one curve for every positive value of A). If we know one point on the curve (i.e., one pair of values (p.q)) then we can substitute into the equation and solve for A. This then tells us what the whole curve is.

Appendix III : BAM Inputs

Table 24: Demand and capacity information on Belgium, Germany, France and the Netherlands

			Belgium	Germany	France	Netherlands
Peak demand (GW)	[1]	See Note	13.6	91.6	81.2	19.6
Domestic energy requirements (TWh)	[2]	See Note	95.0	563.0	499.7	119.5
Available domestic energy (TWh)	[3]	TBG	99.5	716.7	660.8	150.6
Installed capacity by fuel type						
Hydro	[4]	TBG	1.4	9.4	25.4	0.0
Wind	[5]	TBG	0.9	17.5	3.6	1.8
Coal	[6]	TBG	1.3	38.5	6.9	4.3
Gas	[7]	TBG	5.1	21.8	3.6	14.7
Ind gas	[8]	TBG	0.3	2.0	0.1	0.3
Nuc	[9]	TBG	5.6	20.9	63.4	0.4
Oil	[10]	TBG	0.0	3.0	7.5	0.0
Rew	[11]	TBG	0.6	0.4	0.3	0.0
Total installed capacity by fuel type (GW)	[12]	sum([4]-[11])	15.2	113.5	110.8	21.7
Total installed capacity reduced by wind availability	[13]	sum([6]-[11])+[4]+0.27 x [5]	14.5	100.7	108.1	20.3
Forced outage rate, %	[14]	TBG	11%	7.4%	3.9%	3.9%
Available capacity (GW)	[16]	[13] x (1 - [14])	12.9	93.3	103.9	19.5

Sources and Notes:

[1],[2],[3]: 2005 Data for Germany, France and the Netherlands were obtained from the UCTE website. 2005 Data for Belgium come from Elia. A growth rate has been applied to all data, so that 2008 values can be calculated.

Table 25: Fuel prices for Germany in 2008

		Natural Gas, €/Mbtu	Black Lignite, €/GJ	Domestic Coal, €/GJ
January	[1]	5.06	2.24	2.24
February	[2]	5.06	2.24	2.24
March	[3]	5.06	2.24	2.24
April	[4]	4.97	2.23	2.23
May	[5]	4.97	2.23	2.23
June	[6]	4.97	2.23	2.23
July	[7]	5.13	2.22	2.22
August	[8]	5.13	2.22	2.22
September	[9]	5.13	2.22	2.22
October	[10]	5.15	2.20	2.20
November	[11]	5.15	2.20	2.20
December	[12]	5.15	2.20	2.20

Table 26: Gas prices for France and the Netherlands in 2008

		Natural Gas, €/Mbtu
January	[1]	5.06
February	[2]	5.06
March	[3]	5.06
April	[4]	4.97
May	[5]	4.97
June	[6]	4.97
July	[7]	5.13
August	[8]	5.13
September	[9]	5.13
October	[10]	5.15
November	[11]	5.15
December	[12]	5.15

Table 27: Fuel prices in 2008 (all countries)

		GasOil, $/tonne [A]	Low Sulfur Fuel Oil, $/tonne [B]	High Sulfur Fuel Oil, $/tonne [C]	Carbon Costs, €t/CO2 [D]
January	[1]	612.16	326.87	390.11	27.93
February	[2]	609.33	325.21	388.11	27.93
March	[3]	606.67	323.64	386.25	27.93
April	[4]	603.83	321.97	384.26	27.93
May	[5]	601.09	320.36	382.33	27.93
June	[6]	598.25	318.69	380.34	27.93
July	[7]	598.13	318.62	380.25	27.93
August	[8]	598.00	318.54	380.16	27.93
September	[9]	597.87	318.47	380.08	27.93
October	[10]	597.75	318.40	379.99	27.93
November	[11]	597.62	318.32	379.90	27.93
December	[12]	597.50	318.25	379.81	27.93

Appendix IV : Elasticity of demand for electricity

We have used an own-price demand elasticity of 0.2 (strictly -0.2, since demand decreases for an increase in price) for electricity in our calculations. The number of 0.2 is based on a number of studies by academic economists. For example, in her study of market power in the old (pre-NETA) electricity market of England & Wales, known as the pool, Catherine Wolfram uses an elasticity of 0.17.[92] This number is itself based on a paper by David Newbery (a co-author of this paper) and Richard Green which also examined competition in the England & Wales pool.[93]

Two other economists cited by Catherine Wolfram investigated elasticity of demand using four years of data from a Regional Electricity Company (REC) in the United Kingdom.[94] The authors measured the elasticity of demand for different groups of consumers, and found that most consumers had an elasticity of demand of less than 0.1. The highest elasticity of demand found was for water companies (that use electricity to pump water), who had a demand elasticity of 0.27. Another study using data on consumers in California found a price elasticity of 0.2.[95]

Accordingly, we take an elasticity of 0.2 as a number that best reflects the range found in the academic literature. However, we have also performed sensitivities for our main results for demand elasticity values of 0.1 and 0.3, which represent the range of values seen in the academic literature. The figures below illustrate that our main conclusions that:

- The Netherlands defines a geographic market for peak power for the purposes of merger control;
- At least 6,500 MW of interconnector capacity from Belgium/Germany to the Netherlands would be required to expand the peak market beyond the Netherlands;
- At least 9,000 MW of interconnector capacity from Belgium/Germany to the Netherlands would be required to expand the super-peak market beyond the Netherlands.

All hold for the range of elasticity values studied.

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[92] Catherine D. Wolfram 'Measuring Duopoly Power in the British Electricity Spot Market' *American Economic Review*, 1999, vol. 89, issue 4, pp. 805-826.

[93] Green, Richard J. and Newbery, David M. 'Competition in the British Electricity spot market' *Journal of Political Economy*, October 1992, 100(5), pp.929-53.

[94] Patrick, Robert H. and F.A. Wolak 'Estimating the Customer-Level Demand for Electricity Under Real-Time Market Prices' NBER Working Paper 8213, National Bureau of Economic Research, Cambridge MA, April, 2001.

[95] Branch, E. Raphael. 'Short Run Income Elasticity of Demand for Residential Electricity Using Consumers Expenditure Survey Data' *Energy Journal*, November 1993, 14(4), pp.111-21.

Figure 49: SSNIP test for the peak market for a range of elasticity

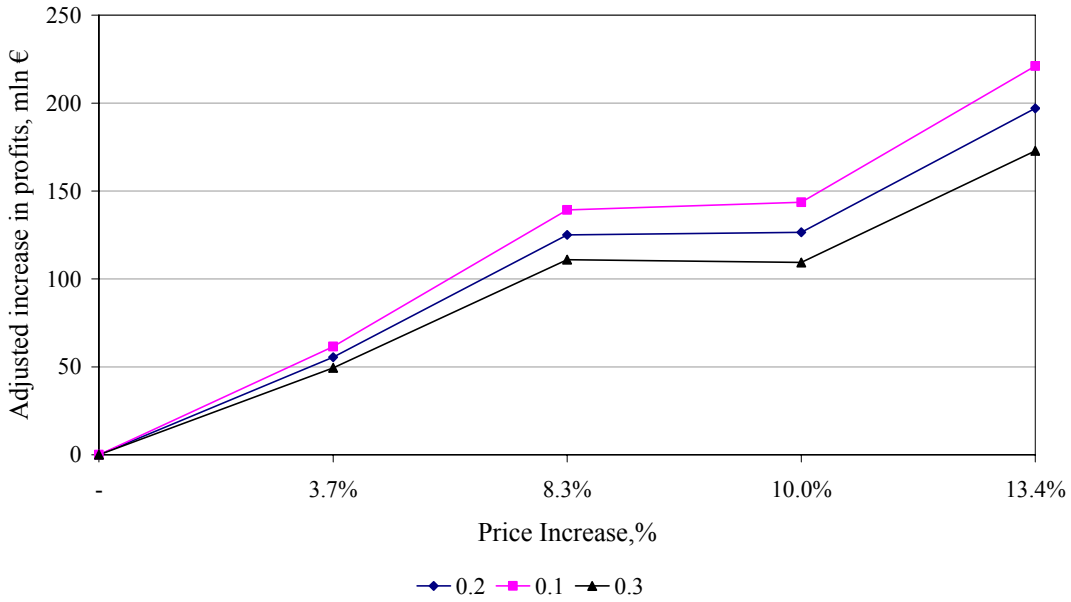


Figure 50: Peak market SSNIP test for an interconnector capacity between the Netherlands and Germany/Belgium of 7,500 MW for a range of elasticity

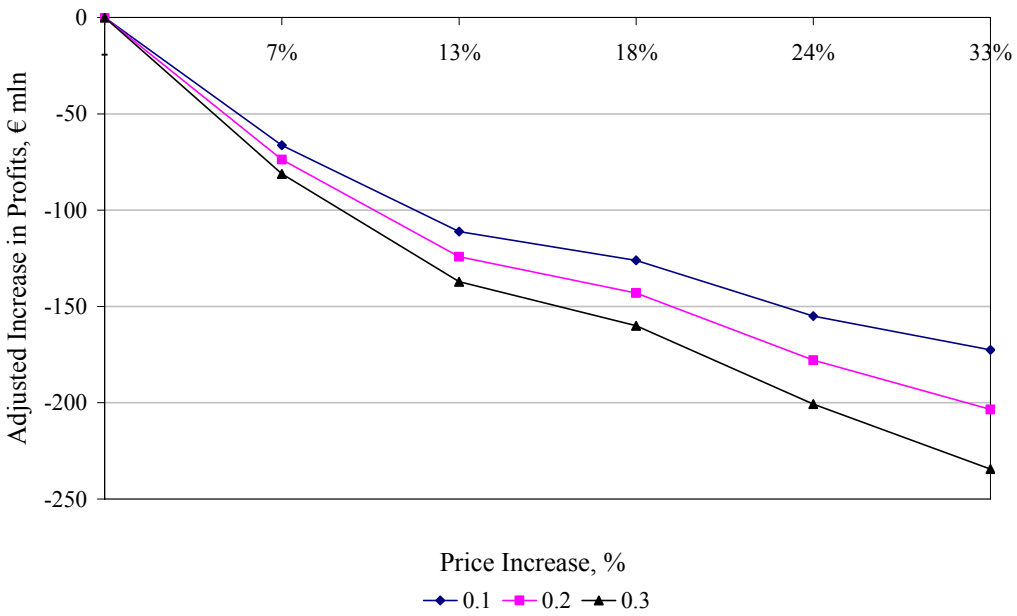


Figure 51: Peak market SSNIP test for an interconnector capacity between the Netherlands and Germany/Belgium of 6,500 MW for a range of elasticity

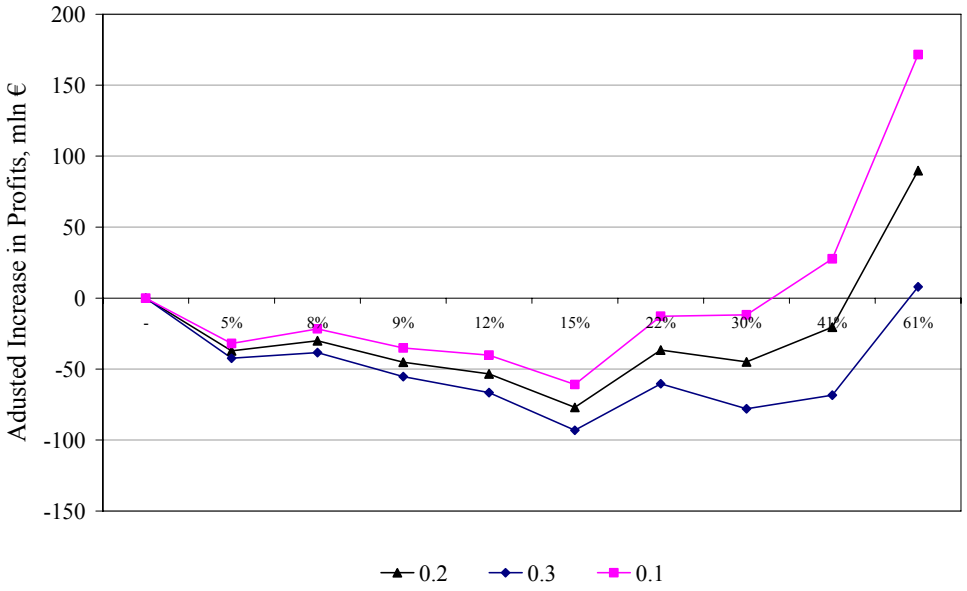
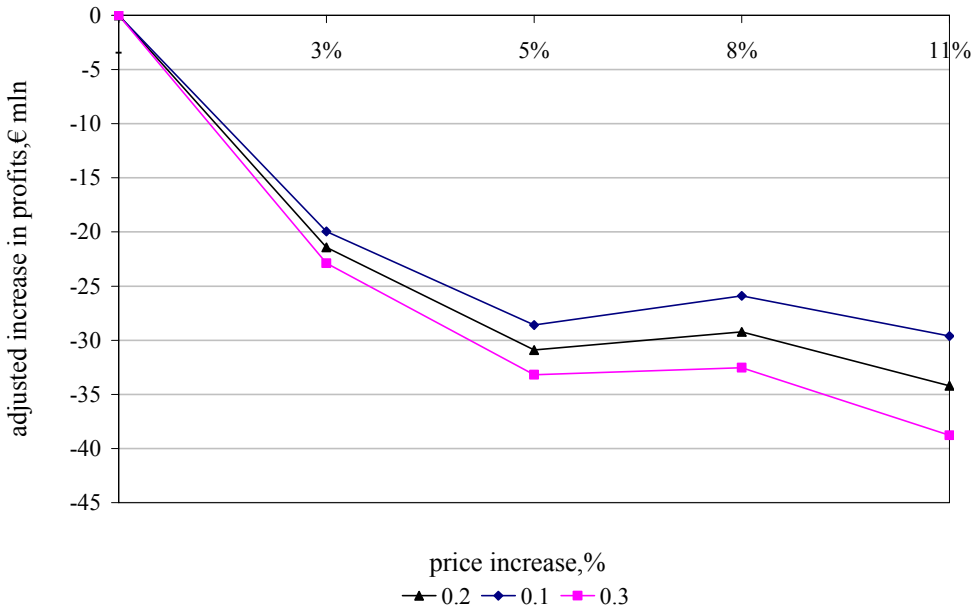


Figure 52: Super-peak market SSNIP test for an interconnector capacity between the Netherlands and Germany/Belgium of 9,000 MW for a range of elasticity



Appendix V : Details of SSNIP test results

Table 28: Peak SSNIP results for the Netherlands

Demand elasticity	[1]	TBG	0.20				
Import capacity from BE+DE, MW	[2]	Tennet	3600				
			[A]	[B]	[C]	[D]	[E]
Annual time weighted peak price SMC (€/MWh)	[3]	TBG	70.9	73.6	76.8	78.0	80.5
Profits, mln €	[4]	TBG	1,545	1,613	1,699	1,706	1,790
Output, TWh	[5]	TBG	56	55	54	54	54
Price increase, €/MWh	[6]	[3] - [3][A]	-	2.7	5.9	7.1	9.5
Price increase, %	[7]	[6] / [3][A]	-	3.7%	8.3%	10.0%	13.4%
Increase in profits, mln €	[8]	[4] - [4][A]	-	68	153	161	245
Decrease in output, TWh	[9]	[5] - [5][A]	-	1	2	2	2
Decrease in output, %	[10]	[9] / [5][A]	-	1.3%	2.7%	3.3%	3.9%
Reduction in total demand, %	[11]	[7] x [1]	-	0.7%	1.7%	2.0%	2.7%
Adjusted profits, mln €	[12]	(1-[11]) x [4]	1,545	1,601	1,670	1,672	1,742
Adjusted increase in profits, mln €	[13]	[12] - [12][A]	-	56	125	126	197
Adjusted output, TWh	[14]	(1-[11]) x [5]	56	55	55	55	54
Decrease in output, %	[15]	[14] - [14][A]	-	-0.7%	-1.7%	-2.0%	-2.7%
% of time congested flow to the Netherlands	[16]	TBG	62%	65%	69%	72%	73%

Table 29: Peak SSNIP results for the Germany-Netherlands single market scenario

Demand elasticity	[1]	TBG	0.2			
Import capacity from both BE+DE, MW	[2]	Tennet	3,600			
			[A]	[B]	[C]	[D]
Annual time weighted peak price SMC (€/MWh)	[3]	TBG	60.4	61.6	63.6	65.8
Dutch Profits, mln €	[4]	TBG	1,044	1,037	1,061	1,068
German Profits, € mln	[5]	TBG	8,158	8,391	8,781	9,073
Total profits, € mln	[6]	[4] +[5]	9,202	9,428	9,842	10,141
Dutch output, TWh	[7]	TBG	49	48	47	45
German output, TWh	[8]	TBG	295	294	293	292
Total output, TWh	[9]	[7] +[8]	344	342	339	337
Price increase, €/MWh	[10]	[3] - [3][A]	-	1.2	3.2	5.4
Price increase, %	[11]	[10] / [3][A]	-	2.0%	5.2%	9.0%
Increase in profits, mln €	[12]	[6] - [6][A]	-	227	641	939
Decrease in output, TWh	[13]	[9] - [9][A]	-	2	4	7
Decrease in output, %	[14]	[13] / [9][A]	-	0.6%	1.2%	2.0%
Reduction in total demand, %	[15]	[11] x [1]	-	0.4%	1.0%	1.8%
Adjusted profits, mln €	[16]	(1-[15]) x [6]	9,202	9,390	9,739	9,958
Adjusted increase in profits, mln €	[17]	[16] - [16][A]	-	188	537	757
Adjusted output, TWh	[18]	(1-[17]) x [9]	344	342	339	333
Decrease in output, %	[19]	([18]-[18][A])/[18][A]	-	0%	-1%	-3%
% time congested FR to GE	[20]	TBG	93%	93%	93%	93%
% time congested BE to NL	[21]	TBG	45%	48%	51%	53%

Table 30: Peak SSNIP results for the Belgium-Netherlands single market scenario

Demand elasticity	[1]	TBG	0.2			
			[A]	[B]	[C]	[D]
Annual time weighted peak price SMC (€/MWh)	[2]	TBG	65.9	66.7	69.0	71.3
Dutch Profits, mln €	[3]	TBG	1,267	1,245	1,284	1,338
German Profits, € mln	[4]	TBG	1,640	1,640	1,704	1,773
Total profits, € mln	[5]	[3] +[4]	2,906	2,885	2,988	3,110
Dutch output, TWh	[6]	TBG	50	49	49	48
German output, TWh	[7]	TBG	42	41	41	41
Total output, TWh	[8]	[6] +[7]	92	91	90	89
Price increase, €/MWh	[9]	[2] - [2][A]	-	0.9	3.1	5.4
Price increase, %	[10]	[9] / [2][A]	-	1.3%	4.8%	8.2%
Increase in profits, mln €	[11]	[5] - [5][A]	-	-21	82	204
Decrease in output, TWh	[12]	[8] - [8][A]	-	-1	-2	-3
Decrease in output, %	[13]	[12]/[8][A]	-	-1.3%	-2.1%	-3.2%
Reduction in total demand, %	[14]	[10] x [1]	-	0.3%	1.0%	1.6%
Adjusted profits, mln €	[15]	(1-[14]) x [5]	2,906	2,878	2,960	3,059
Adjusted increase in profits, mln €	[16]	[15] - [15][A]	-	-29	53	153
Adjusted output, TWh	[17]	(1-[16]) x [8]	92	92	91	89
Decrease in output, %	[18]	([17]-[17][A])/[17][A]	-	0%	-1%	-3%
% time congested FR to GE	[19]	TBG	93%	93%	93%	93%
% time congested BE to NL	[20]	TBG	65%	72%	78%	83%

Table 31: Results for the expansion of Norned capacity

Demand elasticity	[1]	TBG	0.2						
Norned capacity	[2]	TBG	600	600	800	1,000	1,200	1,500	1,800
			[A]	[B]	[C]	[D]	[E]	[F]	[G]
Annual time weighted peak price SMC (€/MWh)	[3]	TBG	65.9	71.3	72.0	70.9	71.9	71.4	70.7
Dutch Profits, mln €	[4]	TBG	1,267	1,338	1,334	1,265	1,267	1,187	1,136
Belgian Profits, € mln	[5]	TBG	1,640	1,773	1,787	1,744	1,770	1,730	1,701
Total profits	[6]	[4] +[5]	2,906	3,110	3,120	3,008	3,038	2,917	2,837
Dutch output, TWh	[7]	TBG	50	49	48	47	46	45	45
Belgian output, TWh	[8]	TBG	42	41	40	40	40	40	39
Total output	[9]	[7] +[8]	92	91	88	87	86	85	84
Price increase, €/MWh	[10]	[3] - [3][A]	-	5.4	6.1	5.1	6.1	5.5	4.9
Price increase, %	[11]	[10] / [3][A]	-	8.2%	9.3%	7.7%	0	8.4%	7.4%
Increase in profits, mln €	[12]	[6] - [6][A]	-	204	214	102	131	11	-70
Decrease in output, TWh	[13]	[9] - [9][A]	-	-1	-4	-5	-6	-7	-8
Decrease in output, %	[14]	[13]/[9][A]	-	-1.3%	-4.3%	-5.1%	-6.2%	-7.5%	-8.5%
Reduction in total demand, %	[15]	[11] x [1]	-	1.6%	1.9%	1.5%	1.8%	1.7%	1.5%
Adjusted profits, mln €	[16]	(1-[15]) x [6]	2,906	3,059	3,062	2,962	2,982	2,868	2,795
Adjusted increase in profits, mln €	[17]	[16] - [16][A]	-	153	156	56	75	-38	-111
Adjusted output, TWh	[18]	(1-[15]) x [9]	92	90	89	87	86	84	83
Decrease in output, %	[19]	([18]-[18][A] /[18][A]	-	-2%	-3%	-5%	-7%	-8%	-10%

Table 32: ETSO net transfer capacity, MW

Reported ETSO Net Transfer Capacity			
BE+DE to NE combined	[1]	ETSO	4,700
BE	[2]	ETSO	2,350
DE	[3]	ETSO	3,800

Table 33: Peak results for interconnector capacity of 3,600 MW

Demand elasticity	[4]	TBG	0.20				
Assumed IC Capacity, BE+DE	[5]	Tennet	3,600	3,600	3,600	3,600	3,600
IC Capacity BE	[6]	([5]/[1]) x [2]	1,800	1,800	1,800	1,800	1,800
IC Capacity DE	[7]	([5]/[1]) x [3]	2,911	2,911	2,911	2,911	2,911
Price in Netherlands, €/MWh	[8]	TBG	70.9	73.6	76.8	78.0	80.5
Profits	[9]	TBG	1,545	1,613	1,699	1,706	1,790
Output	[10]	TBG	56	55	54	54	54
Price rise, %	[11]	([8] - [8][A])/[8][A]	0.0%	3.7%	8.3%	10.0%	13.4%
Increase in profits, € mln	[12]	[9] - [9][A]	0	68	153	161	245
Profit €/MWh	[13]	[9] /[10]	28	29	31	32	33
Reduction in total demand, %	[14]	[11] x [4]	0.0%	0.7%	1.7%	2.0%	2.7%
Adjusted profits, mln €	[15]	(1-[14] x [8]	1,545	1,601	1,670	1,672	1,742
Adjusted increase in profits, mln €	[16]	[15] - [15][A]	0	56	125	126	197
Adjusted output, TWh	[17]	(1-[14]) x [9]	56	55	53	53	52

Table 34: Peak results for interconnector capacity of 6,000 MW

Demand elasticity	[18]	TBG	0.20							
Assumed IC Capacity, BE+DE	[19]	TBG	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
IC Capacity BE	[20]	([19]/[1]) x [2]	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
IC Capacity DE	[21]	([19]/[1]) x [3]	4,851	4,851	4,851	4,851	4,851	4,851	4,851	4,851
Price in Netherlands, €/MWh	[22]	TBG	63.3	65.8	68.5	71.2	74.4	79.1	83.8	92.3
Profits	[23]	TBG	1,148	1,139	1,159	1,184	1,207	1,291	1,305	1,401
Output	[24]	TBG	52	50	48	47	46	45	44	43
Price rise, %	[25]	([22] - [22][A])/[22][A]	-	4.1%	8.3%	12.6%	17.7%	25.1%	32.5%	45.9%
Increase in profits, € mln	[26]	[23] - [23][A]	-	-8	11	37	59	143	157	253
Profit €/MWh	[27]	[23] /[24]	22	23	24	25	26	29	30	33
Reduction in total demand, %	[28]	[25] x [18]	-	1%	2%	3%	4%	5%	7%	9%
Adjusted profits, mln €	[29]	(1-[28]) x [23]	1,148	1,130	1,140	1,155	1,164	1,226	1,220	1,272
Adjusted increase in profits, mln €	[30]	[29] - [29][A]	-	-18	-8	7	17	78	72	124
Adjusted output, TWh	[31]	(1-[28]) x [24]	52	49	47	46	44	43	41	39

Table 35: Peak results for interconnector capacity of 6,500 MW

Demand elasticity	[32]	TBG	0.20									
Assumed IC Capacity, BE+DE	[33]	TBG	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500	6,500
IC Capacity BE	[34]	([33]/[1]) x [2]	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250	3,250
IC Capacity DE	[35]	([33]/[1]) x [3]	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255	5,255
Price in Netherlands, €/MWh	[36]	TBG	61.9	64.9	66.6	67.7	69.5	71.4	75.2	80.2	87.3	99.5
Profits	[37]	TBG	1,093	1,067	1,080	1,068	1,067	1,049	1,104	1,115	1,169	1,347
Output	[38]	TBG	51	48	47	47	46	45	44	42	41	40
Price rise, %	[39]	([36] - [36][A])/[36][A]	-	4.9%	7.7%	9.5%	12.4%	15.4%	21.5%	29.7%	41.1%	60.8%
Increase in profits, € mln	[40]	[37] - [37][A]	-	-27	-13	-25	-27	-45	11	21	76	253
Profit €/MWh	[41]	[37] /[38]	21	22	23	23	23	23	25	26	29	34
Reduction in total demand, %	[42]	[39] x [32]	-	1%	2%	2%	2%	3%	4%	6%	8%	12%
Adjusted profits, mln €	[43]	(1-[42]) x [37]	1,093	1,056	1,063	1,048	1,040	1,016	1,057	1,049	1,073	1,183
Adjusted increase in profits, mln €	[44]	[43] - [43][A]	-	-37	-30	-45	-53	-77	-37	-45	-20	90
Adjusted output, TWh	[45]	(1-[42]) x [38]	51	48	47	46	45	43	42	40	38	35

Table 36: Peak results for interconnector capacity of 7,500 MW

Demand elasticity	[46]	TBG	0.20					
Assumed IC Capacity, BE+DE	[47]	TBG	7,500	7,500	7,500	7,500	7,501	7,503
IC Capacity BE	[48]	([47]/[1]) x [2]	3,750	3,750	3,750	3,750	3,751	3,752
IC Capacity DE	[49]	([47]/[1]) x [3]	6,064	6,064	6,064	6,064	6,065	6,066
Price in Netherlands, €/MWh	[50]	TBG	61.3	65.7	69.5	72.1	76.2	81.7
Profits	[51]	TBG	1,069	1,010	971	960	937	928
Output	[52]	TBG	50	46	43	42	40	39
Price rise, %	[53]	([50] - [50][A])/[50][A]	-	7%	13%	18%	24%	33%
Increase in profits, € mln	[54]	[51] - [51][A]	-	-59	-98	-109	-132	-142
Profit €/MWh	[55]	[51] /[52]	21	22	22	23	23	24
Reduction in total demand, %	[56]	[53] x [46]	-	1%	3%	4%	5%	7%
Adjusted profits, mln €	[57]	(1-[56]) x [51]	1,069	995	945	926	891	866
Adjusted increase in profits, mln €	[58]	[57] - [57][A]	-	-74	-124	-143	-178	-204
Adjusted output, TWh	[59]	(1-[56]) x [52]	50	45	42	40	38	36

Table 37: Reported and assumed net transfer capacities for the super-peak scenario

Reported ETSO Net Transfer Capacity			
BE+DE to NE combined	[1]	ETSO	4,700
BE	[2]	ETSO	2,350
DE	[3]	ETSO	3,800
Assumed Base FTSO Net Transfer Capacity			
BE+DE to NE combined	[4]	Tennet	3,600
BE	[5]	([4]/[1]) x [2]	1,800
DE	[6]	([4]/[1]) x [3]	2,911

Table 38: Super-peak results for interconnector capacity of 6,000 MW

Demand elasticity	[7]	TBG	0.20				
Assumed IC Capacity, BE+DE	[8]	TBG	6,000	6,000	6,000	6,000	6,000
IC Capacity BE	[9]	([8]/[4]) x [5]	3,000	3,000	3,000	3,000	3,000
IC Capacity DE	[10]	([8]/[4]) x [6]	4,852	4,852	4,852	4,852	4,852
Price in Netherlands (€/MWh)	[11]	TBG	61.3	62.2	63.8	66.4	68.7
Profits, € mln	[12]	TBG	290	289	287	300	314
Output, TWh	[13]	TBG	13	13	12	12	12
Price rise,€/MWh	[14]	([11] - [11][A])/[11][A]	-	0.89	2.53	5.06	7.45
Price rise, %	[15]	[14] /[11][A]	-	1.5%	4.1%	8.3%	12.2%
Increase in profits, € mln	[16]	[12] -[12][A]	-	-1	-4	10	24
Reduction in total demand, %	[17]	[14] x [7]	-	0%	1%	2%	2%
Adjusted profits, mln €	[18]	(1-[17]) x [12]	290	288	284	295	306
Adjusted increase in profits, mln €	[19]	[18] - [18][A]	-	-2	-6	5	16
Adjusted output, TWh	[20]	(1-[17]) x [13]	13	13	12	12	12

Table 39: Super-peak results for interconnector capacity of 6,500 MW

Demand elasticity	[21]	TBG	0.20				
Assumed IC Capacity, BE+DE	[22]	TBG	6,500	6,500	6,500	6,500	6,500
IC Capacity BE	[23]	([22]/[4]) x [5]	3,250	3,250	3,250	3,250	3,250
IC Capacity DE	[24]	([22]/[4]) x [6]	5,256	5,256	5,256	5,256	5,256
Price in Netherlands (€/MWh)	[25]	TBG	60.5	62.2	64.4	68.2	70.9
Profits, € mln	[26]	TBG	283	279	282	302	322
Output, TWh	[27]	TBG	13	12	12	12	11
Price rise,€/MWh	[28]	([25] - [25][A])/[25][A]	-	1.72	3.90	7.66	10.43
Price rise, %	[29]	[28] /[25][A]	-	2.8%	6.4%	12.7%	17.2%
Increase in profits, € mln	[30]	[26] -[26][A]	-	-4	-1	19	39
Reduction in total demand, %	[31]	[28] x [21]	-	1%	1%	3%	3%
Adjusted profits, mln €	[32]	(1-[31]) x [26]	283	277	278	294	310
Adjusted increase in profits, mln €	[33]	[32] - [32][A]	-	-5	-5	12	28
Adjusted output, TWh	[34]	(1-[31]) x [27]	13	12	12	11	11

Table 40: Super-peak results for interconnector capacity of 7,500 MW

Demand elasticity	[33]	TBG	0.20				
Assumed IC Capacity, BE+DE	[34]	TBG	7,500	7,500	7,500	7,500	7,501
IC Capacity BE	[35]	([34]/[4]) x [5]	3,750	3,750	3,750	3,750	3,751
IC Capacity DE	[36]	([34]/[4]) x [6]	6,065	6,065	6,065	6,065	6,065
Price in Netherlands (€/MWh)	[37]	TBG	60.5	63.1	64.8	66.9	70.3
Profits, € mln	[38]	TBG	284	276	272	279	296
Output, TWh	[39]	TBG	13	12	11	11	11
Price rise,€/MWh	[40]	([37] - [37][A])/[37][A]	-	2.55	4.26	6.31	9.71
Price rise, %	[41]	[40] /[37][A]	-	4.2%	7.0%	10.4%	16.0%
Increase in profits, € mln	[42]	[38] -[38][A]	-	-9	-12	-5	11
Reduction in total demand, %	[43]	[40] x [33]		1%	1%	2%	3%
Adjusted profits, mln €	[44]	(1-[43]) x [38]	284	273	269	274	286
Adjusted increase in profits, mln €	[45]	[44] - [44][A]	-	-11	-16	-11	2
Adjusted output, TWh	[46]	(1-[43]) x [39]	13	12	11	11	11

Table 41: Super-peak results for interconnector capacity of 9,000 MW

Demand elasticity	[47]	TBG	0.20				
Assumed IC Capacity, BE+DE	[48]	TBG	9,000	9,000	9,000	9,000	9,000
IC Capacity BE	[49]	([48]/[4]) x [5]	4,500	4,500	4,500	4,500	4,500
IC Capacity DE	[50]	([48]/[4]) x [6]	7,278	7,278	7,278	7,278	7,278
Price in Netherlands (€/MWh)	[51]	TBG	59.8	63.2	65.3	67.6	70.6
Profits, € mln	[52]	TBG	280	261	253	257	255
Output, TWh	[53]	TBG	13	11	11	10	10
Price rise,€/MWh	[54]	([51] - [51][A])/[51][A]	-	3.36	5.43	7.72	10.77
Price rise, %	[55]	[54] /[51][A]	-	5.6%	9.1%	12.9%	18.0%
Increase in profits, € mln	[56]	[52] -[52][A]	-	-18	-26	-23	-25
Reduction in total demand, %	[57]	[54] x [47]	-	1%	2%	3%	4%
Adjusted profits, mln €	[58]	(1-[57]) x [52]	280	258	249	250	245
Adjusted increase in profits, mln €	[59]	[58] - [58][A]	-	-21	-31	-29	-34
Adjusted output, TWh	[60]	(1-[57]) x [53]	13	11	11	10	9

Table 42: Peak results for a 7 €/MWh gas price

Demand elasticity	[1]	TBG	0.2				
Gas price, €/MWh	[3]	TBG	7				
Annual peak price (€/MWh)	[4]	TBG	47.45	48.39	49.42	50.11	50.49
Dutch Profits, mln €	[5]	TBG	1,058	1,062	1,064	1,071	1,063
Dutch output, TWh	[6]	TBG	67	66	66	65	65
Price increase, €/MWh	[7]	([4] - [4][A])/[4][A]	-	0.9	2.0	2.7	3.0
Price increase, %	[8]	[7] /[4][A]	-	2.0%	4.1%	5.6%	6.4%
Increase in profits, mln €	[9]	[5] -[5][A]	-	3	6	13	4
Decrease in output, TWh	[10]	[6] -[6][A]	-	-1	-1	-2	-2
Decrease in output, %	[11]	[10]/[6][A]	-	-0.8%	-1.9%	-2.8%	-3.1%
Node A to Netherlands Peak	[12]	TBG	55%	58%	61%	65%	65%
Reduction in total demand, %	[13]	[8] x [1]	-	0.4%	0.8%	1.1%	1.3%
Adjusted profits, mln €	[14]	(1-[13]) x [5]	1,058	1,058	1,055	1,059	1,049
Adjusted increase in profits, mln €	[15]	[14] - [14][A]	-	-1	-3	1	-10
Adjusted output, TWh	[16]	(1-[13]) x [6]	67	66	65	64	64
Decrease in output, %	[17]	([16]-[16][A])/[16][A]	-	-1.2%	-2.7%	-3.9%	-4.4%

Table 43: Peak results for a 14 €/MWh gas price

Demand elasticity	[1]	TBG	0.2				
Gas price , €/MWh	[3]	TBG	14				
Annual peak price (€/MWh)	[4]	TBG	63.05	65.61	67.35	68.92	70.23
Dutch Profits, mln €	[5]	TBG	1,358	1,443	1,456	1,493	1,530
Dutch output, TWh	[6]	TBG	57	57	56	55	55
Price increase, €/MWh	[7]	([4] - [4][A])/[4][A]	-	2.56	4.30	5.87	7.18
Price increase, %	[8]	[7] /[4][A]	-	4.1%	6.8%	9.3%	11.4%
Increase in profits, mln €	[9]	[5] -[5][A]	-	85	98	135	171
Decrease in output, TWh	[10]	[6] -[6][A]	-	-1	-2	-2	-3
Decrease in output, %	[11]	[10]/[6][A]	-	-1.4%	-2.8%	-3.9%	-4.7%
Node A to Netherlands Peak	[12]	TBG	19%	20%	22%	24%	25%
Reduction in total demand, %	[13]	[8] x [1]	-	0.8%	1.4%	1.9%	2.3%
Adjusted profits, mln €	[14]	(1-[13]) x [5]	1,358	1,431	1,437	1,466	1,495
Adjusted increase in profits, mln €	[15]	[14] - [14][A]	-	73	78	107	136
Adjusted output, TWh	[16]	(1-[13]) x [6]	57	56	55	54	54
Decrease in output, %	[17]	([16]-[16][A])/[16][A]	-	-2.2%	-4.2%	-5.7%	-6.9%

Appendix VI : Alternative modelling approaches

Modelling market power in electricity markets is fraught with conceptual and practical difficulties, but one can distinguish a number of strategies. First, though, it is best to be aware of the obvious problems.

Conceptual problems

Standard economic analysis of market power normally assumes that firms are maximising their profits subject to the responses of other firms, of potential entrants, and consumer behaviour. It is unusual for them to explicitly model the constraints of anti-trust agencies, which are relevant if the firms are subject to competition laws which prohibit the abuse of single or joint market dominance. The interpretations of the EU competition laws (especially Article 82) give a list of facilitating conditions that give rise to the potential for joint market dominance, almost all of which are satisfied in many EU electricity markets. Consequently, generating companies (gencos) must be somewhat cautious in their exercise of market power, but how cautious is unclear. Specifically, the short-run elasticity of demand can be very low in the short periods during which scarcity can arise (because of an outage, or extreme demand conditions) and the market clearing price can reach very high levels (certainly well above 1000 Euros/MWh). Just how high it is acceptable to allow prices to reach, given the need to cover fixed costs from a small number of very profitable hours, is a matter for the firms to judge and may vary across jurisdictions with differing attitudes to anti-trust enforcement.

Second, contract coverage reduces the incentive to exercise short-run market power in the spot and short-term markets, but it is hard to model the preferred contract position, which depends on the transparency of the contract market, the risk aversion of the contracting partners, and the threat of entry. Nor is it easy to model the exercise of market power in the contract market.

Finally, it is hard to model the threat of entry, which can have a profound effect on pricing and more importantly on the contracting position of generating companies.

10.3 The various modelling approaches

The three basic approaches to modelling price formation in electricity markets are:

i) mark-ups on a basic competitive model, based on some form of despatch model;
ii) a more fully articulated Cournot model in which gencos take output (and contract positions) of other gencos as given and optimise against residual demand;
iii) a Supply Function Equilibrium model in which each genco optimises against any possible realisation of residual demand (whose position depends on the supply functions of other gencos and the varying level of demand).

The first of these comes in two forms – complex and simplified. The complex models are based on the scheduling models designed originally for optimal despatch, scheduling maintenance, exploring constraint resolution and the like. In their full glory they are large, expensive and cumbersome programs that can deal with the non-convexities of start-up costs, ramp constraints, minimum load, balancing etc, and typically optimise over a significant length of

time (from a day to a fortnight in the case of Powersym). Under rather strong assumptions (including an accurate simulation of various risks, that the value of improved security measured by a reduction in the Loss of Load Probability is properly included *and* that the security standards, such as n-1, are consistent with this valuation – not many of which hold in most electricity markets), the resulting shadow prices are equivalent to competitive prices. If the system is on the least-cost expansion path then it should also be the case that the competitive prices are remunerative, i.e. cover the capital costs as well on average over time.

These models are complex to run and may take considerable computing power to derive a basic solution (despatch over time with associated shadow prices). This is particularly the case if they properly model start-up costs and ramp constraints and simulate a security-constrained despatch against a large number of contingencies. As such they do not lend themselves to repeated iterations of the kind needed to model strategic behaviour or market power.

Such models are useful in testing whether over a sufficient period of time observed market (and contract) prices deliver similar revenues per plant as the competitive benchmark, and they are clearly useful for simulating "what-if" scenarios, such as those involving new investment in plant and transmission. Given the mismatch between the assumptions needed for the models to deliver predictions of competitive prices and the reality of most market designs and engineering standards, they are unlikely to give good short-run predictions of market prices.

Simple scheduling models attempt to simplify reality in order to give a cost function on which market simulations can be built for repeated iterations. They typically simplify start-up costs, determine a merit order based on average heat-rates, and do not determine the short-run marginal costs allowing for all the plant operating constraints. They can determine the avoidable costs that must be covered for each plant given its position in the merit order, and hence determine (roughly) the system marginal cost (SMC). This can then be marked up to simulate the exercise of market power. Exactly how this is done will determine how well the model predicts market outcomes, and thus how much confidence can be placed on "what if" scenarios, of which mergers are the topic of the current inquiry. The various approaches to setting mark-ups over SMC are best left until a discussion of the other main contenders for market power simulations.

Cournot modelling

This work-horse of Industrial Organisation economics assumes that each firm (genco) chooses its output level (in each hour) to maximise its profits given the residual demand it faces (total demand *less* net imports and the outputs of other gencos) assuming that other gencos are simultaneously and independently determining their output levels. The obvious objection to this assumption is that gencos actually offer to supply amounts at various *prices*, and leave the market to determine how much of their offer to accept. One way of finessing this mismatch between the strategy choices assumed and observed is to suppose that gencos offer amounts at prices (which might be variable costs or a mark-up on these to cover various fixed costs) up to a fixed amount that they determine.

This maximum amount offered to the market would be the key short-run decision variable for strategic gencos, and would be the total available capacity for the competitive fringe. Given the marginal cost function of each genco, the strategies would then be levels of maximum output to offer in each hour, and this would determine the market-clearing price MCP). Contracting affects

the equilibrium profoundly by shifting the residual demand schedule facing each strategic genco, and has been the subject of a separate line of research starting with Allaz and Vila[96]. If contracts are simultaneously offered just once then gencos will offer contracts for some fraction of output that is increasing in the number of equivalent firms (i.e. in the inverse of the HHI). If contracts then become public knowledge and gencos can repeatedly offer more contracts, the final equilibrium becomes competitive, but not if contract positions remain confidential. One important lesson from the modelling of contract positions is that the contract cover will likely fall if mergers increase concentration, and this is an additional effect raising the price-cost margin.

The mark-up of the MCP over the SMC is a measure of market power, and will depend on the contract cover (which determines the position of the residual demand schedule), and on the elasticity of the residual demand schedule (which will depend on market concentration, in simple cases as measured by the HHI).

Such models work best in tight demand conditions in which the range of strategic choice is limited by available capacity and residual demand, and work least well in conditions of spare capacity, as the next modelling strategy clarifies.

Supply Function Equilibrium models

These models, building on theoretical work by Klemperer and Meyer[97], assume that each genco offers varying amounts of capacity at increasing offer prices, in effect offering a supply function relating the total amount offered as a function of the market clearing price. The supply function is in equilibrium (and the result is a Supply Function Equilibrium, SFE) when the genco maximises its profits given the supply functions of all other gencos, no matter what the realisation of (residual) demand (within the possible range of such demands). As such it mimics market designs in which offers are made to the System Operator (or Market Operator on a power exchange), who clears the market at a single price at each moment. The equilibria are characterised by a mark-up on marginal costs that is zero for full contract cover, positive and increasing in the tightness of uncovered demand relative to capacity, and negative for over-contracted positions (i.e. when the genco is called on to supply less than he has sold under contract). The mark-up approaches the Cournot mark-up at maximum demand, and approaches the competitive or Bertrand equilibrium as demand falls to the contracted position. Typically there are a range of possible SFEs, and a need to select one on which gencos can coordinate. This may be the profit maximising SFE, or the entry deterring SFE (to take two salient possibilities), but there is an uncomfortable degree of arbitrariness in the selection. Green and Newbery[98] built a simple SFE model of the England and Wales electricity market to explore the consequences of varying degrees of concentration on the equilibrium mark-ups and found that a five-firm

[96] Allaz B., Vila J.L. (1993) "Cournot Competition, Forward Markets and Efficiency", Journal of Economic Theory 59, 1-16.

[97] Klemperer, P.D., and Meyer, M.A. (1989). "Supply Function Equilibria in Oligopoly Under Uncertainty," Econometrica. November. 57(6): 1243-77.

[98] Green, R.J and Newbery, D.M, (1992) "Competition in the British Electricity Spot Market," Journal of Political Economy 100(5): 929-953.

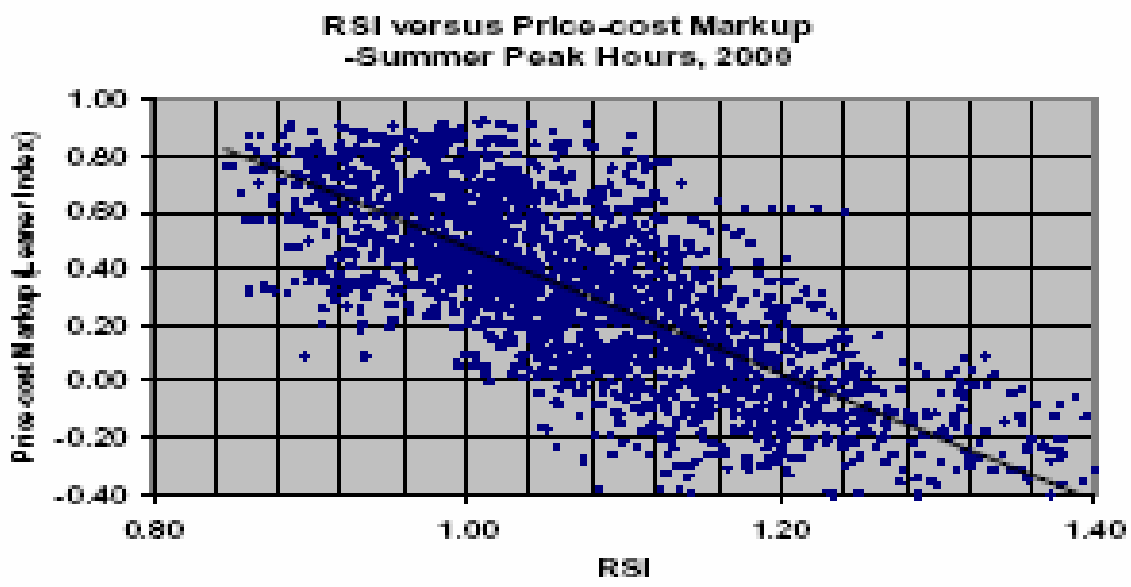
oligopoly would have delivered almost competitive prices, while the chosen duopoly afforded the opportunity for large mark-ups.

Simultaneously determining the contract cover and the SFE consistent with that is a challenging problem that has only been solved under strong assumptions, of which the most appealing is under conditions of market contestability [99]. Finding the unique linear SFE has algebraic (but few other) attractions. Computing equilibria for realistic cost functions is computationally extremely demanding, while there remains an unresolved issue in how best to reconcile the normal assumption of continuous cost functions with the requirement in most market designs that bids and offers must be step functions.

A synthesis

Scheduling models are the natural basis for determining the cost functions that are needed in any market simulation model. The SFE models tell us that the mark-up approaches the Cournot mark-up in tight markets, and the competitive price in very slack markets and as the demand falls to the contract cover. That suggests a simple strategy of diving the number of hours to be modeled into sub-sets with differing degrees of tightness (measured by a Residual Supply Index), and for each determining the mark-up as some fraction of the Cournot mark-up for that configuration (given assumptions about available capacity, contract cover, import capacity, demand and demand elasticities).

Figure 53: Relationship between price-cost mark-up and RSI for California (Sheffrin, 2002)



The Residual Supply Index for a company *i* measures the percent of supply capacity remaining in the market after subtracting company *i*'s capacity of supply:

99 Newbery, D.M. (1998) 'Competition, Contracts and Entry in the Electricity Spot Market', RAND Journal of Economics, 29(4), Winter, 726-49. (DAE Working Paper 9707)

RSI_i = (Total Capacity-Company *i*'s Relevant Capacity)/Total Demand

where:

Total Capacity is the total regional supply capacity plus total net imports,

Company *i*'s Relevant Capacity is company's *i*'s capacity minus company *i*'s contract obligations, and

Total Demand is metered load plus purchased ancillary services.

When RSI is greater than 100 percent, the suppliers other than company *i* have enough capacity to meet the demand of the market, and company *i* should have little short-run influence on the spot market clearing price. It would also be possible to define an RSI excluding contract cover be defining Company *i*'s Relevant Capacity is company's *i*'s expected available capacity, and this measure would both be easier to compute and may also give a measure of potential market power in the contract and spot market together.

The mark-up fraction would then be high if the RSI falls below 100, and tends to zero as the RSI increases substantially above 100, and might be estimated from observations such as those shown above for the Californian market[100] or preferably from the Dutch market. The main problem in calibrating such a model lie in choosing values for the contract cover and the elasticity of demand that allow sensible predictions of the Cournot mark-up before making further adjustments for the impact of the RSI on that mark-up.

Using such models for merger analysis

The apparent sensitivity of model predictions to hard-to-measure parameters such as the demand elasticity, contract cover and the degree of competition implied by the RSI may suggest that the models are of little use for counterfactual analysis of the kind used in merger investigations. That would be a mistake, in that the models are designed to examine the impact of *changing* the degree of competition, and it seems reasonable that once the model has been calibrated to give a fair fit to current market conditions then it should be able to predict the impact of a change in these conditions. Of course, it would still be necessary to test the robustness of the predicted change to variations in the underlying assumptions that are consistent with replicating the original observed prices.

The main remaining uncertainty is the impact of any change in equilibrium prices on the level of investment and entry, but as the gestation lags are quite long, even if the long-run equilibrium prices are less sensitive to short-run market power, it is the short to medium run that is relevant to determining whether the predicted price changes are deleterious.

[100] Sheffrin, A. (2002) "Predicting Market Power Using the Residual Supply Index" Presented to FERC Market Monitoring Workshop December 3-4, 2002.

Appendix VII : The effect of market coupling

By default our model assumes market coupling, whereas in reality in 2005 TSOs allocated interconnector capacity using explicit auctions (with the exception of the SEP contracts). Market coupling and explicit auctions would likely have resulted in different levels of imports for 2005.

To test this possibility, we asked the following question; suppose market coupling had been introduced in 2005 – would prices and imports have been very different from the explicit auction mode of market operation that actually occurred? To answer this, we ran the model for 2005 in market coupling mode, using the mark-ups derived from the explicit auction mode of the model. The logic is that there seems no reason why generators would change their mark-ups at the introduction of market coupling, so applying the mark-ups derived from the explicit auction to the model market coupling mode should yield the effect of market coupling on average prices, and the level of imports.

Figure 54 illustrates that, as expected, market coupling reduces electricity prices, by on average 6%. We suspect that the two months where market coupling appears to increase prices is an artefact of the model, and does not represent a significant result.

Figure 54: Predicted 2005 peak prices in market coupling mode and explicit auction mode

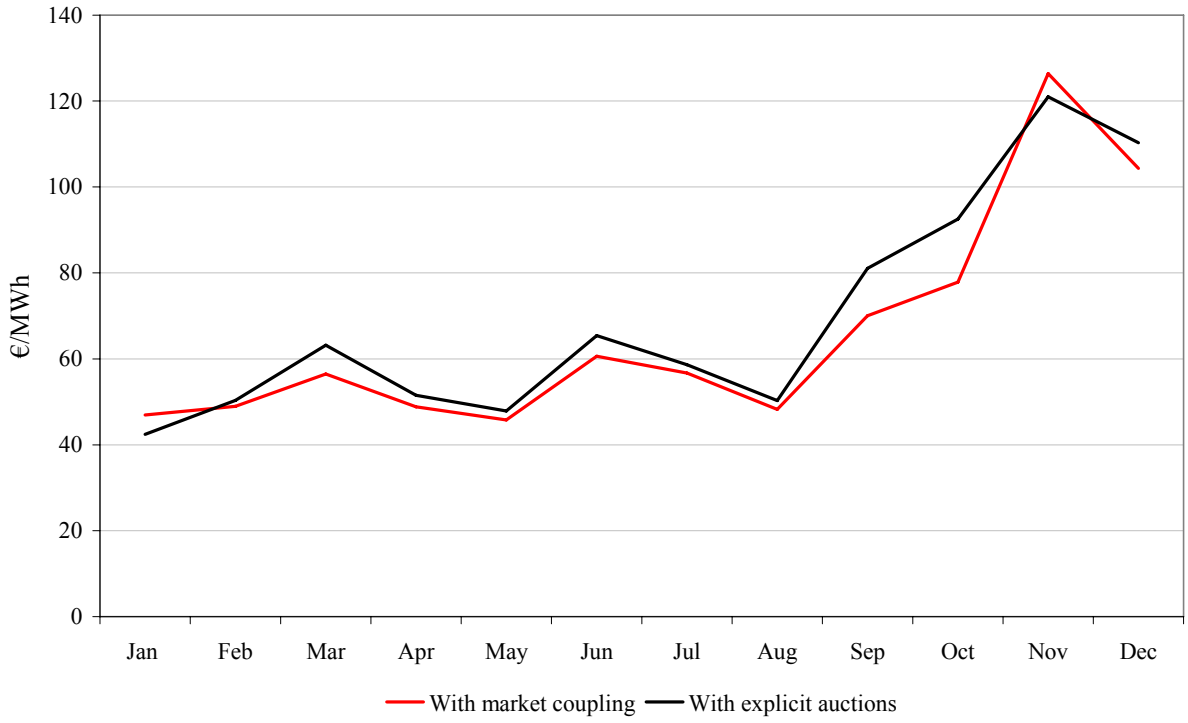
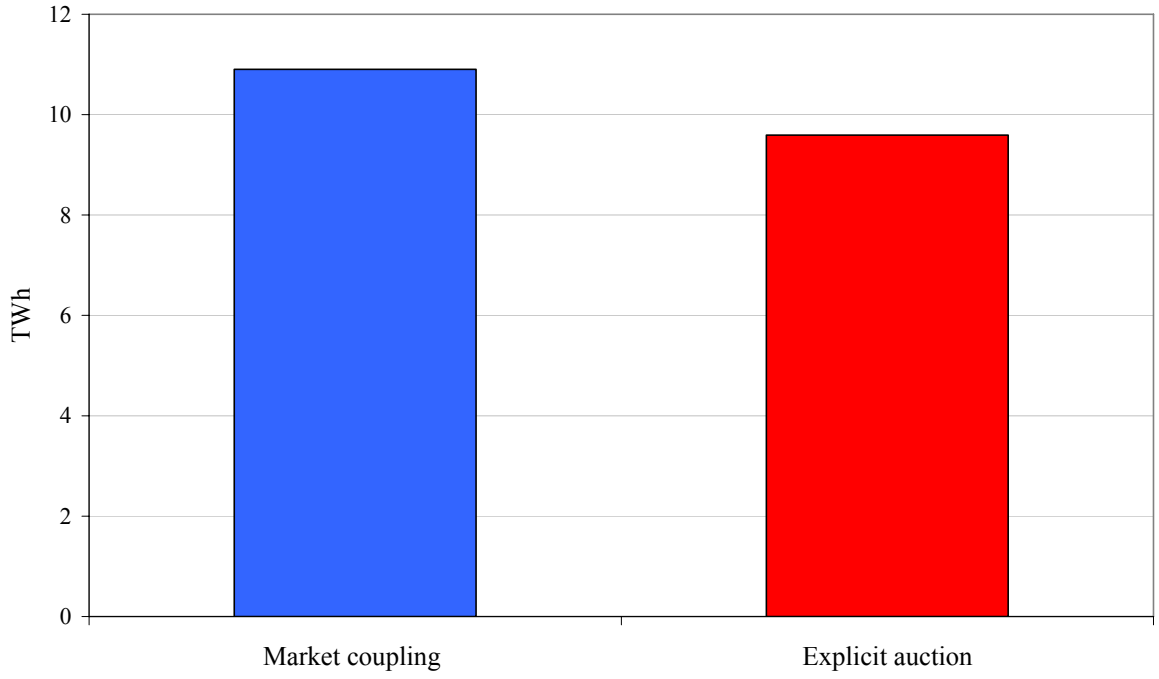


Figure 55 illustrates that market coupling increases peak imports by about 1.3 TWh in 2005, or 14%.

Figure 55: Effect of market coupling on peak 2005 imports



Appendix VIII : Details of merger analysis

Note that, in the Netherlands, we assume that plant jointly owned by EPZ and Essent and controlled by Essent. We list the Rijnmond Intergen plant as controlled by Eneco, because Eneco has a long-term contract for the plant's output.

In Belgium, we divide the capacity of the new Zandvliet power plant between RWE and Electrabel on a 50/50 basis, but we group RWE with 'other' market players in Belgium since it has a relatively small amount of capacity in Belgium.

Table 44: Market shares and HHI for a Dutch peak market

Owner	Capacity	Market Share
Dutch plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	4,620	
ELSTA	405	
Eneco	795	
E.ON	1,795	
Essent	4,871	
Nuon	3,613	
Shell	300	
Other 1	1,079	
Total	18,882	
Imports	Capacity	Market Share
Statkraft	700	
E.ON	400	
Electrabel	400	
Other 2	400	
Other 3	400	
Other 4	400	
Other 5	400	
Other 6	400	
Other 7	400	
Other 8	400	
Total	4300	
Imports and Dutch plant	Capacity	Market Share
Akzo Nobel	350	2%
Delta	869	4%
EDM	185	1%
Electrabel	5,020	22%
ELSTA	405	2%
Eneco	795	3%
E.ON	2,195	9%
Essent	4,871	21%
Nuon	3,613	16%
Shell	300	1%
Statkraft	700	3%
Other 1	1,079	5%
Other 2	400	2%
Other 3	400	2%
Other 4	400	2%
Other 5	400	2%
Other 6	400	2%
Other 7	400	2%
Other 8	400	2%
Total	23,182	
HHI	1,328	

Table 45: Market shares and HHI for a Dutch peak market following a Nuon-Essent merger

Owner	Capacity	Market Share
Dutch plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	4,620	
ELSTA	405	
Eneco	795	
E.ON	1,795	
Nuon/Essent	8,484	
Shell	300	
Other 1	1,079	
Total	18,882	
Imports	Capacity	Market Share
Statkraft	700	
E.ON	400	
Electrabel	400	
Other 2	400	
Other 3	400	
Other 4	400	
Other 5	400	
Other 6	400	
Other 7	400	
Other 8	400	
Total	4300	
Imports and Dutch plant	Capacity	Market Share
Akzo Nobel	350	2%
Delta	869	4%
EDM	185	1%
Electrabel	5,020	22%
ELSTA	405	2%
Eneco	795	3%
E.ON	2,195	9%
Nuon/Essent	8,484	37%
Shell	300	1%
Statkraft	700	3%
Other 1	1,079	5%
Other 2	400	2%
Other 3	400	2%
Other 4	400	2%
Other 5	400	2%
Other 6	400	2%
Other 7	400	2%
Other 8	400	2%
Total	23,182	
HHI	1,983	

Table 46: Market shares and HHI for a Dutch peak market following a Nuon-Essent merger post divestment

Owner	Capacity	Market Share
Dutch plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	4,620	
ELSTA	405	
Eneco	2,689	
E.ON	1,795	
Nuon/Essent	6,590	
Shell	300	
Other 1	1,079	
Total	18,882	
Imports	Capacity	Market Share
Statkraft	700	
E.ON	400	
Electrabel	400	
Other 2	400	
Other 3	400	
Other 4	400	
Other 5	400	
Other 6	400	
Other 7	400	
Other 8	400	
Total	4300	
Imports and Dutch plant	Capacity	Market Share
Akzo Nobel	350	2%
Delta	869	4%
EDM	185	1%
Electrabel	5,020	22%
ELSTA	405	2%
Eneco	2,689	12%
E.ON	2,195	9%
Nuon/Essent	6,590	28%
Shell	300	1%
Statkraft	700	3%
Other 1	1,079	5%
Other 2	400	2%
Other 3	400	2%
Other 4	400	2%
Other 5	400	2%
Other 6	400	2%
Other 7	400	2%
Other 8	400	2%
Total	23,182	
HHI	1,575	

Table 47: Market shares and HHI for a Dutch-Belgian peak market

Owner	Capacity	
Dutch plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	15,855	
ELSTA	405	
Eneco	795	
E.ON	2,355	
Essent	4,991	
Nuon	4,803	
Shell	300	
SPE	1,057	
Other 1	2,825	
Total	34,790	
Imports	Capacity	
Statkraft	700	
E.ON	400	
Electrabel	400	
EdF	400	
Typical importer from FR (1 of 6)	302	
Typical importer from DE (1 of 7)	355	
Total	6,200	
Imports and Dutch plant	Capacity	Market Share
Akzo Nobel	350	1%
Delta	869	2%
EDM	185	0%
Electrabel	16,255	40%
ELSTA	405	1%
Eneco	795	2%
E.ON	2,755	7%
Essent	4,991	12%
Nuon	4,803	12%
Shell	300	1%
SPE	1,057	3%
Statkraft	700	2%
EdF	400	1%
Typical importer from FR (1 of 6)	302	1%
Typical importer from DE (1 of 7)	355	1%
Other 1	2,825	7%
Total	40,990	
HHI	1,981	

Table 48: Market shares and HHI following an Essent-Nuon merger in a Dutch-German peak market

Owner	Capacity	Market Share
Dutch/German plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	5,020	
ELSTA	405	
Eneco	795	
E.ON	24,019	
Nuon/Essent	9,554	
Shell	300	
Other 1	1,079	
EnBW	2,274	
KRAFTWERK	3,359	
NWS	949	
RWE	19,536	
STEAG AG	4,416	
STADTWERKE	10,438	
Vattenfall	15,112	
Various	15,264	
Total	113,924	
Imports	Capacity	Market Share
Statkraft	700	
Electrabel	400	
Poland	863	
Czech Rep	1,725	
Austria	1,050	
Switzerland	3,150	
France	1,926	
Other 2	400	
Other 3	400	
Other 4	400	
Total	11,014	
Akzo Nobel	350	0.3%
Delta	869	0.7%
EDM	185	0.1%
Electrabel	5,420	4.3%
ELSTA	405	0.3%
Eneco	795	0.6%
E.ON	24,019	19.2%
Nuon/Essent	9,554	7.6%
Shell	300	0.2%
Other 1	1,079	0.9%
EnBW	2,274	1.8%
KRAFTWERK	3,359	2.7%
NWS	949	0.8%
RWE	19,536	15.6%
STEAG AG	4,416	3.5%
STADTWERKE	10,438	8.4%
Vattenfall	15,112	12.1%
Various	15,264	12.2%
Statkraft	700	0.6%
Poland	863	0.7%
Czech Rep	1,725	1.4%
Austria	1,050	0.8%
Switzerland	3,150	2.5%
France	1,926	1.5%
Other 2	400	0.3%
Other 3	400	0.3%
Other 4	400	0.3%
Total	124,938	
HHI	876	

Table 49: Market shares and HHI following a RWE-Essent merger in a Dutch-German market

Owner	Capacity	Market Share
Dutch/German plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	5,133	
ELSTA	405	
Eneco	795	
E.ON	24,579	
Nuon	4,683	
Shell	300	
Other 1	1,079	
EnBW	2,274	
KRAFTWERK	3,359	
NWS	949	
RWE/Essent	24,407	
STEAG AG	4,416	
STADTWERKE	10,438	
Vattenfall	15,112	
Various	16,334	
Total	115,667	
Imports	Capacity	Market Share
Statkraft	700	
Electrabel	400	
Poland	863	
Czech Rep	1,725	
Austria	1,050	
Switzerland	3,150	
France	1,926	
Other 2	400	
Other 3	400	
Other 4	400	
Total	11,014	
Akzo Nobel	350	0.3%
Delta	869	0.7%
EDM	185	0.1%
Electrabel	5,533	4.4%
ELSTA	405	0.3%
Eneco	795	0.6%
E.ON	24,579	19.4%
Nuon	4,683	3.7%
Shell	300	0.2%
Other 1	1,079	0.9%
EnBW	2,274	1.8%
KRAFTWERK	3,359	2.7%
NWS	949	0.7%
RWE/Essent	24,407	19.3%
STEAG AG	4,416	3.5%
STADTWERKE	10,438	8.2%
Vattenfall	15,112	11.9%
Various	16,334	12.9%
Statkraft	700	0.6%
Poland	863	0.7%
Czech Rep	1,725	1.4%
Austria	1,050	0.8%
Switzerland	3,150	2.5%
France	1,926	1.5%
Other 2	400	0.3%
Other 3	400	0.3%
Other 4	400	0.3%
Total	126,681	
HHI	960	

Table 50: Market shares and HHI following an Essent-Nuon merger in a Dutch-Belgian market

Owner	Capacity	Market Share
Dutch plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	15,742	
ELSTA	405	
Eneco	795	
E.ON	1,795	
Nuon/Essent	8,724	
Shell	300	
SPE	1,057	
Other 1	2,825	
Total	33,047	
Imports	Capacity	Market Share
Statkraft	700	
E.ON	400	
Electrabel	400	
EdF	400	
Typical importer from FR (1 of 6)	302	
Typical importer from DE (1 of 7)	355	
Total	6,200	
Imports and Dutch plant	Capacity	Market Share
Akzo Nobel	350	1%
Delta	869	2%
EDM	185	0%
Electrabel	16,142	41%
ELSTA	405	1%
Eneco	795	2%
E.ON	2,195	6%
Nuon/Essent	8,724	22%
Shell	300	1%
SPE	1,057	3%
Statkraft	700	2%
EdF	400	1%
Typical importer from FR (1 of 6)	302	1%
Typical importer from DE (1 of 7)	355	1%
Other 1	2,825	7%
Total	39,247	
HHI	2,301	

Table 51: Market shares and HHI following an Essent-Nuon merger with divestment of assets in a Dutch-Belgian market

Owner	Capacity	Market Share
Dutch plant		
Akzo Nobel	350	
Delta	869	
EDM	185	
Electrabel	15,742	
ELSTA	405	
Eneco	1,814	
E.ON	1,795	
Nuon/Essent	7,705	
Shell	300	
SPE	1,057	
Other 1	2,825	
Total	33,047	
Imports	Capacity	Market Share
Statkraft	700	
E.ON	400	
Electrabel	400	
EdF	400	
Typical importer from FR (1 of 6)	302	
Typical importer from DE (1 of 7)	355	
Total	6,200	
Imports and Dutch plant	Capacity	Market Share
Akzo Nobel	350	1%
Delta	869	2%
EDM	185	0%
Electrabel	16,142	41%
ELSTA	405	1%
Eneco	1,814	5%
E.ON	2,195	6%
Nuon/Essent	7,705	20%
Shell	300	1%
SPE	1,057	3%
Statkraft	700	2%
EdF	400	1%
Typical importer from FR (1 of 6)	302	1%
Typical importer from DE (1 of 7)	355	1%
Other 1	2,825	7%
Total	39,247	
HHI	2,210	

Appendix IX : Pivotal Supply

Pivotal Supplier Indicator

The pivotal supplier indicator is an attempt to incorporate demand conditions, in addition to supply conditions, in a measure of potential market power. This indicator examines whether a given generator is necessary (or 'pivotal') in serving demand. In particular, it asks whether the capacity of a generator is larger than the surplus supply (the difference between total supply and demand) in the wholesale market. Bushnell, et. al. (1999) defined the Pivotal Supplier Index (PSI) as a binary indicator for a supplier at a point in time which is set equal to one if the supplier is pivotal, and zero if the supplier is not pivotal. The PSI from each hour over a period of time (e.g. one year) can then aggregated to determine the percentage of time for which a company achieves pivotal status. For example, Bushnell et al (1999),[101] in an ex-ante study of the Wisconsin/Upper Michigan (WUMS) region, found that the largest supplier would have pivotal supplier status in 55% of the hours in a year.

Residual Supply Index

The Residual Supply Index (RSI) is similar to the PSI but is measured on a continuous scale rather than a binary scale. As such the index addresses the criticism of the PSI in that it may be possible for a company to exercise market power when it is nearly, but (as the PSI shows) not actually pivotal. The Residual Supply Index (RSI) was developed by the California Independent System Operator (CAISO).[102] The residual supply index for a company *i* measures the percent of supply capacity remaining in the market after subtracting company *i*'s capacity of supply.

RSI_i = (Total Capacity-Company *i*'s Relevant Capacity)/Total Demand

where:

Total Capacity is the total regional supply capacity plus total net imports,

Company *i*'s Relevant Capacity is company's *i*'s capacity minus company *i*'s contract obligations, and

Total Demand is metered load plus purchased ancillary services.

When RSI is greater than 100 percent, the suppliers other than company *i* have enough capacity to meet the demand of the market, and company *i* should have little influence on the market clearing price. On the other hand if residual supply is less than 100 percent of demand, company *i* is needed to meet demand, and is, therefore a pivotal player in the market.

Analysis

Consider the case in which all but one of the generators are non-pivotal in a given period (e.g. one hour), and suppose that they act as price-takers, so that the only generator with market power

[101] Bushnell, J., Day, C., et al. (1999) "An International Comparison of Models for Measuring Market Power in Electricity", EMF Working Paper 17.1, Energy Modelling Forum Stanford University.

[102] See Sheffrin (2001, 2002a, 2002b, 2002c)

is that for whom the RSI < 100% (at the prevailing price, p). The residual demand facing that genco is $R_i(p) = D - \Sigma_{j \neq i} K_j$, where K_j is the capacity (assumed available and currently supplying at the prevailing and higher prices) of genco j. Genco i's problem is to maximise $(p\text{-}c_i)\ R_i(p)$, from which we derive the Lerner condition:

$$L_i \equiv \frac{p - c_i}{p} = \frac{R_i}{-pR'_i} = \frac{1}{\varepsilon_{RD}}$$

where ε_{RD} is the elasticity of the residual demand facing the genco. If the elasticity of total demand is ε then $\varepsilon_{RD} = \varepsilon\ (R_i(p) + \Sigma_{j \neq i} K_j)/R_i(p) = \varepsilon(1+RSI_i.D/R_i)$ which will be substantially larger than ε and will depend on both the RSI (which depends on capacity) and the ratio R_i/D.

Now suppose that there are two pivotal firms, 1 and 2, and that all others remain price-taking. If each firm plays Nash-Cournot and the aggregate residual demand is $R(p) = D - \Sigma^n_{j=3} K_j$, then each firm maximises $(p\text{-}c_i)(R(p)\text{-}q_j)$:

$$L_i \equiv \frac{p - c_i}{p} = \frac{R - D_j}{-pR'} = \frac{\alpha_i}{\varepsilon_{RD}}$$

where α_i is the share of residual demand by firm i. However, this time $\varepsilon_{RD} = \varepsilon\ (R(p) + \Sigma^n_{j=3} K_j)/R(p)$ and it is not clear that this is directly comparable to the previous example.

What about the effect of multiple mergers?

One question of possible interest is to examine a market of n gencos, none of which is pivotal before mergers. If they each have capacity k that requires that $(n\text{-}1)k > D$. Suppose that after a merger the merged firm with capacity $2k$ becomes pivotal because $(n\text{-}2)k < D$. Is it the case that if two more firms merge so that both merged firms are separately pivotal, that the result is more competitive than if only one pair of firms had merged. To make progress, suppose that $D = A - bp$. Consider the n-firm oligopoly (each firm has the same variable cost c), then the equilibrium output is

$$q = Min\left(k, \frac{A - bc}{n+1}\right),$$

$$p = Max\left(\frac{A - nk}{b}, \frac{A + nbc}{b(n+1)}\right)$$

Suppose, consistent with our assumptions, that initially capacity is not a binding constraint, so the condition on k is

$$(n-1)k > \frac{n(A - bc)}{n+1}.$$

After the merger all the remaining firms presumably produce at full capacity, and the merged firm produces q_m, with

$$(n-2)k < \frac{A - bc + (n-2)k}{2} \quad \text{or} \quad (n-2)k < A - bc \ .$$

These two conditions can be written as

$$(n-1/n)k > A - bc > (n-2)k. \qquad (1)$$

The price after the first merger will be

$$p = \frac{A + bc - (n-2)k)}{2b}.$$

Now consider the second merger, identical to the first, so now there are n - 4 small gencos all producing at k, and two larger pivotal firms each producing q_d, subscripted for duopoly, where

$$q_d = \frac{A - bc - (n-4)k}{3}.$$

The price is now

$$p = \frac{A + bc - (n-4)k)}{3b}.$$

Which configuration has the higher price?

$$p_m - p_d = \frac{A + bc - (n+2)k)}{6b}. \qquad (2)$$

The inequality above does not resolve the sign of this expression. Suppose that the elasticity of market demand before any merger is $\varepsilon = bp/nq$. Solving for this we have $bc/A = (n\varepsilon-1)/\{(1+\varepsilon)n\}$ which implies from (1) that $A > n(n-2)(1+\varepsilon)k/(n+1)$. This in turn implies that the sign of (2) is that of $(n - 2)(n + 2n\varepsilon - 1) - (n + 1)(n +2)$, which is positive for $n > 2+3/\varepsilon$. A plausible value for $\varepsilon = 1/3$, requiring $n > 9$ to be assured that two mergers were better than one.

Conversely, we can start from (1) to find when the second merger definitely makes matters worse by making (2) negative, for $A < (n^2+1)(1+\varepsilon)k/(n+1)$, so the right hand side of (2) is

less than zero if $2n > 1$, which it is. This is a surprisingly strong conclusion, admittedly in an overly simple model of oligopoly and merger analysis. Perhaps not too surprisingly, too mergers are always worse for consumers than one. The result assumes strong symmetry and conceivably might not hold if there were reasons for considerable asymmetry, but that would require a more complex model with differing costs and capacities.

Intuition

At first glance it might seem surprising that if there are two firms that are pivotal rather than one, the price cost margin is likely to be higher, as one might casually argue that two competing firms are surely better than a single firm. This is, however, a mis-description, and it might be more accurate to say that with two pivotal firms facing a competitive fringe, there is one fewer competitive firm than if a single pivotal firm faces a competitive fringe.[103] Suppose that we compare two markets, one of which has a single pivotal supplier with RSI = r, and the other has two pivotal suppliers, each with RSI = r, but otherwise the remaining firms are numerous and price-taking. In the first case, the single pivotal firm can reduce supply (or raise its price to induce reduced demand) while the remaining firms continue to produce at full capacity (or might even increase supply if they are on the increasing part of their supply schedule). All of the burden of raising price falls on the one firm, but the benefits of higher prices are enjoyed by all. In the second case, both pivotal firms have an incentive to reduce supply, and they each benefit from the other's reduction (and share the cost). That intuitively suggests that two firms may find it jointly more attractive to raise prices if they each have the same residual market power as a single firm (and together they can clearly remove more from the market and drive prices far higher than the single pivotal firm could).

If the two-pivotal firms each have a much lower RSI than a single pivotal firm, then their joint market power is reduced relative to the more concentrated single pivotal firm case, and this can offset their incentive to raise prices more, so one cannot just say that two pivotal firms will exercise more market power than just one, without saying how pivotal they are. Another complicating factor is that with only one pivotal firm, that firm's capacity does not influence its RSI, but if there are two pivotal firms, their individual capacity affects the RSI of the other firm. In practical terms, that makes it hard to construct numerical examples with the same RSI and other characteristics, but differing numbers of pivotal firms. For example, if $r = 80\%$, $A=10$, $b=c=1$, then for the single pivotal firm, $F= \Sigma_{j\neq i}K_j = 6$, $q = 1.5$, $p = 2.5$, and $D = 7.5$. The competitive equilibrium with $p = c + k$, where k is the long-run marginal capital cost of expansion, with $k = 1$, would be $p = 2$, $D = 8$, and $K = 2$, so the capacity utilisation of the pivotal firm would be 75% if it had the competitive level of capacity (and there is no reason why it should choose that level).

[103] We are implicitly assuming that if no other firm is pivotal, it lacks the ability to have much influence on price. This is reasonable provided there are sufficient such firms and there is an adequate margin of spare capacity, as supply function analysis suggests, but may be misleading if capacity margins are tight and/or there are fewer non-pivotal firms, for they can then also take advantage of the pivotal firm with-holding supply and further tightening the market. In such cases, a Cournot analysis may be more appropriate.

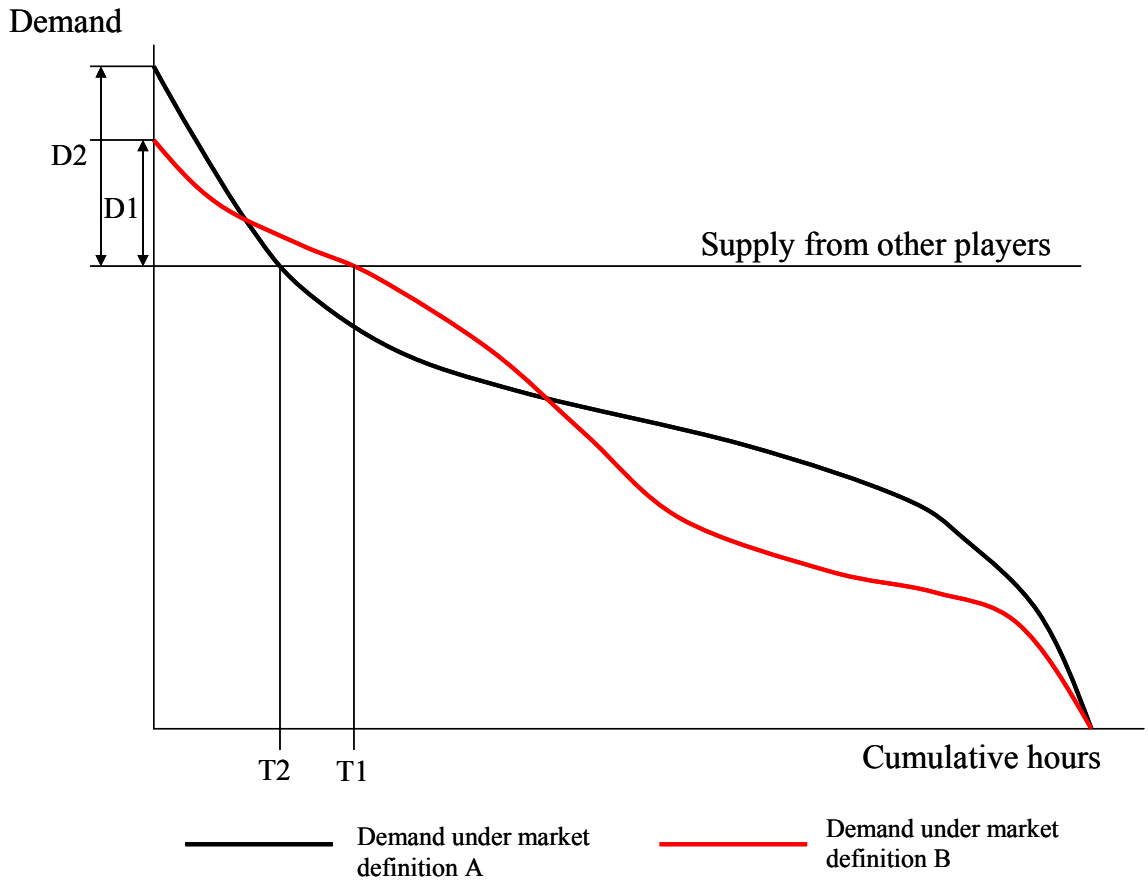
To replicate the same r in the two pivotal firm case, $\Sigma^{n}_{j=3} K_j = F < 4.5$ if $q < K$, so if $F = 4$, $K = 1.87$, $q = 1.67$, $D = 7.33$, and $p = 2.67$, showing a higher markup, as expected, but it is not clear that the two industries are exactly comparable, as they have differing values for F and D (which may not be so surprising given that prices are different). Note that capacity utilisation is 89%, and the competitive equilibrium of $D = 8$ would require $K = 2$, so the pivotal firms are (logically) investing less than the competitive level. In short, it is quite difficult to make direct comparisons between industries that are both comparable in relevant ways but differ in the number of pivotal firms.

Divestment and duration of pivotal supply

Figure 56 illustrates the relationship between the amount of capacity required to avoid being pivotal, and the amount of time a firm is pivotal, for two different markets. Under both market definitions, a player is pivotal whenever the capacity of other players is insufficient to meet demand. In Figure 56 this is all the hours to the left of the point where the load duration curve is less than the supply from other players. To avoid being pivotal at all, a player would need to divest sufficient capacity so that other players could meet the maximum demand, illustrated by D1 and D2 in Figure 56.

Suppose one had two markets, A and B, and that the markets were identical on the supply side by had different demand (*i.e.* the load duration curves were different). In market A, the player being tested for 'pivotalness' is pivotal for T2 hours, and must divest D2 MW to avoid being pivotal. In market B, the same player is pivotal for T1 hours and must divest D1 MW. Figure 56 illustrates, that even though the player is pivotal for less time in market A (*i.e.* T2<T1), in market A the player must divest more capacity (*i.e.* D2>D1). Similarly, a player who is pivotal for more time in a Dutch-Belgian market than in a Dutch market may have to divest less capacity to avoid being pivotal in the Dutch-Belgian than it would have to divest in the Dutch market.

Figure 56: Relationship between the load duration curve, the required divestment and duration of pivotal supply



Appendix X : FERC Indicative Screens for Market Power and Merger Analysis

On April 14, 2004, the Federal Energy Regulatory Commission (FERC) in the United States issued a new interim approach to analyzing market power for those firms applying for Market Based Rates Authorities (MBRs) *i.e.* rates for selling power that are not approved by a regulator.[104] The approach contains a hierarchy of analyses and screens, that all companies have to pass in order to be granted MBR.

The first new test is a Pivotal Supplier Analysis (PSA). The idea behind the PSA is quite straightforward. This indicator examines whether a given generator is necessary (or 'pivotal') in serving demand. If power demand in a specific market cannot be met without at least some power from a supplier, that supplier is pivotal and faces a rebuttable presumption that they possess market power. For example, if demand in a single hour is 300 MW and the total available supply of sellers other than Supplier X is 250 MW, then demand cannot be met unless X sells at least 50 MW to the market. Intuitively, if X's supply is needed to satisfy the demand in the market, X is probably able to charge extremely high prices for at least a portion of its supply. The second test is the basic market share test. If a seller has a proper defined market share of less than 20 percent, the seller passes the test.

If an applicant fails either the PSA or market share test, the applicant may proceed directly to mitigation or to conduct what is called a "Delivered Price Test" (DPT) analysis. Applicants who choose to conduct the DPT must estimate the shares of seller capacities that can be physically and economically delivered to an area within 5 percent of the market price prevailing during a season and load period. The results of the DPT can be used for calculating PSA, market share, and the well-known Herfindahl-Hirschman Index (HHI). If the DPT reveals that the applicant has a share less than 20 percent and the HHI of the relevant market is less than 2500, the applicant is back to a rebuttable presumption of no significant market power. If not, they confront the same mitigation options that follow screen failures for the basic tests.

A relatively new measure of market power is the so-called "Withholding Analysis". This measure was introduced by Joskow and Kahn (2002) in an analysis of market power in the California electricity market.[105] The aim of Withholding Analysis is to determine if output, which could have been sold profitably at the competitive price, was nevertheless withheld from the market. There are two types of withholding – economic withholding, where output is reduced because it is bid into the market above competitive prices, and physical withholding, which involves a deliberate reduction of the output that is bid into the market even though such output could still be sold at prices above marginal cost.

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[104] Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy, 107 F.E.R.C. § 61,018 (2004) [hereinafter 2004 MBR Order].

105 Joskow, P. and Kahn, E. (2002) "A Quantitative Analysis of Pricing Behavior in California's Wholesale Electricity Market During Summer 2000" The Energy Journal, Vol 23, No. 4.

The FERC acknowledges the relevance of Withholding Analysis in an order dated June 26, 2003.[106] In this order, the FERC proposed to condition all new and existing MBR tariffs and authorizations on sellers' compliance with Market Behavior Rules.[107] These Market Behavior Rules address (among others) market manipulation activities[108] with respect to "bidding the output of or misrepresenting the operational capabilities of generation facilities in a manner which raises market prices by withholding available supply from the market". FERC has been using this type of analysis since June 2003. As an example, on August 1, 2003, FERC's Office of Market Oversight and Investigations (OMOI) provided the Commission with its initial report on an investigation of alleged physical withholding by different generators in relation to the California electricity crisis in 2000 and 2001. More recently, on April 2005, FERC accepted a settlement, valued at nearly $500 million, in which Mirant Corp. settles with California parties and FERC a wide range of issues stemming from the 2000-2001 energy crisis in California and other Western states. The global settlement addresses pending proceedings involving among other charges generation withholding disputes.

In energy industries, the Antitrust Division of United States Department of Justice (DOJ) and the FERC both have responsibility for merger review. FERC analyzes such transactions under the familiar "public interest" standard but, as the Supreme Court has long made clear, that review does not exempt electricity and natural gas mergers from review by the Antitrust Division.[109] The DPT test has been used by FERC in all merger proceedings in the United States. Furthermore, the Withholding Analysis is regularly used by both FERC and DOJ in merger cases in the energy industry in the United States.

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[106] The need for these Market Behavior Rules was informed (among other causes) by the types of behavior that FERC observed in the Western markets in the United States during the electricity crisis in 2000 and 2001 and by Commission Staff's Final Report concerning these markets (Final Report on Price Manipulation in Western Markets: Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices, Docket No. PA02-2-000 (March 2003))

107 The Market Behavior rules address: (i) unit operations; (ii) market manipulation; (iii) communications; (iv) reporting; (v) record retention; and (vi) related tariff matters.

108 See Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 103 FERC § 61,349 (2003) (June 26 Order).

109 See Otter Tail Power Co. v. United States, 410 U.S. 366, 374-75 (1973) (electricity); California v. FPC, 369 U.S. 482, 489 (1962) (natural gas).

Appendix XI : Over-the-Counter vs. Power Exchange Price Data

We collected electricity prices for the Netherlands and its neighbours from a variety of sources: From Platts we received "over-the-counter" (OTC) day-ahead baseload price assessments for the Netherlands, Germany, France and Belgium. These prices are published daily in Platts' trade press newsletter European Power Daily. Contracts for power delivery in the Netherlands and Germany are also traded on power exchanges. We collected spot (day-ahead) hourly prices from trading at the APX and EEX (European Energy Exchange) exchanges. For the purpose of comparing APX and EEX prices to Platts prices we calculated a daily baseload price based on the simple average of the prices for each of the 24 hourly products.

Belgium does not have a power exchange, but Electrabel publishes a daily index of Belgian baseload prices

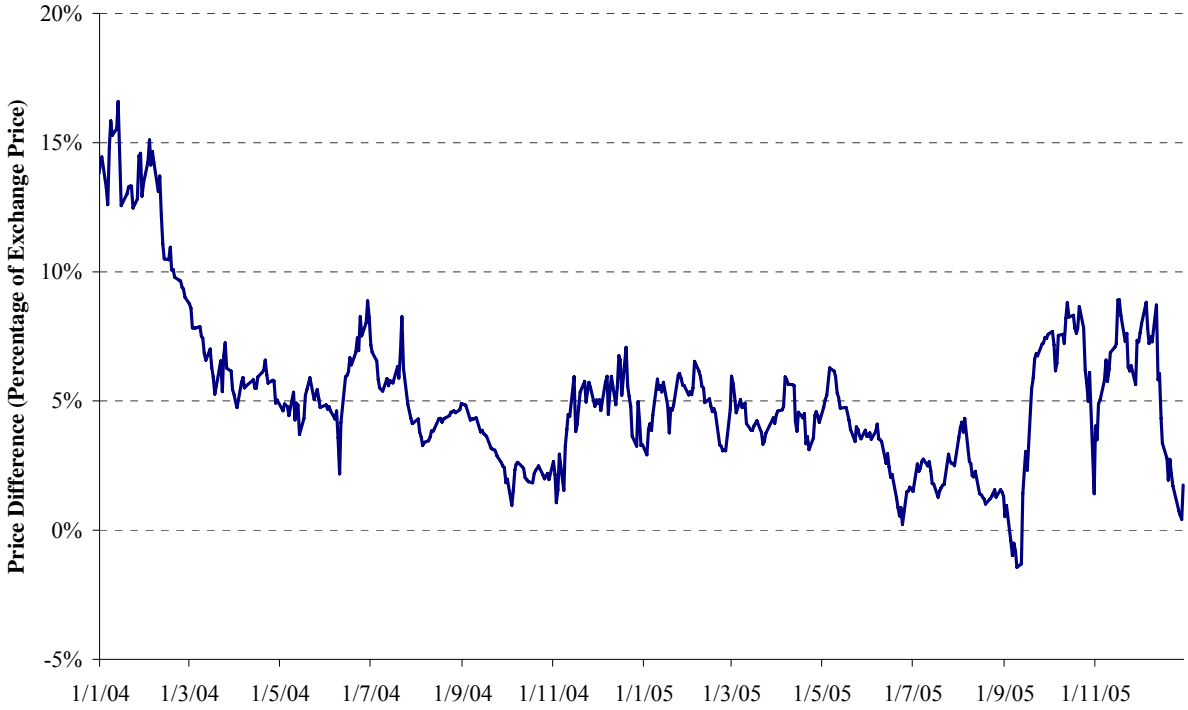
Despite differences in trading mechanism, time of trade, contractual terms, etc., the statistics in Table 52 below show only minor differences between OTC and exchange prices. We note that the magnitude of the differences is similar for the three countries, as well as for weekdays and weekends.

Table 52: Price Differences Between OTC and Exchange Prices
Day-Ahead Baseload Prices

	Netherlands		Germany		Belgium	
	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays
2004						
Minimum	-45%	-27%	-25%	-33%	-23%	-24%
Maximum	61%	62%	55%	49%	52%	22%
Mean	6%	1%	2%	1%	1%	0%
Median	3%	0%	1%	-1%	0%	-1%
Standard Deviation	14%	12%	9%	13%	5%	12%
2005						
Minimum	-59%	-53%	-37%	-17%	-33%	-23%
Maximum	96%	69%	62%	30%	71%	38%
Mean	4%	3%	1%	2%	0%	2%
Median	3%	2%	1%	0%	0%	0%
Standard Deviation	16%	17%	10%	9%	7%	12%

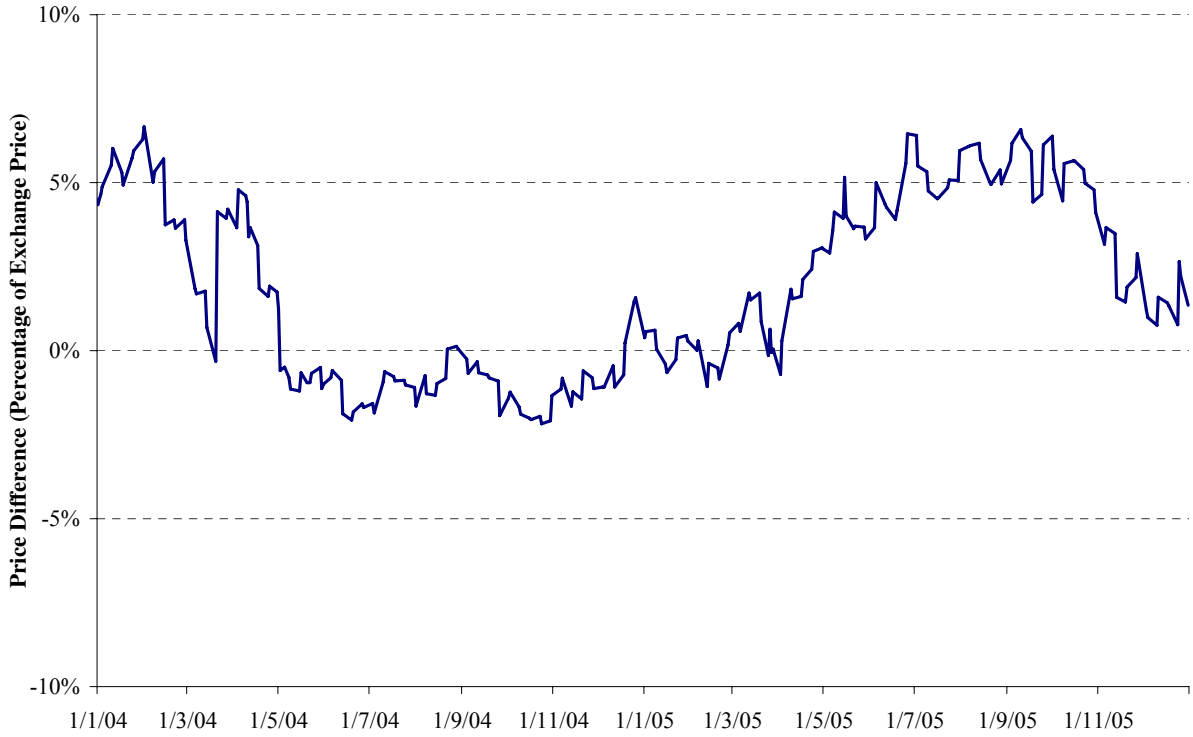
Source: Platts, APX, EEX, Electrabel BPI index.
Note: A negative value indicates the exchange price exceeding the OTC price.

Figure 57: 30-Day Moving Average of Difference Between OTC and Exchange Prices Weekday Prices in The Netherlands



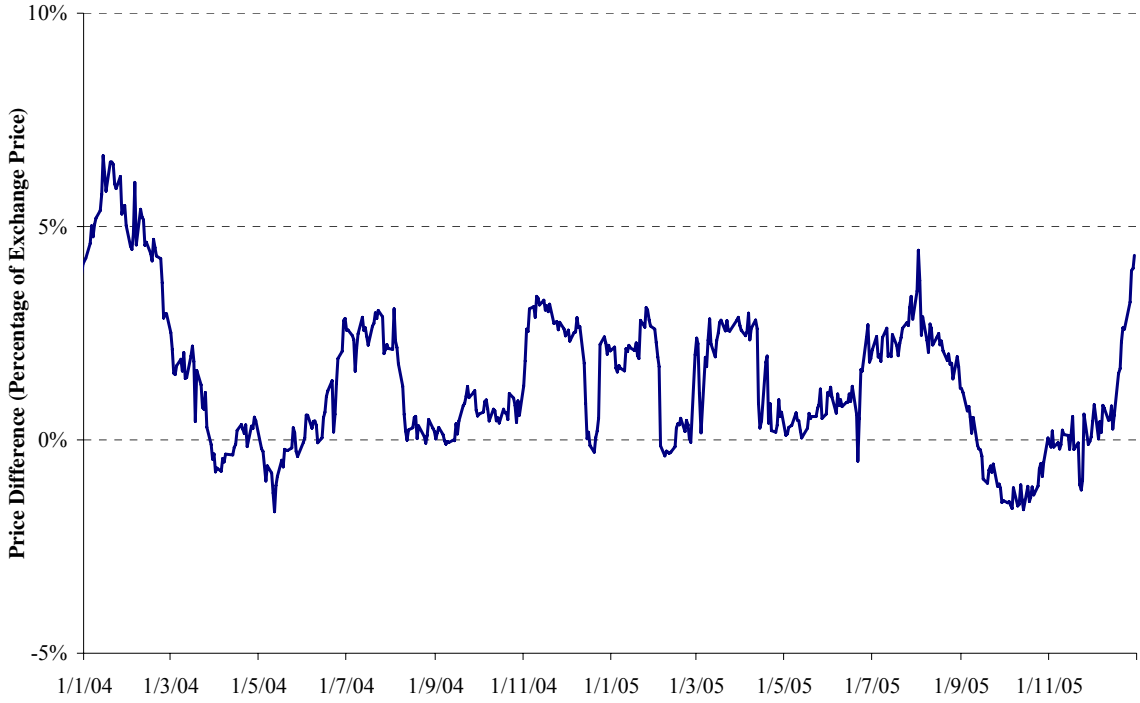
Source: Platts, APX. Note: A negative value indicates the exchange price exceeding the OTC price.

Figure 58: 30-Day Moving Average of Difference Between OTC and Exchange Prices Weekend and Holiday Prices in The Netherlands



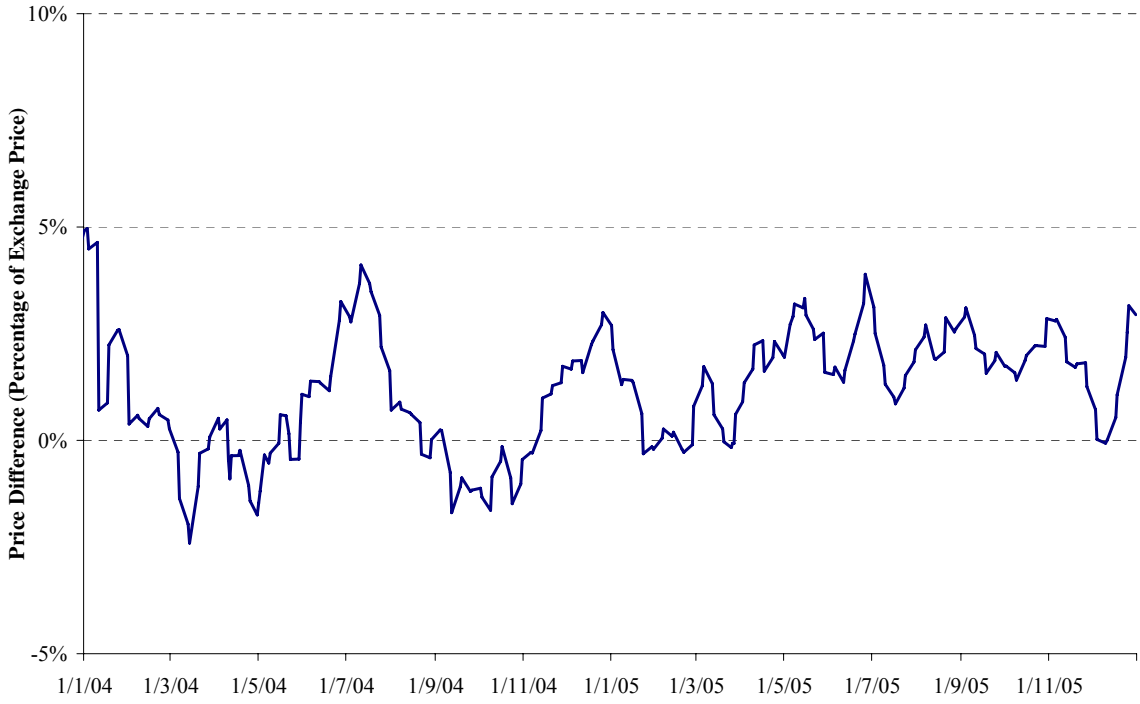
Source: Platts, APX. Note: A negative value indicates the exchange price exceeding the OTC price.

Figure 59: 30-Day Moving Average of Difference Between OTC and Exchange Prices Weekday Prices in Germany



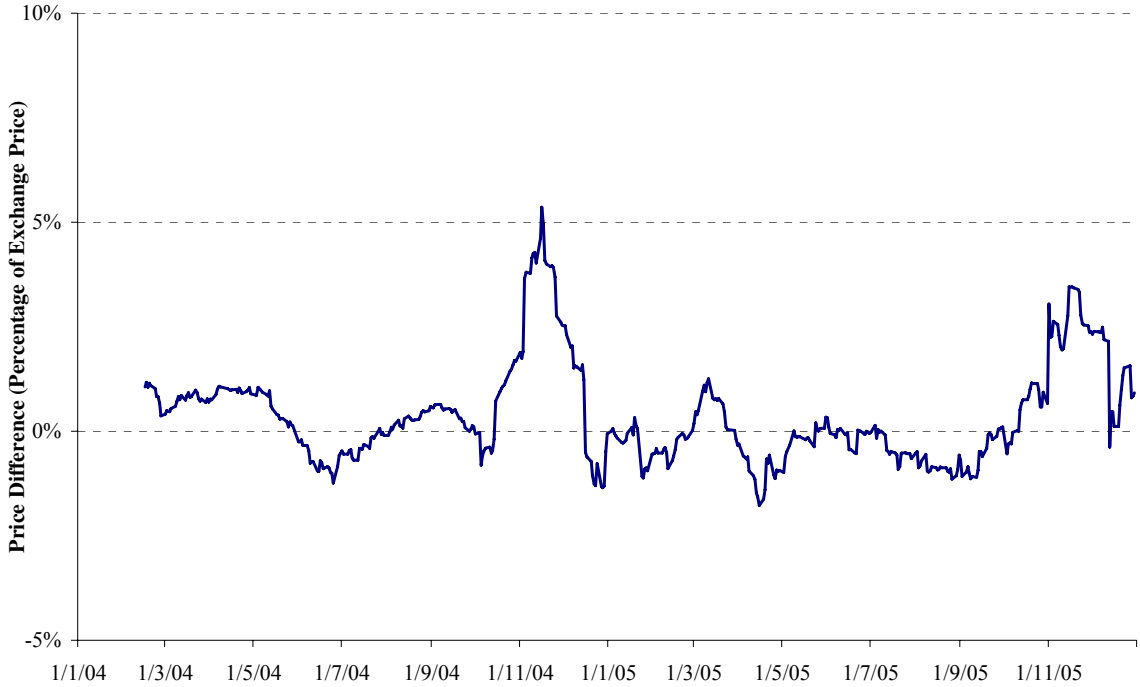
Source: Platts, EEX. Note: A negative value indicates the exchange price exceeding the OTC price.

Figure 60: 30-Day Moving Average of Difference Between OTC and Exchange Prices Weekend and Holiday Prices in Germany



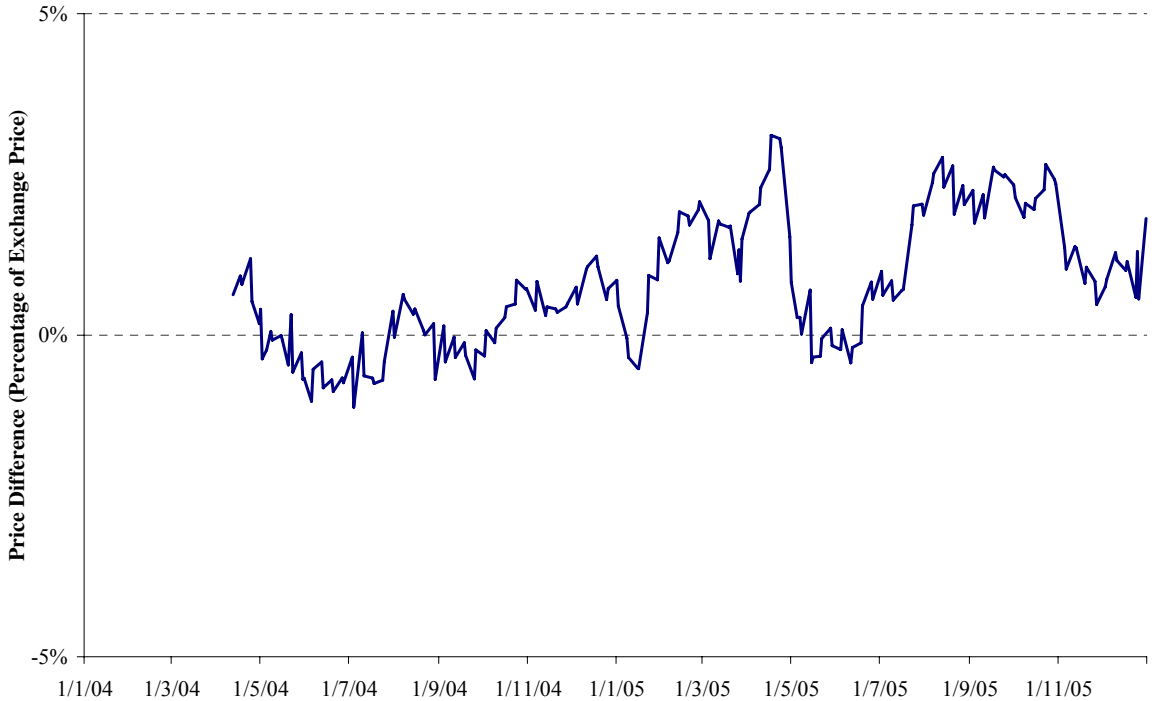
Source: Platts, EEX. Note: A negative value indicates the exchange price exceeding the OTC price.

Figure 61: 30-Day Moving Average of Difference Between OTC and BPI Prices
Weekday Prices in Belgium



Source: Platts, Electrabel BPI index. Note: A negative value indicates the BPI price exceeding the OTC price.

Figure 62: 30-Day Moving Average of Difference Between OTC and BPI Prices
Weekend and Holiday Prices in Belgium



Source: Platts, Electrabel BPI index. Note: A negative value indicates the BPI price exceeding the OTC price.

Appendix XII : Cross-Border Price Differences

This appendix expands on the information provided in section 4.1 regarding the patterns of cross-border price differences. The information in this appendix is presented using data from Platts for the Netherlands, Belgium, France and Germany, the APX for the Netherlands, the EEX for Germany, and the Electrabel BPI Index for Belgium. Our analysis uses data for both 2004 and 2005.

Pages 150 to 159 contain graphs which depict, in both percentage and nominal terms, the cumulative probability distribution of NL-DE, NL-BE and NL-FR daily price differences. Except from for Germany, we show separate graphs using data from Platts and power exchanges. We show separate graphs for weekdays and weekends and holidays, as well as for 2004 and 2005. The pink boxes on the graphs showing the percentage price difference contains information regarding what proportion of time the price differences are greater than 5, 10 and 20 percent. Table 53 and Table 54 below summarize this information for the Platts and power exchange data, respectively.

The data show that both the NL-FR and NL-DE price differences are in excess of 5% for the majority of days (both working weekdays and weekends/holidays) in 2004 and 2005. The NL-DE and NL-FR price differences are similar for weekdays in 2004 and 2005, while the NL-BE price difference is larger and in excess of 5% for a larger number of weekdays in 2005 than in 2004.

In general we note that the price differences are surprisingly similar for weekdays and weekends/holidays. The NL-DE and NL-BE price differences were larger in 2005 than in 2004 during weekends and holidays, while the NL-FR prices differences appear to be smaller during weekends and holidays in 2005 than in 2004.

Table 53: Cross-border baseload price differences (Platts data)

	Netherlands - Germany		Netherlands - Belgium		Netherlands - France	
	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays
2004						
Proportion of time when price difference is larger than or equal to*:						
5%	60%	57%	33%	33%	63%	59%
10%	42%	31%	18%	20%	45%	34%
20%	18%	9%	4%	4%	21%	12%
2005						
Proportion of time when price difference is larger than or equal to*:						
5%	60%	70%	41%	45%	64%	66%
10%	37%	38%	17%	29%	40%	39%
20%	17%	10%	5%	9%	16%	14%

Source: Platts
Note: All prices used in calculations are midpoints between daily high and low.
*: Percentage difference is relative to the price in the Netherlands.

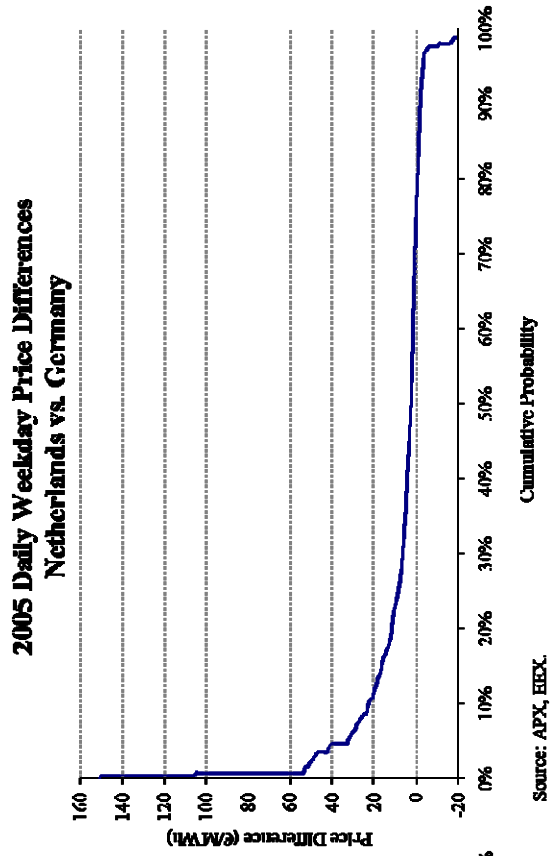
Table 54: Cross-border baseload price differences (power exchange data)

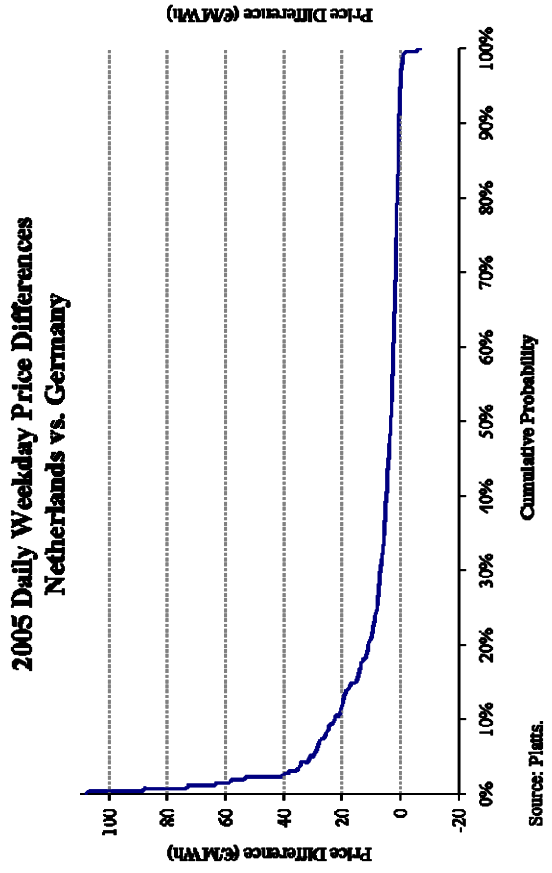
	Netherlands - Germany		Netherlands - Belgium	
	Weekdays	Weekends & Holidays	Weekdays	Weekends & Holidays
2004				
Proportion of time when price difference is larger than or equal to*:				
5%	45%	52%	22%	59%
10%	29%	37%	14%	41%
20%	15%	20%	7%	12%
2005				
Proportion of time when price difference is larger than or equal to*:				
5%	52%	53%	32%	56%
10%	35%	41%	20%	42%
20%	19%	22%	9%	13%

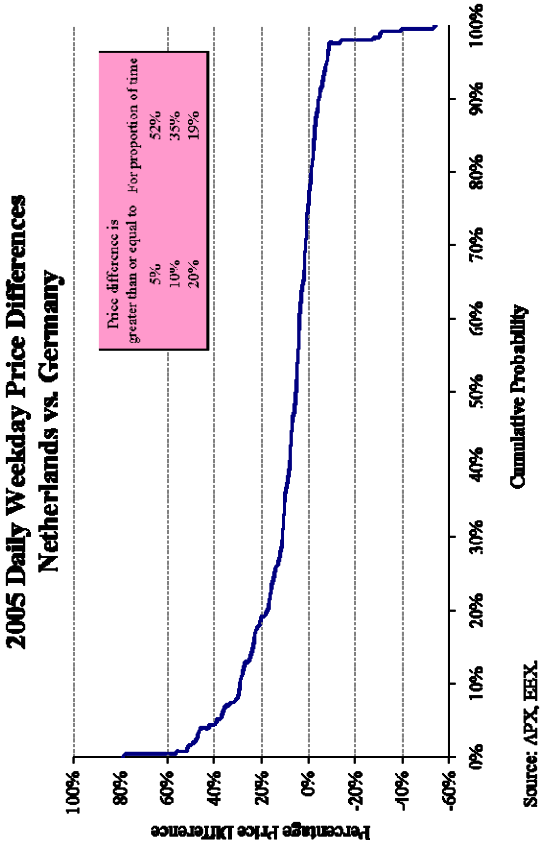
Source: EEX, APX, Electrabel BPI Index.
Note: All prices used in calculations are midpoints between daily high and low.
*: Percentage difference is relative to the price in the Netherlands.

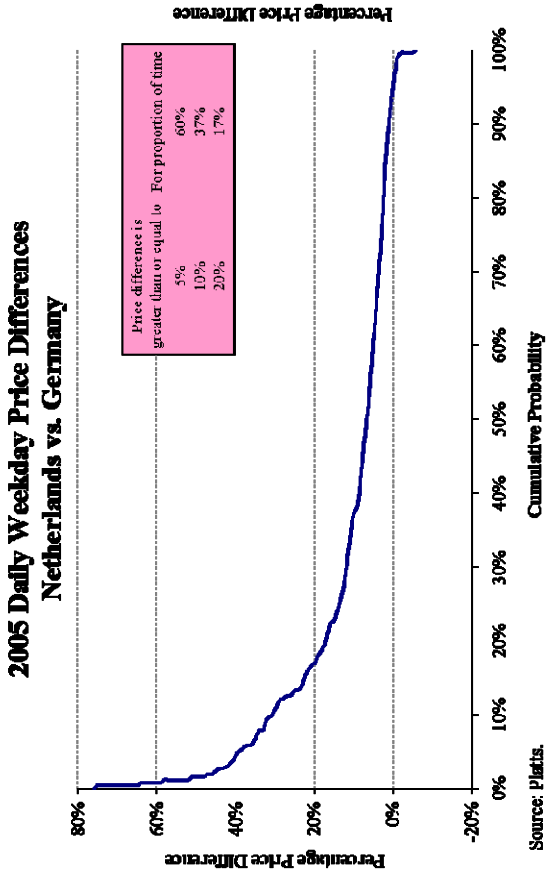
Pages 160 to 171 contain time-series graphs showing the 30-day moving average of daily price differences in nominal and percentage terms for NL-DE and NL-BE. In order to illustrate the closeness of French and German price we also show graphs of the 30-day moving average of daily FR-DE price differences using Platts data. We show graphs in nominal and percentage terms first for weekdays and then for weekends/holidays. As before, we present graphs using both data from Platts and power exchanges. The graphs with Platts data are on pages 160 to 167, while the graphs with power exchange data are on pages 168 to 171.

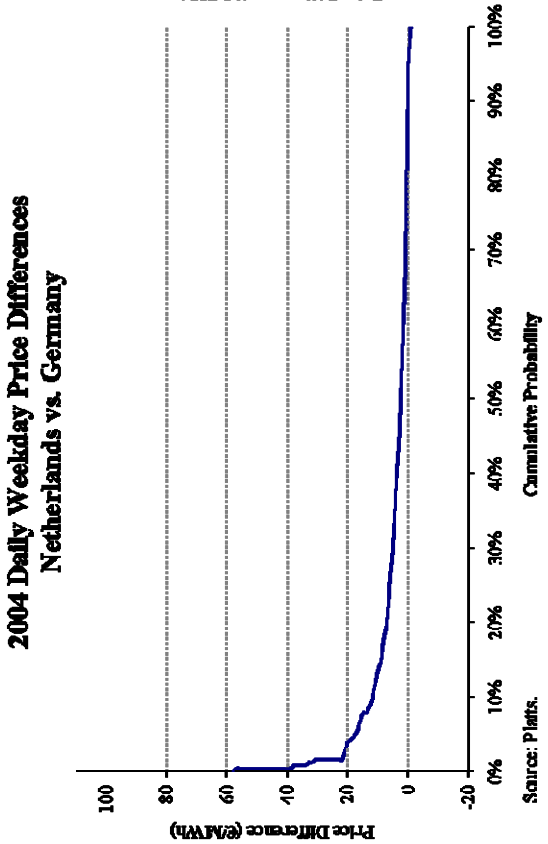
The time series graphs show that cross-border price differences are significant and persistent, and that while often moving together, the NL-DE price difference is consistently larger than the NL-BE price difference. The graphs also show that DE-FR price difference is consistently less than 5 percent.

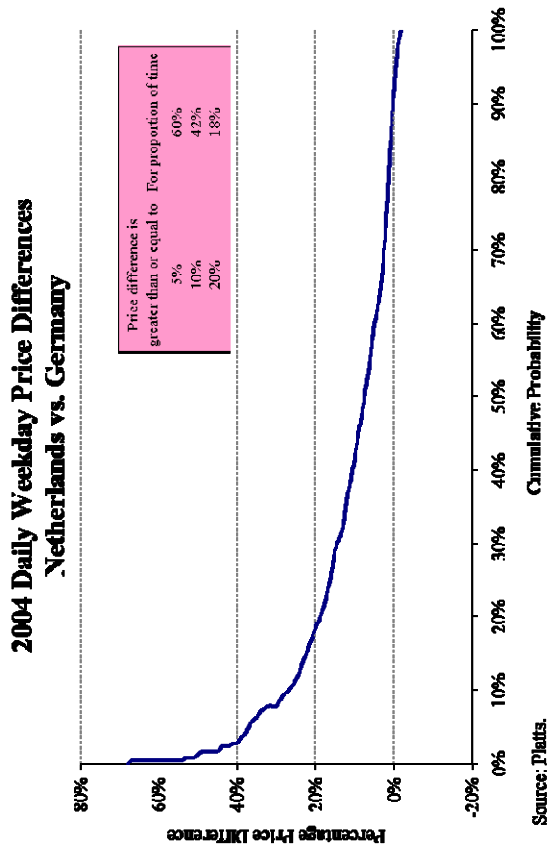

2005 Daily Weekday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
160
140
120
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, EEX.

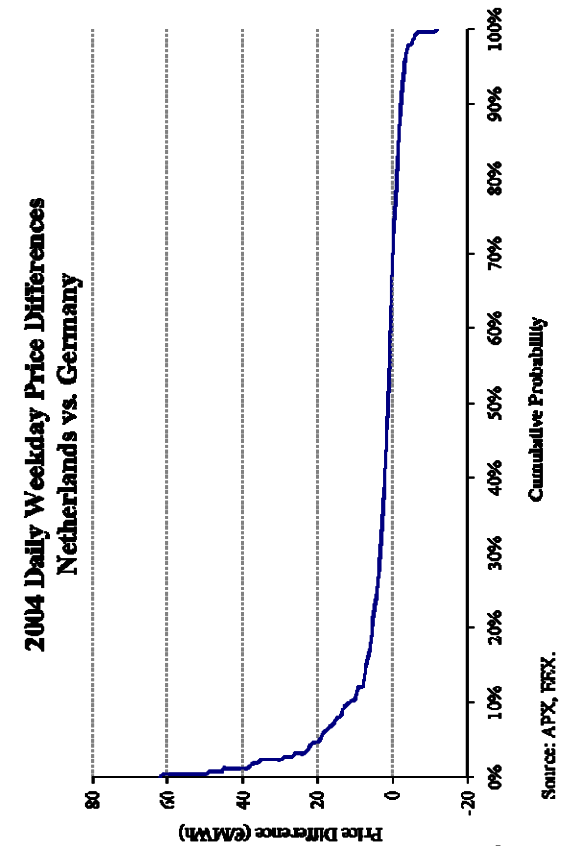

2005 Daily Weekday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

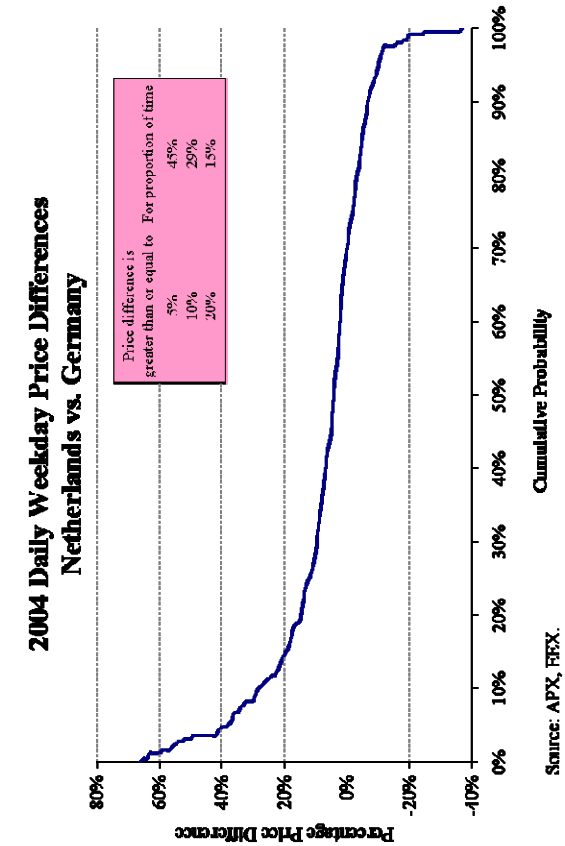

2005 Daily Weekday Price Differences
Netherlands vs. Germany
Percentage Price Difference
100%
80%
60%
40%
20%
0%
-20%
-40%
-60%
Price difference is greater than or equal to
For proportion of time
5%
52%
10%
35%
20%
19%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, EEX.

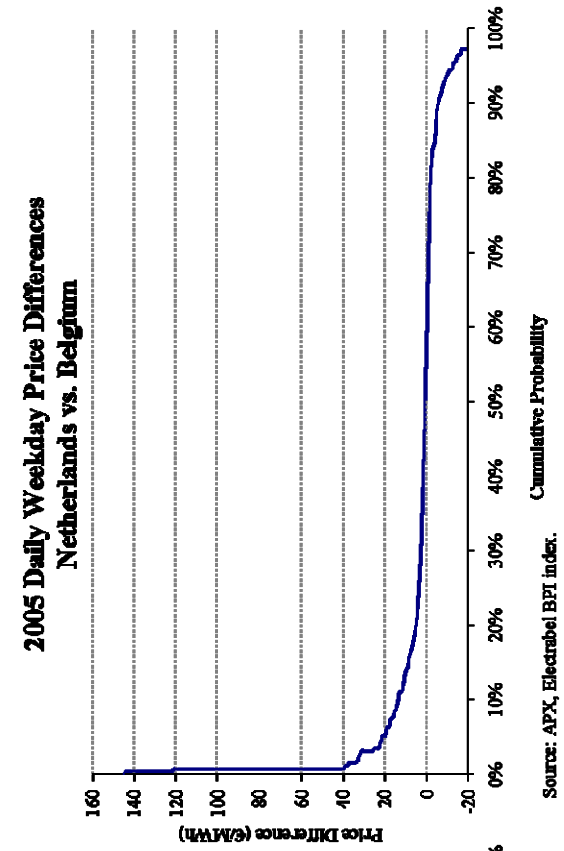

2005 Daily Weekday Price Differences
Netherlands vs. Germany
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
Price difference is greater than or equal to
For proportion of time
5%
60%
10%
37%
20%
17%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

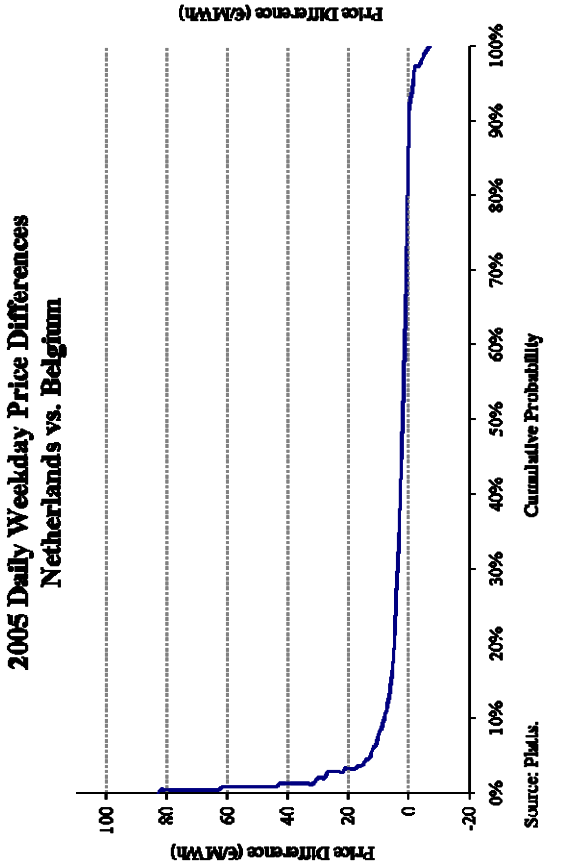

2004 Daily Weekday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

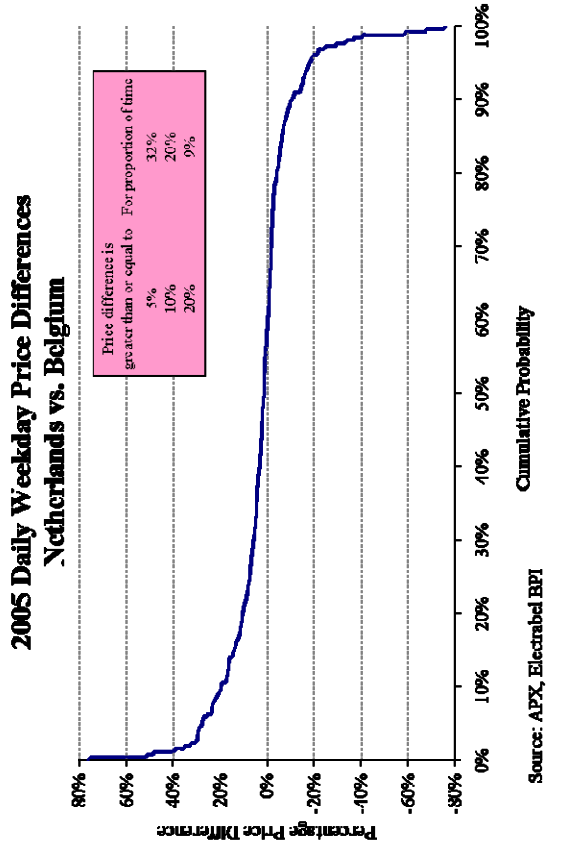

2004 Daily Weekday Price Differences
Netherlands vs. Germany
Price difference is greater than or equal to
For proportion of time
5% 60%
10% 42%
20% 18%
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

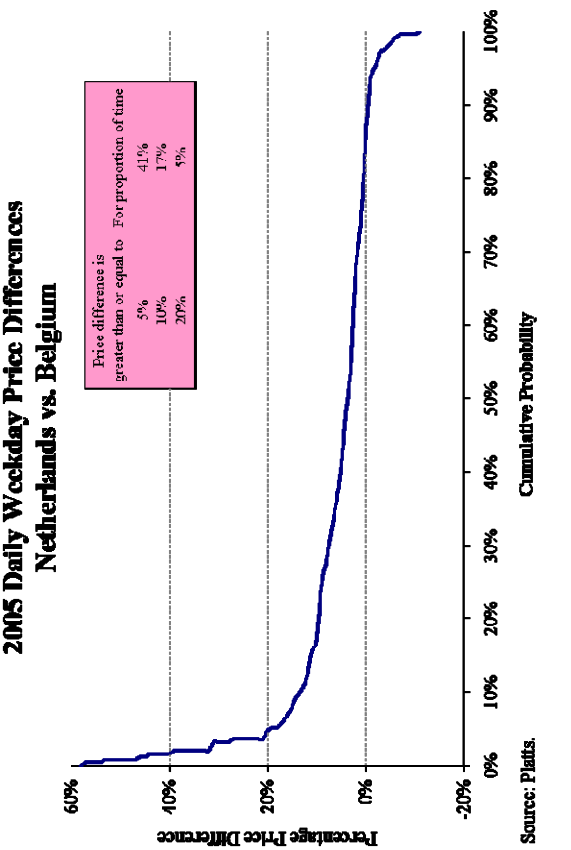

2004 Daily Weekday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, EEX.

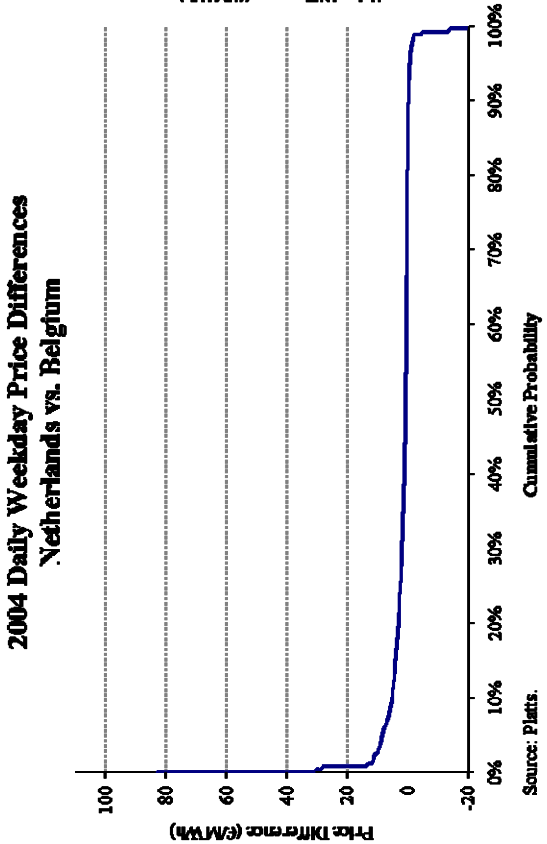

2004 Daily Weekday Price Differences
Netherlands vs. Germany
Price difference is greater than or equal to
For proportion of time
5% 45%
10% 29%
20% 15%
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
-40%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, EEX.

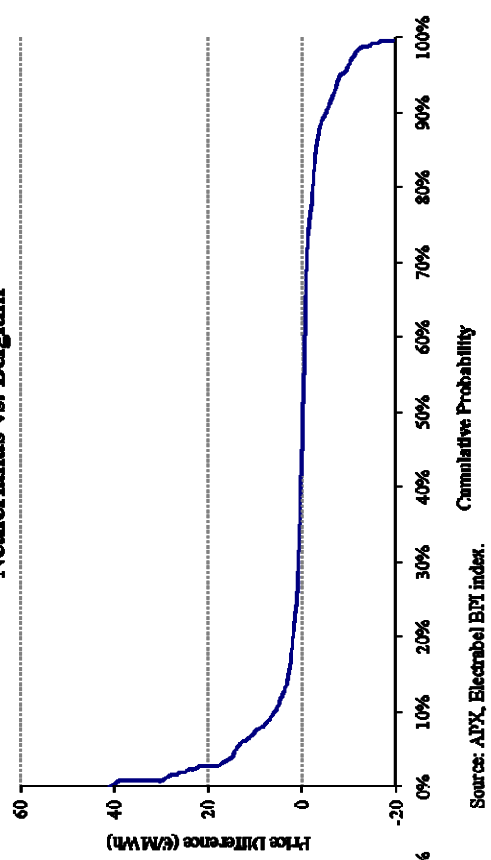

2005 Daily Weekday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
160
140
120
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI index.

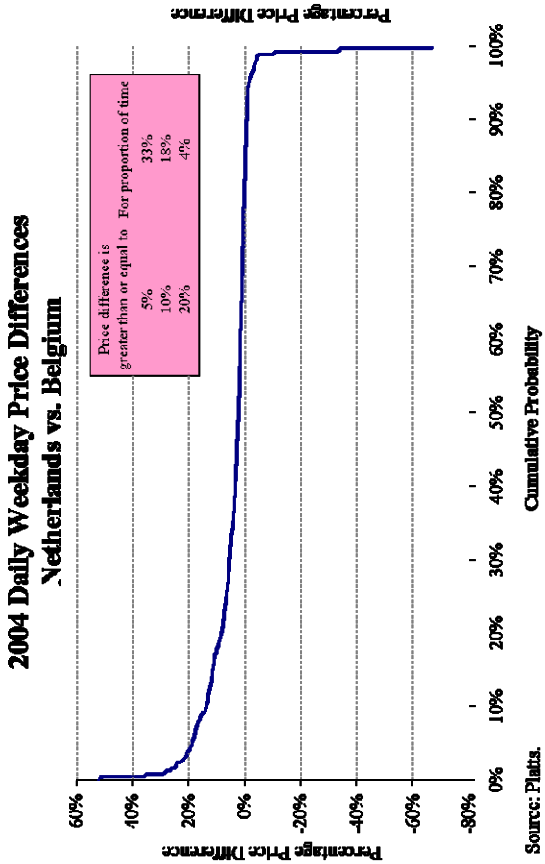

2005 Daily Weekday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

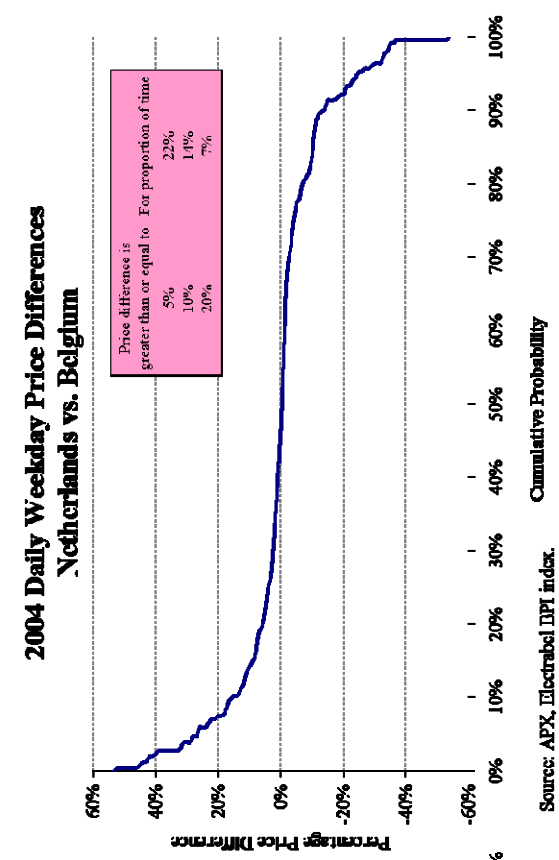

2005 Daily Weekday Price Differences
Netherlands vs. Belgium
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
-40%
-60%
-80%
Price difference is greater than or equal to
For proportion of time
5%
32%
10%
20%
20%
9%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI

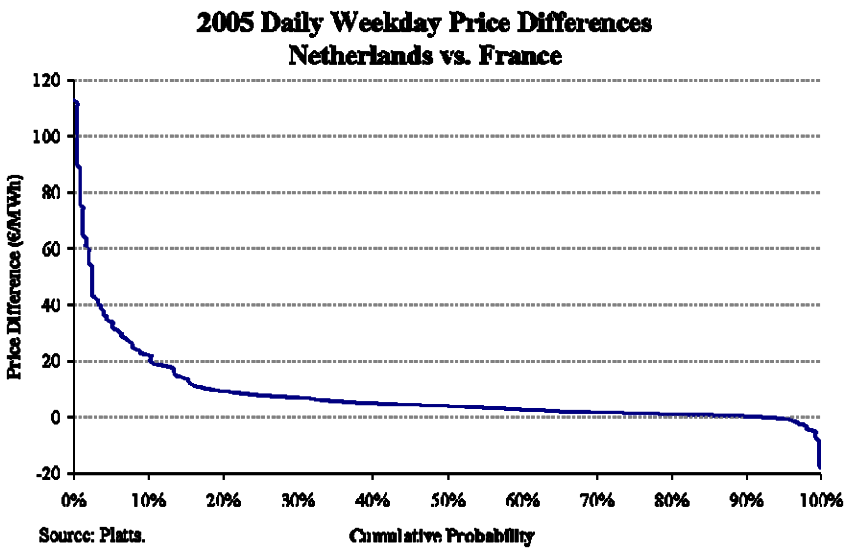

2005 Daily Weekday Price Differences
Netherlands vs. Belgium
Percentage Price Difference
60%
40%
20%
0%
-20%
Price difference is greater than or equal to
For proportion of time
5%
41%
10%
17%
20%
4%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

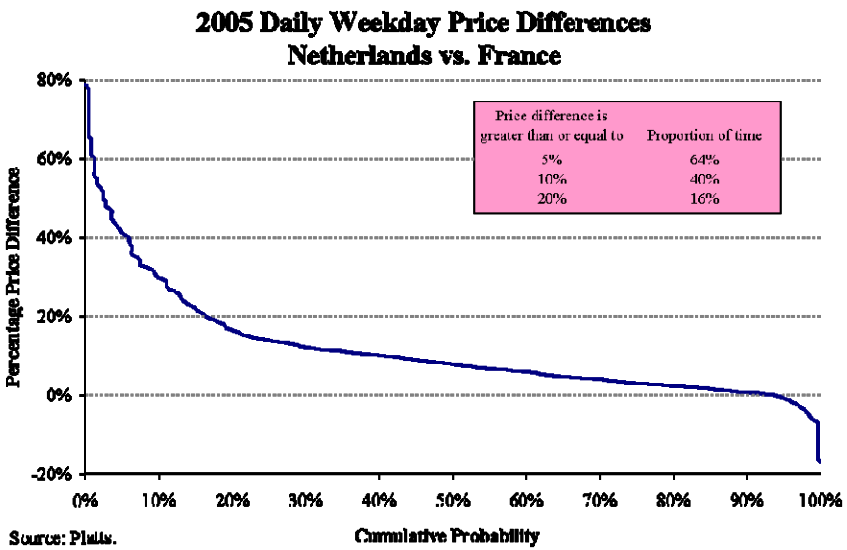

2004 Daily Weekday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

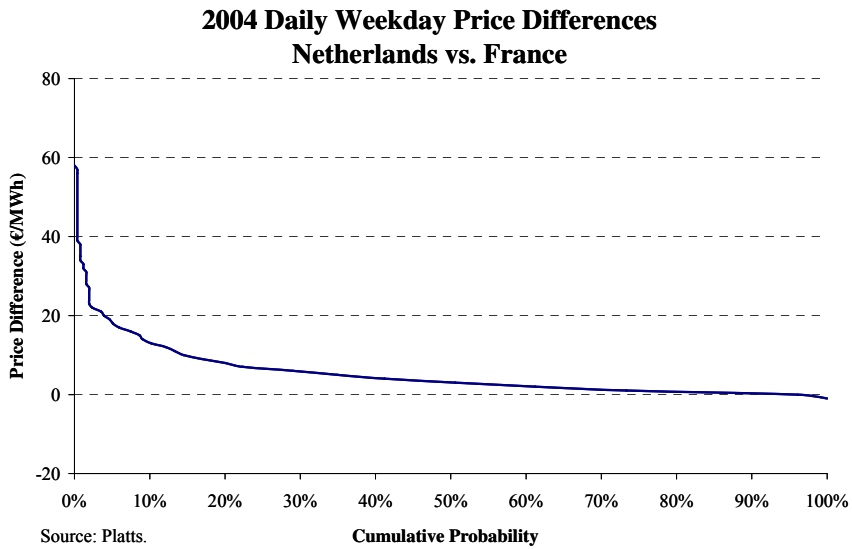

2004 Daily Weekday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI index.

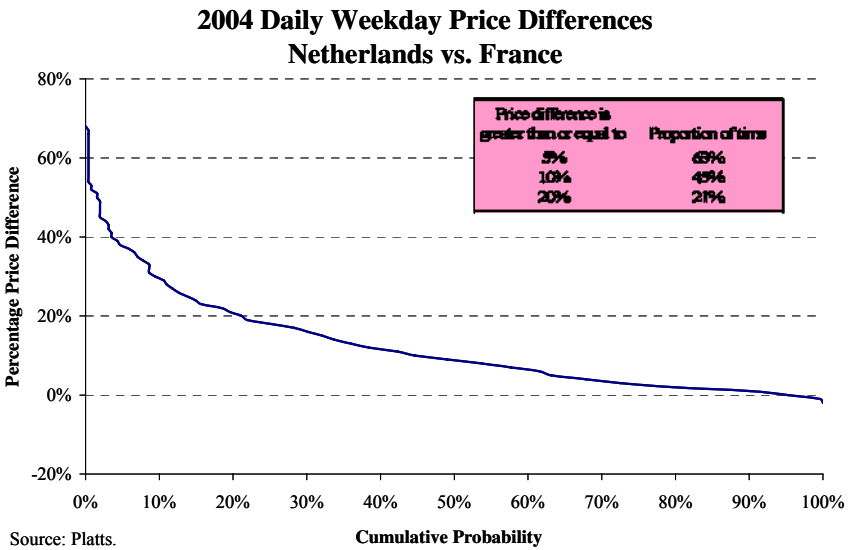

2004 Daily Weekday Price Differences
Netherlands vs. Belgium
Price difference is greater than or equal to
For proportion of time
5%
33%
10%
18%
20%
4%
Percentage Price Difference
60%
40%
20%
0%
-20%
-40%
-60%
-80%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

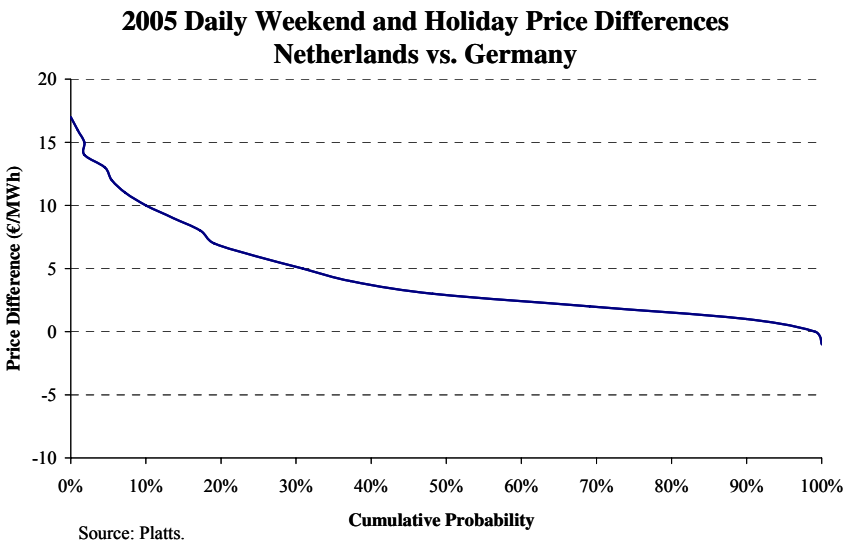

2004 Daily Weekday Price Differences
Netherlands vs. Belgium
Price difference is greater than or equal to
For proportion of time
5%
22%
10%
14%
20%
7%
Percentage Price Difference
60%
40%
20%
0%
-20%
-40%
-60%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI index.

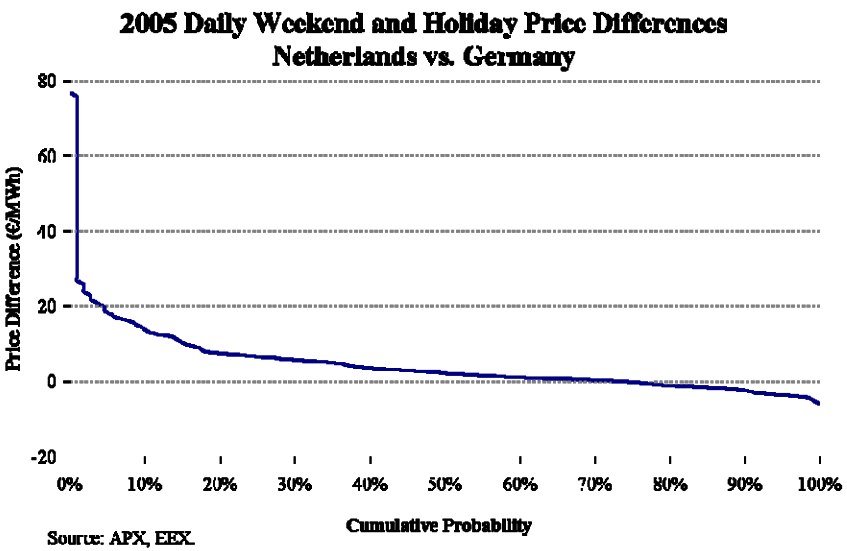

2005 Daily Weekday Price Differences
Netherlands vs. France
Price Difference (€/MWh)
120
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Source: Platts.
Cumulative Probability

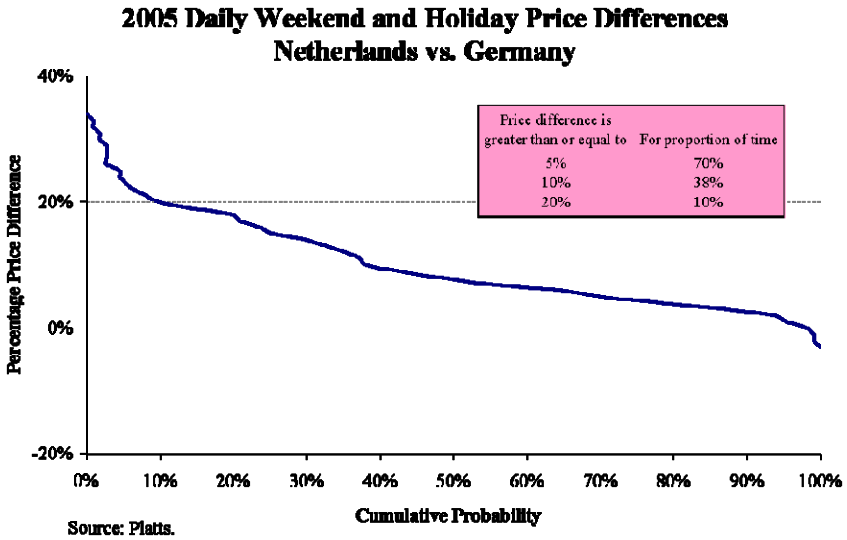

2005 Daily Weekday Price Differences
Netherlands vs. France
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
Price difference is greater than or equal to
Proportion of time
5%
64%
10%
40%
20%
16%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Source: Platts.
Cumulative Probability

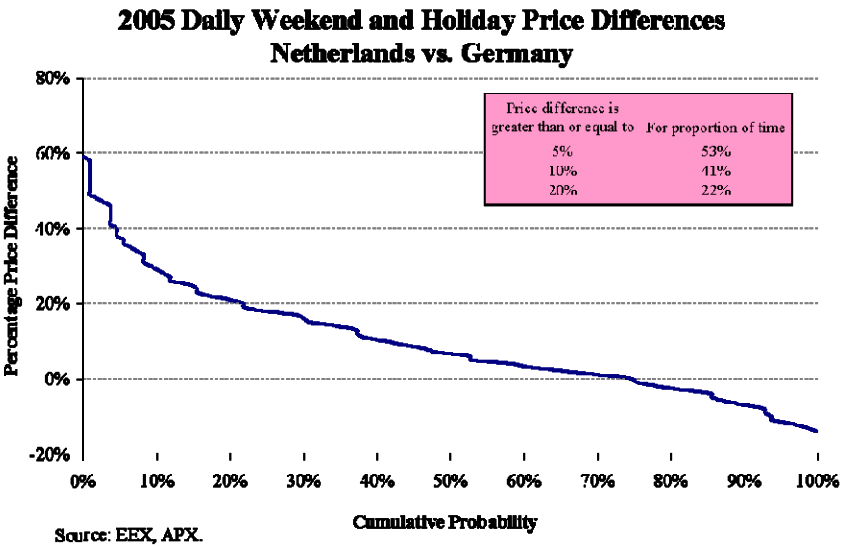

2004 Daily Weekday Price Differences
Netherlands vs. France
Price Difference (€/MWh)
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Source: Platts.
Cumulative Probability

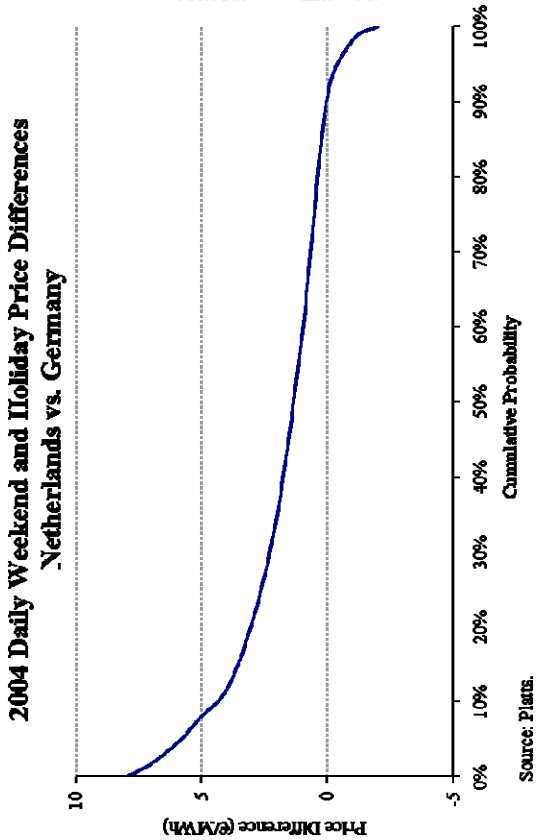

2004 Daily Weekday Price Differences
Netherlands vs. France
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
Price difference is greater than or equal to
Proportion of time
5%
68%
10%
45%
20%
21%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Source: Platts.
Cumulative Probability

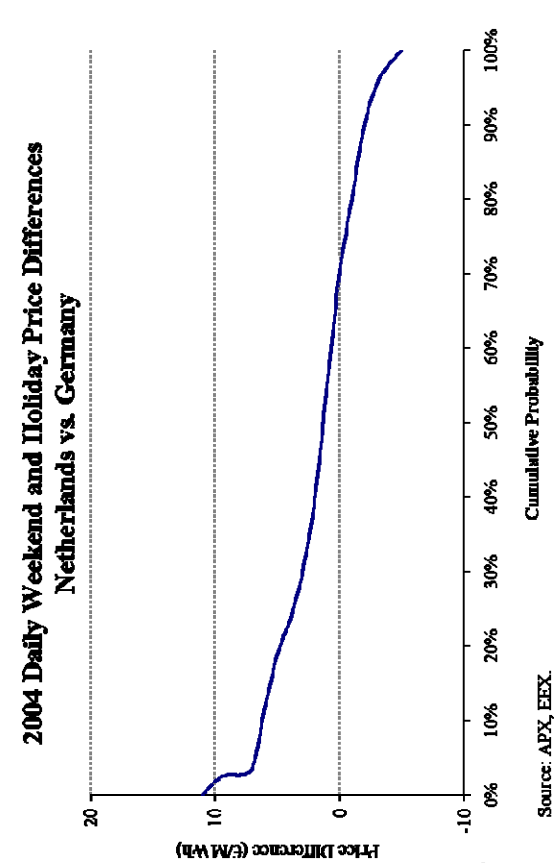

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
20
15
10
5
0
-5
-10
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

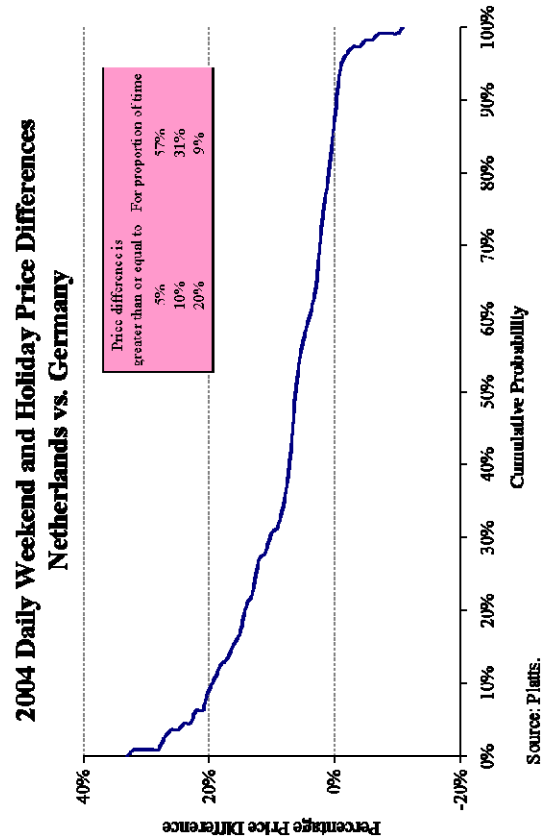

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, EEX.

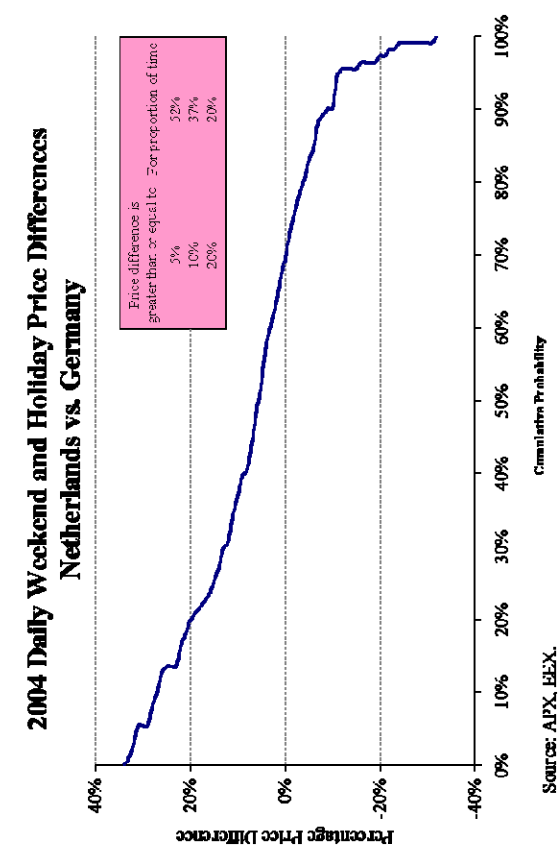

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Percentage Price Difference
40%
20%
0%
-20%
Price difference is
greater than or equal to
For proportion of time
5%
70%
10%
38%
20%
10%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

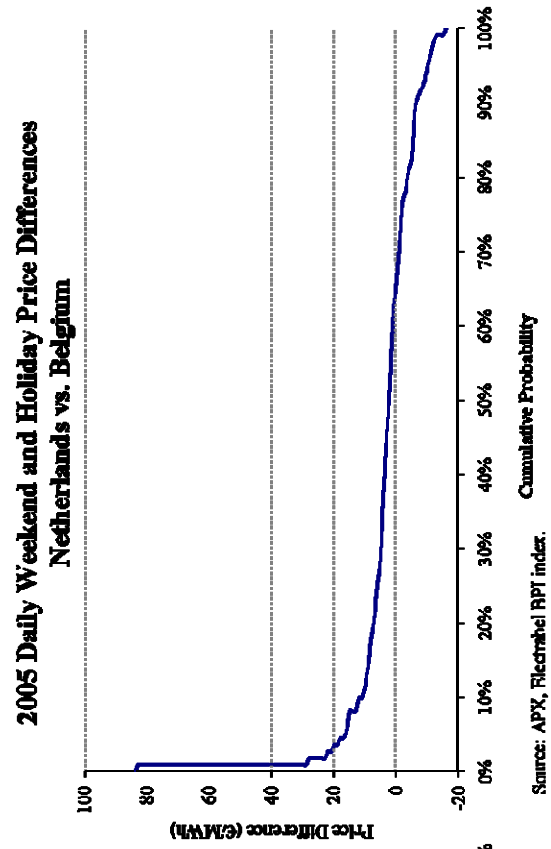

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
Price difference is
greater than or equal to
For proportion of time
5%
53%
10%
41%
20%
22%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: EEX, APX.

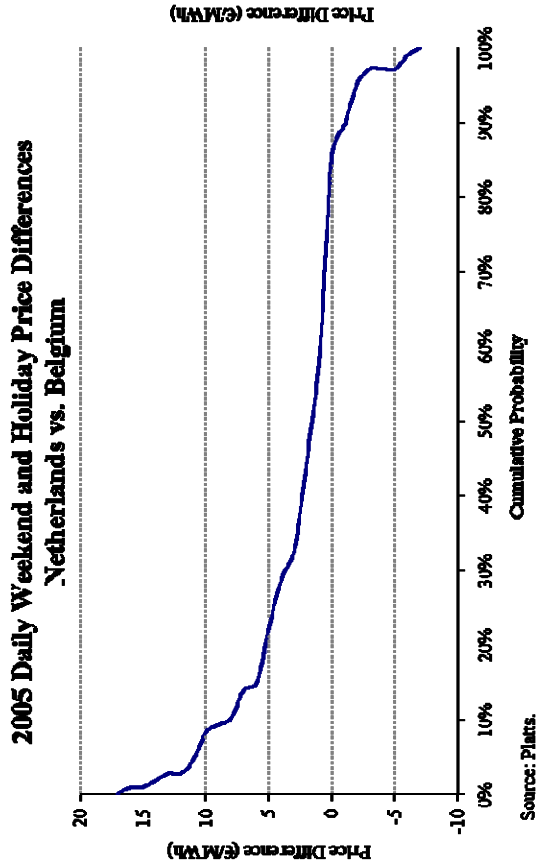

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
10
5
0
-5
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

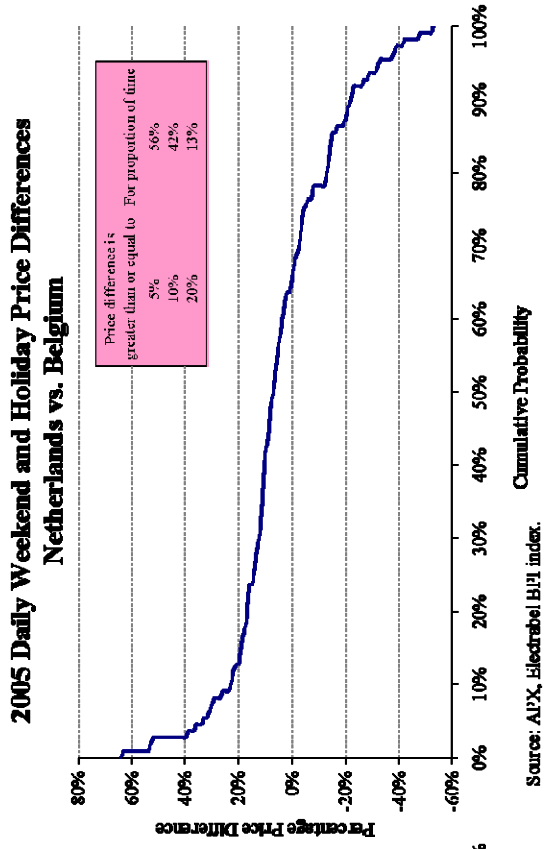

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Price Difference (€/MWh)
20
10
0
-10
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, EEX.

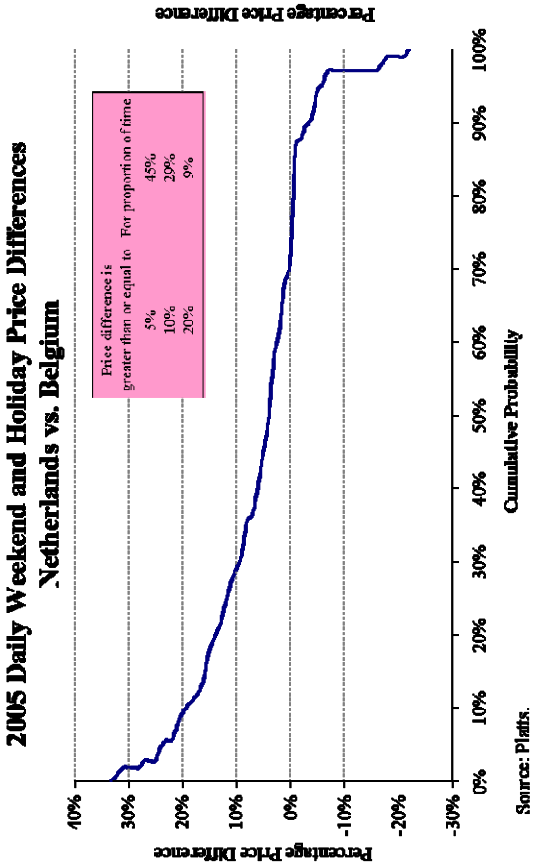

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Price difference is greater than or equal to
For proportion of time
5%
57%
10%
31%
20%
9%
Percentage Price Difference
40%
20%
0%
-20%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

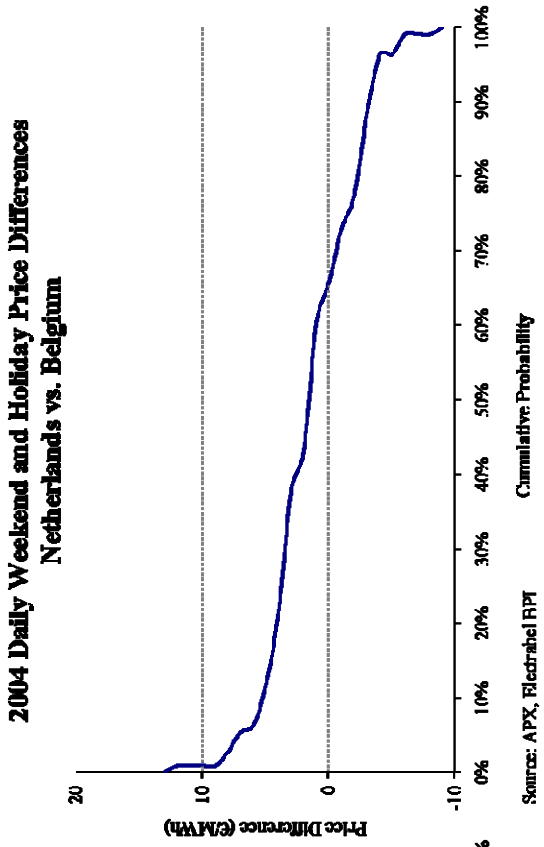

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Germany
Price difference is greater than or equal to
For proportion of time
5%
52%
10%
37%
20%
20%
Percentage Price Difference
40%
20%
0%
-20%
-40%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, EEX.

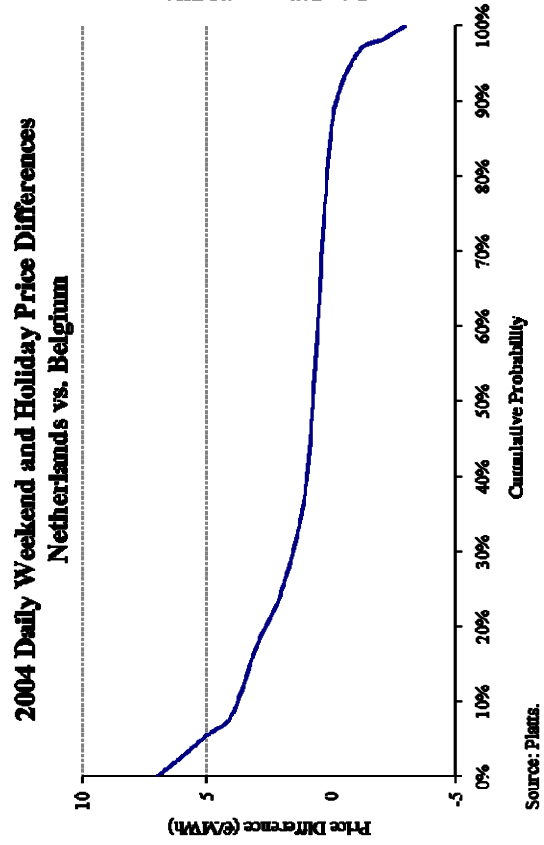

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
100
80
60
40
20
0
-20
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI index.

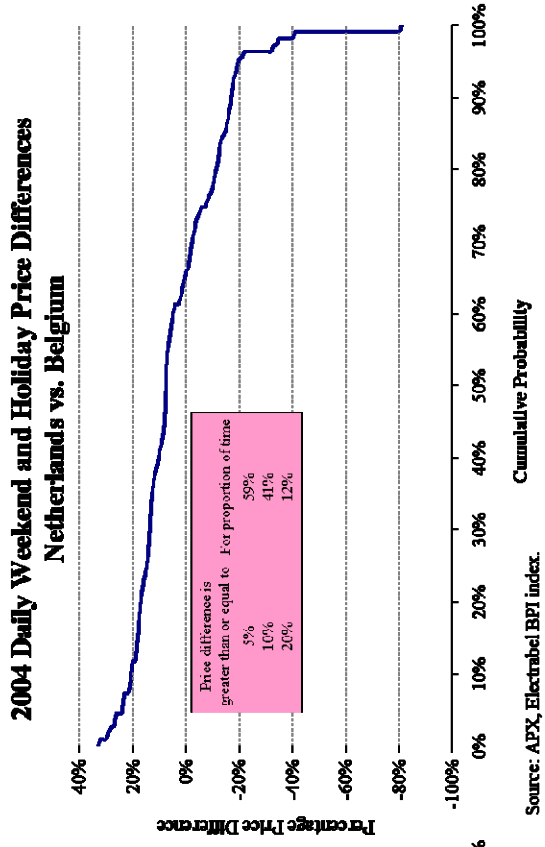

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
20
15
10
5
0
-5
-10
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

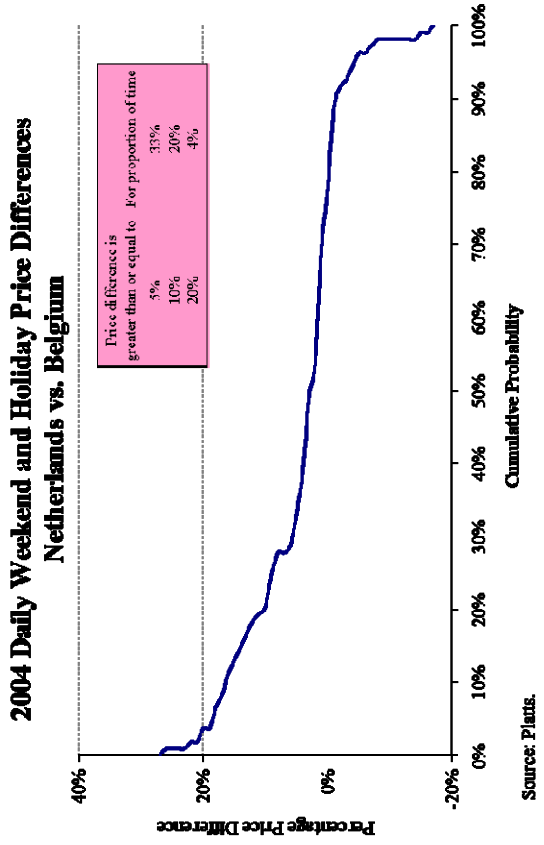

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
-40%
-60%
Price difference is
greater than or equal to
For proportion of time
5%
56%
10%
42%
20%
13%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI index.

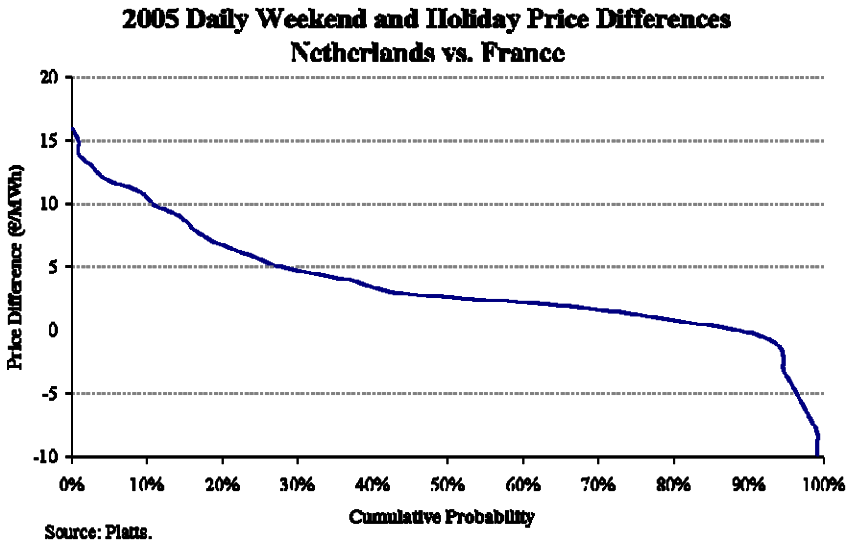

2005 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Percentage Price Difference
40%
30%
20%
10%
0%
-10%
-20%
-30%
Price difference is
greater than or equal to
For proportion of time
5%
45%
10%
29%
20%
9%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

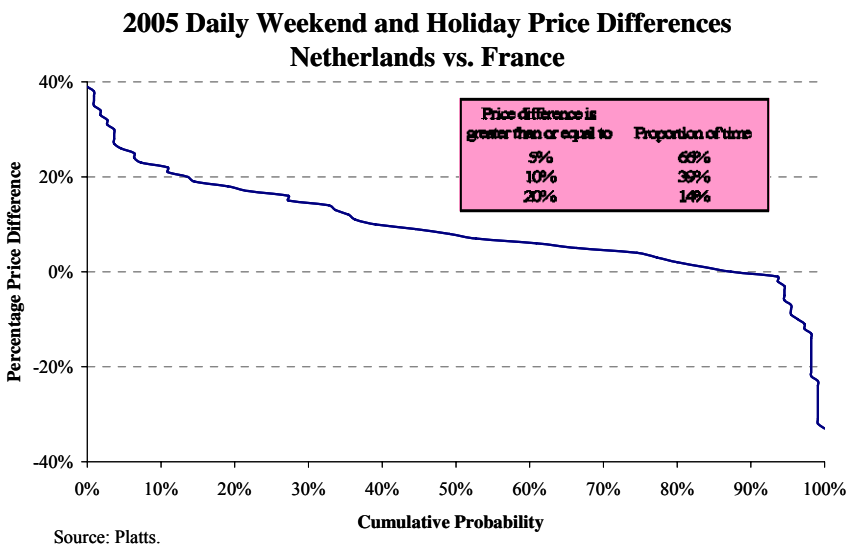

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
20
10
0
-10
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI

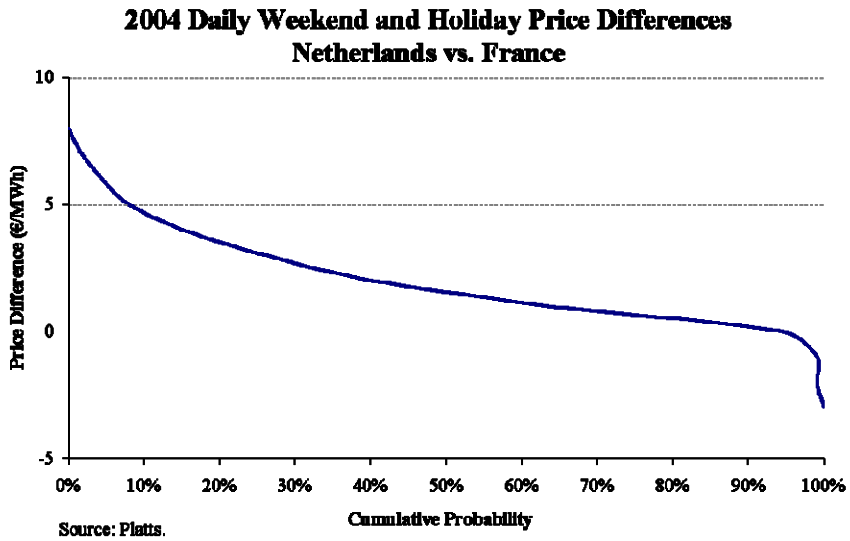

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Price Difference (€/MWh)
10
5
0
-5
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

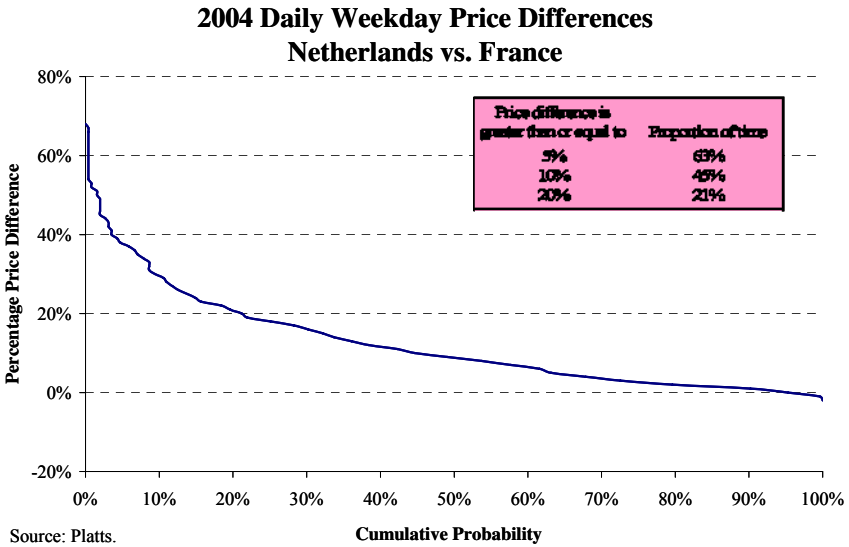

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Percentage Price Difference
40%
20%
0%
-20%
-40%
-60%
-80%
-100%
Price difference is greater than or equal to
For proportion of time
5%
59%
10%
41%
20%
12%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: APX, Electrabel BPI index.

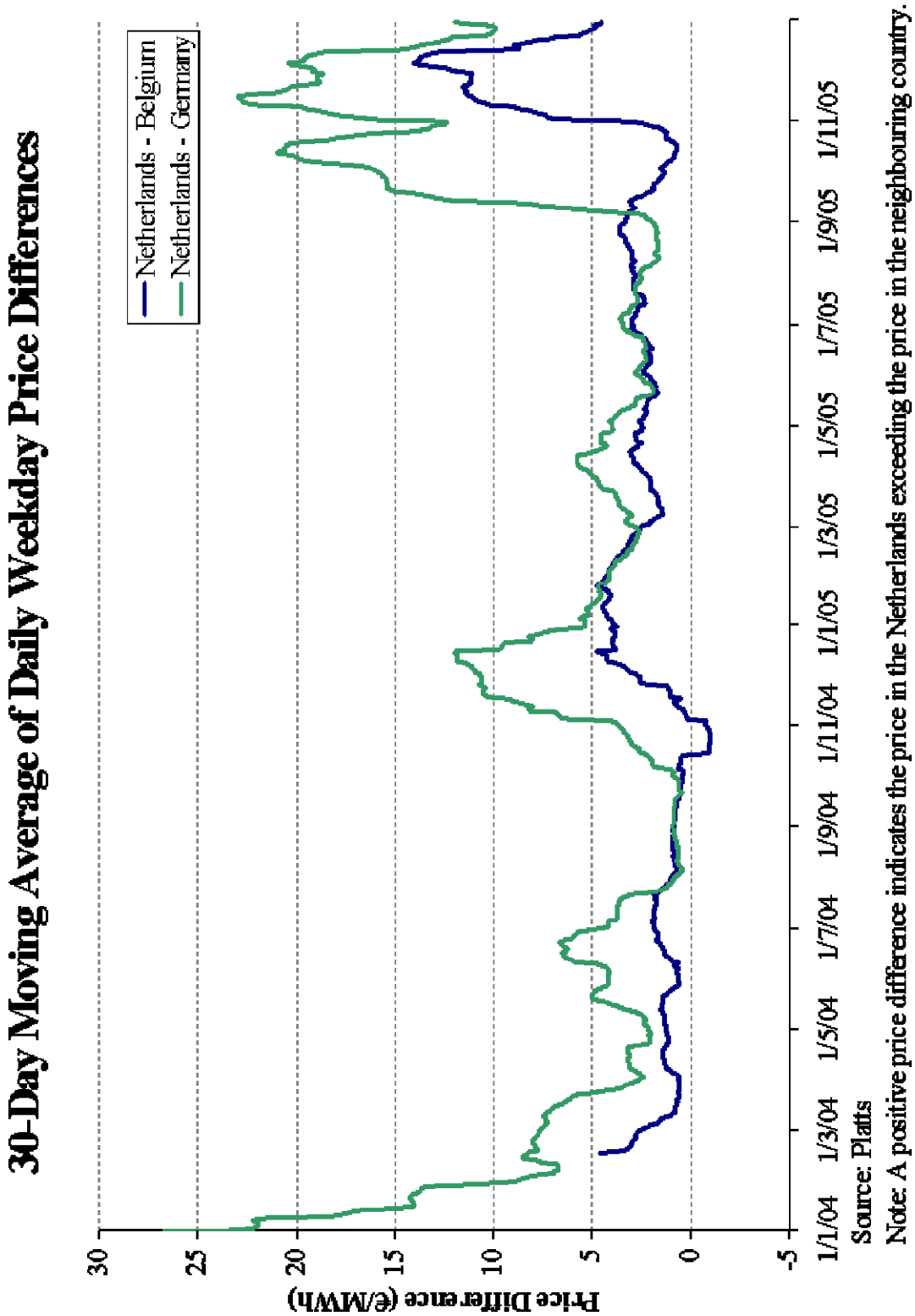

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. Belgium
Percentage Price Difference
40%
20%
0%
-20%
Price difference is greater than or equal to
For proportion of time
5%
33%
10%
20%
20%
4%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.


2005 Daily Weekend and Holiday Price Differences
Netherlands vs. France
Price Difference (€/MWh)
20
15
10
5
0
-5
-10
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.


2005 Daily Weekend and Holiday Price Differences
Netherlands vs. France
Price difference is greater than or equal to
Proportion of time
5%
69%
10%
39%
20%
14%
Percentage Price Difference
40%
20%
0%
-20%
-40%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.

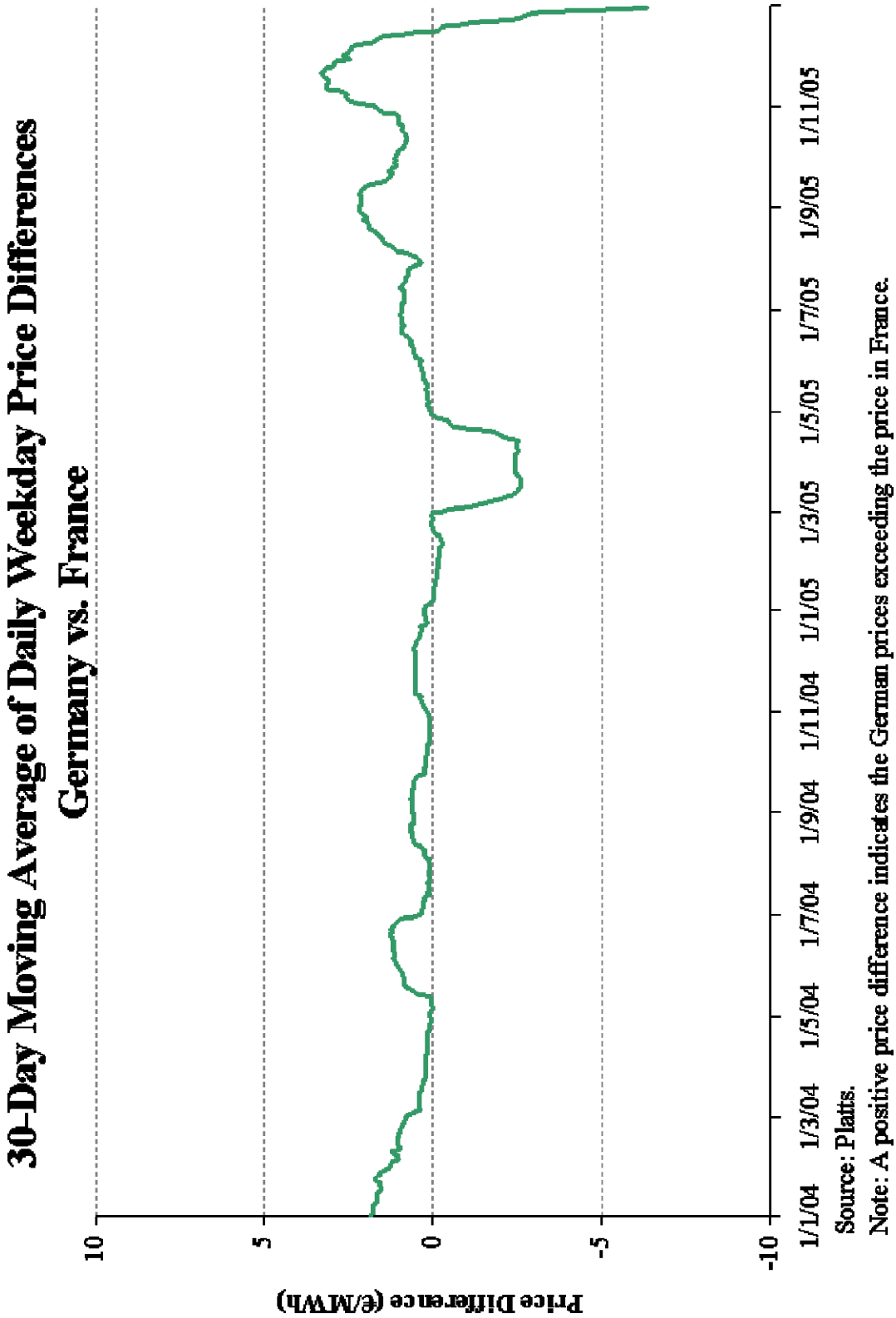

2004 Daily Weekend and Holiday Price Differences
Netherlands vs. France
Price Difference (€/MWh)
10
5
0
-5
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.


2004 Daily Weekday Price Differences
Netherlands vs. France
Price difference is greater than or equal to
Proportion of time
5%
63%
10%
45%
20%
21%
Percentage Price Difference
80%
60%
40%
20%
0%
-20%
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
100%
Cumulative Probability
Source: Platts.



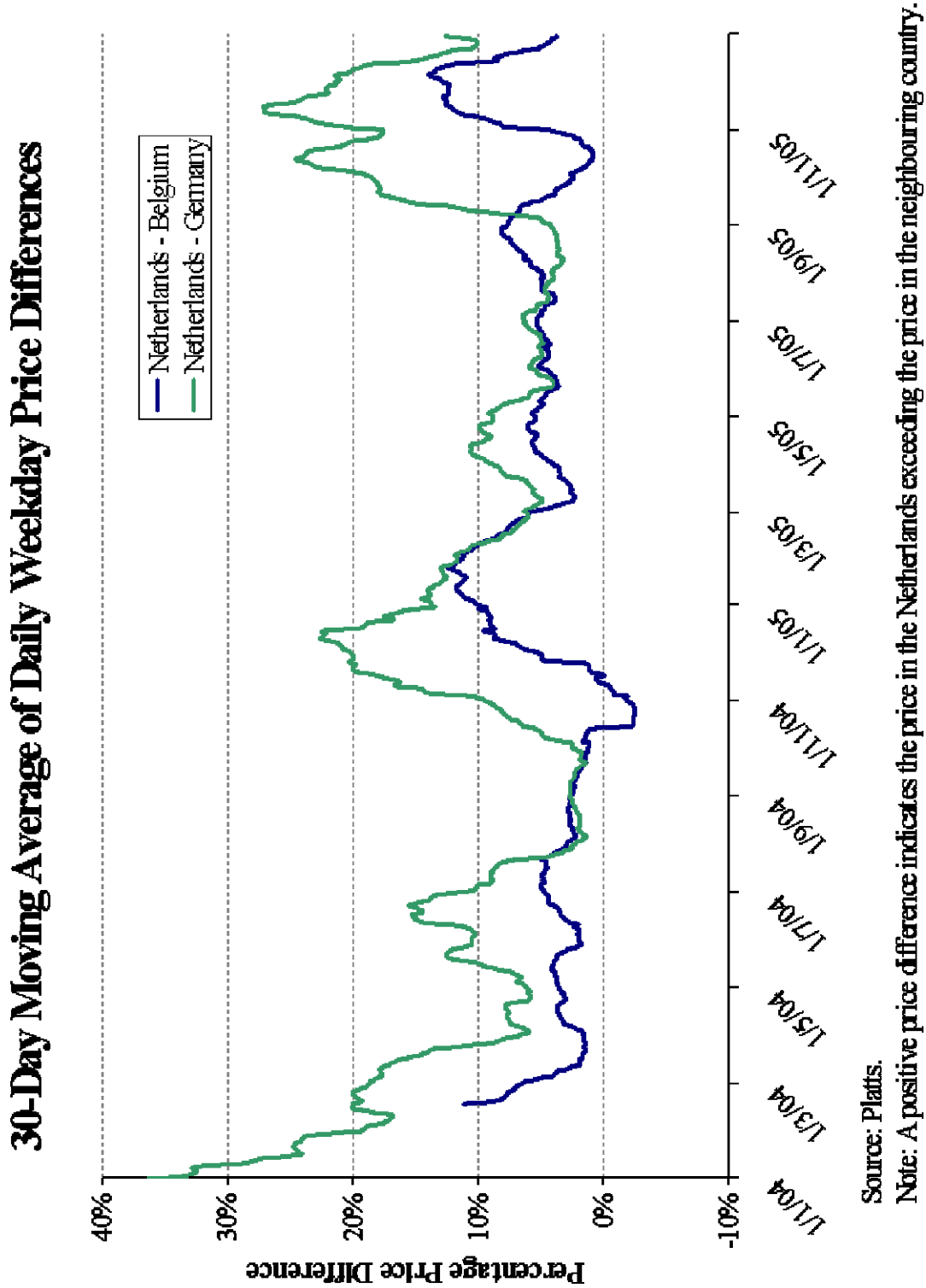
Source: Platts

Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country.

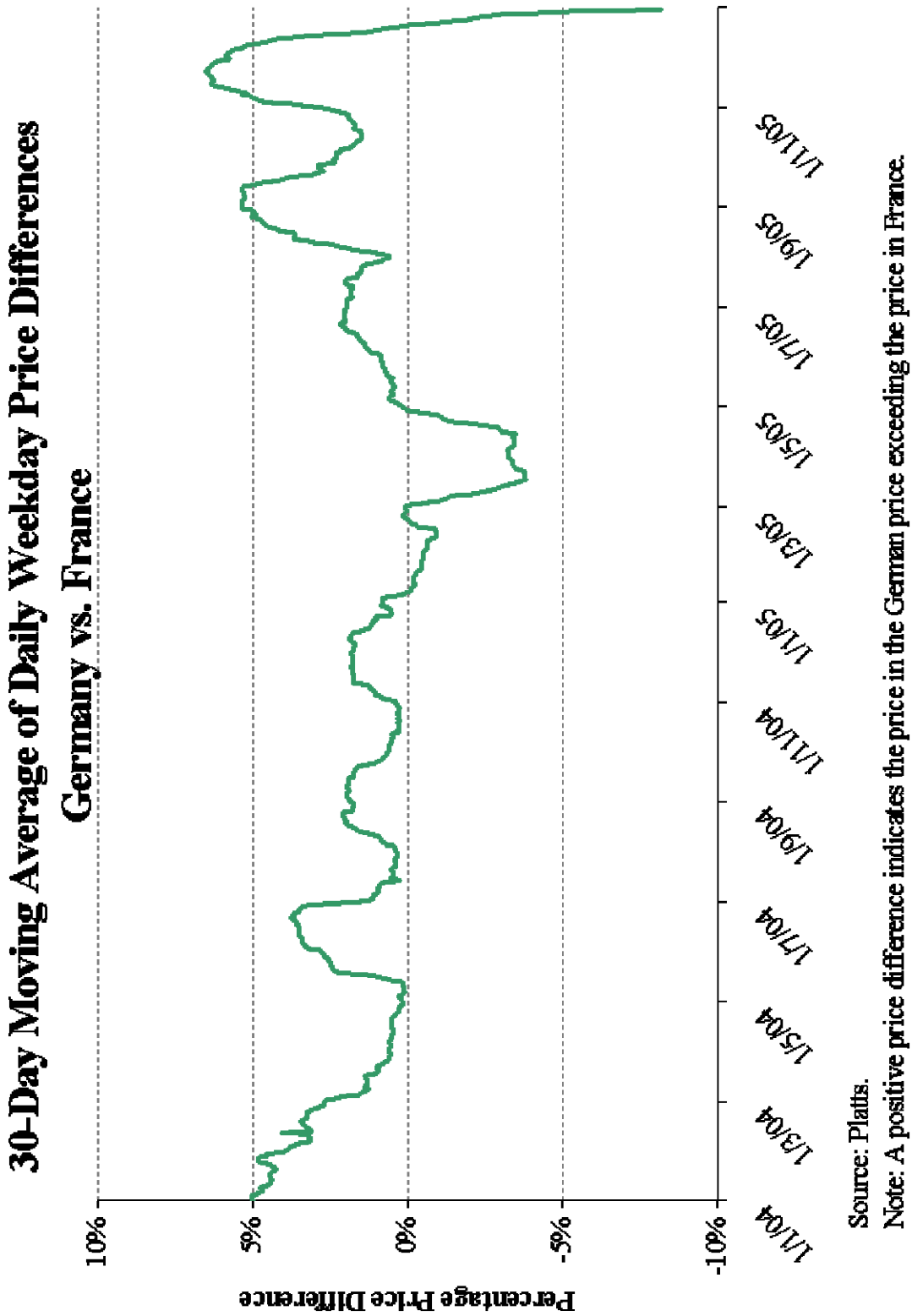


Source: Platts.

Note: A positive price difference indicates the German prices exceeding the price in France.

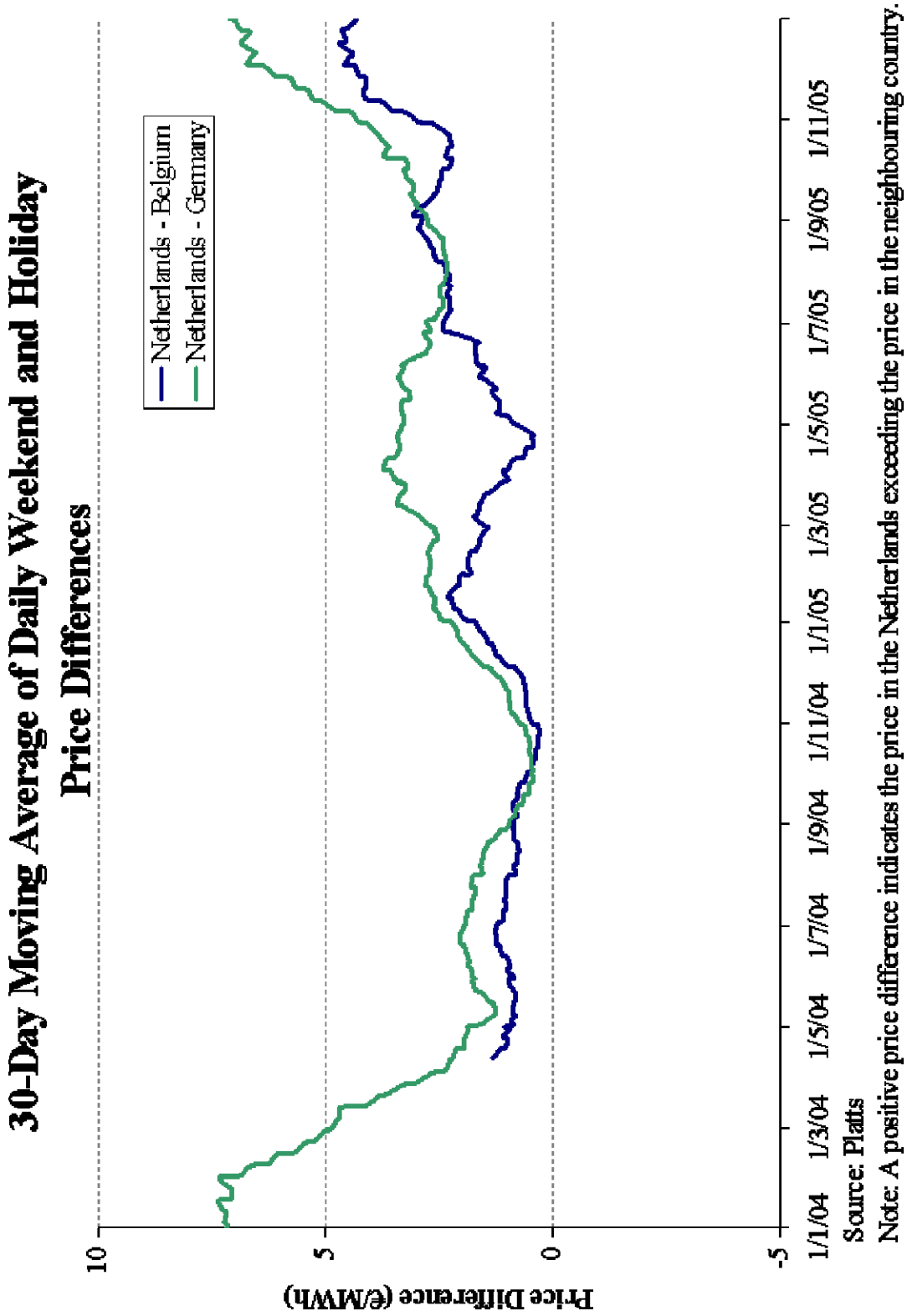


Source: Platts.
Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country.



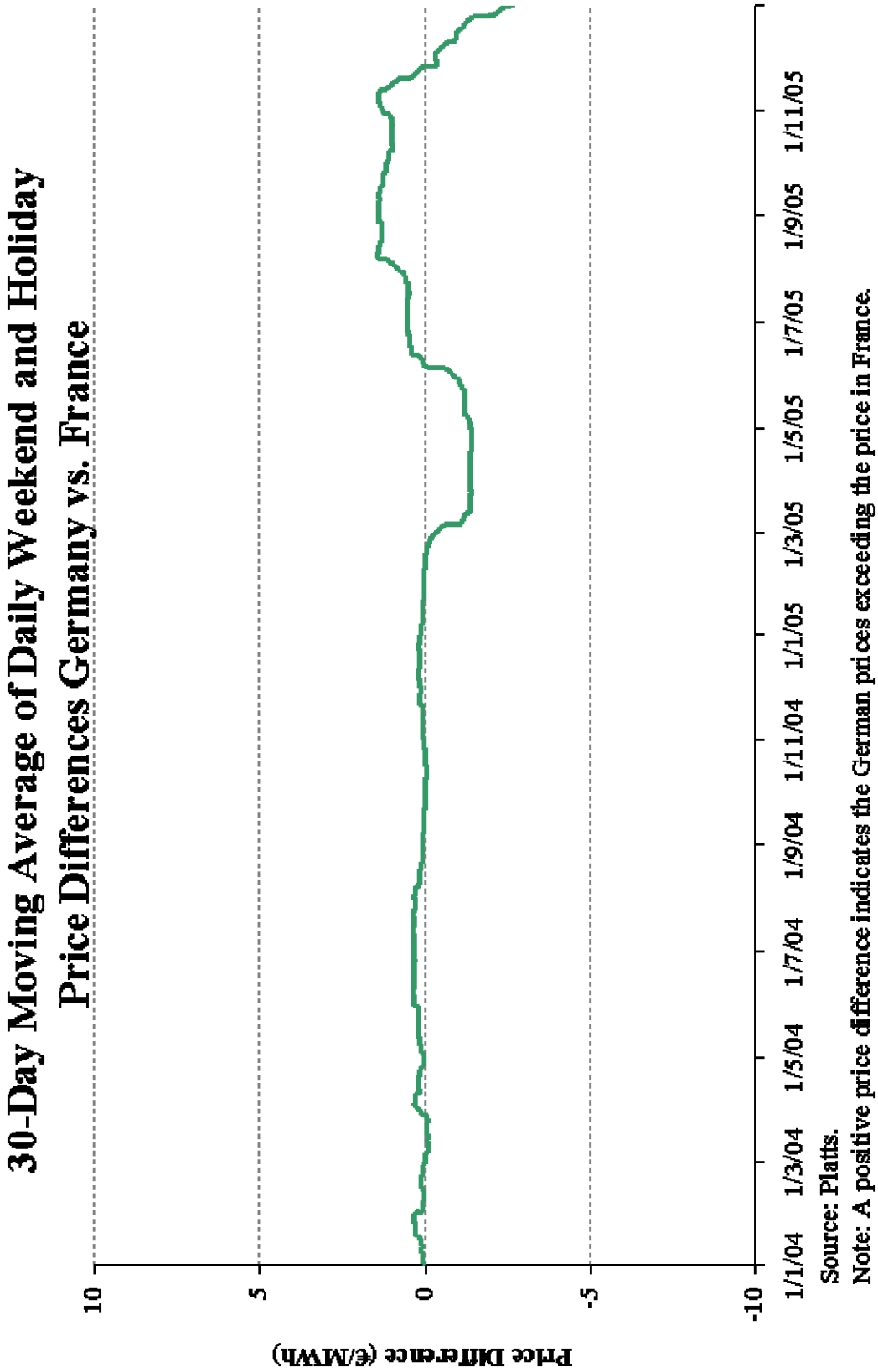
Source: Platts.

Note: A positive price difference indicates the price in the German price exceeding the price in France.

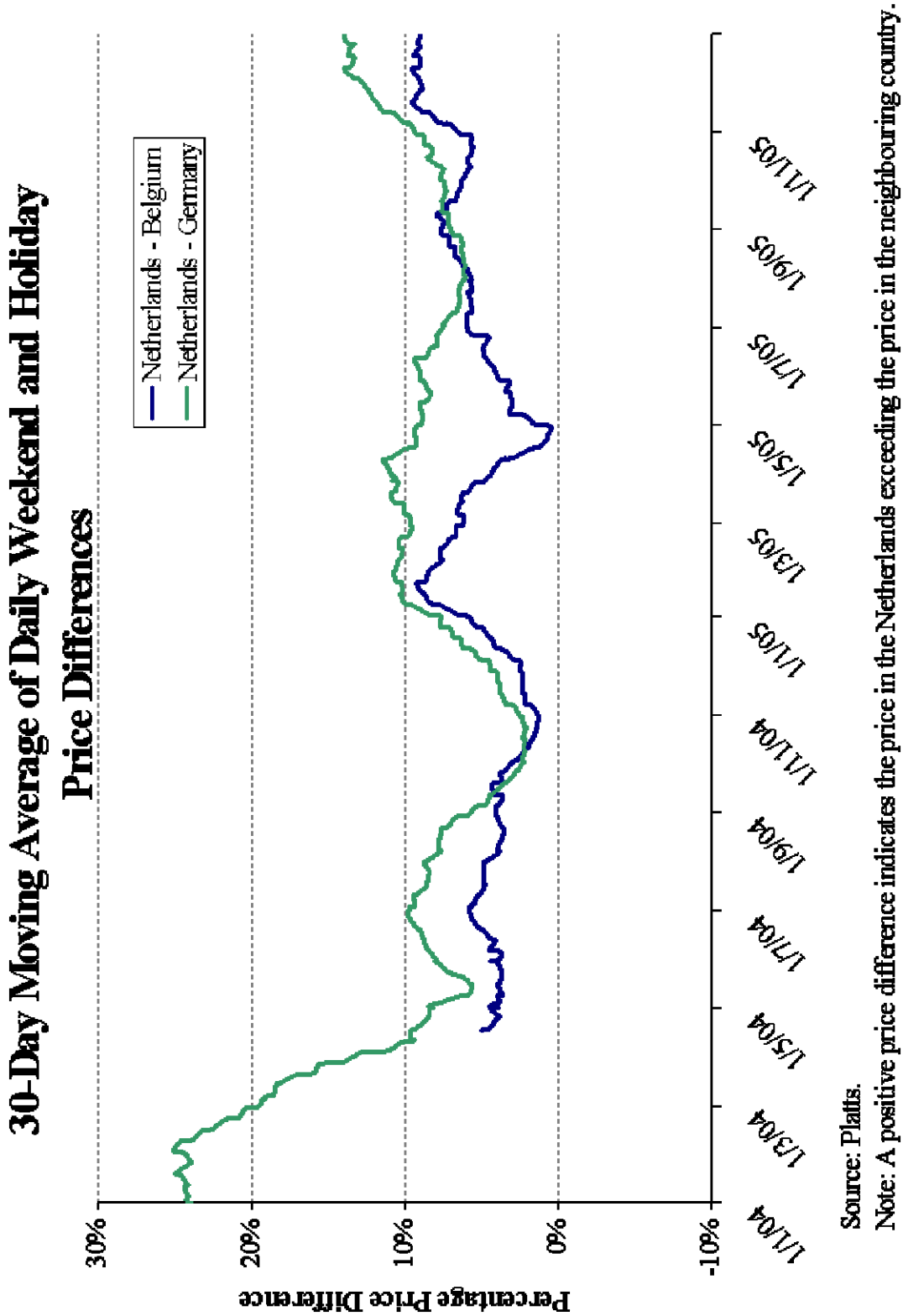


Source: Platts

Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country.

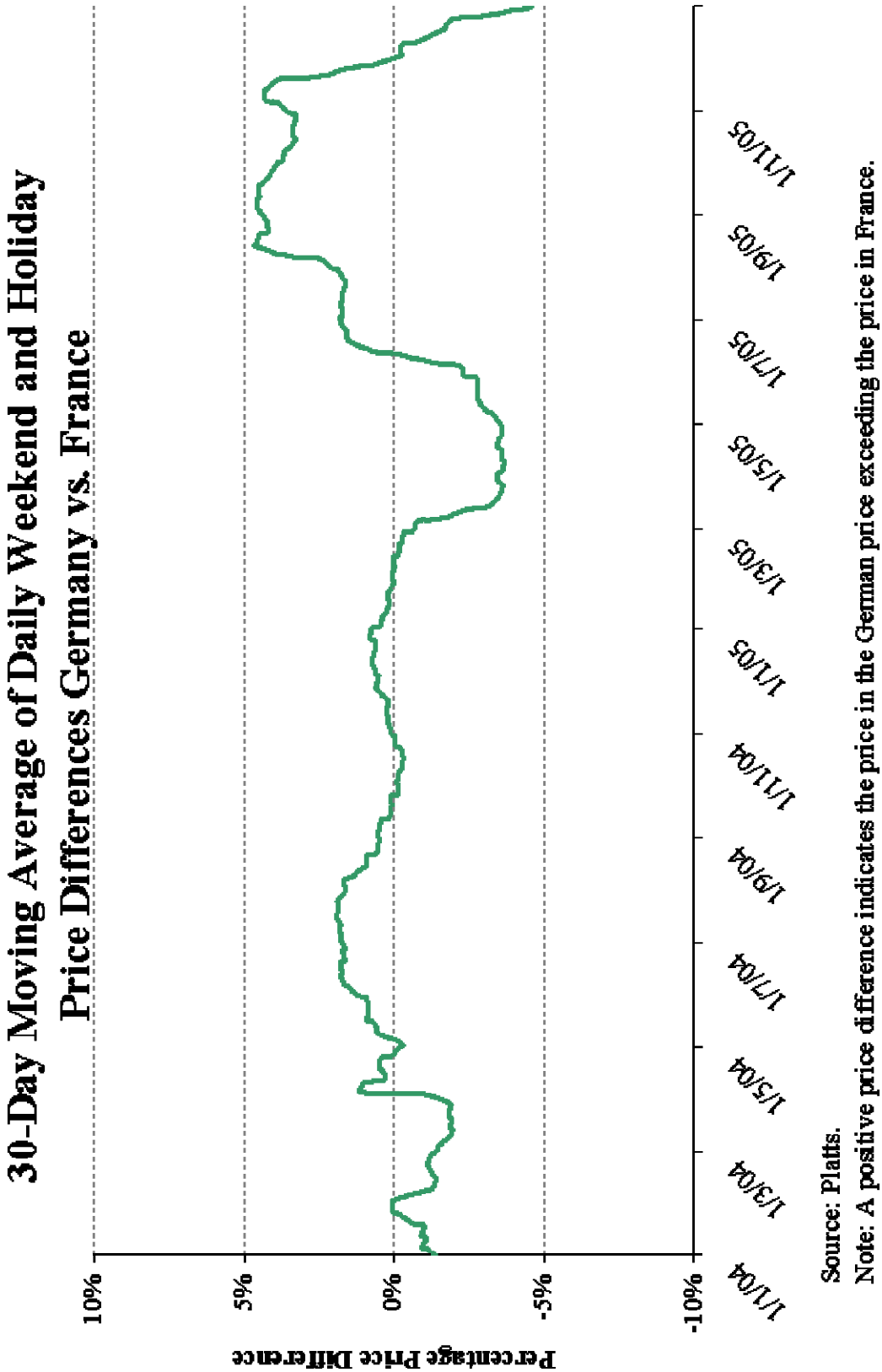


Source: Platts.
Note: A positive price difference indicates the German prices exceeding the price in France.

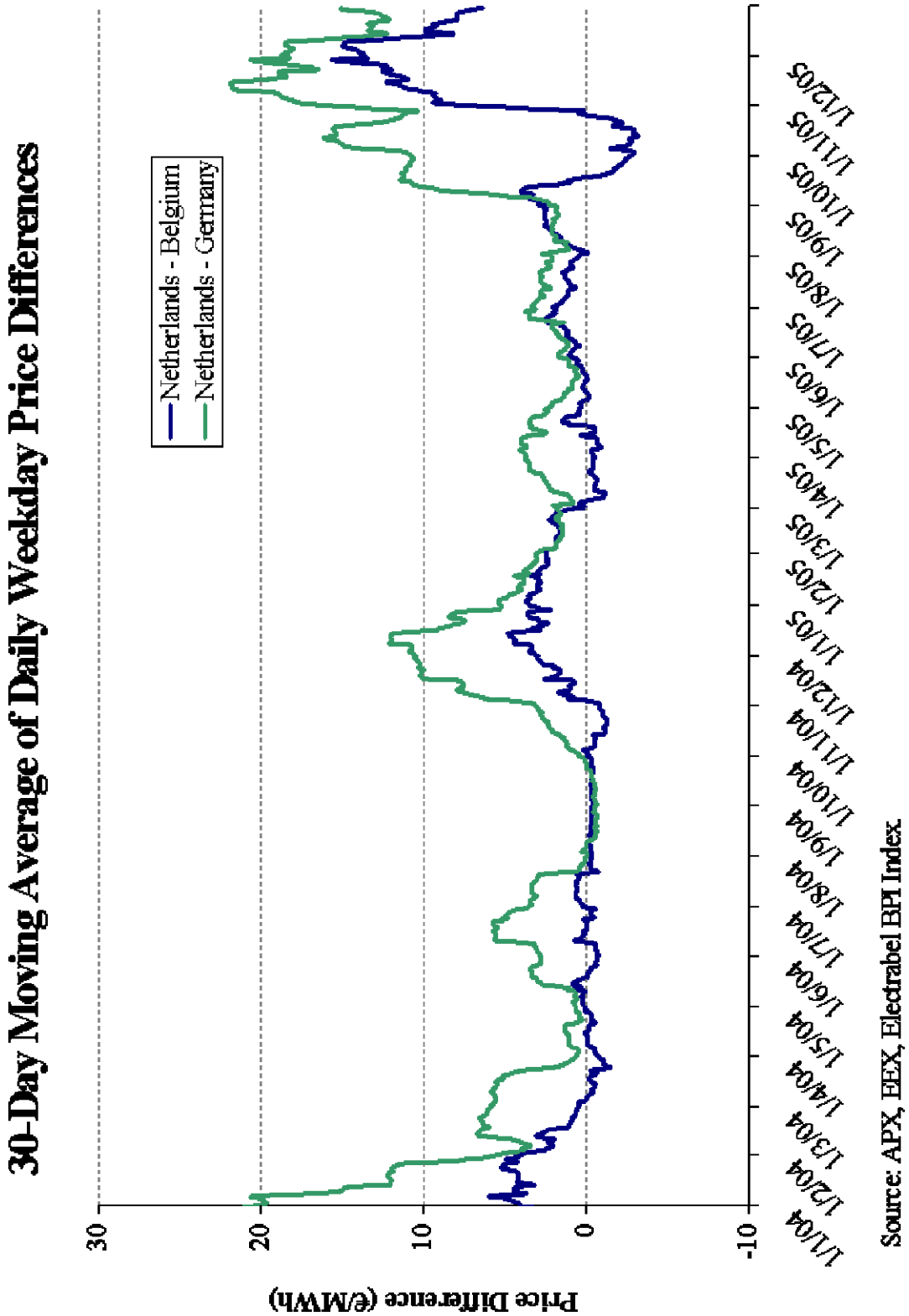


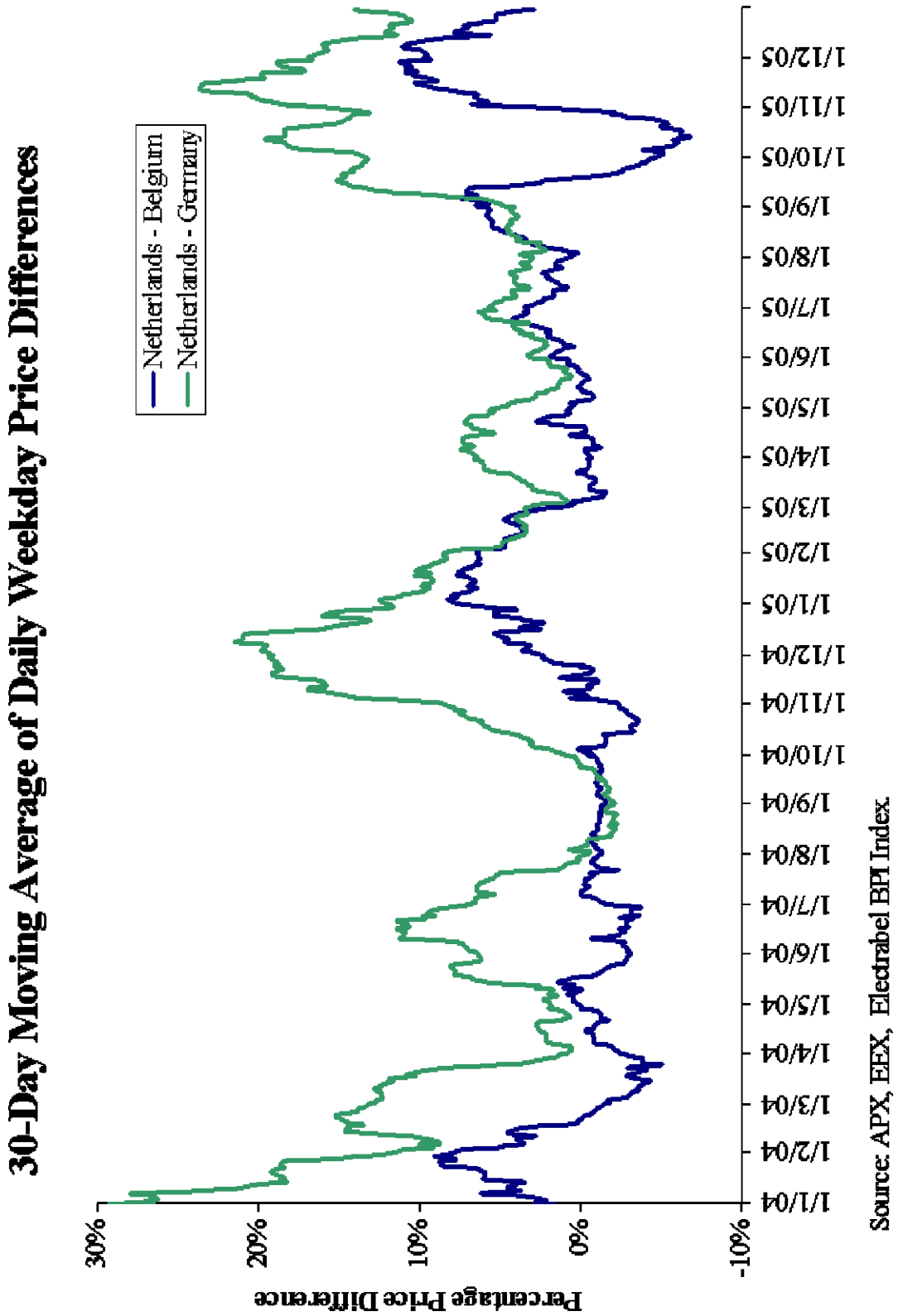
Source: Platts.

Note: A positive price difference indicates the price in the Netherlands exceeding the price in the neighbouring country.

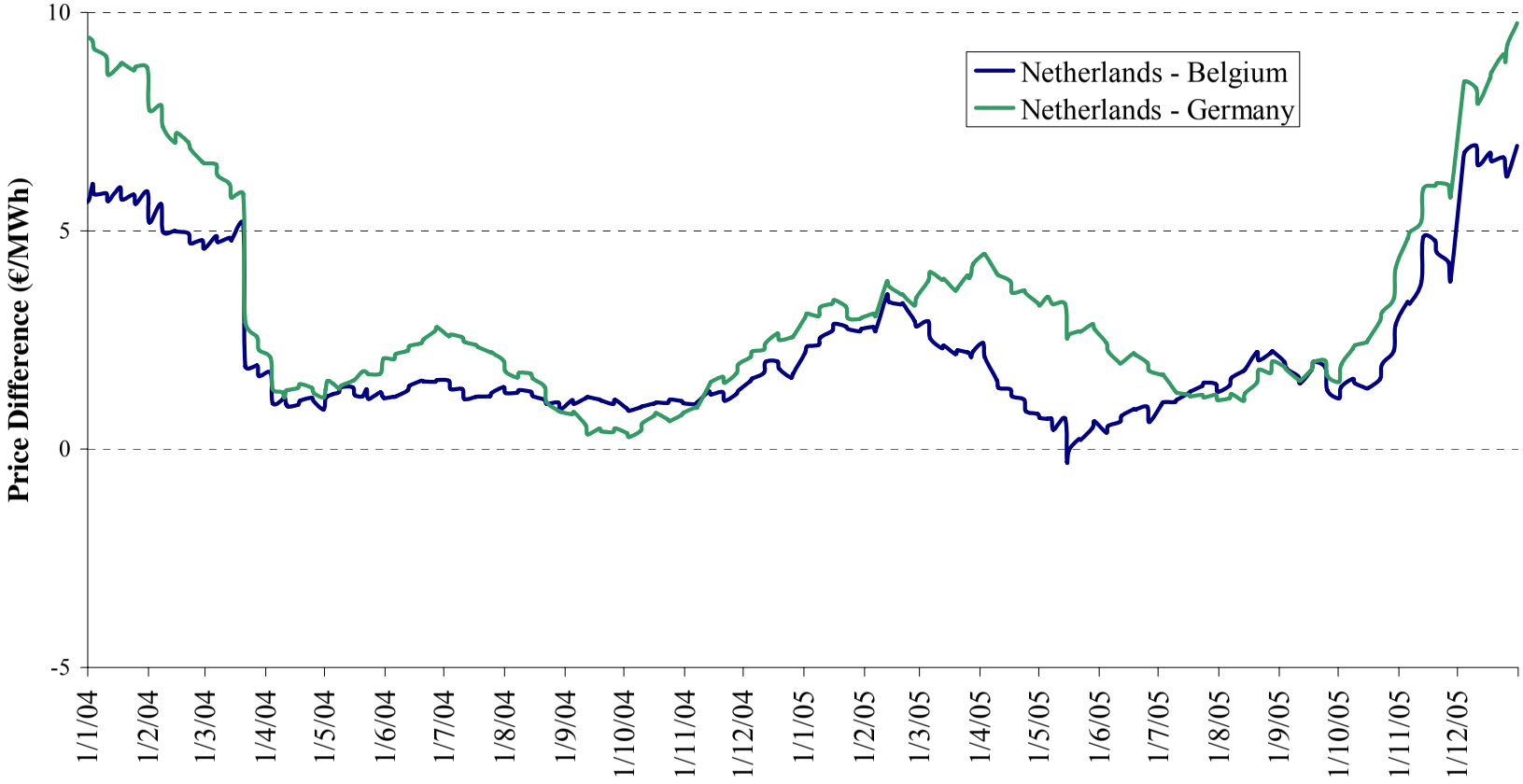


Source: Platts.
Note: A positive price difference indicates the price in the German price exceeding the price in France.

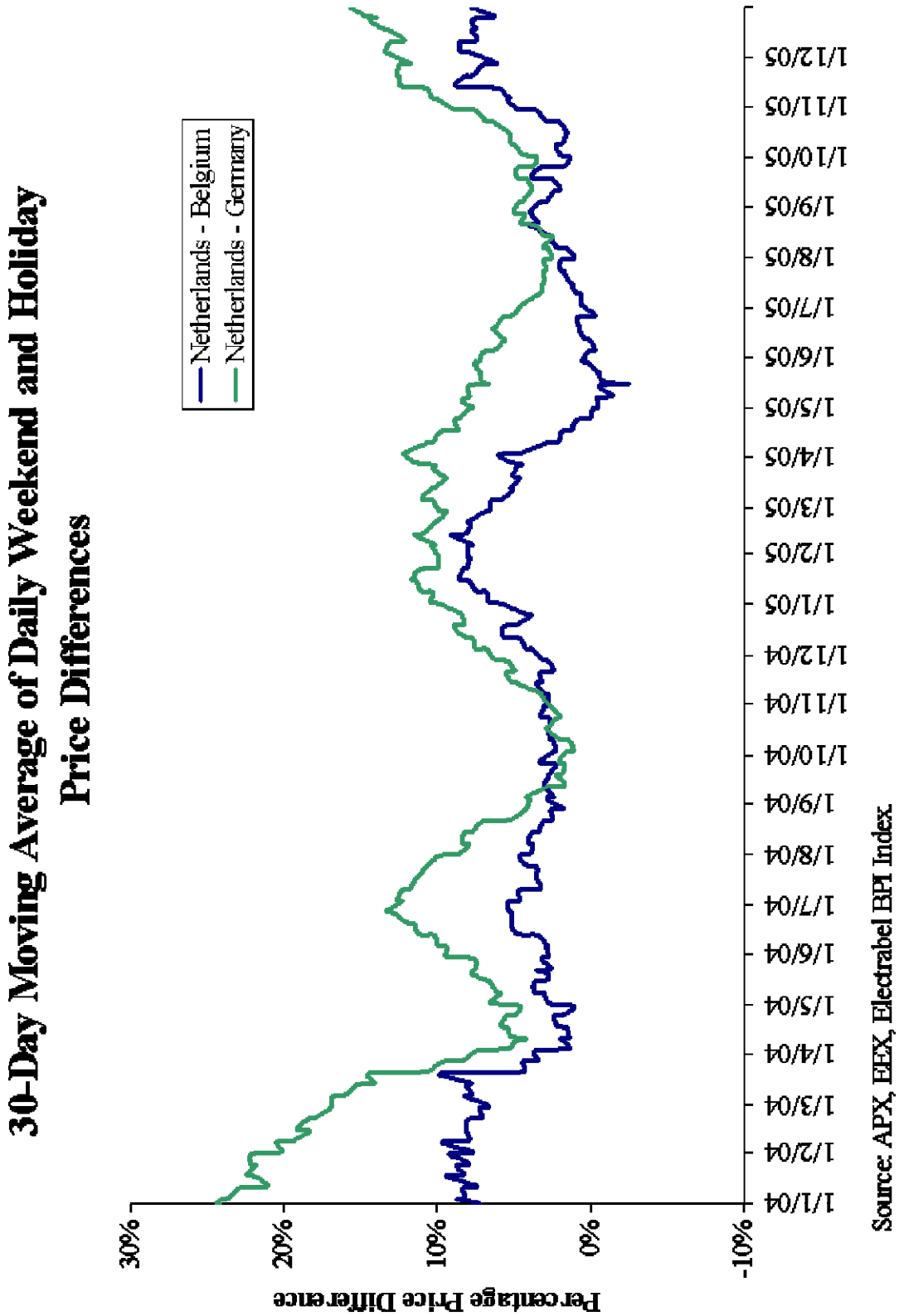

30-Day Moving Average of Daily Weekday Price Differences
Netherlands - Belgium
Netherlands - Germany
Price Difference (€/MWh)
30
20
10
0
-10
1/1/04
1/2/04
1/3/04
1/4/04
1/5/04
1/6/04
1/7/04
1/8/04
1/9/04
1/10/04
1/11/04
1/12/04
1/1/05
1/2/05
1/3/05
1/4/05
1/5/05
1/6/05
1/7/05
1/8/05
1/9/05
1/10/05
1/11/05
1/12/05
Source: APX, EEX, Electrabel BPI Index


30-Day Moving Average of Daily Weekday Price Differences
Netherlands - Belgium
Netherlands - Germany
Percentage Price Difference
30%
20%
10%
0%
-10%
1/1/04
1/2/04
1/3/04
1/4/04
1/5/04
1/6/04
1/7/04
1/8/04
1/9/04
1/10/04
1/11/04
1/12/04
1/1/05
1/2/05
1/3/05
1/4/05
1/5/05
1/6/05
1/7/05
1/8/05
1/9/05
1/10/05
1/11/05
1/12/05
Source: APX, EEX, Electrabel BPI Index

30-Day Moving Average of Daily Weekend and Holiday Price Differences



Source: APX, EEX, Electrabel BPI Index.


30-Day Moving Average of Daily Weekend and Holiday
Price Differences
Netherlands - Belgium
Netherlands - Germany
Percentage Price Difference
30%
20%
10%
0%
-10%
1/1/04
1/2/04
1/3/04
1/4/04
1/5/04
1/6/04
1/7/04
1/8/04
1/9/04
1/10/04
1/11/04
1/12/04
1/1/05
1/2/05
1/3/05
1/4/05
1/5/05
1/6/05
1/7/05
1/8/05
1/9/05
1/10/05
1/11/05
1/12/05
Source: APX, EEX, Electrabel BPI Index.