Structure and Functioning of the Electricity Market in Belgium in a European Perspective

Final report to

Le conseil général de la Commission de Régulation de l'Electricité et du Gaz

London Economics

Non-confidential Version

October 2004

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Introduction

The General Council of the CREG commissioned London Economics in December 2003 to undertake a study on the "Structure and functioning of the electricity market in Belgium in a European perspective". The key question that the study was to answer is whether, and to what extent, the current federal regulation already makes the markets for production, trading, and supply of electricity competitive or potentially competitive at the present time, and if not, what remedies could be implemented. Moreover, the analysis was to take account of electricity market structure developments in major European countries, especially neighbouring countries.

This report presents first our detailed findings regarding: a) the structure and functioning of the three Belgian electricity markets of interest, namely generation, trading, and supply and b) structural and regulatory impediments to competition in these markets, and then proposes a range of remedies to address these impediments.

Generation market

Our assessment of the generation market is that by any measure the Belgian electricity generation market is highly concentrated. Depending on the choice of assumptions regarding interconnection capacity and the VPP, the HHI concentration index is in the range of 5,455 to 6,756. This is well above the typical threshold of 1800 above which serious competition concerns arise.

We have not seen any evidence to date that the incumbent generator has exercised market power. However, it is important to stress that even the (credible) threat of such behaviour, or simply the uncertainty of how the incumbent will react after entry has occurred, could be enough to deter entry. Indeed, the dominant player in the Belgian generation market has the ability (and the incentive[1]) to engage in various forms of price manipulation. This impacts negatively on the liquidity of the wholesale market and also has negative implications for the functioning of downstream markets.

Imbalance charges in Belgium are on average lower and less volatile than in the Dutch balancing market, but substantially above (and less volatile) those under NETA. In our opinion, high imbalance charges represent only one aspect of the problems facing Belgium's liberalisation process. The others arise from their interaction with an opaque, illiquid and very concentrated market(s), which gives few alternatives to buyers in the market.

[1] We refer here to the 'incentive' to raise prices in the general sense that this would be profitable. A firm with market power has the 'incentive' to raise price (restrict output) above (below) competitive levels if it has market power. More discussion of this and evidence of market power is found on pages 44-46.

We have also analysed whether and to what extent imports from neighbouring countries and VPP auctions could constrain Electrabel's behaviour. Our assessment is that, although Belgium benefits of significant interconnection capacity, as a result of various reasons, imports only have a limited impact on competition in generation. Our assessment is that, for to a number of reasons, import capacity currently can only provide very limited competition to incumbent players in the Belgian market. The most important reasons of why this seems to be the case are: a) scarce capacity for periods longer than a day on the French border; b) the absence of an active spot market; and c) the requirement imposed by infra-hourly balancing.

New interconnection with France could have a significant impact on prices, but this is not likely with the current regime of dominant players on both sides of the border, and less than competitive market allocation of the interconnection capacity. Current levels of VPP are also expected to have only a moderate impact on competition in generation. In short, the picture of a very concentrated market is not altered when taking into account possible mitigating factors such as interconnection and VPP auctions. Given the current plans and physical time needed for interconnection, interconnection and VPP alone are not likely to product competitive outcomes over the next 3-5 years, other factors being equal.[2]

Even a simple comparison of baseload prices shows that the Belgium generation market appears to be less competitive than the Dutch wholesale market. Moreover, there are reasons to believe that such a comparison still overstates the actual degree of competition of the Belgian market.

Trading market

The biggest impediment to the development of a trading market in Belgium is a lack of liquidity. Liquidity and the general availability of trading opportunities are fundamental for participants to manage the daily production and delivery of wholesale electricity and for traders to manage their portfolios as efficiently as possible. Transparency and the balancing market risks are other important factors.

The biggest barriers to liquidity are, in order of descending importance: a) the dominant's player position in the trading, generation, and supply markets (in that order); b) the lack of access to the physical commodity; c) the low number of players in the market; and d) the lack of a meaningful reference price. These can all be attributed fundamentally to the dominance of Electrabel.

In some respects, the Belgian market appears to be evolving positively. VPP auctions and the commitment by Electrabel to quote prices and "make a

[2] Conversely, this is not to say that planned interconnection might not have an impact; with proper market power mitigation and resource allocation it could have a substantial impact. More on this in chapter 7.

market″ for a certain range of products are certainly moves in the right direction.

Our view, however, is that these measures are not being taken at a fast enough pace nor on a large enough scale. When a market is illiquid it is often necessary to intervene. Lack of liquidity creates a vicious circle. Players are reluctant to trade because the market is illiquid and this situation in turn contributes to the market′s illiquidity and therefore players don′t trade. The circle is unlikely to be broken if the market is left to its own devices.

We have found little evidence of significant structural deterrents to entry. The market appears to be largely ″contestable″ and we have indeed witnessed interest on the part of a number of potential entrants in entering the market, as soon as some of the other problems we mention are being addressed. Thus, the economically acceptable barriers to trading do not appear to be high.

These factors are all, however, likely to be of a secondary importance. A problem that, barring any other actions, will remain, even after all other corrections are made, is the large market share of Electrabel. Any market, no matter how well designed, where one player represents around 80% of the transactions in that market, faces significant scope for abuse of dominance. This in itself contributes to deter potential entrants from the market. A market under these conditions should be well monitored so that participants are assured that the dominant player is prevented from market manipulation.

Supply

According to available data, the market shares and HHI show evidence of a very highly concentrated supply market. An analysis of the market segments above 10GWh/y suggests that the latter segment suffers from even higher concentration.

Available evidence shows that entry has occurred in Flanders and some entrants have increased their market shares (based on connection points). However, the market remains highly concentrated. Figures in Wallonia show that the number of players is still very small. Electrabel retains a very high market share in terms of total electricity supplied in all three regional markets.

Our analysis shows that electricity prices remained relatively unchanged in the more concentrated markets (large and medium customers) between 1999 and 2003, but fell sharply for the more competitive market (domestic) after 2001. Similar conclusions are found analysing the evolution of the margins. Although we acknowledge the limitation of the data used in the analysis and that there could be other factors at play, this is a piece of evidence that market power may have been exercised in the more concentrated markets.

Retail customer switching in Flanders has been progressing slowly. In its first year after liberalization, it is behind the rates once achieved in England and Wales but is broadly similar to the experience of Sweden.

The fact that the metering data, standard yearly consumption data, master data is not delivered on time or is incorrect has an impact on suppliers business. Suppliers are unable to estimate the consumption volume of the client and to identify customers' profiles. Hence, suppliers run a very high financial risk in a narrow margin market.

Despite the remedies imposed by the Belgian Competition Council, the designation of the default supplier has reinforced the dominant position of existing suppliers on the market of the supply of electricity for various reasons. It has reinforced the vertical integration of Electrabel. Moreover, it has given the default suppliers a lead over new entrants because of its client base. The large customer base could allow the default supplier to exploit economies of scale and achieve lower unit costs than its rivals. Finally, to the extent that being a default supplier is perceived as being trustworthy, it has given an advantage to existing suppliers over new ones.

International developments

The major electricity markets in Continental Western Europe have experienced a wave of merger and acquisitions in recent years that resulted in a few major players dominating their national markets and competing against in each other in a number of national markets.

Looking ahead, it seems likely that the combination of the restrictions resulting from the Kyoto Protocol and the decommissioning of nuclear power stations in several countries will result in a change in the portfolio of generation assets across Europe. Gas and green energy will become relatively more important, though the reliability issues of the latter means that conventional thermal generation (especially in light of the decommissioning in nuclear power) is likely to be retained as an important source of energy.

Large electricity companies seem likely to continue to acquire assets in other countries, though the process is now rather more focussed upon consolidating positions in regional zones, e.g., the concentration of German companies in Northwestern Europe. For the foreseeable future, this will increase the number of multi-market contacts that the companies have, and thus might encourage tacit collusion in these markets.

While this pan-European trend of consolidation and vertical (re)integration is somewhat worrisome, we feel that the more immediate and most important issues for Belgium's electricity sector in the EU-wide context have to do with horizontal concentrations. As long as generation and supply are unconcentrated, then the negative impacts of vertical integration between generation and supply will be of second order; vertical integration becomes a first order issue when combined with concentrated markets. The more worrisome trends are that the benefits of transnational market integration will be muted by horizontal concentration combined with vertical integration. Electrabel now owns significant generation capacity in Holland and France, and EdF now owns generation capacity in Belgium, while maintaining a virtual monopoly in France.

While there is considerable talk about developing a pan-European electricity market, interconnector capacity limitations over the foreseeable future imply that, in Belgium given the current policy trend, the dominant player's market position is unlikely to change substantially in the next few years.

Our conclusions do not change significantly when considering recent and likely future international developments in the European electricity markets. Belgium is likely to retain highly concentrated market(s) for generation, supply and trading. Focusing on generation, while it is true that if an all Franco-Benelux market were fully achieved, then Electrabel's share would be about 12%, we do not feel this is the relevant metric for the next five years. The absence of transmission constraints is a necessary but not a sufficient condition for full integration of the Franco-Belgian-Dutch market. Full integration is neither necessary nor sufficient for full competition. Planned and additional interconnection expansion, introduction of market institutions (power exchange, market power monitoring) and full harmonisation of market rules/allocation procedures will be required to achieve an integrated market. While this should have positive impacts on competition, it is highly unlikely that even near-full market integration can be achieved earlier than 3 years from now, and quite possible it will not be achieved 5 years from now. Pan-European integration is not likely in the next 5 years. Current market structures and (planned) interconnection will still leave Electrabel with a market share of about 72%, and the overall market (on either a national or regional basis) would remain highly concentrated by any measure. This is the relevant metric. Even if full electricity market integration were achieved in the not too distant future, say a French-Belgian-Dutch market, the market would still be characterised by a highly concentrated generation market, so there is no guarantee market integration will bring full competition even if other barriers were low. Moreover, reduction of concentration in the near to medium term should be the primary focus; there is no compelling economic rationale for encouraging a larger domestic player in case a foreign competitor might enter.

Barriers to entry

Belgium's electricity markets are not functioning well in terms of achieving workable competition. A single company controls approximately 80% of the generation market, and this company is vertically integrated, with significant market shares, across all areas of the supply chain.

By far the biggest impediments to achieving competition in Belgium are structural. Among the structural problems, two stand out as particularly onerous. First, is Electrabel's near monopoly position in generation and supply, and second is Electrabel's high degree of vertical integration through all parts of the supply chain, especially the degree of vertical integration from generation into supply, and the natural monopoly elements, such as transmission. In addition, there is a high degree of interaction between these two structural features—effective monopoly in generation and supply, and vertical integration; the later reinforces the former. It has been recognized,

and generally accepted since the early days of competition policy enforcement, that effective upstream monopoly could impair downstream competition even if these markets (supply and trading) were likely to be potentially competitive on their own.

In addition to the two major structural problems, other economic factors exist in the markets that will impact entry negatively. In generation, economies of scale, uncertainty, and current wholesale prices are such that greenfield combined cycle gas turbine (CCGT) entry is unlikely to occur – with current prices being consistent with limit pricing. The case for entry via combined heat and power plants (CHP) is positive, though, if high load factors and thermal efficiencies are achieved. Also, although economies of scope and scale in generation may make entry difficult at current price levels, this is not to say that entry should not be expected to occur with sustainable moderate wholesale price increases.

In trading, lack of liquidity and opacity (i.e. lack of benchmark price) are likely the key entry deterrents. The vertical integration of Electrabel is probably also an important factor. High financial risks are likely to be important economic barriers to entry into the trading market while fixed costs are not.

Finally, with regards to supply, timelines and availability of reliable data, lack of competitively supplied commodity, lack of opportunities to manage risk (through a transparent market place), and an expensive balancing mechanism are likely the most critical factors affecting entry into the market. Economic entry barriers into the supply market are probably the lowest of all three markets. Nevertheless, margins are low and risks are substantial.

Remedies

Several remedies are considered and proposed. The difficulty is weighing priorities and likely impacts versus costs. There will usually be trade-offs; for example, power purchase agreement (PPA) auctioning might limit short-term market power of Electrabel's generation, but could lock in high prices for the long term. All remedies should be considered in concert with the problems and where the most onerous bottlenecks to competition are.

The first remedial step is to complete/bolster the current degree of unbundling of the monopoly elements of electricity from the potentially competitive ones. This was a priority step in almost every successful liberalisation programme globally. We recommend ownership unbundling between generation and transportation and distribution, and further unbundling between all other parts of the business, including regulatory accounting separation and managerial/governance separations. The next step is to put into place a full regulatory programme, including schedules and goals for trading arrangements (PX) and new balancing arrangements.

Full considerations of market design issues and decisions regarding a power exchange for Belgium should be made. If this is not feasible within a

reasonable timescale, then interim trading arrangements, along with schedules for consultations and completions on the final arrangements should be put in place. Interim trading arrangements should include complete accounting separation of Electrabel's vertically integrated businesses, and vesting contracts or trading formulae by which Electrabel trades with itself and despatches plant.

The most important piece of the strategy will be to address the market dominance of Electrabel. Their dominance in the most important market, generation, is greatest. Divestiture is the most complete option, and the one that is most likely to fully address market power problems—above all, the ability to raise the wholesale price of electricity. Our modelling shows that dividing Electrabel into 3-4 equal pieces, along with some secondary measures, could be sufficient to control prices in the range of €35 to €40 MWh. Important pieces of these secondary measures would include implementation of a market power monitoring committee, requirements to sell forward energy or contracts for differences, and publication of data and requirements for plant availability.

If divestiture is not an option, there are a number of other possibilities to address horizontal market power. One would be to greatly expand the VPP contract regime. Another would be to implement a scheme of contractual sale of long-term energy rights through auctioning PPAs. Finally, if these options were not feasible, effectively regulating price in the sector would be the other option. This could be done via some form of long-term contracts, rental agreements, or outright price controls of either the RPI-X form or cost of service type. These could be implemented on a contingency basis, such as was done in the UK, where once workable competition is introduced, the price caps are lifted.

Additional more immediate remedies could be considered to address the horizontal market power problem. Increased interconnection is the most important. Current interconnection plans could have a significant impact, but their ability to enhance competition will be limited if allocation mechanisms are not made more clear and more market oriented. We recommend a regime on the Franco-Belgian border similar to the Dutch-Belgian border. Publication of all relevant data for forecasting interconnection flows, prices, and congestion will also be necessary. Other important possible remedies should be considered, such as a moratorium on Electrabel CHP and autoproducers joint ventures, a requirement to sell sites suitable to new generation, or requirements to share data.

Other remedies should be considered to address problems of a smaller or more specific nature (than market power and vertical integration). For example, reducing regulatory uncertainty for DSO charges could be achieved by fixing maximum charges, and then allowing charges on an interim basis for a limited period. More details on these are given in the text.

Monitoring

Effective monitoring of the sector will be difficult and will require monitoring both market structures and market outcomes. Among many of the proposed monitoring details, monitoring of bids, concentration ratios, and forward sales should be undertaken. Monitoring plant performance, outage rates, and availability should also be done to detect possible withholding. There will still be considerable judgment required, and a range of measures, discussed in detail in Chapter 7 and Chapter 8, should be considered together.

1 Introduction

1.1 Scope of the study

In December 2003, the General Council of the Commission de Régulation de l'Electricité et du Gaz / Commissie voor de Regulering van de Elektriciteit en het Gas (CREG) commissioned London Economics to undertake a study on the "Structure and functioning of the electricity market in Belgium in a European perspective".

According to the terms of reference[3], the key question that was to be answered by the study is whether, and to what extent, the current federal regulation already makes the markets for production, trading, and supply of electricity competitive at the present time or can make them competitive in the future and, if not, what remedies could be implemented.

Moreover, the analysis was to take account of likely developments in structure of key European electricity markets, notably the recent merger trend in the electricity sector, and the potential impact of such developments on the structure and functioning of the three electricity markets mentioned above.

In undertaking this study we relied, among others, on information, studies and reports from a wide range of international and Belgian sources, including the federal and regional electricity regulators, Elia and many other stakeholders, and have held bilateral and roundtable meetings with many stakeholders. We are particularly grateful to all those stakeholders who graciously accepted to respond to our many queries.

As noted above, the overall aim of the study is to identify and study any barriers to entry in the Belgian electricity market in general, and to make recommendations as to how barriers might be removed, or competition improved. In the present report, we distinguish between entry barriers that arise naturally from the technology and cost conditions of the market, and barriers that are generated through regulatory, legal, strategic, or other means not related to the market economics.

We begin our analysis by assessing both quantitatively and qualitatively the state of competition in the three Belgian electricity markets of interest, namely production, trading, and supply. For each market, we discuss the market definition, review the structure of the market, including barriers to entry, and examine its performance.

Following a review of developments in electricity markets in neighbouring countries and potential competition implications for Belgium, we undertake a comprehensive assessment of barriers to entry into electricity generation, trading and supply in Belgium.

[3] The precise terms of reference are provided in Annex 1.

Next, we present a series of remedies that would address the competitive implications of the barriers to entry identified in the previous chapter.

Finally, we set out a methodology for monitoring on an on-going basis the state of competition in the three electricity markets.

1.2 Structure of the report

The structure of the report is as follows:

- The definition, structure and performance of the generation market are discussed in Chapter 2;
- We then analyse the definition, structure and performance of the trading market in Chapter 3. In this chapter we present also our assessment of the VPP auctions;
- Finally, we discuss the definition, structure and performance of the supply market in Chapter 4;
- Next, we provide an overview of developments in the structure of electricity markets in neighbouring countries and draw out a number of potential implications for Belgium in Chapter 5;
- In Chapter 6 we set out a theoretical framework of barriers to entry and analyse in greater detail the barriers to entry into the Belgian electricity generation, trading and supply markets;
- We then present in Chapter 7 a number of remedies that would address many of the barriers to entry identified in the previous chapter.
- In Chapter 8 we map out a detailed methodology for monitoring the state of competition in the generation, trading and supply markets.
- Finally, we offer a number of concluding remarks in Chapter 9.

A glossary of the various acronyms used in the report is provided at page 314.

The report also contains a number of Annexes. These include:

- The terms of reference at Annex 1;
- A summary of the views expressed by stakeholders in bilateral meetings or at the roundtables at Annex 2;
- A discussion of the volatility in the Dutch and NETA balancing mechanisms at Annex 3;
- An analysis of the mechanisms used to allocate capacity on the Belgian-French border at Annex 4; and,
- A model-based analysis of the room for entry into generation at Annex 5.

2 Generation

This chapter provides a detailed description of load, total generation and interconnection capacity available to Belgium. We also analyse the market structure in generation and whether it might facilitate the exercise of market power. In other words, we assess whether and to what extent the available factors that can mitigate the exercise of market power could be expected to play an important role. Finally, we review the wholesale price performance in Belgium and compare it with that in neighbouring countries.

The remainder of this chapter is structured as follows. We first discuss market definition. Next, we discuss market structure, specifically focussing on demand and supply balance, interconnection, market shares of incumbent generators and their implications for conduct. We then assess (and quantify) potential strategic conduct and mitigating factors in the market. Finally, the performance of the Belgian generation market is reviewed by undertaking comparisons between wholesale prices and marginal costs.

2.1 Market definition

Market definition is the starting point of competition analysis. Too broad (narrow) a market definition can lead the measured concentration to be lower (higher) than it actually is.

Market definition can proceed along several lines; these include geographical scope and product segments. In terms of product market definition, the central question is whether the market should be further defined along segments such as peak and baseload, as opposed to just generation capacity. In the case of electricity generation, the key issue regarding geographical scope definition relates to the question of whether/how much to include of the interconnection capacity.

Product market definition

The standard way to define the product market is centred on whether a hypothetical monopolist would find it profitable to increase prices by a significant amount. If two products can sustain price differences, they are not in the same market. The most likely definition is all despatchable generation – a megawatt is a megawatt. We support this definition, but with some significant caveats, and there are a number of reasons for this.

The homogeneous power product assumption is in general correct for the long and medium run. When customers buy electricity, they do not care where, when or how it is produced.[4] The long- and medium-run perspective

[4] Having said that, the reliability of a power supplier is something that is considered (in addition to price) by consumers in their choice of the supplier and not all types of power plants have the same degree of reliability. For example, in some cases the ability to deliver depends on some external circumstances,

is consistent with the current situation in Belgium because any market that can be identified presents a very similar picture of a dominant player and a fringe of small competitors. One would not therefore expect price differences to persist between what one generator could earn versus another within Belgium. This definition is also consistent with definitions used by the Belgian Competition Council, and the EU Commission. Other definitions are possible, however.

More narrow market definitions could include two products, peak and baseload, or peak and off-peak. It is common in electricity futures, such as the New York Mercantile Exchange (NYMEX) contracts, to define different products this way. Further, the USA's federal regulator, the FERC, defines what they call 'economic' capacity, as capacity that is economically capable of satisfying the given load for a given price. There are problems with the FERC's definition, as it essentially would define the market structure as a monopoly when demand is extremely low and only one player owns baseload. In spite of this, in very low demand times, the exercise of market power in power markets is rather limited.

A better narrowing of the generation market definition would delineate a separate market for times when power demand is near peak and when market mechanisms are near real time. The reason is that players that control certain segments in the supply curve can sometimes possess (and exercise) considerable amounts of market power when real-time demand is near perfectly inelastic. This could be in spite of a somewhat low overall market concentration and low barriers to entry. However, as of now, we do not see these as particularly relevant issues in Belgium. This is because 1) Electrabel owns virtually all generation, so the possibility that the all-Belgium generation definition is misleadingly low is also low. 2) Trading and balancing in Belgium are generally not market based, or based on day-ahead, hour-ahead market mechanisms, so the scope of having such conduct is limited.[5] As these markets develop, however, there is a need to consider updating this definition.

Geographical definition

We feel that the correct market definition is an all-Belgium despatchable generation market plus the interconnection capacity. This definition is fairly straightforward to defend. The idea is that the same product, outside the definition, could have a significantly lower price but not effectively compete with the home product. The limited Franco-Belgian interconnection capacity defines this example precisely, as it is generally accepted that price

e.g. wind power. This is precisely why we define the market as all despatchable generation as opposed to all installed generation.

[5] This is not to say that market power cannot be exercised in the Belgian trading and balancing markets, but simply that this conduct makes more sense in more market based set-ups, such as pools, balancing markets, etc.

differences persist. Likewise, constraints are not known to exist within Elia's system.

The inclusion of the interconnector capacity is also important. This is the common practice in both the economic modelling of electric utilities, as well as the engineering planning of supply and demand balances, and system security.

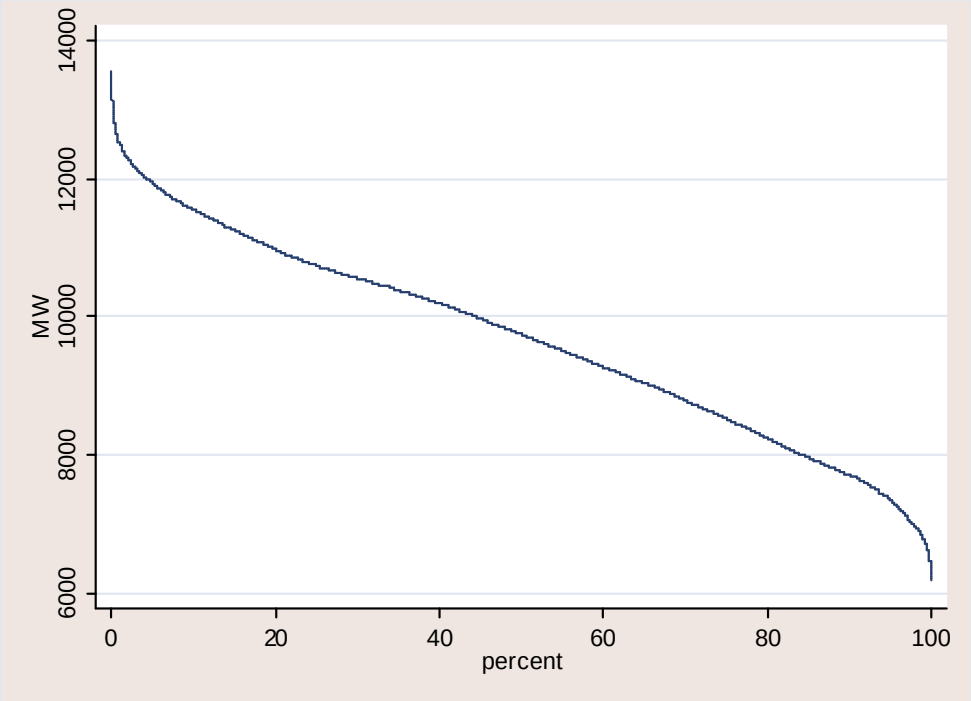
2.2 Market structure

2.2.1 Demand

Total system demand is important for the analysis of the generation market because it will indicate the supply-demand balance for the system. The supply-demand balance for the system of course fluctuates hourly, and so it can also be necessary to consider hourly demand. The load duration curve is a summary figure of hourly system demand throughout the year.

Figure 2.1 presents the load duration curve for Belgium in 2003. The figure shows load in MW on the left, and the percentage of time that load is less than a particular value. Thus, the load duration curve is a mirror image of a cumulative probability distribution of load. The maximum load is 13551 MW, while its minimum value is 6181 MW. Peak demand more than twice minimum demand is typical for many electric systems. The electricity requested in the Elia control area is 50% of the time above 9744 MW, 25% of the times above 10739 MW, 10% of the times above 11547 MW and 1% of the times above 12503 MW.

Figure 2.1: Load duration curve, 2003



Source: London Economics' construction based on Elia data

Figure 2.1 is important because it illustrates the requirements that the (total) generation capacity that is available to Belgium must be able to satisfy. It also shows, roughly, what load factors certain types of generation might achieve. Total generation capacity includes despatchable and non-despatchable generation, and the (net) import capacity from neighbouring countries.

In what follows, we will describe the installed generation in Belgium, interconnection capacity with neighbouring countries (and their usage) and market structure in generation. The last point is of considerable importance because, while social welfare is maximised when power is priced at marginal cost, in reality the load requirements described above can be met at different prices. Market structure is probably the most important element that might cause prices to deviate from marginal costs.

2.2.2 Installed generation capacity

Total installed generation for 2003 was 14,980 MW. This can be divided in 13,840 MW of despatchable generation (92.2% of the total) and 1,141 MW of non-despatchable (7.8% of the total). These figures include 48MW of non-despatchable capacity installed and connected to the grid in 2003 and the

decommissioning of 108MW of hard coal generating units also in 2003. Table 2.1 lists installed capacity by plant type.

Table 2.1: Belgium installed capacity in 2003

	Plant type	Installed capacity (MW)	% of total
[contains confidential information]			

Figure 2.2 shows the plant merit order for Belgium in 2003, excluding interconnection. Three must-run oil and coal units are at the top of merit order with zero marginal cost. Nuclear generators provide the next cheapest block of generation. Pumping units are shown as being the next cheapest.[6]

Mid-merit generation is provided (in order of increasing price) by hard coal, CCGT, and then a block of less efficient coal units. Peaking generation is provided by OGCT and turbojet units (and pumped storage).

Figure 2.2: Plant merit order (€/MWh), 2003

[contains confidential information]

Comparing the plant merit order with the load duration curve in Figure 2.1 shows that the marginal cost of electricity generation should be less than 31-33 €/MWh 90% of the time, less than 43.5 €/MWh 95% of the time and 201-205 €/MWh in the top 3% of the load duration curve.

The (time-weighed) average marginal cost is just above 40 EUR/MWh. This is interpretable as a benchmark for the price a baseload entrant would receive in a competitive market.

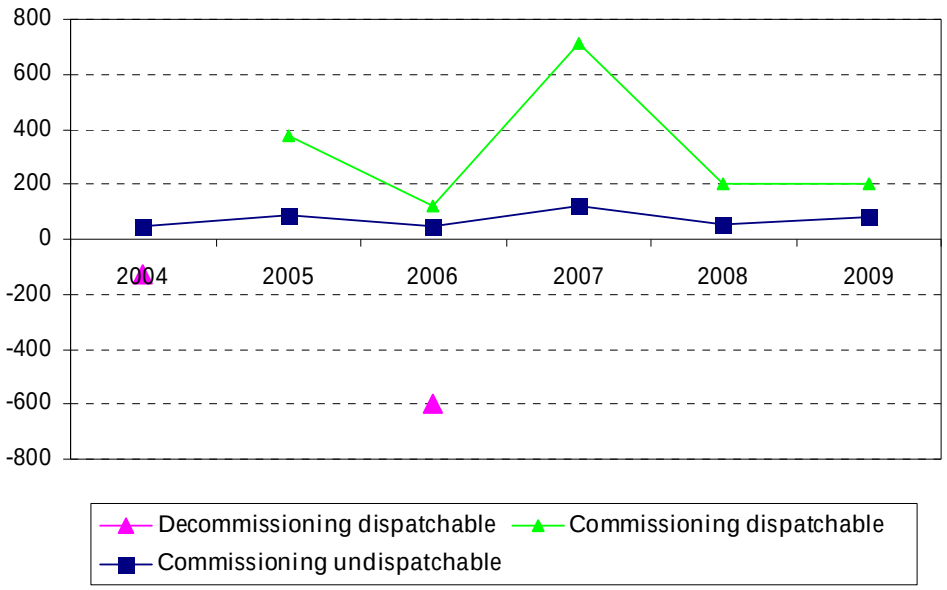
In the next sections we will describe the evolution of installed capacity in Belgium until 2009.

[6] The "marginal cost" shown for pumped storage is assumed to be the cost of electricity generated from nuclear power, adjusted for the loss of energy when pumping. Pumped storage despatches at peak, and the marginal cost of increased despatch at peak (up to capacity limits) is the cost of electricity purchased at night.

2.2.3 Capacity commissioning and decommissioning

According to the CREG, 724 MW of hard coal generating units will be decommissioned by the end of 2006, 1606 MW of new despatchable capacity will be installed in Belgium by 2009[7], and new investment in non-despatchable generation is assumed to increase gradually, reaching 449MW by 2009.[8] These dynamics are illustrated in Figure 2.3.

Figure 2.3: Commissioning and decommissioning of generation capacity in Belgium, 2004-2009 (MW)



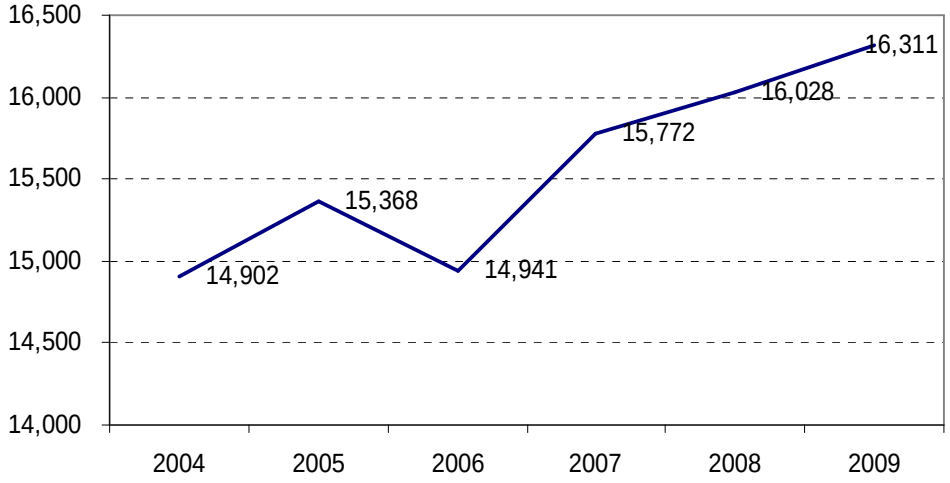
Source: London Economics' elaborations based on data provided by the CREG

Combining the information on installed capacity, decommissioning of existing capacity and new investment in generation, we obtain the trend, illustrated in Figure 2.4, for the total installed capacity for the period 2004-2009.

[7] ZANDVTGV is the only named investment project in despatchable generation and is assumed to be commissioned in January 2005. The new generic projects in despatchable generation are assumed to be of a standard size, i.e. 40MW for a new OCGT and 350MW for a new CCGT.

[8] According to FPE (2003), 1127MW of new capacity is being planned and/or under construction. Almost all this capacity is wind-propelled; Electrabel and SPE are planning to build 409 MW and 50 MW respectively. It is not know when this capacity will begin to operate, nor the time period to which this data refers to.

Figure 2.4: Belgium installed capacity, 2004-2009 (MW)



Source: London Economics' elaborations based on data provided by the CREG

2.2.4 Import and export capacity

The Belgian electricity system is interlinked to the French and Dutch markets via inter-connectors. Total commercial capacity for imports on the French-Belgian border is normally around 1,000 MW in summer, 2,000 in winter and 1,500 MW mid-season.[9] Part of this capacity is reserved for long-term agreements.[10] Total import capacity on the Dutch-Belgian border amounts to approximately 1,257 MW. The total export capacity of Belgium is 2750 MW to France and 1170 MW to the Netherlands. Figure 2.5 illustrates these transfer capacities.

[9] Winter is defined as November, December, January and February; mid-season is defined as March, April, May, June, September and October; and summer is defined as July and August.

[10] See overleaf for details.

Figure 2.5: Schematic picture of cross-border (total) transfer capacities

Source: London Economics on information provided by Elia and the CREG.

French-Belgian interconnector

The import capacity of the French interconnector is divided in long-term, monthly, and daily capacity. Information provided by Elia indicates that approximately [confidential] MW are reserved for long-term contracts in summer, [confidential] MW in mid-season and [confidential] MW in winter; the remaining capacity is divided into monthly and daily capacity. This implies that there are approximately [confidential] MW of commercially available capacity (i.e. capacity available for all market players) left in summer, [confidential] MW in mid-season and [confidential] MW in winter. This points to a varying degree of (possible) import competition during the year, with very limited possibilities to compete during the summer months.

The long-term import capacity is mainly used to import to Belgium the power generated by the nuclear station Chooz B (owned by EDF) in France and for the transit of power from France to the Netherlands (contract SEP).

Under the Chooz B contract, [confidential] MW of the nuclear power station Chooz B are reserved to Electrabel and SPE as follows:

[confidential]

The SEP contract is a long-term supply contract between EDF and six Dutch suppliers for [confidential] MW.[11] Half of this contract ([confidential] MW) flows to the Netherlands trough Belgium, while the other half through Germany. In 2003, the time-weighted average of the nominated flows for this contract was [confidential] MW. The SEP contract expires in March 2009.

The Synatom contract is the only long-term agreement that involves the use of the interconnector from Belgium to France. This contract, on average, involved nominations for [confidential] MW in 2003.

Long-term contracts are given priority in the allocation of import capacity. The remaining available capacity for monthly and daily capacity is jointly

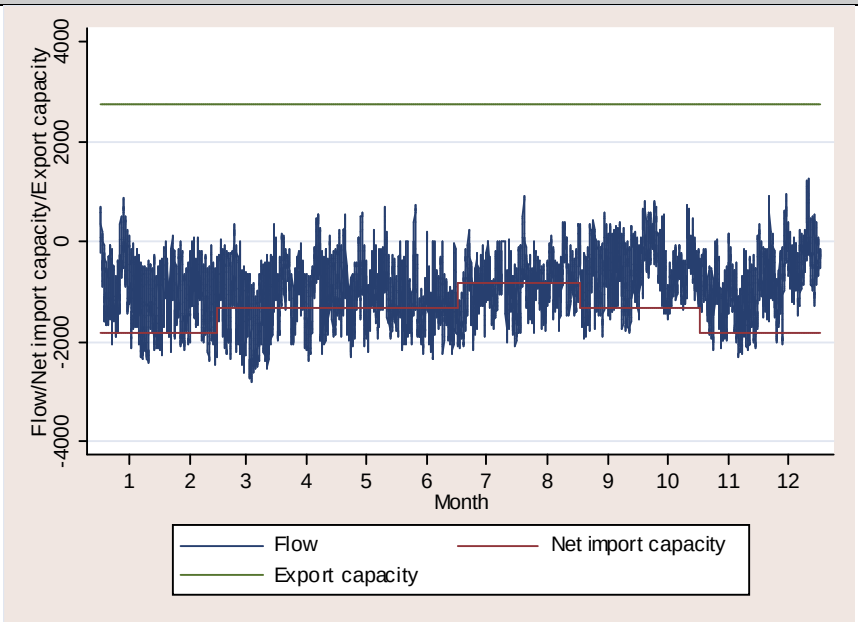
[11] The Dutch suppliers are E.ON Benelux Generation N.V., Electrabel Nederland N.V., Reliant Energy Power Generation Benelux B.V., Essent Energy Trading B.V., N.V. Delta Nutsbedrijven et EdF Trading Limited.

determined and allocated by RTE (daily) and Elia (monthly). The daily capacity is determined on a residual basis, as the difference between the net proposed capacity (CNP) for that day and the summation of monthly and historical contracts. The precise mechanisms used to allocate this capacity are reported in Annex 4. Essentially, these are non-market mechanisms where scarce capacity is allocated on the basis of a "first in, first served" principle. This mechanism has recently been complemented by a "use it or loose it principle".

Figure 2.6 provides an illustration of the direction and size of the real power flows on the French border in 2003 (hourly flows), where the import flows have been adjusted to exclude exports under the SEP contract.[12] In the vast majority of cases the flows were negative; this indicates imports from France to Belgium and/or in transit to the Netherlands. The time-weighted average of the hourly flows is -785 MW, more than 68% the total import capacity on this border excluding that reserved for the SEP contract. Total net imports from France were 6.9 TWh in 2003.

[12] In what follows we have adjusted the real flows by the hourly nominated flows under the SEP contract and the Belgian import capacity from France by subtracting the time-weighted average of the nominated SEP flows.

Figure 2.6: Real power flows on the South border, 2003



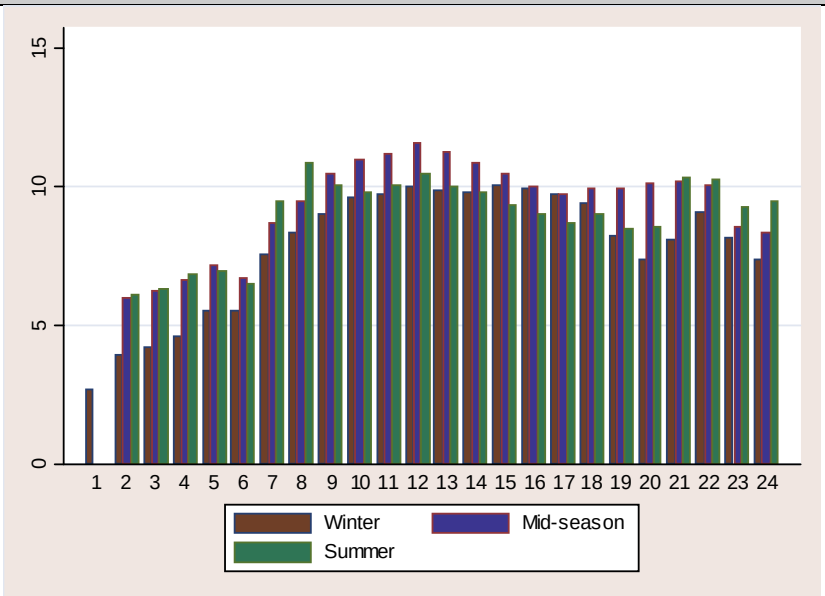
Note: Positive flows denote export from Belgium to France, while negative flows denote Belgian imports from France; straight lines denote import and export capacity.

Source: London Economics' elaborations based on data provided by the CREG.

The average dependency of Belgian demand on French imports is 9%.[13] Belgian demand relies more heavily on French imports in the peak hours than off peak, regardless of the season (Figure 2.7).

[13] This figure is likely to overstate the "truly" dependency of Belgian demand because some imports may be directed to the Dutch market.

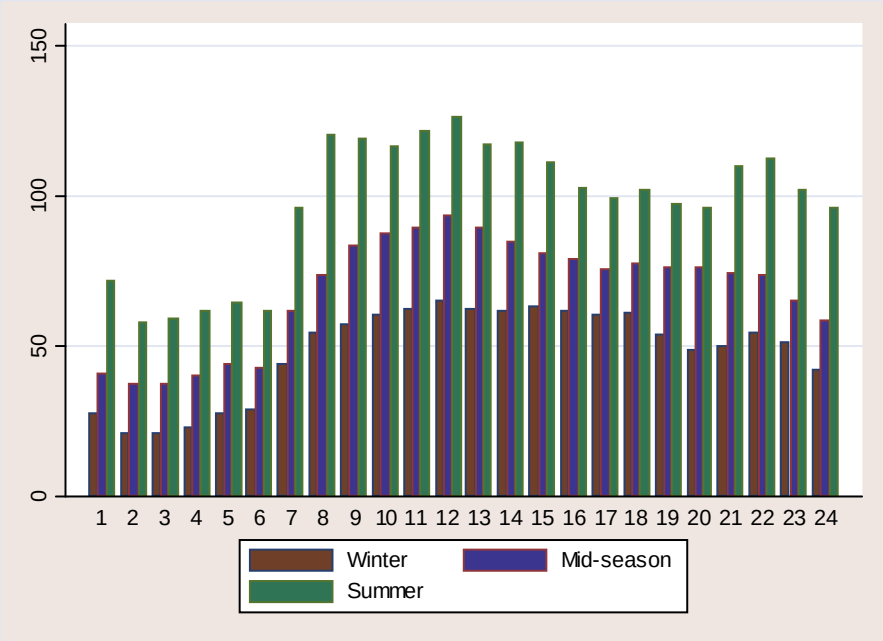
Figure 2.7: Import flows from France as a percentage of hourly demand by season (%), 2003



Source: London Economics' elaborations based on data provided by the CREG.

Import capacity is more intensively used in summer and mid-season than in winter (Figure 2.8). Moreover, the interconnector capacity is most intensively used during peak hours (07-23) than off peak (00-07; 23-24) in all seasons. This is not a consequence of the fact that available capacity changes season by season (typically lower in mid-season and summer), because all import flows are normalised on available capacity on an hourly basis.

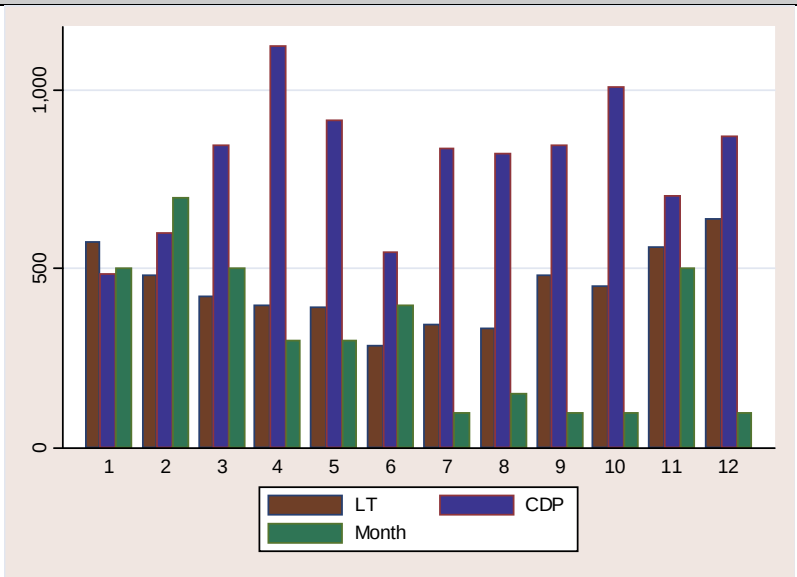
Figure 2.8: Average utilisation rates of import capacity on the South border by season and hour (%), 2003



Source: London Economics' elaborations based on data provided by the CREG.

Figure 2.9 illustrates how the import capacity from France is divided in long-term capacity (LT), monthly and daily capacity (CDP) on a monthly basis. The monthly and daily capacities are important because they represent the "available" capacity for use by importers to compete in the Belgian market. With the exception of January and February, the daily capacity is, on average, always above the monthly capacity that is offered by Elia-RTE.

Figure 2.9: Import capacity from France by type (MW), 2003

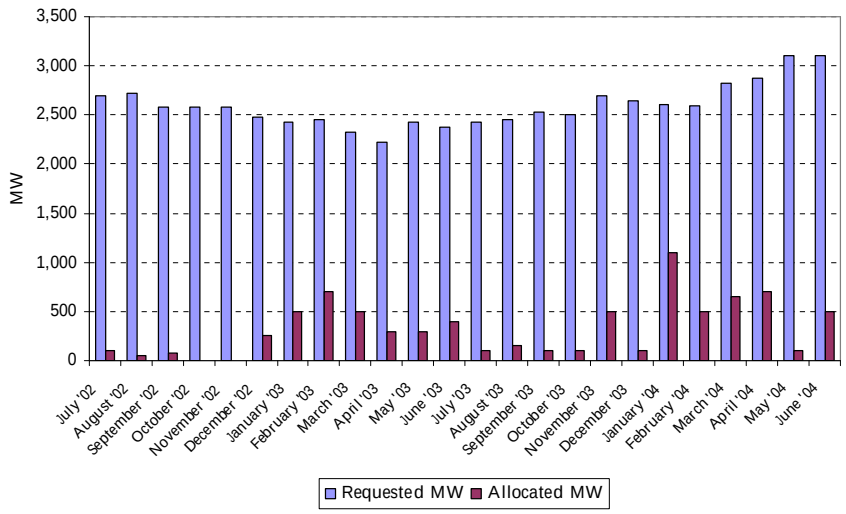


Source: London Economics' elaborations based on data sourced from RTE

Monthly capacity is a valuable but scarce commodity, as shown in Figure 2.10. The amount of capacity requested is on average 15 times the amount of capacity that is declared available by Elia and RTE. This probably indicates that exploiting the existing differential in the price of wholesale power between France and Belgium for an entire month can produce valuable savings. This is the case even considering the limitations of bidding only for (monthly) constant quantities[14] and that the same ARP can only bid for up to four blocks of maximum 25 MW (see Annex 3). In our view, acquiring monthly capacity on the Franco-Belgian border is perhaps the most effective way to compete in the Belgian generation market. However, this possibility is limited, due to the relatively low amounts of monthly capacity offered by Elia-RTE.

[14] In the absence of an active hourly spot market in Belgium, imports from France will primarily occur if these can be directly sold to end-users. As most end-users have a shaped daily profile, this means that the potential supplier will have to bid for additional daily capacity for some hours of every day and/or purchase the difference in the Belgian balancing system. Moreover, assuming that by using a combination of monthly and daily import capacity (that allows to bid on an hourly basis) the supplier is able to match the profile of the user, there is still the problem of matching hourly constant import quantities with the infra hourly balancing requirements in Belgium, which necessarily exposes the supplier to the Belgian balancing system.

Figure 2.10: Requested and allocated monthly capacity (MW), 2002-2004



Source: London Economics' elaborations based on data sourced from Elia

Competing in generation on the basis of the daily imported power does not appear a viable option for at least three important reasons. If for any reason a supplier that has sold forward power to end-users in Belgium is not able to obtain for *every* hour sufficient capacity to satisfy its contracts, this will necessary expose the supplier involved to the Belgian balancing system for the *entire* hourly supply as opposed to any differences between supply and monthly capacity.[15] Moreover, when there is congestion on the interconnector, some of the daily import capacity (C1) is subject to an additional congestion cost.[16] Another important limitation of competing on the basis of daily import capacity is that such suppliers could be perceived by the market as less reliable than those having their own production facilities in Belgium and/or having more stable sources of power (e.g. longer-term agreements), thus further limiting their possibilities to compete against Belgian generators. Finally, to avoid non-delivery to consumers, back-up

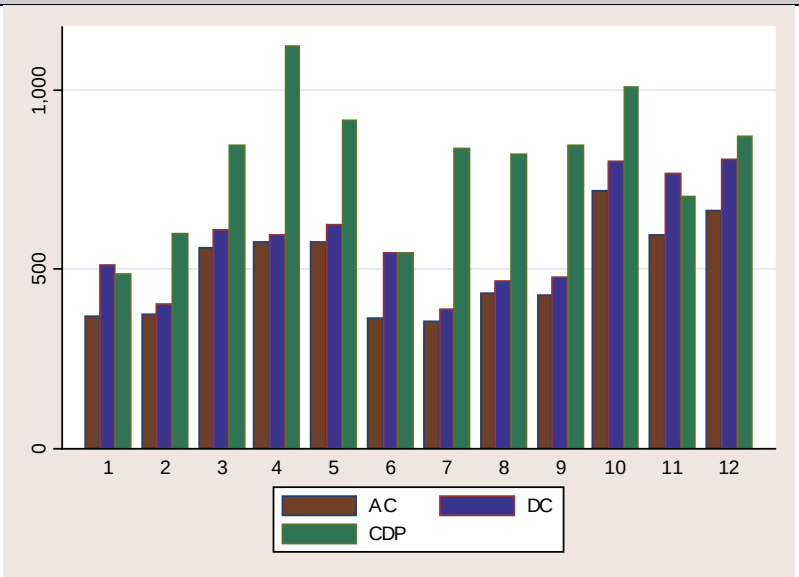
[15] Suppose for example that a supplier of power in Belgium has purchased monthly import capacity for 50 MW and signed a contract with a user for the supply of 70 MW during day time hours and 10 MW at night. If this supplier does not manage to obtain extra capacity during a particular day (day time hours), he will have a short position for 20 MW. Thus, this supplier will have to buy 20 MW from the balancing mechanism (or equivalent) during the day time hours. Conversely, if the same supplier relied only on the daily import capacity to satisfy the same agreement and, for example, is not able to obtain the capacity he needs in a given day/hour, his exposure would be 70 MW as opposed to 20 MW. In other words, monthly capacity can be seen as a type of insurance for potential suppliers.

[16] This congestion cost depends on the costs sustained to relieve the congestion and varies between 1.5 and 15€/MWh.

facilities need to be contracted to provide power in case of interconnector outages.

In essence, in absence of an active spot market in Belgium, local generators are the main beneficiaries of the daily import capacity, which can be used to minimise their own despatching costs. This lower attractiveness for the daily capacity is shown in Figure 2.11, where, with the exception of January, June and November, the capacity that is demanded (DC) and allocated (AC) is, on average, always below (and sometimes substantially) the available capacity (CDP). In 2003, demanded capacity exceeded available capacity 32% of the times; this mostly occurred in the peak hours of January, June and November.[17] The excess of demand of daily capacity on available capacity was substantial; its median was 46% of CDP. This shows that, while in general daily capacity is not fully utilised, there are a few times (32% of the total) in which daily capacity is over demanded and therefore highly valuable.

Figure 2.11: Available, demanded and allocated daily import capacity by month (MW), 2003



Source: London Economics' elaborations based on data sourced from RTE

Frequent congestion is a key feature of this interconnector. In 2003, the likelihood of congestion was "high" in 32% of hours and "very high" in a further 28% of hours (RTE data). In the following exercise we try to assess

[17] This analysis is available upon request.

whether the likelihood of congestion could be the cause of offering only a limited amount of capacity for monthly allocations and higher capacity for daily allocations. We perform this analysis in Table 2.2, where we calculate the share of Capacité Nette Proposée (CNP) reserved for monthly and daily capacity for three levels of likelihood of congestion. If congestion were indeed the reason for allocating a relatively small share of import capacity on a monthly basis (as opposed to daily allocations), we would have expected a negative (positive) relationship between monthly (daily) capacity and congestion. This, however, does not appear to be supported by our analysis.

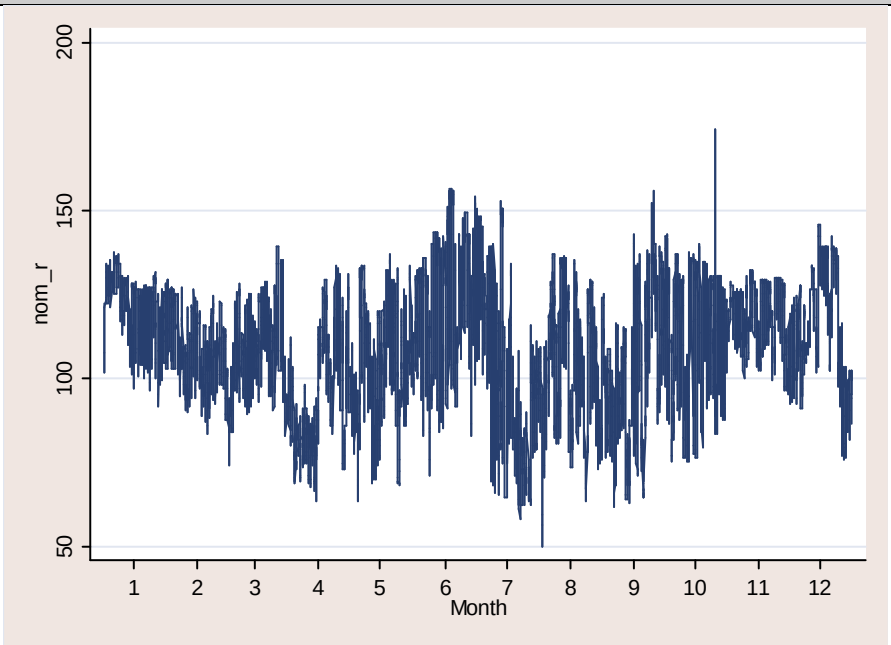
Table 2.2: Monthly and daily capacity by degree of congestion, 2003

Likelihood of congestion	Monthly capacity (% of CNP)	Daily capacity (% of CNP)
Low	17.7	43.6
High	18.1	48.3
Very high	16.8	45.6

Source: London Economics' elaborations based on data sourced from RTE

It is interesting to note that, on the basis of this data, the total nominations for import from France use completely (and in many cases are well above) the total volume proposed by RTE for exchange over the interconnector (CNP). This feature of the data is illustrated in Figure 2.12. This confirms that import capacity on this border is highly demanded and that RTE, through its congestion-relieving program, manages to increase substantially the capacity proposed at D-2.

Figure 2.12: Total hourly nominations as a percentage of CNP (%), 2003



Source: London Economics' elaborations based on data provided by the CREG.

Dutch-Belgian interconnector

The import and export capacity on the North border is mostly allocated by using auctions for capacity. Import capacity is allocated on an annual, monthly and daily basis by using TSO auctions.[18]

According to Elia, the total import capacity to Belgium is 1257 MW (since August 2003) and is divided in [confidential] MW of annual capacity, [confidential] MW of monthly capacity and [confidential] MW of daily capacity. The total export capacity to the Netherlands is 1170 MW (since January 2003) and is divided in [confidential] MW of long-term capacity, [confidential] MW of yearly capacity, [confidential] MW of monthly capacity and [confidential] MW of daily capacity.[19] Almost half of the long-term

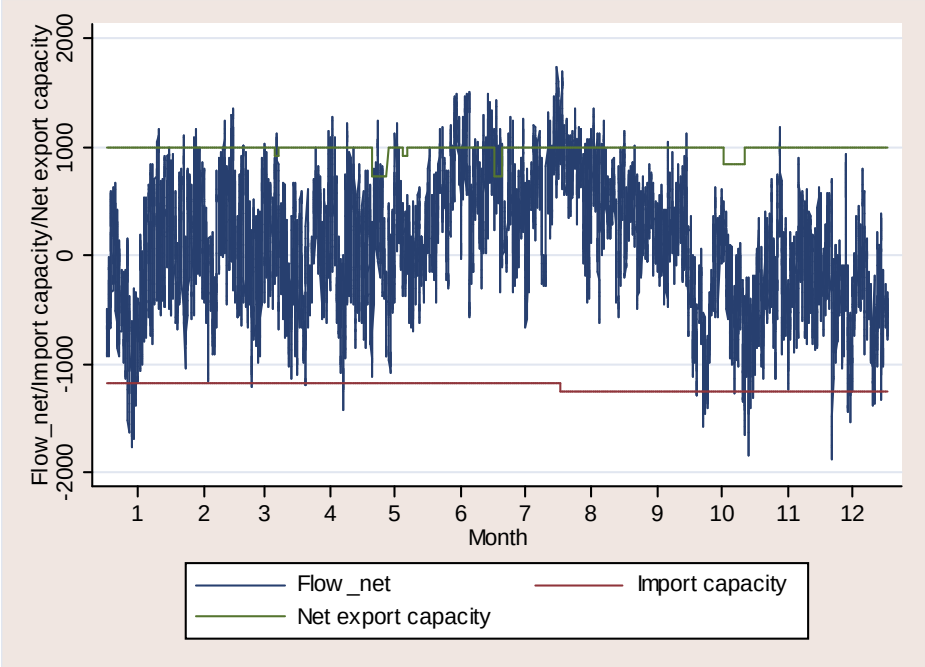
[18] Elia has concluded an agreement with Dutch system operator TenneT and its German counterparts RWE Net and Eon Netz on auctioning off capacity at international connections among system operators. This auction is organized by the Auction Office. Parties wishing to take part in the auction must be registered in Belgium as access responsible parties and in the Netherlands as program responsible parties.

[19] Information provided by Elia.

capacity ([confidential] MW) is used for the transit of power under the previously mentioned SEP contract.[20]

Figure 2.13 illustrates the real hourly flows of power on the Belgian-Dutch border in 2003 excluding the nominated (export) flows under the SEP contract.[21] Over the year, power flows in either direction, but predominantly from Belgium to the Netherlands. The time-weighted average of these flows is 113 MW, thus confirming that Belgium is a (net) exporter of power on this border. Net exports to the Netherlands were approximately 1 TWh in 2003.

Figure 2.13: Real power flows on the North border (MW), 2003



Note: Positive flows denote export from Belgium to the Netherlands, while negative flows denote Belgian imports from the Netherlands; straight lines denote import and (net) export capacity adjusted for planned maintenance. (Net) export capacity is defined as export capacity minus the time-weighted average of nominated SEP flows ([confidential] MW). Indentation reflects temporary reductions of capacity due to planned maintenance work.

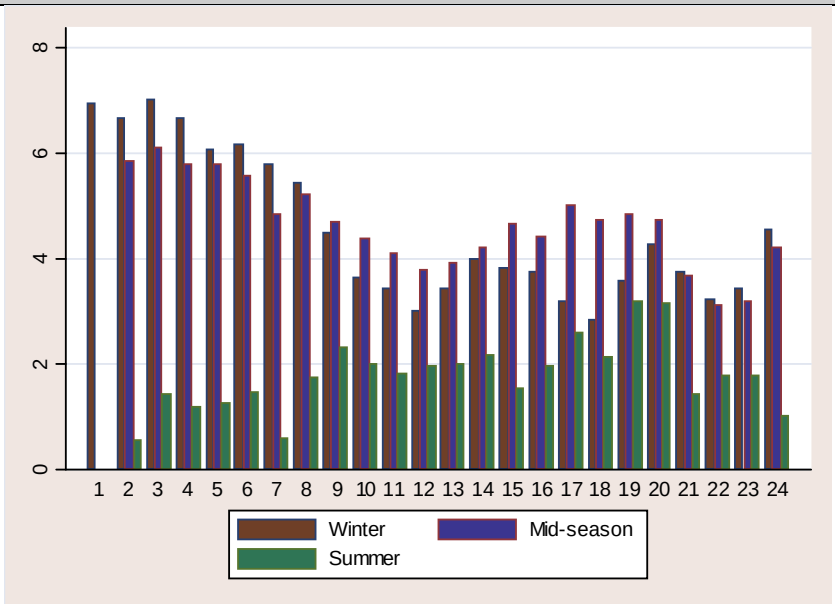
Source: London Economics' elaborations based on data provided by the CREG.

[20] In 2003, the time-weighted average of the nominated flows for this contract was [confidential] MW.

[21] In what follows we have adjusted the real flows by the hourly nominated flows under the SEP contract and the Belgian export capacity to the Netherlands (and other markets interlinked to the Netherlands) by subtracting the time-weighted average of the nominated SEP flows.

Imports from the Netherlands appear to be of little importance in satisfying the demand of electricity in Belgium. This fact is illustrated in Figure 2.14 which shows that import flows are on average less than 5% of hourly load and are relatively more important in winter and mid-season, and in off-peak hours.

Figure 2.14: Import flows from the Netherlands as a percentage of hourly demand by season (%), 2003

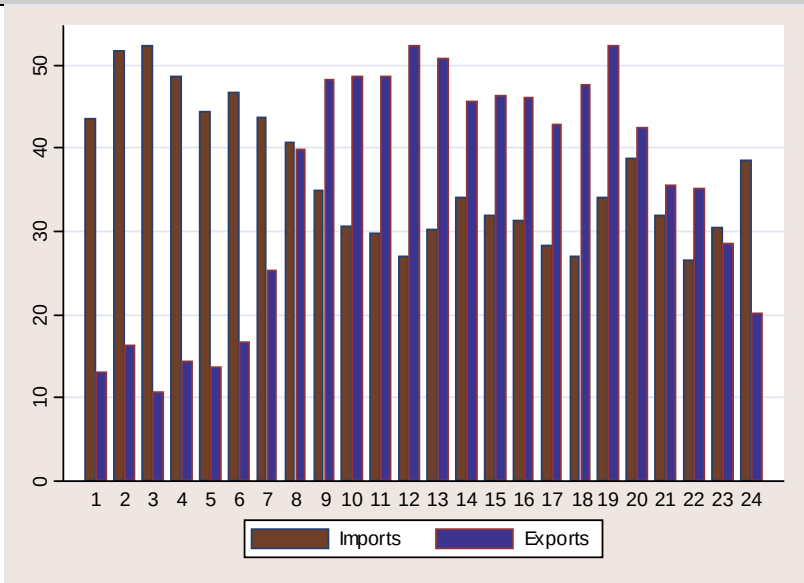


Source: London Economics' elaborations based on data provided by the CREG.

The (average) utilisation rate of import capacity has been 37% of the total, while that of the export capacity has been 53% of total. Figure 2.15 - Figure 2.17 illustrate the hourly average utilisation rates on the interconnection capacity for three seasons of the year, namely winter, mid-season and summer. The import capacity is more intensively used than the export capacity in winter and mid-season, during the off-peak hours. In all the other cases, it is the export capacity that is more intensively used. Interestingly, in summer the utilisation of the import capacity is very low and below that of the export capacity in all hours of the day (Figure 2.17).

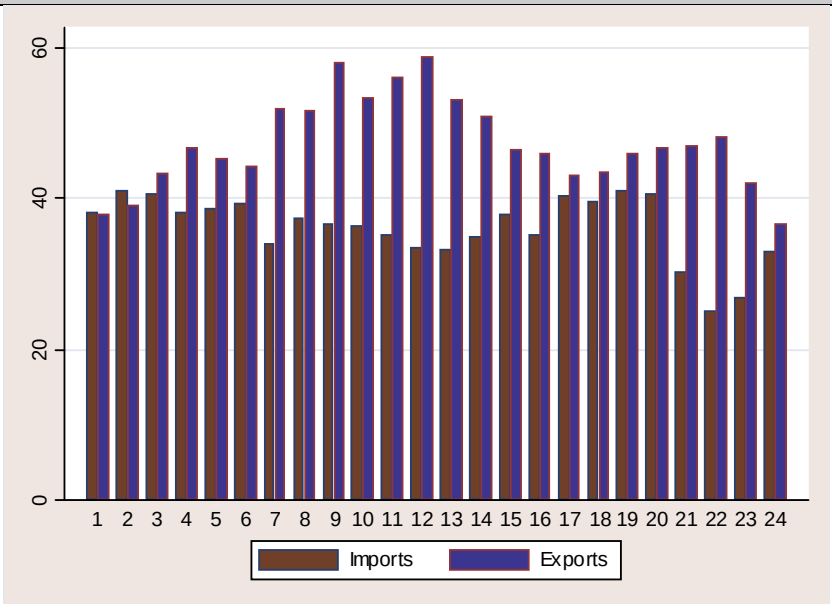
Comparing Figure 2.15-Figure 2.17 with Figure 2.8, we observe that the import capacity on the South border and the export capacity on the North border are intensely utilised in the same seasons/hours of the year. This suggests that at least part of the power imported from France is sold in the Dutch market.

Figure 2.15: Average utilisation rates of import and export capacity on the North border by hour (%), winter 2003



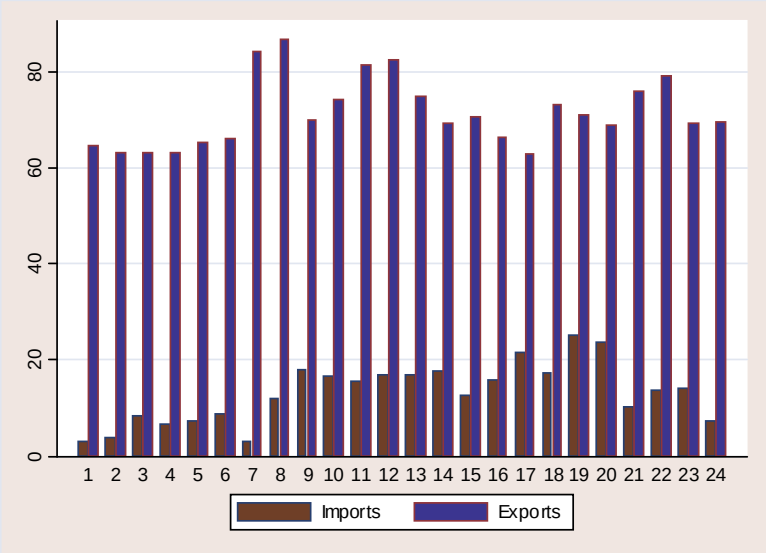
Source: London Economics' elaborations based on data provided by the CREG.

Figure 2.16: Average utilisation rates of import and export capacity on the North border by hour (%), mid-season 2003



Source: London Economics' elaborations based on data provided by the CREG.

Figure 2.17: Average utilisation rates of import and export capacity on the North border by hour (%), summer 2003

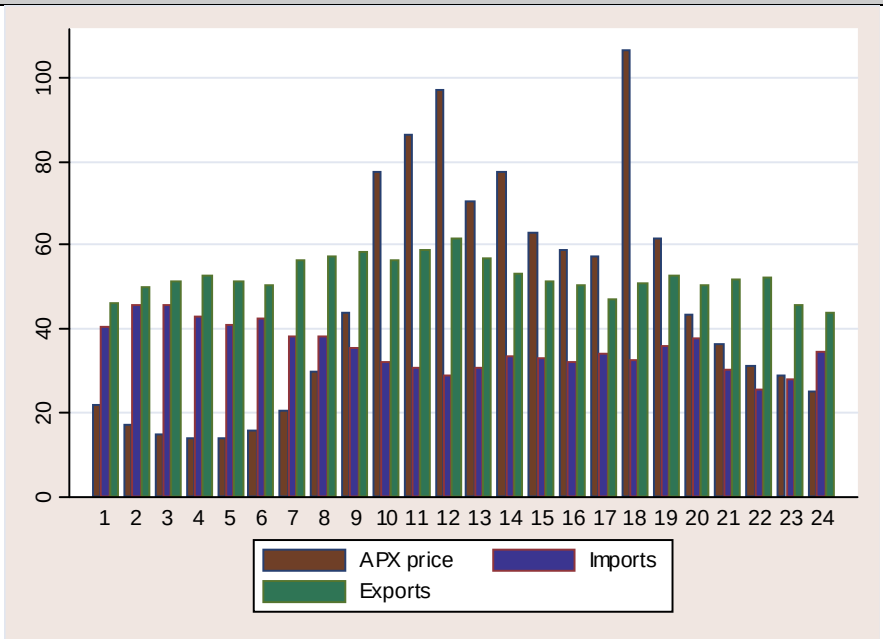


Source: London Economics' elaborations based on data provided by the CREG.

Unsurprisingly, the import (export) capacity is more intensively used when the Dutch wholesale prices are relatively low (high). This is clearly shown in Figure 2.18, where we plot hourly averages of the APX price, import and export capacity.

We further tested this explanation of power flows on the Belgian-Dutch border by calculating correlation measures between import (export) capacity and APX prices. Our analysis confirms the existence of a negative (positive) correlation between the utilisation of import (export) capacity and APX prices. The values of these correlation indices are –16% and 7%, respectively and, more importantly, both of them are statistically significant at a 5% confidence level.

Figure 2.18: Average Dutch prices, utilisation rates of import and export capacity on the North border by hour (%), 2003



Source: London Economics' elaborations based on data provided by the CREG.

Thus, the dynamics of power flows on the Dutch-Belgian border indicate that: 1) the utilisation of import and export capacity reacts to Dutch prices; and 2) the expected profitability of selling wholesale power in the Dutch market is higher than that of selling Dutch power in the Belgian market. The Brattle Group reports that wholesale electricity prices in Belgium are lower than in the Netherlands, but without providing any supportive evidence (The Brattle Group 2003, p. 8).

The relative unattractiveness of the Belgian market to Dutch suppliers is also shown by the auction prices for capacity on the interconnector between Belgium and the Netherlands (Table 2.3). The capacity price paid to export from Belgium to the Netherlands is always above that to import from the Netherlands to Belgium, whatever statistic we use to summarise capacity prices. Moreover, demanded daily capacity is below available capacity in 91% of the times in the direction Tennet→Elia and in 59% of the times in the direction Elia→Tennet.

Table 2.3: Capacity prices by type (€/MWh), 2003				
	Annual	Monthly	Daily	
Tennet→Elia	500	123	Average:	0.02
			Min:	0.00
			Max:	2.71
			No congestion:	91% of the times
Elia→Tennet	2190	427	Average:	1.12
			Min:	0.00
			Max:	27.70
			No congestion:	59% of the times

Source: London Economics' elaborations based on data sourced from TSO Auction BV.

How are the observations reconcilable with the observed higher end-user prices in Belgium than in the Netherlands?[22] What drives cross-border power flows are expectations of higher profits, which may or may not involve higher end-user prices. Two simple reasons of why higher end-user prices in Belgium may not immediately translate into higher profits can be higher costs of selling in Belgium and/or simply the fact that selling in the Belgian market is 'more difficult' than in the Dutch market (more costly). Some costs appear indeed to be higher in Belgium than in the Netherlands. For example, the Brattle Group (as reported in Newbery et al. 2003) estimates that grid charges are, at least for larger users, slightly higher in Belgium than in the Netherlands (6 €/MWh vs. 4 €/MWh).

Regarding the difficulty of selling in the Belgian market, it is important to note that, in the absence of an active hourly spot market in Belgium, imports from the Netherlands will primarily occur if these can be directly sold to end users. In order to be able to sell power to end users, shape contracts have to be offered, as consumption and delivery will have to be balanced within each 15-minute period. Since trade over the interconnector is limited to hourly constant quantities, this will necessarily expose the supplier involved to the Belgian balancing system.[23] Thus, providing power to Belgian customers will involve importing a profile consisting of hourly 'blocks' of power and selling and purchasing the difference with the actual consumption (based on quarterly-hourly values) from the Belgian system operator. Since buying

[22] Global Insights (2004) reports higher end-user prices in Belgium than in the Netherlands for medium industrial consumers and domestic consumers.

[23] Or Belgian producers. However, these will however not have an incentive to offer power at a much lower price than the balancing price.

Belgian balancing power is generally more expensive than buying Dutch wholesale power, and since the sale prices to the system operator are lower, this procedure of balancing demand and supply will constitute a mark-up to costs of providing power to Belgian end-users.

The magnitude of this mark-up will determine the ability to compete with Belgian generators, who can use their own generation units to balance supply and demand. The size will be affected by, on the one hand, the degree of variability of the end-users' power consumption profile, and, on the other hand, by the difference in price of balancing and wholesale power. According to Newbery et al. (2003), the incompatibility between hourly imports and the quarterly-hourly balancing requirement can be a large deterrent to serving Belgian customers from the Netherlands, especially when there is uncertainty over load.

Conclusion

To conclude, our analysis shows that Belgium is, on average, a (net) importer of power from France and a (net) exporter to the Netherlands. The fact that the (net) import flows from France are on average larger than the (net) export flows to the Netherlands suggests that Belgium is overall a net importer of power.

Our assessment is that, for to a number of reasons, import capacity can only provide very limited competition to incumbent players in the Belgian market. In our view, the most important reasons of why this seems to be the case are: a) scarce capacity for periods longer than a day on the French border; b) the absence of an active spot market; and c) the requirement imposed by infra-hourly balancing.

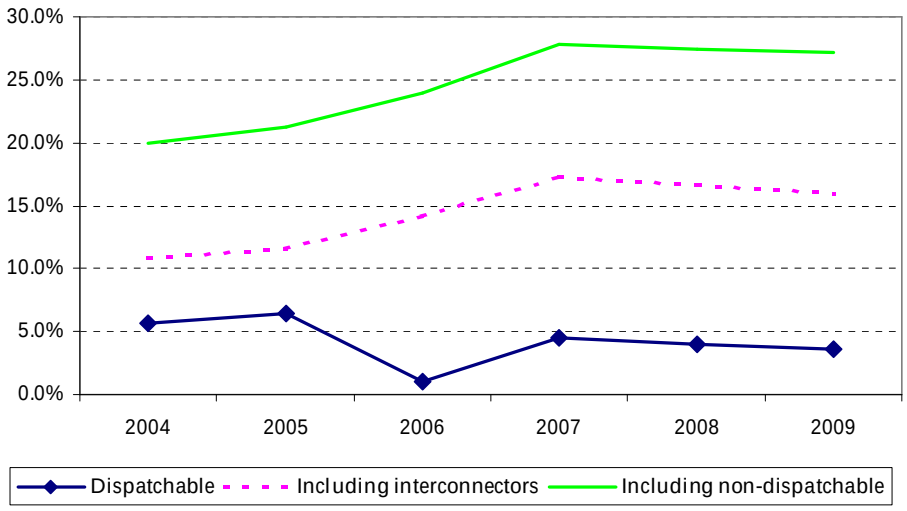
2.2.5 Capacity margin

In 2004, peak demand to be served by total installed generation is 12983MW, increasing to 14208MW by 2009 (data provided by CREG). Combining this data with the assumed installed generation until 2009, we can calculate the capacity margin for Belgium over the 2004-2009 for various definitions of generation capacity (Figure 2.19). The capacity margin for 2003 is 9.5%. The capacity margin based on despatchable generation only is 5.6 % in 2004 and expected to stay around 4.0% for most of the period. The only exception is in 2006, when, due to the decommissioning of 597MW of hard coal capacity), the margin falls at 1.1%.

These capacity margins would be considered from rather low to extremely low by international system reliability standards. However, while non-despatchable generation is less important for competition analysis, it is common to consider non-despatchable generation plus effective interconnection capacity in terms of security of supply. If we also include the interconnection capacity, assuming that power flows at the borders remain similar to those observed in 2003 and adding the planned additional

interconnection capacity from 2006 onwards, the margin is 10-11% of peak demand before 2006 and 15-16% after. Adding the non-despatchable capacity increases the margin at approximately 20% of peak demand before 1996 and above 25% after.

Figure 2.19: Capacity margin, 2004-2009



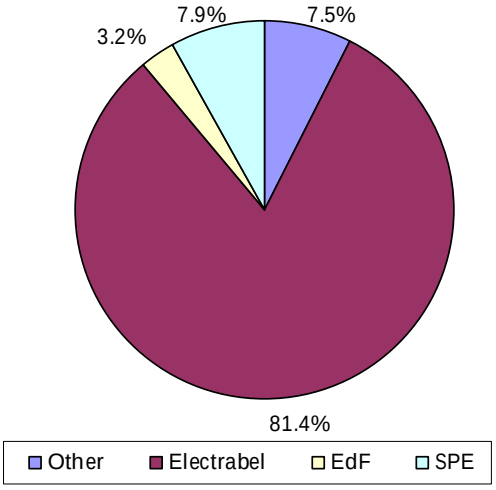
Source: London Economics' elaborations based on data provided by the CREG.

Thus, if i) commissioning and decommissioning of generation capacity proceeds as planned, ii) the use of existing interconnection capacity does not dramatically change relative to 2003, and iii) the new interconnector capacity is built as planned, the capacity margin should approximately be 10-27% of peak demand. This suggests that there is not expected to be any significant excess capacity in Belgium, but that security of supply standard capacity margins are expected to be maintained over the next few years.

2.2.6 Market shares

Electrabel and SPE are the main generators in the Belgian electricity market. According to the CREG's data, Electrabel owns 12,195 MW of installed capacity, which is equivalent to 81.4% of the total. The remaining generation capacity is owned by SPE (1,186 MW), the second largest producer, EdF (481 MW), and a fringe of other smaller players (1,118 MW). Figure 2.20 illustrates each player's share in total generation capacity. As it will become clear later, ignoring the interconnector capacity overstates only very marginally the true position of Electrabel in the Belgium power market.

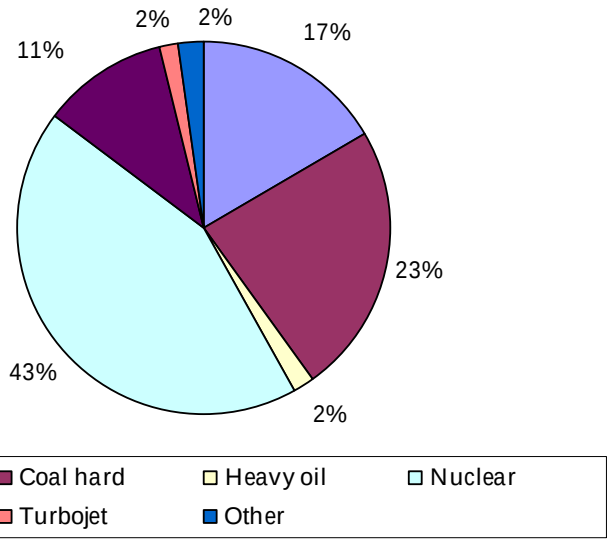
Figure 2.20: Generating capacity ownership in Belgium, 2003



Source: CREG

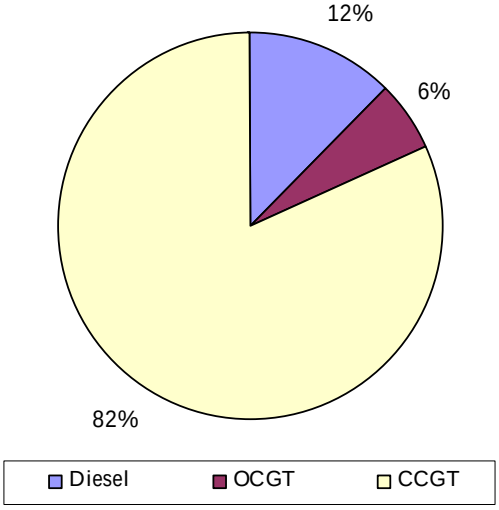
As shown in Figure 2.21, Electrabel controls the totality of coal, pumped storage, turbojet and heavy oil capacity, and approximately 92% of nuclear capacity (5,281 MW) and 68% of CCGT capacity (2,031 MW). CCGT (968 MW) accounts for most of SPE's installed capacity (Figure 2.22).

Figure 2.21: Electrabel's installed capacity by plant type, 2003



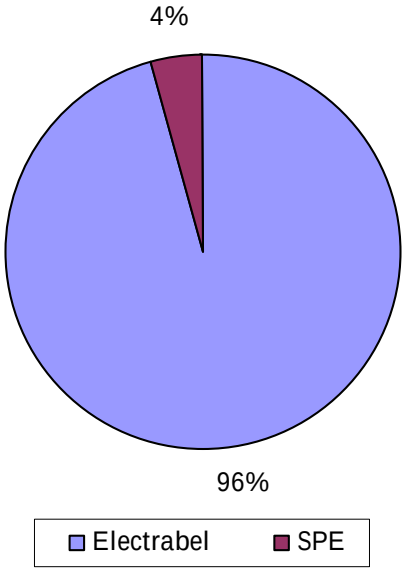
Source: CREG

Figure 2.22: SPE's installed capacity by plant type, 2003



Source: CREG

Figure 2.23: Peak capacity by generator, 2003



Source: CREG

From the previous figures, a number of important points emerge.

- Electrabel has a 'pivotal' role, meaning that its plants are essential for continued supply. This means that Electrabel can unilaterally exercise a considerable amount of market power, raising prices above marginal costs. There is a huge asymmetry between the largest generator (Electrabel) and the second largest (SPE). In comparison to Electrabel, SPE owns a small amount of generation capacity.

- Electrabel possesses a wide range of plant types, including nuclear, thermal, and pumped storage (Figure 2.21). The nuclear plants will have the lowest fuel costs of any plant on the system[24], and will be relatively inflexible. Electrabel also possesses gas, coal, and oil thermal plants, giving it fuel price risk management opportunities (including storage) not enjoyed by SPE, whose portfolio is almost all gas (the hardest fuel to store). Finally, the pumped storage units will be among the most flexible, and also have the best characteristics for providing ancillary services.

- Electrabel controls virtually the totality of peaking plants (turbojet, pumped storage and OCGT; Figure 2.23). Over the period 2005-2009, the CREG assumes that 880 MW of OCGT capacity will be built in Belgium: 280 MW by Electrabel and 600 MW by others. If these assumptions are correct, this could attenuate the concentration of peak capacity in the Belgian market.

- SPE is trying to strengthen its position in the Belgian market. We understand that SPE is actively seeking a major European partner to support its development and growth in the Benelux. To that end, EDF took a 10% participation in SPE in December 2001. However, in late 2003, EDF decided to withdraw from SPE and SPE announced at the time that it wanted to take the time to redefine its strategy in the energy market. More recently, Essent, Nuon and, as a joint venture, Centrica and Gaz de France, have been rumoured to be potential strategic partners.[25]

- EdF owns 481 MW of nuclear capacity (3.2% of total). As nuclear capacity is very inflexible and is typically run all the time, EdF does not currently have the capacity to compete against Electrabel and SPE in close-to-real-time markets. However, the competitive position of EdF in the Belgian market could become stronger if it manages to obtain substantial portions of import capacity from France and/or following possible modifications of the current rules of the Belgian

[24] There are no large non-pumped storage hydro plants which might be considered as lower cost.

[25] De Tijd, 1st October 2004

balancing mechanism (see later). This could more likely be the case after the planned expansion of the interconnector capacity on the South border takes place.

In what follows, we will describe how the current generation market structure raises serious issues for the functioning of the Belgian electricity markets.

Allocative and productive efficiency

In the present circumstances, Electrabel has virtually no competitive pressure to align electricity prices to marginal costs. If, for example, Electrabel decided to price power significantly above marginal generation costs, no force in the market could act to prevent Electrabel from doing so. As the demand for electricity is quite price-inelastic, economic theory would suggest this pricing strategy to be highly profitable. On the contrary, SPE and EdF would be able adopt a similar conduct only if Electrabel decided to acquiesce, i.e. not to enter in competition with them. This is because Electrabel alone is able to satisfy the system load 99% of the time.

In addition to not promoting both allocative and productive efficiency, the structure of the generation market in Belgium is a cause of concern because it could have a detrimental effect on market liquidity and new entry in generation, trading and supply. Entry could well be deterred by possible market manipulation and Electrabel's position in the provision of balancing power and in the gas market. We provide below a few examples of market manipulation and possible strategic use of balancing power, which originates from the control of peak capacity.

Possible price manipulation

The structure of the Belgian generation market gives the incumbent a persistent incentive and ability to exercise market power. Concerns over the possible exercise of market power could persuade market participants to avoid trading actively in any markets in which the incumbent participates, severely reducing market liquidity. High concentration itself implies a limited number of participants who could provide liquidity.

Electrabel's ability to manipulate wholesale prices may have important implications also for downstream markets. As the price of wholesale power enters directly the price that is offered by traders and suppliers to power users, artificially high wholesale prices would directly translate into higher costs for these operators but not for Electrabel. What matters for Electrabel trading and supply is only the cost of power generation in various hours of the day, which by definition is not affected by manipulation. So, while Electrabel's competitors in these markets would struggle to increase or maintain market share, the supply and trading arms of Electrabel would largely be unaffected by these (higher) prices. In fact, Electrabel trading and supply could undercut other players offers and increase / protect their market

share. Factors like Electrabel's brand name, its perceived reliability, market presence and others, can only strengthen the short-term mechanisms described above.

If there were no barriers to entry, in the long run, this situation cannot be expected to persist as high (average) wholesale prices would encourage new entry in generation.[26] However, this tendency to re-equilibrate requires absence or low impediments to enter the generation market; i.e. the attractiveness of entry is not a condition that ensures new entry.

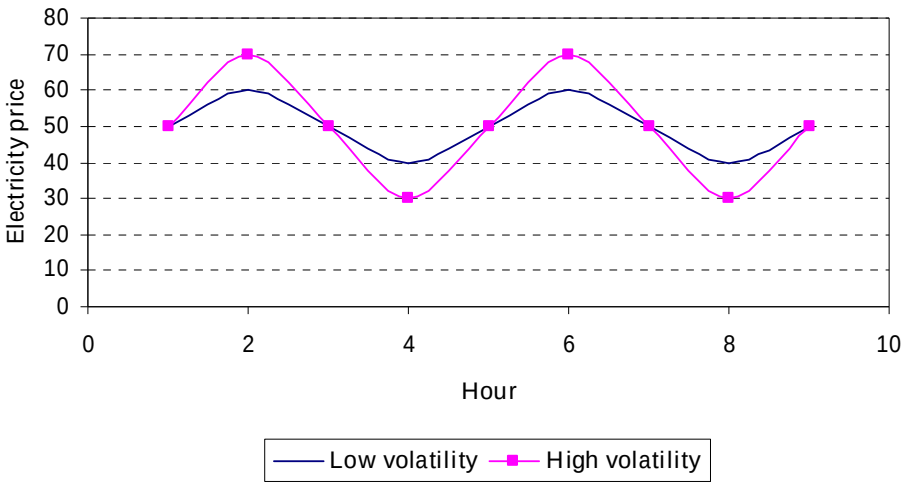
Price manipulation need not be limited to obvious instances of raising price. Electrabel could engage in a limit pricing strategy, i.e., price at levels sufficient to earn an extra-normal profit but still low enough so as not to attract new entry.[27] Electrabel's wide array of generation capacity also gives it the potential to engage in price strategies that SPE or a new entrant could not engage in. For example, a certain amount of inflexible capacity is useful in that it could allow Electrabel to "commit" to lower prices should a new entrant try to gain market share.

Price manipulation can also be aimed at increasing the volatility of prices as opposed to raising their average level. Figure 2.24 shows two hypothetical price series that have the same average of €50 MWh, but different volatility. In such a situation, a risk-averse buyer would be willing to buy power on the forward market (usually at a higher price) instead of the spot market. However, this automatically translates into higher supply costs that, as it might be difficult to pass these costs on to consumers, will reduce the (expected) profitability of entering the downstream markets. In essence, this mechanism will reduce the number of players in the trading and supply market.

[26] This is indeed what happened in the early years of existence of the England and Wales Pool.

[27] The later chapter on barriers provides evidence supporting this hypothesis.

Figure 2.24: High and low price volatility series, €/MWh



Source: London Economics

We have not seen any evidence to date that the incumbent generator in Belgium has exercised market power. However, it is important to stress that even the (credible) threat of such behaviour, or simply the uncertainty of how the incumbent will react after entry has occurred, could be enough to deter entry. Needless to say, the mere fact that an incumbent player has the possibility of adopting an abusive behaviour like that outlined before, which is the clearly the case of the Belgian market, could have a detrimental effect on entry in all electricity markets.

Possible distortions arising from the balancing mechanism

In this section we argue that the balancing mechanism in Belgium may distort the generation market in favour of market players that own generation assets in Belgium, especially Electrabel. We first briefly describe the mechanism for system balancing. We then explain the implications of the Belgian balancing system for competition in the generation market.

System balancing

In Belgium, the balancing mechanism is centred around Access Responsible Parties (ARPs), who are required to submit quarter-hourly balanced schedules of electricity consumption and production. Each ARP is responsible to maintain the balance within its balancing perimeter.[28] All parties that inject/withdraw power in that balancing perimeter have the

[28] The balancing perimeter is defined as any off-take and injection points that are allocated to an ARP.

obligation to nominate their ARP and to provide all the information it needs to balance production and consumption.

Imbalance charges are calculated with a formula, where imbalance prices are related to the realised day-ahead prices of APX and Powernext. The formula differs by time of day, time of year and with the size of imbalance. Imbalance charges are capped at a certain (varying) maximum price. The exact formulae are published on the website of Elia. As an example, Table 2.4 shows the formulae that apply to imbalances below a certain threshold T during the winter months. The table illustrates that the formula differs by time period and whether the imbalance is negative (injection is less than off-take) or positive. It also indicates that the charges depend on the realised APX-prices (APX) and are limited to a maximum tariff. For example, for negative imbalances during the day period this cap amounts to 75 €/MWh. For imbalances above a certain threshold T another set of formulae applies, leading to higher charges. For more detailed descriptions of the formulae we refer to www.elia.be.

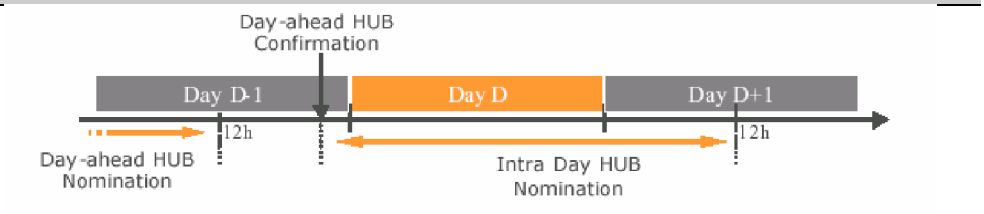
Table 2.4: Charges for imbalances below threshold T during winter months (€/MWh), 2004.

	Day period (7:00-23:00)	Night period (23:00-07:00)
Negative imbalance	Min (175%*APX, 75)	Min (175%*APX, 35)
Positive imbalance	Min (25%*APX, 30)	Min (25%*APX, 20)

Source: Elia website

In order to balance any discrepancies between injection with off-takes, ARPs can buy electricity from and sell it to each other. This is done on the Belgian 'hub'. ARPs must submit to Elia an access schedule of all injections and off takes (also known as a 'nomination') on a day-ahead basis. Since October 1st 2003, bilateral exchanges among ARPs can be agreed on an intra-day basis and the nominations to Elia be submitted until the day after (intra-day hub). This process is illustrated in Figure 2.25.

Figure 2.25: Day ahead and intra day nomination process



Source: Elia website

Market participants' balancing

If the balancing market were perfectly competitive, the price paid for one MW of balancing power should reflect the marginal cost of flexible generating plants that can participate actively in this market.[29] The standard practise to design the imbalance charges is that of adding a surcharge on the price determined in power markets (day-ahead, balancing market, etc.), or devising the rules in a way that produce this outcome, e.g. in the England and Wales power market rules (NETA). It is in this way hoped that market participants have 'enough' incentives to stay in balance. Asymmetric imbalance prices (one of negative and one for positive imbalances) are another notable feature of imbalance charges. How do the Belgian imbalance charges compare with those in other markets?

The average APX prices in 2004 was 37.4 €/MWh in peak hours and 20 €/MWh off-peak. Applying the formulae in Table 2.4 imply that a market participant who was hypothetically short of power (negative imbalance) would face balancing charges above 65 €/MWh for the day period and 35 €/MWh for the night period. If the same type of imbalance occurred in the Dutch market, the corresponding price would have been 90.7 €/MWh in the peak hours and 51.1 €/MWh off peak (Table 2.5). NETA presents somewhat lower balancing charges. In the same way, if a market participant had a long position (positive imbalance), Elia would pay 9.4 €/MWh during the day period (8.9 €/MWh in the Dutch market and 26.4 €/MWh under NETA) and 5 €/MWh during the night period (5.5 €/MWh in the Dutch market and 21.8 €/MWh under NETA). Therefore, we conclude that the Belgian balancing mechanism is less penalising than the Dutch system but more expensive than NETA's[30]. Could this be problematic for the functioning of the market?

[29] To participate in a balancing market, a generating plant must be able to increase production (ramp-up) quickly and at short notice.

[30] A notable characteristic of the NETA balancing mechanism is that its prices are less volatile than in the Dutch balancing mechanism. The full distribution of the Dutch and NETA BM prices is shown in Annex 3.

Table 2.5: Balancing charges in Belgium, Netherlands and England & Wales (€/MWh), January-February 2004

		Belgian BM		Dutch BM		NETA BM	
		Peak	Off-peak	Peak	Off-peak	Peak	Off-peak
Negative imbalance	Mean	65	35	90.7	51.1	38.2	24.8
	SD	41.5	11.4	72.3	54.4	22.8	7.6
	SD / Mean	63.4%	32.5%	79.7%	106.5%	59.8%	30.7%
Positive imbalance	Mean	9.4	5	8.9	5.5	26.4	21.8
	SD	41.5	11.4	34.7	36	9.1	2.1
	SD / Mean	63.4%	32.5%	389.9%	654.5%	34.5%	9.6%

Notes: The Belgian balancing charges have been constructed by using the average APX prices in the period January-February 2004; SD denotes standard deviation; the SD / Mean for the Belgian market has been constructed by using the APX prices and assuming that the imbalance charges are 175% of the APX price.

Source: London Economics' elaborations on Tennet data and data from www.bmreports.com

The combination of high balancing costs and high market concentration may lead to high electricity prices in real time markets. For example, consider an electricity consumer who wishes to buy power to address expected shortfalls. The consumer can purchase this power from the balancing mechanism (by 'going short') at prices of 65 €/MWh in peak hours and 35 €/MWh in off-peak hours.[31] Therefore, the consumer will not accept prices higher than these from other suppliers.[32][33] If the generation market is competitive, prices in this market will reflect the marginal costs of price-setting plants. If, conversely, the generation market is dominated by a few suppliers, they may be able to charge prices above competitive levels, up to the balancing charges.

High prices in real time markets may distort competition in favour of generators. This is because, rather than risk paying high charges, consumers would rather sign longer-term "full requirements" contracts that prevent

[31] On this point we cannot be more precise because the conditions that regulate these transactions are set in private contracts between seller and buyer and therefore are not in the public domain. Strictly speaking, even the balancing charges listed in Table 2.4 concern ARPs and do not necessarily apply to market players that are not ARPs when they are out of balance. Our argumentation is constructed on the basis of some contracts between buyer and seller that have been brought to our attention. This adds a further degree of opacity to transactions concluded in the Belgian generation market that may have a detrimental effect on competition.

[32] This would not of course apply to consumers who can self-supply or shed load at reasonable cost.

[33] In competitive markets, the balancing market, being a real time market, provides an indication of the upper bound for average wholesale price levels. If average prices in the day ahead or intra-day market were higher than prices paid on average for imbalances, market players would have an incentive to incur imbalances rather than contract for energy day-ahead.

exposure to high charges at short notice. Full requirements contracts can only be offered by market participants with generating facilities.

This possibility of distortion exists in Belgium. Electrabel controls more than 80% of total generation capacity and approximately 96% of peak capacity. If, for example, Electrabel wished to sell power at a price above its marginal cost (or manipulate the market in this direction), its competitors could only exert a limited restraining influence.

The risk of being without a full requirement contract appears high. Discussions held with market participants have indicated to us that matching their profile with traded products and/or contracts[34] (what we call 'self-balancing') is indeed a risky option.[35] Thus, many prefer to 'outsource' their balancing requirements to somebody who is willing to accept the risk for a price. This typically happens either (implicitly) within a "full requirements" contract or through a "balancing contract", where the supplier provides the 'residual' power, i.e. the difference between consumption and purchases/production. So, if a market player does not have a full requirements scheme, he also will have to purchase balancing cover.

The possibility of purchasing balancing contracts does not alter the distortion in favour of Belgian generators. These contracts could be priced in a way[36] to reduce the advantages of opting out of "full requirements" schemes. This implies that not only the suppliers that are unable to provide balancing services (essentially traders and owners of single generation units) will find it more difficult to compete[37], but also that power buyers could find simpler, traded products[38] of a limited interest.

Other characteristics of the market compound this distortion. These include:

- Very limited choice to market participants because, for example, only very few simple products are currently traded;
- The trading market appears rather opaque and illiquid[39]; and

[34] This of course exposes them to the risk (and the charges) of less than perfect balancing.

[35] The major risk is of course that to buy power in a very illiquid and quasi-monopolistic market. There are also other risks (and costs) arising from the operational side of the process, such as nominations, possible errors in forecasting the profile, etc.

[36] Or, more generally, require very demanding conditions.

[37] In particular, (pure) traders appear at considerable disadvantage because they have only very limited flexibility to still modify their injections on the grid a few hours before actual off-take. In contrast, market players with access to physical generation capacity can still react to demand changes by adjusting their injection into the system during the day.

[38] As market players will have to buy balancing in addition to energy, if balancing is priced sufficiently high (in both ways: very high when short and very low when long), to have an average price that is comparable to that offered in full requirements contracts, the price of energy should be lower.

[39] See Chapter 3 for details.

- Possible exercise of market power. For example, if a customer needs to buy a few hours per day of peak power, it is not clear at what price he would be able to buy it. The market structure in generation is such that there is virtually no constraint for this price to reach the upper bound (the balancing price).

These features of the market imply that the balancing mechanism plays a bigger role than it should normally do, either as an alternative or as an element of risk.[40] This is a consequence of the inexistence of many viable alternatives or simply because they are priced excessively.

To conclude, the Belgian electricity market has a number of characteristics that work in favour of market participants that control portfolio generating facilities (who can replace the absence of markets). Pure traders and owners of simple generating units appear at considerable disadvantage because they can only offer simple products relative to the general requirements of power users. We would also like to note that the ability to compete against Belgian based generators appears even lower if we consider the fact that the imbalance price ARPs have to pay increase significantly if the imbalance exceeds 10% of the nomination.

2.3 Mitigating factors

There exist two factors that could mitigate the potential competition issues in the generation market. One of them is interconnection capacity; the other is VPP auctions. We address both below.

2.3.1 Interconnection capacity

Interconnection capacity is one of the means by which potential entrants might enter the Belgian production, supply, and trading markets in the short term. Belgium benefits from 3257 MW of import capacity in winter (2000 MW from France plus 1257 MW from the Netherlands), 2757 in mid season (1500 MW from France plus 1257MW from the Netherlands) and 2257 (1000 MW from France plus 1257 MW from the Netherlands) in summer. This amount of capacity is sizeable (it is 20-24% of peak demand by season) and, if it could be effectively used to compete against the incumbent generators, the generation market would potentially become more competitive. There are however some severe limitations that prevent using the interconnector capacity from competing against the incumbent generators. We discuss them below.

[40] The balancing market should only have a residual nature, where market operators are not expected to procure substantial amounts of power (relative to their needs). For example, we have shown that balancing market in the Netherlands is more penalising than that in Belgium, but this does not imply that the Dutch market functions less well. On the contrary, the Dutch power market is more competitive than the Belgian (see analysis in Section 2.5).

French border

- Long-term capacity. A substantial portion of import capacity (approximately [confidential]% of the annual (average) import capacity) is reserved for long term contracts, the beneficiaries of which are Electrabel and SPE. If we exclude the import capacity that is reserved for the SEP contract, the fraction of capacity that is reserved for Electrabel's and SPE's long-term contracts is [confidential]% of the total.
- Monthly capacity. As we pointed out earlier in the chapter, this capacity is scarce (on average [confidential] MW in 2003) but highly valuable (demand is on average 15 times the amount that is declared to be available). It is important to note that Electrabel and SPE have the possibility to be assigned a fraction of this capacity as well. Moreover, the allocation mechanism (see Annex 4) is not particularly transparent[41] and, in case of scarcity, designed to assign the *same* amount of capacity to each ARP.[42] This implies that the allocation mechanism penalises ARPs seeking large amount of capacity (and who are willing to pay for it).
- Daily capacity. The amount of daily capacity that RTE-Elia make available is somewhat larger than monthly capacity (on average [confidential] MW in 2003). This capacity is 2/3 of time not completely subscribed. In addition, it is worth noticing that Electrabel and SPE can also bid for this capacity. The allocation mechanism of daily capacity is broadly similar to that to allocate the monthly capacity and therefore it is subject to the same concerns expressed above. In 2003, the lack of use of the interconnector capacity on the short-term basis was generalised to all times of the year, with the exception of the peak hours in January, June, and November.

Dutch border

Importing from the Netherlands does not appear to be an attractive option to suppliers in the Belgian market. This is evidenced by the dynamics of power flows on this border and the prices paid at auctions for capacity on the Belgian-Netherlands border (see Table 2.3).

[41] The allocation mechanism of capacity on this border is such that understanding why a particular allocation of capacity is made requires information on how many blocks have been requested by others and when the requests have been made. Conversely, market based mechanisms allocate capacity on the basis of how market participants' value it and this is known (capacity price).

[42] This is a direct consequence of the scoring system of the bids. For example, if 100 MW of capacity are available and there are five applications, of which four of 25 MW each (1 bloc) and one of 50 MW, the ARP that is requesting 50 MW will have only 25 MW. In addition, an ARP cannot bid for more than 100 MW of capacity (four bids).

In the context of potential competition from the Netherlands, it is important to mention that Electrabel owns 4,650 MW of capacity in the Netherlands. Electrabel could theoretically utilise the entire Dutch-Belgian interconnector capacity if not prevented by existing interconnector rules.[43]

On the positive side, it is worth noticing that capacity on this border is offered for periods longer than a month and via market mechanisms.

Existing balancing rules

The ability to compete in the Belgian market by relying on imports from neighbouring countries depends, among other things, on the balancing rules in Belgium. We explain below why, in our view, the existing balancing rules do not encourage competition in Belgium.

While the import capacity is limited to hourly constant quantities, the balancing rules require balancing injections and off-takes for each 15 minute period. This will necessarily expose importers of power to the Belgian balancing charges, thus increasing the costs of supplying consumers in Belgium. Recent research done by Newbery et al. al. (2003) suggests that selling power imported from the Netherlands in Belgium does not appear economically viable, especially when there is high uncertainty in the load. This argument might even be more relevant for new entrants in a market, who presumably have less access to historical customer profiles than the incumbent. In the case of power imported from France, this seems less of a problem because of a considerable wholesale price differential between France and Belgium.

Like all other players, traders have to nominate with Elia one day in advance the supply and run the risk of having to pay high imbalance penalties if actual consumption differs from the nomination. However, (pure) traders have only very limited flexibility to still modify the import level a few hours before actual off-take on the grid.[44] In contrast, market players with access to physical generation capacity can still react to demand changes by adjusting their injection into the system during the day. Such a situation works against traders who rely exclusively on electricity imports.

As a result, an increase in electricity imports does not necessarily mean that more competitors will be present on the Belgian market. Indeed, it is important to distinguish importers with access to domestic generation capacity from those who do not. An adjustment to the current balancing and import rules may then be necessary to obtain the desired outcome.

[43] Auction rules forbid any one party obtaining more than 400 MW of interconnector capacity.

[44] In the current context, it is indeed highly unusual that an intra-day nomination is being made for the use of the interconnector that would allow market players to modify their own intra-day nominations.

2.3.2 Virtual Power Plant (VPP) auctions

As we have discussed so far, the Belgian generation market is extremely concentrated with one single firm representing more than 80% of both production and capacity. In view of this, and as a condition for allowing Electrabel Customer Solutions (ECS) to be designated the default supplier in the areas served by the mixed intercommunales, the Belgian Competition Council imposed the requirement on Electrabel to offer up to 1,200 MW of capacity for sale through virtual power plant (VPP) auctions. Access to this virtual capacity will in principle have to be offered by Electrabel until 2008. We say in principle, because the actual amount made available for VPPs is net of any increase in interconnector capacity and net generation capacity by generators other than Electrabel, and net of 100MW that Electrabel will make available on the Belgian power exchange once the latter is established. It is thus possible that the total amount made available for VPPs will be smaller than 1,200 MW and the limit is reached before 2008.

VPPs are option contracts replicating the outputs of power plants. A VPP contract is an option to buy electricity at a pre-set price. The energy price that is pre-determined for the auction is supposed to reflect variable costs (e.g., in the case of baseload VPP, energy price represents off-peak variable costs such as those of a nuclear plant). The energy price is set prior to the auction after consultation with the relevant parties.

The capacity price, as revealed by the auctioning process, is expected to cover the seller's fixed costs. The presence of a reserve price has been used to prevent an outcome where the prices of the auctions are abnormally low.

Two basic types of virtual power plants are sold in these auctions: (a) base-load VPPs, whose strike prices approach the variable cost of a nuclear power plant. The baseload options would be expected to be exercised around the clock for the duration of the contract, as the marginal system plant which sets the marginal value of energy is likely to always have higher marginal costs than a nuclear plant. The second type of VPP is peak-load. Peak-load VPP strike prices approach the variable cost of a peak load plant (and so the options would be exercised only at peak times). Base-load and peak-load VPP are offered in a variety of durations ranging from 3 months to three years.

The division of capacity to be auctioned by Electrabel is 2/3 base capacity and 1/3 peak capacity. Since peak and baseload energy are to a large extent complementary products, the combined offering of the two types of products increases the attractiveness of the auction from the point of view of potential bidders.

An important rule imposed on the Belgian VPP auctions is that no single buyer can acquire more than 40% of the capacity for sale. The rationale for this rule is, presumably, to ensure that more market players are able to participate in the generation market via the VPP. However, its net effect is questionable, since it effectively means no one player will be able to gain a more than 480MW, or 3.2% of capacity and 3.5% of peak demand, and so the

rule might prevent any player from gaining a significant foothold vis-à-vis Electrabel. Such a rule might prove more important if the VPP is expanded beyond 1200MW.

Results of Electrabel's VPP auctions

The total sales of virtual capacity in the first three VPP auctions have totalled 735 MW (230 MW in the first, 265 MW in the second and 240 MW in the third) of capacity. This aggregation is however problematic because these totals correspond to capacity rights sold with different durations. This is particularly important because, as we have seen from the report by PriceWaterhouseCoopers (PWC) of April 2004 (before the third auction took place), a large fraction of the products sold in the first two auctions are of short duration (mainly 3-month and 6-month).

In the table below we make use of the information provided by Endex[45] about the first three Belgian VPP auctions in terms of the impact that they are so far having in releasing capacity away from the control of Electrabel. The table below indicates the amounts of baseload and peakload Electrabel capacity that is under the control of other markets players in the quarter beginning in each date indicated in the left column.

[45] http://www.endex.nl/vpp/public/results.php.

Table 2.6: Virtual capacity released through VPP auctions measured at each point in time (MW)

Quarter beginning:	Baseload	Peakload	Total
Apr-04	245	120	365
Jul-04	385	190	575
Oct-04	325	125	450
Jan-05	140	50	190
Apr-05	140	45	185
Jul-05	140	25	165
Oct-05	140	15	155

Source: London Economics' elaborations.

These values were computed taking into account the duration of the products being sold at each auction. We note that the values from October 2004 onward will in all likelihood be increased by upcoming auctions if the auctioning of virtual capacity continues. The number for July 2004 is a firm estimate of the amount of Electrabel's capacity that will be outside its control at that date, since no new products for that date will be made available.

Additional discussion of the merits of VPP auction will be provided later in the report. For the purpose of this section, it will be sufficient to note that the amount of capacity offered through VPP is not likely to significantly affect competition in the generation market for the following reasons:

- The maximum capacity currently offered through VPP is 12.4% of the average load and 8.6% of peak load; and a single player is limited to 40% of this.
- The parameters that determine how much capacity will be actually sold and for which time span are essentially under the control of Electrabel.

A more detailed analysis of the impacts of interconnection capacity and VPP auctions on market concentration will be provided in the following section.

2.4 Market concentration

In this section, we calculate concentration measures for the generation market. It is well known that the Belgian generation market has very high concentration, but development of rigorous measures of concentration will enable us to undertake additional useful analysis and provide a rigorous framework for market analysis. For example, we can perform scenarios that

describe by how much concentration should fall, given a certain change in market structure. Alternatively, we can place bounds on concentration relative to the uncertainty of measurement of ownership-shares of certain parts of the network. For example, while the allocation of interconnection capacity to different generation owners introduces some uncertainty in calculating concentration, assuming 'atomistic' ownership shares puts a lower bound on the measured concentration. We discuss this in more detail below.

Table 2.7 reports our calculations of the Herfindahl-Hirschman Index (HHI)[46] on the basis of the total installed capacity in Belgium as well as taking into account the existing interconnection from France and the Netherlands as used in 2003.[47] This interconnection has been allocated to known players in the market on the basis of the (annualised) flows of power at the borders nominated by each player. Our calculations also consider the likely effects on market concentration of the long-term contracts modifications occurred between Electrabel and EdF at the end of 2003[48].

We perform two sets of calculations: one in which we only allocate the long-term (net) import capacity[49] from France to Electrabel and SPE, and a second one in which we allocate the total (net) interconnection capacity, as used in 2003.[50] The rationale for such distinction is that the long-term (net) capacity is reserved to holders of long-term contracts and therefore is not made available to other players in the market. Based on the nominated flows in 2003, the long-term capacity that is considered in this exercise is:

- Import capacity under the Chooz B contract [confidential][51]; and
- Export capacity under the Synatom contract – [confidential].

Our estimate of the HHI is 6,756 if we only consider the total installed capacity (excluding auto-producers and independent producers). If we also

[46] Using the Herfindahl-Hirschman Index (HHI) is the most common way to measure concentration in industrial markets. The HHI is a simple, yet sophisticated way of measuring industry concentration. The HHI is obtained by squaring the market-share of the various players, and then summing those squares. As such, the HHI is reflective not just of market shares, but also of the size distribution of all firms in the market. It enables the comparison, for example, of a market with three players where one has a large share, versus a market with two players where shares are equally distributed (50-50 in this case).

[47] Strictly speaking, this is not a measure of capacity, but only of the average utilization of the interconnection capacity on an annual basis. This is calculated by summing the flows nominated by each player in the market over the year and dividing by the total number of hours in one year.

[48] At the end of 2003, EdF and Electrabel modified their agreements in relation to the output of the power stations Tricastin and Tihange 1. [confidential]

[49] The net import capacity is defined as import minus export capacity.

[50] That is the sum of the long-term (net) import capacity, the monthly and daily (net) import capacity with France, and the yearly, monthly and daily net import capacity with the Netherlands.

[51] [confidential] (see Section 2.2.4).

include the interconnection capacity, the HHI ranges from 6,533 to 6,711, depending on how the 'available' net import capacity with France and Netherlands is allocated.[52] The lower bound for the HHI is obtained when we allocate only the historical import capacity from France to Electrabel and SPE, and the remaining (or 'available') capacity is allocated in an atomistic way; i.e. spread among the other players in the market in small amounts. The upper bound is reached when we allocate a further 232 MW of 'used' interconnection capacity to other market participants on the basis of their nominated flows in 2003.[53] We recognise, however, that allocating the residual capacity to one player 'Other' overestimates the true concentration in the market.[54]

[52] The available capacity is the sum of the monthly and daily net import capacity with France, and the yearly, monthly and daily net import capacity with the Netherlands. 232 MW of this (net) capacity were nominated in 2003.

[53] This exercise does not allocate to any market player the [confidential] MW of import capacity that until 2003 were reserved for the Tricastin contract. However, if this capacity were allocated to generators on the basis their market share, the HHI measures computed in Table 2.7 and Table 2.8 will not change.

[54] 'Other' includes the non-despatchable generation that it is not allocated to Electrabel, SPE and EdF.

Table 2.7: HHI for the Belgian generation market, 2003				
Market player	Installed capacity	Long-term interconnection[1]	Atomistic[55] allocation of 'available' capacity[2]	Available capacity allocated on 2003 nominations
Electrabel	12,195	[contains confidential information]		
SPE	1,186			
EdF	481			
Other	1,118			
Total	14,980			
HHI	6,756		6,533	6,711

Notes: 1) Only long-term net import capacity is allocated to Electrabel and SPE – this leaves 232 MW of capacity not allocated to any player; 2) Available capacity is defined as capacity that is not used by the long-term contracts to import/export from France.

Source: London Economics' elaborations based on data provided by the CREG.

These numbers are very high, as the range of possible HHIs is 0 to 10,000, and any HHI value above 1,000 is often considered borderline concentrated, and 1,800 is often used as a cut-off level over which a merger starts to cause concentration and market power problems.[56]

This picture of a highly concentrated market is also not altered by the consideration that Electrabel has to auction up to maximum of 1,200 MW through the VPP auctions. We show this in a further exercise where we assume that the other generators in the market buy the full amount of virtual capacity (the most extreme case).[57] These calculations are shown in Table 2.8. The sale of 1,200 MW of virtual capacity would decrease the HHI to 5,455 in the 'atomistic' scenario and to 5,647 in the nominations-based scenario.

It is important to realise that the calculations of the HHI that include the capacity sold through VPP auctions are upper bounds because we assume that SPE and EdF buy virtual capacity up to the limit that is allowed by the VPP rules (each single player cannot purchase more than 40% of the total

[55] By atomistic, we mean that the capacity is allocated as if the market shares of the owners are infinitely small.

[56] See US Department of Justice Merger Guidelines.

[57] So far, only 575 MW of capacity have been sold through VPP.

capacity offered through the VPP auctions) and the remaining 20% is allocated to 'Other'.

Table 2.8: Impacts of selling 1,200 MW of capacity through VPP on HHI

	Atomistic allocation of 'available' capacity	Available capacity allocated on 2003 nominations
Electrabel	[contains confidential information]	
SPE		
EdF		
Other		
Total		
HHI	5,455	5,647

Notes: in the VPP scenarios we have allocated 480 MW of capacity to SPE and EdF and the remaining to others.

Source: London Economics' elaborations based on data provided by the CREG.

Therefore, as evidenced by the tables, by almost any means of calculation, Electrabel still is predicted to have market power in generation, and the total market remains extremely concentrated.

In spite of the fact that the actual results of the HHI calculations are invariant to methodological concerns, it is important to stress the limitations of the HHI. The HHI does not reflect the possibility of intense price competition—sometimes called Bertrand competition—even if market shares are high, nor does it reflect the possibility of contestable markets, where potential entry is the driving force, and so even a monopoly could be competitive.

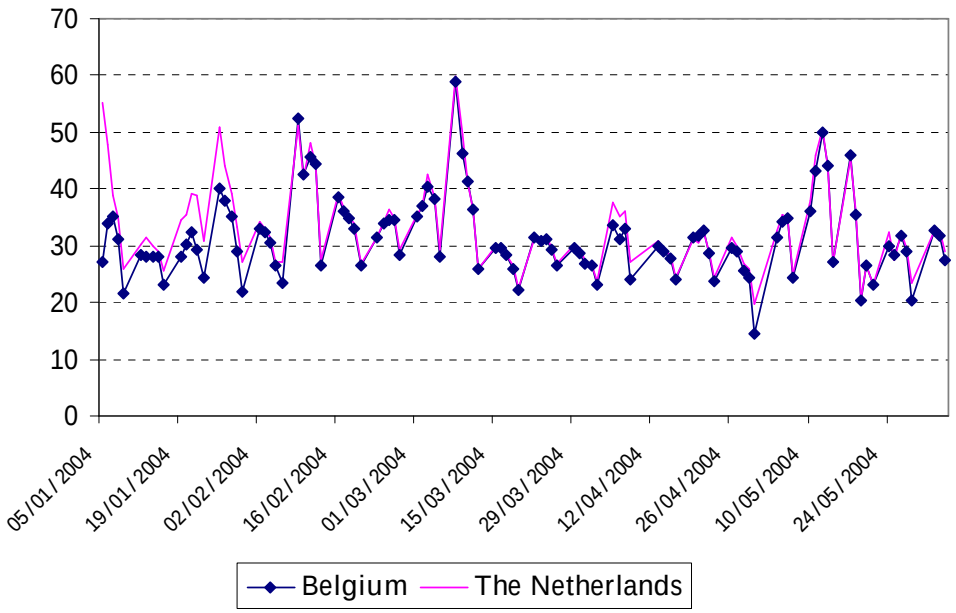
While these cases are possible, we do not find them compelling or likely to occur often in electricity generation markets. The likelihood is in fact that HHI might *underestimate* true concentration or the ability to exercise market power. This is due to factors such as transmission congestion. Detailed analyses of transmission capacity may be necessary, and in many cases the results could be surprising. For example, constraints on the transmission system may be greater during off-peak periods when not all plants are running and there is an economic incentive to use transmission to reach distant, cheaper plants. Furthermore, when the complex transmission interactions are considered, the topology of the market will be driven by electrical distance not geographic distance. With the sometimes poor correlation between electrical topology and geographic topology, we should be prepared for surprises in the definition of the electrical market and, consequently, on the actual levels of market concentration. In the absence of

additional data, we have been unable to further explore this point. However, we have repeatedly been assured by Elia that constraints within Belgium do not exist.

2.5 Price performance

In this section we assess the price performance of the Belgian wholesale electricity market. Belgian wholesale prices are lower and highly correlated with Dutch prices (Figure 2.26). The average difference between the two price series is 5.3% lower in Belgium, while the correlation index between the same series is more than 88%. These characteristics of Belgian and Dutch prices are also evident from forward contracts of higher duration.

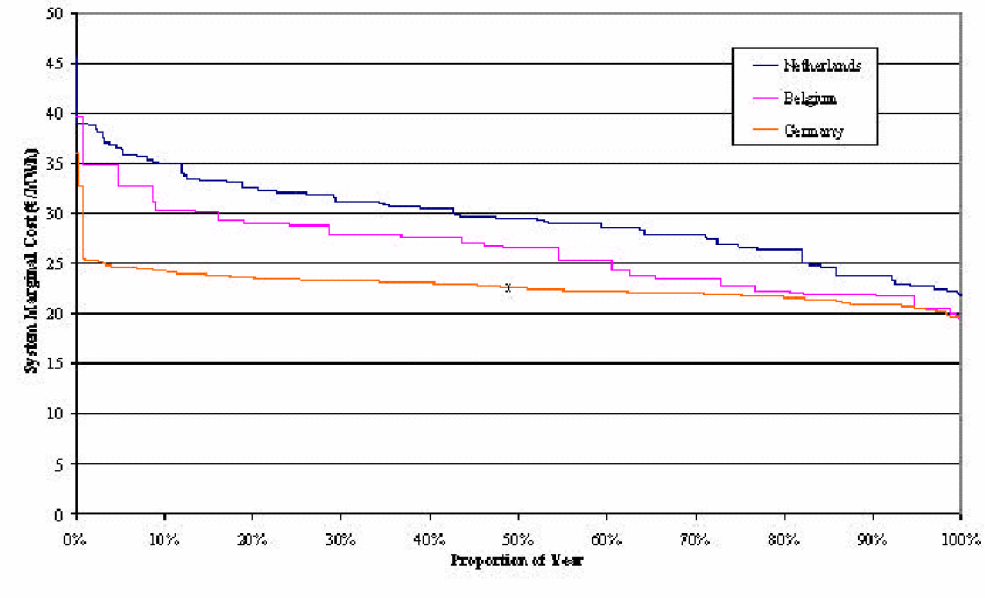
Figure 2.26: Belgian and Dutch day-ahead baseload prices (€/MWh), January-June 2004



Source: Platts

Differences in marginal production costs across the two countries can be the primary explanation of the observed differences in wholesale prices. As nuclear plants form a large part of the Belgian production park, Belgium has somewhat lower production costs compared to the Netherlands. This is clearly shown in the system marginal costs for Belgium, as estimated by The Brattle Group (Figure 2.27).

Figure 2.27: Marginal costs of power in Germany, Belgium and the Netherlands



Source: The Brattle Group (2003)

The Brattle Group has also estimated the marginal system price for various parts of the day and various seasons in the Netherlands and Belgium based on least cost despatch. In this analysis possible imports and exports between the countries is taken into account. These estimates show that the price resulting from least cost despatch in Belgium are on average 3 €/MWh lower than the Dutch prices.[58]

How do these estimates of (competitive) prices compare with actual market prices? We undertake such comparisons in Table 2.9, where we compare market prices and marginal costs in Belgium and the Netherlands. Our analysis reveals that, while on the basis on different marginal costs prices in Belgium should be 11.6% lower than in the Netherlands, actual market prices are only (on average) 5.7% lower. This suggests that the Belgian generation market is less competitive than the Dutch market by an appreciable extent. The Dutch market is not perfectly competitive either, because it shows a mark-up of 11.1%.[59] [60] If we apply the Dutch mark-up to the Belgian marginal

[58] Newbery et al. (2003) report different estimates of marginal generation costs for Belgium and the Netherlands. We prefer not to use these estimates because they generate cross border flows that are not consistent with what we observe in reality.

[59] In a perfectly competitive market the price-cost margin should be equal to zero.

cost, the estimated wholesale (baseload) price is 29.46 €/MWh, 6.3% lower than the observed levels. This last exercise would be equivalent to assume that the Belgian generation market were as competitive as the Dutch market.

Table 2.9: Baseload market prices and system marginal costs in Belgium and the Netherlands

	Baseload market prices (Platts)	Baseload system marginal costs (The Brattle Group)	Price-cost mark-up (%)
Belgium	31.45	26.18	16.7%
Netherlands	33.34	29.64	11.1%
Difference (%)	-5.7%	-11.6%	

Note: baseload market prices are simple averages of daily Platts' prices over the period January-June (2004); Baseload system marginal costs are weighted averages of baseload winter and summer system marginal prices; price-cost mark-ups are defined as: ((p-c)/p)*100.

Source: London Economics' elaborations based on Platts' data and estimates contained in The Brattle Group report (2003).

The analysis in Table 2.9 shows that the generation market in Belgium is less competitive than in the Netherlands.[61] We would like to add that, in our opinion, there are reasons to believe that the calculations in Table 2.9 overstate the 'true' degree of competition in the Belgian market. These reasons are the following:

- The only power prices available are those for the Belgian (baseload) market, published by Platts. It is our understanding that only very limited trading actually takes place in the Belgian OTC market. Thus, it is not clear whether these prices can be regarded as good indicators of the prices encountered by traders in the wider market.[62] The depth and liquidity of this market is also a cause for concern.

[60] Global Insight (2004) reports estimates of the mark-up in generation for four neighbouring countries, including France, Germany, the Netherlands and the UK. In 2003, the Belgian mark-up was the highest in the group (32.5%), followed by France (26.8%), Germany (9.1%), the Netherlands (5.8%) and the UK (3.3%). The difference between our estimates and Global Insights' is primarily due to higher estimates of marginal costs (31.3 €/MWh in Belgium and 43.7 €/MWh in the Netherlands). Moreover, part of the difference with our estimate of the price-cost mark-up in Belgium is due to the fact that Global Insight uses the Dutch wholesale price as a proxy for the Belgian wholesale price.

[61] Comparisons with other countries are difficult because of the inevitable lack of consistency of the estimated system marginal costs. For example, the estimated generation costs reported in Global Insights (2004) are estimates of the average costs as opposed to marginal costs. Moreover, Global Insights (2004) does not provide cost estimates the different seasons of the year, nor hours of the day. This prevents us from doing any meaningful comparisons, because the only available wholesale prices for Belgium are for baseload power and not for the entire year (January-June 2004).

[62] We would like to stress that the prices provided by Platts' for the Dutch market are well in line with the

- The comparisons undertaken in Table 2.9 refer only to baseload power. While the largest industrial consumers have relatively flat energy profiles (and are therefore well-suited to buy baseload contracts), more general consumers have a shaped profile. This means that these consumers will need also to buy other contracts to match their profile (peak and off-peak). If the price of these (complementary) contracts is higher in Belgium than in the Netherlands, Belgian consumers will face additional costs (relative to Dutch) to source their power that are not captured in the price of baseload contracts.
- There have been a number of instances in which large users of power have built (or attempted to) power plants for their own supply, typically a CCGT. These instances can only have been motivated by the expectation of obtaining power at lower prices that what was available in the market. In other words, this suggests that the generation costs of the envisaged power plants must have been below electricity market prices. Although this evidence is only anecdotic, it is nonetheless indicative of the market perceptions in relation to electricity prices.

To conclude, market prices appear to deviate from marginal costs more in Belgium than in the Netherlands. Moreover, there are reasons to believe that relative price-cost mark up in Belgium is higher than what can be measured at present.

2.6 Conclusions

In this chapter, we have assessed the structure and functioning of the generation market in Belgium. Our conclusions indicate that Electrabel has the ability (and the incentive) to engage in various forms of price manipulation. Not only this impacts negatively on the liquidity of the wholesale market, but this could also negative implications for the functioning of downstream markets.

Imbalance charges in Belgium are on average lower and less volatile than in the Dutch balancing market, but substantially above (and less volatile) those under NETA's. In our opinion, high imbalance charges represent only one aspect of the problem facing Belgium. The other arises from their interaction with an opaque, illiquid and very concentrated market, which gives few alternatives to buyers in the market.

We have also analysed whether and to what extent imports from neighbouring countries and VPP auctions could constrain Electrabel's behaviour. Our assessment is that, although Belgium benefits of significant interconnection capacity, as a result of various reasons, imports can only have

prices provided by the APX, and, therefore, our remarks only apply to the Belgian market.

a limited impact on competition in generation. VPP is also expected to have only a moderate impact on competition in generation. In short, the picture of a very concentrated market is not altered when taking into accounts possible mitigating factors such as interconnection and VPP auctions.

When compared to neighbouring countries, Belgium seems to show a lower degree of price competition.

3 Trading

In spite of recent setbacks, such as the collapse of Enron and the financial difficulties of traders in North America, trading in electricity markets and electricity-related products is developing worldwide. Trading in energy commodities and derivatives is concurrently being observed in physical electricity spot and forward markets and in the financial markets for electricity products and derivatives. In the latter, a variety of financial instruments including forward and futures contracts, options, swaps, plain- and exotic options are being offered. Although the trading sector is in general developing globally, development of trading markets in many of the EU's liberalising markets has been sparse so far.

In this chapter, we first describe the main features of electricity trading markets, particularly the reasons why liquidity in these markets is so important for market participants, and why the desired levels of liquidity may be harder to obtain in these than in other markets. In the main body of the chapter we describe the current electricity trading arrangements in Belgium. We conclude with an assessment of eventual features of the trading rules that distort the functioning of and entry into the trading market. Some of the information compiled for this chapter was based on answers to questions posed on the roundtable with traders and to a list of questions subsequently sent to a number of them.

3.1 Main features of electricity trading

Trading in any commodity, and electricity is no different, in its very essence involves the reallocation of resources. This reallocation of resources can be a reallocation of risks, or it can involve the reallocation of the actual commodity from those who value it less to those who value it more. Trading is potentially profitable because the trader promotes efficiency through this reallocation process. Thus the fundamental features of profitable trading involve risk management and arbitrage. Since risk management and arbitrage are the main functions of traders, trading necessarily needs to function on slim margins and speed. Arbitrage opportunities are opportunities for risk free profits (buy low and sell dear) while risk management involves taking risk from one party and selling it to another.

Risk in electricity trading can be due to a variety of factors. These risks can be either price or quantity risks. One way of managing quantity risks is to own generation. Risks can be made worse due to a lack of interconnection capacity because interconnection is the immediate substitute for generation. By necessity, electricity trading markets are often geographically distinct: there are several geographical regions between which moving power is either

physically impossible or non-economical, and costly when feasible.[63] As a result of interconnection limitations, and supply and demand condition differences, substantial price differences are observed in different regions, and this is obviously a feature that electricity prices do not share with other financial assets.[64] A second specific characteristic is that electricity prices fluctuate due to "seasonality", related to cyclical fluctuations of demand by time in the day, week and year. Another key feature of electricity prices is the presence of dramatic price changes, materialised by "spikes", i.e., sudden upward jumps shortly followed by a rapid reversion to normal levels. A famous such spike was observed in 1998, covering some Midwestern states of the U.S., when a tornado and transmission problems combined to bring prices up by several thousand dollars.

Because of the risk management function and the arbitrage function, sufficient liquidity is *the* single most crucial factor in any trading market. Liquidity is the ability to buy and sell at the market price any quantity without moving the price. Under such a definition, notice that liquidity is at odds with a market where market power (the ability to impact price/margins) exists. Without liquidity, traders can find themselves short of the commodity as prices spike, and their risks (financial liabilities) can be unlimited.[65]

Commentators, market designers and participants all know that liquidity is needed, but liquidity is not something that can be merely legislated. Liquidity, for the most part, develops organically, as traders gain experience in the products, and participants start basing their transactions on a single commodity price. For example, IPE Brent Crude futures represent a very small proportion of crude production, but because London traders all use this as a benchmark product, Brent contracts are *the* benchmark crude contracts for Europe and much of the world. Therefore, ultimately, a small number of electricity indexes and exchanges, and/or OTC markets, would be desirable for continental Western Europe since this would promote the liquidity required for spot and forward trading and the manipulation-free environment necessary for derivatives trading.

There are a number of reasons why liquid electricity trading markets may be hard to obtain. The biggest reason is the fact that risks of being short or long cannot be effectively managed by traders. The biggest barriers to this are market power and/or a fundamental lack of the commodity; secondary but important barriers are lack of price transparency. Traders can manage price risk, or quantity risk, but not the two at the same time—market power and

[63] This explains why new futures contracts are being created to cover different regions.

[64] These differences result from varying capacity generation across regions as well as transmission network limitations into a region.

[65] There are of course legal limits to liabilities, but in the economic sense, someone eventually bears these costs.

lack of commodity means that either price or quantity can impact a trader's position negatively.

It is also noteworthy that market power and a fundamental lack of the commodity are not merely affecting the level of liquidity, they can in fact prove the death-card even for already established trading markets. For example, the New York Mercantile Exchange (NYMEX) had established successful electricity futures contracts for delivery at the Palo Verde and California-Oregon Border (COB) well in advance of deregulation in CA. The subsequent CA electricity crisis led to the suspension of these contracts, as price spikes and illiquidity caused traders to abandon trading in these contracts.

The two most active exchanges in Continental Europe are the Amsterdam Power Exchange (APX) created in early 1999 and the Leipzig Power Exchange (LPX), which was established during Summer 2000 and consolidates today the activities of the LPX and what used to be the European Energy Exchange (EEX) in Frankfurt. Recently, PowerNext was built in Paris involving Paris Bourse, Electricité de France and some other major energy structures.

The geographical separation of markets discussed in the paragraph above is likely to change once market coupling occurs (e.g., APX-BPX-PowerNext; APX-LPX). Market coupling will not take away price differences on the various markets, but it may increase the products and quantities offered on the power exchanges. The liquidity on the electricity markets should improve as a result. The impact of market coupling is however limited to the capacity of the countries' interconnectors. Price differences will thus remain inevitable (at times when the interconnectors are congested), but a system of market coupling may nonetheless improve the current market inefficiencies

3.2 Market definition

The relevant market definition for study involves the trading of electricity in Belgium. We include in this both the trading of electricity as a physical commodity and the trading of financial contracts on electricity. Trading can involve financial contracts for derivative products, including forwards, futures, options, swaps, and exotic options. Trading is distinct from supply in that it typically does not involve longer-term contracts for the retail delivery of electricity to end-users. It is distinct from generation in that it does not involve production. That said, it may be useful for a supplier or producer to also be a trader, as this may help them manage risks.

Product market definition

In terms of product market definition, we define the market to be the trading in any electricity commodities or derivatives. It is perfectly possible to define different markets within this category. For example, we could define trading in derivatives (forwards, futures, and options) as distinct from trading spot or

day-ahead, or one might consider the OTC markets to be distinct from exchange-based markets. Trading can also be on a purely bilateral basis.

The standard method of market definition is to consider substitute products and what degree of pricing power a monopolist would have in one product, vis-à-vis a potential substitute. Under this method, options would clearly (*prima facie*) seem to be in a different market than say futures, because the option's price is only functionally related to futures prices. However, we believe splitting these into more narrow products would be inappropriate.

Adopting a more narrow market definition, i.e., splitting trading into say derivates and spot trading, we believe is not relevant because of supply-side conditions. Due to the lack of liquidity on these products, most firms are prepared to trade in a variety of (less standardised) products, and clearly there is not sufficient room for specialisation.

Geographical definition

It is important to consider the geographical extent of the market. We believe that the proper geographical market definition should be Belgium, but the trading market is perhaps the most likely to transcend national boundaries should sufficient market harmonisation with the Netherlands occur. The national boundary definition is considered the relevant one primarily due to the physical structure of the grid. There are no constraints within Belgium, but still potential constraints at the Belgian interconnectors. These constraints can (and do) cause different effective prices to prevail between Belgium and their neighbours. Combined with the lack of risk management instruments, such as financial transmission rights trading, and lack of efficient allocation mechanisms (mainly[66] on the Franco-Belgian border), this means that traders will have difficulty managing price or quantity risks on a cross-border basis. Thus the national definition is seen as the most relevant one.

With the advent of a wide range of developments, the trading market easily could transcend the national-based geographical definition. The advent of (planned) interconnection capacity, increasing liquidity at EU exchanges such as the APX, PowerNext, and EEX, implementation of efficient allocation mechanisms, and increased harmonisation between markets could mean that traders might migrate to a particular hub or exchange and handle Belgium trades under an umbrella-like operation that is based outside of Belgium. The possibility of this is evidenced by the fact that most of the traders at our meetings said that trading within Belgium was handled from their main desks in the Netherlands. Handling trading from a more central operation is also the norm for commodity trading in more traditional energy commodities such as oil.

[66] Most participants feel that the auction process for the NL-BE border has been successful, but that changes such as timing harmonisation with the APX could improve things.

A final word about geographical definition is needed. We have defined "trading within Belgium" as the relevant market, but this is still ill-defined. This is because of the potential non-physical nature of trading. At issue is what matters most: the actual location of the traders; the location of the trades, the location of the exchange or something else. In fact, the relevant definition here is not the location of the traders themselves, but either the location of the counter-parties to the trade or the potential for ultimate physical delivery/exchange of the commodity. All commodity exchanges ultimately must be linked, at least in theory, to the physical commodity.

3.3 Market structure

Participants

Typically, participants in the trading market are generators, pure traders, suppliers.[67] End-consumers are not typically active in the trading market, as they would typically use a broker or trader on their account, although this is possible too, especially for large customers. In Belgium, besides Electrabel, only a small number of companies place bids and offers for baseload energy. These companies show their prices to the market through a small number of brokers.

The total number of market participants is very low. According to the estimates of some of the traders, there are 2-3 brokers, not dedicated to the Belgium market, but working part-time in Belgium as an extension of their Dutch desk. There are 5-10 companies actively trading in Belgium; 3-4 of them on a permanent basis, and the remainder trading only occasionally.[68] Electrabel, perhaps from a different vantage point, estimates the number of active market participants at 20.

Traded volumes

In countries like Germany or Holland, most of the trading takes place in the over-the-counter (OTC) market, where market players can anonymously post bids and offers in standardized products, and counterparties are only known after you have done a trade. As the liquidity in the Belgian market is very low, market players often are forced to call other players directly to see if they can do a trade bilaterally. Occasionally traders in Belgium will call other counterparties to see if they have a specific interest in the market.[69] This sort

[67] Distribution system operators (DSOs) will rarely be active on the trading market. It is however possible that they may purchase and sell electricity under certain limited circumstances determined by law.

[68] We have not been told the identity of these market participants, just an indication of the rough numbers under each group.

[69] For example, Swiss market participants might have cheap hydro resources, but are not necessarily active in the Belgian market. A Belgian trader might know a Swiss producer and ring her up, if he has a

of over-the-counter trading makes tracking of comprehensive volumes data impossible. Anecdotal evidence from participants, and consistent with low liquidity, however, indicates that trading volumes in Belgium are a very small proportion of the overall market.

Products traded

Most of the trades are baseload energy contracts. The focus of the market is more on short-term products--day or week-ahead. Traders try to hedge their daily import volume from France and their export needs into Holland. Baseload contracts could run for anywhere from a month to multiple years. Long-term contracts usually are not associated with liquidity since they may not require the active participation of the contract holders. In the long-term market, activity is usually very low, although we sometimes see more activity around certain events, like VPP-auctions and the publication of the available monthly import capacity from France.

The trading market clearly still has a long way to develop towards maturity. In a more mature market, one would expect to see more products traded, more blocks of energy at different timings (e.g., month-ahead, 6-month-ahead, etc) and prices (representing places in the merit order, etc.) One would also expect to see more sophisticated products, such as options, spark-spreads, block-forwards, and or swaps, etc. These latter derivatives would especially be expected where products or technologies provided technical means of hedging price risk (i.e., like a flexible plant or combined cycle unit, that could run its steam boiler baseload and allow its jet turbine to follow load; other examples are a company that could store gas, or duel fuel (gas-oil) capable plant). When these elements are present (such as they are in Belgium), it is unlikely that the owners of these flexible assets will always be the most in need of risk mitigation; some others might be willing to pay more for it. Therefore, one would expect to see owners of flexible plant trading, and taking on risk of other participants for a premium. There is no evidence that this type of trading is developing in an open and liquid way in Belgium.

In addition, we note that the existence of any one particular market or a combination of certain markets might be 'sufficient' to bring about the proper functioning of the Belgian trading markets, but that is not to say that any one market or combination of markets is 'necessary'. In general however, options such as a day-ahead SMP style market are probably neither *necessary* nor *sufficient*. Other jurisdictions, UK-NETA, Arizona (USA) and others are functioning *without* a day-ahead market, while California, clearly due to other design flaws, went from well-functioning to poorly functioning in-spite of having a well-designed day-ahead market. In addition, as stated, the development of trading markets and liquidity is often a very organic process.

client ready to buy. We also note that there was one Swiss participant at the traders roundtable.

With these caveats in mind, it may still be useful to try to illustrate a contingency-based[70] minimum number of trading markets that might exist and still promote effective competition. We present a bulleted list, with a minimum of one to be necessary from each bullet. We also emphasise that illiquidity and lack of price transparency or market power could render the usefulness in promoting competition of any market low.

- Hourly markets that will enable participants to discover the competitive price of energy: day-head system marginal price, NETA-style[71] bidding, Belgian power exchange (BPX)[72], OTC spot trading;
- Near real-time market(s): imbalances market, NETA-style balancing[73], pure-market clearing real-time market[74];
- Derivatives that allow some hedging of future price risk: OTC forwards (peak and baseload), futures, options, swaps, tolling contracts, etc.

In addition, there may also be the need for markets such as those for ancillary services such as capacity, reserves, load following, voltage and regulation support etc. These may or may not be necessary, though, and can be provided through regulated remuneration. The necessity of having these kinds of market will interact with many of the other market design features.

Liquidity

The fact that market activity seems to increase around VPP auction dates may be an indication that there is willingness to trade in this market but that there is, in most other occasions, an insufficiency of products to trade with. The increased trading around the VPPs may also relate to an attempt from the part of traders to get information about where the prices are and how they may evolve. Increased trading may be due to speculative trading by interested parties who may expect to gain from affecting the prices at which the auctioned VPPs will ultimately be sold. Finally, we note that the CREG studied the allegation that trading was positively correlated with the timing of the VPP auctions, but found no correlation.

The fact that trade volumes also increase around the announcements of monthly import capacity from France is an indication that traders react to the

[70] Meaning, if you have one, you may not need the other. For example, if one has a futures market, then an OTC forwards market might become unnecessary.

[71] No marginal clearing price- what-you-bid-is-what-you-get (WYBWYG).

[72] In the style of the APX, i.e., an system marginal clearing price (SMP) type market.

[73] Essentially, a POOL-like market, but net-imbalances face a penalty, rather than a market price in the end.

[74] In other words, a single price is used to clear the market. This could include both energy and imbalances.

release of new information. This would be expected in any market, but may be particularly noteworthy in a market generally poor in terms of the information made available to traders.

Normally, price quotes are only available for day-ahead delivery, and longer-term forward prices (such as years or months) are usually calculated from the Dutch forward minus a small spread.

According to some of the traders, the spread between offer price ("ask") and bid price is in general considerable, much bigger than in all the surrounding markets. This is consistent with the view that the Belgian market is particularly illiquid. Transactions in illiquid markets command higher spreads, as the spread is the premium the trader can earn in supplying liquidity to the market. The surest way to bring these spreads down is to improve liquidity in the market.

We have sourced data on prices in the Belgian and Amsterdam markets from Platts[75] and have compared day-ahead of OTC trades. The spreads between the high and low of the day since January 2004 were virtually identical, at 1.44 (BE) and 1.45 (NL) euro per MWh. We note that this is not a bid-ask spread, but is a high-low spread.[76] The high-low spread is not as good an indicator of liquidity in the market as is the bid-ask spread, but it does give some evidence that the Belgian market is not too far from the Netherlands market. In addition, according to the Platts data, it is clear that the high-low spreads have come down in the Belgian market as evidenced by the figure below.

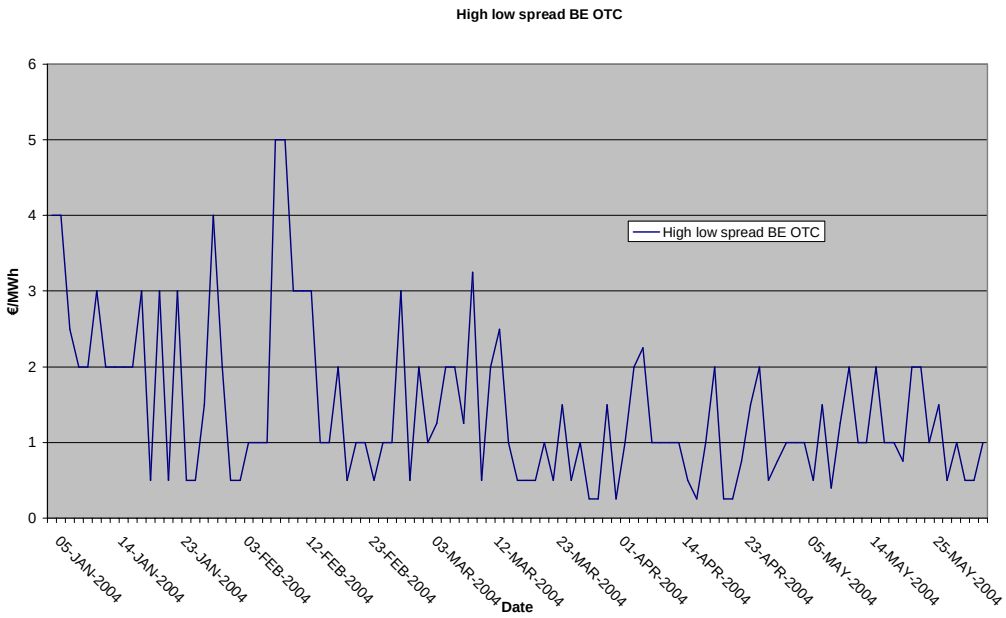
It is difficult to draw strong conclusions from the high-low spread data. Sophisticated analyses of liquidity, that can properly separate out liquidity from other factors usually are done with bid-ask spreads. The high-low spread comes from the *survey* nature of the data and the fact that these are OTC trades; in other words, when Platts ring around to traders on a given day, they ask traders what they are selling/buying at; the spread being the highest price minus the lowest price surveyed. Obviously, it is unlikely that everyone trades at exactly the same price, since there is not particular market clearing price known to all traders. Conversely, bid-ask spread data come from trades that cleared at the market price, but where the buyer (seller) bid just slightly higher (lower) than that price.

[75] These are survey data from Platts, who contact traders and ask them what they are selling and at what prices.

[76] It is important to note the difference between the high-low spread and the bid-ask spread. Sophisticated analyses of liquidity, that can properly separate out liquidity from other factors usually are done with the former. The high-low spread comes from the *survey* nature of the data and the fact that these are OTC trades; in other words, when Platts ring around to traders on a given day, they ask traders what they are selling/buying at; the spread being the highest price minus the lowest price surveyed. Obviously, it is unlikely that everyone trades at exactly the same price, since there is not particular market clearing price known to all traders

Although strong conclusions should not be made, lower bid ask spreads are consistent with higher liquidity. If everyone knew a single market price and could trade all they wanted at that price (i.e., high liquidity) then bid-ask spreads would tend to zero, all else equal. Other factors, market power, timing of trading events cannot be ruled out, however. For example, the actual true market-clearing price might change between the time when one trader and the next respond to the survey. In this example, falling prices during survey times would lower bid-ask spreads, giving the spurious impression of increased liquidity.

Figure 3.1: High-low spread Belgium baseload day-ahead OTC



Source: Platts data, London Economics figure

3.4 Market outcomes

The OTC-market works through brokers, where market participants show their interests and place bids and offers in the market. Only standardized products are traded in the OTC market. As the market for Belgian power is very small, most of the liquidity is generally at one broker, namely GFI[77].

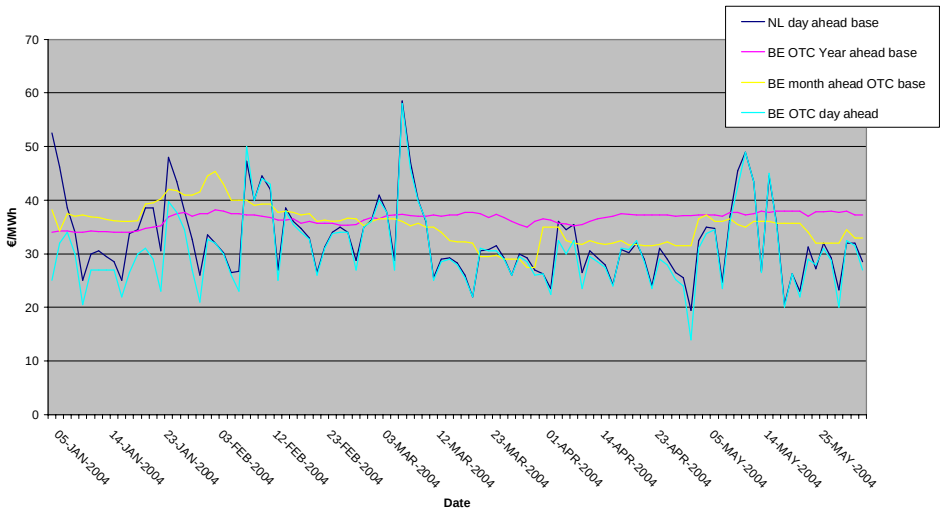
Since January 2004, Platts has published baseload forward prices on a daily basis. These prices are constructed by Platts using information from several

[77] www.GFIgroup.com. Other brokers also mentioned by some of the traders were Spectron and Icap.

market players active on the Belgium market. Thus Platts data are a view from the market and not only from Electrabel. The Belgium forward prices, according to this source, are quite in line with the Dutch wholesale prices, and in general are lower. This can be seen in the figures overleaf.

The first figure (Figure 3.2) shows the levels of Belgian Platts prices for day-ahead, month-ahead and year-ahead contracts. The year-ahead contract is a market-based forecast of what power will be worth in the future. The Dutch day-ahead prices are also shown. The Dutch and Belgian day-ahead prices are very similar, as can be seen by the figure. But in general, the Belgian prices are less than the Dutch prices.

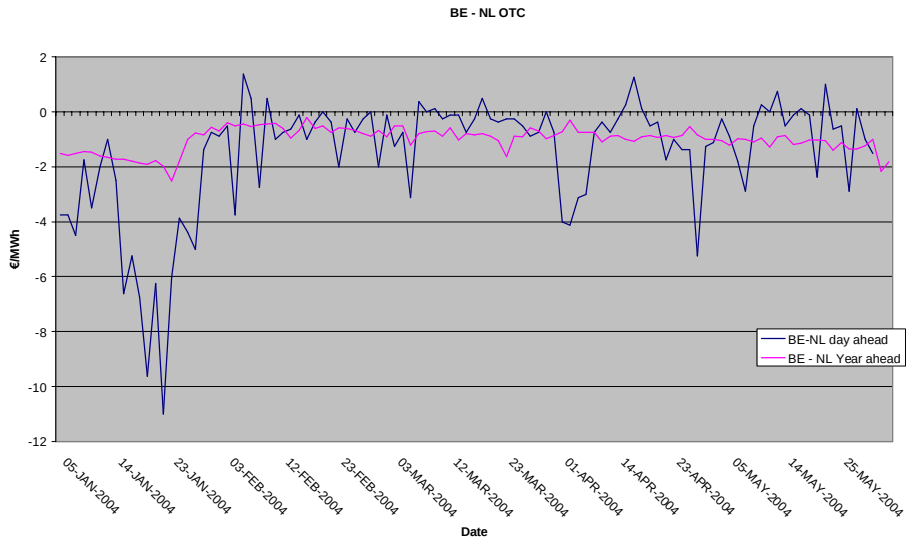
Figure 3.2: Platts prices for Belgium and the Netherlands I



Source: Platts data, London Economics figure

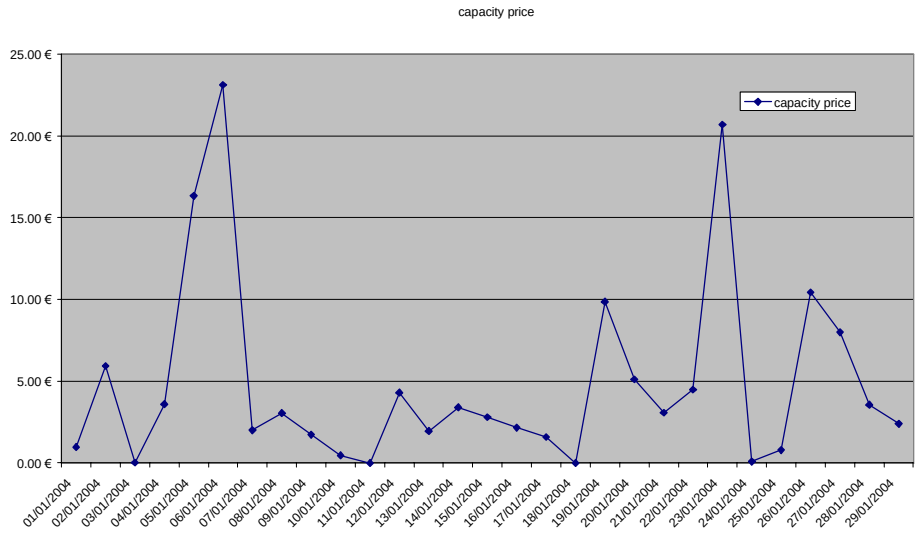
The next figure (Figure 3.3) overleaf shows the spreads between Belgian and Dutch OTC prices as reported by Platts. The figure shows day-ahead and year-ahead prices for 2004. In general, the day-ahead prices of the Netherlands are significantly higher than the Belgian prices. The year-ahead prices are much smoother than the day-ahead prices. This is evidence of the mean-reversion in electricity prices—in other words, the tendency to return to equilibrium. There is also a significant spread between the Dutch and Belgian year ahead prices. This is then a market-based forecast of the expected difference between the two markets in the next year. There is also the tendency for the Dutch prices to occasionally rise substantially relative to the Belgian prices.

Figure 3.3: Platts prices for Belgium and the Netherlands II



Source: Platts data, London Economics figure

Figure 3.4: TSO Auction results, day-ahead BE to NL



Source: TSO auction office

Finally, Figure 3.4 shows the average hourly price of capacity on the Belgian-Dutch interconnector for January 2004. It is clear that, when there is significant congestion (at a price lower than the clearing price) on the interconnector, the prices for capacity go up. This must roughly correlate to the difference in the value of power between Belgium and the Netherlands. In the absence of other factors such as penal balancing costs, illiquidity in the trading market, differentials in transport costs, etc, the relationship would be more exact. Traders would reduce the arbitrage profits to zero. Thus, a power trader would be exactly indifferent between buying in Belgium and shipping the power to Holland, and paying the interconnection fee, versus buying the power spot in Holland.

What is surprising from the figures is that the spreads between the Dutch and Belgian OTC prices stayed so high in January in 2004 (see Figure 3.3), while the value of interconnection was high, but then came down, and then back up again during January 2004, as seen in Figure 3.4. This is indicative, although not fully conclusive, of significant illiquidity in the OTC market or other barriers to trading, because we would expect a higher correlation between the two markets.

3.5 The influence of Electrabel in the trading market

The trading market is hugely influenced by the dominant position of Electrabel as a generator and as a supplier. Electrabel has a virtual monopoly in generation in Belgium, a very large share of supply, and vertical links to the TSO. Electrabel also has a very large market share in the supply market, and most big customers are Electrabel customers. As a result, Electrabel can outbid any position that traders may have with any other counterparty in Belgium. A trader operating in this market can be put into a situation where it cannot find a client for a given purchase. In this case, the trader has only two options: either go to Electrabel and accept whatever price they offer, or face the huge penalties of the imbalance mechanism.[78] In the view of traders, the imbalance mechanism is the most penalising in the EU-15.[79]

[78] These arguments do not hold true for VPP products. Since these constitute options to have electricity delivered they do not commit the holder to find a buyer for these products. If a buyer cannot be found the holder of the VPP may simply choose not to nominate any deliveries for the corresponding period.

[79] Our analysis of balancing charges (see Table 2.5) confirms this statement only partially. The Belgian balancing charges appear to be below (and less volatile) the Dutch and above (and more volatile) NETA's. What could make the matter worse in Belgium than in other countries is that, in the absence of an active hourly spot market, market participants are more reliant on the balancing mechanism to buy/sell power. Moreover, as the Belgian generation market is much more concentrated than in the Dutch and UK markets, prices offered in real-time markets could be closer to the imbalance charges as opposed to the marginal costs of the generating plants that participate in real time markets.

Type of products sold

The baseload products that are mainly traded are the following:

- Short term deals (day, week) – [confidential];
- Longer term (month, quarter, year) – [confidential].

The delivery periods are day ahead, week ahead, the 4 front months ahead, the 2 quarters ahead and the 1-year (2005) ahead; 2006 being offered by Electrabel as well. A summary of these figures provided to us by Electrabel is presented below:

Table 3.1: OTC product transactions, 1st quarter 2004

Delivery period	Traded volumes (GWh)	Number of deals
Day ahead	[confidential]	
Week ahead		
Feb		
March		
April		
May		
June		
Q2		
Q3		
Q4		
Feb-05		
2005		
Total		

Source Electrabel

Some of the traders we spoke to seem to have a different view about the type of products traded in the Belgian electricity market. Their view is that most traded products are daily base and weekend deals, and that there is very little peak and week, month and year deals (one trader estimated the proportions at 80% for baseload daily products and 20% for the rest). This seems to be in direct contradiction with the numbers provided to us by Electrabel and presented in the table above. There we actually have much higher volumes of the longer-term products. As we cannot either verify or refute either of these views we have chosen to report both.

Most traders feel that the amount of energy negotiated through the OTC market is really small. This remarkable lack of liquidity constitutes a major impediment to electricity trading in Belgium.

Electrabel's Belgian Power Index (BPI) and other prices

In Belgium, no day-ahead market exists, but since March 2002 Electrabel has published a Belgian Price Index (BPI) at which it offers to buy or sell 25 MW blocks of day-ahead baseload capacity against a fixed price, up to a limited volume (usually 100 MW). It is only made available to traders for 10 minutes per day (between 9.20 and 9.30 am). In practice this index follows closely the day-ahead price that appears in the Dutch OTC market. There is currently no other publicly quoted price (for e.g. OTC contracts) in Belgium.

The BPI is of very limited value in terms of an indicator of wholesale market prices in Belgium. One important disadvantage of the BPI is the fact that it is just baseload, which makes it difficult for market participants to effectively hedge positions. A real market needs some kind of an hourly exchange on an anonymous basis for both peakload and baseload products. Another problem of the BPI is that it does not really reflect a market price or an equilibrium price. It is a unilateral price decided upon by Electrabel. In a normal market, the price would go down in an event where a large player such as Electrabel found itself long on power. In the case of the BPI, Electrabel has no incentive to do that. An additional problem is the fact that the BPI market closes before the daily-allocated capacity on the French-Belgium border is known.

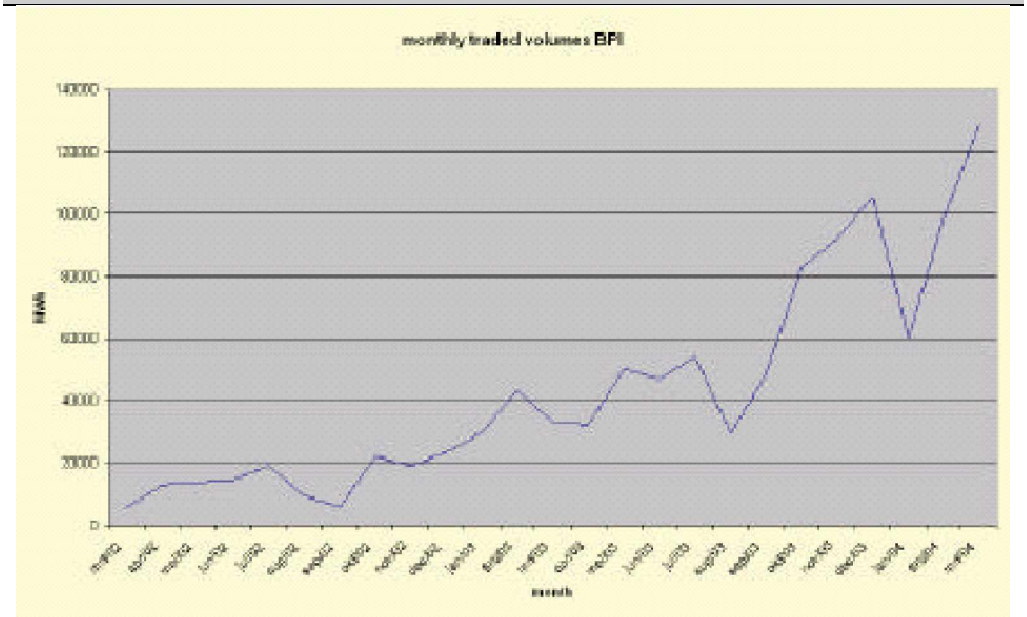
In spite of all the aforementioned problems, the BPI still possesses an even more fundamental flaw: both price *and* quantity are simultaneously determined unilaterally and arbitrarily by Electrabel. It is well known, based on the fundamentals of supply and demand, that price and quantity are jointly determined in a market; one is always endogenous to the other. Therefore, in a market, *even a complete monopolist cannot determine price AND quantity.* The monopolist can set price, but then the market determines the quantity. Therefore, the information content of a situation where a monopolist quotes both a price and quantity is potentially meaningless, because it provides no information from the market.

In addition to the BPI day-ahead prices, Electrabel also quotes, twice per day, forward bid and ask prices for up to 25MW in the most liquid standard products. The quoted spreads in these forward products tend to be quite wide though, therefore most traders only use this as a market of last resort when the OTC market is unable to get any better prices. It is useful to note that spreads are a measure of illiquidity in a trading market.

Electrabel's quoted prices are mostly used to solve problems for the day-ahead market. For the forward products, the spreads in the prices quoted by Electrabel are too high according to traders.

The volume of trading with Electrabel based on the BPI has increased steadily over time as the figure below (from Electrabel) demonstrates:

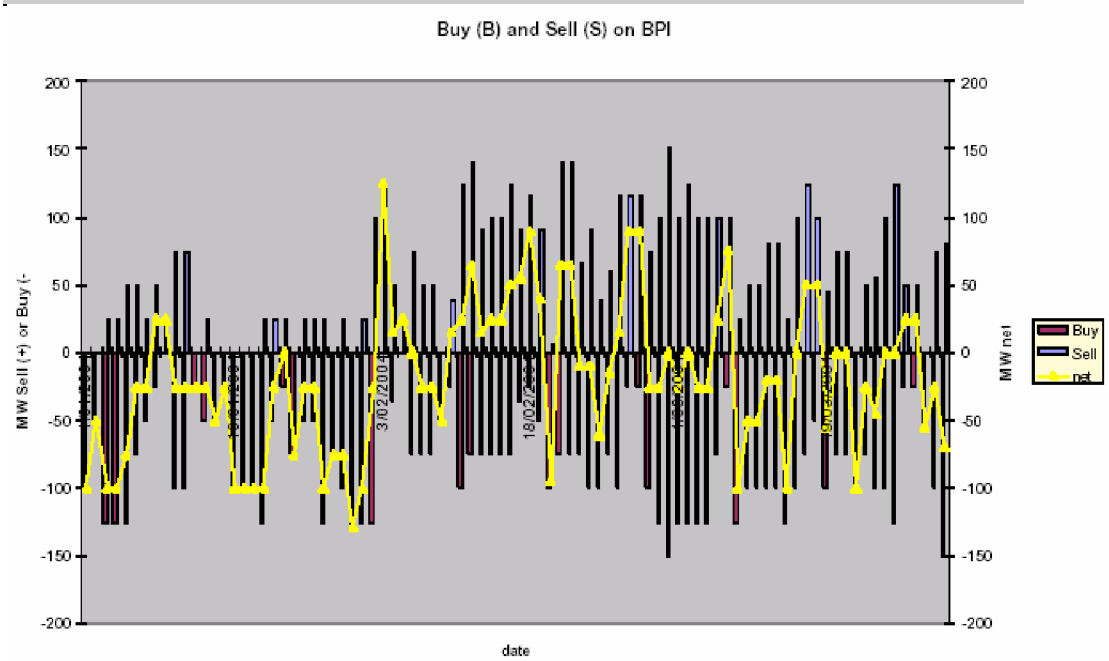
Figure 3.5: BPI-based trading volume (per month)



Source: Electrabel

Electrabel further notes that it is more and more taking a role of central-counterparty in this market. In other words, on a given day, Electrabel will receive both buying and selling requests from the market and may end up with net positions close to zero. This would tend to indicate that the prices quoted by Electrabel on its BPI are approaching market-clearing prices. This is illustrated in the figure below (from Electrabel):

Figure 3.6: Electrabel's net positions on the BPI



Source Electrabel

In addition to the BPI product, Electrabel launched in early 2003 a number of longer-term products through the same bilateral platform. Transactions for this product in the first quarter of 2004 totalled 600 GWh (corresponding to an annualised total of 2.4 TWh). 600 GWh per quarter represent about 274 MW per hour or between about 1.75 to 3.5% of system demand. The distribution across products is given in the table below:

Table 3.2: Electrabel bilateral "trading corner", 1st quarter 2004		
Delivery period	Traded volumes (GWh)	Number of deals
Feb	45.5	10
Mar	44.5	5
Apr	34.6	7
May	78.1	11
Jun	14.4	3
Q2	254.9	11
2005	87.6	2
2006	43.8	1
Total	603.3	50

Source: Electrabel

Table 3.3: Trading volumes for Electrabel	
OTC:	12 TWh / year
Bilateral Trading corner	2.4 TWh / year
VPP (at nominal regime)	8.3 TWh / year

Source Electrabel

Electrabel's rough estimate of global annually traded volumes is between 20 and 25 TWh / year. This refers only to Electrabel's trades and does not include a view on what the other parties trade in Belgium. We know from our discussions with traders that market players such as SPE, EDF Trading, E.ON, Nuon, and perhaps others are developing their trading activities as well.

3.6 VPP auctions and liquidity in the trading market

According to some of the traders we spoke to, the first auctions had very little impact on market liquidity. It appears that this is because participants used the power from the auctions only for hedging their sourcing requirements. While some traders viewed a mechanism such as this as inherently ineffective, others believe that the main problem is the low volume currently available at these auctions. With sales of higher volumes, there is the potential for Electrabel to find itself in a short position (presumably from an

outage). The view of most traders was that this would create the need to be active in the market and give the dominant player the incentive to create some trading activity. Also, with larger volumes auctioned through VPPs, market participants will have more capacity to trade around.

Given the poor liquidity of the OTC market in Belgium and the non-existence of an exchange with hourly/half-hourly supply and demand matching, it is quite difficult for a market in these circumstances to be able to extract the full potential benefits from the VPPs at a wholesale level. In our view, VPP auctions have the potential to improve liquidity in the Belgian market but they probably cannot accomplish this on their own or through the relatively low volumes being offered for sale at present. The risks associated with balancing also limit the value of VPP in terms of liquidity. In our subsequent chapter on remedies, we discuss in more detail the strengths and weaknesses of the VPP auctions as a mechanism to remedy the related problems of lack of liquidity in the trading market and the presence of a large dominant player, as well as the merits of the VPP as a remedy for problems in the other markets.

3.7 Discussion of barriers to entry in trading

Low market liquidity

By far the biggest barrier to entry into the trading market in Belgium is the lack of liquidity as the Belgian electricity trading market is one with low levels of liquidity. There is significant evidence of this. For example, we have been told that in Belgium the percentage of bilateral trades relative to OTC trades is much higher than in other countries.[80] The traded volumes, in any given hour, represent a very small proportion of final demand/delivery—whereas in very liquid markets the opposite holds; traded volumes will exceed actual units delivered. Finally, we note that spreads on the Belgian market are high.

The lack of liquidity, i.e., the lack of participants, traded products and low trading volumes, is a self-reinforcing phenomenon. The lack of liquidity causes a lack of liquidity. Initiatives that break this cycle and "force" new products and more participants into the market are always, in principle, a move in the right direction. In this category we would put the VPP auctions initiative and the quotes and volumes for certain products offered by Electrabel.

An additional manifestation and causation of the problems of liquidity is the lack of certain types of products available for trading in the Belgian market.

[80] This is according to the views of the traders interviewed by London Economics. There are no official records of data on the trading market to either support or disprove this claim.

Most of the transactions seem to be for baseload products and only a comparably very small volume is in peak load products.

In the view of most of the traders we talked to, there is also a lack of long-term products. Nevertheless, this view is not backed up by Electrabel's numbers. According to their figures OTC trading volumes are about [0-15]% for short-term products (day / week) and [85-100]% for the remainder.

Market power and the scope for market manipulation

The next most important barrier to entry, or barrier to development, in the trading market is Electrabel's dominant position. The dominant positions in trading, generation, and supply, all impact the trading market heavily. The dominant position of Electrabel in the trading market is of particular importance. Electrabel is probably involved in at least 80%[81] (in volume terms) of all trades in the Belgian electricity market. This means that Electrabel in all likelihood has the ability to profitably influence prices in a large fraction of all the transactions taking place in this market.

It is an axiom of competition economics that the existence of market power does not necessarily imply its exercise. The anecdotal evidence of traders is that Electrabel *does* manipulate prices. However, so far we have no firm evidence that would support the view that Electrabel does indeed manipulate transaction prices. But, Electrabel's prices are also unlikely to be prices that accurately reflect evolving equilibrium conditions in the Belgian market.

Nonetheless, it is our opinion that the mere existence of market power is potentially sufficient to scare off traders, and limit market participation, and thus liquidity.

Market design issues

There are a number of market design issues that likely impede the development of competition in Belgium. A problem of the Belgian market is the absence of a spot market, which would provide market participants with the possibility to close positions, adjust their load profiles and optimise their VPP requirements. The BPI offers market participants the opportunity to close out trading positions, but the BPI is for 100MW maximum and only baseload. There is also a timing differential between the BPI and the allocations on the south border, with transactions in BPI closing before the south border allocation is known. If the allocation was known ahead of time, a trader could bid either for French power, and use the interconnector, or BPI-based power. In advance of knowing the allocation though, a trader cannot bear the risk of buying power in France and then facing congestion and high balancing charges in Belgium (we assume the customer still uses the power, and that the trader or supplier must then source power from the balancing

[81] This is a very rough estimate just to provide an order of magnitude. There are no official data to support this calculation. [confidential]

market.) A number of traders have decided not to participate in the retail market, given the existence of barriers impossible to overcome, such as the high cost of imbalances, the non-existence of an hourly power exchange and the delay in receiving information on the real consumption of clients (more than one year, according to some of the traders we spoke with).

Spot trading in the form of a real-time market serves to ensure that supply and demand are balanced at all times. Generators, traders and users would value the ability to buy and sell electricity at the spot price for amounts over and under their requirements that are not covered in the day-ahead market or by bilateral transactions. The spot market would, nonetheless, carry the most risk for participants as unforeseen events, such as a sudden transmission line failure or unexpected weather, can cause prices to rise or fall dramatically. Nevertheless, the real-time market is essential to fill the gaps in supply where other trades and transactions may not be sufficient to cover the demand.

Contestability of the trading market

In our view, the trading market is more likely to be contestable than generation and even supply. We present below estimates of fixed set-up costs for a new firm beginning trading operations in an electricity market. These estimates were made[82] for the UK market in 2002, but we expect that they still represent good indicators of current set-up costs, and in a general sense should apply to the current situation in the Belgian market.

[82] DTI "Addressing the issues imposed by electricity trading arrangements on the development and operation of smaller generation", February 2002 (on DTI's website http://www.dti.gov.uk/energy/domestic_markets/electricity_trading/genissues.pdf)

Table 3.4: Entry costs into electricity trading	
Cost category	Trading desk set up cost estimates
IT for non-physical trading	€375,000
Broker connections	€75,000
IT support	€750,000
Risk management system	€150,000 - €6,000,000
Back office	€150,000
Range of total set-up costs	€1,500,000 - €7,350,000

Source: DTI (2002)

The range of these estimates is considerable and while the lower bound is a relatively small number the upper bound may be considered high enough to constitute a non-negligible barrier to entry. To put these numbers in context, it is useful to consider the margins that would be required to cover between €1.5m to 7.5m set up costs relative to Belgium market trading volumes. Consider that some traders estimated the OTC market, the largest, to be about 15TWh annually. Assuming the total market size, including other products, to be somewhat larger, say 20TWh, then if a new entrant captures 5% of that market, they will trade about 1 million MWh annually. A large spread for a trader could be between €0.5 to €1/MWh (different trades will have different spreads). So it could be estimated that a 5% market share would generate between € 500k and €1m annually in cashflow. Converting the set-up costs to annual payments, even using a very high discount rate of 15%, and a 10-year pay-off period only generates an annual cash requirement of just under €200,000.

Our view is that even the value of the upper end is unlikely to correspond to a significant barrier to entry. There are two reasons for this. First, the costs estimated in the table above might not all be sunk. Indeed, setting up of broker connections, risk management systems and back office support are "assets" that can potentially be used in, or sold to, related activities even if the firm decides to leave electricity trading in Belgium. A second and related reason is the fact that an entrant into electricity trading in Belgium may already be trading in electricity in neighbouring and/or similar markets, whereby a large fraction of these set-up costs will not need to be incurred because the current infrastructure can be easily extended to trading in Belgium. This is very much the impression conveyed to us by the traders that we met in the roundtable. Several of the participants in this roundtable were traders who were not fully committed to the Belgian market but they would trade Belgian products on an occasional basis out of operations based in Amsterdam, Germany, or France. This is similar to a situation where hit-and-run entry appears to be of low cost.

Our view, therefore, is that a firm trading in nearby markets would probably incur a relatively small amount of "sunk" costs to enter trading in Belgium. Still, there would have to be some investment in learning about specificities affecting the Belgian market and this investment would not be recovered upon exit. The relative lack of experience of a new entrant could put him/her at a disadvantage when competing with more knowledgeable incumbents.

Regulatory entry conditions

The regulatory and licensing requirements to enter the electricity trading market in Belgium appear to be relatively light. Pure traders do not need a supply (or other) electricity license, although they may need to comply with financial trading laws, depending on exactly what lines of business they are in. According to the Royal decree of 2nd April 2003, a license is required for traders who also supply electricity to users connected to the transmission grid with a voltage higher than 70kV. The application must be submitted to the CREG. It is granted by ministerial decision for a period of 5 years. The decree also sets out the rules of conduct, which apply to the traders who are both traders and suppliers, and who are active on the Belgian market. A license is only required for traders who also supply to end-users.

Conclusions

The biggest impediment to the development of a trading market in Belgium is a lack of liquidity. Although much has been written on this, this is virtually a tautology. Liquidity and the general availability of trading opportunities are fundamental for participants to manage the daily production and delivery of wholesale electricity and for traders to manage their portfolios as efficiently as possible. Transparency and the balancing market risks are other important factors.

The biggest barriers to liquidity are, in order of descending importance: Electrabel's dominant positions in the trading, generation, and supply (in that order) markets. The lack of access to the physical commodity, and the low number of players in the market, and the lack of a meaningful reference price all can be attributed fundamentally to the dominance of Electrabel.

In some respects, the Belgian market seems to be evolving positively. VPP auctions and the commitment by Electrabel to quote prices and "make a market" for a certain range of products are certainly moves in the right direction. Our feeling, which is shared by a number of traders we talked to, is that these measures are not being taken at a fast enough pace nor on a large enough scale. When a market is illiquid it is often necessary to intervene. Liquidity creates a vicious circle. Players are reluctant to trade because the market is illiquid and this situation in turn contributes to the market's illiquidity; and therefore players don't trade. Such a vicious circle is unlikely to be broken if the market is left to its own devices. In terms of market

design, we have also suggested that there are a number of products and markets that are missing[83], e.g., day-ahead spot, reserves, forwards, options, spark-spreads, etc., from the Belgian trading market. Many traders talked about the day-ahead spot market and we have also mentioned the benefits of a real-time market for electricity trading.

In terms of its more structural nature, we have found little evidence of significant deterrents to entry. The market appears to be "contestable" and indeed we have witnessed interest on the part of a number of potential entrants in entering the market, as soon as some of the other problems we mentioned begin to improve. Thus the economically acceptable barriers to trading do not appear to be high.

These factors are all, however, likely to be of a secondary importance. A problem that will (absent other action) remain, even after all other corrections are made, is the large market share of Electrabel. Any market, no matter how well designed, where one player represents somewhere around 80% of the transactions in that market, faces significant scope for abuse of dominance. This in itself may contribute to deter potential entrants from the market. A market under these conditions should be well monitored so that participants are assured that the dominant player will be prevented from market manipulation.

[83] More details are given in the text on pages, 68-70, and 73-74. Other missing markets as detailed in the text include market-based balancing. More details on balancing are found in the generation chapter, 2. Details in terms of the remedies of how to promote liquidity, and thus how to promote trading, are contained in section 7.5.

4 Supply

This chapter analyses the supply market for electricity in Belgium. We find that the largest problems in the supply market are the dominance of the incumbent in generation, the vertical integration of the incumbent into supply and distribution, the inability to manage risk (balancing) and the problems with billing and data transfer. The chapter starts with a discussion on the market definition and then analyses the structure of the market using market shares and the Herfindahl-Hirschman Index (HHI). The last part of the chapter presents some facts on market conduct and performance.

4.1 Market definition

As already noted in previous chapters on generation and trading, market definition is the first step to assess competition in any market setting. This is because a wide definition will tend to decrease perceived structural market power while a narrow definition will do the opposite. These principles apply in general to the Belgian electricity markets, but are perhaps less contentious here because of the large market shares of the dominant players. In other words, no matter how we define the market, a market structure that suggests significant market power is likely to emerge in Belgium.

The product market

Definition of the relevant product market usually involves searching for potential substitutes to the product under investigation. This usually means evaluating the consumers' costs of substituting products or customers' perceptions on their substitutability. While the definition of the relevant product might seem quite straightforward in the present case, because the product (electricity) is a homogeneous one, market definition may still be difficult. For example, electricity supply markets might be properly segmented according to volumes of total consumption or peak segments.

The supply market for Belgium has been recently defined as supply to eligible customers.[84] Moreover, the European Commission, in its referral decision of December 2003[85], notes that a survey undertaken by the Commission has shown that there are no substantial differences between different types of clients, either with regards to their overall consumption,

[84] For example, the decisions rendered on 4th July 2003, 11th September 2003 and 13th October 2003 by the Conseil de la Concurrence and by the European Commission on December 19, 2003.

[85] Decision of December 19, 2003 regarding the referral back to the Belgian Competition Authority of the case regarding the designation of ECS as the default supplier in the case of Sibelga, the Brussels DSO.

profile of consumption or size. Therefore, according to the European Commission, the proper product market is supply to all eligible clients.[86]

While a broader market definition of "all eligible customers" is one of the most natural definitions, we suggest that a narrower definition could be considered plausible as well. Such a definition may prove useful to the CREG, especially when competition is just getting off the ground. When assessing the scope for supply side substitution we think the market could be segmented by consumption volumes.

The main argument supporting market definition along consumption bands is that electricity consumers differ in terms of the level of consumption and not all the suppliers of power presently active in Belgium can meet these requirements. For example, we believe it is difficult for suppliers already supplying a high volume customer (e.g. 2GWh/y) to easily change to supply to a very high volume customer (e.g. 250GWh/y).

In London Economics' consultations with participants, a number of industrial users have informed us that, due to their high annual consumption, they could only be supplied by one company (Electrabel). The supply data reported in the CREG's 2003 annual report provide a similar picture. Of the 33 users directly connected to the grid of more than 70kV, only 4 were supplied in part by suppliers other than Electrabel.[87] The 31 other electricity users relied exclusively on Electrabel. We believe that Electrabel's high market share in the generation of electricity could mean that suppliers cannot buy enough volume of the commodity to supply to the 250GWh/y customer in our previous example. Additionally, suppliers relying on import capacity could be perceived as less reliable than those that have their own production facilities. In this sense, Electrabel's vertical integration will confer an image of more reliable supplier. Finally, we think it is also possible that supplying large volumes of electricity implies a risk (need of diversification of client portfolio, expensive balancing services, etc.) that only large companies (such as Electrabel) can take.

In our consultations, market participants identified the following segments of the market where only one, two three or more suppliers are currently active:

- More than 250GWh/y: Electrabel is the only supplier.
- 100GWh/y-250GWh/y: SPE and Electrabel are active in this segment.
- 10GWh/y-100GWh/y: EDF, Electrabel and SPE are the main active suppliers in the segment.
- Below 10GWh/y (only in Flanders): Various suppliers.

Besides the participants' views, there are other points to consider that would support the argument of product markets that are segmented along usage

[86] According to the Commission decision, the Belgian authorities share this view.

[87] These four users were supplied by three different suppliers.

bands. For one, the type of sales and marketing efforts that must be made for signing up large customers will be very different from that for acquiring small customers (SMEs, residential market). Sales to large customers will be specialised business to business contract negotiations, while residential sales are generally via the normal channels of mass marketing, including advertising, door-to-door, and telephone canvassing.

While our evidence is not sufficient to reject the market definition adopted by the Belgian Competition Authority and the European Commission, we believe that it can be useful to analyse the market according to the more narrow market definition to see how sensitive the results are to the definition of the relevant market. In addition, in the early stages when competition is nascent, caution would suggest erring on the side of the more narrow definition, to ensure that certain important segments of the market are not closed off, or dominated by a single player.

The geographical market

Geographical market definition can proceed along several lines. It can be defined as national, regional, or as small as a part of a city. Evidence of two products belonging to the same geographical market can be found when they are subject to similar market conditions or show strong price correlation over a certain period of time.[88]

An analysis undertaken by the Belgian Competition Authority concluded that supply and demand structures/conditions are similar in the three Belgian regions and very distinct from those in neighbouring countries. Therefore, according to the Conseil de la Concurrence, the national market is the relevant one for competition matters in electricity supply in Belgium.[89]

That being said, foreign competition should not be *a priori* excluded in the definition of the geographic market, as the correct geographical definition need not coincide with national boundaries. As markets tend to become more internationalised, eligible clients will be able to obtain their supply from any supplier outside Belgium. However, the limited interconnectors capacity means that the generation capacity available from abroad is limited and therefore the potential impact of the interconnectors on market concentration and market structure will also be limited (see Chapter 2). The result for electricity suppliers is that ready sources of wholesale power outside of Belgium (where generation and supply are controlled by Electrabel) are not available in significant scale. This suggests that a supra-national geographical market definition for electricity supply is not the relevant one.

[88] Tracking price offers over time and by geographical region is something Ofgem does do. We suggest CREG to undertake similar surveys. This point is addressed again in the "monitoring methodology" chapter.

[89] This position has also been adopted by the European Commission in the referral back to the Belgian competition authorities of 19 December 2003 regarding the Sibelga case.

Therefore, we agree with the geographical definition adopted by the Belgian Competition Council because differences between countries such as tariff structures for transmission and distribution, taxations schemes, line losses, and limited international interconnection would all support the rationale of a national market definition for electricity supply.[90]

We believe that this geographical definition is the most likely long-run definition to be used. Most countries such as the UK, Ireland, and others that are well along on their electricity liberalisation programmes have, for the most part, achieved competition in electricity supply on a national scale.[91] At the same time, perhaps over a time period of more than 5-7 years, it is certainly possible that the relevant market may extend beyond the national boundaries. This would occur to the extent that regulations, taxes, and transport costs, as well as interconnection capacity, begin to converge over time and suppliers in neighbouring countries compete effectively in Belgium. However, there may still be barriers to full international competition, such as language and nationally distinct media markets, though.

4.2 Market structure

Analysis of market structure is an important element in the evaluation of competitive markets. When assessing whether and to what extent market power exists, it is helpful to consider market factors that prevent a player from profitably sustaining prices above competitive levels. One of these factors is the presence of already existing competitors in the market. If customers can switch their purchases to existing competitors, it might be unprofitable for an existing supplier to sustain prices above competitive levels. Therefore, market shares of competitors in the relevant market are one measure of a competitive constraint that would prevent an existing company from sustaining prices above competitive levels.

4.2.1 Market shares

In general, market power is more likely to exist if a company (or group of companies) has a high market share. Likewise, market power is less likely to exist if a company has a low market share.[92] Market share analysis is one approach to analysing market structure, and thus competition.

[90] These would all drive a wedge between the prices that could be offered by a supplier in one country versus a supplier in another country.

[91] Although even in the UK, where supply competition is intense, the incumbents still maintain large market shares in their traditional areas

[92] In some cases the evolution of the market shares can also be informative in assessing market power because high volatile market shares in a dynamic innovative environment can be consistent with effective competition. This is analysed in the next subsection.

In Table 4.1 we show market shares for all Belgium, as reported by the European Commission (COMP/M.3318-ECS/Sibelga). The market shares are measured as the volume[93] of electricity supplied to eligible customers estimated by Electrabel for 2003.

This analysis already illustrates the very high market concentration in the Belgian supply market, with a large share of Electrabel, followed by SPE and Luminus with much smaller percentages. A threshold of 50 per cent is sometimes used as a cut-off point to identify industries with potential abuses of market power.[94] The market shares in the region of 80% for Electrabel are already an important signal that market power might exist in the Belgian electricity supply industry.

Our estimate of the HHI is in the range of 5829 to 7279, depending on the upper or lower bound of Electrabel's market shares. We think that the true HHI value could closer to the upper bound, but in any case, even the low end of the interval already indicates the supply market is highly concentrated.

Table 4.1: Market shares for Belgium (2003)

Supplier	Market share* (% of electricity supplied)
Electrabel	75-85
SPE	5-15
Luminus	5-15
Nuon	1
Essent	1
EDF	1
RWE	1
HHI	5829-7279

Note: *Electrabel estimates.
Source: COMP/M.3318-ECS/Sibelga.

The narrower product market definition proposed, segmented along usage lines, raises a geographic definitional challenge with an all Belgium market, as some segments are ineligible in some of the regions. This is because the

[93] The measurement of market shares on a turnover basis is more common but such data are not available. However, we do not believe this introduces significant bias, as the only way a volumes basis would differ from a turnover basis would be if one company consistently sold a lower price product than another. This is not likely the case in electricity supply in Belgium.

[94] For example, the European Court has stated that dominance can be presumed, in the absence of evidence to the contrary, if a company has a market share persistently above 50 per cent.

liberalisation timetable in Belgium is different in the three regions (Flanders, Brussels, and Wallonia). The market segments above 10GWh/y are eligible for all three regions, whereas the market segment below 10GWh/h is only liberalised in Flanders and for the other two regions the market will remain captive until 2007.[95] Therefore, the relevant market will be the three segments above 10GWh/y for all Belgium, and the segment below 10GWh/y for Flanders only. We should note that as the relevant market has a regional component (due to the different regional liberalisation schedules), such definitions will change as the liberalisation schedule progresses.

Data have been obtained on a regional basis only and this will condition our analysis. The VREG collects markets shares separately for households and industrial consumers, but not by the consumption segments identified above. In the analysis of market concentration we will use those figures as an approximation of the segments below 10GWh/y.

We will start by analysing the market below 10GWh/y using the VREG's market shares for suppliers of households and industrial consumers in Flanders. It is important to note that the market shares are constructed as a percentage of connection points (number of points of delivery served), as this is how VREG reports the market share data. We believe that household connection points shares can be a good estimate of market shares for households because their consumption is likely to be uniformly distributed and below 10GWh/y (according to the VREG, a typical household annual consumption is about 4000 kWh/y). However, industrial consumer data will also include some customers with consumption above 10GWh/y and their market shares will understate market concentration of the volume market. This is because the biggest suppliers are probably more likely to own customers with the biggest consumption.[96]

Table 4.2 reports VREG's market shares as of May 2004 for households, together with our calculations of the HHI. There are 9 main suppliers in Flanders but the market is still very heavily concentrated. Electrabel is the main supplier, with almost 73% of the total share of connected consumers, followed by Luminus with about 20%. Among the rest of suppliers, only Nuon, Essent Belgium and City Power are currently significant suppliers in the residential segment. Nuon has achieved a market share of 5%, but the remaining suppliers' share is still below 1%. It is interesting to note that EDF and Eon are not present in this market segment. In our consultations with market participants it was mentioned that they are not interested in entering

[95] Under the European Directive 2003/54/EC, all non-residential users are entitled to chose their electricity supplier. Residential users will be entitled to choose suppliers by 1st July 2007 at the latest. However, the timetable for the liberalisation of the electricity market is very different in the three Belgian regions: in Flanders, all users have had the possibility of choosing their electricity suppliers since 1st July 2003. In the Brussels and Walloon regions, all users of high voltage are already eligible (since 1st July 2004), whereas low voltage users will become eligible in 2007.

[96] We cannot fully verify this but it is consistent with our private consultations, surveys, and roundtable information gathered from supply industry participants.

that market segment, for the moment. Finally, our estimate of the HHI is 5749, which is indicative of a highly concentrated market.

Using the VREG's market shares for telemetered[97] industrial customers we observe that shares are similar to the household ones. We believe that the industry market share estimates based on the number of points of delivery served understate the level of market concentration. As we have already noted, if data for the volumes of electricity delivered were available, the picture would likely be very different because Electrabel (and also, although to a lesser extent, SPE) is the supplier of the largest customers. For this reason, we believe that Electrabel likely has a higher market share in this segment and the HHI for industrial customers should also be higher than what the current data suggest.

In summary, the market structure for customers below 10GWh/y has been estimated using household and telemetered industry consumers. Although we believe that the figures underestimate the market shares for big suppliers (particularly Electrabel), both estimates show high values of HHI consistent with concentrated markets.

[97] Telemetered corresponds to connections of 100 kVA and higher.

Table 4.2: Estimates of market structure for customers <10 GWh/y (Flanders, May 2004)

Supplier	Market shares* for households	Market shares* for telemetered industry consumers
Electrabel and ECS	72.98	69.44
Luminus	19.95	19.76
Nuon Belgium	4.84	5.53
Essent Belgium	0.92	2.62
SPE	0.01	1.65
Eon	0.00	0.36
EDF	0.00	0.30
Eneco Energie Levering	0.00	0.11
Elektriciteitsbedrijf Merksplas	0.15	0.09
City Power	0.86	0.08
Trianel	0.00	0.04
Ecopower	0.15	0.01
RWE Solutions AG	0.00	0.00
DSO	0.15	0.00
HHI	5749	5253

Note: * % of connection points
Source: VREG, 2004. London Economics computations

We now turn to the three market segments above 10GWh/y. We have reported that, according to consultations with suppliers, for more than 250GWh/y, Electrabel is the only supplier. This would mean a market share of 100% and the highest possible HHI value: 10,000. For supply between 100 and 250 GWh/y Electrabel and SPE are the only suppliers (industry estimates). In this case, the HHI can range from below 10,000 (in the limit case that Electrabel had almost all of the market share) to 5,000 (in the limit case that Electrabel and SPE had both 50% of the market share). We believe that the HHI is more likely to be closer to 10,000 than 5,000 but in any case the values are very high indicating that market power is likely to exist. The segment between 10 and 100 GWh/y is mainly supplied by Electrabel, SPE and EDF. Even in the unlikely situation where the market is uniformly distributed among those three players, the HHI would show a high value of 3,267, which is already high. However, we are more inclined to believe that the HHI would be again closer to 10,000 than to its 3,267 lower bound.

We also analyse the market for consumers with consumption above 10GWh/y in Wallonia and Brussels. The CWAPE provides information on market shares of electricity supplied for the Walloon region's overall

liberalised market. We can see in Table 4.3 that Electrabel is still retaining a very high market share for consumption above 10 GWh/y (above 90%). The calculated HHI, 8678, is very high by any standards. IBGE-BIM has provided information on market shares for the Brussels liberalized market. In Brussels Electrabel and its subsidiary ECS have a share of more than 90% of the market. The concentration of the market is evident with an HHI of 8778.

Table 4.3: Market structure for customers >10 GWh/y
Market share (% of electricity supplied)

Supplier	Walloon liberalised market (2003)	Brussels liberalized market* (2004)
Electrabel and ECS	93	94
EDF	5	5
Others	2	2
HHI	8678	8778

Note: * Figures for SIBELGA and ELIA, first half 2004.
Source: CWAPE, IBGE-BIM

In summary, the market structure is heavily concentrated for a market definition including all eligible customers in Belgium. We believe that the figures are likely to underestimate the market concentration for customers with high consumption volumes. The analysis for market segments above 10GWh/y suggests higher values of HHI. However, all the findings are consistent with a highly concentrated market in Belgium.

4.3 Conduct and performance

Market power can be thought of as the ability to sustain profitably prices above competitive levels. An electricity supplier with market power might also have the ability and incentive to harm competition in other ways, for example, by weakening existing competitors, raising entry barriers or slowing innovation.

The highly concentrated market shares in the electricity supply industry are an important factor in assessing dominance, but they do not determine per se whether a firm actually exercise market power. When assessing whether and to what extent market power exists, it is helpful to consider the strength of any competitive constraints. This is, whether there is anything that can prevent the dominant firm from sustaining prices above competitive levels or harming existing competition.

In the following sections, we explore this issue in greater detail.

4.3.1 Evolution of market shares

The evolution of Electrabel's market shares over time should be analysed because considering market shares at a single point in time might not reveal the dynamic nature of a market. For example, high but volatile market shares might indicate that (dominant) firms constantly innovate to get ahead of each other, which is consistent with effective competition.[98] In addition, evidence of firms with low market shares but growing rapidly to attain relatively large market shares might suggest that barriers to expansion are low, particularly when such growth is observed for recent entrants.

Data have been very difficult to obtain or estimate for Belgium. Historical market share have been obtained from the VREG for the Flemish region and are shown in Table 4.4. These figures are an indication that competition is starting in the Flemish region. After full deregulation, Nuon Belgium has been the most successful new entrant, acquiring more than 5% of the consumers, at the expense of Electrabel, which has lost about 3%, and Luminus (about 1%). Essent Belgium has also increased its market share and, to a lesser extent, City Power, Ecopower, EBEM and DSO (only below 1%). However, despite the slow entry, the initial situation at the beginning of liberalisation (very high concentration of Electrabel and Luminus) means that the market is sill very highly concentrated.

Moreover, industry market share estimates based on the number of points of delivery served are likely to understate the level of market concentration. If data for the volumes of electricity delivered were available, the picture would be different because Electrabel (and also, although to a lesser extent, SPE) is the supplier of the largest customers. For this reason, we believe that the market in Flanders is still heavily concentrated.

[98] Customer churn in domestic supply markets is also important. This is discussed in Chapter 8.

Table 4.4: Evolution of market shares for total supply in Flanders (% of access points)

Supplier	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Change Jan-Jun
Electrabel and ECS	75.84	75.02	74.46	74.01	73.41	72.99	-2.85
Luminus	20.97	20.6	20.32	19.96	19.75	19.57	-1.4
Nuon Belgium	1.66	2.74	3.45	4.17	4.72	5.21	3.55
Essent Belgium	0.6	0.69	0.74	0.81	0.9	1.01	0.41
City Power	0.7	0.72	0.74	0.75	0.79	0.82	0.12
EBEM	0.15	0.15	0.15	0.15	0.15	0.15	0.00
Ecopower	0.07	0.08	0.12	0.13	0.13	0.13	0.06
DSO	0.00	0.00	0.00	0.00	0.12	0.12	0.12
SPE	0.01	0.01	0.01	0.01	0.01	0.01	0.00
E.ON Belgium	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.00
EDF	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.00
Eneco Energie Levering	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.00
Trianel	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	0.00
RWE Solutions AG	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	100	100	100	100	100	100	100

Source: VREG and London Economics calculations.

The market concentration remains high in Flanders, especially if we compare it with the progress achieved in the UK. In England and Wales competition was introduced progressively in 1989. After the first year that the 1 MW market was opened to competition, the regional licensed suppliers (the RECs) had lost two-fifths of their sales volumes. The size of the competitive market increased in April 1994, when consumers between 100 kW and 1 MW were allowed to change their supplier. One quarter of them did so in the first year, and half had done so by the following year.

4.3.2 Entry of new suppliers

A fundamental feature of a competitive market is the choice available to customers in the market. One way this may be measured is by reference to the number of industrial and commercial electricity suppliers entering the market.

The VREG collects information on the number of suppliers active in the geographical area of each distribution networks. Table 4.5 indicates with an "X" the presence of the suppliers (in top row) in the geographical areas of the different distribution networks (first column). In the areas of Iveka, Iverlek, Gaselwest, Imewo, Interelectra and Intergem, 11 or more suppliers are operating. In the areas of Imea, Iveg, Wvem, Etiz, PBE and Sibelgas there are

between 8 and 10 suppliers. The remaining areas are less relevant as Intermosane' areas covers only a few towns in Flanders, Agem serves only the town of Merksplas, and Biac and Havenbedrijf are, respectively, the distributor for the Brussels airport and port of Antwerp.

In the same table, we can also see the presence of the suppliers in the different distribution network areas (in the last row). Although we do not have market shares, the table shows Eneco Energie Levering, Trianel as the suppliers with a narrower distribution, operating in 7 or fewer networks.[99]

Table 4.5: Electricity suppliers by distribution network (as in 1st April 2004)

	Electrabel Customer Solutions	Nuon Belgium	Luminus	Essent Belgium	City Power	Ecopower	Electrabel	SPE	E.ON Belgium	Electricité De France	Eneco Energie Levering	Trianel	Elektriciteitsbedrijf Merksplas (EBEM)	Total
IVEKA	X	X	X	X	X	X	X	X	X	X	X	X	X	13
IVERLEK	X	X	X	X	X	X	X	X	X	X	X	X		12
GASELWEST	X	X	X	X	X	X	X	X	X	X		X		11
IMEWO	X	X	X	X	X	X	X	X	X	X	X			11
INTERELECTRA	X	X	X	X	X	X	X	X	X	X	X			11
INTERGEM	X	X	X	X	X	X	X	X	X	X		X		11
IMEA	X	X	X	X	X	X	X	X	X			X		10
IVEG	X	X	X	X	X	X	X	X		X	X			10
WVEM	X	X	X	X	X	X		X	X	X	X			10
ETIZ	X	X	X	X	X	X	X	X	X					9
SIBELGAS	X	X	X	X	X		X	X	X		X			9
PBE	X	X	X	X	X	X		X		X				8
AGEM	X	X	X	X		X							X	6
BIAC	X	X	X	X			X							5
Havenbedrijf	X	X	X	X			X							5
INTERMOSANE	X	X												2
Total	16	16	15	15	12	12	12	12	10	9	7	5	2	

Source: VREG, 2004.

[99] In this analysis we exclude EBEM as the latter operates only in Merksplas.

Experience in other countries shows that, although after liberalization there is usually an increase in the number of suppliers, the number can fall after some years. For example, in its 1998 annual report Ofgem showed that the market shares of electricity suppliers in both the above 1MW and the 100kW to 1MW markets continued to decline as new entrants established themselves in the UK market. However, since October 1998 the number of suppliers actively competing in the market decreased as a result of some consolidation among the players. The fact that there are fewer suppliers does not in itself necessarily imply reduced rivalry. It would only be evidence of reduced competitive pressure if it were to be accompanied by other adverse indicators such as reduced pressure on prices.

Evidence shows that entry has occurred in Flanders, although differently across distribution networks. The presence of new entrants, though, is still insignificant in the domestic market in terms of connection points shares, as we can observe from Table 4.4. We believe that the current problem in Flanders market is not so much entry (to a large extent this has already taken place) but expansion and consolidation of entrants in the market and preventing their exit.

The situation in Wallonia is different. The number of players is very reduced and the market is still heavily concentrated: Electrabel together with ECS has 93% of the market (measured as % of electricity supplied), and there are only two more players, EDF Benelux and ALE Trading of any significance, all with a market share of less than 5% (see Table 4.3). In this case, lack of entry and consolidation means that there are less market constraints that can prevent the dominant firms from profitably sustaining prices above competitive levels.

4.3.3 Product differentiation

Sometimes the relevant market will contain products that are differentiated. In this case a firm might have a degree of market power because other products in the market are not very close substitutes.

As already seen, there are particular characteristics of the Belgian supply market for the different type of customers with consumption above 10GWh/y. The high concentration in those segments means that one company or group of companies could raise their prices above competition levels without facing competitive pressures to bring them down.

To assess whether prices for large consumers are higher than in a competitive market we have used different approaches. First, we have compared electricity prices with those in more competitive markets, and second we have analysed the margins obtained in that segment.

We first analyse price data from Global Insight[100] for three different customer types: large industrial customers, medium industrial customers and domestic customers. Prices for large and medium industrial customers are in each case calculated as an average of two representative groups. Large industrial customers include consumption of 50 GWh/y (annual load: 5000 hours) and 70 GWh/y[101] (annual load: 7000 hours). Medium industrial customers include consumption of 2 GWh/y and 10 GWh/y[102] (annual load: 4000 hours). Finally, domestic customers correspond to consumption of 3.5 MWh/y[103] (1.3 MWh at night, and 12kVA service capacity). The price paid data exclude VAT and taxes.

The data we use is the best data available for this analysis, but there remain some issues that must be considered to fully appreciate the significance of our results. First, the data are based on the whole Belgian market, not just the liberalised part: the market relevant to this study. Second, the data is not uniformly available. Not every country has a wholesale market from which price information can be recovered. Global Insight used Dutch and German wholesale prices, for instance, as estimates for the wholesale prices in Belgium and France, respectively. Dutch prices, themselves, were estimated using market intelligence and APX prices. Only UK and German prices were readily available from liquid wholesale trading markets.

We refine Global Insight's data by drawing on our own knowledge on Belgian wholesale prices. Since January 2004, we have Belgian wholesale prices, published by Platts. Using this information, we have estimated that the average wholesale price in Belgium was 5.7% higher than the corresponding price in the Netherlands over the period January 2004 to June 2004.[104] Accordingly, we adjust Global Insight's Belgian wholesale prices (which were simply the Dutch prices) by this percentage to create our own estimates of the historical Belgian wholesale price.

In Figure 4.1 to Figure 4.3 we describe the prices for different consumers. Figure 4.1 shows the evolution of prices for large industrial users in the three countries where data are available: Belgium (B), Germany (D) and the United Kingdom (UK). We can see that prices in Belgium remained almost constant, rising slightly over the four-year period. Prices fell in the other two countries. However, while the prices in the United Kingdom decreased steadily, in Germany prices fell sharply in 2000 but rose again in the following three years recovering almost half of the initial fall by 2003. The evolution of prices

[100] Global Insight (2004) Report Prepared For The CREG On The Comparison Of Power Prices And Costs In Belgium With Four Neighbouring Countries: 1999-2003.

[101] These consumers correspond to Eurostat types Ih and Ii.

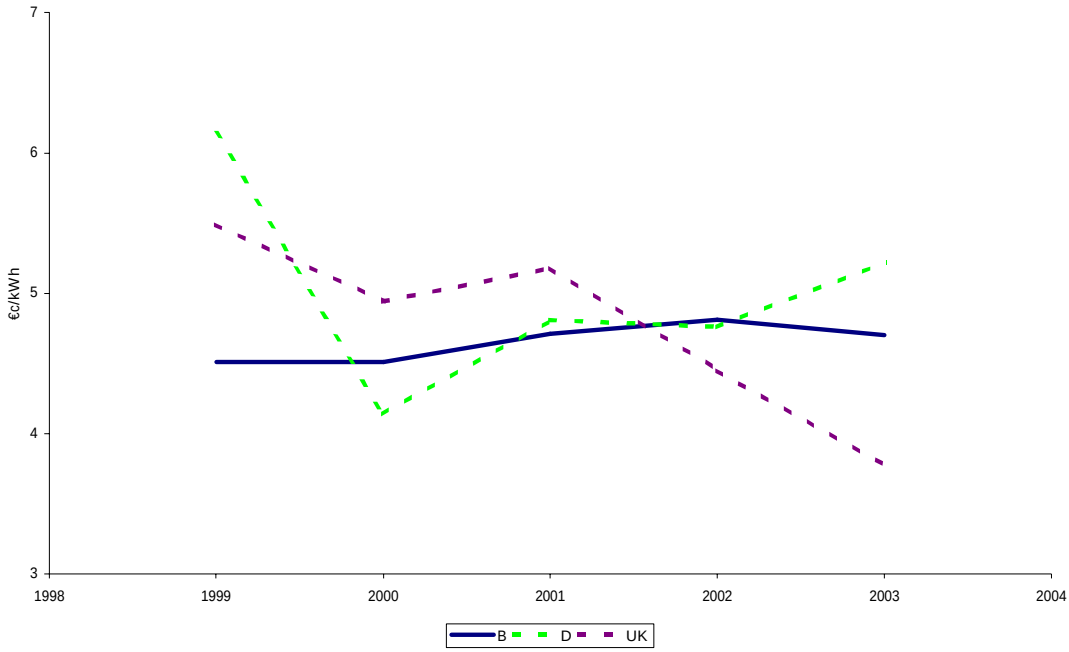
[102] Eurostat types Ie and If.

[103] Eurostat type Dc.

[104] See Table 2.9 in page 66.

in the United Kingdom and Germany resembles the one observed for medium industrial customers (see Figure 4.2). This means that although Belgian prices were the lowest of the three in 1999, in 2003 they were above UK prices and only 0.5 €c / kWh below than German prices.

Figure 4.1: Price charged to large industrial customers, 1999-2003



Source: Global Insight

Like prices to large industrial customers, prices to medium industrial customers in Belgium rose very slightly between 1999 and 2003. Again, the trend in other countries, now including France (F) and the Netherlands (NL), was one of falling prices (see Figure 4.2).

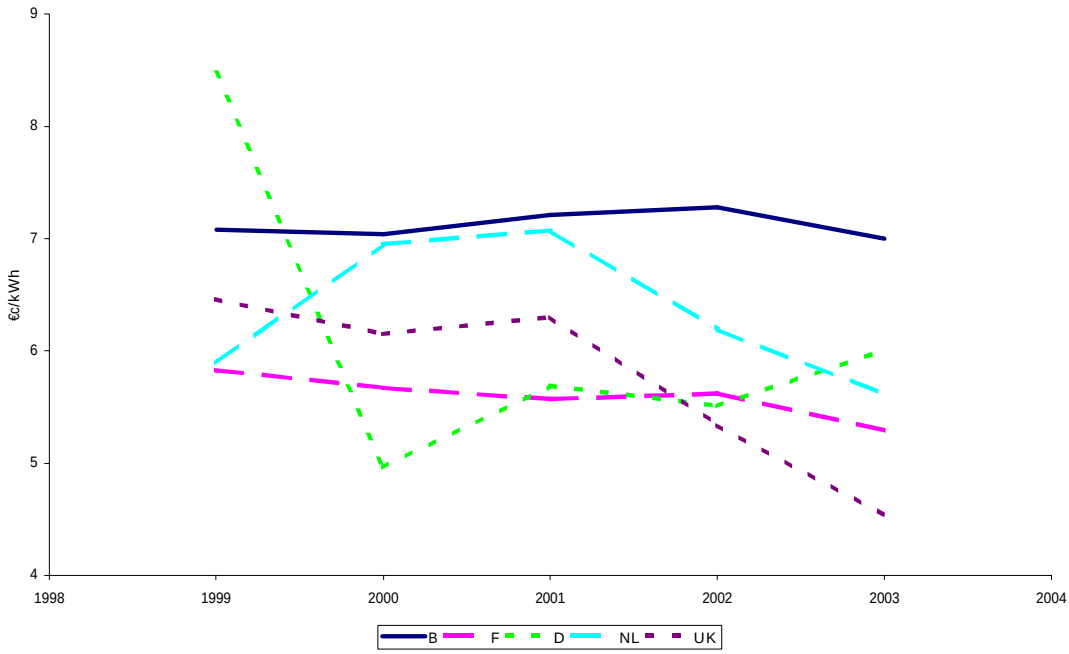
With prices to medium industrial customers falling in all other countries, prices in Belgium, which were the second highest in 1999, were the highest by a long way in 2003.

In France and the United Kingdom, the price fall was steady. We observe that French electricity prices are systematically lower than those in most other countries, which is likely to be a result of the large-scale use of nuclear generators. However, this lower price advantage is not found in the prices for domestic customers (see below).

In contrast to France and the United Kingdom, prices to medium industrial customers in Germany fell sharply between 1999 and 2000, but then rose steadily, recovering almost a third of the initial fall by 2003.

In the Netherlands, the price was higher in 2000 and in 2001 than in the rest of the sample period, but overall there was a slight fall in the Dutch price between 1999 and 2003.

Figure 4.2: Price charged to medium industrial customers, 1999-2003



Source: Global Insight

Whereas Belgian prices remained almost constant in the first two customer groups, Belgian prices to domestic customers fell sharply between 2001 and 2003. The total fall between 2001 and 2003 was 2.05 €c (from 12.31 €c/kWh to 10.26 €c/kWh).

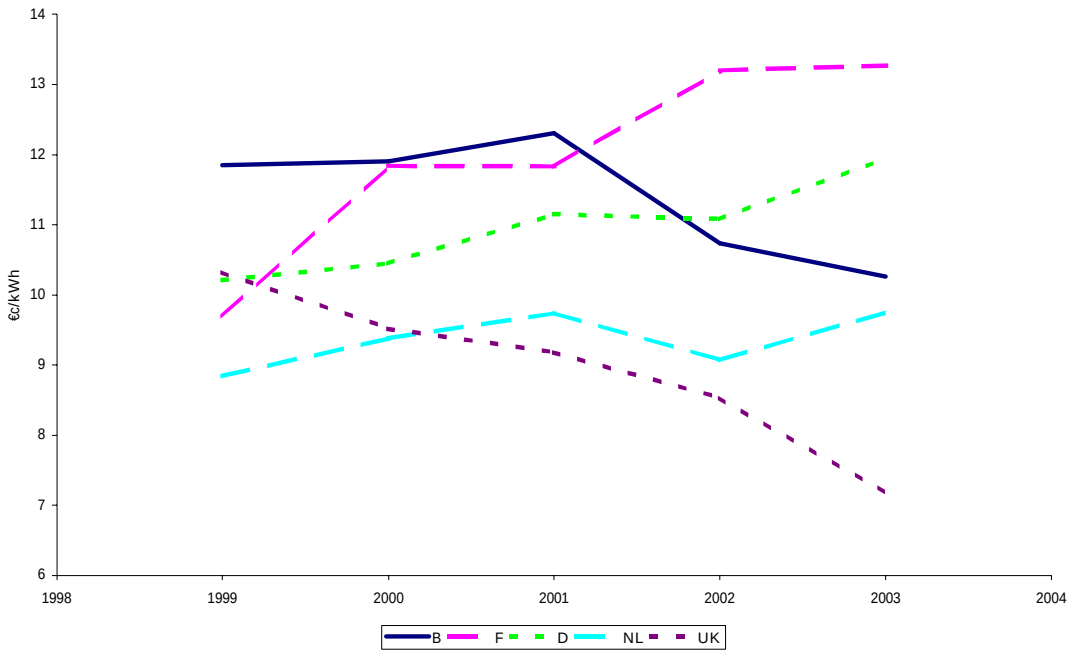
A comparison of prices to domestic customers across the five countries shows that the prices to domestic customers evolved in a markedly different manner from those of industrial customers.

The only other country, in which prices to domestic customers fell, was the United Kingdom, where the price fell even more steeply than in Belgium. But prices in France and Germany rose such that both countries posted higher prices than Belgium in 2003. The contrast between Belgium and France is stark, with the initial situation being that Belgian prices were higher by more than 2 €c/kWh, and the situation in 2003 being that French prices were higher by 3 €c/kWh.

Dutch and German prices moved almost in parallel in the sample period, which led to the German price for domestic customers rising above the

Belgian one and the gap between the Dutch and the Belgian prices closing significantly (from 3 €c / kWh in 1999 to 0.5 €c / kWh in 2003).

Figure 4.3: Price charged to domestic customers, 1999-2003



Source: Global Insight

Overall, the analysis (Figure 4.1 to Figure 4.3) shows that, according to the Global Insight data, electricity prices in Belgium for (both large and medium) industrial customers remained relatively unchanged between 1999 and 2003 whereas those for domestic customers did show a fall in the second half of the period.

Because the supply for large industrial customers is highly concentrated this evidence would support the hypothesis that market power is being used to sustain industrial consumer prices at a high level, when in other countries the prices have been decreasing.

In contrast, prices for domestic customers have experienced a big fall in Belgium since 2001. Competitive forces after the opening of the market for domestic consumers in Flanders in 2003 could partly be explaining this reduction.

We complement our analysis of prices with an analysis of retail margins using the Global Insight data. The retail margin shows the surplus above input costs that suppliers make on selling electricity to customers. The retail margin for supply to large industrial customers is constructed as the price charged to the customer *less* the wholesale price of electricity, and *less* the

costs of transmission. The retail margins for supply to medium industrial customers, and to domestic customers, are calculated in the same way, except that the cost of distribution is also subtracted from the price charged to the customer.

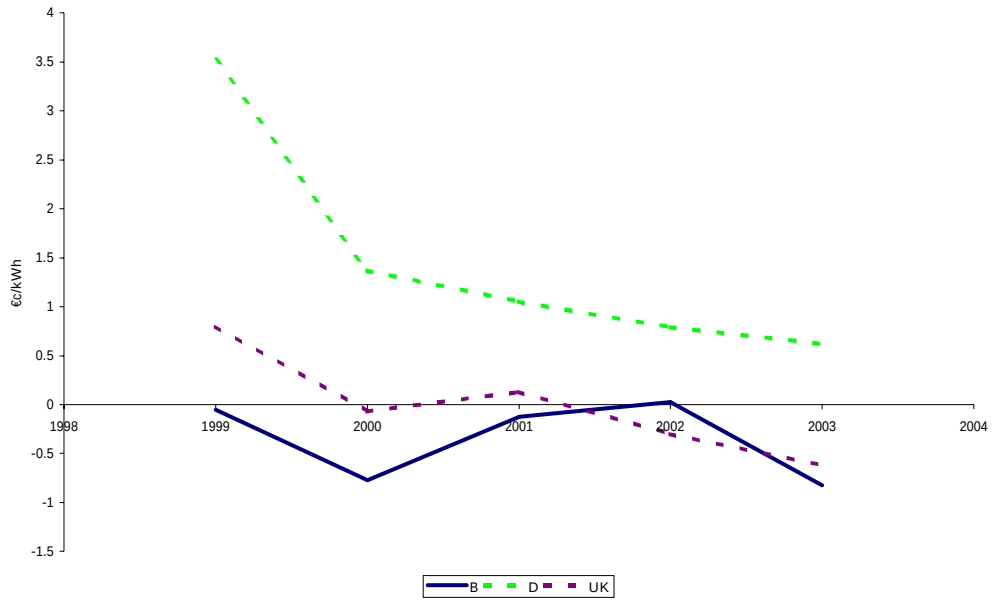
For large industrial customers, the Belgian retail margin, shown in Figure 4.4, was negative for almost the whole period between 1999 and 2003 (t was very slightly positive in 2002). At first glance, this seems unusual since it suggests that the activity is loss making. However, the suppliers of electricity to large industrial customers in Belgium are also generators. This means that they can still make a positive margin combining supply and generation margins.

The retail margin in Belgium on supply to large industrial customers fluctuated between 0.03 €c/kWh and -0.83 €c/kWh with no clear pattern over time.

The retail margin on supply to large industrial customers fell in both Germany (sharply at first) and the United Kingdom, the only two countries for which we have these data.

The German market was liberalised in 1998, which might help to explain the sharp fall between 1999 and 2000. Since 2000, the retail margin on large industrial customers in Germany fell at about the same rate as in the United Kingdom, the liberalisation of whose electricity market began in 1989.

Figure 4.4: Retail margin on sales to large industrial customers, 1999-2003

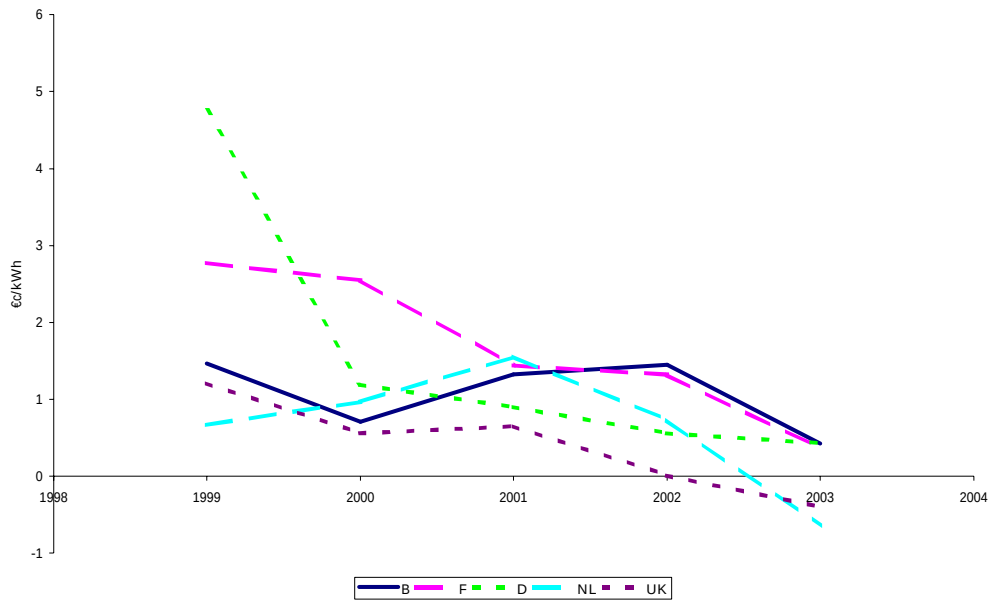


Source: London Economics' elaborations on data from Global Insight

The evolution of the retail margin in supply to medium industrial customers in Belgium was very similar to that of the margins on sales to large industrial customers between 1999 and 2003. However, in this instance, the margin was positive, fluctuating between 0.4 €c / kWh and 1.5 €c / kWh.

In all four of the other countries, the retail margin fell to within the boundaries of ±1 €c / kWh. This seems to be evidence of increased competition in the market for medium industrial customers, which would be as a result of the (sometimes gradual) market opening across Europe, in line with EC directives.

Figure 4.5: Retail margin on sales to medium industrial customers, 1999-2003



Source: London Economics' elaborations on data from Global Insight

Whereas the trend evolution of retail margins in the supply of electricity to (both large and medium) industrial customers was relatively uniform across countries, this is not true of the evolution of retail margins in the supply of electricity to domestic customers.

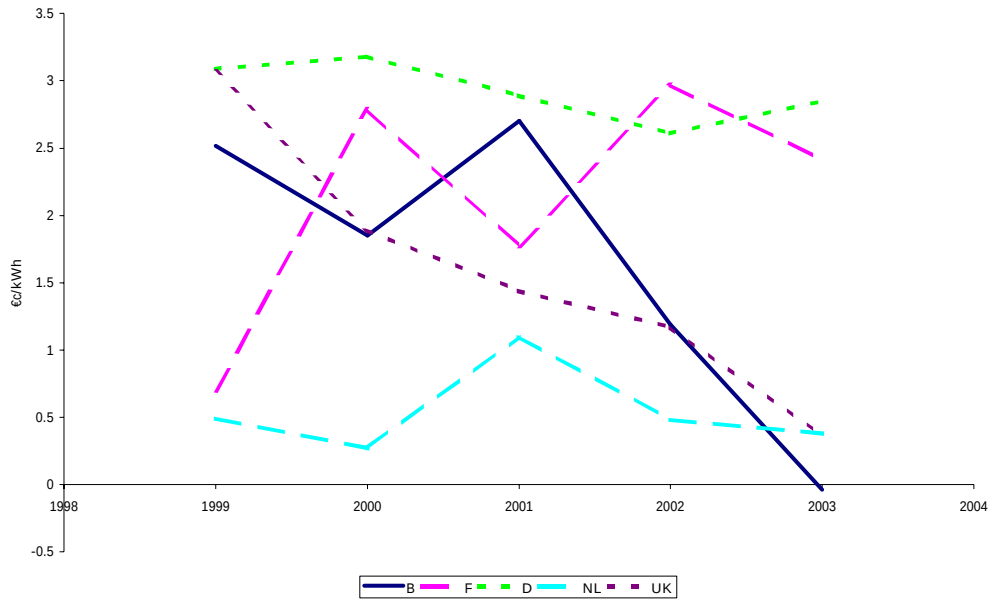
The fall in the Belgian retail margin in electricity supply to domestic customers is dramatically different from the relative constancy of retail margins of sales to the other two customer groups, and similar to the fall in the domestic customer retail margin in the UK electricity market. The fall in Belgium occurred mostly between 2001 and 2003, perhaps in anticipation of the coming liberalisation in 2003 in Flanders.

The differing timetables for market opening are reflected in the divergent evolutions of retail margins in supply to domestic customers. The United Kingdom and Germany have fully opened their electricity markets to competition. The Netherlands had only partially opened the market by 2003, with full liberalisation in July 2004. Though the liberalisation process in France began in 1999, the electricity market will not be opened at the domestic customer level until July 2007.

The corresponding retail margin in Germany fell slightly, though it remained the highest of domestic customer retail margins in the five countries.

Similarly, the Dutch retail margin fell slightly, after a small rise in 2001. The French retail margin, against the trend in the other four countries, rose strongly from being second lowest in 1999 (0.7 €c/kWh) to second highest in 2003 (2.4 €c/kWh).

Figure 4.6: Retail margin on sales to domestic customers, 1999-2003



Source: London Economics' elaborations on data from Global Insight

Overall, the investigation into the evolution of the margins (Figure 4.4 to Figure 4.6) shows that, in Belgium, the retail margins in supply to (both large and medium) industrial customers fell slightly between 1999 and 2003, though recurring fluctuations means that any suggestion of a trend must be interpreted with caution. The evidence of a trend tends to be stronger in the other countries, where liberalisation in the market for industrial customers as been taking place.

The reverse finding was made in the market of domestic customers. Here, the retail margin fell in Belgium as much as it fell in the United Kingdom. Again this could be partly explained by the opening of the Flanders domestic market in 2003. In contrast, relatively little change happened in the German and Dutch markets. In the French market, the retail margin on supply to domestic customers rose sharply.

These differences can, in large part, be explained by the different degree of market opening that happened and is expected to happen in the next few years. For example, the French market for domestic customers will not be opened until 2007.

4.3.4 Difficulty in purchasing electricity

As we have already seen in previous chapters, the generation market is very concentrated in Belgium with Electrabel controlling more than 81% of the electricity production capacity. Buying electricity from abroad is not really an option currently, as the import capacity is physically limited, congestion is unpredictable, and risk management for energy and balancing is not feasible. Finally, investing in generating capacity is not easy because generation sites are not readily available to new entrants. The dominant position of Electrabel in generation creates a number of risks for new entrants.

Refusal to supply

A refusal to supply occurs where a dominant firm stops supplying an existing customer or withholds supplies from a new customer. A refusal to supply by a dominant firm is likely to be considered an abuse where it results in the elimination of competition or suppress the emergence of new entry.

There appears to exist one potential precedent of refusal to supply in Belgium. SourcePower alleged that Electrabel refused to supply them with emergency energy to replace energy that could not be imported over the congested interconnector.

At present, we do not have evidence that refusal to supply is occurring in Belgium, but we believe that if entrants view this as a distinct risk it could act as an important barrier to entry. Sometimes behaviour that has the same effect as a refusal to supply could also constitute an abuse. For example, the dominant firm might supply at such an inferior level of quality, that customers would effectively be prevented from purchasing it.

Manipulation of wholesale prices

The limited alternative of other sources of power (which is likely to prevail in the long run) could allow Electrabel to manipulate the wholesale prices and set them above the competitive level. As a result, the price of power would enter at artificially high prices that directly translate into higher costs for the suppliers. For example, some suppliers reported that the wholesale price has

been rising at times they were trying to negotiate significant long-term volume contracts with large electricity consumers. As a result, their margin was reduced. We have not been able to corroborate this because of lack of data. To evaluate this one would require wholesale prices (ideally daily) and the dates at which contracts were negotiated. One could then test if important changes in the wholesale prices took place at the same time than contracts were being negotiated.[105]

Price manipulation can also be aimed at increasing the volatility of prices as opposed to their average level. In such a situation, a risk-averse buyer would be willing to buy power on the forward market (usually at a higher price) instead of the spot market. This would automatically translate into higher supply costs that might be difficult to pass on to consumers. As a result, this reduces the expected profitability of existing suppliers and could make entry into the supply market unprofitable.

Margin squeeze

A margin squeeze may be observed in an industry where a vertically integrated firm is dominant in the supply of an important input for a downstream market in which it also operates. The vertically integrated firm could then harm competition by setting such a low margin between its input price (e.g. wholesale price) and the price it sets in the downstream market (e.g. retail price) that an efficient downstream competitor is forced to exit the market or is unable to compete effectively.

Electrabel is operating in the supply electricity market directly and indirectly through its subsidiary company ECS. The current vertical integration structure makes margin squeeze a possible option. It is possible for Electrabel to raise the wholesale price and squeeze the margin between the wholesale and retail price such that supply competitors find it unprofitable to operate. So, while supply competitors would struggle to survive financially, the Electrabel group profits would remain largely unchanged thanks to higher wholesale prices charged by the generation arm.

Even if actual wholesale prices were set the level of marginal generation costs, this would not protect a new entrant in the supply market against the *possibility* of being squeezed in the future. Wholesale prices might not be observed to be persistently high over time, but the prospect that they could be raised in the future constitutes a risk for suppliers, and might act as a barrier to entry. The threat of raising wholesale prices to punish new entrants into the supply market might deter *potential* entrants from entering the market.

To test whether margin squeeze has occurred recently in Belgium we have analysed the evolution of the margins between retail and wholesale prices

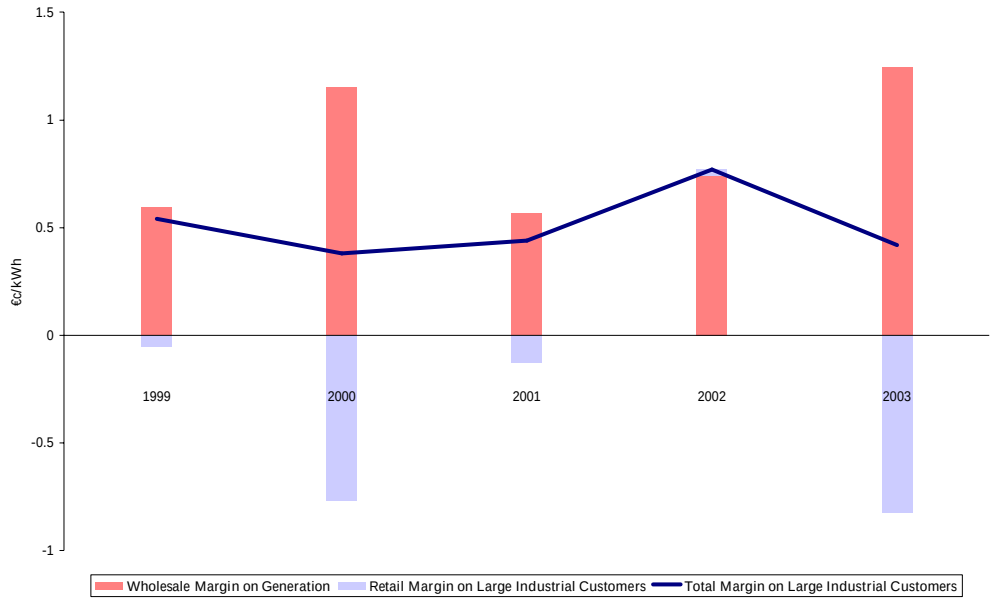
[105] Statistical tests could be used to assess whether this differences are statistically significant compared with other moments in time.

and between wholesale and generation costs. A margin squeeze would be consistent with findings that retail-wholesale margins have been reduced while wholesale-generation margins have increased.

We have analysed these margins using Global Insight data for three different customer types: large industrial customers, medium industrial customers and domestic customers (defined as above). The retail margin for supply to large industrial customers was constructed as the customer price less the wholesale price of electricity and transmission costs. The retail margins for supply to medium industrial customers, and to domestic customers, were calculated in the same way, except that the cost of distribution was also subtracted from the price charged to the customer.

Figure 4.7 shows the wholesale margin, the retail margin on sales to large industrial customers, and the total margin (the sum of the margins on wholesale and retail). We can see that the total margin on sales to large industrial users remained fairly constant between 1999 and 2003, at about 0.5 €c/kWh.

Figure 4.7: Total margin on electricity produced and sold to large industrial customers, 1999-2003



Source: London Economics' elaborations on data from Global Insight

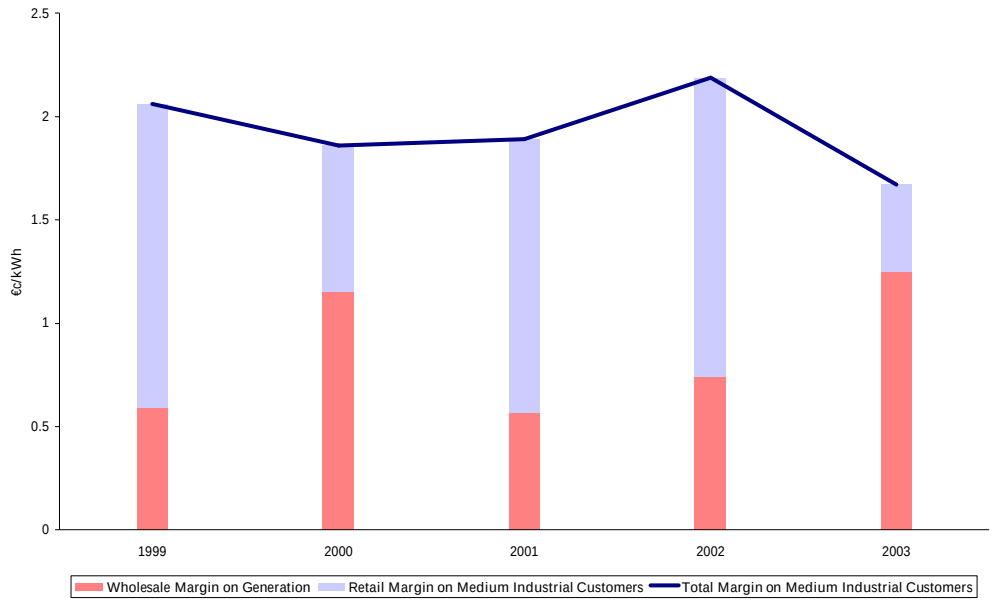
The retail margin on sales to large industrial customers was negative throughout the sample period, and was relatively volatile. Nevertheless, the total margin is relatively stable as any changes in the retail margin were to a large extent offset for by changes in the wholesale margin on generation. Although the retail margin on sales to industrial customers was negative

throughout most of the period, the wholesale margin was sufficiently positive that the total margin was also positive.

The market in Belgium for electricity to large industrial customers is characterised by vertically integrated companies. Mainly Electrabel, SPE and EDF supply large industrial customers. These companies appear to have made a positive margin over the whole supply chain, since the retail price was always higher than total costs (production costs, and transmission costs). However, it is surprising that in 2003 when all Belgian customers above 10GWh/y where eligible, we observe that the retail margin for large industrial customers is much lower than in previous years. This could be a sign of margin squeeze to deter entry from new entrants.

The total margin on electricity consumed by medium industrial customers shows a similar profile to that of the margin on sales to large industrial customers, except that the absolute value of the margin was about four times as high, at 2 €c/kWh. There seems to have been a slightly stronger downward trend in this segment. As was the case of sales to large industrial users, variations in the retail margin of sales to medium industrial users seem to be offset by changes in the wholesale margin on generation (Figure 4.8).

Figure 4.8: Total margin on electricity produced and sold to medium industrial customers, 1999-2003



Source: London Economics' elaborations on data from Global Insight

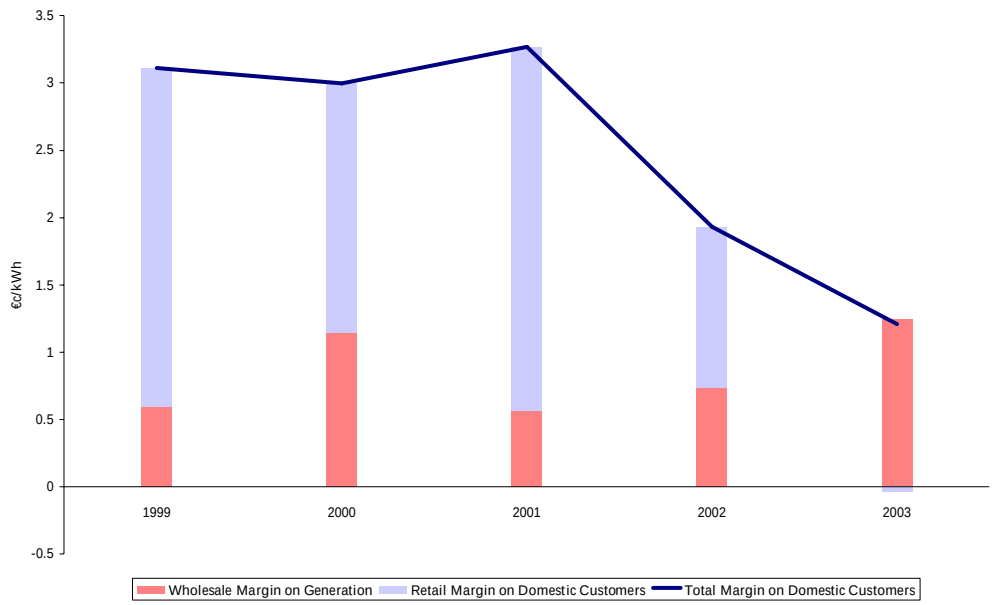
If the data on medium industrial consumers were representative of the margins in Flanders, not an unreasonable assumption since Flanders represents 64% of the Belgian electricity supply market, this could be

indicative of margin squeeze. This could mean that in recent years the dominant vertically integrated firm has increased its margins at the generation stage and reduced dramatically the margins on sales to medium industrial consumers in 2003. However, the picture observed in Figure 4.8 could also be compatible with the argument that an increase of competition in the medium industrial consumers market has brought margins down to a competitive level. Therefore, although indicative, we think these results should be used with caution.

The situation is similar for domestic customers. The total margin on electricity to domestic customers showed a sharp fall in 2002 and 2003. What used to be the largest margin, at about 3 €c/kWh in 1999, roughly fell by half in four years. The difference between this result and those for the other two customer groups is due to the sharper fall in the retail margin for supply to domestic customers.

The fall in the total margin that occurred in 2002 and 2003 is reflecting perhaps increasing competition in this segment, as the Flanders market became eligible to all customers in 2003. This could also be evidence of margin squeeze meaning that the vertically integrated company is shifting the margins to generation.

Figure 4.9: Total margin on electricity produced and sold to domestic customers, 1999-2003



Source: London Economics' elaborations on data from Global Insight

Overall we have not only shown that the current structure makes market squeeze in Belgium possible, but also that there is some evidence that suggests that a margin squeeze may have occurred in Belgium.

Supply under preferential terms

Competition in the supply market can also be distorted if Electrabel is able to supply its subsidiary at better terms than those available to the competitors in the supply market. This could mean that the generation business provides better service to its own supply business in terms of customer service, or provision of not only faster but also more accurate information. There is the additional possibility that the generation business and supply business share commercially sensitive information of competitors in the supply business.

Whether Electrabel supplies its sales arm and ECS at preferential terms is something London Economics has been unable to corroborate. In any case, even if discrimination is currently inexistent, suppliers might fear that the dominant supplier could engage in such practice in the future, especially if they become too successful. Also, potential new market entrants might view the risk that they could be discriminated against as very high and, therefore may be deterred from entering the supply market.

Transaction costs

Although the major debate in vertical integrated markets has been on the potential abuse of market power, there are a number of theories that discuss efficiency reasons for firms to integrate. Some economists (Williamson, 1971) have argued that vertical integration might reduce transaction costs, i.e., costs associated with market transactions between buyers and sellers. Firms have costs due to market transaction such as acquiring, handling and processing information to ensure correct decisions are being taken. In this sense, if transactions through the market are costly it provides incentives for firms to "internalise" such transactions. One way of doing so would be to integrate vertically.

According to the transaction costs theory, vertical integration in the Belgian electricity market would mean that one company would be able to achieve efficiency gains, but not the others. In such a case, Electrabel would have a competitive advantage over its rival suppliers. This is because the rest of suppliers would have to bear the costs of transactions that Electrabel can reduce by being vertically integrated. We believe that there are some efficiency reasons for vertical integration between generation and supply, as is evident from the recent UK experience, and suggested by Newbery (2002).

Following this argument, if efficiency reasons for vertical integration exist in the Belgian electricity market, vertical integration should not be limited to only one firm only. Electrabel's dominant position in generation prevents other firms from achieving efficiencies that Electrabel enjoys. Thus, if there are efficiencies from vertical integration, then vertical integration, *combined*

with Electrabel's dominance in generation, represents a competitive advantage and could also be a significant barrier to entry into supply.

Effect of the VPP

While the current levels of VPP offered in the market do facilitate entry into the market, we feel there is still a long way to go if VPP is to be the only way a supplier can source commodity, besides buying from Electrabel or over the interconnectors, especially at current interconnector capacity.

The fact that virtual generating capacity is being made available to the market offers a new source of wholesale electricity that suppliers can then sell to their final customers. Without the VPP vehicle, suppliers would be limited to buying their power directly from Electrabel, or through more uncertain channels, such as electricity imports, where there is the possibility of congestion and little to no possibility to economically hedge the risks of congestions.

The structure of the contracts and the prices should be sufficient to allow suppliers to gain a foothold in the market. The fact that both base-load and peak-load capacity contracts are offered in the Belgian VPPs should also contribute to making the auction more attractive to suppliers, who obviously need to have both these types of capacity available. In addition, the VPP products offer suppliers more flexibility than many traded 'base-load' and 'peak-load' products. This is because the schedule of deliveries for the VPP products can be chosen one day ahead, on a quarter-hourly basis, and is not pre-determined.

There are a number of downsides to the VPP. Above all is that buying VPPs is still buying from Electrabel. Rightly or wrongly, suppliers fear that Electrabel is aware of when they are trying to negotiate deals with large to medium-sized customers. Also, suppliers fear that Electrabel will know what power they are using and when, at what price, etc.

In the first two auctions there was a low demand for the longer-term products. This may reflect either lack of interest from current potential buyers (where suppliers are included), too few potential buyers to begin with, or the possibility that these contracts were being offered at too high a premium over shorter-term products. In the last auction (May 25, 2004) there has been an increase in the purchase of long-term products: the average maturity of the products purchased by suppliers, as computed by the CREG[106], increased from 11 months in the first two auctions to 14 months in the last one. The explanation cannot lie on an increase in the number of potential buyers, since the number of qualified parties has only increased from 14 to 15 in the last two auctions. However, the number of VPP buyers

[106] CREG (2004) L'évaluation au 20 juin 2004 de la mise en œuvre des capacités virtuelles de production d'électricité.

increased from 6 to 9 in the last auction which suggests an increase in interest that could partly explain the increase in demand for long-term products.

4.3.5 Transmission costs

In Belgium, the transmission grid is operated by Elia Systems Operations, which is in turn owned by Electrabel. The natural monopoly position of Elia has potential threats that can harm competition.

At present, the regulator determines the tariffs for the use of the transmission grid based on the cost estimates of Elia, which are not observable. Moreover, as in any regulated industry, despite the regulator's efforts, the regulated company has incentives to provide information that benefits the company and not the regulator.

In the supply industry there exists the belief that Elia will estimate their costs on the high side. These fears seem particularly relevant in this case where the regulated company is vertically integrated to supply. Inflating Elia's costs will not only increase its benefits, but will also harm the competition on the supply side as suppliers will incur in higher costs. This is likely to reduce competition in the supply side to the benefit of Electrabel.

When consulted, suppliers stated that the transportation tariffs are too high. We have not been able to confirm this impression. Transmission costs in Belgium, as reported by Global Insight (2004), are broadly similar across its four neighbouring countries and Belgian transmission costs in 2003 were in line with the average of the four neighbouring countries. However, the belief among suppliers of high transmission costs could already act as a barrier to entry. In addition, the tariffs currently imposed by the CREG are valid for three months, with the possibility for extension for another three. This provisional tariffs system creates a sense of uncertainty among suppliers because they do not know what will happen after the period of three months. Because the next tariffs could be higher, lower or equal as the previous ones it is not possible to forecast annual transmission costs, and this has an impact on suppliers ability to offer fixed price contracts. It is possible that this constitutes a barrier to entry if Electrabel has some privileged information or experience in forecasting Elia's tariffs that other suppliers do not have. Distribution networks

Ownership

While major industrial consumers are generally connected directly to the transportation grid, all other users are supplied through the distribution grids which are operated by the DSOs. Many of these DSOs are mixed intercommunales and about 80% of the distribution is carried out by the mixed intercommunales. Electrabel owns in most cases more than 50% of the

capital[107] of these intercommunales and provides the technical operating services.

This creates the problem that suppliers may not face a level playing field in term of information about clients and potential clients. We address this point more extensively in our discussion of the barriers to entry in Chapter 6.

Distribution tariffs and surcharges

There is a general problem with regulating any utility on a cost of service basis. The costs are unknown to the regulator and the companies invariably have better information than the regulator. Therefore, there will necessarily be the problem of the regulatory need to estimate uncertain costs based on limited information.

Currently, the main problem with regulated distribution tariffs is that, so far, they have mainly been approved on a provisional basis. This can create uncertainty for suppliers when quoting supply prices to their clients.

Additional uncertainty for suppliers originates from the fact that many surcharges are levied on electricity, both at the federal and regional level, and that the level of these surcharges has been difficult to predict.

Suppliers typically strike contracts on an all in energy basis. Changes in tariffs that run during a contract will thus be absorbed by the supplier. Unless the suppliers can include conditions in their supply contracts to pass tariffs and surcharges to the final consumer this constitutes a risk for suppliers. If suppliers do not know their own costs it is hard to properly set their prices. If they set the prices above their costs this will make them lose market share to other competitors. But if they set prices below cost they will be losing money on a per unit basis. The uncertainty surrounding provisional distribution tariffs is likely to have different effects in the companies. Larger suppliers may be better positioned to cover that risk than smaller companies. Again, we discuss this point in greater details in Chapter 6.

Difficulties of switching supplier

One of the areas where the supply market competition necessitates much work is in customer switching.

According to some suppliers, it takes quite a long time to switch end-users. We are unable to confirm if the switching time is "too long" or not. Whether this sluggishness is intended or not is hard to assess, but what is clear is that switching could be done faster if the DSOs had the right incentives to switch customers quickly. For example, under the current system in Wallonia, DSOs have up to 180 days to notify the EAN code to customers who request this information. Suppliers and customers must have confidence in the transfer process is made quick and effective for competition to be effective. Some

[107] Annual Report (2000). CREG.

progress is being made in as of 1 January 2005 the maximum period in Wallonia for providing the EAN code will be reduced to 30 days. But, more improvements could be made. For example, monitoring to ensure that mistakes and delays in billing and switching are minimised or that customer switching is not blocked by companies. In chapter 8 we discuss the data collection needs for CREG and we propose a range of indicators to monitor the proper functioning of the market; these include customer turnover, customer switching times, number of customer complaints, amount of time to correct errors, etc.

The speed at which customers are being switched is also an important factor to make the market more contestable. For example, a potential entrant might identify a clientele who will purchase its output below the current supplier's price. If the entrant has the possibility to sell to these customers before the incumbent has time to react the entrant will find it profitable to enter the market if he can recover fixed and variable costs. It could also even be possible for the entrant to follow a "hit-and-run" strategy leaving the market before the incumbent has time to react. The theory of contestable markets shows that under certain conditions incumbents may be forced to reduce their profits to a normal level because of *potential* rather than actual competition.

Customer switching is a crucial issue under the theory of contestable markets. This is because low customer switching costs in the absence of other barriers allows more entrants to compete for the electricity market, but also because it enforces the incumbents to reduce their profits at a normal level under the threat of potential entrants seeking a hit-and-run strategy.

The problem of customer switching supplier, and ensuring that the transfer is conducted promptly and reliably, is not a new one. For example, in the UK Energywatch (the energy industry's consumer watchdog) and the industry regulator Ofgem are challenging gas and electricity supply companies to make switching energy simpler for Britain's consumers.

Ofgem recognises that although the change of supplier involves a complex process, this is "critical to the operation of the market".[108] The threat to competition lies in customers being put off switching because of fears of the impact of process errors.

In June 2001 Ofgem set out the way forward[109] through the Improving Customer Transfers project. This document explained Ofgem's role in the existing change control process and published a revised set of principles against which Ofgem considered that changes to the transfer process should

[108] Ofgem (2003). Customer Transfer Process - Discussion Document: June 2003. http://www.ofgem.gov.uk /temp/ofgem/cache/cmsattach/3416_3503custtrans.pdf.

[109] Ofgem (2001). Improving the Customer Transfer Process – The Way Forward: June 2001. http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/73_26june01.pdf. See also Ofgem (2000) The ICT Project: Improving Customer Transfers in the domestic and designated energy markets. http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/75_12july00.pdf.

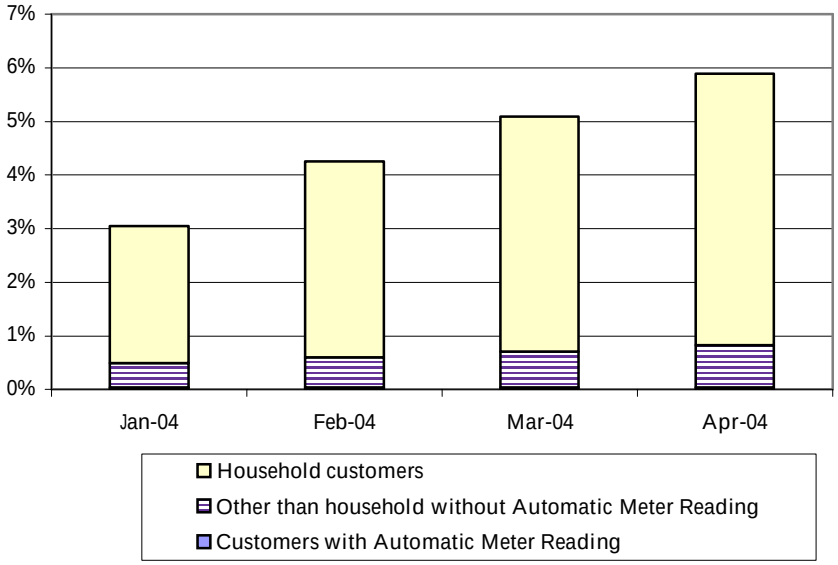
be judged. The industry has since implemented a number of significant changes. For example, suppliers have put in place arrangements for returning customers with the minimum of fuss following an erroneous transfer. Progress has also been made on data handling and the industry is moving to allow electricity suppliers on-line access to the data that they require to service their customers.

Ofgem highlights that, as a result of competition, the rates of customer switching are very high. Ofgem estimates that in 2003 4.2 million electricity household customers changed suppliers. The current rate of switching (38 per cent) is higher than in any other comparable industry and higher than anywhere else in the world. Research[110] also shows that suppliers lose customers when they increase their prices, which is suggestive that competition is working. As a result, customer satisfaction levels are high with the majority finding switching easy.

The VREG provides data on the share of customers having a contract with a new supplier in 2004 (other than ECS, Luminus or Elektriciteitsbedrijf Merksplas). There is some evidence of consumers switching slowly to new suppliers in the Flemish region. In April 2004, about 6% of all consumers had switched to a new supplier.

[110] Ofgem (2004). Energy competition working for customers - the state of competition in domestic gas and electricity supply http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/7238_factsheet40_april04.pdf.

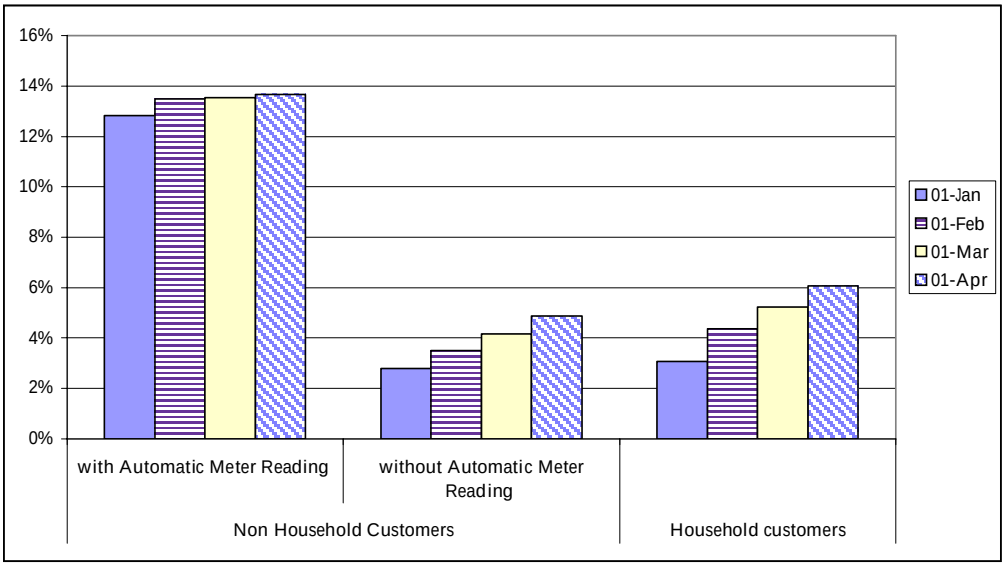
Figure 4.10: Share* of customers having a contract with a new supplier. Flanders (2004)



Note: * Share of access points for customers in Flanders under the competence of VREG. New suppliers are those other than ECS, Luminus or Elektriciteitsbedrijf Merksplas.

In the next figure we observe the shares of number of consumers (connection points) switching within each customer category. Almost 14% of customers with automatic reading have switched to a new supplier (other than ECS, Luminus or Elektriciteitsbedrijf Merksplas). The percentage of households who have switched is much lower, below 6%, but has been increasing rapidly recently.

Figure 4.11: Customers having contract with a new supplier as a share* of each category. Flanders (2004)



Note: * Share of access points for customers in Flanders under the competence of VREG. New suppliers are those other than ECS, Luminus or Elektriciteitsbedrijf Merksplas.

The current structure in the Walloon liberalised market also shows signs that switching has been progressing slowly. In Table 4.3 we reported that the market is still very concentrated with Electrabel/ECS having 93% of the market.

The IBGE-BIM report that since liberalisation in Brussels there have been 13 switches (11 from January to December 2003 and 2 from January 2004 to March 2004) out of 71 EAN for Sibelga's distribution grid and there have been no switches (out of 8 connection points) recorded for Elia's network. The Brussels market is still very concentrated.

We can compare the customer switching in Flanders with the progress achieved in England and Wales. After the first year competition was introduced, the regional licensed suppliers (the RECs) had lost two-fifths of their sales volumes of the 1 MW market. When consumers between 100 kW and 1 MW were allowed to change their supplier, one quarter of them did so in the first year, and half had done so by the following year. The current rate of switching in the United Kingdom is 38% (this is net switching rate, i.e. the percentage of customers that are not with their incumbent supplier).

As another example we provide is the experience in Sweden, where the markets were liberalised in 1998. Since then, switching activity in Sweden has been evident and active. The first year after liberalization 7% of customers had switched. The share of switchers after 2, 3 and 4 years were

respectively 10%, 17% and 21%.[111] The main factors behind consumer switching behaviour in Sweden have been price[112], service quality and bill accuracy. Some of the reasons why the switching activity is higher in Sweden than in other European countries include customers' initiative (it is common that customers make the first contact with a supplier after having searched the Internet, or received information from friends or newspapers) or customers' awareness (in 2002, 96% of Swedish consumers were aware that they could switch electricity supplier).

The experience in Flanders shows that so far customer switching is behind the achievements in England and Wales but broadly similar to the experience of Sweden.

Metering information

A very important aspect for operating in the supply market is to have access to accurate information on profiles, loads shapes, metered volumes, etc. Among the biggest concerns of suppliers is the lack of proper information on their actual and potential clients[113], lack of a rich set of customer profiles, very late provision of information on their customers' actual consumption and problems with allocation and reconciliation combined with an expensive balancing mechanism.

Suppliers complained that the information they receive is of low quality, and made available only with long delays (sometimes six months). In addition, in some cases inefficiencies might come from the way distribution operators are currently collecting the information. One supplier told us that the distribution operators only collect aggregate night and day customer information and this makes it difficult for suppliers to create daily customer profiles.

The fact that the metering data, standard yearly consumption data, master data is not delivered on time or is incorrect has an impact on suppliers business. Suppliers are unable to estimate the consumption volume of the client and to identify customers' profiles. Hence, suppliers run a very high financial risk in a narrow margin market. As a result, the risk/reward balance is, according to the suppliers we met, much poorer in Belgium than in other European markets. This point is addressed in the Chapter on barriers to entry.

[111] Sources: Arvidson (2003), Ketola and Matsson (2000).

[112] Dialego 2002, KV 2002 and Ofgem 2001.

[113] For example, we have been informed that the lack of a complete EAN code register results in a lot of problems such as wrong switching, missing measurement and master data, wrong sourcing, etc and, that the process of addressing these problems is resource-intensive.

Asymmetric access to information

Another important issue is the fact that Electrabel still provides the technical operational services to the mixed intercommunales and that the information systems used by these DSO are integrated into Electrabel's own IT systems. While Chinese wall exist in theory between the part of Electrabel providing the technical services to the mixed intercommunales and the Electrabel proper, leaks may occur. Suppliers told us that, as a result of this fact, Electrabel has an unfair advantage over them because it can gain access to commercially valuable information about their clients. We have been unable to ascertain whether such leaks did actually occur. But, the mere fact that they may occur increases risk to Electrabel's competitors and may deter entry.

4.3.6 Issues related to the choice of the default supplier

Through 2002 and 2003, the Belgian Competition Council started approved various transactions leading to the appointment of ECS as the default supplier for the customers of the mixed intercommunales.

We believe the choice to designate ECS as the default supplier has missed an important opportunity to introduce competition in the supply market for the following reasons:

- It gives Electrabel a lead over new entrants because of its client base. New entrants will need to invest significant resources to acquire new customers whereas Electrabel will need to invest only in keeping customers from switching.[114]
- It reinforces the vertical integration of Electrabel. The problems from vertical integration could have been mitigated if the default supplier had been a different supplier. In some situations, an increase of market power in the supply market may help countervail the market power in generation.
- The large customer base will confer the default supplier a much larger company size than the rest of suppliers. This will allow the default supplier to exploit economies of scale. Economies of scale exist if the cost per unit declines with the number of units supplied. In the electricity supply market, economies of scale could exist mainly for managerial reasons (a large firm employing specialist managers, salesmen, risk analysts, etc.) and marketing reasons (spreading the high cost of advertising or investing in brand value, across a large level of output). In essence, if economies of scale are

[114] The choice of any existing supplier as the default supplier does not facilitate new entry in the supply. However, we believe that the choice of ECS creates additional difficulties for the degree of competition in the supply market.

present this will imply new entrants having higher costs for the only reason of having a smaller customer base than the default supplier.[115]

- In the eyes of customers, being a default supplier is perceived as being trustworthy. Customers will probably have doubts about the reliability of the new supplier. For example, they might wonder whether the new supplier will be able to deliver electricity without cuts, get their billing information correct, resolve customer service problems quickly, etc. Therefore, when choosing a new supplier, customers will, in practice, perceive they are facing a risk. Other things equal, the new supplier will have to offer the same product at better conditions to compensate the customer for that risk.
- The large customer base also provides an additional advantage in the generation level. Because of its vertical integration, Electrabel has a guaranteed usage of its generation capacity thanks to ECS being the default supplier. If a smaller share had been given to a new entrant this could have provided an initial customer base for the entrant to start a new business in generation.

The Conseil de la Concurrence imposed a series of remedies to Electrabel to neutralise the effects of its designation as the default supplier. Such remedies include the right to switch with no penalty for customers who use ECS as the default supplier, improving the liquidity of the supply market (Electrabel has to make available to other suppliers to facilitate the entry on new suppliers), raising Chinese walls within Electrabel between technicians working for the intercommunales and the rest of Electrabel, prohibition to show Electrabel's logo on any equipment/material/information of the intercommunales, prohibition of joint marketing, etc.

We understand that the remedies are necessary to address the problem of vertical integration. It is hard to imagine how could new entrants enter the market if they could not buy electricity. However, the advantages obtained from being the default supplier are still unresolved: Electrabel has started business with an established client base that other suppliers need to acquire. New suppliers will have higher costs just because they need to invest to acquire new customers (as described in previous paragraphs). But this has also implications on the quality of the customer base. New suppliers will be able to attract the customers that are more mobile and likely to change supplier again. Instead, by being the default supplier, Electrabel will keep the customers that do not switch or take longer to do so.

In conclusion, the designation of the default supplier has reinforced the dominant position of Electrabel on the market of the supply of electricity.

[115] We estimate the impact of scale economies later in the modelling annex, Annex 5. The results suggest that economies of scale are low in supply. They are more significant for small customer supply, where margins are low as well, and less significant in larger customer supply.

Luminus has also been designated as the default supplier in the territories of the pure intercommunales. The same problems related to the access to a customer base in preferential terms are also valid in this case. Namely, Luminus will not need to invest in customer acquisition and will keep the less mobile customers. In addition, a large customer base can allow Luminus to exploit economies of scale. Finally, being the default provider will also benefit Luminus from being perceived as trustworthy in the eyes of customers.

A better solution for consumers could have been achieved fractioning the liberalised consumer base into a higher number of suppliers so that they could compete against each other. For example, in England and Wales, transitional franchise monopolies were created in retail supply in form of twelve distribution companies (known as the Regional Electric Companies, RECs). When full liberalization took place the market had a starting point with 12 established suppliers and not only one. Another possible way of allocating the eligible consumers to different suppliers could have been achieved through auctioning parts of the consumer base. In addition, the ownership rights to the default customer base could have been given or sold to a supplier for only a limited period of time.

4.3.7 Other issues

Brand name

The operational component of the grid management within the mixed intercommunales is in turn outsourced to Electrabel Netmanagement, which is a wholly owned subsidiary of Electrabel. This means that a consumer, in an area where a mixed intercommunale is the DSO, who wants a new connection or a reinforcement of his existing connection is assisted by Electrabel personnel, irrespective of the supplier that he has chosen. Suppliers claim that consumers always faced personnel with Electrabel's uniform, vehicle fleet, or logo and this lead to confusion. However, following the default supplier decisions of the Conseil de la Concurrence, this situation will change as the Electrabel technicians working for the DSOs are prohibited from exhibiting external signs identifying them as Electrabel employees.

That being said, Electrabel has already huge brand advantages from being the historical player. It is important that those advantages are not increased over time.

Complex regulatory systems and lack of clarity and predictability

Suppliers noted that they face a large amount of administrative and regulatory paperwork in the supply market. The companies need to hire extra personnel just to deal with these bureaucratic aspects. Suppliers require a supply license for each region, which comes with extensive reporting requirements. Each of the regulators requires suppliers to provide regular

information to keep their statistics updated (e.g. numbers of switchers, volumes sold, etc.). Every regulator has its own segmentation, which makes each request a separate requirement and report. On top of this, the European Commission, the National Statistics Office, and the Federation of the electricity companies in Belgium also request similar statistics. At present, suppliers have to deliver a high number of reports to the different bodies. In addition, reporting for green certificates, free electricity and social tariffs requires additional extensive reporting: The green certificate systems and reporting requirements are again different by regions (for example the Walloon regulator asks on a three monthly basis for the volume sold in order to be able to calculate the green certificate system, whilst in Flanders the regulator obtains this information direct from the DGO's). Delivery of free electricity causes extensive reporting requirements and administrative and operational efforts due to the number of parties involved and the complexity and sheer number of the data exchanges and interfaces. In order to get compensation for social tariffs, suppliers need to hand in a customer-by-customer based request to the CREG to obtain compensation.

Suppliers note that consistency would reduce their reporting efforts and improve efficiency. The complex system of taxes/charges system with many different charges and taxes also adds complication and costs. As distribution tariffs take into account grid losses, different DGO areas and segments, in Flanders alone suppliers have 54 different amounts of the federal contribution ("federale bijdrage") tax to charge to their consumers.

Excessive regulation costs could make larger suppliers better positioned to compete if they are able to exploit economies of scale. Economies of scale would be possible if the bureaucratic cost could be spread across a large level of output. In this context, smaller suppliers would have higher costs than larger suppliers. Hence, excessive regulation costs will make small companies inefficient and this could be acting as a barrier to entry to small firms.

General policy uncertainty

According to suppliers, the Belgian electricity sector as a whole faces considerable policy uncertainty at both the federal and regional level. It is not clear what the implications of Kyoto and carbon emission reductions will be for the sector even so this is critical for taking decisions regarding new generation investment. Another area of concern are the frequent changes of the rules regarding green energy. This was noted as a source of uncertainty by many suppliers.

4.4 Conclusions

Several conclusions emerge from this chapter.

We have analysed the market for all eligible customers. Although we believe that the figures are likely to underestimate the market concentration for

customers with high consumption volumes, the market shares and HHI already show evidence of a very high concentrated market.

We have proposed a narrower product market definition, segmented along usage lines. In this sense, the analysis for market segments above 10GWh/y suggests even higher values of HHI. However, regardless of the market definition used, all the findings are consistent with a high concentrated market.

The conduct and performance of the market is difficult to measure because of lack of data. This is in part merely due to the nascent nature of these markets. Available evidence shows that entry has occurred in Flanders and some entrants have increased their market shares (based on connection points). However, the market remains highly concentrated. Figures in Wallonia show that the number of players is small and Electrabel still retains a high market share in terms of total electricity supplied.

We believe that customers with consumption above 10GWh/y could be particularly subject to market power. Our analysis has shown how electricity prices remained relatively unchanged in the more concentrated markets (large and medium customers) between 1999 and 2003 but fell sharply for the competitive market (domestic) after 2001. Similar conclusions are found analysing evolution of the margins. Although we reckon the limitation of the data and that there could be other factors at play, this is a piece of evidence that market power could have been used in the concentrated markets.

Concentration in generation together with vertical integration poses some threats to competition. For one, Electrabel is able to manipulate wholesale prices and could set them artificially high to increase rivals' costs and harm competition. Additionally, Electrabel could be harming competition by setting such a low margin between its wholesale and retail that suppliers are forced to exit the market or are unable to compete effectively. The existing data seems to suggest margin squeeze in the domestic market may have occurred in 2003.

So far, suppliers have had to work with provisional distribution and transmission tariffs, which can be different from the official approved final tariff. Additionally many surcharges are levied on electricity and the level of these surcharges is difficult to predict. This has created uncertainty for suppliers when quoting supply prices to their clients. The uncertainty surrounding provisional distribution tariffs is likely to have different effects in the companies. We believe that larger suppliers are going to be better positioned to cover that risk than smaller companies.

Customer switching in Flanders has been progressing slowly. In its first year after liberalisation it is behind the rates once achieved in England and Wales but not so far from Sweden.

The fact that the metering data, standard yearly consumption data, master data is not delivered on time or is incorrect has an impact on suppliers business. Suppliers are unable to estimate the consumption volume of the

client and to identify customers' profiles. Hence, suppliers run a very high financial risk in a narrow margin market.

The designation of the default supplier has reinforced the dominant position of Electrabel on the market of the supply of electricity for various reasons. It has reinforced the vertical integration of Electrabel. Moreover, it has given the default supplier a lead over new entrants because of its client base. New suppliers will need to invest in acquiring new customers whereas Electrabel can invest only in keeping customers from switching. A large customer base could allow the default supplier to exploit economies of scale and achieve lower unit costs than its rivals. Finally, to the extent that being a default supplier is perceived as being trustworthy, it has given an advantage to existing companies over new. The designation of Luminus as the default supplier in some areas also gives this company the same customer base advantages over new entrants.

5 Industry developments in Europe

This chapter describes some of the broad trends of the European electricity market(s), placing emphasis on the developments in the countries in close proximity to Belgium, namely France, the Netherlands and Germany, and, more briefly, Austria, Luxembourg and Switzerland. The general trends are combined with more specific evidence on the structure of competition and the degree of multi-market interactions in the electricity sector from the rest of Europe to draw some conclusions on how these developments might affect Belgium.

5.1 Overview of neighbouring countries

While liberalisation across Northern Europe is progressing in the legal sense and the practical sense, market power in the home country remains the dominant feature of Continental Europe's electricity markets[116]. There are six other markets in close proximity to Belgium: three relatively large (France, Germany and the Netherlands) and three relatively small (Austria, Luxembourg and Switzerland). Each of France, Germany and the Netherlands has relatively concentrated electricity markets, often with the presence of local monopoly power either on a national basis, or within regions of the country. The three smaller markets are characterised by strong regional utilities, and cooperation rather than competition.

In anticipation of the continued liberalisation of the European electricity market, which will eventually transcend national boundaries, erstwhile regional or national electricity companies have been expanding both across borders and across utility industries (i.e., gas and water) in order to establish themselves as strong European players.

Since it has so far proved difficult to increase market share via competition, companies have been gaining greater market share mainly through acquisitions. Across the three countries surveyed, there has been a high degree of activity in mergers and acquisitions, which seems set to continue, in both the generation and the supply of electricity. For example, the purchases of regional utilities by E.ON and RWE, and the presence of Vattenfall and EdF in Germany, show how companies have bought market share rather than entered the market as a new entrant and grown organically. This has created a small group of large multinationals, each with activities spanning most countries in Northwestern Europe, and most with both generation and supply businesses.

[116] See for example, EU Commission (2003) "2nd benchmarking report on the implementation of the internal electricity and gas market" and Newbery et. al., (2002) "Benelux market integration market power concerns".

This section provides a broad overview of the electricity industry in each country, focusing on the biggest companies, rather than on the sector as a whole. It also comments on major prospects for each of the countries' electricity industries in terms of company evolution. The information is based upon a combination of European press articles and information available from relevant governmental and corporate websites.

Four themes run throughout the analysis:

- The future of generation and energy sources;
- The expansion of electricity companies into neighbouring markets;
- The importance of network control, pricing, and connection; and
- The emergence of power exchanges.

Table 5.1: Characteristics of electricity markets in Northwestern European countries

Country	Total capacity (GW)	Peak load (GW)	Peak load/Total capacity (%)	Imports (TWh)	Exports (TWh)	Net imports (TWh)
Belgium	15.8	12.8	81%	16.6	9.1	7.6
France	114.3	74.1	65%	3.0(1)	79.9(1)	-76.9(1)
Germany	111.2	76.6	69%	37.0	22.2	14.9
Netherlands	20.6	13.9	67%	20.9	4.5	16.4

NOTE (1): provisional

Sources: London Economics calculations based on data from UCTE and Eurostat

5.1.1 France

Generation

More than 95% of electricity generated in France is produced by Electricité de France (EdF), which owns sites all over France. EdF is wholly owned by the French state, and has existed since 1946. In combination with its European subsidiaries, EdF produces about a fifth of Europe's electricity. In 2003, EdF had a capacity of 102 GW of electricity (GWe). EdF sells 6 GW of capacity through virtual power plant (VPP) auctions.

In line with the commitments towards the European Commission related to the participation taken in EnBW in 2001 (see the section on Germany), EdF has made available 6 GW of generating capacity via a VPP, which represents approximately 42 TWh of energy per year. The contracts are sold by auction

and EdF intends to conduct these auctions at approximately quarterly intervals. The energy price in June 2004 for the Virtual Power Plant (VPP) peak product was unchanged from that in summer 2003, at € 23/MWh, and the energy price of the VPP base product was unchanged at € 8/MWh. Around 30 energy traders and suppliers competed in previous auctions, which were conducted over the Internet, with approximately 20 bidders emerging as successful purchasers.

Other than EdF, there are several independent generators and suppliers of electricity in France, though none that can match EdF for size and scope, partly due to EdF's presently protected position as monopolist in the major part of the French electricity market. EdF's main competition comes from two French companies, in both of which, until recently, it had minority shareholdings. The first is Compagnie Nationale du Rhône (CNR), and the second, Société Nationale d'Electricité et de Thermique (SNET).

Compagnie Nationale du Rhône is France's second largest electricity producer, accounting for 3.3% of the country's total electricity output. CNR generates electricity via 19 hydropower power stations, which have a total capacity of 2.9 GWe, and are all located along the Rhône.

Though the majority of CNR is owned by various state-controlled organisations, including SNCF and several local governments, its biggest single shareholder is Electrabel (47.88% holding), itself owned by Suez SA. Having already set up a joint venture, called Energie du Rhône, to supply electricity with CNR, Electrabel purchased EdF's 22.22% stake in July 2003.

According to its own website, la SNET is the leading independent electrical supplier in France. Founded in 1995, la SNET generates electricity in France with eight coal-fired units, which have a combined capacity of 2.5 GWe.

As of the end of 2003, the SNET group had three shareholders: Charbonnages de France (51.25% holding), Spain's Endesa (30%) and EdF (18.7%).

Transmission

RTE, which, as part of the EdF group, is owned by the French state, is the sole operator of the French transmission system. RTE by law performs its activities independently of the activities of EdF, as is stipulated in the Act of 10th February 2000 concerning the modernisation and development of the electricity public service. RTE must maintain the continual operational status of the national grid, providing equal access to all users of public power transmission network and ensuring the balancing of generation and consumption at all times.

Distribution

EdF controls the distribution (low-voltage) network, which connects the end-users to the electricity system. EdF took over control of this from the local authorities, as set out in the French law of 10th February 2000.

Supply

EdF is the legal sole supplier in France for all but the biggest consumers of electricity, who have free choice across Europe due to the liberalisation of the European electricity market.

Since 2003, users that consume more than 7 GWh per year (in practice, only large industrial companies) have been eligible to choose their own supplier. 3 100 companies in France satisfy the eligibility requirement, opening 37% of the power market to competition.

Despite this, EdF still sells more than 90% of the electricity consumed within France. Eligibility is to be extended to all businesses (some 3 million customers in total, which comprise 70% of the French demand for electricity) from 1st July 2004, but EdF will remain the monopoly supplier to households until at least 2007. In 2003, EdF sold 407.7 TWh to consumers in France.

CNR has a joint venture subsidiary with Electrabel, also CNR's biggest shareholder, called Energie du Rhône, aimed at taking market share way from EdF. After starting as an independent electricity generator and supplier in April 2001, CNR sold in 2002 a total of 15.2 TWh of electricity. In 2003, the SNET group made sales of 5.6 TWh of electricity to eligible users.

Trading

Trading electricity in France is possible via the Powernext exchange, which began in November 2001. There is a day-ahead market and a futures market. On the day-ahead market, there are 39 active members (of 43 agreed members in total) and on the futures market, which opened on 18 June 2004, there are 11 agreed members.

Euronext Paris owns 34% of the company's shares. A holding of European transmission operators, known as HGRT and formed of the French RTE, the Belgian Elia and the Dutch TenneT, holds 17%. The HGRT concept allows the TSOs to be represented within Powernext SA and ensures the consistency of market rules with the electricity networks safety requirements. The remaining 49% is divided up amongst: BNP Paribas, EdF, Electrabel, Société Générale, Total, Endesa and Atel.

The volumes traded on Powernext have risen steadily since its inception, but, nevertheless, most trading occurs in the Over the Counter (OTC) market, which accounted for trading of about 250 TWh in 2002.

Although Powernext only traded volumes about 4-5% of total eligible consumption in 2002, three times as much volume was traded in 2003 (7.5 TWh). The average prices for base and peak hours were € 29.225 / MWh and € 37.822 / MWh, respectively. Powernext now represents over 50% of balancing requirements in France and is set for sustained growth in the future, due to the expansion of its product range, such as the futures market.

Future developments

In all likelihood, EdF will remain a state-controlled company in the next few years, though plans have been made to reduce the state's shareholding. A draft law unveiled by the French government sets out that EdF is to become a joint-stock company by July 2004, and that this will be followed by a part privatisation of the company some time in 2005. The government will, however, retain a controlling stake in the company, which will be protected by the same law.

On 21st April 2004, the European Commission indicated that it had approved the acquisition of a controlling stake by Endesa, a Spanish utility company, in the SNET group, via an increase in its stake from 30% to 65%. The French privatisation regulators approved the deal at the end of July 2004, and Endesa formally finalised the purchase from Charbonnages de France of its additional 35% stake on 13th September 2004. The remaining 35% of SNET, of which 16.25% is in the hands of Charbonnages de France and 18.75% in EDF's portfolio, is to be acquired by Gaz de France (GdF). This presents opportunities for cooperation between Endesa and GdF with respect to the vertical supply chain of electricity [117].

Endesa sees potential for the installation of a further 3.6 GW, and is developing a renewable energy programme. By strengthening SNET, Endesa intends to enhance its position on the French electricity market, making the company a dynamic and competitive operator within the framework of electricity sector deregulation now under way in France, ensuring that its activity contributes to a more competitive market [118].

Enel SpA, which had also been touted to buy a stake in la SNET, is on the verge of entry into the French market through an agreement with EdF. Under the terms of the agreement, Enel would purchase electricity from EdF, and then resell it to French electricity users. Estimates of how much electricity EdF will make available vary from 4 GW to 7.5 GW (4% and 7.5%, respectively, of EdF's generation capacity).

Thus we can see that, though EdF remains dominant, there have recently been some moves towards entry into France, from within and abroad, and including established electricity companies.

5.1.2 Germany

Germany's retail and wholesale market for electricity was deregulated in 1998, allowing full competition. However, deregulation occurred without any significant divestiture or legal unbundling of vertically bundled services, allowing companies to retain generation, transmission, distribution, and

[117] Business Wire, 13 September 2004

[118] ibid.

supply capabilities. Of note is the fact that Germany's utilities retained ties with natural monopoly elements of the supply chain as well as potentially competitive elements. Furthermore, tariffs for the natural monopoly elements were set on a negotiated third party access basis, as opposed to an independent regulatory tariff setting mechanism (regulated third party access). While this is being changed (although Germany's new energy regulator is still not up and running), the high cost of third party access to the grid has been a major negative element of Germany's liberalisation efforts.

Germany has no independent energy regulator, with the Federal Cartel Office (Bundeskartellamt; FCO) being the sole legal arbiter[119]. In addition to the FCO, though, there exists voluntary self-regulation in the form of association agreements (Verbändevereinbarungen) for third party network access. Under this regime, mergers have been allowed between some of Germany's biggest energy companies, which are also major players in Europe. It is anticipated that an official regulator for the electricity sector will be installed in July 2004, though it is unlikely that there will be much immediate impact.

A series of mergers and acquisitions by the biggest energy companies in Germany restored somewhat the monopolies that had existed prior to deregulation. In 2000, two huge mergers, of VEBA with VIAG, to form E.ON, and of RWE with VEW, resulted in a generation market that now borders on an effective duopoly with a competitive fringe.

The Federal Cartel Office in 2002[120] estimated that RWE and E.ON, between them, controlled about 65% of German generation capacity, 70% of net electricity generation, 70% of the national high voltage network, 50% of the medium and low voltage network. Aside from E.ON and RWE, there are two other important electricity companies in Germany, and almost 900 smaller companies. A fuller description of the rest of the firms in the market is given below.

In 2003, E.ON bought Ruhrgas, Europe's biggest gas importer. Despite concerns from the Federal Cartel Office, the deal went ahead, with conditions on E.ON to divest some activities to mitigate the trading advantage gained. One of the fears was that E.ON would have an incentive to restrict competition in the electricity industry, by offering disadvantageous terms to its competitors in the electricity sector for gas transportation and gas supply.

The other major players on a national scale are Energie Baden-Württemberg AG (EnBW) and Vattenfall, a Swedish state-controlled utility company. EdF, of France, has a significant minority stake of 34.5% in EnBW. Between 2000 and 2002, Vattenfall subsumed HEW, VEAG, LAUBAG and Bewag into a

[119] Most observers agree that the national competition authorities are not well equipped to deal with electricity regulation. Above all, the problem of the legal context that "abuse" is the problem, not the mere existence of monopoly power. Monopoly power in electricity markets can "appear" whenever the system is tight, and the results can be very high prices.

[120] Bundeskartellamt, 8. Beschlussabteilung, B 8 – 40000 – U – 109/01, 21.01.2002, Paragraph 50 (at http://www.bundeskartellamt.de/wDeutsch/download/pdf/Fusion/Fusion02/B8_109_01.pdf)

single entity, Vattenfall Europe, though it retained the recognised and long-established brand names HEW and Bewag, in Hamburg and Berlin, respectively. The company is considering further expansion into the countries surrounding Germany.

Beyond the big four, there are almost 900 municipal utilities, many of which, though, are partially owned by one or more of the big four, resulting in further effective vertical integration.

Only one municipal utility, MVV Energie AG, which is also the fifth-largest supplier of electricity in Germany, is publicly listed and traded; about a quarter of its share capitalisation is publicly traded.

Though there is a high concentration of market share in just a few companies, the majority of complaints about prices seem to have been directed towards the charges imposed by the networks. As will be explained below, the biggest four electricity companies in Germany control regional sections of the power grid, and there have been inquiries by the FCO, such as those in 2003 on the tariffs charged by RWE and E.ON, into whether the pricing of electricity by grid operators is too high. The FCO found in March 2003 that "the prices RWE Net charges its competitors for billing and metering services are improperly high" and "are a major handicap for new suppliers".[121] FCO president Ulf Boge said that, "Competition is being seriously eroded, especially in the household market, with the collapse of 10 suppliers and the withdrawal of 20 more."[122]

Generation

E.ON has reorganised its activities worldwide into five broad regions. E.ON Energie oversees the Central European region that incorporates Germany and the surrounding countries. E.ON's generation capacity in Germany was about 25 GW in 2002, with another 9 GW in the other European countries in that region. In 2003, E.ON Energie provided 269 TWh of electricity.

RWE's generation business is performed through a wide range of energy sources, ranging from nuclear and lignite to renewable energies. RWE has the most generating capacity in Germany: about 33 GW, which provides about 190 TWh of electricity per year.

EnBW Gesellschaft für Stromhandel GmbH is the company responsible for producing electricity for EnBW. It draws on a generation capacity of about 15 GW, which was used to generate 127 TWh in 2003.

Vattenfall has a generation capacity of about 16 GW, with 60% of that capacity coming from lignite (brown coal)-fuelled generators, several of which, being built since 1997, are relatively new, and thus relatively efficient

[121] Quotes taken from "German watchdog in new RWE/Eon probe" in *Utility Week*, 7 March 2003, p.11.

[122] ibid.

and environmentally friendly. It also has nuclear power stations, though these are considerably older units. In total, in 2003, Vattenfall generated 74.6 TWh.

Transmission

The high-voltage network in Germany is subject to regulation. The major energy companies in Germany, being vertically integrated, each own and maintain their own power grid. The national grid is basically split into four geographic regions, with a different company owning each part. The four transmission network operators are E.ON Netz GmbH, RWE Transportnetz Strom GmbH, EnBW Transportnetze AG, and Vattenfall Europe Transmission GmbH (VET).

Though operation of the transmission networks is regulated, the system of access pricing has largely been left to association agreements. It has been commented in the press that these agreements can make long distance trade prohibitively difficult.

Distribution

As with the transmission network, German energy companies also own and maintain (low-voltage) distribution networks. Reportedly high access charges to the distribution grids, determined by association agreements, on top of complex procedures for access have impeded the progress of competition, and have prompted the FCO to make inquiries into whether the prices charged have been too high. However, there are more companies involved at the distribution level, since the municipal utilities also have their own sections of the distribution grid.

Supply

E.ON Energie, through its regional subsidiaries, supplied 189 TWh to customers in Germany in 2002. A close second, within Germany at least, was RWE Energy, which supplied 167.5 TWh. Neither of the other two large electricity suppliers was very close behind with EnBW having supplied 110 TWh and Vattenfall Europe, 93.9 TWh.

Trading

The European Energy Exchange AG (EEX) operates the Spot and Futures Market for power in Germany. With 112 participants from 13 countries, EEX has the highest number participants of any power exchange in Continental Europe. Its primary target is to set itself up as the major energy exchange in Central Europe. However, the EEX is yet to become more important in terms of volume traded than the OTC market, with even its most successful venture, financial futures, being small compared to its counterpart, the OTC forwards market.

The trading data for 2003 show that the market had recovered from the severe damage caused to it by the demise of Enron in 2001/2002. The EEX had actually booked higher volumes in 2002 compared to 2001, despite the problems associated with Enron, but grew even more in 2003.

The traded volumes in 2003 at EEX's Spot and Futures Markets amounted to 391 TWh, more than twice the volume of the preceding year (150 TWh). 342 TWh was traded on the Futures Market in 2003, nearly treble the volume traded during 2002 (117 TWh). The volume traded on the Futures Market was nearly seven times higher than the Spot Market volume. Of that amount, OTC Clearing accounted for 191 TWh. The chairman of the EEX board, Dr. Hans-Bernd Menzel, believes that the positive development of the Futures Market and OTC-Clearing show an increasing awareness in the market regarding counterparty risk[123].

The 2002 Spot Market volume of 33 TWh was increased by 49% to 49 TWh. The Spot Market volume constitutes 10% of the German power consumption. The yearly average Spot Market price was € 29.49/MWh. At the Futures Market, the closing price for the Baseload Year Future 2004 was set on 29 December 2003 at € 32.87/MWh.

Future developments

There seem to be two main trends occurring in the German market. Firstly, the four large players are seeking to consolidate their positions by strengthening their electricity businesses in Germany's neighbouring countries, and by seeking complementary utility activities (e.g., gas, water), rather than by purchasing more market share in electricity within Germany. Secondly, the smaller players are seeking to grow, in order to give them a better position against the big four.

MVV was, at the end of 2003, seeking partnerships with generators in Germany and also in neighbouring countries, as it considered whether to purchase or build power stations for itself in order to avoid being exposed to higher prices from the big power producers.

The German mining and chemicals group, RAG, planned in March 2004 to merge its subsidiaries, STEAG and RAG Saarberg, to create the country's fifth-largest electricity generator, as a company to be called STEAG. Electrabel and Gaz de France were both reportedly interested in purchasing a 25% minority stake, but RWE, which already has a 30.2% stake in RAG, agreed in June 2004 with RAG to receive an option to purchase a stake of about 25% in the restructured division. Through STEAG, RAG will control 8% of all German power generation, and 25% of hard coal-fired generation. E.ON has a 39.2% stake in RAG. It is commonly anticipated that about 30 to 40 GW of generating capacity will need to be replaced within the next 10 to 15

[123] Quoted in EEX press release 15 January 2004, available from http://www.eex.de/info_center/downloads

years in Germany. The new STEAG aims especially to develop new plants to provide replacement capacity as older fossil plants are retired and the country's 19 nuclear plants totalling 22 GW are phased out by 2020.

Further restructuring is likely in the industry, with EnBW recently seeking to diversify in a manner similar to E.ON, by acquiring a stake in the regional gas and water utility of the city of Backnang. Concurrently, it is seeking to streamline its own portfolio, having sold its stake in Würth Solar in April 2004, and at the same time making plans to expand its hydropower business. EdF, a large stakeholder in the company, has agreed to contribute towards a capital injection into the firm without seeking more of a controlling share.

Essent NV, the largest Dutch power supplier, announced in February 2004 that it planned to expand energy trading operations in Germany, as part of its plan to become influential throughout the markets of Northwestern Europe. It anticipated that the introduction of a sector regulator in Germany in the middle of 2004 would help smaller companies compete against E.ON and RWE. Essent, which already has a subsidiary, Deutsche Essent GmbH, based in Germany, also made a bid for a majority stake in the municipal utility unit of the city of Kiel, as it looked to achieve some vertical integration in Germany. Among the other bidders was MVV Energie.

5.1.3 Netherlands

Generation

There are four major generation companies in the Netherlands electricity market: Electrabel, E.ON Energie, Essent NV, and Nuon NV. The latter two companies are each owned by a number of Dutch municipalities. In total, the Dutch market has a generation capacity of about 20 GW. Generation capacity is fairly evenly split between the four companies. Essent had a generation capacity of 4.7 GW in 2002. Electrabel, in 2003, had the same 4.7 GW of generation capacity. E.ON Energie's generation capacity in 2002 was 1.8 GW, which generated 14 TWh over that year.

Nuon only recently became an important player in electricity generation, having acquired the bulk of its generation assets when it purchased the European activities of the American company, Reliant Energy, in December 2003. In so doing, it increased its generation capacity from 900 MW to 4.4 GW. However, the Dutch competition authority, afraid that Nuon might have gained enough market power to manipulate wholesale prices, ruled that it should subsequently auction the rights (valid for five years) to 900 MW of capacity (20% of its total capacity, compared to the 9% that Electrabel auctions in VPP). Nuon, who will be appealing against the decision, Essent and Electrabel would all be excluded from the virtual auctions. Nuon claims that the relevant market context should be the European one, rather than the Dutch one alone—we take this up later in this chapter.

Beyond the top four, Delta has a sizeable share, 7% of installed Dutch capacity, which is about 1.4 GW. Eneco Energie, one of the biggest Dutch suppliers, owns just 300 MW of capacity.

Transmission

The high voltage transmission system operator, TenneT, is a 100% state-owned company, purchased in October 2001 from a group of local authorities and utilities as part of the liberalisation of the Dutch electricity industry. TenneT's high voltage grid is connected to the grids of E.ON Netz and RWE Transportnetz in Germany, and to that of Elia in Belgium. In total, the interconnections with these neighbouring countries have a capacity of 3.7 GW to import or export electricity, which is allocated via auctions organized by TSO Auction, a subsidiary of TenneT and the foreign grid owners.

TenneT, having purchased the regional grid administrator, BV Transportnet Zuid-Holland (TZH) in December 2003, controls about 40% of the national transmission grid. The rest is controlled by four regional grid administrators: Essent, Nuon, Delta and Eneco Energie. The regional nature of the allocation of grid ownership confers (local) monopoly power onto the owners, thus requiring regulation.

The network owners' wholly owned, but legally distinct, subsidiaries manage, independently, the maintenance and operation of the distribution networks. The Dutch energy regulator (DTe) regulates network charges.

Distribution

The low-voltage distribution grids are regulated local monopolies, maintaining the ownerships structure from prior to liberalization. Nuon, Eneco Energie, and Essent are the biggest owners in the distribution network, with regional utilities owning the remainder. There has been in recent years, some consolidation by the main distribution network owners, such as the series of purchases made by Eneco Energie, which included Remu in 2003 (described below).

Supply

The biggest supply companies in the Netherlands are Nuon, Essent, Electrabel, and Eneco Energie. Currently, only larger consumers and those low-volume users consuming renewable energy are allowed to choose their supplier. Total liberalisation of supply is expected to occur in July 2004.

Essent is the biggest electricity supplier in the Netherlands, with sales of almost 48 TWh in 2003, up from about 45 TWh a year earlier. Essent's primary focus for expansion has been Germany and Belgium. This is about 40% of the retail market, which is higher than its share of roughly a quarter of generation capacity.

Nuon, based in Amsterdam, supplies an amount of electricity similar in magnitude to that of Essent, and has also been looking to expand further into Belgium and Germany. Like Essent, Nuon seems to have a greater market share in supply than in generation.

Electrabel, in 2003, supplied 23.2 TWh of electricity in the Netherlands, giving it a market share of about 20%, slightly lower than the one-quarter of generation capacity that it controls.

Eneco Energie, based in Rotterdam, strengthened its position in the Dutch electricity market through its purchase on 1st January 2003 of Remu, which had been the fourth largest Dutch supplier, and whose business is based mainly in the Utrecht region. Eneco Energie almost doubled the volume of electricity it supplied as a result of the purchase: it sold just under 20 GWh in 2003, compared to just over 12 GWh in each of 2001 and 2002.

Trading

Based in Amsterdam, the Amsterdam Power Exchange (APX) is an independent exchange and is the central counterparty in all electricity trades on its market, retaining anonymity for participants throughout. APX is equipped to develop, service and support energy related products. APX staff and systems are used to provide OTC Clearing of energy contracts.

APX was established in 1999 as the first fully electronic exchange for international electricity trading in continental Europe. APX has been a subsidiary of TenneT since May 2001. The total number of participants on the APX Spot Market at the end of 2003 was 36 compared to 39 at the end of 2002. The main cause of the decline is the consolidation in the market. In 2003, 11.96 TWh was traded on APX, a decrease of 15% compared to 2002. This volume corresponds to 13% of the net Dutch electricity consumption (15% in 2002). Volumes in 2002 had been boosted by the tax regime for green electricity, which did not apply in 2003.

The APX-index, the average price for electricity traded on the APX Spot Market, was € 46.5 / MWh in 2003 (€ 30 / MWh in 2002). Price spikes were recorded in the second week of August during the heat wave in Europe, with all-time-high daily prices on the APX of € 660 / MWh, when cooling water restrictions (code red) came into force due to the fact that the available level of reserve power in the Netherlands became less than 700 MW. These spikes raised the average price from the average price of € 36 / MWh that had been recorded for the first half of the year.

In 2003, APX also offered services to third parties such as the energy derivatives exchange Endex, which offers clearing services for Dutch OTC power contracts in conjunction with London Clearing House. Physically settled volumes for OTC trade rose throughout the year.

Bert den Ouden, CEO APX Group commented, "We have seen a somewhat mixed year for 2003 with a small decline in traded power volumes but an increase in gas traded volumes on our EnMO exchange. We have noted

various mergers and acquisitions throughout the year that have reduced the number of market players, particularly on the electricity side, but the markets remain robust and the signs for this year are very positive. The APX Group has significant plans in place for the development of new markets and products in 2004 and we shall continue to develop new, multi-commodity, multi-market product and service offerings to better meet evolving needs."[124]

The OTC market in the Netherlands has suffered from the withdrawal of Enron and other US new entrants. The big players that remained in the market were Electrabel, Essent and Nuon. Despite the relative lack of liquidity, volumes traded were far in excess those on the APX, at about 150% of Dutch consumption in the first half of 2003.

Future developments

Eneco Energie, an important supplier of electricity in the Netherlands, has little of its own generation capacity, trading presently with companies whose sole activity in the electricity market is generation. It is actively seeking to expand its business in generation units.

The Dutch government is planning the complete nationalization of the transmission network under the control of TenneT. Only Eneco Energie, of the current owners, seems to be strongly against the idea.

The Dutch economics minister announced in April 2004, that he wanted the separation of ownership of generation and supply activities from the distribution network by the beginning of 2007. He also proposed that TenneT should extend its scope to medium-voltage lines. The proposal must pass through parliament, and is strongly opposed by the current distribution network owners.

Several bids by foreign utility groups for Dutch companies in 2002 failed, as the government delayed on a schedule for full liberalisation. In an evaluation in May 2002, the Ministry for Economic Affairs concluded that a decision on the privatisation of more than 49% of the shares in any gas and electricity suppliers should be postponed until 2004.

The Dutch government's energy advisory council had made a call in March 2004 for a merger between Nuon and Essent, in order for the combined company to compete strongly, as a representative of the Netherlands, in the European market. However, this was directly at odds with a statement made a few weeks later by the Dutch economics minister, who, in a letter to parliament, wrote that creating a national champion was not one of the government's aims.

All the big Dutch electricity companies, according to their websites and press announcements are seeking to expand into Belgium and Germany.

[124] Quoted in APX press release 8 January 2004, available from http://www.apx.nl/press/main.html

Furthermore, both Vattenfall and E.ON Energie are looking to expand the scope of their operations in the Dutch market.

5.1.4 Austria

Generation and supply

The Austrian energy sector is characterised by the importance of renewable energy, and by the abandonment of nuclear energy in the late 1970s, in generation. Austria makes considerable use of renewable resources, especially hydropower, though wind energy and solar energy have grown the quickest recently, due in part to favourable subsidies and price guarantees. Traditional fossil fuels accounted for around 70% of overall energy consumption in 2002, whilst renewable sources provided almost 27%. This was around four times higher than the EU average, putting Austria to the fore in using environmentally friendly energy.

Some 30% of Austria's total energy needs in 2002 were met by domestic sources, according to the Austrian Institute of Economic Research, mainly generated using hydroelectric power (70% of domestic output in 2002). There are no plans for major new hydroelectricity projects, as most economically viable generators have already been built.

The landscape of the Austrian electricity industry is on the verge of undergoing a major shift, due to the imminent merger of two of its largest players in October 2004. The European Commission announced on 11th June 2003 conditional approval of the union of Österreichische Elektrizitätswirtschafts-AG (Verbund) and five Austrian regional power suppliers, already grouped together as EnergieAllianz[125]. The decision came after a lengthy deliberation, because the Commission feared that existing dominant positions would be strengthened; hence the requirement of major commitments from the parties to the deal.

The commitments included the selling off of APC, a subsidiary of Verbund, which itself is majority controlled by the Austrian federal government, dealing with large industrial customers that had a market share in Austria of about 10 to 15%. Other commitments were for the parties to waive voting rights in some of the regional utilities that they partially owned, auctioning of electricity output in line with the consumption profile of small Austrian customers, and self-imposed price caps until an integrated cross-border market in balancing energy is achieved. These measures were designed to create, encourage and foster competition amongst existing players in the

[125] EnergieAllianz consists of the five regional electricity suppliers EVN AG, Wien Energie GmbH, Energie AG Oberösterreich, Burgenländische Elektrizitätswirtschafts-Aktiengesellschaft (BEWAG) and Linz AG für Energie, Telekommunikation, Verkehr und Kommunale Dienste. Local or regional authorities hold majority control in these companies. Burgenländische Erdgasversorgungs-AG (BEGAS), the gas counterpart of BEWAG, is also part of the alliance.

Austrian market and prospective entrants (primarily from neighbouring countries).

The European Commission also considered mitigating factors in how the Austrian market related to its neighbours in assessing whether the merger would be harmful to competition. One such concern was the obstacle to competition from imports. Apart from RWE's ownership of the regional supplier Kelag, foreign utilities are not very active in Austria. For instance, EdF has a minority holding in Styria-based Energie Steiermark AG (ESTAG), which sold 9 TWh in 2002. Although the country has good physical interconnections with Germany and Switzerland, the abundance of cheap hydropower means that most imports are not competitive. The conditions that APC must be sold, and that the auction of generated output must be implemented are designed to encourage the use of hydroelectric power by competitors to the new EnergieAllianz.

The two parties to the merger have operations at opposite ends of the supply chain for electricity. Verbund is the largest generator in Austria, with about half of all domestic production. It has plant capacity of almost 8.9 GW, and produced 31 TWh in 2002. Reinforcing the evidence that hydroelectric power is important in Austria, 107 of Verbund′s 124 power stations are hydroelectric. Its small share of the retail market (4 TWh in 2002), which is dominated by regional suppliers, comes mainly through APC′s operations. EnergieAllianz, in contrast, performs it business mainly in retail. It does have a quarter share in the generation market, producing 13 TWh in 2002, but its strength is in supply, where it sold 26 TWh in 2002. As a joint venture, EnergieAllianz and Verbund will account for up to 70% of generation and up to 60% of sales in the Austrian electricity market.

Verbund sold APC to Slovenia's Istrabenz Energetski Sistemi on 3rd May 2004, thus enabling the merger with EnergieAllianz to go ahead. Within the new group, which will retain the name EnergieAllianz, Verbund will control power trading and EnergieAllianz will operate the wholesale business. The deal leaves five independent regional utilities in Austria competing with the new group.

Transmission and distribution

The bulk of the national transmission grid in Austria is owned and controlled by Verbund, such that it is responsible for transmission of almost 80% of Austria′s electricity. Two regions of Austria have their own high-voltage grid operators: Tirol has Tiroler Regelzone AG (TIRAG) and Vorarlberg has Vorarlberger Kraftwerke AG (VKW). The distribution network is owned by the individual provincial utilities. Due to requirements of the EU framework for liberalisation, the legal unbundling of the networks from the vertically integrated utilities is an issue in Austria.

Trading

Energy Exchange Austria (EXAA) is the trading market for electricity. Its largest shareholder (32.26%) is the Vienna Stock Exchange (Wiener Börse AG), but most of the Austrian electricity companies hold stakes in it too (mostly of 2.42%). With the primary goal of transparent organization of the Austrian electricity market, spot trading was successfully introduced according to plan and officially launched on 21st March 2002. By the end of 2003, there were 26 members active on EXAA: nine Austrian (among them one end consumer and one broker), five German, four Swiss and three British companies, as well as one company from Italy, Belgium, the Netherlands, Spain and Slovenia.

In 2003, the EXAA base load price was € 30.68 / Mwh and the peak load price was € 39.35 / MWh. In total, 1.3 TWh were traded on EXAA in 2003, corresponding to about 2.5% of domestic electricity consumption during that period. The average daily traded volume in 2003 was 3.6 GWh. Since autumn 2003, EXAA made derivatives (day-ahead futures) available to its exchange members to allow them to take advantage of the price differences between the European spot markets or to hedge against them.

5.1.5 Luxembourg

There are three major domestic electricity companies in Luxembourg. The largest is Cegedel S.A., which is 33% owned by the government of Luxembourg. Luxempart-Energie S.A. owns 26%, and, notably, Electrabel owns 8% of the company.

The second-most important electricity company is Sotel S.C., whose activity is focused on supplying electricity to the Arcelor steel group, its owner.

The third company is Société Electrique de l'Our S.A. (SEO), which is the national electricity importer, and which owns the largest power station in Luxembourg: a 1.1 GW pumped storage plant at Vianden, which is used mainly to meet peak demand in Germany. SEO generated 831 GWh in 2003. Cegedel owns a 4.5% stake in SEO.

Generation

Until recently, Luxembourg relied almost entirely upon electricity imports for energy, with no large generation facilities installed domestically. In November 2002, a Belgian company named Twinerg became owner and operator of a newly completed 350 MW, gas-fired power station.

It was the first gas-fired, combined-cycle power station in Luxembourg, which, in 2000, had been importing electricity to cover 95% of its electricity requirements. Twinerg is a private Luxembourg company, whose main shareholder is Electrabel (65%). The other shareholders are the Luxembourg companies Cegedel (17.5%) and Sotel (17.5%). The plant's output accounts for around one-third of the country's consumption, thus providing a

substitute for imports, which came mainly from RWE in Germany and Electrabel in Belgium.

The plant will supply power to Cegedel (100 MW) to cover local utility demand and also will supply power directly to Arcelor's steel plants (100 MW) via Sotel. Electrabel is free to sell the remainder of the energy on the European market.

Transmission and distribution

The Luxembourg power system consists of two high voltage networks. The Cegedel network is connected to the German grid of RWE and the Sotel network is connected to the Belgian Elia grid, but the two are not interconnected within Luxembourg. Almost 70% of electricity used in Luxembourg is transported via the Cegedel network. The Sotel grid is primarily used to service the needs of the steel industry. All of the distribution networks are connected to the Cegedel grid.

Supply and trading

Cegedel sold 5.26 TWh of electricity in Luxembourg in 2003, of which 1.02 TWh was sales from trading. Cegedel trades on the European Energy Exchange (EEX) in Leipzig, in which it owns a 1% stake. There is no power exchange in Luxembourg.

Overall electricity consumption in Luxembourg was 6.13 TWh, showing that Cegedel has more than two-thirds of the consumer market. The remainder is essentially attributable to the needs of the steel industry, and thus to Sotel.

Future developments

The new directive from the European Commission on 26th June 2003, which set new deadlines for market liberalisation, means that the Luxembourg companies, especially Cegedel, will face upheaval in the next few years, including the legal separation of grid operation from electricity supply.

5.1.6 Switzerland

There are around 1100 electricity companies in Switzerland, which vary hugely in size, but most are local operators. Just 1% of the companies cover a combined share of one-half of the market. There are seven large, vertically integrated companies, each with a regional base, which perform all tasks from generation, through to supply and trading. They are Atel Olten, CKW Luzern, BKW FMB Energie Bern, EGL Laufenburg, EOS Lausanne, EWZ Zürich and NOK Baden. 1000 of the utilities are active only in the latter end of the supply chain.

Generation

Each of the seven vertically integrated companies has generation facilities, with capacity ranging from 0.5 GW to 3.5 GW. Generation in Switzerland is mainly achieved with hydroelectric power (about 60%), but there also exists nuclear power (about 40%).

Transmission and distribution

In order to comply with the ongoing liberalisation of the electricity market across Europe, an independent coordination company for the Swiss extra high voltage grid was set up in 2000. Named ETRANS, it is owned by the seven Swiss high-voltage grid operators, each holding a share in proportion to their share of grid ownership. ETRANS is independent from particular interests and organisations engaged in trading, supply and production.

The distribution network is much more local, with small local utilities each having their own grids. There are between 900 and 1100 of these companies.

Supply and trading

Supply is seemingly coupled with distribution, since each utility seems to have its own local monopoly, based on the size of their distribution network. The Swiss electricity industry at the retail-end is thus characterized by a few large electric utilities, which generate and distribute a high percentage of total sales of electricity, and many small public electric utilities, which essentially distribute electric power to their local communities. The major Swiss electricity companies trade on the EEX in Leipzig.

5.2 General developments across Europe

In addition to the requirements set out by the European Union's electricity directive, the requirements of the Kyoto protocol, an international agreement that has yet to become law and which is aimed at limiting emissions and addressing climate change, have nonetheless been passed as a law within the EU. Each Member State has had to provide a target for emissions, but there is scope for adjustment through a pan-EU market for carbon credits and emissions trading, expected to open in January 2005.

The restrictions of the Kyoto treaty will affect what types of electricity generators will be used in the future, though the targets set, and the price of the carbon emissions trading, will determine the magnitude of the effect. Very generally speaking, emissions trading will increase the variable production costs of thermal generation relative to nuclear, hydro, wind and other renewables. Further, coal, oil and less efficiently peaking power stations will find their variable production costs increasing by a greater proportion than efficient gas-fired power stations, because coal and oil are more carbon intensive fuels, and because the thermal efficiency of the plant will impact carbon emissions inverse-proportionately.

Nuclear power might provide a solution to the problem of emissions, though there is strong opposition in a lot of Europe to the use of nuclear power as a source of electricity. Some countries, such as Belgium and Germany, plan to withdraw from nuclear power over the next few decades, though this might change in the future. France, via EdF, is focused on the potential of using nuclear power across the EU, and has been trying to elicit support for a joint project from electricity generation companies from other Member States. There have been signs from Finnish industry and Italy's Enel that nuclear power might actually have a future.

It is foreseen that renewable energy will become more important across Europe, but that the potential capacity that this type of energy could supply would be limited. This is because it is not as reliable as conventional thermal power, and, as such requires back-up generation facilities to ensure the security of supply in the market.

Wind power is the most significant source of renewable energy, and capacity has grown rapidly (by 23% in 2003), but it still only accounted for 2.4% of total EU electricity consumption in 2003, and it is highly concentrated in a few countries, especially in Northwestern Europe (84% in Germany, Spain and Denmark). However, there has been progress in several other countries, and, should achievements in capacity building match promises made by governments, it could be provide a sizeable share of capacity. For instance, the German government is actively helping companies to meet its aims for green energy to cover 12.5% of power demand in 2010, and 20% by 2020.

The main issue remains reliability, though. Elia has commented that, even though there is no direct connection between Germany and Belgium, factors affecting the ability of wind power in Germany have a knock-on effect on prices in the Belgian market. They claim that, when there is a lack of wind, this increases the import of electricity into Germany from France. In turn, this reduces the available interconnection from France to Belgium. Priority, in view of congestion on the interconnectors, is given to the historic agreements (with Electrabel, SPE and the SEP contract), and, as such, the reduction in supply would raise imported electricity prices.

Coal-fired, and oil-fired power stations are the most common and pollutant generators, and will be hit hardest by emissions trading, with reductions of 40-48% in coal-fired generation and of up to 77% in oil-fired generation forecasted[126] within 10 years. Germany is likely to be affected to a greater extent than Belgium or the Netherlands by the implementation of emissions trading, and so is likely to become a net importer from the Netherlands[127]. Having said that, new power stations are much cleaner than the ones they

[126] Global Insight (2004) "European Power Price Summary 2004"

[127] Newbery et al (2003), p. 17.

replace, and this will help to mitigate some of the negative effect, especially in Germany where a lot of new capacity will be needed[128].

E.ON is unlikely to build new capacity until 2010 (according to a 2003 report by BNP Paribas). According to BNP Paribas, the market dominance of the four biggest players in Germany makes it fairly unlikely new entrants will be seen in the German generation market in the near future.

In view of the Kyoto Protocol, the widespread decommissioning of nuclear power stations, and the problems with green energy, power generators might be forced to accelerate the pace of new gas-fired capacity construction due to an absence of viable alternatives, and perhaps even to use gas for baseload generation.

In May 2004, however, Tapio Kuula, head of Fortum's heat and power division, called nuclear "the best choice for new capacity, especially taking into account the CO_2 emissions"[129]. Also, Vattenfall has recently announced that it is exploring the possibility of meeting future increased demand for electricity in Sweden by reactivating oil-fired units, not just for peak demand, but to be run permanently.

Gas is likely, therefore, to become more important in the near future, since it is relatively abundant, can meet the capacity requirements of future demand for electricity, and produces electricity with less pollution than coal or oil. It has a role to play as an input to generation, and as a substitute to electricity in supply (for example, in heating). Electricity companies will be considering the possibilities for acquiring gas, as was shown by the acquisition of Ruhrgas by E.ON. In the more distant future, micro-CHP (combined heat and power), which uses gas to generate electricity and heat, might become an important way in which emissions targets can be achieved. The energy is generated by an on-site unit, which would replace the boiler, and would be suitable for use in homes and small businesses. Trials have started, in which E.ON has been participating in both Germany and the UK.

It is noticeable that the large energy companies' geographical positioning of their operations reflects the focus of the European Commission in projects to increase interconnection between regions, most notably the axes of France-Belgium-Netherlands-Germany, UK-Continental Europe and France-Spain-Portugal. We have already seen, especially, the manoeuvring of EdF, E.ON and RWE, but others, including Vattenfall, Endesa, Electrabel and Enel have sought to extend their capabilities into new territories, such as Poland. EdF has identified Spain as a future core market, though it has plans to become important across all the major Member States of the EU, whilst Vattenfall, already strong in the Nordic region, is seeking to expand in Northwestern

[128] VGB PowerTech predicts the need for 40 GW of replacement capacity in Germany by 2020, which is more than a third of the capacity currently available.

[129] Quoted in "Nuclear still seen as Finland's best bet for new baseload power" in *Nucleonics Week*, 19 May 2004, p.7.

Europe, and Endesa has tried to strengthen its position in France. The expansion of the EU has provided an extra opportunity for more merger activity.

There has been some resistance from authorities to mergers, such as the competition authorities in the Nordic region, who claimed in a joint-statement in September 2003 that the prospect of large-scale mergers presented the "biggest single future danger to competition in Nordic electricity markets"[130]. Outside of the Nordic region, though, mergers, such as between E.ON and Ruhrgas, seem to have been allowed, though in that particular case, only after a protracted struggle with the competition authorities.

Large-scale mergers seem to have stimulated responses for pre-emptive action in the Netherlands. The Dutch government's energy advisory council (the Energieraad) recently called for the merger of Essent and Nuon, to create a national champion, to protect themselves against takeover by French and German energy groups. The Energieraad argued that the Netherlands needed a dominant national supplier (to be gradually created over a period of 10 years) to compete with neighbouring rivals in the liberalised European market. A spokesman for Essent, though, said that the merger was "unnecessary", because both companies were strong in supply in Holland and already had operations in Germany[131].

Consolidation has started to occur in some of the more (in terms of liberalisation) mature electricity markets. At the end of 2003, EdF, E.ON and RWE collectively supplied about 60% of domestic electricity customers in Great Britain according to data from the distribution companies and reported by Ofgem, the regulator. EdF has steadily acquired several distributors and suppliers of electricity in England and Wales, including London Electricity in 1998. E.ON bought Powergen, one of the biggest electricity companies in the UK, in 2002. That same year, RWE purchased Innogy (formerly National Power). Despite these companies' involvement in the UK market, Ofgem considers the market to have remained competitive, and not yet fully mature. We have already mentioned that the large electricity companies in Germany are seeking to grow in the immediate surrounding countries.

Further to the expansion of generation and supply companies, the grids of some Member States are being joined up already, with the establishment of a common Iberian market for electricity, called Mibel, for Spain and Portugal. This has been an effort in terms of harmonising regulation and building interconnection. Energy ministers in the Scandinavian countries, though not all the network operators, backed plans for a single Nordic grid at the end of 2003. The TSOs did agree, however, in May 2004, to a common strategic approach to the Nordic market. This is likely to have been a response to the

[130] Quoted in "Nordic mega-mergers face zero tolerance" in *Utility Week*, 12 September 2003, p.11.

[131] "Advisor calls for Nuon/Essent merger" in Utility Week, 1 April 2004, p.9.

understanding that the Nordic market has become dangerously dependent upon imports from outside the region (primarily Germany and Russia), and on hydroelectric power. There are also proposals to extend the linkage of the European grid to the Eastern European countries. The Polish grid is already linked to the rest of Europe and there was a proposal in 2003 for the Baltic region to be joined to the Polish grid, and thus to Europe. Interconnection is one of the primary limitations with respect to greater market integration, hence the European Commission's focus on cross-border links.

It is important to realise that most countries within the EU will be net importers of electricity so that the role of interconnection will be more to encourage competitive pricing than to provide emergency capacity in the event of a sudden peak in demand. For instance, increasing the interconnection capacity between Belgium and its neighbours will increase the extent to which imported electricity will be able to influence the price of electricity in Belgium.

Vertically integrated companies have come under fire from traders for having access to information not available to pure traders, and thus for having an unfair competitive advantage. E.ON, RWE and EdF control sections of grid, and also 45% of the EU's generation capacity. Prospex Research found in a 2003 study that German electricity trading volumes fell by 40% in 2002. One major factor, particularly in early 2002, which had a negative effect on trading volumes, was the collapse of Enron. Since then, though, Prospex Research asserts, "the German market has become dominated by the 'big four' supra-regional utilities of E.ON, RWE, EnBW and Vattenfall Europe"[132], all of which own large sections of the German electricity grid. However, grid access pricing and independent operation (of the grid from generation and supply) has been a topic of consideration not just in Germany, but also in the Netherlands and in Italy. Both Italy and the Netherlands are looking at removing control of the networks, at least at the transmission level, from vertically integrated electricity companies.

Power exchanges, which allow pure trading of electricity, and can enhance competition, have been part of the successful energy market liberalisation strategies of countries worldwide. This can be seen in Sweden's experience, where nationally defined markets would suggest a duopoly between Vattenfall and E.ON, but where electricity trading in NordPool on a pan-Scandinavian basis, allows over 100 traders to actively participate[133].

Electricity is traded in England and Wales in the wholesale market using the New Electricity Trading Agreements (NETA). NETA did make trading more competitive and prices remained low since its introduction in 2001, though they had been falling since 1998, when the first reforms to trading were

[132] "France: A Land of Opportunity?" (October 2003) available from www.prospex.co.uk

[133] The degree of demand side participation, and the fact that Norway has about 90% storage hydro power, also means that electricity is a fundamentally different commodity in NordPool.

introduced by the UK government. A lack of generation, however, has caused concern since the introduction of a new electricity trading system three years ago, and prices have recently been rising. NETA introduced a system of bilateral contracts between electricity producers and suppliers, with just a small amount of energy traded beyond the contract to provide flexibility. The new arrangements have reduced wholesale electricity prices but have also meant that generators have reduced their power capacity because price incentives are not as strong as under the previous arrangements.

Nevertheless, power exchanges are becoming more common in Member States, with one being set up in Italy in March 2004, and companies from the Nordic countries entering the Germany-based European Energy Exchange in 2003. This is an example of the expansion of electricity exchanges beyond their home markets as trading volumes reach critical mass.

5.3 Multi-market contact

Currently, the electricity markets in the various European countries are relatively segregated with respect to generation, because of constraints on the flow of electricity across borders that are imposed by interconnection capacity. However, the larger electricity companies are each present in several countries, and are active in the same markets in some instances. The "meeting" of companies in several geographically separate markets is referred to in economic literature as "multi-market contact". Theoretical and empirical studies on multi-market contact suggest that it may influence the strategic decisions that firms make in all markets where they are mutually active, and is not necessarily dependent upon symmetrical market concentration.

In a seminal piece, Bernheim and Whinston (1990) provide a theoretical framework that suggests that in a wide range of circumstances, the effect of multi-market contact is to relax "the incentive constraints that limit the extent of collusion"[134]. This implies that the firms that experience multi-market contact face stronger incentives, than firms meeting in one market only, to sell at a price higher than the fully competitive price. Thus firms can benefit from higher profits, but Bernheim and Whinston find that the effects of multi-market contact are ambiguous when some markets are competitive and some are not. For example, their predictions are that multi-market contact causes the price in the monopolistic market (few firms, each with a substantial share of the market) to fall, and in the competitive market (many firms, with relatively smaller market shares) to rise. They also propose, though not formally, that the presence of significant single-market players (i.e., companies present in only one country) would tend to retard the effects of multi-market contact. However, they concede that the significance of multi-

[134] Bernheim & Whinston (1990), p.22.

market contact depends on the actual circumstances of the markets involved. Scott (2004) suggests that the "greater familiarity and contemporaneous experience" of firms that meet in several markets increases their ability to choose desirable equilibria—i.e., to exercise market power jointly.

Though there has not been a statistical study of multi-market contact specifically on the electricity markets in Northwestern Europe, work by Evans and Kessides (1994) on the US airline industry, and by Parker and Röller (1997) on the US mobile telephone industry, find evidence of non-competitive behaviour in situations of network industry mergers across different geographical markets. These situations are broadly similar to that of electricity markets in Northwestern Europe.

We have seen that the major electricity companies are active in several European countries, and often have focused that presence on particular regions, depending on their original core market. Table 5.2, below, shows where the biggest electricity companies in Europe own generation assets. The letter G, which is in bold typeface if the country is the company's home market, denotes their presence in that market.

Table 5.2: Ownership by major electricity companies of generation assets (G) in European countries

	Electrabel	EdF	E.ON	RWE	Fortum	Vattenfall	Endesa	Enel
Northwestern Europe								
Austria				G				
Belgium	G	G(1)						
France	G(2)	G					G(3)	
Germany	G	G(4)	G	G		G		
Luxembourg	G							
Netherlands	G		G					
Switzerland		G						
Southern Europe								
Italy	G	G	G				G	G
Cyprus								
Greece								
Malta								
Scandinavia								
Denmark						G		
Finland			G		G	G		
Norway								
Sweden			G		G	G		
Central Eastern Europe								
Czech Republic			G					
Estonia					G			
Hungary	G	G	G	G				
Latvia								
Lithuania			G					
Poland	G	G	G			G		
Slovakia								
Slovenia								
Iberia								
Portugal	G	G					G	
Spain		G					G	G
UK & Ireland								
United Kingdom		G	G	G				
Ireland								

NOTES: (1) Through its share of Tihange 1's output, (2) CNR, (3) SNET, (4) EnBW.

Source: London Economics

In many of the countries, there are at least three large electricity companies present, though it should be noted that this table does not provide details of the size of the capacity held by each of the companies. Whilst it would be expected that the biggest companies would be present in several countries, some companies seem to have generation assets in almost every country in particular regions. For example, Electrabel and EdF, appear to have a wider presence in Northwestern Europe than any other company. Even E.ON, whose E.ON Energie unit is focused on Northwestern Europe (in addition to Central and Eastern Europe), does not cover as many countries in that region.

What might influence company behaviour, though, is the occurrence of multi-market contact. The common meeting of companies in separate markets, as we have described above, can increase the feasibility of tacit collusion. Table 5.2 shows that Electrabel, EdF and E.ON meet in four countries, including two of the largest European markets, Germany and Italy. Electrabel and EdF meet in seven markets in total. EdF, E.ON and RWE mutually meet in three markets, including Germany and the United Kingdom. Relative to the first four companies listed in the table, the remaining big European electricity companies are somewhat more concentrated in their respective regional markets.

While the experience on multimarket contact is significant, we want to emphasize, however, that this is a second order effect relative to horizontal concentration. Thus, while multimarket contact should be considered as a factor that might reduce competition in say, somewhat concentrated markets, this does not out-weigh the anti-competitive potential of a highly concentrated market, without multimarket contact.

5.4 Market concentration indicators

In this section, we consider the market structure of electricity generation in Belgium with a range of assumptions about the integration with neighbouring countries. We show that the Belgian market for the generation of electricity is one of the most concentrated of those in the immediate vicinity, and that maintaining Electrabel's current size will not result in the market becoming less concentrated or more competitive, regardless of the degree to which the market (i.e. the transmission network) is integrated with its neighbours.

It should be noted that to maintain internal consistency in the analysis in this section, we have used data that are comparable across countries. This is true for both the overall capacity within each country, and capacity attributable to each individual company. Although we have data on generation capacity in the Belgian market that specifies the realistic capacity that is available to the market (as used elsewhere in the report), we do not have this for the rest of the countries we are analysing.

Companies announce the hypothetical maximum capacity that is available from their generation assets, regardless of such practicalities as power plants being unable to run permanently at 100% capacity. Therefore, in order to compare across countries, we use data from company websites for all companies, including the Belgian ones. We will also therefore recall the findings for Belgium from Chapter 2 (page 19), which vary slightly, due to the different data being used. Our data from the Union for the Co-ordination of Transmission of Electricity (UCTE) for the overall capacity within countries also represent, in correspondence to the company data, maximum output capacity.

We have included all capacity held by each company significantly involved in electricity generation in each country. For example, we include the capacity held by Electrabel in Belgium, France, Germany, and the Netherlands, in the calculations for each relevant market.

Table 5.3 shows the total installed capacity in each of Belgium, France, Germany and the Netherlands in 2003, using data from UCTE. Using the capacity data presented by companies on their websites, we have estimated concentrations ratios (the total market share) for the top four companies (CR4) in generation capacity in each of the countries. For Belgium, we have only data for the top three companies, and hence record the CR3, as noted in the table.

Using data for all the major companies in each respective market, we have also estimated HHIs. Following the same methodology as in Section 2.4, we estimate upper and lower bounds for the HHI by making the assumption that all other companies are small, and calculating the HHI in two distinct ways: firstly, on the basis that their market share is insignificantly small (atomistic); and secondly, that it is represented by one single company (a representative residual classified "other"). The discrepancy between the two estimates of the HHI increases as the total market share accounted for by these residual companies increases, with the former method tending to underestimate the HHI (attributing too little significance to the residual companies) and the latter overestimating it (attributing too much significance to the residual companies).

Table 5.3: Market concentrations in generation capacity of the Northwestern European electricity markets

Member States	Total Capacity (GW)	Concentration Ratio of 4 Biggest Companies (CR4)	HHI(3)	
			Lower bound	Upper bound
Belgium(1)	15.8	98.5%(2)	7811	7814
France	114.3	94.3%	7858	7890
Germany	111.2	81.6%	1867	2207
Netherlands	20.6	75.4%	1611	1920

NOTES: (1) We used data from UCTE for the Belgian data, rather than data from Section 2.2.6 (page 43) for comparability purposes. The previous analysis estimates the corresponding HHI to be 6756 (see Table 2.7, page 62); (2) CR3; (3) Belgian HHI calculated using data for 3 companies, French HHI calculated using data for 5 companies (representing 94.4% of the market), German HHIs calculated using data for 4 companies, Dutch HHI calculated using data for 5 companies (82.4% of the market).

Source: London Economics calculations based on data from UCTE and individual company websites

The table shows that the Belgian and French markets are much more concentrated than the German and the Dutch, by both measures used, but also that none of the four countries' electricity markets have strikingly competitive generation sectors.

Table 5.4 shows the same descriptive statistics, but for hypothetical situations with two or more of the countries' markets merged together (i.e., assuming that there are no interconnection capacity constraints across national borders). This provides an indication of the prospective market concentration (derived from data on domestically installed capacity) if the transmission grids in the corresponding countries were fully integrated.

Table 5.4: Market concentrations in generation capacity for hypothetical scenarios of fully integrated networks

Member States(1)	Total Capacity (GW)	Concentration Ratio of 4 Biggest Companies (CR4)	HHI(2)	
			Lower bound	Upper bound
BE-FR	130.1	93.9%	6254	6281
BE-NL	36.4	80.9%	2966	3077
BE-NL-FR	150.7	86.6%	4749	4857
BE-NL-FR-D	261.9	69.9%	1919	2190

NOTES: (1) BE: Belgium, FR: France, D: Germany, NL: Netherlands; (2) BE-FR HHI calculated using data for 5 companies (representing 94.9% of the market), BE-NL HHI calculated using data for 7 companies (89.4%), BE-NL-FR HHI calculated using data for 7 companies (89.6%), BE-NL-FR-D HHI calculated using data for 12 companies (88.3%).

Source: London Economics calculations based on data from UCTE and individual company websites

This table shows that merging the Belgian market for electricity generation with one, or more, of its neighbours could indeed reduce the concentration against that for the Belgian market alone, but that only the merger of the Dutch and the Belgian markets, or the integration of all four markets, significantly reduces the 4-firm concentration ratio and the HHI.

The merger of the Dutch and the Belgian markets, however, provides Electrabel with more than half of the market. The two big Dutch companies, Essent and Nuon would each hold about one-eighth of the market, with the remaining companies having market shares no bigger than 5%. This would still therefore be a market dominated by one player, which would be Electrabel.

Even in the event (very unlikely in the near future) that all four markets were fully integrated, EdF would hold a market share of just under 40%, with the big German companies, RWE and E.ON, holding just over 10%. Electrabel, Vattenfall, EnBW would each have shares of between just under 6% and 8%, with the two large Dutch companies having shares of about 2%. Although this configuration produces the least concentrated market of all of our hypothetical situations, EdF would still have a commanding position in the market, even against RWE and E.ON. The HHI falls to 2190, which is still higher than the threshold 1800 above which competition concerns are considered to clearly deserve further investigation.

It is important to recall that the prior analysis represents the polar case of *full integration,* i.e., as if there were no constraints in terms of interconnection, no cost to shipping power longer distances, etc. In reality, there is a limit to the capacity that can be accessed by importers and exporters of electricity across national borders. The actual situation facing the Belgian market is given in

Table 5.5, which shows the capacity available in Belgium, when import interconnection constraints are considered.

The Net Transfer Capacity (NTC) is "the maximum exchange programme between two areas compatible with security standards applicable in both areas and taking into account the technical uncertainties on future network conditions"[135]. On average, for the years 2003 and 2004, the NTC into Belgium was between 2 GW and 2.5 GW from each of France and the Netherlands. Interconnection capacity is allocated to companies either through pre-arranged agreements, or via market mechanisms (such as auctions). In the same manner that the generation capacity announced by companies is an upper bound that takes no account of the practicalities of running, the NTC measure is the upper bound of what capacity there exists across borders.

Section 2.2.4 (page 25) described the long-term agreements regarding cross-border interconnection capacity from France into Belgium made by EdF with Electrabel and with SPE. We therefore include here also the requirements set by the long-term contracts on the French-Belgian interconnection. Similarly, the SEP contract (held between EdF and six Dutch suppliers), which preserves [confidential] MW of cross-border capacity for transmission of electricity from France to the Netherlands via Belgium, is also taken into consideration. This is because the contract, which runs until 2009, will place a constraint on the capacity available in Belgium for several years to come.

We assume that the interconnection capacity into Belgium available to each company is related to their market share within the exporting country. We calculate, say, Company X's share of interconnection capacity from, say, Country A into Belgium as the product of the total interconnection capacity from Country A to Belgium and Company X's market share of (domestic) installed capacity in Country A.[136]

We adapt this methodology to reflect the rules governing import capacity into Belgium from both France and the Netherlands. We have already commented upon the long-term agreements that Electrabel and SPE have with EdF, regarding imports from France into Belgium. The remaining import capacity is allocated subject to an upper limit on the amount available to any one company of 200 MW (100 MW of daily capacity and 100 MW of monthly capacity). As remarked upon in footnote 43 (page 56), one of the rules of the auction on the Dutch-Belgian border forbids any one party obtaining more than 400 MW of interconnection capacity into Belgium. We incorporate these features into our calculation of companies' import

[135] ETSO (2001) "Definition of transfer capacities in liberalised electricity markets", Final Report, April, p.7.

[136] It is worth noting that Newbery et al (2003) prescribe market coupling as the most efficient way to use interconnection capacity. By implementing spot markets in both price regions and appointing an independent market operator to arbitrage between the two (via control of some, or all, the interconnection capacity), prices in the two regions can be equalised in the absence of binding interconnection capacity constraints, or brought closer if constraints do bind.

capacities from the Netherlands into Belgium, then proceed as before with the remaining companies that are not party to long-term agreements and/or constrained by the upper capacity limits.[137]

We suggest that the most appropriate of our hypotheses of full network integration is the conjunction of Belgium, France and the Netherlands into one market. Of all the interconnections of the Belgian network with its neighbours', only that with France is due to increase. RTE announced[138] that it plans to increase its interconnection capacity to Belgium by about 1 GW to 3.7 GW in winter periods, with work set to start in the second half of 2004. TenneT has stated[139] that it has no plans to increase interconnection capacity from the Netherlands, since the Belgian and German grids need to be improved first. There are currently no interconnectors directly between Belgium and Germany.

Table 5.5 shows a comparison of various scenarios that could illustrate the past, present and (distant) future Belgian market for electricity generation. Three scenarios are compared. The first, "Belgium (2003)", is the situation in 2003, which was calculated and analysed in Section 2.4 (Table 2.7, page 62). The second, "Belgium + NTC", which uses the data from UCTE, ETSO and individual company websites, shows the situation as it is in 2004 (with the caveat that the capacity data are of maximum output capacity, rather than available capacity). The final row, "BE-NL-FR", repeats the findings from Table 5.4, which shows what the market concentration (counting only domestically installed capacity[140]) would be if electricity companies retained their present installed capacities, but there were no interconnection capacity constraints on cross-border flows.

[137] In practice, we estimate the impact of the 400 MW limit on the Dutch-Belgian border to be no more than 80 MW on any one company, the effect of which is negligible on the overall picture. On the French-Belgian border, EdF is rather more heavily constrained by the 200 MW limit.

[138] RTE/Elia on 16 December 2003 http://www.rte-france.com/jsp/an/actu/viewdepeche.jsp?Id=5341

[139] TenneT on 24 July 2003, available at http://www.tennet.nl/english/transmission_services/capacity/0

[140] Given the much larger size of the market, the effect on the market concentration of cross-border interconnection with countries outside of Belgium, France and the Netherlands would be negligible.

Table 5.5: Comparison of scenarios

Market definition(1)	Relevance to actuality	Total Capacity (GW)	Concentration Ratio of 4 Biggest Companies (CR4)	HHI(4)	
				Lower bound	Upper bound
Belgium (as in Chapter 2)(2)	2003	15.8	92.6%(3)	6533	6711
Belgium + NTC	2004 potential	19.7	87.8%	5869	5934
BE-NL-FR	Hypothe-tical	150.7	86.6%	4749	4857

NOTES: (1) BE: Belgium, NL: Netherlands, FR: France, NTC: net transfer capacity into Belgium; (2) This repeats findings from Table 2.7 (page 62); (3) CR3; (4) Belgian HHI calculated using data for 3 companies, "Belgium + NTC" HHI calculated using data for 9 companies (representing 92.2% of the market), BE-NL-FR HHI calculated using data for 7 companies (89.6%).

Source: London Economics calculations based on data from the CREG, UCTE, ETSO and individual company websites

It is immediately obvious that the concentration ratios of the top four companies and the HHIs are similar in all three scenarios, but are the lowest when considering the fully integrated market. In none of the scenarios, however, is the market evenly distributed amongst several players. In Belgium, as we know, Electrabel dominates. Using the UCTE and company website data, we estimate that Electrabel has a market share in Belgium of 88.0%[141] of domestically installed capacity. With interconnection constraints, we estimate that, in Belgium, EdF would have about 3.5% market share, but that Electrabel would retain a large market share of over 76%. In the fully integrated Franco-Belgian-Dutch market, EdF would have almost 68% of the market, and Electrabel just over 13%.

Due to the pattern of ownership in relation to generation capacity in Northwestern Europe, it appears that there will exist a high degree of market concentration in the near future. Even the full integration of the Belgian grid with the French and Dutch grids (individually or together) would not create a competitive market, due to EdF's strength in France, and Electrabel's presence in the Netherlands. This full integration is not, in any case, a likely scenario in the near future, since cross-border capacity is only due to increase between Belgium and France in the next few years. The presence of

[141] This market share is more than the 81.4% reported in Section 2.2.6 (page 43); the discrepancy is due to the limitations of the data available for use in this section. This illustrates the need for an internally consistent analysis for comparison with companies from outside of Belgium, though the broad implication by either measure of Electrabel's market share is the same.

interconnection capacity constraints[142] means that Electrabel will remain the dominant player in Belgium even if EDF is many times larger.

5.5 Conclusions

There are four themes to recall that run throughout the analysis:

- The future of generation and energy sources;
- The expansion of electricity companies into neighbouring markets;
- The importance of network control, pricing, and connection; and
- The emergence of power exchanges.

It seems likely that the combination of the restrictions resulting from the Kyoto Protocol and the decommissioning of nuclear power stations in several countries is likely to result in a change in the portfolio of generation assets across Europe. Gas and green energy will become relatively more important, though the reliability issues of the latter means that conventional thermal generation (especially in light of the decommissioning in nuclear power) is likely to be retained as an important source of energy.

Large electricity companies seem likely to continue to acquire assets in other countries, though the process is now rather more focussed upon consolidating positions in regional zones. For instance, the concentration of German companies in Northwestern Europe. For the foreseeable future, this will increase the number of multi-market contacts that the companies have, and thus might encourage tacit collusion in these markets.

The ownership and control of the transmission and distribution networks is a major issue, not just in terms of pricing, which in many countries is regulated, but in terms of information and incentives. Grid owners often have an informational advantage on volumes and prices over other firms that inhibits the ability of these latter firms to compete.

Power exchanges can be an important aspect in creating a competitive wholesale market, but rely on many players being involved for sufficient liquidity. One way in which the efficiency of the power exchanges, and of electricity markets in general, could be improved is by increasing interconnection capacity between countries. This would allow a greater influence on the part of arbitrageurs to reduce the market power of local players. However, the present situation with regards to ownership of capacity in Northwestern Europe means that, even if there was, contrary to current plans, an extensive increase in cross-border interconnection capacity, it is likely that the market for generation of electricity facing Belgium would remain highly concentrated.

[142] These constraints may not be binding in every hour, but this does not mean that EdF can bring their full weight over the interconnector whenever they want.

6 Barriers to entry into the Belgian electricity markets

6.1 Introduction

The CREG is naturally concerned about barriers to the entry in the three electricity markets in Belgium. Existing barriers are usually very important determinants of market performance since they allow incumbent firms to raise prices and make supra-normal profits. Conversely, a market with low entry barriers is a market where economic inefficiency will not persist. There are two ways in which this link may be formed: 1) low entry barriers mean that there will be entry and therefore healthy competition in the market and 2) low entry barriers imply that incumbents feel the potential threat of entry and therefore will price on competitive terms in response to that potential competition.

The rest of this chapter is structured as follows. Section 6.2 discusses the definition of entry barriers and gives a taxonomy of barrier types. Section 6.3 discusses economic models of entry. Section 6.4 discusses entry conditions in the Belgian markets in general, while Section 6.5 discusses barriers to the generation market, 6.6 discusses barriers to trading, and 6.7 discusses barriers to supply. Section 6.8 gives conclusions to this chapter.

6.2 Barriers to entry: definitions and types of barriers

There are a number of different definitions of "barriers to entry" and, unfortunately, economists have yet to reach a broad consensus on which is the more correct one. For the purpose of this study we will adopt Bain's original definition, dating back to 1956, where he defines a barrier to entry as

> "an advantage of established sellers in an industry over potential entrant sellers, which is reflected in the extent to which established sellers can persistently raise their prices above competitive levels without attracting new firms to enter the industry".

In terms of a framework for thinking about barriers to entry in real-world markets, it is helpful to consider three main categories of entry barriers. First, entry barriers may be *structural*, meaning that they arise as the result of demand and supply (production and costs) conditions in the market and are due solely to conditions outside the control of market participants. Second, entry barriers may be *behavioural/strategic*, in that they result from the actions of incumbents, particularly when these represent abuse of dominant position by which "relatively large" firms engage in anti-competitive conduct or

restrictive business practices, preventing entry or forcing exit of competitors through various kinds of monopolistic conduct. Third, entry barriers may be *regulatory*, arising as the result of legal or regulatory requirements (or administrative practices) by government and/or other policy makers.

Structural barriers to entry

Where scale economies are large relative to the level of demand, the market may only be able to sustain a small number of firms in which case entry may be blockaded. In the context of the Belgian electricity market, it is important to consider the nature of fixed costs and, in particular, to distinguish between 'sunk' costs and fixed costs. Sunk costs are costs that cannot be recovered once incurred.

Sunk costs are generally a form of fixed cost and their significance is that if a firm were to exit the industry, it could not recoup the cost by selling the asset or putting it to another use. Thus, in markets where the fixed cost of entry entails a heavy sunk cost element, barriers to entry (and exit) will be high. The result is that market dynamics, in terms of entry and exit, will be low (entry of new efficient firms may be blockaded and exit of inefficient existing firms may be held up) and consumer/buyer welfare will tend to suffer as a result.

Other sources of structural barriers to entry may be:

- Large capital requirements
- Asset specificity
- Absolute cost advantages – access to non-replicable natural resources or human resources
- In network industries – potential competitors need to share some critical facility like transportation and telecommunications
- Demand conditions – including switching costs and brand loyalty
- Informational advantages
- Organizational advantages

Strategic or behavioural barriers to entry

Through their actions and business strategy incumbents can make a market look less attractive to potential entrants. We deal with the main three classes of models of strategic entry deterrence in Section 6.3.3. Here we provide some examples of more commonly referred strategic barriers.

Vertical integration can be a way to deter entry. Vertical integration may create barriers to entry by forcing entrants to compete at all stages of the chain of production, and not only at their chosen one. For example, in the UK, energy producers facing the new NETA rules have been increasingly

looking to buy distribution companies, in part, to hedge their exposure from wholesale to retail pricing.

Vertical integration might be either a technical barrier or a non-technical barrier. For example, in electricity, before real-time electronic information systems were available on standard platforms, vertical integration of transmission and generation was probably a technical necessity. Today, vertical integration in electricity is probably a non-technical barrier.

Pricing strategy can also be used as a way to keep potential entrants out. Among the most important early models of barriers to entry is the Sylos-Labini-Modigliani (1962) 'limit pricing' model. This model shows that it could be possible for firms to block entry, and still earn a positive profit. The model has some features applicable to electricity markets.

Potential entrants also need to be concerned about the reaction that they can expect from incumbents upon entry. Incumbents, in turn, have clear incentives to make a threat of aggressive pricing upon entry credible. This may be accomplished through spells of such behaviour as a response to past entry.

Another important way to signal disposition of aggressive behaviour is through investment in excess capacity. This makes the cost of lowering prices lower for the incumbent than for the entrant, thus making the incumbent more likely to win a price war, and the threat of a price war more credible.

US economist Robert Smiley carried out a survey to establish the more common types of strategies used by firms to limit or deter entry in practice.[143] In order of frequency of response, respondents noted the following strategies:

- Sign long-term contracts with customers, middlemen or wholesalers;
- Have product specifications or controlling regulations designed so that only your product qualifies;
- React aggressively when a new entrant is in the promotion stage, especially with wholesalers and retailers, thereby denying them reliable information about their new product's steady-state profitability;
- Keep products or processes secret as long as possible;
- Make pre-emptive purchases of all available raw materials or supplies;
- Make early sales to critical buyers-opinion leaders;
- Announce the product long before it is ready.

Other forms of strategic barriers to entry can include:

[143] His results were based on 294 responses from product managers of major US corporations (Smiley, R., 1980).

- Horizontal restraints – cartels or collusion (price-fixing agreements, market sharing territorial arrangements, bid rigging)
- Price discrimination
- Intense advertising
- Product proliferation
- Exclusive patent cross-licensing
- Vertical integration and vertical restraints – resale price maintenance, exclusive dealing, tying, contracts to block distribution
- Foreclosure and exclusion
- Tactics to increase rivals' costs

Public, regulatory and legal barriers

Other barriers to entry may result from government regulation. Barriers to entry created by governments may be the most durable (Tirole 1992). For example, most governments gave electricity suppliers legal monopolies before EU market liberalisation, and legal monopoly over parts of the system has remained.

Public, regulatory or legal entry barriers may arise as a specific form of entry impediment involving: "a cost that must be incurred by a new entrant that incumbents do not (or have not had to) bear".[144] For instance, a change in legislation may impose differential access conditions on new entrants compared with their predecessors (i.e. incumbents). Public entry barriers may be 'innocent' in the sense that they were designed to protect the public interest (e.g. by having more stringent health and safety requirements) but inadvertently result in the creation of an entry barrier. Alternatively, they may be the result of 'rent-seeking' behaviour by incumbents. Rather than protecting the public interest or addressing some market failure, regulation or access requirements may instead serve to protect incumbents from new competition and thereby restrict competition.

Other legal practices that may contribute to restrict entry include:

- Special permits, license to operate
- Regulations influencing the use of some inputs
- Discriminatory export practices
- Ownership restrictions

[144] This narrower definition of an (asymmetric) entry barrier is taken from Carlton, D. W. and Perloff, J. M. (1994).

6.3 Economic models of entry

In this section we provide a brief overview of the different types of entry models that can be found in the economic literature.

Various entry models have been described in the economic literature attempting to explain what the decision to set up a new business depends on. One usual element in practically all approaches is the assumption that agents/firms will enter the market if they expect to obtain profits that exceed or at least equal the opportunity cost of the resources employed in the future activity. Rational agents, according to the economic theory of investment decision-making, will attempt entry only if risk-adjusted discounted[145] expected returns are greater than the necessary investment. In other words, one reason why we may fail to observe entry in a particular market is because potential entrants do not expect to profit from that entry. The models we discuss in this section help us to identify potential sources of why the costs of investment may exceed the expected value of the stream of revenue accruing to the investor in the Belgian electricity markets.

6.3.1 Entry as investment

In order to understand strategic competition and industry entry and exit, it is necessary to understand as background what drives investment. This is because all entry is essentially an investment—a business or entrepreneur takes his or her financial capital and converts it into physical capital by purchasing new or existing plant and equipment.

There is a traditional view of investment under which decisions depend on the signal of expected discounted cashflows. This view has subsequently been refined by the more recent theory of "investment under uncertainty" developed by Dixit and Pindyck (1994). This new approach to investment recognises the option value of waiting for better (but never complete) information. It exploits an analogy with the theory of options in financial markets - investment decisions are like options, and thus there is a value to 'waiting' to invest. Under this theory, the expected future discounted cashflows are not the only relevant parameters that enter an investment decision; other parameters such as the volatility of prices and the risk free rate of interest will have a real impact too.

The implications of this alternative theory are striking. The investment under uncertainty theory suggests that it may be optimal for firms to 'wait' when considering an investment in the presence of sunk costs and uncertainty, even when a project has positive net expected discounted cashflow. This is because 'new information' is likely to arrive, and so some of the uncertainty should 'resolve itself' as the firm waits. Thus, one should expect greater

[145] The proper risk adjustment to the discount rate would include the opportunity cost of capital.

'investment hysteresis' or a 'lagging tendency' the greater the uncertainty in the market place.

6.3.2 Static versus dynamic models of entry

There are two main approaches to the theory of entry. The first is the static traditional approach of industrial organisation, and the second is a dynamic approach in which innovation and technological progress determine the evolution of market structure.

In the static approach entry models are based on the traditional microeconomic theory of the firm where firms are described through a production function. In these models, potential entrants are not dissimilar from incumbents and thus they would, in principle, be as able to generate profits as the incumbents. In this view, a market where incumbents make supra-normal profits should attract entry unless some barriers exist to deter it.

Absent entry barriers, the entry process is seen as the mechanism by which competition erodes the market power of incumbents and the profits of the industry reach their long run equilibrium. Entry will lead to an increase in the degree of competition in the markets, and ultimately to an increase in efficiency. In the presence of entry barriers, however, the industry is imperfectly competitive and the long run profits will depend on the height of the entry barriers.

Dynamic approaches associate the processes of entry and exit of establishments with processes of innovation and change in the industry and its technologies. In most of these models it is the possibility of exploiting an innovation which induces agents to enter a market. Unlike the static approach, in which firms are assumed to have similar capabilities, the dynamic approach is based on the assumption that both entrants and incumbents are asymmetric. This view suggests that, over time, it is managerial thinking and initiative that drive new entrants to progressively gain market share.

In the context of the electricity market we have opted to follow the traditional industrial organisation approach to entry modelling. Managerial and technological advantage and innovation do not appear to be particularly significant features of competition in electricity markets. Electricity is an essentially homogeneous good with alternative production technologies that are well known by both current and potential competitors.

As a result, we dedicate a large part of this chapter to the analysis of barriers to entry affecting one or more of the three markets under study.

6.3.3 Models of entry deterrence

Models of entry deterrence study how an incumbent could profitably deter entry or survival of competitors in a market, via a strategy that is credible.

The discussion of models of entry deterrence is particularly relevant for the present study where we have one large incumbent present in all three markets. The study of models of entry deterrence can help elucidate how particular strategies of this incumbent may have the purpose (and/or the effect) of deterring entry.

There are three broad categories of models of entry deterrence: pre-emption, signalling and predation. We briefly discuss them below.

Pre-emption

The thrust of these models is to develop the idea that incumbency provides an inherent advantage to move first in committing to irreversible investments that restrict the opportunities available to entrants. These investments constitute a "commitment", in the form of (usually costly) actions that irreversibly strengthen the incumbent's options to exclude competitors. Some examples are investments in advertising, research and product design, productive (but possibly spare) capacity (as in the Spence-Dixit model of entry deterrence), durable equipment and other cost reduction, and vertical integration.

Dixit (1980) and Spence (1979) propose that incumbent firms may have an incentive to install excess capacity. Incumbency gives firms the opportunity to move first and commit irreversible investments in durable capacity. This restricts the opportunities available to entrants. A similar justification may explain why Electrabel[146] has made investments in generation, supply, and trading that could be interpreted in this light.

Vertical integration as a strategy to deter entry falls within the long-term contracting framework developed by Aghion and Bolton (1987). We discuss the impact that vertical integration of Electrabel can have on the Belgian electricity market in the following sections.

Bernheim (1984) studies a model where incumbents expend resources (for example, through advertising) to raise entrants' sunk costs of entry. This is a strategy that can be applied to electricity supply in Belgium where the brand name of Electrabel contributes to raise rivals' costs of entry.

The models of switching costs of Klemperer (1987a, 1987b and 1989), among others, can also have some applicability to the case of electricity supply in Belgium.

[146] Electrabel certainly has made investments into supply and trading with its ECS, according to information on the website. In terms of generation, Electrabel has been very keen to do joint deals with auto-producers, CHP, green producers, etc. They also have brought on capacity in the last few years. In spite of the fact that there is no expectation of 'overcapacity', capacity investments can still be entry deterring. The argument is the flip side of limit pricing. Limit pricing says positive profits can be made while not encouraging entry. Similarly, entry can be deterred without necessarily having obvious overcapacity.

Signalling

These models explain how an incumbent firm reliably conveys information that discourages entry or survival of competitors. They indicate that an incumbent's behaviour can be affected by private information about costs or demand either prior to entry (limit pricing) or afterwards (attrition). The hallmark is credible communication, in the form of others' inferences from observations of costly actions. Models in this category differ from those in the previous heading because here incumbents are not assumed to be able to make "commitments". The incumbents in these models have an advantage, not because they can move first, but because they can incur more costly forms of "communication" than entrants.

The two main types of model under this heading are models of attrition (representative models are by Nalebuff and Riley (1985) and Riley (1980)) and models of limit pricing (originally by Milgrom and Roberts (1982a)).

Attrition models study markets where (an excess of) firms have already entered and describe how the market works to select survivors. In the Belgian electricity context, these models are thus likely to be of narrow applicability.

Studies of limit pricing examine the incentives of incumbent firms to signal their private information about cost or demand to deter entry. Monopolist incumbents will price well below monopolistic levels to signal to entrants that that particular market is unattractive. A large incumbent like Electrabel is in a particularly favourable position to use a strategy of this type.

Predation

These models explain how an incumbent firm profits from battling a current entrant to deter subsequent potential entrants. In these models, a 'predatory' price war advertises that later entrants might also meet aggressive responses; its cost is an investment whose payoff is intimidation of subsequent entrants. These models are based on the concept of reputation: the incumbent battles to maintain others' perception of its readiness to fight entry.

These models apply to situations where other firms are operating in the market and the dominant player is trying to make them suffer losses and ultimately lead them to exit and deter further potential entrants. Kreps and Wilson (1982) and Milgrom and Roberts (1982b) are examples of models of this type.

There have been a few examples of entry into different parts of the Belgian electricity supply chain. Some of these experiences have been unsuccessful, thus it could be interesting to study whether a behaviour of the type described here may have been involved.

6.3.4 Contestability theory

The CREG has asked London Economics, as part of this project, to explicitly consider whether any of the three markets, production, trading and supply,

are nearly or likely to be 'contestable' in Belgium. The implication is that if some markets are not contestable, then it would be appropriate for the CREG to take action to improve the competitive conditions of the markets in question.

William Baumol, John Panzar and Robert Willig first presented the theory of contestable markets in 1982. Their theory is based on a simple and sensible idea; the threat of entry can induce incumbent firms to moderate pricing behaviour even in industries with only a single firm. The theory of contestability maintains that competition is effective and sufficient where the market is perfectly contestable, as the existence of a potential new entrant is enough to keep the prices of the incumbent service provider at competitive levels.

A market is perfectly contestable if three conditions are satisfied:

1) New firms must face no disadvantage vis-à-vis existing firms. This means that new firms have access to the same production technology, input prices, products, and information about demand.
2) There are zero sunk costs; that is, all costs associated with entry are fully recoverable. A new firm can then costlessly exit the industry. In other words, if entry requires construction of a production facility or the establishment of a physical presence in a market at cost K, then sunk costs are zero if, on exiting the industry, a firm can sell its facilities or commercial presence for K (less any amount due to physical depreciation).
3) The entry lag (which equals the time between when a firm's entry into the industry is known by existing firms and when the new firm is able to supply the market) is less than the price adjustment lag for existing firms (the time between when it desires to change prices and when it can change prices).

The proponents of the concept of contestability thus characterise a perfectly contestable market as one that is vulnerable to costless "hit-and-run" entry and exit. Stated differently, contestability is a theory for which potential, rather than actual, competition plays the dominant role in generating competitive behaviour.

Apart from the stringency of the first two conditions, there is a significant problem with the plausibility of non-strategic behaviour, implicitly assumed by the third condition. The usual articulation of contestability doctrines is that if the firm charged a higher price, some other firm would enter, undercut, and become the dominant firm. Potential competition, not actual competition, is what matters. The theory postulates that the dominant incumbent firm either does not react or is so sluggish in response to entry that it is unable to respond in any way to deter entry until the entrant has secured a viable and sustainable market share. But such a strong sluggishness assumption seems exaggerated and thus entry is likely to be affected not by the level of profits before entry, but by anticipations about profit levels afterwards, once the

incumbent reacts to entry. Strategic behaviour considerations can affect (rational) expectations about profits after entry.

In other words, the theory assumes that incumbents either cannot or simply do not respond to entry, so that potential entrants base their decisions on pre-entry prices. But in fact, entrants may expect, upon entry, any number of reactions from incumbents which make entry unprofitable. Therefore, incumbents may become unconstrained by potential entry, even when this entry (an subsequent exit) are costless.

The academic world has further criticised the contestable market theory on conceptual, theoretical, and empirical grounds. Typical criticisms, in each of these three categories, are as follows:

- A contestable market does not always have a sustainable equilibrium (Vickers and Yarrow, 1988). This poses the significant problem that contestability theory is unable to predict a market outcome, in a number of actual market configurations;
- The contestability theorem is not robust in an imperfect contestable market where the assumptions of the reaction lag of an incumbent firm and zero sunk cost are only partially satisfied (Schwartz and Reynolds, 1983; Schwartz, 1986). Baumol et al. accepted these criticisms (Baumol, Panzar and Willig, 1983). In other words, a slight deviation from the assumptions causes a dramatic change in the predicted outcome.
- Several empirical studies for the airline industry (a potentially good candidate for a contestable market) found that passenger fares are positively correlated with market share (Keeler and Abrahams, 1981; Graham, Kaplan and Sibley, 1983; Bailey, Graham and Kaplan, 1985; Call and Keeler, 1985; Town and Milliman, 1989) and that passenger fares also depend upon whether a competitor actually exists (Moore, 1986; Morrison and Winston, 1987; Baker and Pratte, 1989). Thus, both actual market concentration and actual (rather than potential) presence of competitors affect pricing by incumbents, contrary to the predictions of contestability.

This discussion of contestability theory is of particular relevance to the CREG. An implication of the theory is that, if any of the markets the CREG regulates are in fact contestable, the CREG's role as regulator might properly be reduced. It is therefore important to understand the debate on contestability in sufficient detail to assess its applicability as a market model to electric power markets in Belgium.

Prefect contestability, similarly to perfect competition, should be seen as a limit case, which is unlikely ever to be reached. In practice, however, we

expect that markets that are "relatively contestable" will work better (closer to the competitive outcome) than those that are less contestable.[147]

We have therefore to analyse and discuss whether:

1) potential entrants face no disadvantage vis-à-vis existing firms
2) there are "relatively low" sunk costs
3) incumbents take longer to adjust prices than entrants take to become operational selling in the market

There are a number of disadvantages that potential entrants face in the markets under analysis. We discuss all of these in turn under the appropriate headings (structural, strategic, and regulatory barriers to entry) in the next section.

Sunk costs are discussed for all markets under the heading of structural barriers to entry.

This leaves us with the question of whether incumbents may take a long time to adjust prices. This question is particularly relevant to an analysis of contestability, but less so to a more traditional analysis of barriers to entry. If this condition is not met, we may still have a market that, albeit not contestable, has low barriers to entry. This would imply that, although a concentrated market under those conditions would probably not result in market outcomes close to the competitive outcome, we would expect that market to see entry and this entry would eventually result in outcomes close to the competitive outcome. We look at this issue for each of the three markets in turn, below.

Generation

In generation, it is wholly unlikely that that third condition, above, is met. Lead times for new entrants to build generation facilities are longer than one year. This is not exactly a market where "hit-and-run" entry seems feasible. There could be hit-and-run entry from abroad, from producers with already established generation facilities. However, with the current limitations on interconnection this is unlikely to pose a significant threat because the amount of wholesale electricity that can be brought into the market in that way is very small.

Our view is thus that the applicability of contestability theory to generation markets is very limited. This means that, without entry, the market is unlikely to work "as if" it were a competitive market. We need, therefore, to analyse entry barriers and models of entry deterrence, which is what we do in the following subsection, 6.5.

[147] This, unfortunately, is not entirely correct; according to the theoretical criticism that notes low robustness of the results of the model to deviations from the "zero sunk costs" and the "reaction lag greater than entry lag" assumptions. Still, we may expect that, in a broad sense, moving closer to these assumptions may improve market outcomes.

Trading

In trading, there is no reason for any significant lag for incumbents to change their pricing (bid/ask spreads in the case of trading) in response to new entry. But in trading, entry and exit can also happen very fast. Hit-and-run can even occur on a trade-by-trade basis, by traders that are already established in similar and/or nearby markets and therefore can very easily trade in the Belgium market if they see an opportunity of high profit, even if momentary.

This implies that electricity trading meets one of the three conditions for applicability of contestability. We will discuss the other two in the subsection on trading entry barriers, 6.6.

To anticipate the conclusion, however, we view electricity trading in Belgium as a market likely to be contestable. This means that outcomes can be expected to approach competitive outcomes even with a relatively small number of traders established in that market.

Supply

Electricity suppliers typically have no long-term commitments to their prices. Lowering prices in response to entry, in particular, does not seem to involve any significant lag. This implies that contestability theory is not well suited to predict outcomes in this market. Rather, we need to analyse entry barriers to predict whether or not this market is likely to be or become competitive in the near future. This is what we do in the following subsection, 6.7.

6.4 Entry conditions in the Belgian electricity markets

The Belgian electricity sector currently exhibits a number of features, which make entry into any of the three electricity markets more risky for new entrants than would be the case otherwise, and thus are likely to discourage entry. Prominent above these are the vertical integration and dominance of Electrabel and the lack of a functioning wholesale market for electricity.

In this section we discuss problems that simultaneously affect entry conditions in more than one of the three markets under study. In the following sections we discuss separately problems affecting entry conditions into each of the three markets.

6.4.1 Structural barriers

Vertical integration

The Belgian electricity market remains highly vertically integrated. At the present time, Electrabel:

- owns some 81% of generation capacity;
- owns 64.5% of Elia;
- remains the owner of part of the mixed Intercommunales; and
- is the dominant supplier.

In relation to the last point, it should also be noted that Electrabel is the technical operator of these Intercommunales and will continue to provide the technical operational know-how to these intercommunales once divestiture has been completed.

Electrabel's subsidiary, ECS, is the default supplier and Electrabel has a dominant position in the trading market. While Electrabel's current shareholding in Elia is due to decrease significantly, it will remain substantial (30% at maximum including SPE). In addition to this 30%, there will be a secondary relationship that continues in that the intercommunales will still own part of Elia, and the former are, in many cases, also part-owned by Electrabel.

Finally, Electrabel is vertically integrated along the energy supply chain, due to its parent's (Tractabel) ownership of the major natural gas utility, Distrigas. Since natural gas constitutes the major input into new generation that is economically feasible in Belgium – including CHP and autonomous and auto-producer CCGT[148] – the price and availability of natural gas can have a knock-on effect on the degree to which these options constitute competitive alternatives to purchasing power from Electrabel. At the same time, at the retail level, natural gas is substitutable with electricity in things such as water heating, stoves, space heating, etc. In addition, there are marketing and small supply (billing) efficiencies arising from the ability to provide 'dual fuel' offerings.[149]

Vertical integration in electricity is a major obstacle to liberalisation. The ability of the vertically integrated firm to raise rivals' costs, act strategically in ways that rivals' may not, and possess information unavailable to its rivals, is well documented. There is some suggestion that Electrabel may use its relationships with Elia to leverage market power, as alleged in the case of SourcePower or in relation to the issues surrounding ECS, (e.g., the claim that ECS is able to get data in advance of competitors). Evidence from other jurisdictions, including the UK and Germany, shows that insufficient vertical unbundling[150] can block liberalisation and reduce its benefits. In the case of

[148] We heard no particular complaints from large users at the roundtable discussions. Also, we note that Zeebrugge hub gas prices are developing and tracking the UK NBP hub prices closely. In general, this suggests that Belgian prices are unlikely to be deviating too greatly from a more competitive and liquid pricing mechanism, as arbitrage opportunities would otherwise exist.

[149] This feature was mentioned to the consultancy team by suppliers during the roundtable discussions.

[150] By 'insufficient' vertical unbundling, we mean any programme of unbundling that does not break the incentives of the vertically related elements of the firm. In general, ownership unbundling is sufficient, but not necessary, for successful unbundling.

the UK, Scotland is seen to be weakly vertically unbundled[151], and Scottish[152] prices, previously lower than in England & Wales, are now higher. In Germany, vertical ownership of transmission has led to high grid charges and negotiated third-party access.[153] When the vertically integrated firm is also the incumbent, and when such a firm retains dominant positions in almost all markets (plus the transmission system and individually the distribution systems remain natural, and legal, monopolies), then vertical integration becomes an even *more onerous* problem.

One of the problems facing market liberalisation when the incumbent is both a virtual monopoly and is vertically integrated is extreme opacity in the functioning of the market: transactions are internalised within the monopoly. It is for this reason that quantitative assessment of the impacts of vertical integration is very difficult.

Nonetheless, it is useful to note that vertical separation between the potentially competitive markets (generation, supply, etc) and the natural monopoly elements (transmission and distribution) was widely regarded, including by the EU Commission[154], by the designers of the England and Wales liberalisation, and by liberalisation designers in North America and Australia, as *prima facie* a prerequisite for liberalisation. Vertical separation was a first step. In addition, in locations such as Scotland where vertically separation was weak, it is generally accepted that liberalisation has been less successful than in England and Wales.[155]

As noted earlier vertical integration is in itself a barrier to entry. There are two main reasons the firm might be vertically integrated: it might engender efficiencies across intra-company transactions; or it might help the firm leverage market power from one market to another. In the case where there are efficiencies from vertical integration, it becomes a barrier because the non-integrated firm will not have the same cost structure as the incumbent. The incumbent will have a lower average cost than the entrant. This works in a way similar to economies of scale as a barrier to entry. In the case of vertical

[151] See, for example, Bergman, L., G. Brunekreeft, C. Doyle, B-H von der Fehr, D. M. Newbery, M. Pollitt, and P. Regibeau, (1999).

[152] The case of Scotland is also useful in highlighting how regulated monopolies tend to have higher prices in the long run, even though they might have lower prices in the short run.

[153] Germany is in the process of reforming this aspect of the market with the institution of regulated access and, soon, an independent regulator.

[154] The EU Directive sets out the *minimum* requirements. This is logical, as some jurisdictions have managed successful vertical unbundling with less than full ownership separation. But while the minimum levels are considered the 'prerequisites', this is not to say that further efforts at vertical separation might not be required. Thus the EU Directive sets out the *necessary, but not the sufficient* conditions for successful unbundling. Further, full ownership unbundling, is (logically) in general *sufficient, but not necessary.* However, should other more light-handed approaches prove insufficient, full ownership unbundling would be warranted.

[155] The EU Commission, 2nd Benchmarking report, 2002.

integration breeding market power, the vertically integrated firm can raise rivals costs, discriminate against competitors, etc. In the former case, the barrier will be an economically justifiable one; in the latter case, it will be the opposite. In either case, however, vertical integration will be a barrier to entry.

There are thus two trade-offs that must be considered when studying vertical integration. First, one must weight the market power of vertical integration against its efficiency benefits, second, one must weigh any potential benefits in terms of efficiency against barriers to entry.

The immediate case that then comes to mind is whether the economically justifiable barriers created by vertical integration outweigh the costs in terms of barriers to entry *plus* the negatives of market power. There are some economically justifiable efficiencies to vertical integration in electricity markets (Newbery 2001). With respect to generation and supply, the ability to manage risk internally is considered the main source of efficiency gain from vertical integration.

In the case of Electrabel in Belgium one faces an extreme degree of vertical integration. We note that an important factor of the vertical integration is how it interacts with dominant positions and natural monopoly elements of the supply chain. For example, what one would typically worry about is an industry where, say, downstream, a lower market share, could mask effective market power, because upstream the firm dominated the wholesale market. Such a structure could lead the downstream market shares to be a misleading indicator of competition, because the upstream firm would be exerting anticompetitive influence, and so merely observing the market on a horizontal level would be incomplete. However, while this is the general risk with vertical integration, there is no risk of such errors with Electrabel. There is no risk low market shares downstream mask true market power because Electrabel has a dominant position at both ends of the supply chain.

We propose a simple variation of the HHI as an index of vertical integration. An index of vertical integration can be used within the framework of the HHI. (An alternative index of vertical integration has been studied by previous authors (Davies and Morris 1995)) [156]. To calculate this, we take the geometric mean[157] of the market shares squared for each company within the vertical market: or, if there are i=1 to n companies, between two markets, 1, and 2, then:

[156] Davies, S, C. Morris (1995), "A new index of vertical integration: some estimates," *International Journal of Industrial Organisation."* We do not use their index, because its calculation depends on input-output table data for which 2004 data are not available in Belgium. Further, their index does not have a fixed maximum and minimum.

[157] The geometric mean, by definition, is the nth-root of the product of n numbers. This is distinct from the arithmetic mean, which is the sum of n numbers divided by n. So in our case, the n numbers are each of the squared market shares. If we have two markets, n=2, and we take the square root. This is in fact what the equation does.

Equation 1: $VI = \sqrt{\left(s_{11}^2 \times s_{12}^2\right)} + \ldots\ldots \sqrt{\left(s_{i1}^2 \times s_{i2}^2\right)} + \ldots\ldots\ldots \sqrt{\left(s_{n1}^2 \times s_{n2}^2\right)}$

Or, in the case of just two markets[158], this simplifies to:

Equation 2: $VI = \left(s_{11} \times s_{12}\right) + \ldots\ldots \left(s_{i1} \times s_{i2}\right) + \ldots\ldots\ldots \left(s_{n1} \times s_{n2}\right)$

The index is on a total scale of up to 10,000, like the HHI. Thus, if a company has no downstream subsidiary, then their impact on the index is zero. So for example, an industry with 2 firms upstream and downstream, even if firm 1 is a monopoly upstream, and firm 2 is a monopoly downstream, the index of vertical integration will be zero, so horizontal concentration does not impact the index per se. Alternatively, if the upstream firm is a monopoly, and is perfectly vertically integrated, then the index will give a value of 10000. Considering the market shares of Electrabel, SPE, and EdF in generation and supply we calculate the index as:

$$VHHI = \sqrt{\left(81.4^2 \times 80_{12}^2\right)} + \sqrt{\left(7.9_{i1}^2 \times 10_{i2}^2\right)} + \sqrt{\left(3.2_{n1}^2 \times 1_{n2}^2\right)} = 6594$$

The index is on a total scale of up to 10,000, like the HHI. Although clear boundaries are not well-recognised with such an index, it is still clear that an index of above 5000 would represent a very highly vertically integrated market. It is also useful to note that of the calculation above, Electrabel's shares account for 6512 of the index calculated.

Given the very high degree of vertical integration, it is almost certain that the market power concerns outweigh any potential efficiencies. We argue by way of the analogy to economies of scale. Similar to economies of scale, economies from vertical integration are not typically or generally known to be continually decreasing. Therefore, the efficiencies of vertical integration should be exhausted at a certain level. We argue, qualitatively, that since it is generally believed that the main source of efficiencies is risk management, that these would be exhausted at moderate levels of generation and supply ownership. We assert that a generation portfolio of about 2 baseload, one mid-merit, and two peaking plant would be sufficient to exhaust an efficiencies. This leads to an estimate of approximately 400x2MW + 100 + 50+50, or approximately, 1000MW. A roughly similar sized supply business would enable the firm to hedge all price risk via internal trade (ignoring balancing and other such ancillary services).

Thus, as a rough estimate, we estimate that any benefits of vertical integration would be exhausted at about 1000MW. This can be translated into market shares in Belgium and we can use our index of vertical integration to compare, and generate what levels of concentration / market power emerge. A generation and supply portfolio of 1000MW, would lead to a market share of about 7% in Belgium. Assuming each company had 7% in generation and

[158] We could consider the case of where we are comparing across more than 2 markets, say m, in which case we would be taking, the mth root of the product of m market shares squared. This would be different than in equation 2.

7% in supply, calculating the index as above leads to a VHHI of 714. Clearly, this is very low relative to the index as calculated now. Thus, we conclude that the amount of vertical integration currently observed is by a long way in excess of any level of vertical integration that would be justified by efficiency concerns. Further, there may be a small barrier to entry for firms that have no generation, in the sense that they will have to manage risks in an alternative way. The cost of this, if the trading market were function, would be relatively small, as traders in mature markets generally operate on tight margins.

That the current level of vertical integration breeds market power to Electrabel is the last piece. We argue that there is evidence that it has. The evidence in the supply chapter, Chapter 4, based on data on margins from the CREG's report by Global Insight, indicates that certain margins for supply have been reduced while margins in wholesale power have recently increased—this is a classic example of both "raising rivals costs" and "lowering rivals revenues". Other ways that vertical integration will enhance market power, for example, by giving the downstream firm knowledge about the costs and volumes of downstream competitors (because they must buy from the upstream firm), also exist. For example, ECS, if it wants to undercut a rival, might be able to "just undercut" the rival, and thus hit the limit price, due to its informational advantage.

We have yet not discussed here so far vertical integration in terms of integration between Electrabel and Elia, or the mixed intercommunales. In terms of this type of vertical integration, there are two issues. First there is the issue of whether the current level of vertical separation is sufficient, and second, there is the issue of whether, even given the best vertical separation, if there will be ways that continued ownership of the grid by a generation still can engender a barrier. In either case vertical integration can create significant potential for market power, as these parts of the business are considered natural monopolies—this is the major reason for vertical separation in the first place. While CREG's tariff regulatory regime no doubt is doing the best it can to keep the regulated monopoly tariffs as geared to cost as possible, Elia will invariably possess better information about costs than CREG. There will be the potential for decisions that seem reasonable to any outside observer. Consider, for example, that in terms of grid security, generation and transmission are substitutes. Thus, when there is a decision about whether to build more transmission or more generation at the margin, it is possible that transmission would be chosen because these costs can be recovered with certainty. We assert that such an effect, i.e., the ability to substitute transmission for generation, could act as a barrier to entry, and that it will be almost impossible to determine if the current transmission expansion plan is influenced by such factors or not.

The second concern is that vertical integration (ownership structure) is creating a barrier *in spite of efforts to create an independent* TSO (and DSOs to a lesser extent). While the current legal structure is meant to ensure that Elia does not discriminate against 3rd parties, it has been alleged that they may have in the past, i.e., the SourcePower case. If the system operator Elia is, or

is perceived to be not impartial, this will create a barrier to entry. This is because firms who are entrants will have higher costs than the incumbent. Higher costs could also be manifested in longer waiting times to get grid connections, the decisions about the exact future configuration of the grid, the level of bank guarantees, etc.

Discriminatory behaviour will not always be easy to detect. Consider the example of future grid configurations, maintenance schedules, etc. The impact of grid configurations could impact competitors' costs. As a simple example, it may be, for example, that there are two places to put a new transmission line, nearer to a competitors' site, or nearer to an Electrabel site. If Elia says the line nearer the Electrabel site will enhance system security, without an independent engineering company to study grid flows, who is to determine if this is true. Further, Elia can reject connections based on grid security reasons. If an application for connection is rejected, it of course can be verified that based on Elia's load flow study, that there is a grid security concern—but what of alternative solutions? It will very hard to determine, say, if an alternative despatch of generation would solve the problem.[159]

Absence of an hourly spot market

As noted in the previous chapters, at the present time, electricity wholesale trading is all in the form of OTC trades. This market suffers from low liquidity, is not very deep and it is not particularly transparent; i.e. price information is only available for forward baseload contracts, while volume information it is not generally available. The absence of a proper hourly spot market impacts negatively on the possibility of entering the markets in the following way:

- Lack of transparency. Market transparency is an important pre-requisite for the well functioning of the market. Without transparency market participants have no assurance that the price they pay or receive is the "true" market price for that power. A transparent market informs market players of the value in any season, hour and any other contingencies. This is valuable information that market participants use in deciding their actions and therefore to compete against each other. Lack of transparency tends to favour market participants that have better access to information; these typically tend to be incumbent players.

[159] Since Elia informs London Economics that there are no grid constraints, this situation seems unlikely. But the possibility might arise in the future, as the nature of the network and the generation and load connected change over time. Note also that the trade-off between grid security and changes to the despatch is a difficult problem for some systems. The existence of such as problem is exactly why systems such as PJM, NYISO, ISO-NE, Eirgrid (Ireland) and others have implemented locational marginal pricing (LMP) regimes.

- Absence of hourly price information. Market parties do not have access to hourly price information. This makes inefficient the use of interconnector capacity.
- Limited availability of financial products. An active spot market facilitates the development (and trading) of sophisticated financial products that market players may use to hedge certain risks, e.g. one way and two-way Contract for Differences (CfDs), various types of options and others.[160] One of the difficulties facing market participants in Belgium is that only a very limited range of product is currently traded, such as forward contracts for baseload power.
- Focus on suppliers/users. Generally speaking, a spot market pools together bids and offers of power to produce demand and supply curves. The intersection of these schedules then produces a price (system marginal price) at which generators can sell and consumers buy power.[161] So, in very general terms, market participants can always refer to the spot market to buy/sell the desired amount of power.[162] In the absence of such market institutions, generators will sell *directly* to end-users and end-users will source their power requirements *directly* from generators. While in an atomistic generation and supply market this (essentially bilateral) way to operate would 'only' be inefficient[163], the absence of a spot market could have more serious implications in Belgium. Electrabel controls more than 80% of the generation capacity, about 80% of the liberalised supply market and, through its stake in the mixed intercommunales, a substantial portion of the captive market. Not only does this restrict the choice of generators and suppliers (outside Electrabel), but it also raises the issue of the terms (in essence price and other contractual terms) at which Electrabel would sell to (buy from) a direct competitor in the supply (generator) market. Electrabel has clearly the incentive not to facilitate the business of its competitors. In contrast, a spot market would improve market transparency and, if mandatory, could be able to create a level playing field even in the Belgian structural conditions.

[160] CfDs having the pool price as the strike price were the preferred way to hedge power prices risks in the England and Wales Pool.

[161] In reality, these mechanisms are much more complex and of a varying strength, depending on whether the pool is mandatory or not, whether it works on a system marginal price basis (everybody pays the same price) or not, etc.

[162] While we have implicitly described the functioning of a centralised pool, this argument holds also for more flexible market set-ups.

[163] There are reasons to believe that an auctioneer who has access to bids and offers for the entire market, at the same time and for every hour of the day is better placed to minimise system despatching costs than market participants that observe only part of this information.

- Use of interconnector capacity. Without an hourly spot market in Belgium, imports will primarily occur if these can be directly sold to end-users. Since trade over the interconnector is limited to hourly constant quantities, and consumption and delivery have to be balanced within each 15 minute period, this will necessarily expose the supplier involved to the Belgian balancing system. As the exposure to the Belgian balancing mechanism will increase the costs of providing power to Belgian end-users, this will reduce the ability of importers to compete with Belgian generators, who can use their own generation units to balance supply and demand.[164]

The creation of a power exchange in Belgium could contribute to deepen liquidity in the wholesale market and provide for much needed price transparency.[165] By providing for anonymous trading, equal treatment of all participants and a robust trading set-up (clear legal environment, clearing services, etc), the establishment of power exchange can make an important contribution to the development of a competitive spot wholesale market. In principle, the price information resulting from the trading on the power exchange will also influence the price of OTC trades and limit any potential use of market power in such trades.

However, it is important to point out that the creation of a central and transparent wholesale electricity market place does not guarantee in itself that the market will become more competitive as it does not address the fundamental issue of lack of competition in generation and supply. At the minimum it will be necessary to take a number of complementary measures that would help to prevent price manipulation and deepen liquidity, and require key market players to provide more supply information (such as the characteristics of the production capacity, actual and expected usage of production capacity, maintenance, plant shutdowns and production disruptions) and more demand information (such as up-to-date, or perhaps even, real time information on total demand, demand covered by bilateral long-term contracts or forward contracts, etc).

Balancing prices

Our analysis of the balancing mechanism shows that the imbalance charges in Belgium are on average lower and less volatile than in the Dutch balancing market, but substantially above (and less volatile) those under NETA's (see section 2.2.6). High balancing charges can have a detrimental effect on competition because they create risks that can be very difficult (or expensive) to hedge. For example, in the Dutch balancing market there have been a few times in which the upward despatch price (the price to pay in case of negative

[164] This issue is further discussed in sections 2.2.4 and 2.3.1.

[165] For a good overview of the various European power exchanges, see R, Madlener and M. Kaufman, Power exchange spot market trading in Europe: theoretical considerations and empirical evidence, OSCOGEN, March 2002

imbalance) has been in the order of 400-500 € / MWh. If a supplier had a large exposure at one of these times, the imbalance cost could be so high as to force the supplier out of business. The more frequent and unpredictable these times are the more difficult it will be to hedge these risks. Suppliers are in a particularly difficult position because they are in a natural 'short' position and they are exposed to the considerable swings in demand.

In our opinion, high imbalance charges represent only one aspect of the problem facing Belgium. In any market, imbalance charges set the upper bound on prices. However, the extent to which this upper bound can influence actual prices is determined by other factors in the market. An opaque, illiquid and very concentrated market, which gives few alternatives to buyers in the market[166], distorts competition in favour of incumbent generators, who, in the Belgian case, have virtually no constraints to raise prices above marginal costs. This makes it easier for prices to be pushed toward the upper bound (as determined by the imbalance charges). It is the combination of this tendency of prices to move towards to the upper bound and the height of the upper bound (the high balancing price) itself that creates a problem in Belgium.

In short, in our opinion what makes the Belgian balancing system more penalising than in other countries[167] is the lack of (transparent) options aside from baseload contracts. Market players that do not have "full requirements" contracts are then exposed either to the imbalance charges or to power prices that can easily tend toward the same level, due to concentration in generation in Belgium.[168] This not only impacts negatively on market liquidity, but also increases the difficulty, for those players that do not own generating facilities and / or with single generating units, of competing. Traders and suppliers that are not linked to Electrabel and SPE appear at considerable disadvantage.

Balancing rules

There are in our view some features of the existing balancing rules in Belgium that do not encourage entry in the electricity markets. We explain them below.

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[166] As we have seen in Chapter 3, trading is only limited to baseload forward contracts. The only other 'transparent' prices in the market are the imbalance charges. It is not known what contracts are traded or deals are offered between these two extremes.

[167] We have specifically analysed and compared and contrasted the Belgian balancing with the UK, and the Netherlands. A price review of the balancing system in Ireland, France, Austria, the USA, Canada, and Australia, suggests that the Belgian mechanism is more burdensome than in these jurisdictions. Most round-table participants also echoed that the Belgian balancing regime was the worst, or close to the worst in Europe, although this is debatable.

[168] An alternative would be to purchase "balancing contract" (see p.51) from incumbent generators and matching the consumption profile with other contracts. However, there is always the possibility that balancing could be priced in way that it is not too different from the imbalance charges. If this were the case, market participants could lose interest in traded products; the result would be a significant weakening of market participants that trade such products.

While the import capacity is limited to hourly constant quantities, the balancing rules require balancing injections and off-takes for each 15-minute period. This will necessarily expose importers of power to the Belgian balancing charges, thus increasing the costs of supplying consumers in Belgium. Recent research done by Newbery et al. (2003) suggests that selling power imported from the Netherlands in Belgium does not appear economically viable, especially when there is high uncertainty in the load. This argument might even be more relevant for new entrants in a market, who presumably have less access to historical customer profiles than the incumbent does. This seems less of a problem on the South border because of a considerable wholesale price differential between France and Belgium.

Like all other players, traders have to nominate with Elia one day in advance the supply and run the risk of having to pay high imbalance penalties if actual consumption differs from the nomination. However, (pure) traders have only very limited flexibility to still modify the import level a few hours before actual off-take on the grid.[169] In contrast, market players with access to physical generation capacity can still react to demand changes by adjusting their injection into the system during the day. Such a situation works against traders who rely exclusively on electricity imports.

Interconnector capacity on the South border

At present, import capacity on this border can only be obtained on a monthly and daily basis. Our analysis of import and export capacity (see section 2.2.4) clearly shows that 1) monthly import capacity on the South border is a scarce but valuable commodity; and 2) daily capacity is largely unutilised.

Due to its competitiveness, power imported from France is probably the best option to compete against incumbent generators in Belgium. There are however a number of factors that constrain using French power to compete in the Belgian market:

- The largest portion of the capacity goes to long term/historic agreements (that is, contracts concluded prior to liberalisation).
- Most of the remaining available import capacity is currently allocated on a daily basis (see Figure 2.9). Competing in generation on the basis of the daily imported power does not appear a viable option for a number of reasons. A supplier that has sold power on a forward basis will be highly exposed to the Belgian balancing mechanism whenever he will not able to secure enough capacity. Moreover, when there is congestion on the interconnector, some of the daily import capacity (C1) is subject to an additional congestion cost. Another important constraint on the ability to compete arises from the fact that suppliers that essentially rely on daily import capacity

[169] It is indeed highly unusual that an intra-day nomination is being made for the use of the interconnector that would allow market players to modify their own intra-day nominations.

could be perceived by the market as less reliable than those having their own production facilities in Belgium and/or having more stable sources of power (e.g. longer-term agreements).

- The allocation mechanism is opaque and penalises ARPs that request larger amounts of capacity. In other words, with the existing allocation rules, an ARP that attaches a very high value to import capacity is not more likely to obtain interconnector capacity than somebody who values import capacity very little. This suggests a certain degree of allocative inefficiency in the allocation of import capacity that prevents the proper functioning of market forces.
- Import competition requires back-up facilities to provide power in case of interconnector outages. In our view, the market for back-up facilities is subject to the same shortcomings as those faced by the generation market.

Lack of level playing field in terms of access to information

A recurrent theme throughout the consultations was the opacity of the Belgian electricity market and lack of access by new entrants to basic information about production, prices, end-user profiles etc. By virtue of its dominance in generation, supply and trading, vertical integration and presence in all electricity markets, and its close relationship with ELIA and many DSOs, Electrabel has access to vastly superior information about all aspects of the Belgian electricity sector. It is also important to note that in many cases, it may not be the lack of information that is at issue, but the fact that Electrabel may have access to better information, or has the information *in advance* of potential competitors.

Informational advantages to Electrabel come from all areas of the markets. Price information is of primary concern. Information such as the BPI is naturally of limited use – how much energy was traded at this price? How true an indicator of the marginal value of energy, marginal cost is the BPI? Electrabel will know this while competitors do not.

Information on the operation of plant may give key indicators as to various forecasts of market conditions. How often are those peaking units being called on? If peakers are running 20% more often, indicating need for new generation (and if price signals are weak or murky), Electrabel will be miles ahead of a competitor looking to enter generation.

Information on the use, likely flows, and marginal values of interconnection are also likely to be to the advantage of the incumbent, if they have access to this information in advance of competitors.

Information on the supply and trading markets will also be important, and likely weigh in the advantage of the incumbent. Information on particular customer's usage patterns, demand characteristics, the costs of generation, the likelihood of outages of both generation and transmission assets are all better known by the incumbent. If a supplier does not know these, they will not be

able to negotiate as keen of prices; they will not be able to manage their own risks; they will not be able to offer customers customised risk management products (such as interruptible contracts, options, etc).

This asymmetric access to information clearly puts new entrants at a disadvantage and increases the risk of entry. (More discussion of information needs is found in the Remedies chapter, section 7.7.)

6.4.2 Strategic/behavioural barriers

We believe that the most serious strategic and behavioural barriers to enter the electricity market arise from the vertical structure of Electrabel and its significance in each market. Not only do Electrabel's generation and supply arms have significant advantages over their competitors, but also Electrabel's position is such that it can *deliberately* behave to deter entry and/or drive a competitor out of any of the electricity markets.[170] We would like to remark that although there is no evidence to date of such behaviour, simply the *possibility* to have an abusive conduct could have a detrimental effect on entry.

6.4.3 Legal/regulatory barriers

Regulatory complexity

A number of stakeholders commented on the fact the two-tiered system of regulation (federal and regional), the different speed of market opening and the still relatively infant liberalisation of the Belgian electricity liberalisation has made entry into the relatively small Belgian market more complex, and uncertain to the extent that the regulatory regimes were not yet fully settled down.

Different speeds of liberalisation across regions may have an impact on entry in the short run, especially entry by smaller regional companies; larger companies will have sufficient resources that any costs from a staggered start will be negligible. These will be also outweighed by economies of scope and scale from marketing to the country as a whole. As by 2007, full liberalisation will have been achieved throughout Belgium, the different speed of liberalisation is at best only a temporary barrier to entry.

Obviously, compliance with three different regulatory regimes for small regions increases fixed costs associated with regulation and so has the potential to increase entry barriers. Most of the companies on the list of supply companies, and ARPs are in fact very large and well-resourced international or pan-EU energy companies, and so would be well-equipped to

[170] These issues are discussed at length in the subsections to this chapter on barriers, sections 6.5.3 for generation, subsection 6.6.3 for trading, and subsection 6.7.3 for supply.

deal with differences across regions, as they are equipped to deal with differences across member states.

That being said, the existence of different, separate green certificate systems in Flanders and Wallonia[171], and different regional technical codes increases entry costs into Belgium for a firm wishing to be a supplier in the whole of Belgium as, relative to entry into a larger market, more resources will need to be devoted to learn the three regional regulatory regimes and ensure on-going compliance.[172] According to stakeholders, additional costs also arise from the fact that through the year the three regional regulators and the federal regulator make different information requests.

Overall, due to the particular federal structure of the Belgian State and the distribution of competencies between the federal and regional government, the regulatory structure is more complex in Belgium than in unitary States. The partitioning out of powers makes the system more complex, and in general more complexity will add to uncertainty and uncertainty will raise the margins needed for entry, *ceteris paribus*. For generation, this is unlikely to create a significant barrier to entry as the decision-making process regarding electricity generation rests at the federal level although the regional level also plays an important role through the green certificate system. For suppliers this regulatory complexity may create a barrier to entry although larger suppliers are used to work in many different jurisdictions and should therefore not be deterred from entering the market.

Overall, we believe regulatory complexity is likely to be only a mild barrier to entry. It is more likely that the impact of the regulatory complexity is mainly felt in terms of higher supplier operating costs as the per customer compliance costs are likely to be higher than with a single regulatory regime applying throughout Belgium.

Regulatory uncertainty

Regulatory uncertainty[173] generally arises because regulated costs or remuneration can change as regulation, legislation, or regulatory practice changes. Regulatory uncertainty can be created from a wide range of factors.

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[171] We understand that, according to the information provided on the web site of IBGE that no green certificate system has yet been set up in the Brussels region.

[172] We have not undertaken a detailed comparison of the Flemish technical code (Vreg, *Technisch Regelement Distibutie Eletriciteit Vlaams Geweest*, Versie 14.10.2003) and the Walloon technical code (Decree of Wallon Government of 16th October 2003 *Arrêté du Gouvernement wallon relatif au règlement technique pour la gestion du réseau de transport local d'électricité en Région wallonne et l'accès à celui-ci*), but a number of stakeholders have noted that they differ occasionally.

[173] We use the term "regulatory economics" to refer to any uncertainty that arises for the legislative and regulatory framework within which market participants have to operate. Such uncertainty can arise form actions of the legislator, the government or the regulator.

Regulatory uncertainty in Belgium can have a number of sources, and it is interesting to explore these. In Belgium, the lack of executive power of the federal and regional regulators[174] is of concern, as many facets affecting the functioning of the three electricity markets are ultimately taken at the political level, adding an additional layer of uncertainty to the decision-making process. Political decision-making adds uncertainty because of the possibility of regime change, the lack of sectoral expertise at the political level, and the possibility of political influence of the regulator. At the federal level, the CREG has been given a wide range of advisory and control responsibilities by the Electricity Law of April 1999, but the only truly executive power the regulator has is the power to approve transportation and distribution tariffs. This is clearly reflected in the CREG's mission statement according to which its two key roles are to advise public authorities and monitor and control the application of laws and regulations (rather than to make policy, design and enforce license conditions, limit prices, etc). Similarly, regional regulators have important advisory and control roles but the executive power with regards to the aspects of the electricity markets of regional competence rests with the regional government.[175]

Regulatory uncertainty is thus hard to define, and even harder to quantify; however some attempts have been made. For example, investment bankers have attributed changes in debt spreads on traded corporate debt of regulated companies to changes in regulatory uncertainty. One study[176] found that a reduction in regulatory uncertainty was associated with a reduction in the debt yield from 5.6% to 5.0%. Just to put this in context, using our trigger price model, a 60 basis point drop in corporate debt spreads would correspond to a €0.15/MWh reduction in wholesale energy costs. If a new entrant were the marginal generator, or if incumbents priced according to a limit pricing strategy, then the marginal effect could be seen in the market-clearing price.

Other models (besides the debt-yield-increase approach above) of regulatory uncertainty and its estimated impact are certainly possible, but there are few attempts at a more rigorous level to assess regulatory uncertainty. A notable exception is Echeverri (2003).[177] He estimated base case uncertainty costs to be $40m (€33.3m) for a coal fired power plant in the US. €33m would add

[174] Lack of independence is additionally a concern, mostly at the regional level. Possible breaches of complete independence at the federal level are only second order, such as the political influence on the appointment of directors, etc.

[175] This is somewhat of a generalisation there exists differences across the three regions. For example, the Flemish technical code was issued by the Flemish regulator while the Walloon technical code is set out in a decree of the Walloon government.

[176] Moore, Chris, 2001, IMI Bank. "Italgas investment analysts report". Borsa Italia website.

[177] Echeverri, D, "The cost of regulatory uncertainty in air emissions for a coal-fired power plant," Carnegie Mellon University working seminar http://wpweb2k.gsia.cmu.edu/ceic/SeminarPDFs/Patino_Echeverri_CEIC_Seminar_2_18_03.pdf.

about €1.23/MWh to the price of wholesale electricity under our new entrant model, with limit pricing by incumbents. So applying Echevarri's model predicts a much larger impact (€1.23) from regulatory uncertainty than the bond-yield approach (€0.15).

In these examples, we see that the likely marginal impact of regulatory uncertainty is somewhat small, especially when compared to the range of new entrant prices possibly generated by energy price uncertainty.[178] However, the analysis cannot actually attribute the cause and effect of the drop in spreads from 5.6% to 5.0% to a reduction in regulatory uncertainty, because we do not know what other factors were also changing; we also do not have a *scale* or index of regulatory uncertainty within which we can compare across cases. Nonetheless, we feel the analysis here is informative in a general sense that it is indicative of the impact of regulatory uncertainty, with judgement applied due to the mentioned caveats.

Regulatory uncertainty, as with uncertainty in general, can create a significant barrier to entry and disincentive to investment. Indeed, regulatory uncertainty can come from courts, ministers, or other political decision makers. If a court, a regional or national parliament or minister, or other body, can potentially change regulatory decisions, then the impact of these decisions cannot be known until the decision is tested in the courts, or put up for other review. Court review can take time as well as having an uncertain outcome. This increases regulatory uncertainty. While the quantitative analysis presented is only indicative, we believe that increased regulatory uncertainty is an important aspect of the current levels and likelihood of entry into the Belgian electricity markets.

NIMBYSM

Many stakeholders felt that there were significant barriers to the further development of the electricity system in Belgium on the whole due to 'not in my backyard' (NIMBY[179]) behaviour. Such phenomenon was viewed as particularly problematic with regards to the siting of wind turbines, wind farms, other forms of generation, as well as high and medium voltage transmission lines. It is also of interest that NIMBYSM was generally agreed to be a problem in liberalising markets such as California, where the time to site generation often was several years longer than in neighbouring states, and the failure to bring new generation online quickly contributed significantly to the well-known electricity crisis there.

[178] Elsewhere, we calculate the impact of energy price uncertainty on the equilibrium new entrant price. This added between about €7 to €15 to the DCF trigger price. See Annex 5, and specifically Table A5.2.

[179] Interestingly, the English acronym 'NIMBY' has come into use in the French and the Dutch in Belgium. NIMBY behaviour is also generally accepted as one of the causes of electricity crises in places such as California, where a lack of generation investment and growing demand were the first-hand causes of the crisis, and market power and poor regulatory design were of secondary importance.

It is evident that most advanced industrial societies are affected by NIMBYSM, although the depth and impact of this phenomenon most probably varies across countries. We are not aware of a formal study comparing forms and effects of NIMBYISM across countries, regions or industries and, therefore, we cannot draw firm conclusions on whether Belgium is worse affected by this phenomenon than neighbouring countries.

That being said, it is undoubtedly a factor affecting the development of the Belgian electricity sector. This is clearly illustrated by the objections to the Tihange- Avernas 150 kV line[180] feeding the Brussels – Liege high-speed train, the many court cases involving wind turbine projects in Flanders and off-shore[181], among other examples. Nevertheless, Belgian citizens appear to be perhaps somewhat more opposed to wind power installations than those of some other countries. For example, a recent overview of surveys of public acceptance of wind power reports that, in Belgium in 2002, 31.3% of residents living on the Belgian coast had a "very negative to moderately negative" attitude towards near shore wind farms at 6km from the shore. In contrast, a 2003 survey of people living closest to Scotland's 10 largest wind farms shows that 82% want an increase in electricity generated from wind and surveys undertaken in 2002 and 2003 found that between 66% and 88% were in favour construction of wind farms.[182]

6.5 Entry conditions into generation

In this subsection, we discuss factors that likely deter profitable entry into the generation market in Belgium.

6.5.1 Structural barriers

Lack of 'suppliers'

Electrabel controls approximately 80% of the liberalised supply market. Electrabel also owns a majority stake in nine mixed intercommunales and significant share in the remaining seven. These 16 intercommunales supplied

[180] See for example, Conseil d'Etat, Section d'Administration, Arrêt no 106.094 du 25 avril 2002 et Arrêt no 105.306 du 28 mars 2002.

[181] See for example, Raad Van State, Asfdeling Administratie, Arrest nr. 133.487 van 2 juli 2004, Arrest nr. 133.258 van 29 juni 2004, Arrest nr. 127.548 van 29 january 2004, Arrest nr. 127.083 van 15 january 2004, Arrest nr. 125.814 en 125.815 van 28 november 2003, Arrest nr. 125.230 en 125.229 van 7 november 2003, Arrest nr. 117 908 en 117.906 van 3 april 2003, Arrest nr. 117.482 van 25 maart 2003, Arrest Arrest nr. 112.680 van 19 november 2002.

[182] Source: EWEA, The European Energy Association (2003),"Wind Energy - The Facts" Volume 4, Environment

in 2002 almost 80% of the low-voltage consumers.[183] Without anonymous centralised trading, high concentration of buying power may make entry in the generation market less likely because it exposes generators to the risk of not being able to recover their investment costs.[184] Moreover, as the largest supplier (Electrabel Customer Solutions) has also generation assets, this cuts a substantial portion of demand off the generation market.

There are therefore two sources of barriers here; the vertical integration/structural barrier and the informational barrier. The first is the structural barrier. Companies wishing to enter generation must find suppliers to purchase their output. If they must sell to ECS, they will fear giving away secrets, helping their competitors, etc. ECS, having market power, may be able to negotiate a lower price. The second barrier is the informational barrier, where prices and price discovery is muted because information is transferred between Electrabel and its subsidiaries without being made public to the market. These all are important barriers. But the most important barrier is probably the sum of the parts. The vertical integration--combined with the high market shares at all stages—combined with the lack of market institutions and information (exchanges etc), make a formidable barrier to generation on the whole.

Level and volatility of wholesale prices

When there are fixed costs in an industry that must be recovered, due to the technology of the sector, then the most common economically justifiable barrier would be that current price levels might be too low to justify. The margins might be insufficient to cover the fixed costs. It is also true, that volatility in price levels will tend to delay entry. This is because the option to delay entry, and wait to see of prices rise or fall, has value. Therefore, increased volatility will lead to increased waiting as per the investment under uncertainty view of entry. Several of the participants in our consultations suggested current price levels were too low, or that prices were too volatile. As a check of this, London Economics therefore undertook some detailed modelling of entry prices and compared them with prices observed.

To study the wholesale energy price that would trigger entry, we used two models, one that was based on the straight "discounted cashflow" method of determining the entry price, and one based on the model of investment under uncertainty developed by Dixit and Pindyck (1994). The model essentially assumes 400MW nameplate capacity CCGT with 55% thermal efficiency and 90% load factor achieved.[185] We also did sensitivity analysis on some of the

[183] London Economics (1997).

[184] The most extreme case is that in which generators are paid their variable generation cost, which is the lower bound for a generator inside the market.

[185] This corresponds well with the station database obtained from the CREG for recent CCGT in Belgium. It also corresponds with international studies of new entrant prices in Australia (see IPART, 2004, "The Long run marginal cost of electricity generation in New South Wales"), the UK (Coolkeragh study by

key parameters. The details of the cases and scenarios are contained in Annex 5.

The results of the entry modelling for generation can be summarised as follows:

1. Entry for new, green-field CCGT is difficult, but not impossible. A pure DCF view of entry suggests that current and near future real wholesale prices (approximately €41/MWh) are just above new entry levels (approx. €37/MWh).
2. Incorporating the effect of uncertainty (volatility), suggests that new, green-field CCGT is not likely.
3. A model of CHP shows that CHP entry is economically justifiable, given current price and volatility levels. There is considerable additional uncertainty with this model due to the need to value the heat generated.

The estimates do not entirely suggest that entry is totally blockaded purely on an economic basis. The pure DCF modelled price in the low case, at €34.17/MWh, is below the APX average price of €41.21/MWh. This suggests that, if the investment under uncertainty model were not correct, then one might expect entry under current market conditions *in the absence of other entry barriers*. It is true, that the pure DCF model *does* account for *some uncertainty* in that the parameters of the discounting scheme may vary with risk. These points are discussed if greater details in Annex 5.

Sunk costs

Entry into electricity generation is subject to significant sunk costs. Examples are: survey, market study, feasibility, ground preparations, etc. There may even be decommissioning/mothballing costs that are significant. Plus, given that the plant must shut down or mothball, a significant portion of the initial capital outlays are not likely to be recouped.

This all has been in evidence from the recent operations of the England and Wales electricity markets. Firms sold out and left, for a fraction of their initial investment costs. This is not even counting all the adjustment costs and explicitly entry costs involved with purchasing assets or greenfield entry. Finally, recent low prices in England and Wales have led to certain recent new entrants mothballing generation. Under the investment under uncertainty theory, mothballing behaviour is evidence of "keeping your options alive" when there are sunk costs and volatile prices. In other words, exit is not optimal, because costs are sunk *and* there is a real probability that prices rise in the future.

The conclusion is that sunk costs and uncertainty likely create a barrier to entry in the generation market; but only just. Our analysis (details in Annex

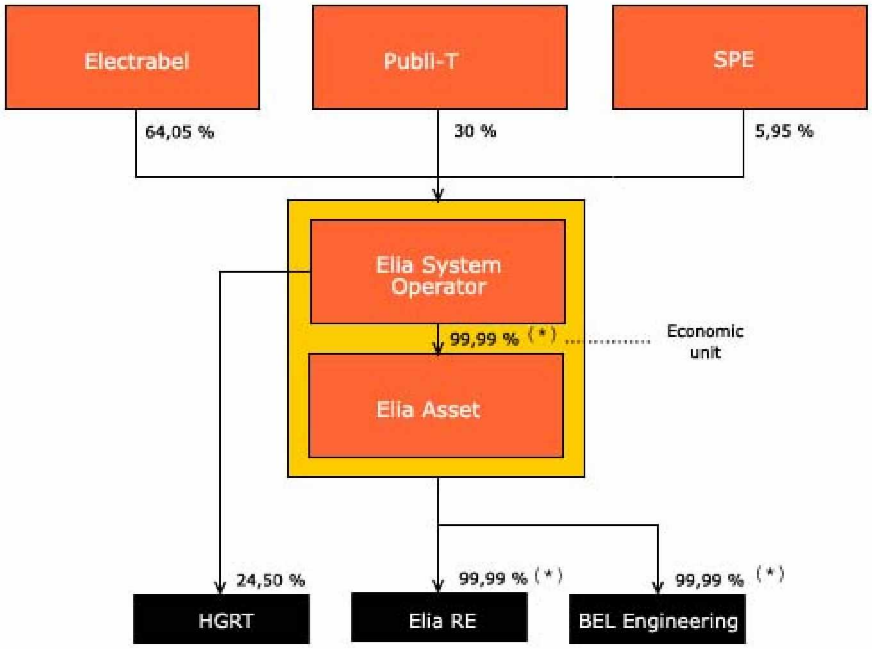
London Economics), and Ireland (see CER Best New Entrant Price 2002: the Commission's Decision).

5) shows that sunk costs and uncertainty make the price at which generation entry would occur between about €42 / MWh to €50 / MWh. Where wholesale prices to rise or if uncertainty were to fall, this conclusion would change of course.

Ownership and management of Elia

Elia System Operator (ESO) is the Belgian Transmission System Operator (TSO) at the federal level. ESO is an independent public limited company founded in June 2001 in order to comply with the federal requirements of independency. Figure 6.1 shows the ownership structure of ESO.[186]

Figure 6.1: Ownership structure of ESO, 2004



Source: Elia website

[186] Publi-T is a co-operative company representing the Belgian municipalities (i.e. local authorities). Elia's former shareholders (Electrabel and SPE) have reached an agreement with the federal government on the future shareholder structure. Electrabel and SPE will further reduce their participation from currently 70 % to 30 % of the shares, and 40 % of the shares will in principle be listed on the stock exchange.

Independent operation of Elia is supervised by its board of directors, and ensured by provisions in the Belgian Electricity Law. Three of the twelve members of the board of Elia are representatives of Electrabel.

Despite the administrative measures taken to ensure independence of Elia, the participation of Belgian production in the ownership structure of TSO gives grounds for concern. Decisions on investment and maintenance of infrastructure have implications for generation, and generators may therefore try to influence such decisions. Of particular concern in the present context would be the availability of interconnector capacity on both borders of Belgium, which determines the competitive position of generation in Belgium. On the system operation side, there should be special concern for the current functioning of the balancing mechanism, and other aspects that may involve barriers for competing suppliers. Connection to the grid has also been mentioned as an important issue.

While the Royal Decree of 3 May 1999 provides for the current structure and aims to ensure effective unbundling, other factors seem to indicate that there is still significant overlap between the two companies. For example, according to Elia's own annual report (2003), "The Boards of Directors of Elia Asset and Elia System Operator consist of 12 members each. The same members sit on each Board. These members do not have a management function within either Elia System Operator or Elia Asset. Half of the members are independent directors appointed by the General Meeting" Moreover, 3 directors represent Electrabel, and 3 directors represent Publi-T. While 6 directors are independent directors, it is interesting to observe that they are largely elected by Electrabel as Electrabel owns 64.05% of Elia System Operator, which in turn owns 99.99% of Elia Asset.

Again from the 2003 annual report, "In accordance with the Articles of Association, the members of the Boards of Directors always strive to achieve consensus during their deliberations. If they are unable to reach a consensus, then decisions are taken by either a simple or qualified majority (depending on the matter at hand) of the members present or represented. The Boards of Directors are only duly empowered to deliberate or take decisions if at least half of the members are present or represented. If convened a second time, they may take decisions regardless of the number of members present or represented. Certain decisions, such as appointing or dismissing members of the Management Committee, or submitting proposals to the General Meeting to dismiss an independent director, can only be taken by a qualified majority."

It is thus reasonably certain the Electrabel has near effective control of Elia System Operator and Elia asset, since evidently most major decisions will not be possible without Electrabel's support as consensus is the norm, and if consensus is not reached a qualified (super) majority is needed for major decisions.

To conclude, it would be highly desirable to avoid that the dominant generator has influence over the grid operator Elia. This means in particular

that representatives of Electrabel should be prevented from exercising influence over Elia's board.

6.5.2 Strategic/behavioural barriers

In this section we provide some examples of strategic behaviour that Electrabel would not find difficult to undertake. We do not have evidence of such behaviour to date, but it is important to stress that even the credible *threat* of such behaviour may suffice to deter entry. In addition, several of the barriers listed could arguably be classified as structural, but, given Electrabel's control over outcomes such as price, we prefer to classify these are strategic.

Price manipulation

As we have seen in section 2.2.6, the structure of the Belgian generation market gives the incumbent a persistent incentive and ability to exercise market power. Concerns over the possible exercise of market power could persuade market participants to avoid trading actively in any markets in which the incumbent participates, severely reducing market liquidity.

Price manipulation can take several forms, including raising prices, lowering prices and increasing price volatility. One example of price manipulation aimed at deterring entry in generation is a strategy of limit pricing, i.e. setting prices at levels sufficient to earn an extra-normal profit but still low enough so as not to attract new entry. In the absence of a spot market, this strategy would allow Electrabel to maintain its dominant position in generation without attracting entry in downstream markets. Significant entry in downstream markets would be foreclosed by difficulties in sourcing wholesale power, while Electrabel's profits would not be dented by price manipulation at the wholesale level since Electrabel then goes on to sell most of its power to final users. What matters for Electrabel is the difference between end-user prices and generation costs.

Control of the gas market

Natural gas is the primary fuel of SPE's power generation plants as well as that of CCGT capacity. CCGT power stations are the entrants' preferred technology at present. The control of the supply of gas in Belgium is therefore of crucial importance in determining the possibility of entry in the electricity market.

Potential entrants into the generation market may be deterred by the fact that Distrigaz, a dominant supplier of natural gas to large gas consumers, and Fluxys, the natural gas transport operator are controlled by Tractabel, which also controls Electrabel. Potential entrants face the risk that Distrigas may exploit its dominant position and favour Electrabel in the supply of natural gas to electricity generators through a range of mechanisms such as cross-subsidies or simple discrimination. Even in the absence of discrimination,

Distrigas could still favour Electrabel by charging very high prices and severely squeeze margins of all generators, including Electrabel. However, the Tractabel's group's overall profitability would not be affected as Electrabel's squeezed margins would be offset by higher margins at Distrigas while Electrabel's competitors may be driven out of business.

Potential entrants into the generation market may also be concerned that Electrabel could gain access to commercially confidential information about the profile of their gas consumption and/or transport from either Distrigas or Fluxys and exploit this information to their detriment.

While entrants may be concerned about anti-competitive practices, it is not obvious that such activities will actually occur because of the existence of a number of legal safeguards and the fact that they may not necessarily be in the best interest of all the shareholders of each company. In our consultations with stakeholders, this issue never came up explicitly and, in fact, one potential entrant into the generation market expressed his whole satisfaction with the services offered by the relevant parties in the natural gas market. That being said, we aware that a number of market participants have raised the issue of the gas supply with the CREG.

Thus, in conclusion, we believe that access to gas and gas supply integration may create a barrier, and it is something that the CREG should continue monitor. While tracking prices for gas to rivals may be relatively easy, possible exchanges of sensitive information on rivals' usage may be more difficult to monitor. The fear of this may be a barrier itself. We suggest that the integration of Electrabel into gas should therefore be a contributory, but not apparently a primary barrier at the current time.

Long term contracts

Generators in Belgium may have cut prices and signed longer-term contracts with key suppliers *in advance*[187] of deregulation.[188] Having long-term contracts signed with large users in advance of deregulation would pose a barrier in and of itself, as it would lock users in to prices and a particular supplier/generator.

[187] We note that although this occurred in the past, they still represent a barrier to entry, just as an investment in plant could have occurred in the past but still be a barrier.

[188] We note here that, according to the Conseil de la Concurrence, prior to liberalisation a large majority of end-users about to become eligible to chose their own supplier had or were in the process of signing longer-term supply contracts with Electrabel of a duration of 3 to 5 years. (Conseil de la Concurrence, decisions of 4th July 2003 regarding the cases of ECS / INTEREST, IEH, IVEKA, IMEWO, INTERGEM, IVERLEK, IGAO and GAZELWEST).

6.5.3 Legal/regulatory barriers

Regulatory uncertainty

A potential entrant into the generation market faces two key types of regulatory uncertainty.

First, according to the federal Electricity Law of April 1999 as amended in 2003 and the Royal Decree of October 2000, the construction of a new generation plant[189] or the expansion of an existing plant[190] requires a federal licence (autorisation in French legal texts). While some form of licensing process is of course natural, it is perhaps unavoidable that this creates some uncertainty. However, we believe the Belgian process might have more uncertainty that others. As part of the approval process, the federal regulator requests a number of federal and regional government bodies to provide their views and makes a recommendation to the federal Minister responsible for energy. But, the final decision rests at the ministerial level, thus introducing an additional layer[191] of uncertainty in the process over and above from the one arising from the pure regulatory approval process.

The second source of uncertainty comes from the allocation of green certificates to new gas-powered generation. How the certificates are allocated is unclear, contributing to uncertainty about the validity of the financial calculations regarding the economic viability of the new plant.

In the absence of hard data, is difficult to evaluate the validity of these claims. However, we would note the following in response. First, there is some regulatory uncertainty, but this is likely to be small in relation to other forms of uncertainty, especially prices. This is especially true for generation. Second, while the regulatory uncertainty and difficulties might *slow* the process of entry, and thus create a barrier, they do not seem to be very high barriers relative to other barriers that need to be hurdled.

Lack of suitable sites for generation

We understand that number of sites suitable for the construction of new non-renewable generation capacity is extremely limited in Belgium. For example a potential entrant, a joint venture between {name withheld} and {name withheld}, informed us that an exhaustive search by independent brokers of

[189] New generations plants of less 25MW are exempted from this requirement.

[190] More precisely, an authorisation is required for any expansion greater than 25MW or 10% of installed capacity.

[191] In Belgium, the ultimate approval rests with the Minister. Whether this is really an additional layer is thus debatable; we feel it is, however. This is because, *de facto*, what is likely is that there are practical hurdles to satisfy the CREG. The Minister is unlikely to approve a project that the CREG has strong practical misgivings about. On the other hand, the likelihood of a project that is acceptable to the CREG being unacceptable to the Minister for other reasons (political) is quite possible.

suitable sites for new capacity identified initially 20 such sites.[192] However, after further examination of the characteristics of such sites, only two turned out to be suitable. Because of the noise generated by new gas-fuelled plants, the close proximity of residential areas ruled out all but two of the potential sites.

We have contacted regional environmental and planning administrations to further investigate this point but have received no response. We have also raised this issue in our discussions with Elia, and have asked the officials of the grid operator whether they had either a map of potential new generation sites or a view on the issue of site scarcity. Apparently no such map exists within Elia but the officials expressed a clear desire to see new generation capacity locate in areas close to existing generation plants that are scheduled to be shutdown or in areas where, according to Elia's current investment plans, grid capacity will be increased in future years.

We were also repeatedly told by a number of stakeholders that Electrabel has effectively a hold on all industrial sites that are suitable for CHP generation, leaving no or very little room for entry into the generation market through this route.

Overall it would appear that the lack of sites appears to be a serious barrier to entry into the generation market even so we have been unable to independently ascertain the precise situation.[193]

Difficulties in obtaining connections to the grid[194]

According to information provided to us by a potential entrant, it would appear that access to the grid is difficult to obtain. Moreover, according to the potential entrant ELIA is not particularly cooperative in developing cost-effective access solutions that would meet an entrant's needs while protecting the integrity of the system. According to this participant, grid connection took about 2 years. ELIA was also unable or unwilling to give them an estimate of the amount of power that they could safely inject into the grid. They said that they were forced to make repeated applications for incremental amounts, in other words, asked if they could inject 150MW, 200MW, etc, rather than receiving an answer as to what the possible injections were.

[192] The names and precise location of these sites were not provided to us.

[193] The proximity of potential sites to grid connections, as well as the need for potential grid reinforcement to accommodate a new generator is also an issue. We were unable to obtain information of which sites were of particular value relative to the grid.

[194] These could be considered either regulatory or behavioural barriers. They are regulatory in the sense that it is the regulation that defines the grid connection procedures, limits, codes, etc. They are behavioural in the sense that Electrabel might actively influence how the technical study of connections are done or obtained.

We recognise that this is only anecdotal evidence of potential obstruction by ELIA and that ideally this point would need to be further explored. But, even if the problem has subsequently been remedied, the mere fact that a potential entrant is of the view that it encountered many problems in obtaining access to the grid may discourage other potential entrants if such information is known in market place.

It is also useful to note that the same participant said that they felt that this was more of a cultural factor at ELIA, than an ownership issues (although naturally the owner defines the culture). They supported this claim with evidence that they had been dealt with fairly and quickly when dealing with Fluxys.

Connection to the grid is often a sticky issue in electricity liberalisation. However, usually the issues involved tend to surround more difficult problems, such as who should pay *system-wide* shared costs, say for ancillary services for a wind generator, or who-should pay for upgrade of lines, not directly connected to the entrant power plant (but often in need of upgrade due mainly to the new entrant). It seems that these are not an issue in Belgium. We feel that grid connections and the processes involved are probably evolving, and that although some problems occurred, it is likely that these turn out to be mostly 'teething' pains.

6.6 Entry conditions into trading

The main benefits to the electricity markets of a well functioning trading market would be lower transactions costs and better risk management services for suppliers and generators. In this section we discuss the factors that could make profitable entry difficult in the Belgian trading market. Lack of liquidity, lack of market/price transparency and high concentration in the generation and supply markets are in our view the most significant impediments to entry in this market.

6.6.1 Structural barriers

Lack of liquidity and transparency

Two major barriers to entry in trading are lack of liquidity and lack of price transparency. Liquidity is the ability to buy and sell very quickly without impacting the market. Transparency is the ability to observe price and be confident that the current price reflects the market fundamentals. Transparency and liquidity thus go hand in hand.

The structure of the Belgian electricity markets is the first major impediment to liquidity and transparency. Market power is not consistent with liquidity, in that a single player can move market price. Vertical integration is not consistent with transparency, in that a single firm can trade within itself, without other market participants gaining knowledge of the prices. When

markets at many points along the supply chain are concentrated *and* vertical integration is high, this impact becomes even worse.

Lack of liquidity and lack of transparency will also be barriers to the *types* of trades and products that traders can provide, rather than just being a barrier to entry. This is especially true for more sophisticated derivatives such as options and swaps. To see this, it is important to note that options, say a call option (the right to buy at a certain price) give payoff of Max(P-X,0) to the option holder (where P is the price of the asset and X is the strike price). Thus, the holder has minimum value zero and unlimited upside to an option. The option seller's payoff is the mirror image of this—it has maximum payoff zero, maximum downside unlimited. Thus selling options is a very risky business unless risks can be hedged.[195] Hedging often requires frequent trading.

Traders will sell an option only if they receive a significant risk premium, and are able to trade subsequently to hedge the risk in the short position. If the markets are not transparent, the prices observed and the market volatilities will not be representative of the actual fundamentals of the commodity and thus pricing the option premium will become impossible. If the market is illiquid, continuously adjusting the portfolio (to hedge the risk) will be difficult or costly.

Sunk costs

Barriers that are justified by the economic fundamentals are not expected to be large in trading and our evidence supports this. We have performed a new entry DCF type analysis similar to the ones done for generation and supply.[196] The fixed costs of trading are expected to be low, even though margins are low. Moreover, if we consider entry by other firms already trading on nearby or similar markets, sunk costs of entry appear to be particularly low in the Belgian trading market.[197] There may be economies of vertical integration, but these are not expected to be high, based on discussions with participants. There may be barriers such as knowledge of the workforce, and the need for credit, but again these should not be exceptionally high.

The impact of the removal of the most significant barriers to entry into trading is expected to be positive. The roundtables for trading were attended by the greatest number of participants, many from large European energy companies. We predict that some number of them represent serious potential entrants who would enter if the barriers were removed, as the *additional* costs

[195] As it turns out, if markets are functioning well there is a replicating portfolio that can in theory create a risk free position in the option.

[196] See page 89.

[197] Still, there would have to be some investment in learning about specificities affecting the Belgian market and this investment would not be recovered upon exit.

of extending trading from their Amsterdam, Paris, or London desks would be small.

6.6.2 Strategic/behavioural barriers

Market power in generation and supply

Market power in generation or supply, the ability to manipulate price either up or down, is the most relevant barrier to entry into the trading market. This is because of the nature of trading. Traders' raison(s) d'être is (are) to provide transactions services, to provide risk management services, and to provide portfolio (rebalancing, reallocating) services to their clients. Traders will thus frequently have open positions in derivative contracts such as forwards. If traders find the price going up (down) when they are short (long), they will want to unwind the position quickly to limit their losses. If the market is illiquid, this will be impossible, and traders' losses, at least in short positions, are theoretically unlimited. As a result, in practice, traders will not choose to enter into such a market where their trading risks cannot be managed. Note also, that it is likely that, but owning generation and supply, Electrabel may be able to manage these trading risks where pure traders cannot.

Availability of relevant information

Lack of access to information will reduce transparency and thus also act as a barrier to trading. Traders especially fear a situation where one player has superior information, because this will enable their competitor to make profitable trades when they cannot. The lack of information or the ability to have superior information can be especially impacted by access to information from the TSO. For example, the TSO might be able to observe technical details of power flows that indicate early that a generator is having a problem. If a trader knew this, she might be able to trade profitably on this information, i.e., go long[198] on power forward contracts. Access to information such as this might give a trader a competitive advantage over rivals.

6.6.3 Legal/regulatory barriers

Regulatory uncertainty

We assess regulatory uncertainty for the trading market in section 6.7.3, together with the supply market.

[198] A long position in a forward contract is the right and obligation to buy at a fixed price. Thus, if the spot price soars, the long position holder makes large profits, because they can buy cheap and immediately sell dear to the spot market.

6.7 Entry conditions into supply

The Belgian electricity sector exhibits a number of features that make entry in the supply market relatively unattractive. Electrabel's dominance throughout the value chain is likely not only to distort competition, but also discourage entry from potential suppliers.

6.7.1 Structural barriers

Lack of 'generators'

As we have already seen in Chapter 2, the generation market is very concentrated with Electrabel controlling more than 81% of the electricity production capacity. This problem is exacerbated by the absence of an active spot market in Belgium. Buying electricity from abroad does not appear to be a viable option because:

- Import capacity on the South border for a period longer than one day is very limited and hugely over-demanded. Relying on daily import capacity does not appear sustainable because it exposes the supplier to the risks of the Belgian balancing system, it usually attracts an additional congestion cost, and could signal a low degree of reliability of such suppliers (see analysis in section 2.2.4).[199] Moreover the allocation mechanism of capacity is opaque and tends to penalise ARPs that are seeking large amounts of capacity.
- Our analysis of power flows and capacity costs on the North border indicates the supply market in Belgium as less profitable than in the Netherlands. This implies more that the Dutch market will rather attract Belgian suppliers than the Belgian market attract Dutch suppliers.
- The balancing rules in Belgium are such to discourage effective import competition (see section 2.3.1).

Finally, investing in new generating capacity does not appear straightforward because it seems rather difficult to locate sites suitable for generation and to connect the plant to the grid.

Fixed costs

Fixed costs such as IT equipment and software, etc, may be only partially sunk, and not significantly large. Many firms that enter the supply market might already have customer billing, meter reading, call centres, and other similar operations, and so the additional costs of entry are low and the degree

[199] As a result of these forces, daily import capacity on the South border is not completely utilised in 2/3 of the times.

of 'sunkness' of these costs is limited. The degree of sunk costs is likely to be a low barrier to entry in the supply market.

Surcharges and taxes

Surcharges, CO2 charges, and energy taxes will in general potentially have an impact on the market and the entry conditions into the market. Most of these are levied at the retail or end-user level, so their impact is most likely on the supply market, but the exact incidence of the tax is borne by the level of the supply chain which is least able to shift the tax on to other vertical elements, combined with the elasticity of demand. Given Electrabel's dominance in generation and the lack of elasticity of most end-use demand, supply is the most likely candidate. We consider the case of an excise (per unit) tax as a general example.

The nature of the impact of an excise tax on energy on entry conditions depends on the status and nature of competition. For example, if Bertrand (price competition) is the fact, then profit margins are zero, so entry is not impacted. Likewise, in perfect competition, firms are very small, and so there is little to no impact. However, a situation of monopoly, duopoly, or Cournot competition is the much more likely model to apply. In Cournot, firms compete in quantities and take the output of their competitor as given. This is the most straightforward case and the most applicable.

If firms are Cournot competitors, then it can be shown that if demand is linear, say $P = a - bQ$, where P is price, Q is industry output, and a is the intercept and b the slope of the demand curve, then increases in unit cost will reduce operating profit, and therefore, make entry more difficult. (Since operating profit has to cover fixed cost amortised over the life of the project at the economic cost of capital). If firm costs are $C = f + cq$, where c is the unit cost, then firm profits can be shown[200] to be: $\pi^*_1 = (a - c)^2/9b$. It is readily verifiable that the derivative of the firms optimal profit, pi-star, is decreasing as c increases. Therefore, under reasonable assumptions, entry is slowed by an increase in the unit cost. Addition of an excise tax is equivalent to an increase in the unit cost.

6.7.2 Strategic/behavioural barriers

In this section we provide a few examples of behaviour that Electrabel is in a position to undertake in Belgium. We would like to stress that, although we have not seen any particular evidence to date that the incumbent generator in Belgium has exercised market power, even the (credible) threat of such behaviour, or simply the uncertainty of how the incumbent will react after entry has occurred, could be enough to deter entry.

[200] Set up the firms' profit equations, take the first derivative and set equal to zero; solve the equations for each firms equilibrium output, then substitute this back into the profit equation.

Wholesale price manipulation

Due to its pivotal position in generation, Electrabel has the capability (and the incentive) of manipulating wholesale prices in what way it deems useful. This has important implications for the supply market. As the price of wholesale power enters directly the price that is offered by suppliers to power users, artificially high wholesale prices would directly translate into higher costs for these operators but not for Electrabel (see analysis on p. 47). Price manipulation can also be aimed at increasing the volatility of prices as opposed to their average level. With more volatile wholesale prices a risk-averse buyer would be willing to buy power on the forward market (usually at a higher price) instead of the spot market. However, this automatically translates into higher supply costs that, as it might be difficult to pass these costs on to consumers, will reduce the (expected) profitability of entering the downstream markets. In essence, these mechanisms will reduce the profitability of the supply market.

Refusal to supply

Additionally, the present situation does not prevent Electrabel from restricting or even refusing to supply energy. New suppliers could see this as an important barrier to entry. In fact, Electrabel could supply at an inferior level of quality such that new entrants would find it more costly to compete.

Choice of the default supplier

We believe the choice to designate ECS as the default supplier could make entry more difficult in the supply market for the following reasons:

- It gives Electrabel a lead over new entrants because of its client base. New entrants will need to invest significant resources to acquire new customers whereas Electrabel will need to invest only in keeping customers from switching.[201]
- It reinforces the vertical integration of Electrabel. The problems from vertical integration could have been mitigated if the default supplier had been a different supplier. In some situations, an increase of market power in the supply market may help countervail the market power in generation.
- The large customer base will confer the default supplier a much larger company size than the rest of suppliers. This will allow the default supplier to exploit economies of scale.
- In the eyes of customers, being a default supplier is perceived as being trustworthy. Customers may have some doubts about the

[201] The choice of any existing supplier as the default supplier does not facilitate new entry in the supply. However, we believe that the choice of ECS creates additional difficulties for the degree of competition in the supply market.

reliability of the new supplier. For example, they might wonder whether the new supplier will be able to deliver electricity without cuts, get their billing information correct, resolve customer service problems quickly, etc. Therefore, when choosing a new supplier, customers will, in practice, perceive that they are facing a risk. Other things equal, the new supplier will have to offer the same product at better conditions to compensate the customer for that risk.

- The large customer base also provides an additional advantage in the generation level. Because of its vertical integration, Electrabel has a guaranteed usage of its generation capacity thanks to ECS being the default supplier.
- The new entrant will be facing an additional obstacle with respect to the default supplier. The type of customers that the new entrant will be able to attract are obviously those that are more willing to change suppliers. In contrast, the default supplier's clientele will be constituted by those customers that are less likely to change. This will confer the default supplier with two type of advantages over new entrants. The first advantage is related to the loyalty of the default supplier's clientele. The default supplier will need to spend less amount of resources to retain its customers than a new entrant. This will increase new entrant's costs. Secondly, since the new entrant's customers are probably more price sensitive, the new entrant will need to operate with lower retail margins.

Availability of timely and accurate information

Suppliers have told us repeatedly that lack of proper information on their actual and potential clients[202], lack of a rich set of customer profiles, very late provision of information on their customers' actual consumption and problems with allocation and reconciliation combined with a expensive balancing mechanism imply that, currently, suppliers run a very high financial risk in a narrow margin market.

Essentially, suppliers face a number of problems.

First, before signing any electricity supply contract suppliers need to have some basic information about potential clients' electricity consumption, load profile, etc. According to suppliers this information is sometimes relatively difficult obtain from the DSOs as, according to suppliers, responses may arrive late or be incomplete. DSOs acknowledged in the roundtables that this is a point of contention but argued that the DSOs own this commercial information and that while they were prepared to respond to any reasonable

[202] For example, we have been informed that the lack of a complete EAN code register results in a lot of problems such as wrong switching, missing measurement and master data, wrong sourcing, etc and, that the process of addressing these problems is resource-intensive.

request from a supplier, they were not willing make the information on all users connected to the distribution grid publicly available.

What appears to be lacking at the present time is a clear definition of the DSOs' responsibilities and obligations with regards to responding to suppliers' request for information about potential clients.

In this regard it is interesting to note that the Walloon technical code for the management of the distribution grids specifies in detail the information, and the timeframe for providing such information, the DSOs have to provide to suppliers of actual clients connected to the distribution grid[203] but is silent about the information that can or should be provided about prospective clients. The Flemish technical code foresees explicitly that historical electricity consumption information be provided to a new supplier but at the time the request for a supplier switch is being made.[204] None of the codes appear to address to issue of information exchange prior to the actual signing of a supply contract.[205]

In itself the difficulties faced by suppliers in obtaining information from DSOs about potential clients are a barrier to entry. This barrier to entry is compounded by the fact that no all suppliers face a level playing field in this regard. Indeed, through its activities with the mixed intercommunales, Electrabel has accumulated considerable information about a wide customer base which other suppliers wanting to compete with Electrabel (or its subsidiary ECS) need to obtain on case-by-case basis from the DSOs.

As a result of the decisions of the Belgian competition authorities regarding the nomination of ECS as the default supplier of the intercommunales, Chinese walls are to be erected between the intercommunales's operating systems and Electrabel, and Electrabel technicians operating the intercommunales systems' are not to communicate information gained as part of these activities to Electrabel. However, so far this disentanglement between the intercommunales' operating systems and Electrabel has not yet been fully implemented. This point may eventually become less of an issue if the Chinese walls are truly impermeable and the passage of time reduces the value of Electrabel's stock of information accumulated until now.

Nevertheless, this may take some time and it would be important to address this barrier relatively quickly to establish a more even playing field between the incumbent supplier and new suppliers, and support effective competition

[203] See Articles 217 to 225 of *Arrêté du Gouvernement wallon relatif au règlement technique pour la gestion des réseaux de distribution d'électricité en Région wallonne et l'accès à ceux-ci* of 16 October 2003.

[204] See Article 3.10.1 §1 and §2 of VREG, *Technisch Reglement Distributie Elektriciteit Vlaams Gewest*, Version of 14 October 2003

[205] Obviously, a supplier could ask an electricity consumer to obtain the necessary information as the latter has right to this information. But, from a commercial point of view this route may not always be a desirable one to pursue by the supplier as it presupposes that the supplier and the potential client have already entered into some form of discussions.

in the supply market.[206] Obviously, this is an issue that falls under the competence of the regions. But, barring formal changes to the regional technical codes to formalise the procedure for sharing information with suppliers about potential clients, CREG could perhaps work with the regional regulators on promoting a best practice-code of conduct regarding the exchange of information about future clients. Such a code could define the information set about potential clients which is to be provided upon request to suppliers, the timeframe over which such information is to be provided and even, perhaps, establish an arbitrage procedure.

The second problem mentioned by suppliers having signed up clients is that, at the present time, they face many difficulties in obtaining from the DSOs accurate and timely information on the consumption of their clients. With regards to lack of accuracy, wrong switching, mismatch between suppliers client base and clients assigned to supplier by DSO, missing measurement or master data, wrong sourcing, etc are said by suppliers to be a recurring characteristic of the system.[207] Moreover, despite the fact the regional technical codes clearly specify the timeframe within which the actual consumption information is to be made available to suppliers, in would appear that in 2003 these deadlines were not always respected, and that in some cases, the time lags were significant. In the roundtable discussions, DSO acknowledged that the transmission of consumption data to suppliers was not entirely flawless in 2003, but they attribute this mainly to teething problems with their information systems. One would expect such teething problems to diminish in intensity and frequency over time.

That being said, obviously any inaccurate data and delayed data transmission create an operating risk for suppliers as certainty is achieved only after some lag.

Of interest is the fact that the regional technical codes applicable to the DSOs set out the DSOs' responsibilities and obligations vis-à-vis suppliers, but do not foresee any penalties if DSOs fail to comply with the prescribed conduct.

Overall, as a result of the various problems with electricity usage data, the risk/reward balance is, according to the suppliers we met, much poorer in Belgium than in other European markets. Entry is not only likely to be discouraged as a result, but significant exit may very well occur in the future.

[206] For example, in Wallonia the time period within which a DSO will have to give to an electricity consumer, upon a request from the consumer, his/her EAN code will be reduced from 180 days to 30 days by 1st January 2005.

[207] A number of suppliers have also indicated that the current number (4) of synthetic load profiles produced by Belgian Federation of Electricity Producers and used in all three regions to estimate the consumption profile of those clients with no real time metering is too small and does not adequately capture the variety of consumption profiles that exist. As result, some cross-subsidies between suppliers may occur although we are not aware of any hard evidence substantiating this point.

Difficulties in switching supplier[208]

The distribution grid is operated by pure and mixed intercommunales. About 80% of the distribution is carried out by the mixed intercommunales in which Electrabel owns —in most cases— more than 50% of the capital. Suppliers feel that currently switching is done too slowly. This is dictated by the regional codes and the 'rule of 1 month'. New suppliers must have confidence in the transfer process for entry to be effective.

Evidence on the difficulties in switching supplier has been sparse other than anecdotal evidence from suppliers themselves. However, the VREG[209] has recently published a study of the difficulties. Among the findings of the study are:

1) Promotion by suppliers

According to the survey results, 83% of survey respondents received no supply offer from any supplier, 10% received 1 offer, 4% two offers and 2% 3 or more offers. (This suggests that suppliers would have to work much more actively at developing the market)

2) Information sought from suppliers

According to the survey results, 87% of respondents did not seek any offer from suppliers, 8% contacted 1 supplier, 2% contacted 2 suppliers and 2% contacted 3 or more suppliers. This suggests that even the non-client specific advertising by new suppliers did not have much of an impact, and that incumbent suppliers benefit from a very high degree of customer inertia; fixed entry costs are likely to be very high/higher than anticipated if normal levels and forms of advertising do not impact customer decisions to switch.

3) Distribution of customers by type of supplier

According to the survey results, 85% of respondents have been assigned by default to the incumbent supplier, 5% have signed a contract with the incumbent supplier, 1% transferred to another established supplier (either ECS or Luminus), and 9% moved to a new supplier. The latter figure is somewhat higher than the one reported in the monthly VREG report on switching.

4) Contract duration + break clause

2/3 of contracts were for one year, 22% of respondents did not know the length of their contract and 4% reported that the term of their contract was of indefinite. 1% signed contracts of 2 years and 3% of 3 years. 54% did not

[208] This could also be a behavioural barrier, to the extent that difficulties in switching supplier are encountered from actions taken (or not taken) by Electrabel or its affiliates.

[209] Source: VREG (2004), Rapport van de Vlaamse Reguleringsinstatie voor de Elektriciteits- en Gasmarkt van April 2004 met betrekking tot de resultaten van de INRA-studie - Switchgedrag van huishoudelijke elektriciteitsklanten in Vlaanderen n.a.v. de vrijmaking op 1 juli 2003, RAPP-2004-4

know the required notice for breaking their contract, 15% reported 1 month, 10% 1.5 to 2 months, 16% 3 months, 3% 6 months or more. (The lack of knowledge about the break clauses is serious source of inertia even among those that have changed suppliers).

5) views about transfer to new supplier

According to the survey results, the transfer went generally well. But, 18% of those having signed a contract with a new supplier, and having answered the relevant questions, reported that the closing bill of the old supplier was not clear and 10% have the impression that the old supplier tried to slow down the transfer. On the other hand, 13% are not satisfied with the after-sale services of the new supplier.

6) Assigned customers

According to the survey results, of the 85% of respondents who were assigned to the default supplier, 83% are satisfied and are not interested in transferring to a new supplier. 76% of those assigned to the default supplier declared that they had either not received any supply offer or not a more advantageous supply offer. 17% received an offer but found it unclear.

Only 7% of assigned customers are considering transferring to a new supplier over the next 6 months, 16% do not yet know, 33% indicated they are unlikely to switch and 44% reported they would definitely not switch over the next 6 months.

Looking 3 years ahead, 13% of assigned customers reported that they may switch, 26% did not know, 32% reported that is was unlikely that they would switch and 32% reported they definitely would not switch.

The overall results indicate a very high resistance to switching -- if reported switching/non-switching pattern actually materializes the market for new suppliers will not grow very much. This would very likely affect entry negatively into the supply market and/or lead to exit among current suppliers. Thus, barriers to entry are likely to exist because of supplier switching difficulties.

6.7.3 Legal/regulatory barriers

Regulatory uncertainty

While in the generation market regulatory uncertainty affects both the possibility to enter the market (through the licensing procedure) and potentially the financial reward of entry (availability of green certificates for gas-powered generation plants), regulatory uncertainty faced by traders and more particularly suppliers affects primarily the financial reward of entry. This regulatory uncertainty relates directly to the uncertainty traders and suppliers face with regards to the transportation and distribution tariffs and various surcharges they will have to factor into the supply price that they will

quote to their potential clients. The greater the share of these tariffs and surcharges in the final electricity price the greater the regulatory risk faced by market participants, especially if the level of tariffs and surcharges is relatively unpredictable.

At the present time, Belgium can be characterised as a country in which this type of uncertainty is high, as the whole system of tariffs and surcharges does not appear to have yet firmly bedded down. For example, the 2003 distribution tariffs were announced by the CREG only on 23rd May 2003, and this only on a provisional basis, for a number of distributors.[210] In 2004, the transportation and distribution tariffs were announced much earlier, i.e. on 9th January.[211] But, as in the previous year, many of these tariffs were approved only on a provisional basis for a period of 3 months. In fact, only 24 of the 29 distributors and the grid operator received only provisional approval for their tariffs. Until the tariff setting system becomes more established and predictable, traders and distributors face a significant regulatory risk with regards to the precise tariff level they will to include in the price quotes to final clients.

This regulatory risk is compounded by the fact that distribution tariffs vary significantly across the 29 distributors. For example, for a residential customer (Eurostat type Dc consuming 3,500 kWh per year) the tariffs (including regional surcharges) announced on 9th January 2004 range from slightly less than €150 per year to about €250 per year across the 14 distributors in Flanders[212] and from about €120 per year to about €220 per year in Wallonia.[213] Thus any supplier wishing to be active in a range of areas served by different distributors faces the need to closely track factors affecting distributors tariff. While some degree of heterogeneity here is probably unavoidable, and even beneficial, this still creates regulatory risk.

The regulatory uncertainty facing suppliers in quoting supply prices to their clients is also compounded by the fact that many surcharges are levied on electricity, both at the federal and regional level, and that the level of these surcharges was and, in some cases still is, not always easily predictable (see Table 6.1 for details of surcharges from late 2002 to 2004). Unless the suppliers are able to include conditions in their supply contracts that any such surcharges will be passed straight through to customers, they face the risk of seeing their profit margin reduced by any unanticipated introductions of or changes in existing levies.

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[210] See CREG, Tarifs applicables à la distribution de l'électricité, Conférence de presse du 23 mai 2003 par M. Guido Camps.

[211] See CREG, Tarifs 2004 pour le transport et la distribution d'électricité et le transport de gaz, Communiqué de presse, 9 janvier 2004.

[212] There exists another distributor in Flanders, namely BIAC. However, the latter serves only industrial clients.

[213] See CREG, Conférence de presse par M. Guido Camps 9 Janvier 2004

Federal law impacts regulatory uncertainty especially as royal decrees can impact the final price. At the federal level, the Royal Decree of 24 March 2003 (as modified by the Royal Decree of 8th July 2003) sets out a clear formulaic approach for respectively determining: a) the level of the surcharges levied to finance the federal greenhouse gas (GHG) policy; and b) the social policy measures foreseen by the law of 4 September 2002.[214] As well, the Royal Decree of 19th December 2003 has set out clearly the level of funds that need to be raised by the decommissioning surcharge in each year over the period 2004-2008. Thus, these particular federal surcharges are relatively predictable in the sense that, barring any further legislative change, the formulas set out in the legislation can be used to forecast future levels of these three surcharges. In contrast, the level of the federal surcharges levied to cover the part of the cost of CREG has to be set annually by a Royal Decree.[215] This introduces a certain element of unpredictability but, provided CREG's costs grow in line with general inflation, the recent levels of this surcharge should be a good predictor of future levels, after adjustment for inflation.

The modalities for determining the level of the recently introduced surcharge to finance the cost of protected clients are clearly set out in the Royal Decree of 22 December 2003. However, because the precise amount to be raised each year depends among others on actual electricity prices, maximum electricity prices for protected clients and their consumption, and potential shortfalls/surpluses in the special purpose fund, predicting the precise level of this surcharge is fraud with uncertainty.

Regarding the federal energy 'cotisation', which is only applicable to low voltage customers, its future level is much more difficult to predict as it depends on broader policy considerations of the government and is not related in one way or another to the specific aspects of the electricity market.

In spite of some of the surcharges due to federal law often being relatively certain, the sum total can create significant uncertainty. The bottom line is that through 2003, the total amount of the various federal surcharges to be applied to electricity was highly uncertain as new surcharges were added on and the modalities for determining the precise level of the surcharges was being clarified.

Similar observations apply at the regional level where the system of surcharges appears to still have been is a stage in transition in 2003. For example in Wallonia, a new connection levy, to finance various activities such the regional regulator, aid to green energy producers, etc, was introduced as of 15th July 2003.[216]

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[214] See article 4 paragraphs §3 and §4 of Royal Decree of 23 March 2003.

[215] See article 4 paragraphs §1 and §2 of Royal Decree of 23 March 2003. For 2004, the CREG levy was set in the Royal Decree of 8th March 2004 and the decommissioning surcharge was set in the Royal Decree of 19th December 2003.

[216] Walloon government decree of 19th June 2003.

Looking ahead, the degree of regulatory uncertainty arising from the surcharges should be somewhat reduced, provided the federal and regional governments do not further tinker with the existing system nor add new surcharges. As many suppliers view 2003 as a having been a very difficult year in terms of predictability of the surcharges, their perception of the regulatory risk associated with such surcharges is likely to remain high for a while and will only abate in response to clear evidence that the system is becoming more stable and predictable.

Table 6.1: Federal and regional surcharges (€/MWh)

	Apr.–Jun. 2004	Jan.–Mar. 2004	Oct.–Dec. 2003	Jul. – Sep. 2003	Apr.–Jun. 2003	Jan.–Mar. 2003	Oct.–Dec. 2002
Federal							
Energy cotisation[1]	1.9088	1.9088	1.9088	1.9088 / 1.36	1.36	1.36	1.36
Costs of CREG	0.0868	0.0868	0.1049	0.1049	0.1049	0.1049	0.2492
Financing of decommissioning of Mol-Dessel BP1 and BP2	0.7176	0.7176	0.5446	0.5446	0.5446	0.5446	
Financing of federal GHG reduction policy	0.3225	0.3225	0.3583	0.3583	0.3583	0.3583	
Financing of federal public service obligations					0.3191	0.3191	0.3191
Financing of social measures as per law of Sep. 2002	0.3216	0.3216	0.3177	0.3177			
Surcharge protected clients	0.2021	0.2021					
Regional – Brussels							
Connection surcharge[4]	0.025 to 0.050						
Regional – Flanders							
Financing of promotion of rational energy use[2]	0.0769	0.0769	0.0777	0.0777	0.0777	0.0777	0.0777
Use of public domain[2]	0.0093	0.0093	0.0850	0.0850	0.0850	0.0850	0.0850
Tariff to compensate for active power losses[3]			0.0883 to 0.3566	0.0883 to 0.3566	0.0883 to 0.3566	0.0883 to 0.3566	0.0883 to 0.3566
Regional – Wallonia							
Use of public domain[2]	0 to 0.2956	0 to 0.2956	0 to 0.2956	0 to 0.2956	0 to 0.2956	0 to 0.2956	
Connection levy	Less than 100 kWh: fixed charge of 7.5c€ Above 100KWh: 0.075-0.03 c€ / kWh	Less than 100 kWh: fixed charge of 7.5c€ Above 100KWh: 0.075-0.03 c€ / kWh	Less than 100 kWh: fixed charge of 7.5c€ Above 100KWh: 0.075-0.03 c€ / kWh	Less than 100 kWh: fixed charge of 7.5c€ Above 100KWh: 0.075-0.03 c€ / kWh			

Notes: (1) Applies only to low-voltage grid customers; (2)Varies according to voltage grid. The precise definition of high voltage varies across the various surcharges; (3) Precise level depends on voltage of grid and period. (4) lower level for more than 70kV grid and upper level for less than 70kV grid. The surcharges are levied on the grid operator and distributors and passed on downstream except the federal energy cotisation and the Brussels and Walloon connection levies that are levied directly on suppliers.

6.8 Political influence

We have been requested to comment and study, as part of the terms of reference for the project, how political barriers likely impact on the electricity markets in question in Belgium. There is a significant literature on political influence and its interaction with market power (Scherer and Ross 1990).[217] One of the sources of study of the influence of political power and its influence on markets is the question of whether "aggregate size matters" or whether "conglomerate mergers matter" in a market power sense, since typically horizontal market concentration and vertical relationships are the focus of market power studies.

A limited number of studies suggest that aggregate size or conglomerateness does matter, and that these firms tend to have higher margins, even when controlling for market size, market concentration (horizontal) and other variables such as advertising.[218] There are also a few celebrated anecdotes of the influences of political power and its interaction with big firms at the highest levels. On such case is when White House tapes from the Nixon administration were released showing Nixon telling his Attorney General to fire the Deputy attorney General for Anti-trust, McClaren, over his pursuing ITT on a conglomerate merger, noting ITT's contributions to Nixon's campaign.[219]

However, anecdotes and research notwithstanding, this area of study is extremely difficult to quantify and study rigorously. The nature of political influence is by its very nature clandestine, and therefore, to attempt to draw significant conclusions for this area, would be very difficult. Further, since we feel that other areas have shown significant barriers, and the addition of political barriers can only enhance them, we feel that to add in political barriers would be an exercise in clouding the good with the bad. We nonetheless conclude that such barriers likely exist, but as to their relative size this is the subject of speculation.

6.9 Conclusions

In practice, based on our review of the Belgian electricity market and the information provided by stakeholders, we believe that the biggest barrier to

[217] See references in F.M. Scherer and D. Ross, Industrial Market Structure and Economic Performance, Third Edition, 1990, Boston: Houghton Mifflin Company.

[218] In one study, Swinand and Rogers (1992) found that aggregate size was a significant determinant of concentration and price cost margins in two-digit census of manufacturing industry in the US.

[219] See for example, Fox, Sullivan and Peritz' (2004), "Cases and Materials on United States Antitrust in Global Context, 2d (West Law Casebook Series).

entry is the lack of competitive supply of commodity and the market power of Electrabel.

In generation, economic barriers (i.e., prevalent price), and siting and interconnection issues are likely to be important barriers.

In trading, lack of liquidity and opacity (i.e. lack of benchmark price) are likely the key entry deterrents. The vertical integration of Electrabel is also an important factor. Low margins and high risk are likely to be important economic barriers to entry into the trading market while fixed costs are not.

Finally, with regards to supply, lack of timely availability of reliable data, lack of competitively supplied commodity, lack of opportunities to manage risk (through a transparent market place), and an expensive balancing mechanism are most likely the most critical factors affecting entry into the market. Economic entry barriers into the supply market are probably the lowest of all three markets. Nevertheless, margins are low and risks are substantial.

7 Remedies to improve the functioning of the electricity markets

7.1 Introduction

In this chapter, we discuss the relevant issues and consider a range of potential remedies to improve the functioning of the Belgian electricity markets. The fundamental issues facing these three markets - generation, trading and supply are the dominance of the incumbent and its vertical integration along the electricity value chain, the lack of a proper wholesale market, and the resulting lack of transparency associated with the Belgian power sector more generally.

As we noted in our discussion on barriers to entry, while there exist a number of other barriers, one can argue that these are of second order relative to the key structural issues highlighted above. Nevertheless, we believe that addressing these other barriers will assist in improving, at the margin, the functioning of the Belgian electricity markets and we discuss potential remedies below.

The impact of the fundamental characteristics of the Belgian electricity sector is manifold and can be summarised as follows:

- There is no meaningful competition in the generation market, which in turn impacts on the functioning of the trading and supply markets;
- Entrants into any one of three electricity markets face a clear informational disadvantage as Electrabel has access to superior information; and
- Entry is furthermore deterred as potential entrants into any one of three markets face the risk that Electrabel may abuse its dominant position, irrespective of whether the latter has done so or not in the past.

To address these problems, a number of structural and behavioural remedies can be envisaged and we discuss the pros and cons of each in turn, and then we conclude this chapter with our recommendations.

7.2 Overview of importance of remedies

It is instructive at this point to consider the general nature and order of importance of potential remedies to address the problems summarised above, before considering the detailed range of remedies and issues.

We believe that the highest importance for electricity market structure and functioning should be attached to the availability for trade of the electricity commodity. Lack of sufficient commodity could be seen as the greatest problem facing any power market.

Lack of sufficient power commodity can involve either fundamental shortage, which can occur either through insufficient supply and/or sudden surges in demand, or through a lack of free trade in the commodity, the latter stemming from the presence of market power in generation and vertical integration. Of course, shortage of supply relative to demand will tend to exacerbate market power problems. We have, however, examined the supply-demand balances and forecasts for the Belgian electricity market, and our findings suggest that this issue is not expected to be problematic over the next few years.[220] Our conclusion is that market power and vertical integration in generation are likely to remain the key problems facing the sector.

There are of course other problems, but they are generally of an order of magnitude smaller than the issues of market power and vertical integration associated with the incumbent.[221] We discuss these issues, including the benefits of a Belgian Power Exchange, in the course of this chapter.

7.3 Issue 1: Electrabel's vertical integration

The first issue we examine concerns that of vertical integration.

At a minimum, there is a perception among players that vertical separation is weak; while at worst, anecdotal evidence suggests that vertical ties may have been used to interact with competitive markets (for example, in the SourcePower case, where time delay differentials were cited in relation to DSO connections between pure and mixed intercommunales). Therefore, in the Belgian context, we would recommend that as much effort as possible should be geared towards achieving vertical separation. While Belgium has of course complied with the Directive by implementing the latter with appropriate national legislation and regulation, it appears that the current levels of vertical separation have not achieved the goals of clear and transparent access to the commodity and the infrastructure[222] (including data).

[220] CREG, ETSO and other organisations have conducted more detailed studies of the market and have reached similar conclusions. In addition, Belgium does not depend on storage hydro - which is subject to weather conditions - for significant proportions of its supply (although indirectly, Alpine storage hydro could impact Belgium through the inter-connectors.)

[221] This conclusion is, in general, corroborated by the EU Commission's Benchmarking report on the status of competition in the EU electricity sectors. In one survey, dominance of the incumbent ranked as the number one problem in every EU Member State but one.

[222] The clearest evidence of this is in the generation chapter (chapter 2), especially the parts on interconnection, 2.2.4 and 2.3.1, balancing, and market share, 2.2.6. Access to the grid with respect to interconnection is but one area where the grid and generation interact. In many instances we feel the market share elements are barriers in and of themselves. Discussion of the relationships between vertical relationships and access to the commodity are also found in 6.4.1.

The economics of how vertical integration can impact on market competition are well documented.[223] The vertically integrated firm has the ability to raise rivals' costs, has knowledge that the downstream/upstream competitors do not, or offers terms and conditions to its own vertically related subsidiaries that are not available to competitors.

Is there evidence of this in Belgium? The evidence is shadowy, since one impact of vertical integration is that transactions get carried out within the firm rather than the market, but we feel that there is. Consider the balancing costs, discussed in Chapter 3 (generation). Here, higher balancing costs impact firms asymmetrically. Electrabel's generators are no doubt compensated (by how much we cannot ascertain) for providing balancing services (Elia has started to obtain some balancing services by competitive tender we understand—but we suspect the majority of this is still provided by Electrabel, as they own units like the pumped storage units capable of providing the service at a low cost). Elia is also compensated for the services – all this is cashflowing *to* Electrabel *from* competitors. In our opinion, this is the classic example of raising rivals costs.

Other evidence of insufficient vertical separation comes from governance structures. The same people sit on the same boards in most cases, and cross-shareholdings between almost all parties in the sector exist.

7.3.1 Remedies to bolster vertical separation

The first objective requiring consideration is the need to break the link between Electrabel and Elia. There exist no sound economic reasons why an electricity generator, trader and supplier should also own part of the transportation grid, while there *are* good economic reasons why they should not. Obviously, such ownership may provide access to privileged information; this will be clearly to the detriment of Electrabel's competitors in any of the three electricity markets. Moreover, even if Electrabel did not exploit this information, the mere fact that it could so would create an uneven level playing field between Electrabel and its competitors. Breaking the link between Electrabel and Elia would also eliminate any real or perceived conflicts of interest in Elia's dealings with Electrabel's competitors. In terms of entry decisions, the perceptions of potential entrants or their bankers could be as important as any proven conduct.[224]

[223] See for example Scherer and Ross (1998) or Tirole (1987).

[224] There are of course subtle difficulties that will have to be worked out. The perception of discrimination between SPE and Electrabel is suggested as one such problem. However, we do not see this as a large problem. In other EU jurisdictions this is most often handled via some sort of significant market power clause (SMP). For example, in Ireland's telecoms sector, if an operator is deemed to have SMP, then this gives the regulator all kinds of additional powers. A similar designation could be implemented, because SPE owning part of Elia is unlikely to be material given its low market share. Similar provisions could be said for the shareholdings in the intercommunales. For example, the total % ownership share in any one firm, region, and the total sector, could be limited to a maximum for firms, such as Electrabel, whose market share exceeds a limit in the other markets. Similar

The second element to consider would be a divestiture of Electrabel's technical activities from the mixed intercommunales. The worrisome link here is between ECS and the DSOs, and to a lesser extent Electrabel' generation. A divested Elia could maintain the links with the DSOs without any competition worries.[225] We understand that, as part of its approval of the designation of Electrabel Customer Solutions as the default supplier of the mixed intercommunales, the Belgian Competition Council required that strict 'Chinese walls' be established between Electrabel's regular activities and the technical services provided to the mixed intercommunales. While Chinese walls are theoretically appealing, the practice in other sectors such as the financial services industry has shown that Chinese walls are permeable and are not a good approximation of separation of ownership. In fact, in the case of the Belgian electricity sector, we understand that at the present time, the information systems of the mixed intercommunales are still integrated with Electrabel's own IT systems. In general, information sharing from the mixed intercommunales to Electrabel could put Electrabel's competitors at a disadvantage. Therefore, forced separation or divestiture between Electrabel and its technical activities undertaken for the mixed intercommunales should be considered.

In short, the first two structural remedies described above would result in a clear break between Electrabel and the TSO and DSOs, and would go a long way towards eliminating the current asymmetry in access to information between Electrabel and its competitors.

We also recommend ownership separation between, at a minimum, Elia and Electrabel. While ownership separation is a sufficient, but not necessary, condition (not a 100% requirement) we consider that it is the most appropriate option for Belgium for the following reasons:

1. In spite of what future conduct might be, Electrabel may use its vertical relationships to impede entry, as alleged in the SourcePower case;
2. Limited separation seems to have been inadequate; at the very least, there is a strong perception among almost all participants that separation is not sufficient;
3. The evidence in relation to the adverse impact of lack of ownership separation in other jurisdictions. We have already noted the German and Scottish cases. Other cases include California, where utilities remained owners of grid assets and failed to make grid investments. In Ireland, recently, the grid asset owner, ESB National Grid, has been in dispute with the TSO, Eirgrid. ESBNG essentially sued Eirgrid over rights to control planning and maintenance of grid assets, took over

arrangements are found in other markets, such as EU Telecoms markets, where if a firm is designated to have significant market power (SMP), then a range of other restrictions come into play

[225] In fact, this should be encouraged. That is, one of the benefits of divestiture for Elia would be that then Elia and Electrabel Netmanagement could continue to be an integrated firm without worries.

Eirgrid's website, and blocked Eirgrid's plans on a number of system issues[226];

4. A number of international academic experts, including Newbery (2001)[227], recommend that "no ownership interest" between TSO and generation is a requirement; and
5. Lack of maximum vertical separation may hinder competitive operation of interconnection. Interconnection (discussed further later in this chapter) is one of the most important features of potential market power mitigation in Belgium. Interconnection is in part a 'public good'[228], which may create perverse incentives arising from the presence of vertical ownership structures.

It in interesting to note in this regard that the 1999 Electricity Law clearly states that the TSO cannot have any direct or indirect economic and financial interests in generators, distributors, suppliers and other intermediaries (traders)[229] but does not require the opposite, namely that generators, distributors, suppliers and other intermediaries should not hold any interest in the TSO.

The other potential structural remedy that would assist in addressing Electrabel's vertical integration would be ownership separation of Electrabel into independent generation, trading and supply companies. While such a step would clearly establish a level playing field in the trading and supply market, it would still leave a dominant player in the generation market, which is the most critical structural issue facing the Belgian electricity sector.

There are also more limited remedies that could strengthen vertical separation within the Belgian electricity market in the short term. These could include:

- A requirement to publish separate, audited regulatory accounts for trading, generation, supply, and transmission. Such regulatory accounts should include price, quantity, and cost information at a disaggregated level, which will enhance transparency and assure participants that subsidiaries are not being cross-subsidised;
- A requirement for complete separation of boards, directors, executive management, etc. Our understanding is that currently there is a

[226] This is a very interesting case, because, ESBNG and Eirgrid are each still in effect owned by the Irish Government.

[227] Newbery D. (2001a).

[228] A public good is a good like "clean air" or "national defence". It is noteworthy, that, if interconnection is in fact a public good, then it might be considered whether "private" ownership is also the best ownership structure—the alternative being public ownership. Perhaps this has been taken to heart in the case of the gas network in the Netherlands, where Gasunie is to be 51% owned by the Government.

[229] See article 1 §1 of Loi relative à l'organisation du marché de l'électricité, 29th April 1999

significant degree of interlocking governance structures among boards, directors and executives of Electrabel subsidiaries[230];

- A requirement for physical separation of all entities, buildings, IT, personnel, etc;
- A requirement that information, which might be shared (even covertly) between the vertical elements of the incumbent firm (customer data, gas usage, etc), be shared with all market participants, as long as significant vertical shareholding remains;
- To require Elia and the DSOs to provide a published plan, on how they will assure that sensitive information is not passed between them and elements of Electrabel, which are in the potentially competitive areas; and
- To set clear performance standards for the activities of the natural monopoly elements (transmission and distribution), and require that the performance standards are tracked with audited data, allowing detailed statistical analysis of how various 'types' of participants are being treated.

While we are not aware of any particular legislative measure of itself being implemented in jurisdictions internationally, there is certainly evidence in other countries that various forms and flavours of regulation and non-regulatory initiatives have been implemented subsequent to initial reforms, including ownership changes. For example, in the US, the New England system operator, ISO-NE is currently owned by NEPOOL participants, which is the group of users and utilities in New England. An arms-length agreement sets out the governance between the two groups, but ISO-NE has the right to unilaterally implement rules to ensure both security of the system and proper functioning of the markets. ISO-NE was also considering breaking away from NEPOOL, and becoming a separately owned entity.

In the UK, Ofgem has on occasion changed the licensing conditions of NGC to strengthen vertical separation. Elsewhere, in Ireland, Eirgrid has taken legal action against ESB National Grid over certain rights and responsibilities regarding the ownership of transmission assets and their maintenance (in spite of having the same owner, the Irish Government). This later case, we feel, is also indicative of the benefits of having separate boards and complete separation of ownership structures. The rationale for this separation, apart from maximising vertical separation, follows from the managerial view of the firm. Under this view, managers can often maximise their own benefits, (including wealth and prestige, etc) independently of shareholders.

[230] Corporate governance, as a general topic covers a very wide remit. Good corporate governance, however, will go hand-in-hand with well-functioning markets. The ability of outside observers and investors to observe normal corporate accounts (disaggregated by subsidiary) will aid in increasing transparency of the market. We note that especially in some markets, such as trading, that normal accounting procedures will not be up to speed in terms of sophisticated energy contract valuation, such as sparkspread options, tolling contracts, etc.

Therefore, if managers have effective control of the firm, then managerial separation may have a significant impact even without full ownership separation. So the degree of managerial control will be an important indicator of the need for ownership versus managerial separation.

For another example, the Grid Code in the UK allows National Grid a set time within which they must either give permission for connection or reject on reasonable grounds, and then a fixed time within which they need to perform connections. We believe that the CREG should consider the merits of adopting a similar approach and to track whether there is any differential in the service standards as applied to potential competitors versus the services given to Electrabel's own subsidiaries.[231]

As a final note on vertical separation, we suggest that vertical separation is desirable for a number of additional reasons. Much of this has to do with the expertise that is currently in Elia and in Netmanagement. Elia and Netmanagement can take a more active role in the liberalisation process. Setting up structures, codes, institutions, such as a PX, a customer data exchange, a DSO customer codes, etc, can be handled in a different way if these operators are made sufficiently independent that all participants feel comfortable with dealing with them. For example, Elia would be an obvious participant and contributor to the actual running of the PX, and would likely have to have large interactions with the PX in any case due to their needs to control grid security. A fully separated grid would immediately eliminate a layer of needed safeguards, suspicion and potential problems.

7.4 Issue 2: Electrabel's dominance and market power in generation

The second issue requiring examination concerns Electrabel's dominant position in the generation market. We believe that this issue is at the core of the structural problems faced by the Belgian electricity market and we discuss below a number of potential remedies. Electrabel's dominance in generation provides it with the power to raise prices so as to squeeze suppliers or to hold prices just below the price that would suffice to justify new entry. Combined with the high degree of vertical integration, we believe that this feature leads to a complete absence of transparency within the Belgian electricity market.

7.4.1 Remedy: required generation capacity divestiture

To increase competition in the Belgian electricity generation market, one potential remedy that could be considered is to break up Electrabel into a

[231] This approach may be difficult in the Belgian context as there may be a lack of data simply because, for example, so few players have actually attempted to obtain a grid connection. In the absence of detailed data or observations, it may still be feasible for CREG to collect data on Electrabel/Elia's actions/activities in the past, including in relation to the time taken by Elia to connect, on average, Electrabel owned or part-owned projects.

number of independent generation companies. It is likely that a significant proportion of the capacity sold from these generation companies would eventually be acquired by one of the major European electricity players such as EDF, Eon, RWE, etc.

There are a number of important potential costs and benefits associated with a possible break-up of Electrabel. We first discuss the likely benefits.

First, a break-up is perhaps the best way to ensure competition. Other methods, such as vesting contracts, PPA contract coverage, enhanced VPP, will fundamentally all result in a structure where the commercial interests of Electrabel remain aligned both horizontally, across generation, and vertically. Another benefit from divestiture is that this would also likely solve both generation concentration and vertical integration issues at once. Divestiture of generation would also allow for competition in other related ancillary services (markets), such as spinning reserves, regulation, voltage support, etc. Furthermore, divestiture could enhance competition in trading and supply, as ownership of generation would give current and potential competitors in these markets (i) the physical means to expand on current footholds, (ii) strong incentives to trade, (iii) strong incentives to hedge risk, (iv) the ability to supply big customers, (v) the ability to supply value-added services, and (vi) access to data and information.

However, there are a number of considerations that would argue against divestiture. Firstly, at issue is whether the (likely major) resulting players would actively compete against each other in the Belgian market, especially when they meet in a number of European market places. This question raises two important issues: one is whether the resulting players will compete; the second concerns the extent to which multi-market contact among likely players would (eventually) blunt the competition benefits of a break-up.[232] In responding to these issues, it should be noted that various studies have shown that concentration remains the principal determinant of market power and market performance, but that multi-market contact can have independent and significant negative impacts on market performance.[233] While it does not consider the aggregate concentration issue directly, the EU Commission's benchmarking report ranked incumbent dominance as the biggest issue in all but one EU country.[234]

While we believe that the concern that divestiture will be costly and cumbersome and may not reduce market power is not without merit, we consider that the potentially adverse multi-market contact impact on

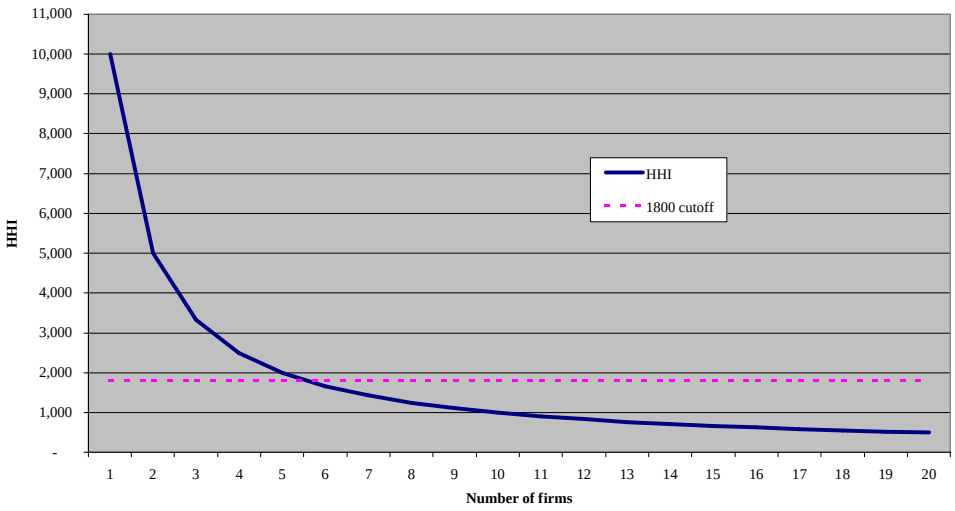
[232] A concern, we interpret from the CREG's most recent annual report (2003), is that big EU firms (i.e., if say, EdF and RWE were to buy slices of Electrabel) might not compete as vigorously as expected. Therefore, the benefits of divestiture might prove a pyrrhic victory.

[233] We are not aware of any recent studies in the electricity industry. See for example, Swinand, G. and Rogers, T (1992).

[234] Op. cit.

competition is likely to be small when compared with the market concentration issue. We believe that the single most important factor preventing the emergence of effective competition is continued concentration, with multi-market contact being a second order concern. Previous studies, undertaken by London Economics, suggest that 3-4 additional competitors (bringing the total number of competitors to possibly 5) may still be insufficient to ensure vigorous competition. This would point to a HHI concentration index level of 2000, assuming equal market shares. The relationship between HHI and the number of firms is shown in the figure overleaf.

Figure 7.1: Relationship between HHI and number of firms



Source: London Economics

Modelling work completed previously in England and Wales, in California and Alberta, and now for Belgium suggest that 7-9 competitors would be required to avoid significant possibilities for exercising market power strategies profitably. While it is likely that it will never be feasible to remove all market power from the market or to ensure that market power can never be exercised, we believe that reasonably competitive markets can be achieved with these levels of competition. It is important, however, to note that workable competition is not achievable without the full range of regulatory oversight, market power monitoring, trading institutions (power exchange) and above all, sufficient generation capacity.

The figures discussed above relate in general to merger policy as well as divestiture policy. In each area, we do not believe that a 'one size fits all' approach is appropriate. The relevance of normal competition measures is firstly related to the capacity situation. The capacity conditions of the market are the most important in general, and it is this combined with the non-storable real-time balancing nature of the electricity commodity that makes extreme caution necessary when estimating the necessary number of competitors or a threshold HHI.

It should be noted in this regard that an HHI for a tight market of 1200 might be too high, while an HHI of 2000 for a market with hydro storage, demand side bidding, and excess capacity might be more than sufficient.

The figures discussed above in relation to the number of competitors can be related to the HHI index of concentration. From the figure, one can observe that the suggested requirement of 7-9 competitors would correspond to an HHI of around 1250. Recognised authors such as Stoft[235] agree, stating that the standard 1800 HHI cut-off, developed as a general rule, may be problematic for electricity markets due to the short-term inelasticity of demand in electricity. Specificity of the 'peakiness' of demand, and supply and demand conditions at different times during the year, will impact on the exact number of competitors required.[236]

CustomBid modelling

To test a hypothesis concerning the potential extent of competition created through divestiture, we have undertaken a number of modelling exercises based on various portfolios of Electrabel plants. These scenarios have been completed using our strategic bidding model of liberalising electricity markets: CustomBid.[237] The scenarios use as inputs data on generation capacity, outages, thermal efficiency, fuel prices, demand, and import/export flows. The scenarios assume certain supply and demand conditions, such as a small amount of demand elasticity (-0.1), and other factors such as 70% contract cover[238] for Electrabel, no strategic use of interconnectors, and a maximum of 20% withdrawal[239] possible by any strategic player.

The scenarios compare the current case, namely Electrabel as one player, and then consider the cases of breaking up Electrabel's generation units into 2, 3, and 4 roughly equal-sized players. Prices from bidding strategies where players can withdraw capacity are calculated for each hour of the year and are compared to the marginal cost bidding strategies. The resulting average price-cost margins (Lerner Index) and the corresponding HHI indices are presented in the table overleaf.

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[235] See Stoft (2002).

[236] Which is why we undertake the detailed modelling of this issue. Additional considerations such as the detailed treatment of the interconnectors will be important determinants of market power too.

[237] Annex 6 contains more details of CustomBid and its inherent assumptions.

[238] This essentially assumes that the firms will have 70% of their output sold forward, or "hedged". A generator would not typically go with a generation portfolio that sells "exclusively" into the spot market. This risk aversion effectively inhibits the generator's ability to exercise market power, as they will treat this percentage as effectively 'inflexible', since they would face financial losses if they did not honour these contractual commitments.

[239] The analysis assumes firms increase profit by essentially withholding capacity from the market. This is often referred to as 'withdrawal'. The effect is to shift the whole supply curve back (left), leaving the remaining higher priced units. There is a duality between this and raising price, as the two are effectively the same under certain circumstances. For example, Cournot competition is equivalent to Bertrand competition with capacity constraints.

Table 7.1: Modelled Results of Possible Divestiture Scenarios - Current Situation

Electrabel players	Scenario			
	1	2	3	4
Assumed no. of players	5	6	7	8
CR4 Ratio	96	93	85	77
HHI Index	6,200	3,174	2,199	1,699
Avg strategic prices €/MWh	€83	€51	€42	€40
Avg. marginal cost bids €/MWh	€31	€31	€31	€31
Price-Cost Margin (PCM)	63%	39%	26%	23%

Source: London Economics

The table above presents the modelling results for various scenarios, 1-4, corresponding to the number of players Electrabel owns in the current market. Scenario 1 represents the prevailing situation, where Electrabel's current portfolio is owned entirely by one player. This yields an HHI of about 6200. It should be noted that this is affected by the fact that the interconnectors are allocated to a single player other than Electrabel. The interconnectors are assumed to be 'non-strategic' and so cannot withhold or engage in strategic bidding.[240] Under all of the scenarios presented, Electrabel and the Electrabel "babies" are assumed to be the sole strategic bidder(s).[241] That is to say, Electrabel is the only strategic bidder in scenario 1, while the two Electrabel "pieces" in scenario 2 bid strategically, and 3 and 4 are strategic bidders in scenarios 3 and 4.[242]

The table also indicates the degree of pricing power that remains in the market with each successive division of Electrabel, i.e. into 2, 3, and 4 players.[243] The corresponding HHIs falls from 6200, in the case of the prevailing market structure, to 3174 under in the 2-player division, to 2199 under the 3-player-breakup structure, and to 1700 in the case of 4 players. The corresponding prices from the average of the strategic bidding outcomes

[240] The point of this assumption is to assume: 1) what the situation might be with appropriate oversight and regulation; and 2) the same conditions across all scenarios, i.e., *ceteris paribus,* with the exception of the number of players that Electrabel is divided into. Thus the stronger evidence of the scenarios is the "relative" price levels, rather than the absolute price levels themselves.

[241] Naturally, if others can bid strategically, and if they are able to at least implicitly coordinate their actions, this could raise the resulting prices. Note that the effect of allowing others to be strategic bidders when Electrabel has a "very high" market share will be almost nil, however. This is because, effectively, Electrabel will always have the largest interest and ability to withhold.

[242] We subsequently refer to these as the 1,2,3 and 4-player-Eletrabel cases. This is to say, that Electrabel is to comprise that number of players.

[243] We omit the scenario of where concentration in the market increases, as the current scenarios are evidently effectively "spanning" the space of "high market power = high prices" and the incremental impacts of lowering concentration.

are €83/MWh, €51/MWh, €42/MWh, and €40/MWh. These prices compare with the modelled competitive prices, or the marginal price bid outcomes. The modelled competitive prices are then used to calculate the price cost margins (PCM). It can be seen that the margins for the 1-player and 2-player scenarios are unreasonably high and reflect massive pricing power, in spite of the assumed market power mitigation measures.[244]

By contrast, the margins for the 3- and 4-player-Electrabel cases are quite reasonable, given the evidence of economies of scale and prices in our trigger price models for generation. In this case it was found that 'levelised'[245] fixed costs were around €9-10/MWh, and total unit cost (or long-run average total cost) was between €35-37/MWh for CCGT, with variable costs plus operating and maintenance costs estimated to be about €26.5/MWh. We also studied the impact of the planned increase in interconnection capacity on the Franco-Belgian border. In this case, the assumptions underlying the scenarios were maintained exactly as presented above for the current market situation, with the one exception that the capacity available was increased by 1,087MW.[246] The new results are shown in the table below.

Table 7.2: Modelled Results of Possible Divestiture Scenarios – 1,450MW Planned Increase on Franco-Belgian Interconnector

Electrabel players	Scenario			
	1b	2b	3b	4b
Assumed no. of players	5	6	7	8
CR4 Ratio	96	89	82	75
HHI Index	5,824	2,999	2,088	1,621
Avg strategic prices €/MWh	€68	€41	€36	€35
Avg. Marginal cost bids	€29	€29	€29	€29
Price-Cost Margin (PCM)	57%	29%	19%	17%

Source: London Economics

The results evident from introducing the increase in capacity into the modelling are very interesting. Firstly, the results indicate that prices in Belgium are potentially very sensitive to increases in capacity. Even the price with no break-up falls from €83/MWh to €68/MWh. This is for two reasons. Mainly, it is due to the fact that the supply curve is initially rather flat, due to

[244] These include things such as minimum degree of contract cover, and maximum withdrawal of 20%.

[245] This means spreading fixed costs over the lifetime of the plant – effectively through an amortisation.

[246] 1,087 MW was the estimated average available commercial capacity. To arrive at this figure, we took the 1,450MW planned increased capacity (winter peak) (source: Elia press release). This was then multiplied by the annual average available commercial capacity (1,500MW), divided by the total current peak capacity (2000MW).

large amounts of nuclear capacity, but also because the supply curve becomes steeper due to peaking oil and other units, so staying away from the steep peaking parts of the curve can keep demand down on very inexpensive capacity. The impact on the 2-, 3-, and 4-player scenarios is still significant, but smaller than the 1-player scenario. This is because competitive pressures prevent players from bidding up too much at the outset, and so the impact of the additional capacity is muted.

There are two other interesting results that should be highlighted. Firstly, with the additional capacity coming through from the interconnector, the 2-player break-up average strategic price is now down to €41/MWh. The latter is still a fairly high margin, at 29%, but is now comparable to the current situation modelled with 3 Electrabel players, where the price was €42/MWh and margins were 26%.[247] The second interesting result is that there is little difference now between the 3- and 4-player scenarios, with the former indicating an average price of €36/MWh and the latter €35/MWh. It is also important to note that this level[248] of prices is in line with what we consider to be close to the long-run marginal cost of generation, as per our entry pricing model results. It is, however, still difficult to say what price-cost margins are 'justified' by the economic fundamentals. For example, Bernstein and Bushnell (2000) estimated that average price-cost margins in the California PX were 17% in 1998, while Mansur (2003) estimated that price-cost margins in the PJM-Interconnection were 12.5%. In the case of California, a 17% price-cost margin level was considered to be evidence of market power, though the market was nonetheless seen to be fairly well functioning (two years later, when surging demand, drought, nuclear outages, and soaring temperatures came together in a perfect storm, matters were different, of course). PJM is still considered a model of a well functioning electricity generation market (although local retail competition in Pennsylvania went less well).

It is of course important to realise that the modelling results are dependent on a wide range of assumptions. An important part of modelling is therefore to test which assumptions are the more sensitive ones, and therefore we conducted a number of sensitivity analyses. The results of what we believed to be the most important sensitivities are found in the table overleaf.

[247] It is assumed that the power coming in over the interconnector is significantly cheaper than the average price, thus, the competitive prices are slightly lower too in the planned FR-BE interconnector increase scenario. In addition, a difference of €42/MWh to €41/MWh is probably not significant.

[248] Please note that the level of prices predicted by the model must be interpreted with much more caution than the relative prices. In other words, we feel that much stronger conclusions can be made regarding the relative price impacts between models than can be made about the price levels themselves. This is because the latter represents a ceteris paribus change.

Table 7.3: Sensitivity of Modelling Results – 1,450MW Planned Increase on Franco-Belgian Interconnector Divestment 2-4 Players Scenarios

Sensitivity/Scenario	Prices in €/MWh	2b	3b	4b
Without contract cover	Avg. strategic prices	€43	€37	€36
	PCM	33%	22%	19%
FR-BE Interconnector strategic	Avg. strategic prices	€45	€40	€39
	PCM	36%	28%	26%
10% increase in max. withdrawal	Avg. strategic prices	€50	€41	€40
	PCM	42%	29%	28%
Demand elasticity zero	Avg. strategic prices	€85	€61	€53
	PCM	66%	52%	45%

Source: London Economics

In the sensitivity analysis, we focus on the parameters or assumptions of the model that will most likely be impacted by regulatory policy. One of the particular assumptions was that a minimum amount of contract cover[249] would be put into place[250] for the strategic Electrabel generators. This was held at 50% for all cases. Interestingly, reducing the amount of contract cover only has a marginally positive impact on prices. Thus, we conclude that, while the amount of contract cover may be important, the model predicts that other factors are more important in keeping prices down.

The next sensitivity was to allow the Franco-Belgian interconnector to behave strategically. In essence, previously the interconnector was assumed to be one player, but it was also assumed that this player always behaved competitively. The impact of allowing the interconnector to be strategic is significant, but small. Prices rise only to €45/MWh in the 2-player case and €39/MWh in the 4-player case. Again, strategic use of the interconnector might play a bigger role in other scenarios, but in this case, it is evidently not a substantial factor at the margin.

[249] Essentially, when a contract for differences is put into place, the incumbent has no incentive to bid strategically in the spot market, because the prices he will ultimately receive are completely hedged for the contracted capacity. Therefore, as the degree of contract cover increases, short-run market power is reduced. Of course, long-run market power might increase as capacity is increasingly contracted out forward.

[250] This could be the result of pre-contracting on a private commercial basis, or it could be the result of regulatory intervention, where the regulator requires the incumbent to sign contracts for differences with suppliers or other large purchasers.

It should also be noted that this case assumes that the interconnector is just another strategic player. Obviously, if one of the Electrabel incumbent players were able to strategically withhold capacity on the interconnector, then this could have a much bigger impact on prices. The same would be true if ALL players were assumed to be strategic, as the total amount of withdrawal possible could increase substantially.

The next sensitivity focused on increasing the maximum withdrawal[251] of any of the Electrabel strategic players. The results indicate that this has a much bigger impact on prices than the previous two sensitivity tests. The 2-player-Electrabel case now predicts a price of €50/MWh. However, now the 3- and 4-player-Electrabel cases are somewhat higher (between €1-5 relative to the other cases). Thus, clearly the extent of competitive pressure increases with the greater number of players, all else equal. What is more interesting is that the extent of competitive pressure is significantly increased between the assumed break-up of Electrabel into 2-players and the break-up assuming 3 players.

The final sensitivity we studied was the impact of changes in demand elasticity. The previous scenarios were all run with the assumption that demand elasticity is set equal to –0.1[252], which is a fairly low number (i.e. not elastic). An issue with short-run supply-demand conditions in electricity markets is that demand elasticity may be zero or close to zero as supply runs very tight, or in systems that do not allow for demand-side participation.

From the sensitivity results, it is clear that demand elasticity is the most important and most sensitive parameter. Small changes in demand elasticity have very big impacts on the price of electricity in Belgium according to our model. While zero elasticity is the polar case, zero elasticity will certainly be closer to the truth at certain hours of the day. The highest price for the zero elasticity case is €85/MWh, and the lowest is €53/MWh. While the €83/MWh is obviously unacceptably high, the €53/MWh is in line with current *retail* industrial prices in Belgium (based on data from Eurostat), and a *wholesale* price of this size would be seen to be quite high. Nonetheless, €53/MWh is probably at the low end of the range of prices where entry would be expected in the absence of barriers, when one recalls that our entry analysis for generation showed the high-end range of new entry prices with uncertainty factored in to be around €52.72/MWh.

[251] We assumed a base case where strategic players could withdraw a maximum of 20% of capacity at any one time. It is noteworthy that market power in power markets can be modelled as pricing power, where quantity becomes endogenous, or as capacity withholding, where price becomes endogenous. Since supply and demand balance is so important in electricity, it is more common to model market power via a quantity withholding strategy.

[252] This is consistent with international long-run estimates, and some short-run estimates. Greene and Newbery (1993), for example, used -0.2 as the elasticity for their original study of the England & Wales pool. In Belgium, in spite of not having any market system for demand side participation, the interconnectors above all will provide a degree of demand elasticity, as is evidenced by the fact that in certain hours Belgium is a net exporter and others a net importer of power with Holland.

Conclusions from the CustomBid modelling

The conclusions from our modelling follow from the analyses presented above. First, Electrabel has substantial market power in its current position. Regardless of the degree of contract cover or market power monitoring undertaken, high price level outcomes are likely. It is also important to note that, in the absence of a standard Pool or other trading market, these high price outcomes might manifest themselves in other markets, or only in submarkets (i.e. prices to certain classes of consumer might be high).

The second important conclusion from our modelling analyses is that the large, planned new increase in interconnection is expected to have a big impact on Belgian prices and competitive pressures (provided pro-competitive structures are put into place). With the new interconnector, it is conceivable that competition would occur with Electrabel's generation capacity broken into 2-3 players, while robust competition could be expected with 4 players.

The final conclusion concerns the sensitivity of the modelling results. It is seen that the results are extremely sensitive to the input assumptions for the 2b case (with Electrabel split into two), and only somewhat sensitive for the 3b case, while, in general, the 4b case is likely to ensure that reasonable competition is possible. Finally, in all cases, the most important parameter is the demand elasticity. Demand elasticity will be increased by certain forms of market design, increased competition in the supply and trading markets, and increased interconnection capacity.

7.4.2 Remedy: vastly increased Virtual Power Plant

Virtual Power Plant (VPP) capacity auctions are an alternative to full divestiture. In theory, the VPP could be effectively equivalent in terms of its potential impact on horizontal market concentration in generation. That is to say, that short of second order details (discussed later) on contract design, a market designer should consider VPP to be potentially interchangeable with divestiture in terms of its horizontal concentration impacts. This is because the incentives of the owner of VPP should be the same as those of an owner of a plant, at least in terms of selling power. The VPP contract owner has an effective call option on power, with a fuel indexed strike price.

It is well known that a flexible[253] plant such as a CCGT can be regarded as a series of real call-options on the spread between power and gas prices.[254]

[253] While electricity price volatility is well documented, there are ways by which this price risk can be managed. The plant, when sufficiently flexible, can start and stop virtually within 15 minutes for some CCGT (or ramp up and down – i.e., part loading). The plant thus does not run when prices are low, but can shut down, and only run when prices are high. Thus the value of the plant as a whole is increased in expectation. The cashflow of each hour of operation is thus a call option on the price of electricity, with electricity being the underlying asset. The strike price of this real option is the price of gas, adjusted for thermal efficiency of the plant. So in each hour the plant has the right but not the obligation to either use the gas, obtain the electricity price less the gas price, or save the gas. This is a so-called 'spark spread' option. If the gas price were fixed by an indexation formula for a contract

Thus, in theory, the cashflows from the VPP should be closely matched to the cashflows from plant ownership, so the competitive impacts should be similar.

VPPs as a remedy to reduce market dominance

As we have noted previously, VPPs are option contracts replicating the outputs of power plants. A VPP contract is an option to buy electricity at pre-determined prices expressed in €/MWh ("Energy Price"). VPP contracts can be for baseload or peakload electricity. The main difference between the VPP base-load and the VPP peak-load products is this Energy Price. The single variable to be determined in the auction is the price to be paid for holding the right to a particular amount of virtual capacity, expressed in €/MW/month ("Capacity Price").

Successful buyers have the right to submit requests for electricity to be delivered (or nominations). A nomination is a schedule of nominated energy volumes for each product to be delivered in each quarter of an hour of the delivery day, which has to be submitted the previous day. Nominations can be any MW value up to the maximum corresponding to the capacity bought at auction. The product sold at a VPP auction is thus different from comparable OTC products in that the daily nomination profile is not pre-determined for the VPP products. This makes, to some extent, the VPP product more attractive than the more commonly traded OTC products.

We briefly describe below the current VPP system.[255] Delivery of power is on the Belgian high voltage grid. In order to take delivery of electricity, buyers need to obtain various authorisations and set up required contractual arrangements, including an Access Responsible Party ("ARP") contract with Elia or appoint a third party as their ARP provider. The duration of the virtual power contracts is between 3 months and 3 years, and auctions will, in principle[256], take place until 2008. While there is nothing in particular about the above VPP structure that is in theory objectionable, in practice, it should be noted, however, that short duration virtual power plant contracts have typically less effect on market power than longer-term contracts or complete divestments.

similar to the VPP, then, ignoring maintenance etc, one would be indifferent between owning the plant and owning a VPP contract.

[254] See, for example, Swinand, G., and C. Rufin (2004, forthcoming).

[255] In this section we describe the current VPP system. The major barriers to a fully successful VPP system are outside the VPP. These include, for example, the absence of a clear and transparent reference price, the limited number of suppliers, etc. That being said a few of the modalities of the current VPP system could be improved and we discuss these later in the section.

[256] This will depend, among other things, on whether new entry into generation, or other generating capacity releases by Electrabel, take place between now and 2008.

In this type of auction, it is expected that different bidders will exhibit different preferences across different durations. The seller, however, will not typically possess a reliable method for predicting the demands for the various durations other than through the auction itself. By contrast, the seller is likely to have excellent information about its own willingness to substitute quantities among durations, as a function of price. The seller thus submits an indifference curve connecting the products in each group. This curve expresses the price differentials among the various products within a group that would make the seller indifferent between selling one product or another. As a result, the prices of the various products within a group are linked together and increase in lockstep. (However, the prices associated with different product groups move independently of one another.)

The results for the VPP auctions already completed in Belgium show until recently a lack of take up for longer term products, particularly for the peakload. This may be due to the fact that Electrabel's view of the value of longer-term products is higher than the view of the market. As a result, given the submitted 'indifference curves', bidders were relatively more attracted to the shorter duration products.

The economics of auctioning virtual capacity

Selling capacity is different from selling output. In abstract, selling capacity is theoretically similar to divestment of capacity or a sale of plant. There are, however, a number of ways in which the two are different.

The VPP auction results in a contract to provide the services of generating capacity at a specified price. It thus transfers the beneficial economic interest in a virtual plant from the owner to the contract holder. The operator is then incentivised to pursue efficient operation. This sale, however, is not actually attached to a particular plant or plants. The seller has the choice of which of its plants to use to meet the associated energy commitments.

The latter point above forms the basis of one of the criticisms of VPP auctions, namely that neither market structure nor the scope for market manipulation are significantly changed by this type of remedy. The divestment of generation has the greatest potential to reduce or eliminate the incentive for strategic operation of one plant for the benefit of others. Both methods should, however, require that a significant fraction of the incumbent's total capacity be sold.

The VPP is an auction of capacity, not an auction of electricity. If it were an electricity forward sale, then a firm would face a firm price for energy, and would not be able to 'choose' delivery; they would have to take energy at the given price. The market mechanism is designed so that individual players determine how much virtual capacity is worth to them. The price of the electricity is pre-determined outside the auction mechanism. In other words,

the auction does not give the market guidance as to the equilibrium price of electricity.[257] In principle, it is does not reduce prices *per se*.

It is important to be attentive to the mechanism used to determine the price of electricity associated with a given VPP auction, in particular, whether or not the seller has scope to manipulate this price in its favour. The incentive to manipulate this price may, however, not be as great it would first appear. The higher the 'attached' electricity price, the lower the value that bidders will put on the virtual capacity being sold. In principle these two effects could cancel out. What additional revenue that Electrabel would receive through generating the electricity would be offset by lower prices for this capacity. This may not be the case where the reserve price for capacity (also determined by Electrabel) becomes a binding constraint. In that case, the outcome of the auction could be that a significant part of the capacity put up for auction is not sold. The results of the auctions so far, however, would counter this view, as sales have been quite close to total amounts being made available.

In the Belgian market, Electrabel represents both a very large share of the market's capacity and of its production. Electrabel has huge market power both in terms of capacity and in terms of production. This is a distinction that is generally not made in other markets, but it is interesting in this context. In electricity, capacity can more directly contribute to market power than is the case in other markets because the ability to serve the market when others cannot can translate into large rents.

The value of the auctioned capacity for buyers relates the price they expect to be able to sell this electricity.[258] However, both electricity and capacity are worth less for buyers at the auction than they are for the seller who has a dominant market position. The sale of capacity lowers the seller's ability to manipulate prices in the electricity market. When the seller tries to take advantage of its market power to raise electricity prices, this will benefit those that purchase the virtual capacity at the auction because they will also sell at the higher price. In fact, if the auctioned capacity is sufficiently large, the seller will not be able to sustain such high prices because of the presence of such new sellers who are in a position to undercut it. The way in which the seller is able to raise prices is through reducing production of electricity: when there are other players who can offer additional electricity, the potential for this price-raising strategy to work is reduced.

[257] This is not to say that the price setting mechanism is efficient, especially given Electrabel's market power.

[258] This is specifically the case for traders but may be somewhat different for final users participating in the auction. Final users are willing to pay what they expect to save on the difference between the pre-determined electricity price for auctioned capacity and the price of electricity in the regular market or purchased directly from the producer.

In the remainder of this section we report on some of the views that have been expressed by interested parties and industry experts, and we conclude with a discussion and our final comments.

Views of participants

Bidders contacted by PwC subsequent to the auctions expressed the view that the latter had been run "in an efficient, economically reasonable, non-discriminatory and transparent manner." However, there were a number of problems identified by some of the participants, the most significant of which were as follows:

- The durations of the products do not correspond to periods for which cross-border interconnection capacity can be bought. Thus, buyers with no electricity needs in Belgium run the risk of being exposed to an illiquid Belgian market;
- Excessive burden of documentation needed to be submitted to be accepted as auction participant;
- The lack of interest for the longer term products may have been caused by a combination of factors, namely:
    a. Valuation distortion of the indifference curve;
    b. Uncertainty about future demand in the Belgian market;
    c. Uncertainty about export capacity fees at the Dutch and the French borders;
    d. Uncertainty about exposure to CO_2 emission liabilities; and

Other views included suggestions to publish information, such as available and used capacity.

Views in the literature

It is instructive to illustrate some of the diverging views surrounding capacity auctioning. We summarise below one view mostly in favour and one mostly against.

Commenting on the virtual capacity auctions in the French electricity sector, Newbery (2004) states:

> "There are a number of perceived benefits to the sale of virtual capacity. As it is not tied to any particular plant, it can be sold in amounts which are unconstrained by plant configuration. Thus, more new entrants can be brought in. Difficult issues that might be associated with a transfer of an interest in any of the plant, especially remembering that EDF's portfolio includes substantial nuclear capacity, are also avoided.
>
> The contract form is largely familiar to many traders and certain of the initial purchasers did in fact sell on the capacity. The term of the products on offer was intended to reflect the expected term of contracts the purchasers would offer their customers. There were suggestions that many

> of the purchasers only took part to see how the process worked. While there clearly were some in that category, the continued participation of a considerable number of bidders would seem to contradict that. The on-line auction also seems to have operated smoothly despite a degree of complexity. It is difficult to see how the prices that it delivered can be anything other than market reflective.
>
> (…) virtual capacity (…) is certainly a way of opening up a market which can be implemented quickly and bring in a large number of new entrants on a trial basis." [259]

The International Federation of Industrial Energy Consumers (2001) [260] notes that theoretically, under market conditions where competition is clearly established among a sufficient number of actors so as to render the market dynamic and fluid and where no one network user dominates the market, an auctioning scheme might be able to function properly. However, in reality such a situation will clearly not exist for a long time to come in most of the markets where such solutions are being contemplated. The fundamental problem with these auctions is that they are open to manipulation by the dominant market players. The IFIEC Europe believes that any capacity auction system could be subject to abuse by dominant utilities who are, in many cases, owners of public grids and dispose of substantial financial resources in order to influence auction bids and prices.

We believe that are valid reasons on both sides of the debate, as we discuss in our conclusions at the end of this discussion on VPPs. However, it is also important not to look at VPPs in isolation but as one of the several alternative remedies that can be used to deal with situations of excessive market power in electricity markets. It may be particularly interesting to compare VPPs with divestment as a more definitive attempt to counter market dominance. We look at this comparison below.

Virtual capacity auctioning versus divestment

VPPs are used as a means to increase liquidity in the market and facilitate the entry of new players in markets that are very concentrated. The auctioning of virtual power plants differs from divestiture in a number of significant ways. In particular, it is targeted on outputs; it is temporary (often even very short term) since it regulates, for a temporary period of time, a part of the dominant player's generation in quantity and in price; and it entails no sale of assets of the dominant player.

Although divestment may appear a more fundamental solution to apply in a highly concentrated market, there may be practical reasons for resorting to divestiture in all cases. Indeed, the design and transactions costs associated with divestments may be very high in some instances, especially where assets

[259] Newbery, D. (2004).

[260] IFIEC (2001).

are common, complementary and intangible. If, in such circumstances, divestiture remedies are too hastily designed, numerous problems are likely to occur during or after implementation. There is a trade-off between design costs and enforcement costs on the one hand, and effectiveness on the other. As a consequence, if insufficient time is allowed in the structuring and design of divestitures, it may be less costly and more effective to utilise easier-to-design regulatory instruments.

The above arguments, however, appear weak in the particular circumstances of the electricity market generally and the Belgian electricity market in particular. For a market characterised by dominant generator with ownership of a large number of plants, divestment of a fraction of these plants would not appear to pose insurmountable issues of asset complementarity or intangibility. While there are portfolio issues that need to be taken into account (because particular combinations of types of generating plants are can be complements in production), these may be overcome with appropriate choice of divesting assets.

Discussion

We view VPP auctions as a mechanism offering significant potential for correction of market dominance. However, we see a number of potential and actual problems associated with their practical implementation and we discuss these further below.

On the plus side, we note that the VPP approach has a number of benefits compared to the divestiture option, including in particular:

- Relative simplicity;
- Greater scope for design and speedier implementation; and
- The absence of a requirement for complex studies of market functioning in advance of implementation.

Table 7.4 represents the scenarios studied previously. It shows the associated capacity divestments, and instead assumes they are VPP increases. It therefore calculates the % increase in VPP required to achieve the same level of market concentration as the associated divestiture.

Theoretically, VPP should be a close substitute to divestment as it releases capacity under the control of the dominant market player, which is then made available for purchase by other market participants. In addition, unlike many traded 'base-load' and 'peak-load' products, the schedule of deliveries for VPP products is decided by the purchaser (one day ahead on a quarter-hourly basis) and is not pre-determined. The combination of complementary products (baseload capacity contracts and peakload capacity contracts) offered in the Belgian VPPs should contribute to making the auction more

attractive to purchasers, as they can then best meet the needs of customers with a particular combination of baseload and peakload capacity.[261]

There are, however, a number of caveats to be noted with respect to VPP auctions in general and the form they have taken in Belgium. A general problem is that the seller is left with significant scope for market manipulation: with the seller aware exactly of what virtual power it has sold, it also knows exactly the production constraints faced by its new competitors. If the seller detects a gap in some of the products sold, it will be able to raise prices for that segment. Another problem is that the constraining effect of competition may be very small if the quantity of VPP sold at auction is small. If a firm with 90% of the capacity of the market is forced to sell 5% or even 10% of this in auction, the remaining capacity under its control remains much more substantial than that of all its competitors.

A further problem, noted earlier, is that short-duration VPP contracts typically have less impact on market power than longer-term contracts. If the result of the majority of auctions is that Electrabel generally sells shorter duration contracts, then there will be relatively less overall commitment of capacity. It is, of course, possible that Electrabel may also recognise this outcome and, through a strategic design of 'indifference curves', attempts to lead bidders towards the shorter-term products so that the impact of the VPP auctions on its market power is minimised.

In this respect, Electrabel claims that longer-term products have a higher 'option value[262]', which, according to their calculations corresponds to [confidential].[263] In general, a longer-term contract would attract a higher premium, and part of this would be due to option value. This is ostensibly due to an option generally increasing in value with time to maturity. [confidential]. We have not calculated the option value, as reliable price-series of the underlying asset would be difficult to obtain. In any case, it appears that participants in the auction did not place a high value on this optionality (in other words, Electrabel is setting the price where the market might), which may explain the low rate of take-up of the longer duration products.

This discussion raises a number of questions that may be worth further investigation. Is it possible that the 'option value' referred to above is actually higher for Electrabel than for all other market participants? Or, might it be that Electrabel is manipulating the indifference curves to reduce

[261] This, however, has probably not been considered as such by bidders. According to the confidential results reported by PwC, only a minority of bidders chose to buy both baseload and peakload products.

[262] The option value comes from the fact that the contract is flexible. If prices are low, a contract owner can choose to do nothing, and limit losses. If the price is high, he/she chooses to strike the contract (purchase energy) and sells it on at a high price.

[263] This information is according to the confidential PwC report on the 2nd Electrabel VPP Auction, April 2004.

the attractiveness of longer-term products? Are there other reasons why market participants were less keen on buying these products (for example, because they represent an excessive financial commitment that they may have trouble passing on to users in a relatively illiquid market)? In relation to the latter issue, bidders interviewed by PwC after the 2nd auction expressed [confidential] as reasons that may have contributed to the relatively low attractiveness of longer duration products.

A further issue concerns the 40% limit on VPP purchase by any single purchaser. We believe that this limit may not be the most effective approach to increasing competition in the electricity market. When one player is very large, competition may be better served by allowing one or more other players to become large as well. Otherwise, the dominant player is unlikely to feel threatened.

Some users also complained of an excessive documentation burden in order to qualify as a participant in VPP auctions. Furthermore, since delivery is on the Belgian high-voltage grid, in order to take delivery of electricity, purchasers must obtain various authorisations and set up required contractual arrangements, including an Access Responsibility Party ('ARP') contract with Elia, or to appoint a third party as their ARP provider.

VPP and modelling results

Given our view that, at least from the perspective of competition theory, VPP offers a potential substitute for divestiture, it is important to relate the VPP option to the modelling results presented earlier. These modelling results indicated that planned increases in the Franco-Belgian interconnector could have significant impacts on competitive pressures in Belgium. In the table, overleaf we present details of the approximate[264] divestiture and VPP quantities based on Scenarios 1b-4b from the previous modelling results.

Table 7.4: Modelling of Required VPP Capacity Sales Corresponding to Divestiture

Scenario	Installed Capacity per Player	Total Capacity Divested	Implied % Increase on Current Sales
1b	12,676	0	N/a
2b	6,338	6,338	428%

[264] These quantities are approximated since the modelling is not undertaken in terms of installed capacity, but in terms of available 'despatchable' capacity. There is also a discreteness or lumpiness problem in relation to the sale of plant, a problem which is solved in the VPP; i.e. VPP can be divided up as finely as 1MW or smaller, whereas plants come in big chunks.

Table 7.4: Modelling of Required VPP Capacity Sales Corresponding to Divestiture

Scenario	Installed Capacity per Player	Total Capacity Divested	Implied % Increase on Current Sales
1b	12,676	0	N/a
3b	4,225	8,451	604%
4b	3,169	9,507	692%

Source: London Economics

It is clear that, in order to approach the borderline case under Scenario 2b, the level of capacity divested via the VPP would have to be increased from 1,200 MW to 6,338 MW, i.e. a 428% increase on the current sales. The implied increases on current sales required to arrive at 3 players (of equal size) would be 604%, while the 4-player case would require a 692% increase on current sales. What is perhaps interesting from the analysis is that the level of increased VPP required to move from the 2-player case to the 3-player case is much smaller than the initial amount. This would suggest that the additional difficulty of going from a 2b to a 3b scenario would be less than the initial difficulty.

It is also noteworthy to recall that the modelling results presented represent a particular case where Electrabel's capacity is divided equally among equal sized players. There is the possibility to create more numerous smaller players as well. Given the current levels of competition, a greater number of players would generally indicate more competition, even if this would mean leaving the incumbent as a bigger player than the new entrants.[265]

Weighing VPP versus divestiture

While in theory, at least in terms of capacity and concentrations achievable, VPP can be viewed as being interchangeable with divestiture, there are a number of reasons why the two approaches differ. Firstly, VPP does not correspond to a particular plant. This feature enables Electrabel to limit the risks from outages, as well as manage fuel mix to manage risk. The VPP owner will have more limited scope for managing fuel risks because they will most likely not own gas storage or will not have their own gas contracts, for example. In addition and by contrast with Electrabel, VPP owners will not have the portfolio options required to shift the generation mix according changing fuel prices. The ability to store fuel or shift the fuel mix will create an operational capability for risk management that is not available to VPP

[265] We did not include this as a scenario in the modelling. Naturally, there are numerous combinations of small players that would have various levels of competition. This is because the modelling is showing the various impacts of different levels of divestiture. The scenarios run, we are confident, sufficiently showed the incremental impacts.

owners. They will also not internalise the risk of outages. Thus, Electrabel retains all the benefits of a portfolio of generation assets, and is in a position to utilise this portfolio in anyway they like, while the VPP contract owner does not own a portfolio.

There are also a number of pros and cons in relation to competition impacts associated with VPP vis-à-vis the divestiture option. One obvious benefit of the VPP approach concerns the practical difficulties associated with physical as opposed to financial asset sales; the latter are in general simpler and less costly. One of the most important benefits of VPP expansion is perhaps that the VPP can be designed with more continuous increments than is the case for divestiture. Generation capacity itself must occur in significant 'chunks', corresponding to plant sizes; VPP capacity, by contrast, may be sold in much smaller increments.

One of the more notable aspects of the VPP option vis-à-vis divestiture is that it provides more flexibility. An issue put forward in EU policy-making circles is the idea that once the single electricity market becomes a reality, competition analysis will no longer be undertaken on the basis of national markets.[266] The VPP expansion option could be seen to allow for a certain degree of 'reversibility', should the competitive landscape change dramatically over the next 3-5 years.

Suggested approaches to improving VPP

There were a number of suggestions that emerged from London Economics' consultations on potential approaches to improving the VPP. The majority of suppliers and traders consulted were in agreement that the VPP was probably the best and most immediate way to increase of the extent of commodity available in the market and that it was a step in the right direction. However, it was noted that VPP does nothing to change market fundamentals. The scarcity of commodity at wholesale level was cited by suppliers and traders as one of their greatest difficulties. They were unanimous in stating that increasing the VPP by a multiple of around 3 would be of significant and immediate benefit (given that around 4000MW of additional supply was required). They also suggested:

- The starting prices for the auction were too high; the starting price should be relative to the expected marginal cost of energy; if this expected can be estimated then the starting prices should be set accordingly.
- Insufficient peak capacity was auctioned; this is fairly easily remedied through the addition of more peak capacity.

[266] While we agree with this in general, the real questions that remain surround the speed at which the single market will be realised. We discuss this in more detail in Chapter 5.

- Information requests and bank guarantees required for participation were either burdensome or redundant;
- Contract timing specifics (energy nominations) were not coordinated with interconnection capacity contracts; and
- Because of the difficulty with hedging fuel prices, that a portion of VPP could include a fuel price hedge, as well as a fixed energy price, or alternatively to have a 'spark spread' contract under the VPP.

With the exception of the last point, most of these points are easily remedied, will relatively little downside, e.g., bank guarantees. The reasonableness of guarantees should be straightforward as they should be proportional to the amount of capacity taken times its price. In addition, benchmarking against other forward markets should be straightforward.

Our understanding is that the VPP provides a contract to purchase energy from Electrabel at a fixed price, along with a fuel indexation. This essentially mimics the cashflows from ownership of generation assets, since the owner faces volatile fuel prices and then sells into the volatile wholesale market. Since some traders might not be willing to take on such risks, one alternative would be to fix fuel prices in some (though not all) of the VPP contracts.

Another alternative would be to allow both fuel and energy prices to change, but then to fix the spread between the two (adjusted for a standard thermal energy conversion). We believe this is an innovative approach, i.e., indexing to the spread rather than just the fuel price, would merit further investigation. Some potential concerns with this approach could include that it may place undue risk on Electrabel, as it would then be managing the fuel price risks of 'spark spread' VPP contract holders. It might also be difficult to price such contracts in the current state of the market[267], and so bidding or use of the contracts might be limited; hedging services might alternatively be value-added services that might be provided by traders.

In conclusion the implementation of the above recommendations along with others, such as the vertical integration recommendations, should be sufficient to reduce the market power of Electrabel. The VPP remedy is more difficult in some ways in that it leaves open things such as the possibility of informational sharing etc between Electrabel generation and other parts of the business. It has some benefits such as the ability to allow smaller investments for potential entrants. For these and other reasons, the VPP is difficult, but manageable in our opinion. With all the discussion of detail, it is important to recall that the major focus though should be the resulting market shares.

[267] The valuation and pricing of 'spark-spread' options via standard techniques depends on the availability of clear market price signals, liquid trading that allows the hedging of positions, and the potential realisation of no-arbitrage pricing.

7.4.3 Remedy: alternatives to divestiture and VPP

Apart from divestiture and VPP, there are potential alternative approaches to accomplishing an effective reduction in market concentration. We discuss these options below.

Under one scenario, Electrabel could be required to sell power purchase agreements (PPAs), contracts-for-differences (Cfds[268]), or to rent[269] out at cost, for a period of say, 5 to 10 years, a certain proportion of its generation portfolio. In all cases, the short-run incentives for Electrabel to increase price are eliminated by locking in a contract price for energy (or contractually transferring control of the plant in the leasing option), for whatever the time period. There are also other alternatives that have been suggested in the academic literature. For example, Chao and Wilson (1999) suggest the use of option contracts for the mitigation of market power. Under such contracts, the upside of potentially high prices is converted to an upfront premium, which is a function of price expectations. All of these mechanisms are essentially ways of striking long-run contracts for power with Electrabel. Thus, generators would have no incentive to raise prices in the short run, once they possessed such options. Through such a mechanism, a potential entrant could gain access to a balanced mix of generation capacity and credibly compete against Electrabel with a reliable and comprehensive alternative source of electricity for end-users, traders and suppliers by being able to provide base, peak and balance power.

The power purchase agreement (PPA) option has been considered and implemented in other jurisdictions, including Alberta.[270] Vesting contracts, essentially PPAs (and/or Cfds), have also been used as market power mitigation mechanisms in England and Wales, Scotland, Northern Ireland, and the Republic of Ireland. The option contracts were used to a limited extent in the England and Wales Pool, where they were called one-way contracts for differences (while what were effectively swaps or forward

[268] Cfds are contracts for differences. There are one-way and two-way Cfds. Cfds are essentially medium to long-term swap (two-way) and option (one-way) arrangements (usually, as was the case in the UK) on the pool price. They are effectively hedging instruments, but can have the effect of mitigating short-term market power because they remove the incentive for an individual generator to increase prices, since the price the generator will receive is fixed by the contract. The difference between a Cfd and a PPA is that the cashflows of the PPA are generally matched to the life of the plant, whereas the Cfd can be for block amounts, and usually much shorter time periods. A PPA thus is close to a "contractual" ownership of the variable cashflows of the plant. Whereas a Cfd is akin to selling forward, say, 100MWhs, for every hour over the life of the contract.

[269] These options for remedy - PPA, Cfd, or rental - are very similar in terms of their potential impact on the market, and so we discuss them simultaneously using the PPA example. Most of the differences between a PPA and a rental agreement, if energy prices are fixed in the agreement, would be legal, and specific to the precise construction and wording of the contracts. In other words, economically speaking, it need not make a difference whether the plant is essentially legally 'rented' or 'contractually' rented via a PPA, if energy prices are fixed by contract. We are not aware of the details of power plant rentals in general, but could provide CREG with some (made anonymous) copies of PPAs if they desire.

[270] See, for example, London Economics (1998).

bundles were termed two-way contracts for differences.) The ability of the PPA remedy to mitigate short-run market power (an issue we discuss further later) is perhaps one of its more interesting features.

The difference between the VPP and PPA remedies is that the PPA is a contract that is matched specifically to a power plant.[271] A PPA is in effect a bundle of forward energy and capacity contracts, generally for the life of the plant (e.g. 15-20 years for thermal plant). The objective of most PPAs is in fact to match financial cashflows of the contract as closely as possible to the cashflows from physical ownership of the plants, but also to completely hedge energy price risk.[272] Thus, the PPA option hedges energy price risk, whereas the VPP option does not. The PPA hedges energy price risk because PPAs typically specify the price of energy and the quantity. The plant has thus effectively sold forward all, or all but a small slice, of its potential output. The PPA can also be indexed to fuel prices, eliminating fuel price risk for the contract owner.

There are, therefore, a number of benefits associated with the PPA remedy vis-à-vis divestiture or (expanded) VPP. The PPA remedy is more flexible and probably less costly than full divestiture. More importantly, however, the PPA measure is likely to mitigate market power in the short run. This feature can be understood by noting that the price received by the asset owner is fixed by the PPA or Cfd. The PPA remedy will also provide effective risk management for potential buyers/suppliers.[273] Finally, relative to the VPP, the PPA option will provide a longer-term, and thus greater, risk reduction for a potential buyer, and thus give the latter a greater ability to leverage these acquisitions and plan investments in other areas such as supply and trading. Finally, PPA designs have been tested such that incentives can be included to increase productivity and reliability. This was the case in the UK at the time of the original break-up of the CEGB.[274]

There are a number of drawbacks to the PPA option. For one, the PPA option might reduce the need to trade 'spot' in the commodity - although this can be remedied with (among alternatives) a mandatory pool.[275] For example, if

[271] The PPA contract will generally contain clauses for dealing with availability, forced outages etc., including possible liquidated damages if the plant owner is unable achieve minimum availability rates, for example.

[272] Originally, PPAs were developed to allow off-balance sheet financing of merchant or independent power producers (IPP). Merchant banks often required recourse to a PPA, as security in the case of financing that did not have recourse to an IPP developer's equity assets.

[273] The PPA fixes the energy price, so the prices are hedged on both sides of the contract.

[274] Although, we suspect a large portion of the productivity gains related to the routing out of inefficiencies due to 'public ownership', rather than to 'gold-plating' or the X-inefficiency generally associated with monopoly power.

[275] Alberta, for example, covered its generators with PPAs in lieu of divestiture, but still operated a mandatory pool. There may still be sufficient energy at the margin to allow the pool price to be an effective indicator of the marginal value of energy on the system for the particular (1/2) hour.

plant owner A's energy is contracted forward, they can simply schedule the energy and have no need to trade spot. If there is a mandatory pool, though, they might still be required to bid in the energy at a price. In addition, the full power plant PPA option could suffer from almost the same degree of 'discreteness' as full generation divestiture - that is to say, because generators represent discrete 'blocks' of capacity, there may be difficulties with divesting such large hunks. On the other hand, less standard PPAs or other contracts such as Cfds, can be designed to allow them to be divided up more finely. The simplification of PPA auctioning versus divestiture, might also be small, since PPA design will require detailed contractual arrangements for outages and availability, etc. (although, since this has been undertaken previously, it is presumed that the template may be replicated).

The most important drawback to the PPA or Cfd remedy option is that it is likely to entail a trade-off between short-run versus long-run market power. While the contracts put in place will mitigate the incentive for the firms (owning a long position in the contracts) to raise the price in the short run, the PPA option will run the risk of effectively 'locking in' today's energy prices for (say) 10-15 years.[276] The result is that any *benefits* from liberalisation, if not forecasted in the initial PPA, will not be realised on the generation front. Typically, the price of energy in the contract is regulated or negotiated, and indexed. But, even if this price is regulated, there is the general regulatory problem of forecasting the value of a commodity. The incumbent has better information than the regulator, and will behave in his self-interest. ([confidential]). Therefore, the current market power of the incumbent generator will most likely come to bear on what price is negotiated—thus long-run market power is substituted for potential short-run market power (although short-run market power in electricity markets can be severe). This was the experience in Scotland and Northern Ireland (NI)[277], where for example, the Director General of Ofreg, the NI regulator, eventually brought legal action to the Mergers and Monopolies Commission ("MMC"), effectively suing to renegotiate the high-priced PPAs (about £42/MWh or €65/MWh for energy) put in place for NI after liberalisation. Another example of where PPAs failed is California. There, after rejecting PPAs early in the process (because they were perceived to deliver prices that were too high) the State rushed to sign PPAs (as a non-market solution to the energy crisis and obvious problems with short-run market power). The State Government, being slow to react at first, did this on the tail end of the crises, but when commodity prices were still at their peak. In addition to short run market power, part of the crises was due to dry winters in the mountains, hot summers, and nuclear outages – all transient events; but events that likely influenced forecasts of the future value of power. Thus, the State managed to

[276] The price is fixed for both sides usually for the life of the contract, so if prices fall, consumers or suppliers on the long side of the contract will be buying at above market prices.

[277] It was the general consensus that NI and Scotland were too small to have markets similar to the England and Wales Pool, while there was insufficient interconnection to include them in the Pool.

lock in its consumers to prices that were historically high by any standard and likely well above the long-run marginal cost of power.

An additional drawback to either the PPA or the VPP, or any contractual divestiture offer should also be noted, namely that in any case where Electrabel maintains ownership of the plants, they will have control over the plant in terms of outages, maintenance, maximum capacity[278] and other operational decisions, as well as information about these. While incentive schemes for plant availability can be put in place, Electrabel will still retain control. In addition, knowledge of the generation, output, outages, etc, will remain with Electrabel. If a player possesses a VPP contract for peaking capacity, Electrabel will know exactly when, and for how much, that player uses energy, what the price of that energy was, what the fuel cost was, for how long it was used, etc. This could prove to be valuable information to Electrabel Generation, as well as say, Electrabel trading or supply subsidiaries. With such knowledge, they would know exactly the cost of energy of their competitors.[279] They will know the exact values of key strategic variables of competitors of ECS.

When suppliers enter into negotiations with customers, they will be aware of this. Note also that this would enable Electrabel to 'just undercut' offers by VPP holders, whereas, if they did not know the exact costs of competitors, they would have to adjust their bids for that uncertainty. If plants were sold, the heat rate of the plant, and thus its marginal cost would be known by Electrabel only as an estimate.[280] In addition, they would have to make price offers ('strike contracts') such that they had a reasonable expectation of winning the business. As a final note, it is useful to recall the nature of the contract option vis-à-vis the divestiture option or greenfield investment. In the case of a new investment, the new entrant has to undertake all the operational know-how, expense and risk of the plant. The PPA or contractual owner does not. In either case, though, the holder of the long side of the contract (right to purchase) will typically have a minimum off-take, and so it is not obvious that the PPA price will set the whole energy price.

[278] The absolute capacity and/or thermal efficiency of the plant, although rated at (say) 400MW, will in fact be endogenous to decisions such as maintenance, etc. For example, while the maximum capacity might be just slightly degraded over years, this may be corrected through a major overhaul. Thus, the plant owner makes a decision about the trade-off between investment (maintenance) and additional capacity. In the aggregate, the more a given player can co-ordinate such activities, the more that player has an opportunity to manipulate prices. It should also be noted that the 'detectibility' of such a strategy will be almost zero, as a market monitoring committee will have great difficulty questioning such decisions.

[279] We note that there are confidentiality requirements in Belgium. It is difficult to assess the strength of these.

[280] Heat rates will degrade over time. They can be improved with maintenance, overhauls, re-engineering, etc. In addition, options such as the ability to use different fuels or fuels with different grades or heat contents will also be possible. Finally, the exact price at which the firm buys fuel will not be known to Electrabel (under the divestiture option). All of these factors will combine

7.4.4 Remedy: Require Electrabel to sell sites suitable for greenfield capacity (CCGT or CHP)

Anecdotal information provided to the consultancy team suggests that there is a lack of available sites suitable for new gas-fired or CHP generation, and that Electrabel owns a number of suitable sites but does not use them at the present time. This points to a number of potential remedies that could be envisaged. First, the CREG, with the assistance of the regional planning and environmental authorities, and Elia, could draw up an inventory of sites that could be used for new greenfield operations and new CHPs, and make such information publicly available. Second, Electrabel could be forced to identify all suitable but unused sites that it currently owns and divest itself of a number of such sites at a fair price determined neutrally by an outside party.

We believe this last remedy to be a potentially important one, but for different reasons than the others identified. Of primary importance for the evaluation of this remedy are two factors: (i) supply demand balance forecasts, and (ii) the new entry analysis from the barriers section.

In terms of the supply demand balance (at least over the next few years), Belgium is not expected to face any significant deficiencies in terms of security margins over the next few years. The forecasts show that at some point in time the margin might fall to around 15%; however, it generally averages around 20%. While we have already examined the supply and demand balance[281], the market power of the incumbent will provide a greater incentive for the withholding of power, or potentially give an incentive to keep the system tight.

One potential downside of this option relates to the economic analysis of greenfield entry. In general, current price levels are probably just below the sufficient level, at least to justify greenfield 400MW baseload CCGT entry. Therefore, this remedy would not be expected to have much impact in the short run. On the other hand, our new entry modelling shows that CHP can achieve thermal efficiencies of 85% and could be economic. Therefore, the focus of such an option might be more properly based on CHP. The sites of CHP, as well, might be more likely to be located at alternative industrial sites of industries that already have plant in operation with large heat and power needs.

We consider this option to be important, however, and that it is probably a relatively straightforward possibility for a 'win-win' (i.e. no trade-offs), and therefore believe that the CREG should strongly consider the merits of its implementation.[282] The technical difficulties associated with site divestiture should be low relative to plant divestiture. In spite of the current economics of entry, should the system experience significant upward revisions in

[281] And others, including the CREG, have conducted more detailed studies.

[282] An alternative would be to use this as a bargaining chip in negotiating options with Electrabel.

demand growth rates (and forecasts), power prices might well rise, making entry economical.

This may be particularly important in the future when new capacity needs to be built to replace the phased-out nuclear plants. Under such a scenario, the implementation of site divestiture will be seen to have been quite prescient.

7.4.5 Remedy: increased interconnection capacity and improved capacity allocation mechanisms

Increased interconnection capacity

Interconnection capacity could be one of the quickest ways of introducing competition in generation and supply into the Belgian market. Fundamentally, interconnections can be seen as interchangeable with a generator, in the sense that power can readily and quickly be supplied to the amount of the rated capacity. In fact, interconnection might be preferred to generation in certain respects: interconnection might need less maintenance; it can provide reserves that some plant might not; it does not need to ramp up and ramp down, etc. Interconnector capacity expansion is currently planned. Most important for competition improvements will be the 1,450MW (winter peak) planned increase on the Franco-Belgian interconnectors. According to TenneT's website, no new interconnection on the Dutch-Belgian border is planned in the next five years.

There are a number of very important positive aspects of interconnection capacity expansion. First, it is probably more straightforward than new generation build and likely to be less time consuming. Second, once built, the power available will be flexible, and the allocation is open and available to any potential supplier. Third, interconnectors can be effective for increasing demand elasticity, since, unlike plants, they can either export or import power.

On the other hand, interconnection might be less desirable to generation. The main reason for this is that interconnection could become unavailable at peak times due to congestion or due to failures within the interconnected grid. Congestion on the interconnectors is also difficult to predict, even for the grid operators, and especially for market participants. Demand spikes within the two areas might be highly correlated as well, and so interconnection might be expensive in the hours when it is needed most.

Finally, interconnection can export power as well as import it; this of course is a double-edged sword, as it very well might be that power is exported at peak demand times, merely because people are willing to pay more for it over the border. This will enhance allocative efficiency on the whole, but at the expense of individuals exposed to the locally high(er) prices.

There is, of course, a limit to the extent of capacity increase available through interconnection, and therefore a limited potential resulting impact on competition in the Belgian electricity market.

The benefits of additional interconnection need to be weighed against the costs. For example, even if ten firms were to share equally an additional (say) 2000MW of capacity on the interconnector between France and Belgium, this would reduce the effective HHI to about 5,666. In fact, Electrabel's market share alone would still be over 2/3 - the level for effective monopoly - and would stand at about 75%, even if Electrabel acquired none of this new capacity. Notably, we solved the equation[283] numerically for the value of additional interconnection that would be needed to reduce Electrabel's market share to (a still high) 65% using the data on HHI in the generation chapter. The analysis indicates that, when considering concentration measures *only* (recall that concentration measures can be misleading in electricity), about 3,850 MW[284] of additional interconnection would be required to reduce concentration even to levels that would still be considered dominant (e.g. a 65% market share). It is difficult to estimate the cost of this required additional interconnection. However, a rough estimate is that 25 miles (40km) of 380kv transmission line might cost about €40m. On a proportionate basis, this would indicate a cost of approximately €500m, and this would just be to achieve an Electrabel share of 65%.

Nonetheless, increased interconnection capacity is likely to have important salutary impacts on the supply and trading markets. Further, it is our understanding from Elia that current plans are to double the capacity on the Franco-Belgian border. The impact on Electrabel's market share of a net average available capacity increase of 1,087 MW on the south border would be to reduce it from a current 81% to 75%.

The benefits of additional interconnection also need to be considered in the light of the findings from our research on the EU context and our earlier modelling results. On the one hand, the international results showed that the degree of market competition would always be limited by the interconnectors. With a single dominant player, the market concentration in Belgium will always be high, even if the interconnection was increased to say, 5000MW. This is because both France and Belgium have single dominant players. Overall, no matter what interconnection does, this can only decrease concentration by a limited amount.

The indication is that the additional interconnection capacity with France *could* have very beneficial impacts on Belgian prices. But some divestiture of assets/division of market share is required, as well as a competitive behaviour of users of the interconnector. The benefits of the interconnector also depend on the availability of cheap power from France.[285]

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[283] Using *Goal Seek*, Microsoft Excel's iterative numerical solver.

[284] More formally, we solve the equation for X: 0.65 = (current capacity Electrabel)/(current capacity system + X).

[285] This was done to a partial extent. More specifically, the interconnector flows were put in at €15, 20, 25, 30, and €40/MWh, in 200MW tranches. Thus, when power is expensive in Belgium, more power from France comes in; when the cheap French power is fully used, then more expensive power is required.

Alternative capacity allocation mechanisms

There are two issues that we focus on in relation to capacity allocation mechanisms.[286] First, capacity allocation mechanisms should be designed to promote economic efficiency. This means that a mechanism such as an auction should be implemented. Efficiency requires that those who most highly value the use of the resource will be in a position to utilise this resource with priority. This has been achieved on the border with the Netherlands.

The second issue is that market power-based utilisation of the interconnector will have to be blocked. This means that purchasing capacity for the effective purpose of withholding energy from the market may have to be monitored and curtailed or stopped. The way of ensuring against this in the Franco-Belgian interconnectors is to implement 'use-it-or-lose-it' clauses in the use of interconnectors. Alternatively, players could trade unused interconnection nomination. We would strongly suggest an auction allocation mechanism similar to the one applied on the Belgian-Dutch border.

We believe that the current arrangements give no clear indicator of the value of interconnection, the possibility of purchasing capacity, or the likelihood of congestion. There also needs to be enough time, between when a capacity rights 'requestor' receives an allocation and energy must be scheduled, allowed for the original capacity rights owners' capacity allocation to be reallocated to an alternative player, who could then make use of this power. While we discuss in more detail the potential for market power interactions between Electrabel and EdF elsewhere in this chapter (and in Chapter 5), we emphasise that merely having capacity available on the interconnector does not ensure that it will be used competitively. The results here and elsewhere suggest that the impact of the interconnector on competition in the Belgian market is likely to be sensitive to this issue, while also suggesting that there would be a high degree of concentration in an integrated Franco-Belgian market.

Other design issues have also been identified above, and although likely to be of second order in importance, we believe that these nonetheless should be implemented, once issues such as precise timing of gate closures and nomination processes for a potential spot market are addressed.

These issues include important details, such as allowing the timing of nominations for the spot market and the interconnectors to be harmonised. No doubt, this would also have to be harmonised *across* grids, as Dutch participants are suggesting harmonisation of interconnection timing with the APX. We believe that coordination with the APX and with PowerNext would

These prices are in the reasonable range for nuclear generation, hydro, CHP, and CCGT, which are all baseload plant in general.

[286] Of course, there a many issues that need to be addressed in fully designing a capacity allocation mechanism and auctions.

therefore constitute a potentially effective option in general, while also offering a potential win-win remedy.

Conclusions regarding increased interconnection

A number of important conclusions are worth noting in relation to the interconnection option. First, interconnection has many desirable properties and is probably the fastest and most economical way to introduce more competition into the Belgian electricity market. The additional planned capacity on the Franco-Belgian border, under the conditions of properly functioning markets (i.e. reduced market power for Electrabel, no strategic power in the use of the interconnector, proper market power monitoring, fully functioning trading arrangements, etc), has significant potential to reduce prices in Belgium. Whether additional interconnection is economical and feasible is another issue. An additional important issue concerns whether if additional interconnection with France is put in place, EdF will start to potentially have significant market power in the Franco-Belgian electricity market.

7.4.6 Remedy: re-regulation of Electrabel as a utility

An alternative to the break-up of Electrabel's generation activities into a number of independent companies would be to vest all of Electrabel's generation activities into a separate company owned by Electrabel, and then require this company to sell all its output at cost to end-users and suppliers at a regulated price.

There are a number of negative aspects to this option, and we consider this only a last resort. The most important weakness associated with this potential option is that it suffers from all the standard drawbacks to regulation, including, in particular, the principal-agent problem[287] and the Averch-Johnson[288] effect (the tendency to 'goldplate'). The incumbent has better knowledge of its costs, and can essentially extract monopoly profits from customers in a variety of ways. In addition, the CREG would have to implement difficult and lengthy cost determination processes to determine allowed levels of cost. There is the distinct likelihood that prices would not come down as much as they could.

On a more positive side, the 'threat' of price regulation could be an effective tool for the CREG. For example, Ofgem (previously OFFER) regulated local supply costs well after liberalisation. In addition, telecoms regulators throughout Europe have often imposed conditions that price regulation on

[287]. Averch, H., Johnson, L.L. (1962). This is the general problem of where the firm to be regulated, the agent, possesses better information (about cost) than the principle (regulator). The regulator may not be able to offer a contract to supply the service and still minimize costs.

[288] This is the general effect that firms, when facing rate of return regulation, have an incentive to employ more than the optimal amount of capital; this is often commonly referred to as 'gold-plating'.

incumbents will only be lifted once certain targets for entry have been achieved.

7.4.7 Remedy: Institute market power mitigation committee

So far in this sub-section, we have focused on the market power of Electrabel alone, and Electrabel's dominant position. It is important to realise, however, that once the issue of Electrabel's dominant position is solved, and a more detailed market design is put in place, the problem of market power in electricity generation may still not be solved in its entirety. Market power will become more difficult to exercise, as it will take at least tacit co-ordination by the remaining players—but it may still exist and be exercised. Therefore, the institution of a market power monitoring committee is likely to become more imperative. The relevance of such a committee will also become more important as an integral part of other arrangements, such as a power exchange. We have no doubt that CREG is aware of such issues, but we discuss them for emphasis. We discuss later, in the chapter on the methodology for the ongoing indicators to monitor competition, the details of the areas that such committees might monitor.

A particular related point that should be noted is to emphasise that the results from the CustomBid modelling included limits on the amount of strategic behaviour that was allowed, either by Electrabel or any one player. This is quite a reasonable assumption, but it will require that significant market power monitoring be put into place. Significant market power monitoring should include a number of features, namely:

- The market power monitoring committee could be overall operated by the (eventual) power exchange, (a separated) Elia, the CREG, or jointly among these groups, and include other independent stakeholders[289];
- Probably at least 3 highly qualified CREG staff (trained in game theory, economics, finance, numerical/statistical techniques, and competition policy);
- Outside CREG industry stakeholder participants, consultants, (independent from those with market power);
- The power to requisition data, maintenance plans, question participants on outages, etc.
- Firms with significant market power would be excluded.

[289] The inclusion of independent stakeholders is for a number of reasons. One they will be needed to buy into the process. In addition, they likely have expertise or knowledge that will be difficult for the CREG to develop in-house. Finally, it would not be typical or advisable to have firms with significant market power to hold positions on such a committee.

In addition, the market power monitoring committee should have significant powers[290] beyond the informational and other resources identified above. Above all, a committee should have to have powers in relation to prices. This can, and should, take place on both a micro (hourly prices) and macro level (i.e. price caps). For example, market power monitoring committees often have the power to actually change prices *ex post* for settlement purposes for a limited time after market close, if they consider undue market manipulation to have existed. The New York Independent System Operator (NYISO) exercised such powers early on during its lifetime pre-2000. NYISO also publish price and bid (price, quantity pairs) data, anonymously, after a lag.[291]

There are other possible additions to market power monitoring that should be considered as likely. For example, the staff would likely need to interact with despatch (Elia), and have knowledge of control room despatch procedures etc. If Elia were a separate entity from Electrabel, Elia would be a stakeholder to include as they will have detailed knowledge of the power system, for example, when constraints or actions were necessary or at least consistent with grid security, etc. (An additional reason for further separation of Elia.)

We believe that a monitoring committee should also have some specific powers of coercion, which would include fines or legal action for cases of non-compliance. The fines and/or other penalties must be set in proportion to the costs/prices involved. For example, it is well known[292] that prices in competitive markets can spike for real scarcity reasons. The committee should also have the power to institute rules changes with regard to the market and the prevention of the exercise of market power.

There are some other suggested remedies for the proper functioning of a market power monitoring committee (we discuss some additional potential remedies in the section on 'Methodology for the Ongoing Monitoring of Markets'). For example, Newbery (2001b) suggests that certain forms of market conduct could be established as *prima facie* forms of the exercise of market power. This would shift the legal burden of proof from the committee. A similar option could be to establish *per se* illegal activities. The precise legal means to establish such rules needs to be furthered if these remedies are deemed potentially interesting, but, at least according the early 20th Century US Antitrust jurisprudence, *per se illegal* activities cannot be justified via a rule of reason.

[290] More general regulatory powers are discussed in a subsequent subsection of this chapter.

[291] As best we know (2001) ISO-NE, has similar powers, PJM (Pennsylvania), did not have bid-modification powers at the time, but was considering them. The Mid-west ISO (Indiana) is currently recruiting for its market power monitoring analysis team. Ofgem's powers come from the statute and the license condition.

[292] Stoft (2002).

7.4.8 Remedy: Encourage competition from autonomous/green producers

One of the few areas where there is potential for more entry (and where there has been entry in the recent past) is in relation to auto, anonymous and green producers. These include producers who are either CHP, small-medium scale green producers, distributed generation, etc. Our evidence from the entry trigger price modelling suggests that CHP is the only place[293] where the fundamentals support the case for new entry. From the evidence, it appears that a large number of these companies have links with Electrabel. This is likely for a number of reasons, including the need for technical expertise, Electrabel is likely to provide these entities certain power management services, etc. Electrabel is also probably the only company in a position to offer these companies certain financial services, such as risk management, etc. Of course, if the supply and trading markets were functioning properly, there would be competition to Electrabel for these services, but in their absence, it is Electrabel who is virtually the sole supplier. In fact, it appears that even big and technically advanced companies need Electrabel to provide such services, as evidenced by the BASF CHP plant built by RWE with Electrabel at BASF's Antwerp site.[294]

The question follows as to how to encourage competition from these producers. While obviously a functioning power exchange would be helpful, other medium term options could also be considered, as many of these players may still not be willing or able to trade on their own account on such an exchange; many are already tied to Electrabel; or, in the meantime, Electrabel may be signing more contracts with new CHP entrants.

One option would be to place a moratorium on Electrabel contracts which effectively tie-up these producers to sell directly to Electrabel. An alternative might be to provide a more general contractual framework, where companies (i.e. potential competitors with Electrabel) would bid for the right to provide the services to the CHP producers. Another option that should be considered simultaneously would be to require Electrabel to divest itself of a certain number of these contracts or relationships. This later option is likely to be more effective in promoting competition. However, it is probably not feasible until supply and trading markets are more fully functional, as there might not exist competitors capable of providing services without the ability to trade,

[293] We haven't fully studied green power sources such as wind power. Wind power's economic fundamentals will depend crucially on a number of factors, above all, the price of carbon in the EU Emissions trading scheme. Wind power's economics also, however, depend on things like whether wind is charged for increased spinning reserve needed beyond certain wind penetration thresholds. Assessments of these factors are beyond the scope of this report.

[294] It of course is possible that the likes of RWE do not 'need' Electrabel to undertake CHP, but they evidently had some commercial reason for doing so. There are also allegations from stakeholder sources that Electrabel's price-bidding to sign up deals with CHP providers immediately in advance of liberalisation/separation from Elia were either predatory or at least consistent with limit pricing.

hedge risk, self-balance part of energy/supply needs, buy emergency power, find customers, etc.

7.4.9 Remedy: Consideration of more limited price caps and pre-conditions for their lifting

While we have previously suggested one option for the market power mitigation of Electrabel's current position to include re-regulation of Electrabel as a utility, there is a subset of alternative possibilities that might be considered as more light-handed approaches, in terms of introducing more limited or more specific price controls. We believe that this type of remedy should potentially apply to all of the markets involved.

There are a number of potential price caps that CREG should consider. Firstly, it is very common internationally to set a price cap on a day-ahead and/or real time market, especially if these take design forms involving system marginal clearing prices. The most common approach is for this to be set under normal circumstances according to an estimate of the value of lost load. It is also common internationally for these prices to be adjustable downward, usually upon decision of the market power monitoring committee, should an 'abnormal situation' be determined to exist. This might, for example, result from the forced outage of a large nuclear plant that results in a tightening of the system.

However, there are risks involved with the placing of such price caps. Above all, there is the risk that a price cap during a time of scarcity could exacerbate this scarcity. This, of course, was well documented in California where PX price caps caused power to depart the system, only to be brought back in via the CAISO balancing market (albeit, at much higher prices). The fundamental problem was scarcity throughout the Pacific Northwest, and wholesale prices on the NYMEX for front end (soon to mature next month futures) contracts were actually substantially higher in Oregon, at around €120/MWh, while CA NYMEX prices were around €90/MWh. At the same time, the CAISO was, during some hours, paying up to $1000/MWh, or even announcing that they would pay any price for power.

We do not take an ideological view, but simply note that we believe that price caps can be useful in times of extraordinary circumstances, but that it must be kept in mind that such price caps will necessarily limit players' willingness to invest in infrastructure such as peaking units in the long run. Therefore, if price caps are being hit repeatedly in the short run of (say) a one day-ahead PX-type market, and should Belgium implement this approach, it should be considered subsequently whether, over the medium and longer term, other mechanisms are warranted, such as capacity payments for peaking units or units in general.

A particular question we have been asked to address is whether there is any recommended response by CREG to a 'limit pricing' strategy, i.e. maintaining prices sufficiently low to prevent entry and to generate extra-normal profits.

We consider that the benefits of regulatory intervention in this instance are likely to outweigh the costs. Knowing the exact limit price will be extremely difficult, as can be observed in relation to the uncertainty evident in the modelling of new entry, presented earlier. The current market price may be just above the true limit price, in which case any attempts to lower the limit price would inefficiently preclude entry, while attempts to raise the price would inefficiently result in charging the consumers of wholesale power more than would be gained through new entry that might come on stream. Alternatives, including a windfall profits tax on Electrabel, might be considered, but these would not normally be the remit of the CREG.

7.5 Issue 3: Absence of liquid and transparent wholesale market

The third issue that we examine concerns the absence of a liquid and transparent wholesale electricity market in Belgium. The fundamental issue in this case is not the absence of a Belgian power exchange, but that price transparency and trading liquidity are seen to be elusive. In other words, it is at least possible to have a liquid market without a power exchange.[295] Conversely, it is possible to have a power exchange with efficient trading but which has no impact on market power and limited impact on liquidity and transparency. Liquidity and transparency, of course, go hand in hand: one feature cannot be attained in the absence of the other.

We believe that the key issue in this case is not simply a question of "what market design should Belgium have?" although this is of course an important issue. It is also important to separate the differences between the debate on "what kind of exchange to have" (which is mostly a market design issue) and the approach to encouraging transparent trading. There are a number of options in relation to the latter, including mandatory trading within a pool, which, given the current level of dominance, would *par force* inject some liquidity and transparency into the market. However, for now, market design is not the primary focus.

It is also important to note that the creation of an exchange or other trading platform is perhaps a necessary but not a sufficient condition for the proper functioning of the market. We note that the CalPX and Alberta PX, and the original design of the E&W Pool, did little to mitigate market power problems in these areas. They nonetheless had well functioning exchanges, in the sense that trading was open, clear, and for-the-most-part liquid.[296]

[295] The US had a fairly liquid OTC trading that dwarfed futures trading activity, like NYMEX, years in advance of 2000, when most major restructuring efforts had reached full initial operation.

[296] Liquidity in electricity exchanges is generally lower than in other commodities, where traded volumes exceed the physical volumes by multiples exceeding 10 in some cases.

This is can be illustrated through consideration of the international experience in electricity liberalisation. Consider, for example, the case of the establishment of a power exchange. Much has been written on this area and, in particular, the potential applicability of this approach in the Belgian context. Internationally, California, Alberta, the original England and Wales Pool, and other countries, all had power exchanges. In addition, California had (reasonably) liquid futures trading in 2 futures contracts on the NYMEX. However, California and Alberta experienced catastrophe and major problems respectively, while market power was a major problem in the original Pool. Retrospectively, it has emerged that market power exacerbated existing problems in California and Alberta.

7.5.1 Remedy: creation of a Belgian Power Exchange[297]

An extensive range of literature has been produced in relation to the potential creation of a Belgian Power Exchange. Some of this research has been produced by participants with particular vested interests (APX, for example, would no doubt like to have Belgium power traded on their platform). This has led to some interesting claims, such as the forecasted 'reduced price volatility' of an all-Benelux market.[298]

In general, we believe that there are merits in the power exchange option, which has a significant probability of being achieved. A power exchange would be likely to assist in promoting price transparency in the market, increasing available energy to potential suppliers, and increasing liquidity in trading. It would also form an integral part of market integration. The more interesting questions surround the extent of linkages with neighbouring markets and the type of design that would work best.

An important issue concerns the degree of integration. There would clearly be scale economies and benefits to liquidity associated with linking with the APX or PowerNext. Moreover, Belgium is not a small market, having almost 14,000MW peak demand, and successful power exchanges have been established in smaller markets, such as Alberta, NSW and New Zealand, so linkage is not an absolute necessity.

The regulatory conditions required for a power exchange have been studied in a report commissioned by the CREG.[299] While it is important to note that competition can be achieved without a standard-style exchange, the exchange route is one of the clearest paths to achieving minimum levels of transparency and liquidity.

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[297] The details involving a Power Exchange and market design are outside the scope of this report..

[298] In fact, price volatility of the sum of the two markets will depend on the covariance of demand and the particular shapes of the supply and demand curves.

[299] See CREG (2004), "Mesures régulatrices nécessaires pour la création d'une bourse belge d'électricité", Brussel, avril.

It is also of note that concerns such as market power can be addressed via the exchange. For example, some independent system operators (ISOs) in the US (where the ISOs often run the markets), began trading with cost-based bids that were not changeable month-to-month. Once there was consensus competition was ready, participants were allowed to bid their price to supply.

7.5.2 Remedy: require Elia/Electrabel to publish system shadow price data

The development of a power exchange or other trading platforms, as well as the necessary liquidity involved, would take some time. In the shorter run, and since the stated problem is a lack of price transparency, one potential remedy could be to require Elia to publish system[300] marginal cost data. The marginal cost is essentially the shadow price[301] of Elia's optimal system despatch programme. Using the appropriate duality theorems, the system marginal cost is known to be equivalent to the perfectly competitive market-clearing price. The concept of system shadow price is an engineering concept and is based on Elia's despatch algorithm.[302] Elia would possess such data for every hourly or half-hourly despatch, as, without this, it would not know how to despatch the system efficiently. Utilities in the USA and Canada have, for many years, published such data prior to deregulation. In the long run, we believe that this approach should be abandoned, however, as the publication of competitive bids to supply could facilitate collusion.[303]

Furthermore, the requirement for publishing system shadow price data can be seen as technically equivalent to other market liquidity remedies, such as a mandatory pool with mandatory marginal cost bids for the dominant incumbent. In other words, the system least-cost despatch shadow price is equivalent to the market outcome where all players are required to bid and there is no market power (or the players with market power are required to bid at marginal cost).

Under the current regime, it is not clear how Elia despatches the system. We assume that essentially many plants simply self-despatch to satisfy contracts

[300] It is important not to confuse system marginal cost data, which is the shadow price of meeting demand with the capacity-constrained generation resources available, with Elia's marginal cost of operation. The former is required by Elia to efficiently despatch the system, both in an hours-ahead scheduling and real-time sense; the later is the cost for Elia of performing its operations. When Elia's regulated tariffs are 'geared to cost', it is the average cost of operating Elia as grid operator to which these data refer.

[301] A single shadow price will exist when there is no congestion on the system. When congestion exists, there will be potentially two shadow prices for each congested line, and more complicated shadow prices can exist.

[302] This is generally a security constrained (approximated) linear programme when ignoring grid constraints and dynamics of start-up and stops. The general despatch problem is actually nonlinear.

[303] Another option to mitigate potential collusion would be to publish bids anonymously and with a time lag. This is done in the US ISOs such as ISO New York (NYISO) and ISO New England (ISONE).

between Electrabel's generators and ECS customers. We do not know how Elia calls on specific plants to provide balancing energy. Most probably, though, this is based on standard system engineering concepts which are based on marginal cost security constrained despatch—i.e., Elia must have the shadow price and quantity data.

Another issue of concern has been Elia's efficiency and incentives to despatch the system efficiently. Very generally, this is potentially one of the areas where competition is supposed to intervene. Pre-competition regimes essentially did not incentivize efficiency. The system despatch was (is) an engineering problem. Now it can be hypothesised that even the regulated monopolist will have incentives to minimise costs, but there are well-known problems with this in terms of despatch. For example, the system costs can be charged to others or externalities can exist (e.g., who is constrained-off first in the case of congestion?).

7.5.3 Remedy: institute interim trading rules

Another potential remedy to addressing the absence of a liquid and transparent wholesale market could be to implement an interim trading rules structure while the details of a full trading market, power exchange, etc, are being worked out. In Belgium's case, this might prove useful, especially in the light of how difficulties in generation are spilling over into other markets.

Interim trading rules need not be overly complex and have been applied successfully in countries such as Singapore and the Republic of Ireland. The general principle behind this approach is to start the incumbent trading, at least between its own vertically owned subsidiaries, and at real and observable marginal cost pricing. On this basis, the market can obtain one, two, or possibly three years of data on marginal costs in the industry, while access to commodity by third parties can be obtained via the wholesale market. The suggested market design is often a mandatory Pool, with the incumbent then required to bid at marginal cost. The regulator can implement a fuel-price indexed formula for marginal cost for each generator. If this is not an option, there may also be other possibilities, including price caps, vesting contracts (vesting contracts are contracts that cover (dictate price, quantity, availability, etc[304]) the output of the plant during some interim period, such as the period of transition between the old regime and competition), etc.

[304] For example, the NSW Treasury report on electricity competition states, "In the transitional phase, vesting contracts will be used for risk management. Retailers must use this period to become familiar with operating in a market environment, which includes the need to develop customer awareness. There must be sufficient time for systems development. Metering, communications and data processing systems will have to be upgraded, expanded or installed. These considerations will determine both the choice of initial entry threshold and the rate at which the market develops."

7.5.4 Remedy: further integration with neighbouring countries

A further potential remedy is to bring about further integration with neighbouring countries. However, in this case, it is important to understand the distinction between a number of different concepts. These concepts can be categorised into linking markets and market coupling. One involves the general principle of linking or combining markets; the second represents a choice between market design options.

Linkages across power exchanges

There has been an extensive literature in relation to combining the Belgian market with either the APX or possibly the French PowerNext. Since market coupling is the perceived way forward as espoused by the APX, it has received a lot of attention as a potential remedy in addressing existing market deficiencies. In fact, the main remedy entails linking Belgium with the APX—market coupling is merely a specific design mechanism by which these linkages would operate. We nonetheless support the idea of market coupling, but believe that this approach would not, of itself, constitute the required remedy. By comparison, a linking of the Belgium with the Dutch system could prove more effective. This would be achieved through harmonisation of regulation, transport tariffs, timing issues such as gate closures for day-ahead trading and interconnection capacity allocation, and the combination and harmonisation of pricing and bidding markets.

The potential benefits from harmonisation of markets are substantial. Once markets are operational, if their timing is not harmonised, then players with contracts or open positions, order etc, in one market, would not always be in a position to arbitrage between the two markets. To understand this aspect it is useful to consider a hypothetical example. Consider the case where one possesses a contract to buy 1MW in APX (a long forward position). Perhaps one's client is based in Belgium, so the purchase relates to capacity rights on the interconnector in the Belgian direction. Now on the day, one sees offers to buy power at a higher price in APX, while simultaneously the newly established BPX price is lower. Under correct timing, it would be possible to resell as a spot the power contracted forward in the Netherlands, and buy spot in Belgium to satisfy the contractual obligation to the client in Belgium. One will also want to make sure that one has not nominated the power flows on the Interconnector, and one's capacity-rights call option, if not traded, can expire unused. If the differentials are large, then considerable efficiency will be gained, and also traders will be attracted by the differentials, and provide liquidity. It should be clear that if the hypothetical BPX is not synchronised with the APX, this might break down. Further, if one had to nominate one's power to flow over the interconnector sufficiently far in advance of the other two markets, then one wouldn't be able to act on such a strategy either.

There are a number of potential benefits from a market integration of this type, which include, in particular, the following:

- Integration reduces market power in the more concentrated market (although it may increase concentration in the previously relatively low concentration market); and
- It will be easier and more attractive to enter the market, given the existence of a bigger potential market.

Development of Benelux market

The potential liquidity benefits arising from an all-Benelux market are clear, notably in the sense that trading overall would be increased between the three countries. We have commented significantly on the benefits of integration. However, one point we wish to restate is that the potential to import cheaper power from France, especially given that the additional interconnection is planned, is more likely to have a benign impact on competition in the supply market. Again, this would, however, be dependent on the avoidance of exercise of market power by EdF/Electrabel, efficient allocation of the interconnector capacity, and the absence of congestion on the interconnector, among other factors.

Market coupling/splitting

Market coupling describes the method of integrating powergrids as implemented in NordPool and proposed by the APX. In essence, it involves a single price absent of constraints, and allows price differences to prevail across constraints. The alternative is a 're-despatch' system, whereby grid security/constraints are handled by adding and subtracting online generators.[305]

This approach could have definite advantages for groups of countries occupying relatively small geographical areas, as is the case in the Benelux. In general, market coupling will have benefits vis-à-vis alternative market integration mechanisms including:

- Efficiency in the use of interconnection capacity will be maximised; and
- The eventual spot market will be more liquid.

Other notable issues arise in the consideration of enhanced interconnections and the results from our modelling exercise. While there might be a preference to integrate Belgium increasingly with the Dutch market, the modelling points particularly to the potential for increased interconnection with France. This is because France has excess capacity and cheap power. If French power is expected to have a big impact on generation, then one of the

[305] There are of course many flavours of this. The original E&W Pool had a system of redespatch and "uplift". California implemented a system of zonal prices, whereas Pennsylvania-NJ-Maryland (PJM) implemented a complete nodal pricing system, which allows prices to differ at each injection or off-take point on the grid.

requirements for this to become evident is some degree of demand side elasticity, in addition to participation and competition in supply and trading, at least to a greater extent than currently. It is likely that coordination would be necessary with the French infrastructure, namely the PowerNext market, timing, nominations, procedures, etc. This would suggest that integrating the Belgian market with the French market would be likely to be more effective than attempting to integrate with the Dutch system. Additional integration with the French, however, will raise market power concerns, since EdF is itself a large player and it would have significant market power in the integrated market (as would Electrabel, though EdF would be even larger).

7.5.5 Remedy: additional recommendations for liquidity in wholesale and other derivative markets

We noted earlier that liquidity is one of the key features of a well functioning trading market. However, while liquidity is much coveted, it is not something that can be legislated for or implemented readily via regulatory policy (although there may be means to address this issue and the example of the mandatory day-ahead pool, where liquidity is (partially) mandated is relevant in this instance). Commodities exchanges internationally are continuously launching new contracts and occasionally retiring contracts for which liquidity has suddenly dried up. We discuss below a number of general recommendations for improving the liquidity position in the Belgian markets.

Transparency

Price transparency is probably the most important element of liquidity. We understand that there is next to zero price transparency in the Belgian market at present. Maximising price transparency requires a number of factors, which are outlined below:

- Firstly, there must be a reliable reference price, which is truly representative of the marginal value of the resource on the system (a system clearing price is one option—we also discussed previously that the current BPI would not be effective in this sense (see Chapter 3, heading Electrabel's Belgian Power Index (BPI) and other prices page 82);
- Secondly, there must be immediate and public dissemination of all relevant price information as this becomes available. Above all, this should include settlement prices. The information should also include volumes, open positions, bid-ask spreads, daily (or half daily) high and low bids, etc. The information should exclude any data that would facilitate identifying a trader, and thus allow potential tacit collusive strategies. Any time lag will potentially give insiders an upper hand in trading on information that is not publicly available;

- Thirdly, the timing of the market outcomes should be brought in line with the timing of market relevant information. Again, if information becomes available, but traders cannot trade on this immediately, traders will shrink from the market, because they may get stuck in positions[306] or may not have ready means to price the uncertainty such time lags create in their portfolios;
- Between the exchange, Elia and the CREG, information should be provided in a timely fashion on the physical production of the market that is of general use to all participants. This should include all planned outages and maintenance, demand forecasts, total available capacity, forced outages, required and available spinning reserves, etc. Until a proper market is functioning, additional information such as plant marginal cost and capacity data and contract cover should also be made available. (It should, however, be noted that once some competition is introduced, this data could facilitate tacit collusion).

Market power

We note again that market power in generation markets will impact negatively on liquidity in trading markets. Any measures to reduce market power would therefore be positive for liquidity. We have commented extensively on market power previously, and the CREG's (2004) report on the regulatory conditions for establishing a Belgian power exchange also discusses the impact of market power. The CREG report notes, for example, that only after strict market power measures were put in place did liquid electricity trading in the UK take off. Most observers, however, agree that the main factors leading to the reduction in market power in the UK were structural, i.e. a greater number of market players and less concentrated markets.

Numbers of participants and extent of trading activity

Another important issue concerns the number of actors or participants in the wholesale market, as well as other related markets (such as balancing energy markets). Firstly, we observe that the number of participants is too small, and the quantities demanded (or that might be demanded) are also quite small. Even with added numbers (there are probably a sufficient number of ARPs, but they do not trade very actively), current trading levels[307] are not sufficient for liquid trading. This points to a number of issues. For one, it is not just the

[306] Traders may be holding open positions in contracts that are long or short. Often pricing formulae for the valuation of options or other derivative contracts requires near continuous trading and/or the continuous rebalancing of positions.

[307] Participants at the round table discussions indicated that trading was not very active. For example, no summary data of trades is available. Platts also collates survey-based data, but notes that trading is not liquid.

requirement *to trade* that will enhance liquidity but also the requirement for *'immediacy',* i.e. the need to trade on very short notice.

While the immediate provision of market information, and the synchronisation of this with market timing, represents one piece in this puzzle, there are additional requirements. Firstly, immediacy will require those parties who 'demand' immediacy, and are willing to pay for it (often in terms of spreads, or fees). In turn, there will have to be suppliers of immediacy.

The recommendation follows that measures should be considered that facilitate additional participants in the markets (wholesale and balancing energy). One possibility could entail a separate party, who is not an ARP, entering the balancing market and starting to match buy and sell orders to effectively allow parties to anonymously self balance on the whole. Another option could be to further liberalise participation in wholesale and balancing markets. While this may be premature at present, once more formal market structures are in place we believe that these options should be considered. Studies have shown (for example, Saravia (2003)), that the initial ban on speculator participation in day-ahead and other forward markets in the NYISO system was inefficient, and that subsequent liberalisation and the entry of speculative traders increased liquidity, drove down market power, and reduced forward/spot risk premiums.

7.6 Issue 4: High balancing costs and risks

The fourth issue that we examine concerns the presence in the Belgian market of very high balancing costs and associated risks. Virtually every participant interviewed, consulted, or present at the roundtables expressed concern that the balancing mechanism is not proportionate to costs and creates excessive risks. We believe that reform of the balancing mechanism constitutes one of the more detailed and important features of potential remedies. In addition, relative to divestitures and large contract auctions, this reform would be straightforward to implement. Another important consideration for balancing market reform is integration with other reforms, such as the development of a power exchange or spot market, and interconnection allocation methods.

We believe that significant reforms to the balancing regime are warranted. The current balancing regime puts smaller generators, pure traders and suppliers at a disadvantage to the larger and more integrated Electrabel. This is because firms without generation will have no choice but to pay the imbalance charge if they are short (or long) of energy. Firms, as was the case with Source Power, could end up paying the balancing price for what is really emergency energy. The imbalance charge is ostensibly intended for small errors in usage predictions between day ahead and real time.

The current balancing regime is unlikely to maximise efficiency (all those who can provide balancing energy/demand response are not able to do so).

Maximising economic efficiency requires that price be set equal to marginal cost. There is little evidence the imbalance charges are set equal to marginal cost, but ample evidence they are not. Marginal cost in balancing, although likely correlated with the APX, is not likely to move one-for-one with the APX. Further, there is no particular reason the APX price is needed, as Elia should be able to estimate marginal system costs. In addition, there is no consideration of when the system is net long or short, and there are no proper links between the interconnection allocations and balancing. Marginal costs typically would be related to the net position of the system, not to any one particular user or generator.

Further, the efficiency of the current balancing mechanism is also likely not optimal because evidence suggests gains from trade cannot be exploited under the current regime. There is little possibility to manage balancing risk, and no current way for customers to trade amongst themselves and net-out imbalances. Thus, if 10 customers are plus 5% and 10 minus 5%, everyone pays, the net effect on the system is zero, and Elia collects from everyone; this cannot be efficient. There is high volatility on the system, and there is no apparent economic justification for the scale of escalation in the balancing formulae. If someone is out of balance more than a certain %, why is the charge multiplied by 175%, why not 120%? For low negative imbalances (as a percentage of the total nomination), where does €75/MWh come from? Is it any relation to cost? Consideration of the economic cost of balancing should be given in the interim, until a market-based balancing regime can be put into place. We also discuss the balancing regime in detail in Chapter 2, pages 49 and 56.

7.6.1 Remedy: implement significant reforms in balancing

Specific proposals for balancing reform can perhaps only be developed once other reforms have been implemented. Nevertheless, we would point to the reforms implemented in the balancing mechanism in England and Wales, which were carried though between the Pool and the introduction of NETA.

Consideration of a mechanism (pricing formula) that reflects two primary goals should be considered. First, the balancing code should be reflective of the marginal cost of energy on the system. Second, the balancing pricing mechanism should be reflective of the marginal value of the TSO's needs to procure more power, or to reduce output. This should be reflective of whether the system is net long or net short. Roundtable participants also noted the efficiency benefits of a dichotomy between actual physical imbalances and artificial, or data error imbalances – where the latter may not impose any real costs on the system.

Detailed consultations on how to reform the balancing mechanism should be carried out. We recommend a system more in the style of NETA, but more simple systems can be imagined. A fundamental function would be for each participant capable of providing balancing services to have standing bids (or

regulated cost estimates) for incremental and decremental balancing energy. Elia could then publish net positions of the system relative to schedules in the run up to real time.

The possibility of trading imbalances should be encouraged. This occurs in Ireland via the IPX, where the only real feature is the ability of market participants to net-off imbalances against each other through trade on the exchange.

A new balancing regime will probably take time to put into place. In the interim (if a more market-based system eventually is adopted), the CREG should consider regulating the balancing charges and prices currently charged by Elia. These are charges set by a monopoly, and so they should be regulated. We believe that CREG's current powers to regulate Elia's charges to reasonableness standard should be sufficient, but if they are not then consideration should be given to how they should be bolstered. We note that a separate Elia could be a more willing participant in the reform process, as evidence from the England and Wales experience and NETA (where balancing charges were brought down over time) suggests.

7.6.2 Remedy: re-regulate balancing power prices

An alternative remedy would be to require Electrabel to sell balancing power to participants at prices set by the CREG. The current system relates balancing power prices to APX prices multiplied by a factor. Another option would be to have a regulated balancing power price. The benefits of this would be that it would limit risk. A downside would be that it could make it possible for generators to profitably be out of balance, if for example, the market value of energy is very high, but the price of balancing is fixed (and lower).

7.6.3 Remedy: encourage mechanisms for trading imbalances, self-balancing, and balancing risk mitigation

Currently, ARPs can trade imbalances between each other on a bilateral basis. The reason why bilateral trading is often inferior to exchange-based or other more organised trading forms is well documented. There are a number of problems with this, including the fact that the lack of anonymity might reduce the willingness to trade.

There are a number of possibilities here. At a basic level, the preferred option would be to implement a market based balancing option, where the cost of balancing is reflective of the marginal cost of additional power needed (or decremented) to balance the system in real time. This will have the benefits of improving efficiency and reducing search costs. Since imbalances are necessarily a very 'close-to-real-time' phenomenon, then it would appear natural that the search costs or feasibility of finding a counter party for trade in imbalanced markets would be very high.

In the absence of such a mechanism in the near term, interim-trading rules could be implemented with administrative (regulated) pricing imposed on Elia. This could work in a similar fashion to the approach of publishing system marginal price on a regulated basis. Elia should be able to estimate the marginal cost of balancing since otherwise it would not be balancing the system optimally (pointing to another potential source of efficiency gain from implementation of a market mechanism). One option might be to implement a mechanism along the lines of France, where participants, especially large users, may bid into a balancing market.

Alternatively, along with other interim trading rules and market designs, other jurisdictions such as the Republic of Ireland have successfully implemented market-based exchanges for balancing power. Here, participants were able to self-balance by exchanging imbalances prior to real time. The exact details and implementation of such a mechanism would have to be worked out with Elia and participants. The important details should mainly focus on timing.

The timing of the market must be sufficiently early for Elia to balance the system, but sufficiently late such that participants can predict their imbalances in the hours ahead. There is also the possibility of learning here. For example, in NETA, the balancing market was seen to be difficult and risky, but the gate closure for nominating a schedule was eventually moved closer to real time (1hr ahead). A full balancing market, *à la* NETA, would probably not be feasible, until a day-ahead market or other forward market designs aspects are fully in place.

7.7 Issue 5: Informational and IT problems between DSOs, TSO, suppliers and customers

Another fundamental issue across all[308] of the markets we have examined has been the lack of information or opacity of information, and IT problems between the DSOs, the TSO, suppliers and customers. This is perhaps most onerous in the supply market. Here, suppliers claim that they do not know what historical customer usage patterns, and they sometimes do not even know what usage has been ex post. Customer data transfer has been difficult and problematic in liberalisations of gas and electric markets throughout Europe.

Alternatively, from the perspective of the DSOs, they claim that these issues are being addressed, and that this is mostly a 'growing pain'. While we see some truth in this observation, there remains the possible existence of a number of problematic concerns, such as the possibility that Electrabel may

[308] Informational remedies in the generation market were discussed previously, such as the importance of potentially providing system marginal cost data. The biggest informational benefits for generators might come from having market price data themselves, and the remedies re a Belgian power exchange are most relevant here. We also discuss further informational requirements in the chapter that follows, "methodology to monitor the status of competition".

possess customer information not available to other players and may use such information to its advantage. In addition, once more vibrant retail competition for smaller customers takes hold, the IT and customer data transfer needs will have to be further integrated and higher levels of functionality achieved in order to handle greater numbers of switchers. Therefore, it is important that some action be taken by the regulators to establish precisely where the line exists between so-called 'growing pains' and 'falling behind' or worse, behaving anti-competitively. We recognise that this is an issue that is primarily of regional competence, but perhaps the CREG working with the regional regulators could take an active facilitator role in addressing these issues.

As already noted earlier in the chapter on barriers to entry, the regional distribution technical codes are very specific about the information DSOs have to provide to suppliers regarding their clients and the timeframe within which this information has to be provided, but do not appear to provide for any penalties in case DSOs do not meet their statutory obligations. There needs to be some form of incentivising the DSOs to perform a task that will use their resources. This could take the form of penalties or rewards.

The other issue is that, at the present time, the distribution technical codes are silent with regards to information that DSOs should provide to suppliers about prospective clients. We recommend some minimum access to usage patterns (3-years, preferably hourly for big customers, daily for other large customers), technical aspects of usage such as power factors[309], and other data such as interuptibility. The information could be made available only to ARP suppliers, and if large users feared giving information that could be used by their competitors, data could be anonymised. Suppliers could potentially approach the anonymous company via a website to initiate discussions.

7.7.1 Remedy: improve definition of roles, responsibilities and data ownership

A potential remedy for addressing the current informational and IT problems regarding the suppliers' existing client base would be to consider setting clear timetables for the implementation of a well-functioning data exchange system and, imposing from a certain date onwards penalties for the non-respect of information exchange obligations set out in the regional distribution technical codes.

Regarding the provision to suppliers of information about prospective clients, and the lack of level playing field between Electrabel and new suppliers, a solution would to be to require making publicly available all or a subset of the information that DSOs have about the electricity users connected to their grid. A serious potential downside to this approach might

[309] It is often the case that suppliers may be able to help a group of firms manage power quality: ratios of real to reactive power, maximum versus minimum demand, etc.

be that customers could perceive this information as confidential. If this were a serious legal obstacle to the release of such data, it would be worthwhile exploring with relevant parties to what extent such information could be anonymised while still providing useful market information to new suppliers.

While these approaches would deal with some of the data issues, a number of other issues would remain. For example, DSOs complained that there were technical problems at the level of data transfer and infometrics between TSO and DSO. For example, some participants cited problems of mismatches between Elia measurements and the measurements of DSOs. They suggested the establishment of a central database to be used by the TSO and the DSOs. The DSOs also complained that making them responsible for imbalances/imbalance charging was unfair, because this then placed all the risk of imbalances on them (or they pass this on to suppliers). This was said to exacerbate the potential for competitive by-pass of the distribution system by large end-users. We believe that these issues need to be addressed urgently to improve the functioning of the Belgian electricity markets. However, they do not appear to raise any barriers to entry in any of the 3 markets of interest and therefore a discussion of potential remedies (for the competitive by-pass) are outside the scope of this report.

7.8 Issue 6: Problems in supply contracts

There were also a number of problems identified concerning contracts and available options. These problems mainly related to contracts between network operators and suppliers and other participants (such as big end-users). Firstly, it was claimed that the risks of contracts between users (suppliers) and the network operators, i.e. balancing and the financial impacts of forced outages (transmission and distribution) were all placed on the suppliers.

Suppliers also claimed that they could not obtain contracts of sufficient duration or correct load shape. This implies either that it is not efficient to fulfil such contracts or that it is a function of Electrabel's existing market power. We suspect that the market power issue is important and have already discussed this in detail. The efficiency reasons (that such contracts would or would not be available) are very hard to evaluate. In fact, this is precisely why market-based mechanisms are expected to bring efficiencies to the electricity industry in general, since the level and mix of load shapes, duration of contract, etc., are likely to be best decided by the market. However, when market power exists, the market outcomes are unlikely to be efficient.

7.8.1 Remedies: institute availability and/or other incentives into regulated network tariffs

Since the remedies for market power in generation are discussed in detail above, we focus here on the remedies for contractual issues between participants, particularly suppliers, end-users, and network operators. While it is very hard to determine whether contracts are 'too one-sided', basic principals would suggest that it would be inefficient for contractual relationships *not* to include incentives for efficiency, quality, etc.[310] In the case of network operators, these would take the form of availability incentives, clauses for attaining specific service quality standards (these might include certain factors concerning power quality, including frequency tolerances, etc). They would typically include financial incentives that would be based on marginal cost principles, but could also include penal clauses if the network operator is viewed to be grossly negligent or potentially behaving strategically.

It is also important to note that there is a general regulatory problem facing the regulated firm when fixing tariffs and requiring that (exogenous) demand be fulfilled. When demand is fixed exogenously and it is required that the regulated natural monopoly service satisfies this demand, it can then be shown that service quality[311] becomes the endogenous output variable for the firm. It is then required that the levels of service quality be monitored closely by the regulator. When the regulated firm is also vertically integrated with a potentially competitive firm there are additional reasons to monitor service quality as there are possibilities of the regulated firm behaving strategically, either in their own interest or in the interest of the potentially competitive firm (generation, supply and trading in this case).

There are two elements of economic rationale for quality standards. One is the ensure that some (potential competitors) are not receiving a different quality (discrimination), and the other is that the firm should have no incentive to degrade quality in general (regulatory). Therefore, this suggests that quality standards should be set in terms of the marginal cost of providing quality, as well as relative to the whole (i.e., the relative quality a particular user receives). In the case of the discriminatory quality reduction, charges should be set as fines to discourage such behaviour. The level of the charge should reflect the marginal damage imposed on the customer by say, incurring more outages than the standard. In terms of the general level of quality, typical ways of addressing the problem are to allow some margin for error, and some amount of time to correct the problem (the firm is given

[310] We note that the CREG was of the opinion that the initial contracts were too one-sided, and so instituted and lengthy consultation process and significant reforms.

[311] For an introductory discussion and model of service quality as the endogenous production variable for a regulated firm, see Swinand, G. (2003).

'insurance'). However, fines, reflective of the cost of providing quality should come into force if corrective action is not taken.

Around the EU, countries adopting regulatory regimes for Transmission and Distribution in a liberalised environment have opted for various approaches. The most common approach is a refund, or fine, penalty, etc. A refund approach has been adopted in Italy. In the UK, interruptions, customer service, and frequency are tracked and can impact on the companies' allowed revenues under the price cap. In the Netherlands, quality standards for frequency and interruptions are expected to come into force in 2005, with reductions in allowed revenues for companies failing to hit the targets, and bonuses for those that exceed the targets.

7.9 Issue 7: Regulatory risks

We now turn to the issue of regulatory risks. This area can be a difficult topic to comment on, since while it is likely to be real, it is also difficult to measure. In addition, participants will often point to regulatory risk as providing something akin to a 'catch-all' rationale for a plethora of issues, such as insufficient investment, etc, but this is often unverifiable. We nonetheless previously presented some evidence that regulatory risk exists and impacts investment, or indirectly impacts investment via factors such as share values.

There are a number of difficulties with the current system, including:

- The CREG is dependent on the proposals of the companies; if the CREG wishes to dispute the proposals, the CREG must work with provisional tariffs.
- The CREG does not control the length of the tariffs; the legislation sets the time period (one year, or three months for provisional tariffs).
- The legislation requires a cost plus system and rules out a price cap.

Because of the difficulties with regulatory risk as a topic, we will try to focus on areas where regulatory risk is more tangible, and thus where the benefits of its mitigation are more likely to be significant. By this, we mean changes in regulated tariffs. In particular, one area of concern that was echoed among mainly suppliers, in addition to traders, was that the level of tariffs applying, for example, to distribution charges was 'preliminary' and thus subject to change. We understand that the CREG faces a particularly difficult[312] task in attempting to set tariffs at the outset of a market construction, as well as after initial (administrative) unbundling.

[312] For example, if the job were to regulate the use of a new asset, the construction cost of the asset would be the regulatory asset base. When regulating recently unbundled assets for the first time, cost allocation, economic asset values (as opposed to accounting values), depreciation rates, and rates of productivity improvement all must be considered at once.

7.9.1 Remedy: consider operational changes to timing, scheduling, and structuring of CREG tariff decisions

An additional potential remedy could entail the consideration of operational changes to timing, scheduling and structuring of CREG tariff decisions. In particular, we believe that some of the following might be helpful in reducing regulatory uncertainty in the setting of regulated charges for high voltage and local distribution.

- Consideration of a more public consultation process: Suppliers, traders, and other participants need to understand and be comfortable with this process. If they are brought in at the start of a more public process, they will then both learn in advance what the 'probability distribution' of potential tariffs is, as well as feel more comfortable once a decision has been made. Publication of public consultation documents and position papers from interested parties on CREG's website would also be helpful in this context.
- Announcement of a range of possible tariffs well in advance of the decision: this could be done to provide suppliers with an indication of what prices might be, and allow advance planning.
- If tariffs must be left open to retroactive change, consideration of a cap, as opposed to a possible change in either direction would be helpful. In the case of where CREG has determined provisional tariffs, it would greatly limit the risk of suppliers, who would be able to make firm offers to customers on an 'all-in price' basis, if the provisional tariff included a cap. Thus, suppliers and other participants would be assured that their charges would not rise, but should the provisional tariff change, they could receive a refund;
- Consideration of allowing limited negotiated third party access[313]: this proposal would allow entrants or suppliers to negotiate longer-term contracts with Elia or local DSOs or both. This would enable them to provide themselves with regulatory certainty over a longer period of time. Some participants claimed this would be useful. The downside of this proposal is that it could potentially open the possibilities of cross-subsidisation. We believe that the cross-subsidy risk is greater under the current degree of vertical integration in the industry (which is another reason to improve separation);
- Publish a long-range plan on CREG's website: An additional option, that would give participants some knowledge of what the regulatory

[313] We note that the legislation currently does not allow this. While it seems reasonable to "require" regulated tariffs, ruling out other forms of access may or may not be warranted. Typically, the rationale for such requirements is to avoid the possibility of competitive bypass when there are charges such as the "competitive transition charge (payment for sunk costs)" in California's restructuring. There, utilities were required to trade all energy through the CalPX where the charge was levied. This had the perverse effect of eliminating the possibility of hedging and trading forward, which had major consequences when California's supply got very tight.

future might hold, (say) more than 2 to 3 years in advance, would be to publish some kind of strategy paper for issues pertaining to tariffs. Among the issues that such a paper could address include: (i) if and when will the move to RPI-X type price caps might occur?; (ii) is the likely period of regulatory price review to be fixed after a certain date?; (iii) is that period expected to be 3 years, 4 years, 5 years, etc?; (iv) does the CREG see the need for more local specificity in distribution tariffs?; (v) or does the CREG see a convergence over time (perhaps by applying catch-up factors)?

7.10 Issue 8: regulatory powers and responsibilities

A final issue that merits attention concerns regulatory power. These issues arise in several ways, including insufficient executive powers in general (both at the regional and federal) level, issues with the structure of powers vis-à-vis responsibilities, particularly at the regional level, and lack of independence of the regulatory process from political influence. These issues have been echoed by all regional regulators, as well as by other industry participants.[314]

7.10.1 Remedy: restructuring of regulatory powers

Our recommendations with regard to regulatory powers commence with an outline review of appropriate general principles. Of the general principles, we suggest two over-riding components.

Enhance powers

The absence of, or insufficient, regulatory powers is a recurrent theme. We focus in this instance on two particular areas: (i) an overarching principle for regulatory power; and (ii) and where powers already granted do not have sufficient 'teeth'.

While the overall powers of the CREG are set in *law*, generating *structural* power for a regulator is often required. The generality of such a principle can be easily demonstrated with an example. Consider that it is often a *legal* requirement for a regulatory body to be politically independent. Nonetheless, it is universally accepted regulatory design and practice that structural measures should be implemented to ensure the regulator's independence, including measures such as independent oversight, independent sources of funding, fixed terms for executives, etc.

An example of such a structural power is the licensing requirement for participants in the UK. The UK regulator, Ofgem, can rewrite the licensing conditions of participants. Ofgem has sweeping powers, and can write in requirements, such as the requirement to provide information, the

[314] The CREG, to maintain independence of the report, has not weighed in on such issues.

requirement to not engage in market price manipulation, and not to withhold capacity, etc. These powers are not unlimited, and there is the possibility participants will appeal[315] (as they successfully did regarding changes in the licence conditions for generators with respect to market power). However, Ofgem ultimately has the first mover advantage here. The burden of appeal is then placed on the participants. We recommend that the CREG be given such a power, both to license participants and to write the licensing conditions.

A second option for an over-arching regulatory power structure would follow from the legal powers available to the Federal Energy Regulatory Commission (FERC) in the US. The FERC can adjudicate cases, prices, and other issues, especially as pertains to inter-state competition, with all the powers of an administrative law process. The FERC also has the power to (ultimately) regulate prices, in spite of the fact that the States' Public Utility Commissions undertake *all* the primary tasks of regulating prices—the FERC only has oversight. Ultimately, it is statute that gives FERC its powers, but legal precedents also play a large part. The FERC has the power, and the responsibility, to ensure that prices are *just and reasonable*. The vagueness of *just and reasonable* naturally gives FERC potentially sweeping powers, and it is the courts, the possibility of appeal, and precedents, which limit FERC's powers with respect to this.

We recommend considering a legal structure, perhaps a statute/decree giving the CREG power to ensure reasonable prices, which gives CREG both ultimate *power and responsibility,* over the structure and functioning of Belgium's electricity markets. We recognise that this would require a substantial amendments to the 1999 electricity bill, but it would greatly empower CREG.

Establish prima facie evidence or per se rules

Another possibility, mentioned previously, would be for the CREG, in concert with the necessary legal entities, be it the courts or the legislature to determine, that certain conduct or practices might be established as *prima facie* evidence of market abuse, or that certain practices might be banned outright as *per se* disallowed (if not illegal). The usefulness of this would be that often the burden of proof is extremely difficult when mixing standard competition law with electricity markets. This is because, for example, the tightness of the market, might be a wholly ephemeral thing: a situation of extreme market power could arise[316] to one player, and then disappear, due to flux on the grid, outage conditions, weather, etc. Further, the nature of grid flows and flux, although well understood in theory and normal practice, can

[315] Appeals are made to other independent bodies such as the Competition Commission (previously the MMC).

[316] Of course, currently, there is already a monopoly in generation, so extreme market power would not arise as it is already evident.

occasionally baffle even grid operators and experts. Thus, for a competition or regulatory authority to try to sort out whether a certain situation was in fact an exercise of market power/abuse of a dominant position or not will be exceedingly difficult. Note also that the foundations of modern competition law will often limit it's usefulness. For example, the nature of defining market abuse does precludes from being abusive a monopoly where monopoly was "thrust upon it". Times of grid flux causing market power seems a textbook example of how monopoly power is "thrust upon" a firm occasionally.

7.11 Summary and conclusions for remedies

This chapter has discussed and detailed a number of possible remedies for the improvement of competition in the Belgian electricity markets. A number of key suggestions bear emphasis and we list them here. Several remedies were considered and proposed. The difficulty is weighing priorities and likely impacts versus costs, as well as their use of implementation.

The first remedial step is to complete/bolster the current degree of unbundling of the monopoly elements of electricity from the potentially competitive ones. This was a priority step in almost every successful liberalisation programme globally. We recommend ownership separation between, at a minimum, Elia and Electrabel for the following reasons:

1. Electrabel may use its vertical relationships to impede entry, as alleged in the SourcePower case;
2. Limited separation seems to have been inadequate; at the very least there is a strong perception among almost all participants that separation is not sufficient;
3. The evidence in relation to the adverse impact of lack of ownership separation in other jurisdictions;
4. A number of international academic experts recommend that "no ownership interest" between TSO and generation is a requirement; and
5. Lack of maximum vertical separation may hinder competitive operation of interconnection.

In addition to ownership separation, in the short term, a number of remedies can bolster vertical separation. Further unbundling between all other parts of the chair, including regulatory accounting separation and managerial/governance separations is the first step. Other remedies discussed in the text include enhancing requirements to publish audited separated regulatory accounts, full-board and governance separation, physical separation requirements, public publishing of potentially shared data or the requirement to track quality and service by customer type.

The next step is to put into place a full regulatory programme, including schedules, goals, detailed requirements and market designs for trading arrangements (PX), and new balancing arrangements. Full considerations of market design issues and decisions regarding a power exchange for Belgium should be made. If this is not feasible within a reasonable timescale, then interim-trading arrangements, along with schedules for consultations and completions on the final arrangements should be put in place. Interim trading arrangements should include complete accounting separation of Electrabel's vertically integrated businesses, and vesting contracts or trading formulae by which Electrabel trades with itself and despatches plant.

The final piece of the strategy will be to address the market dominance of Electrabel. Their dominance in the most important market, generation, is greatest. Our modelling showed that Electrabel has substantial market power in its current position. The second important conclusion from our modelling analyses is that the large, planned new increase in interconnection is expected to have a big impact on Belgian prices and competitive pressures if certain conditions are met. It was shown that the results are extremely sensitive to the input assumptions surrounding the degree of market power mitigation available (limitations on withdrawal, contract cover, etc). Finally, in all cases, the most important parameter is the demand elasticity. Demand elasticity will be increased by certain forms of market design, increased competition in the supply and trading markets, increased demand-side bidding, and increased interconnection capacity.

Divestiture is the most complete option, and the one that is most likely to fully address market power problems—above all, the ability to raise the wholesale price of electricity. Our modelling shows that dividing Electrabel into 3-4 equal pieces, along with some secondary measures, would be sufficient to control prices to near current levels (approx. €40/MWh). If divestiture is not an option, there are a number of other possibilities. One would be to greatly expand the VPP contract regime. Another would be to implement a scheme of contractual sale of long-term energy rights through auctioning PPAs. Finally, if these options were not feasible, effectively regulating price in the sector would be the other option. This could be done via some form of long-term contracts or outright price controls of either the RPI-X form or cost of service type.

In addition to the remedies above discussing the major problems of vertical-separation and market power, a number of other remedial actions were discussed. These should be considered, either on an interim, temporary or permanent basis as is fitting with the chosen regulatory programme. With regards to market power mitigation, these remedies could include: requirements to sell suitable sites, implementing interconnector capacity allocation mechanisms similar to the Dte-Elia system, further increases in interconnection capacity, instituting a market power monitoring committee and mechanisms, and encouraging autonomous producers to become potential competitors to Electrabel. With regards to other barriers, like informational barriers, detailed remedies were discussed including:

requirements to publish or share data on customers, prices, etc., price caps with incentive clauses and X-factors, market integration, and balancing reform or re-regulation. Many of these could be implemented with the contingency that they should be lifted if other objectives (e.g., Electrabel's market share in generation is reduced below X%) were achieved. Finally, regulatory remedies were discussed, including ways of reducing regulatory uncertainty, and bolstering regulatory powers. Remedial options for regulatory risk reduction included the possibility of issuing provisional tariff 'caps' in place of provisional tariffs (so suppliers would not risk a higher tariff), altering the timing or structure of CREG decisions (preliminary consultations, giving predicted expected ranges for tariffs, etc). In terms of regulatory powers, consideration of some fundamental changes warrants further effort. We noted that the CREG lacks a fundamental overriding principle with regards to its regulatory powers, such as the FERC's remit to keep prices 'just and reasonable' or the powers accruing to Ofgem's licensing abilities.

In all, we believe that a significant number of regulatory and other remedies are available and that implementation of a subset of them would go a long way to creating a competitive market(s) in Belgium. We cannot say exactly what this appropriate subset is, but we can say that if serious remedies to address market power and vertical integration are not undertaken, then significant amounts of time and resources may be wasted implementing power exchanges and other remedies that are an integral part of the solution, but that cannot work in and of themselves.

8 Methodology for monitoring of competition in electricity markets

8.1 Introduction

An important function of the CREG as the regulator of the electricity industry is to monitor, on a continuous basis, the status of competition in each of the three potentially competitive electricity markets in Belgium. In this section, we briefly explain the framework underlying the proposed methodology before outlining both general and specific methodologies to assist the CREG in fulfilling this key function.

8.2 Framework for methodology

The methodology proposed in this section relies on an overarching framework rooted in the structure-conduction-performance (SCP) industrial organisation paradigm. That is to say, the framework takes as its foundation that the CREG should monitor market *structure*, and that certain structures will indicate the potential for market *conduct* including anticompetitive behaviour, and that there is a need to monitor market *performance* in terms of outcomes. Therefore, for each market we recommend a set of *structure, conduct* and *performance* indicators. After setting out a range of structural indicators that should be monitored, we recommend a number of important factors relating to potential conduct that would be indicative of strategic behaviour, or impeding competition. Finally, we recommend the standard indicators of market performance, as well as specific measures that might be relevant to the particular markets.

It is important to bear certain caveats in mind when using these measures of competition, which are discussed below.

- Ultimately, there will always remain a certain amount of judgement in the assessment of market competition. Competitive markets are not usually identifiable by a single, one-dimensional measure, but rather the nature and extent of competition are the outcome of both structural and behavioural factors.
- The measures proposed should be tracked with regard to sensitivities in the assumptions, such as market definition. This is an important point that we wish to emphasize, and it applies to many of the measures and indicators across all three markets. For example, while we have discussed market definition in prior chapters, we suggest that the purpose of such discussions is primarily to inform CREG of how markets should be defined. A key realisation is that there exists

no thin black line separating one market definition as correct and one as inferior. Since the CREG as regulator has a considerably different remit than say, the Competition Council, the CREG should use this flexibility to its advantage where possible. Therefore, when tracking market conditions, the CREG should not be constrained to one methodology or decision and should seek to define the market in a number of ways. Studying and tracking markets on a number of bases is an example of one possibility of overcoming such sensitivities in the assumptions.

- Lastly, we note that our recommendation may constitute a list of potential indicators that could all be useful in order to form a complete picture of the status and evolution of competitive forces in the market. However, it is also possible that some indicators will eventually become less useful, while other become more important. Furthermore, it is also possible that new indicators may emerge as useful as the markets develop. While some indicators (e.g. liquidity measures in trading, optimal hedge ratios, and others) could be of little relevance to the current situation, they may become useful as other market structures are achieved, such as the development of a liquid spot and forward market. This is especially true in Belgium, where for example, market power monitoring as performed by many ISOs is currently less relevant because no exchange exists.

In this section, we provide a discussion in these terms and offer our conclusions in the form of a small list of preferred indicators.

8.3 Indicators of competition in generation

8.3.1 Structural indicators

Due to the generally homogeneous nature of the electricity commodity, and the economic fundamentals of its production, market structure in electricity generation will be extremely important in terms of ongoing monitoring of the competitive landscape. In generation, the most important indicators of market structure are market concentration measures. This is mostly due to the capacity constraints on generation and the quantity (Cournot) nature of competition.

Market structure is most generally seen to be a function of two elements: the number and sizes of existing competitors, and the possibility of potential competitors to enter the market. Here we outline indicators relating to the number and size of competitors, electricity generation-specific structural indicators, demand-side structural indicators, and barriers to entry.

Number and size of competitors

The measures of market structure that CREG should monitor are:

- HHI;
- Concentration Ratios (CR4, CRn) ;
- the number of players competing in the market;
- the number of players with more than 5% market share; and
- the market share of the largest player.

Issues of market definition have been discussed previously in the generation chapter. We note here that the measures are all based on horizontally defined markets, and that they might be calculated using a number of different market definitions as part of the process of forming a more general understanding of the market.

The most important indicator among these concentration measures is the HHI.[317] The HHI is a summary measure of market shares, which includes the size distribution of firms as well as the market concentration. It is thus a general measure of concentration, which accounts for the possibility of competitive fringes and dominant players. In general, the threshold for when a market is likely to be subject to market power problems is an HHI of 1,800 or greater.

We have discussed details of the HHI in previous chapters and the only point we would add here is that the relevance of certain formulations of HHI, based on market definitional nuances, may change as different design options are put into place. For example, suppose that little baseload capacity is contracted forward and that daily peaks in summer and winter (much of the year) are close to system capacity less reserve margins (i.e., a tight system). Also suppose that a mandatory Pool with a system marginal clearing price is in place. Under such a situation, the ability to control peak bids, and use them to earn inframarginal rents from baseload, will be a key and potentially profitable strategy. The HHI based on all available capacity might be misleading (biased towards suggesting less market power than there is). In such a situation, an HHI for peaking units should be looked at, in conjunction with a measure of inframarginal plant (i.e., plants that will run, even if a peaker, who bids too high, is not despatched).

Concentration ratios (CR4, CRn) are also summary measures of market structure. High concentration ratios indicate that comparatively small numbers of sellers dominate a market; whereas low concentration ratios mean larger numbers of sellers split market sales more equally.

An important point to note is that, in the context of electricity markets, these measures are not necessarily static across the different hours of the day or the different times of the year. Rather, the degree of competition often differs

[317] We discuss the HHI and other measures generally here, but will not do so in the context of our discussion of the other markets.

significantly between peak and baseload periods, as it may do between these and balancing power supply.

The correct computation of these concentration indices also requires information on the interconnection capacities at the borders of the national transmission systems and their load factor, that is, their actual usage.

In electricity markets the ability to provide plant flexibility may contribute to market power. In the case of the Belgian electricity market these services are not currently subject to a market mechanism, therefore indicators based on these would not be meaningful. If there were functioning markets for ancillary services, it would be important to compute concentration measures for those markets as well.

Electricity generation-specific structural indicators

One of the problems with electricity generation markets is that they do not always behave similarly to other markets. Therefore, more standard indicators, such as the HHI[318], will have to be analysed in conjunction with other indicators.

In electricity markets, straight concentration measures have particular shortcomings in that there is a need for indicators which reflect three key factors affecting market outcomes:

1. Demand;
2. Total available supply; and
3. Large suppliers' capacity share and contract position.

These concerns have given rise to new indicators that take into account the specificities of competition in electricity markets. We discuss some of these new indicators below.

Reserve margins – Reserve margins are commonly calculated and tracked by regulators and grid operators, primarily for reasons relating to security of supply. However, reserve margins give a good general idea of competitive conditions, in the sense that when they become low, there can often be problems. For example, Newbery (2001b) suggests that reserve margins of less than 10% indicate the potential for serious market power problems. The exact type of reserves are not defined explicitly, but they could include all reserves, spinning and non-spinning that could be ready to meet demand within, say, a short time period, say, four hours.

Dominant capacity reserve ratio – Newbery (2002) suggests the following index: the ratio of (dominant firm's capacity)/(reserve + import capacity). This is a rough measure of the dominant firm's ability to make the system so tight that there is a price spike. For example, if the ratio is say, less than one, then the dominant firm cannot, from initial conditions, make the system hit the value

[318] Borenstein, S *et al.* (1999).

of loss load even if they withdraw all their capacity, because there will always be enough reserve and import capacity to cover this. We suggest that the measure could be impacted by the situation in Belgium, where the dominant player has the ability to influence reserve margins, but we note that this is not in the interest of the incumbent.[319] It should be noted that while the measure is an interesting one in general, it is less interesting for the current situation in Belgium, because the incumbent has almost *all* the capacity. The measure is meant to reflect the power of the incumbent relative to whether the system is tight or long – indicating whether the incumbent has the capacity to withdrawal sufficient power that cannot be met by reserves. There is little doubt of this withdrawing capability in Belgium. It might become interesting in the context of Belgium if there arise questions over whether a certain market share is sufficient to reduce the dominance of a single firm or if Electrabel's market share is reduced.

Residual supply index — The residual supply index (RSI) represents the proportion of demand that is supplied by all but the largest supplier.[320] The larger the index, the smaller the influence of the market's largest supplier.

RSI = (Total Supply Capacity – Largest Supplier's Capacity) / Demand.

This index could similarly be computed with respect to any given firm *i*, that is, not only the largest firm. When residual supply, relative to firm *i*, is greater than 100 percent, suppliers other than firm *i* have enough capacity to meet the demand of the market, and firm *i* has little influence on market clearing price. On the other hand, if residual supply is less than 100 percent of demand, firm *i* is needed to meet demand, and is therefore a potentially pivotal strategic player in the market. As a pivotal player, firm *i* has great influence over the market clearing price[321] and can manipulate this price to its advantage.

It is necessary to highlight some potential caveats with the RSI, as, if used incorrectly, it could give focus to the potential market power of say, SPE, which is really of limited importance in Belgium. The RSI is used as an indicator of market power potential in other jurisdictions, for example, in ISO-NE, where testimony from participants to FERC contested its usefulness. We suggest that the RSI is a more interesting measure in an oligopolistic setting rather than a near monopoly setting, and can be informative if used appropriately. As an example of the limitations of the index, consider that no

[319] What one usually fears is that the incumbent artificially lowers reserves, to make power scarce, by say, mothballing plant, taking plant down for maintenance at sub-optimal (from the social perspective) times, etc.

[320] We have not computed the RSI for Belgium, because it is obvious that Electrabel has very large amounts of market power, and is needed to meet demand. SPE is needed to meet demand only in peak hours.

[321] Assuming that a market design with such a price is implemented. Even if it is not, there will still *implicitly* be a market-clearing price, and the RSI might still be used. In fact, it could be argued that uncertainty over whether a particular firm is needed to meet residual demand is exactly what the NETA market design is supposed to use to combat market power.

indication of merit order or whether the largest suppliers' capacity is in merit is given. Therefore, it could be the case that the dominant player who has many old expensive plants, most of which don't run, would get the same score as an dominant player with many cheap plants, all of which run.

Ownership of Marginal Units — This is a measure of the ownership distribution of marginal units. We need to identify all units that were on the margin for each specified time interval (5 minutes, 15 minutes, 1 hour) during a specified year. Next we establish the ownership of these units. When all marginal units are allocated to each firm in the market, it is possible to calculate each firm's share of all the marginal units in a given year. This will tell us what percentage of occasions in a given year when each firm was the marginal electricity provider. These percentages can then be used to compute concentration-like indices similar to the HHI. In the context of electricity markets this may be a more accurate way to estimate market power. For example, in a market where the HHI is decreasing but the distribution of ownership of marginal units stays unchanged it is unlikely that the decrease in the HHI will have any impact on the degree of competition in the market.

The CREG can identify marginal units by looking at demand levels and observing where they fall on the supply curve. The CREG merely needs to update the hourly demand data with the latest figures from Elia, and new additions to the generation supply curve, changes in fuel prices, etc. So the calculation could be done as follows: for each hour, obtain the demand level from Elia; then, either obtain the actual supply curve from Elia or construct a supply curve based on thermal efficiency, capacity, and fuel prices (this is schedule of capacity and variable cost, for each unit, sorted from low to high.) Now in each hour, note who owns the unit that is the last (most expensive) unit despatched.[322] Now sum over hours for each player, and divide by 8760 hours in the year – giving a market share of plants at the margin. This can then be used to calculate HHIs, CRns, etc.

Of course, in general, this is currently an uninteresting measure, as Electrabel owns all of peaking generation. However, there exists the possibility that the interconnectors may be occasionally on the margin though.

Demand-side structural indicators

Another important part of the structure of the market that sometimes is overlooked in electricity generation markets is demand structure. Improving the ability of demand to reduce load in response to price signals is ultimately one of the ways in which electricity liberalisation will improve economic efficiency. Typically the way demand-side responsiveness occurs is via the market place, either the PX, in a day-ahead context or in a balancing market day-of. Other ways demand-side can respond to price is via specific contracts with participants. The contract would have a clause saying – "if price hits

[322] This can be done via a spreadsheet.

some level, we can reduce demand by 100MW". With no (reliable) price signals this is of course difficult in Belgium. Our understanding is that Elia currently has a load-shedding working group, which is implementing some reforms that should increase demand responsiveness, but we recommend going further and introducing market-based mechanisms, i.e., demand participation in markets (ultimately, this would involve a market design similar to NETA or NordPool).

Demand-side structural indicators should include:

- Estimates of total amount of demand (MW) that can be reduced in response to price signals (or other signals from Elia before price signals). This should include the interconnectors. This should also be calculated relative to a day-ahead and real-time (balancing) market. In other words, some load might be able to reduce relative to price signals from the day-ahead market, and some say, hour-ahead. The estimates should be made for both winter and summer peaks, and for normal daily peak and off peak situations.
- The number of participants that have the ability to participate in demand-side bidding.
- Contractually interruptible load (total in MW), and at what prices the load is reduced, if possible.
- Ratio of total price-responsive load to absolute peak demand minus baseload demand (to calculate baseload demand, use the load from 85% on the load duration curve—this could be adjusted up or down by 5%).

Barriers to entry

While much of this report is *about* barriers to entry, it will be useful to monitor the situation concerning identifiable barriers in order to understand the current state and the likely future evolution of market structure.

The difficulty with barriers to entry is that, unlike concentration ratios, or the HHI, there is no summary index of entry barriers. Therefore, we propose that the CREG make use some of the tools developed for this project, but also that the CREG will have to monitor entry barriers on a more subjective basis.

Economic barriers: In terms of entry barriers, the first observable barriers relate to the economic fundamentals—the new entrant trigger price financial models developed as spreadsheet tools for CREG as part of this project. The CREG should use these models to generate an ongoing indicator of the economics of the generation market.[323] Thus the CREG will be able to

[323] The models should be used as an indicator of the likelihood of entry, and come with the usual caveats of models with uncertain parameters. In addition, we emphasize that the usefulness of models is more often with respect to estimating the impact of a "potential change, *ceteris paribus*". This is because input parameter estimation might be (in spite of the users best efforts) biased in the levels, but not *differentially* biased.

continually have an updated forecast as to whether entry into generation is at least feasible based on the economic and financial fundamentals. With respect to this, we recommend that the CREG update on a semi-annual basis for the generation market:

- Short- term interest rates;
- Wholesale electricity price (average);
- Volatility of wholesale electricity price;
- The price/cost of new entry CCGT/CHP (there are two versions of the same model, one for each 400MW CCGT and one for CHP); and
- Fuel prices for natural gas.

On a longer-term basis, the appropriateness of CCGT/natural gas fired generation as the most likely new entrant scenario should be monitored, as well as the capacity needed to achieve maximum thermal efficiency, and the required load factors should be monitored also.

Non-economic barriers: With respect to non-economic barriers, the task will be more subjective for the CREG. First, we recommend using the economic fundamentals-trigger price spreadsheet models. When these models indicate that entry is feasible/likely, but no entry is observed, then this should give rise to concern, and initiate the search for other barriers. Secondly, the CREG should monitor the concerns of industry participants, and perhaps convene an annual or semi-annual roundtable meeting with potential entrants to address such issues of non-economic entry barriers.

Access to downstream markets — This includes an analysis of the access to and liquidity of the supply and trading market as an important condition for a new generator to be able to present a credible competitive threat to more established incumbents. Therefore, the indicators for the other two markets should be considered as part of the indicators for the competitive state of the generation market.

Market power indicators – It is important to note that market power in the generation market may be a barrier to entry in and of itself because the mere ability of a firm to manipulate price may keep potential entrants away. Therefore, indicators of market power may be considered indicators of barriers to entry. In addition to the market concentration measures listed above (structural indicators—which indicate the potential for market power abuses), the market power exercise measures (conduct measures – discussed below) should also be tracked.

All indicators discussed so far, should be additionally analysed in terms of their evolution over time. These are not only static pictures of the degree of competition in the Belgian electricity market, but should help us form a dynamic view of identifiable trends. For example, if a firm with a very large market share has seen its share decrease over time, even if it still remains the dominant firm, this may be interpreted as a signal of intensifying competition in that market. Similarly, if the pace and size of new entrants has been

increasing in recent years, we would infer that entry barriers are decreasing over time.

8.3.2 Conduct and performance indicators

Market power monitoring

The conduct of players in the generation markets will be of particular interest, as will be the performance of the market as whole. Above all, the CREG will be required to monitor whether market power is being exercised or abused and what impact this has on prices. The proper functioning of an electricity exchange, and other such institutions will also require monitoring, and almost all international commodities exchanges have their own oversight committees to detect dubious practices and trading.

Thus, a first recommendation is that the CREG put in place a market power monitoring committee to oversee the functioning of the generation markets. The Committee should have the responsibility to ensure the proper functioning of the generation market (once a more formal market design is put into place). In the general sense, proper functioning should include that: efficient (least cost) despatch is achieved; obvious withholding practices are not undertaken; there are no refusals to deal within the market; etc.

There are also a number of specific items that market power monitoring committees at ISO's internationally track on an ongoing basis, as outlined below.

1. Generation set data, including:

   - Available capacities, availability, output, outages (forced and planned), heat rates, and fuels used.
   - Significant changes in availability over time.
   - Changes in planned outages; changes in the expected % of hours lost to forced outage.
   - Mothballing, closures, decommissioning.[324]

   These measures allow the committee to observe covert withholding strategies and changes in marginal costs.

2. Bidding data, including:

   - Hourly bids (if an exchange is established)

[324] We understand that the CREG already has the powers to investigate these factors, but that the exercise of the powers to impose fines in relation to non-compliance may have significant time lags.

- Degree of contract cover (how much of the plant's output is contracted in advance—high contract cover limits short-run market power).
- Correlations[325] of bids: among players, by player over time, forward versus spot correlations (discussed further under trading).

3. Wholesale pricing data, including:

- Prices — are the prices of wholesale electricity close to costs? Price cost margins (PCM) should be calculated. This can be done once an established wholesale price is known, and generation marginal costs can be calculated *ex post* from market despatch data from Elia. (In lieu of this, the spreadsheet despatch model is a simplified version of this and should give a first approximation to hourly cost data). Since there will be an hourly PCM, average annual PCMs (simple average, and demand weighted average) should be calculated.
- Price trends — price changes over time are indicative of many things. We have discussed price changes in other sections, and the CREG already tracks detailed pricing data.
- Relative Price Performance - Are cost reductions passed on to customers as changes in prices? This can be worked out in terms of fuel prices and thermal efficiencies for price setting plant. It is currently more difficult of a measure to track, because the more relevant and easy measure would be in relation to wholesale energy prices—but currently wholesale energy prices do not really exist in any particularly meaningful form. Once a more reliable wholesale price is available, this could become a more interesting measure. The actual implementation of such a measure can take on various degrees of sophistication. Simply measuring average prices for energy over a representative time period, and comparing to average natural gas prices (converted to MWh equivalents with thermal efficiencies and fuel heat contents), as well as computing the average changes, would be interesting, and very easy to implement. However, there is a trade-off (as always) between simplicity/ease of implementation and richness. Such a simple approach will have limited ability to capture the richer dynamics of fuel price pass through. Companies may have storage facilities, long term contracts for fuels, or face different supply and demand conditions than the market. They therefore may engage in (competitive or non-competitive) strategies that do not entail full short-run price pass through. As the market matures, the CREG's methodology could mature, and the CREG might consider

[325] We suggest the simple correlation coefficient. The simple linear regression beta or ordinary least squares coefficient could also be used. More sophisticated econometric tests can be developed, but their full description is outside the scope of this report.

building an error-correction model of the Engle and Granger (1987) form. Such a model will allow for short run dynamics of price pass through, and study whether prices are passed on in the long run, as well as provide appropriate test statistics and a framework for measurement. Such a framework can also be modified to test for asymmetric pass-through (i.e., cost rises passed through but reductions not).

- Optimal hedge ratio – the correlation of the forward price to the spot price, times the volatility in the spot price, divided by the volatility in the forward price:

$$H = \rho_{sf} (\sigma_s / \sigma_f).$$

This indicates the degree of contract cover that a generator would normally prefer in order to balance risk and reward in selling power either spot or forward. The optimal hedge ratio is both one of the more interesting and more tricky of the indicators suggested. The reason for tracking such a measure is as follows. For one, it will give the amount of forward contract cover that a particular generator would be expected to use if behaving competitively and optimally. Thus deviations from this are an indicator of potential problems. The tricky part is that deviations should not be seen as necessarily indicators of market power abuse—there may be reasons, such as illiquidity in the forward or spot market, that the player prefers to deviate from a delta[326] hedging strategy. It is also probably less useful at present for Belgium, as forward markets are undeveloped (although OTC and bilateral contracts are effectively forward markets, we refer to the more formal forward and futures basis – i.e., trading more standard contracts through brokers or exchanges (futures)). Nonetheless it should prove an interesting measure once markets become more developed.

- Degree of mean reversion[327] – This measure is suggested by ISO-NE.[328] The degree of mean reversion can be calculated from the OLS regression of wholesale prices on its lagged value. The resulting slope coefficient is then tested to see if it is significantly different from 1. If it is not, an augmented Dickey-Fuller test should be performed. If the hypothesis of a unit root cannot be rejected, this indicates that standard market forces are not pulling prices back into equilibrium, or that the equilibrium is not stable dynamically. Prices should be

[326] This is a hedging strategy for participants. The delta is the derivative of the value of the derivative with respect to the spot price of the underlying asset. It is thus the sensitivity of the portfolio to changes in the price. The delta hedging strategy means adjusting the positions in the underlying asset and derivative assets to maintain a risk-free portfolio.

[327] See Footnote 259 for a detailed explanation of the concept of mean reversion.

[328] ISO-NE (2002).

deseasonalised. The appropriate lag structure and the appropriate time-frame for an observation should be selected. We suggest, for hourly price data, a 3-hour moving average price, lagged by 24 hours.

Other indicators of conduct that should be observed by CREG include:

Patterns of market entry — the entry of new competitors may indicate that entry barriers are low. It is important also to examine investment trends by new and incumbent firms. For example, are new entrants typically taking on small fringes of the market (in electricity this could be entry in the renewables fringe, which due to its non-despatchable nature pose little competitive threat to bigger generators)? What are the motivations for entry - are new firms entering in view of supra normal profits by incumbents?

Financial performance – The utility of standard financial measures is of course limited for competition analysis, because the source of profits for a company are often so varied. Nonetheless, these measures satisfy the cost-benefit test, in that, in spite of their limited usefulness, the cost in obtaining them is low. They are readily available from company financial accounts. We note that financial accounting separation between subsidiaries of companies with significant market power is a very important remedy (as previously discussed in the remedies section) and this is one reason for that requirement.

8.3.3 Conclusion

In conclusion, we believe the potentially most useful set of structural indicators would be the indicators of market concentration, the residual supply index, and concentration indices in terms of ownership of marginal units.

Tracking market conduct will have to be on a more judgemental basis, as decisions such as when to bring a unit down for maintenance, when a unit should be retired versus refurbished, etc., could often be seemingly justified by plausible business or engineering conditions and assumptions.

These should be combined with the pricing measures, most importantly the price cost margins to form a view of market performance.

8.4 Indicators of competition trading

8.4.1 Structural indicators

The measures for the ongoing monitoring of the market structure of the trading markets are similar to those for the generation markets, as discussed above.

Numbers and sizes of players

The measures of market structure that CREG should monitor are:

- HHI;
- Concentration Ratios (CR4, CRn) ;
- the number of players competing in the market;
- the number of players with more than 5% market share; and
- the market share of the largest player.

Issues of market definition are discussed previously in the trading chapter. We note here that the measures are all based on horizontally defined markets, and that they might be calculated using a number of different market definitions as part of the process of forming a more general understanding of the market. In addition to tracking these measures as indicators of market structure in the trading markets, we suggest the CREG should also track:

- The number of pure traders, and their share in the total trading market (define pure trader as one who does not trade with primary links to generation or supply).
- The number of traders integrated with generation companies, and their share in the total trading market.
- The number of traders integrated with supply companies, and their share in the total trading market.

Shares should be calculated on a total volume basis.

Barriers to entry

There are a number of barriers to entry in the trading markets. We focus the discussion here on methods of identifying and tracking them.

Economic barriers: In terms of entry barriers, the first observable barriers relate to the economic fundamentals. The new entry models for trading developed as spreadsheet tools for the CREG as part of this project may be used to give an ongoing indicator of the economics of the trading market.[329] Thus the CREG will be able to continually have an updated forecast as to whether entry into trading is at least feasible based on the economic and financial fundamentals and assumptions of its choosing. With respect to this, we recommend that the CREG consider updating the model on a annual basis for the trading market for the following assumptions:

- Short term interest rates;
- Trading margins—survey data, bid-ask spread data for standard products; and

[329] The models should be used as an indicator of the likelihood of entry, and come with the usual caveats of models with uncertain parameters. In addition, we emphasize that the usefulness of models is more often with respect to estimating the impact of a "potential change, *ceteris paribus*". This is because input parameter estimation might be (in spite of the users best efforts) biased in the levels, but not *differentially* biased.

- The set-up costs of a trading operation.

Non-economic barriers:

Liquidity -- Liquidity, as previously stated, is the ability to buy and sell large or small quantities immediately, and without moving the market price. Thus, liquidity is by definition, at odds with market power. A lack of liquidity is a barrier to entry. We discuss liquidity further under the heading of market performance below.

Other indicators for the CREG to track are:

- The size of credit guarantees and credit limits of traders - these should be tracked and compared to the risks that the traders are taking.
- The size of fixed and variable fees for trading on the exchange (when an exchange is established.[330])
- These should be compared to bid-ask spreads and margins on trades in the market.

Indicators of liquidity most often focus on bid-ask spreads, half-spreads, and other measures.[331] There is not any particular threshold of liquidity, and traders will view it somewhat subjectively as to when they view liquidity as sufficient.

Volatility in prices (calculate as the sample standard deviation of the natural log of price). It is important to note that volatility may or may not be a bad thing. If markets are liquid, then it may actually facilitate entry into trading, as traders will be able to perform a value added function for other participants, i.e., hedge risk (trade options and other derivatives). However, if markets are not liquid, then traders will be unable to price risk, as the value of risk in the market will not be well-defined.

8.4.2 Conduct and performance indicators

In trading markets, an extremely important indicator of proper functioning is the liquidity of the market. Liquidity can often be inferred from a set of indicators such as:

- Volume traded, on a monthly basis;

[330] It is customary to fund the exchange with such fees. It may be, that the CREG has direct control over such fees, in which case the need to monitor them will be trivial. In the US, for example, ISO's file a general tariff application with the FERC, including their funding mechanism, which the FERC then approves.

[331] Details of measures of liquidity in financial markets can be found in the London Economics report to the EC on Financial Market Integration, http://europa.eu.int/comm/internal_market/en/finances/mobil/overview/report-londonecon_en.zip.

- Open interest (number of contracts, MWh);
- Bid-ask spreads - for 1-month, 2-months, 1-quarter and 1-year ahead contracts;
- Price volatility;
- Average contract size (MWh) by length of contract – longer-term and short-term (day ahead, month ahead, year ahead) contracts, (data based on surveys of traders);
- Adjusted measure of market size – the total trading volume minus the volume of transactions where Electrabel takes either side of the transaction; and
- Spot – forward price ratio. This measure is also suggested by ISO-NE as well as the DTE. The measure is very interesting, but comes with some caveats. It will be more useful once Belgium's markets are further developed.

  This measure tests the following: does the forward/futures[332] price equal the expected future spot price? There are certain conditions where it should.[333] Electricity presents an interesting case of this measure. Normally, forward prices rise into the future at the risk free rate of interest due to the standard arbitrage strategy.[334] The way to calculate the measure is to take the forward price, and then check it against the realised spot price *ex post*. We suggest only going out up to a month-ahead on the forward curve, as the measure will present some difficulties with respect to adjusting for seasonality and other factors. For this reason, we suggest that further work should be done on how to study this measure over longer-dated points on the forward curve. Very short-dated forward price, such as day-ahead versus real time prices might also be difficult. The balancing market may simply be more related to non-market fluctuations, and not have much relationship with the day-ahead market.

  Significant differences in the forward price over the realised spot price indicate the existence of risk premiums. Risk premiums are consistent

[332] As long as the risk-free interest rate and the futures price is not correlated, then forward prices equal futures prices. Futures prices are marked-to-market forward prices. So if interest rates rise along with commodity prices, say when a trader shorts a commodity, then the short position ends up costing more when it is marked to market than when it is not. See Hull, J.C. (2002 for a detailed discussion of this point.

[333] Hull, J.C. (2002).

[334] If the spot price today is above the futures price (adjusted for risk free interest) at some date in the future, then the strategy is: sell the commodity short today on spot, take the proceeds of the short sale and put them on deposit at the risk free rate of interest. Simultaneously enter into a long futures contract position to buy the commodity back at some point in the future. At the end of the period, you unwind the position. If the futures price is less than the spot price plus risk free interest, then risk free profits are achieved. Obviously, traders recognise this and eliminate such opportunities quickly.

with the possibility of market power, market manipulation, but not *prima facie* evidence of them, as risk premia could be due to other market inefficiencies.

Electricity trading-specific indicators

In addition to the indicators and performance measures discussed, there are a number of indicators that are specific to the trading market that should be tracked or monitored.

- "Wash-trades"; wash-trades are trades where a trader agrees to sell back and forth with counterparties, possibly waiving fees, with the aim to give the market the perception that liquidity is good, when in fact it is not. Thus, wash-trades are manipulating liquidity, if not price.
  - This was evidently endemic in budding North American electricity markets. While Enron was at the heart of some of the allegations, the practice was wide-spread[335] among the big US utilities trying to build market share. Wash-trades should be banned[336], and, as they indicate collusive behaviour between two parties to manipulate the market, are probably[337] already illegal under competition law.
- Trading "ahead" of customers; trading ahead of customers means making trades (presumably profitable) on one's own account ahead—or in advance of customer's trade that has been placed. This kind of practice is indicative of market power[338], and also only possible in illiquid markets. It essentially requires a lag time between when the customer places an order and when the trade is actually executed, and a spread between when the trade order is placed and when it is executed that is sufficient that the trader can take part of the spread for their own account. This is also a way of artificially increasing bid-ask spreads. In a liquid and competitive market, this kind of activity would be impossible, as spreads would be low, and the amount of time to execute a trade would be (and would be expected by the client) to be almost immediate.

[335] See for example, Knowledge@Wharton (2004).

[336] We have contacted the Belgian equivalent of the FSA, the Banking, Finance and Insurance Commission (CBFA). While we presume that they, similar to the UK and France, would have some jurisdiction over trading markets, we have received no reply.

[337] We do not attempt to interpret the legality of such things further.

[338] In general, the trader will be hard pressed to maintain this practice without market power. The trader is manipulating price charged to his client effectively, albeit, clandestinely, and the client is evidently insensitive to this. If competition were perfect, the customer would immediately recognise that his trade was not performed at the known market price, and an alternative trader could then steal the customer away.

The difficulties for CREG regarding wash trades, trading ahead, and other such practices is several fold. First, how to detect such practices, and second, what to do about them. First, it is quite normal that traders might trade back and forth with the same counterparty. If the market is liquid, they will do so at the same market-clearing price. In terms of trading ahead, traders naturally take a bid-ask spread as part of their fees, and in illiquid and opaque markets, this spread will naturally be set by the traders, and market forces will not bring it back to competitive equilibrium immediately as they would in competitive markets. There is no clear line where trading activity becomes wash trading. Likewise, traders, especially if they are acting as market makers, trade on their own account for their own profit and loss. There is the added detection difficulty that trading data at the customer level will be needed. In addition to the difficulty in detection, wash trading should be seen as virtually innocuous for very small players, while it should be seen as particularly manipulative by players with significant market power. Trading ahead is equally bad for either big or small players.

In addition to the above indicators of market manipulation, there are some trading indicators that are more relevant to more mature trading markets, and futures markets in particular. The CREG, likely in conjunction with the other relevant financial services authorities and the exchange itself (when operational), should track the following indicators of proper functioning in trading markets:

- Margin trading (the practice of "depositing cash with a brokerage and then borrowing a % of the purchase price of trades);
- Times credit limits are hit by individual traders;
- Margin calls; and
- Short selling.

8.5 Indicators of competition in supply

Similar to our discussion for electricity generation, and trading, there is a large potential set of indicators covering both market structure and market participants' behaviour and performance. We provide a discussion of the more relevant ones below.

Ideally, all of these indicators would be useful in order to form a complete picture of the status and evolution of competitive forces in the supply market. However, it is perhaps more useful to the CREG to consider the advantages and disadvantages of the listed indicators in order to choose a smaller subset, keeping in mind that some indicators may become obsolete, while some might be of limited use until other developments in the market take place. We provide a discussion in these terms after our listing of indicators.

8.5.1 Structural indicators

Numbers and sizes of players

Indicators of supply market structure are similar to the generation and trading markets. Measures under this heading should include:

- HHI;
- Concentration Ratios (CR4, CRn) ;
- the number of players competing in the market;
- the number of players with more than 5% market share; and
- the market share of the largest player.

Electricity supply-specific structural indicators

Customer choice - Competition is likely to be strong where consumers have numerous viable alternative service providers and can renegotiate contracts and switch between them. It is important to monitor the proportion of consumers that are in the position to choose their electricity supplier. While currently, this is a relatively straightforward exercise, delimited on regional and customer demand bounds, it may be that this changes in the future. That is to say, once eligibility is 100%, it may be that supply companies are not active in certain regions or towards certain customer segments. In such a case, while legal customer choice might be 100%, *de facto* customer choice might be somewhat less.

In addition to customer choice, we suggest that CREG should consider monitoring themselves, or liaising with the regional regulators in terms of monitoring switching among different groups of customers. Groups could be identified by age, social class / income, education level, or other demographic features. Indications, for example, that the elderly or less educated people were less likely to switch, would be indications that the process of switching is not as smooth as could be, or that there are real barriers to switching at a very micro level.

Customer turnover, or churn – This is the amount of current market share that is new (i.e., resulting from a recent switch) in each period, say, every 6 months. Once switching becomes more prevalent, and competition more vigorous, market share related data will have to be interpreted with an additional caution. This is because a company could have say, 25% of the market, but could be losing half their customers to competitors while simultaneously winning others every year. In this case, competition is strong, and the market share belies the strength of competition. Of course the converse is also possible, where market share is low but customers never switch.

Number of dual-fuel offers – This is evidence of market structure. If a current supplier cannot offer dual fuel, they may be at a disadvantage to the incumbent who can.

Barriers to entry

Economic barriers: In terms of entry barriers, the first observable barriers relate to the economic fundamentals—the new entry models for the supply markets developed as spreadsheet tools for CREG by London Economics as part of this project. The CREG can use these models to give an ongoing indicator of the economics of the trading market.[339] Thus the CREG will be able to continually have an updated forecast as to whether entry into supply is at least feasible based on the economic and financial fundamentals and assumptions of its choosing. There is a model for each of large customer supply and small customer supply. With respect to this, we recommend that the CREG consider updating the model on a annual basis for the supply market for the following assumptions:

- Short term interest rates;
- Supply margins—survey key market participants;
- The set-up costs of a supply operation; and
- The cost of customer acquisition (survey).

Non economic barriers:

The measurement of non-economic barriers to competition can be assessed in supply markets and recent research suggests that econometric techniques can be employed, when the proper data are collected. There will still be judgement that needs to be exercised, but one of the interesting features of supply market competition is (will be outside of Flanders) that considerable data on customer behaviour will gradually become available.

Customer switching —How many have actually chosen to switch? There are some important details that the CREG should be aware in this area. London Economics has had certain recent experiences with a client in relation to Ofgem's switching modelling and our experience suggests that Ofgem's data and methods could be improved[340], mainly by collecting panel data.

[339] The models should be used as an indicator of the likelihood of entry, and come with the usual caveats of models with uncertain parameters. In addition, we emphasize that the usefulness of models is more often with respect to estimating the impact of a "potential change, *ceteris paribus*". This is because input parameter estimation might be (in spite of the users best efforts) biased in the levels, but not *differentially* biased.

[340] This is not to say that Ofgem has 'got it wrong' because obviously a cost benefit test must be considered.

Ofgem conducts detailed surveys of customer switching using a variety of means, but perhaps their most important data comes from standard market research-type surveys (usually telephone surveys, and sometimes backed up with subset of face-to-face interviews). Ofgem is developing econometric models of customer switching.

Above all, as identified in the barriers chapter, the degree of barriers is reflected in the price differentials between competitive offers, when no switch occurs, and when a switch does occur. A model of the following type can be further developed. We suggest the CREG consider developing a model along the lines of Chen and Hitt (2002).

Chen and Hitt (2002) propose a discrete choice dependent variable model of the form:

Equation 8.1: $$\Pr(\textit{Switch}) = \alpha_j + \beta_j \mathbf{x} - \chi_j \mathbf{y} + \delta_j \mathbf{z} + \boldsymbol{\varepsilon}$$

The dependent variable is a variable that takes on a value of 1 if the customer switched over the previous period, and zero otherwise. It is also important to define switching on a consistent basis of time – such as 'within the last 6-months'. The greek letters are the coefficients to be estimated. Standard econometric software can estimate the model using an appropriate limited dependent variable model and assumptions, such as probit or logit. Here, the bold letters are the independent variables, and indicate a vector of observations—i.e., the data on characteristics, attitudes, prices faced, etc. Observations are assumed to cover customers, time, and suppliers.

Implementation of such a model means collecting data by customer over time—the important thing is to develop a panel dataset – this means tracking a set of the same individuals over time. This is not to say that cross-sectional-time-series data are not useful, but that the types of analyses that can be done with such data will be much more limited than if a panel is used.

8.5.2 Conduct and performance indicators

General conduct and performance indicators

Many of the performance measures suggested for the generation market can also be applied to the supply market, as outlined below:

Prices — Are retail electricity prices close to costs? Are prices close to those in countries producing with similar fuel combinations?

Pricing trends — Price reductions may provide an indication of rivalry as competitors strive for efficiency gains.

Relative Price Performance - Do prices react to changes in the various costs involved in electricity supply (if such changes take place)? Price cost margins are the starting point here. The retail energy price is used with the wholesale energy price (average annual spot price if a spot price is available) used as the

marginal cost figure. A comparison of spot prices with wholesale contract prices should be made.

Number of discounted offers and size distribution of discounts – For each customer class, (demand size, domestic commercial, etc) it is suggested to collect data on the number of discounted offers a customer has relative to the incumbents tariffs. The size and distribution of the offers should also be tracked. This information can then be put up on the web of the CREG and the regional regulators—effectively giving free advertising to entrants.

Innovation — This can be in terms of the type of contracts offered to final customers and the number of value-added services offered to customers.

Advertising – Advertising has the potential to either enhance competition, or lessen it, depending on the type of advertising. Advertising that imparts information to consumers about price or specific sales conditions is generally known to be salutary towards competition, while advertising that is of the brand image or product differentiation type, generally reduces competition. Excessive brand-image advertising could be evidence of market power. Substantial levels of advertising cause barrier to entry, low levels of price competition and high operating margins. We suggest that the CREG consider, in liaison with the regional regulators, tracking some basic advertising figures. Local marketing companies should be able to provide basic summary statistics on ad spend by type of advertising by industry.

Electricity supply-specific conduct and performance indicators

There are several suggested indicators that should be either tracked or spot check by the CREG. These will become more relevant once liberalisation is at a more advanced stage. Although some of these may be within the remit of the regional regulators, or even consumer protection authorities, if spot checks are the only means of monitoring, then some overlap with the regional regulators might be welcomed. Also, as the supply markets develop and as the liberalisation reaches 100% for all of Belgium, supply may increasingly be offered on an all-Belgium basis, in which case the regulatory framework would increasingly fall within the remit of the CREG. Further, comparing and contrasting the progress of the regions should be done by the CREG. Indicators that the CREG should monitor (or where the CREG might monitor the regional regulators) include:

Customer switch blocking – It is our understanding that, quite naturally, companies will have the possibility of stopping customers from switching, such as if these customers are in debt to the current supplier. Recently, Ofgem fined British Gas Transco ("BGT") £200,000 for blocking customers under this rule, who in fact were not in debt. The CREG should therefore monitor the number of blocks that occur, and should spot-check the details of customers (obviously checking everyone could be impossible). It is important also that CREG has the powers to investigate customer details and company records along these lines.

Mistakes and delays in billing and switching– When a customer switches supplier, delays to the process or mistakes in the bill can cause anguish and problems, especially to small customers. It is important that such problems, especially billing mistakes can be resolved quickly. Without this, small customers will lose faith in the liberalisation process, and may become averse to trying to switch again in the future, if the first try at the process becomes a hassle. Some such problems have been occurring in the UK.

Customer 'slamming' – This is the occurrence of when a customer is switched without their knowledge. Our understanding is that such issues are the remit of the regional regulators, and understand from VREG is that this has occurred, but is currently very rare. Nonetheless, once liberalisation is more complete, the CREG might consider monitoring this on a cross regional basis. Is the practice more prevalent in one region than the others? If so, why?

Customer satisfaction given that they have switched/not switched – One of the barriers to switching is often the perception that a new service provider will be less secure or provide inferior service. Independent assessment of this kind of information, and making it readily available to consumers would combat this. Alternatively, there can be very real cases where service quality is lower for a new entrant. At the beginning of the competition introduction process, this could impact on the general perception of the benefits of competition. The provision of information about the market is a public good, and therefore can be provided to consumers. This information should include service quality information. We have mentioned this as part of the remedies section, and so the tracking of such data is also required. Standard market survey techniques should suffice.

9 Conclusions

Generation market

Our assessment of the generation market is that by any measure the Belgian electricity generation market is highly concentrated. Depending on the choice of assumptions regarding interconnection capacity and the VPP, the HHI concentration index is in the range of 5,455 to 6,756. This is well above the typical threshold of 1800 above which serious competition concerns arise.

We have not seen any evidence to date that the incumbent generator in Belgium has exercised market power. However, it is important to stress that even the credible threat of such behaviour or simply the uncertainty of hoe the incumbent will react after entry has occurred could be enough to deter entry. Indeed, the dominant player in the Belgian generation market has the ability (and the incentive) to engage in various forms of price manipulation. This impacts negatively on the liquidity of the wholesale market and this also has negative implications for the functioning of downstream markets.

Imbalance charges in Belgium are on average lower and less volatile than in the Dutch balancing market, but substantially above (and less volatile) those under NETA. In our opinion, high imbalance charges represent only one aspect of the problems facing Belgium's liberalisation process. The others arise from their interaction with an opaque, illiquid and very concentrated market(s), which gives few alternatives to buyers in the market.

We have also analysed whether and to what extent imports from neighbouring countries and VPP auctions could constrain Electrabel's behaviour. Our assessment is that, although Belgium benefits from significant interconnection capacity, as a result of various reasons, imports only have a limited impact on competition in generation. New interconnection with France could have a significant impact on prices, but this is not likely under the current regime. Current levels of VPP are also expected to have only a moderate impact on competition in generation. In short, the picture of a very concentrated market is not altered when taking into accounts possible mitigating factors such as interconnection and VPP auctions.

A comparison of baseload prices shows that the Belgium generation market appears to be less competitive than the Dutch wholesale market. Moreover, there are reasons to believe that such a comparison overstates the actual degree of competition of the Belgian market.

Trading market

The biggest impediment to the development of a trading market in Belgium is a lack of liquidity. Liquidity and the general availability of trading opportunities are fundamental for participants to manage the daily production and delivery of wholesale electricity and for traders to manage

their portfolios as efficiently as possible. Transparency and the balancing market risks are other important factors.

The biggest barriers to liquidity are, in order of descending importance: a) the dominant's player position in the trading, generation, and supply markets (in that order); b) the lack of access to the physical commodity; c) the low number of players in the market; and d) the lack of a meaningful reference price. These all can be attributed fundamentally to the dominance of Electrabel.

In some respects, the Belgian market appears to be evolving positively. VPP auctions and the commitment by Electrabel to quote prices and "make a market" for a certain range of products are certainly moves in the right direction.

Our view, however, is that these measures are not being taken at a fast enough pace nor on a large enough scale. When a market is illiquid it is often necessary to intervene. Lack of liquidity creates a vicious circle. Players are reluctant to trade because the market illiquid and this situation in turn contributes to the market's illiquidity and therefore players don't trade. The circle is unlikely to be broken if the market is left to its own devices.

We have found little evidence of significant structural deterrents to entry. The market appears to be largely "contestable" and indeed we have witnessed interest on the part of a number of potential entrants in entering the market, as soon as some of the other problems we mention are being addressed. Thus the economically acceptable barriers to trading do not appear to be high.

These factors are all, however, likely to be of a secondary importance. A problem that, barring any other actions, will remain even after all other corrections are made, is the large market share of Electrabel. Any market, no matter how well designed, where one player represents around 80% of the transactions in that market, faces significant scope for abuse of dominance. This in itself contributes to deter potential entrants from the market. A market under these conditions should be well monitored so that participants are assured that the dominant player is prevented from market manipulation.

Supply

Although we believe that the figures are likely to underestimate the market concentration for customers with high consumption volumes, the market shares and HHI already show evidence of a very highly concentrated supply market.

An analysis of the market segments above 10GWh/y suggests that the latter segment suffers from even higher concentration.

Available evidence shows that entry has occurred in Flanders and some entrants have increased their market shares (based on connection points). However, the market remains highly concentrated. Figures in Wallonia show

that the number of players is still very small. Electrabel retains a very high market share in terms of total electricity supplied in all three regional markets.

Our analysis has shown how electricity prices remained relatively unchanged in the more concentrated markets (large and medium customers) between 1999 and 2003 but fell sharply for the competitive market (domestic) after 2001. Similar conclusions are found analysing the evolution of the margins. Although we acknowledge the limitation of the data used in the analysis and that there could be other factors at play, this is a piece of evidence that market power may have been exercised in the more concentrated markets.

Retail customer switching in Flanders has been progressing slowly. In its first year after liberalization it is behind the rates once achieved in England and Wales but is broadly similar to the experience of Sweden.

The fact that the metering data, standard yearly consumption data, master data is not delivered on time or is incorrect has an impact on suppliers business. Suppliers are unable to estimate the consumption volume of the client and to identify customers' profiles. Hence, suppliers run a very high financial risk in a narrow margin market.

Despite the remedies imposed by the Belgian Competition Council, the designation of the default supplier has reinforced the dominant position of existing suppliers on the market of the supply of electricity for various reasons. It has reinforced the vertical integration of Electrabel. Moreover, it has given the default suppliers a lead over new entrants because of its client base. The large customer base could allow the default supplier to exploit economies of scale and achieve lower unit costs than its rivals. Finally, to the extent that being a default supplier is perceived as being trustworthy, it has given an advantage to existing companies over new.

International developments

The major electricity markets in Continental Western Europe have experienced a wave of merger and acquisitions in very recent years that resulted in a few major players dominating their national markets and competing against in each other in a number of national markets.

Looking ahead, it seems likely that the combination of the restrictions resulting from the Kyoto Protocol and the decommissioning of nuclear power stations in several countries will result in a change in the portfolio of generation assets across Europe. Gas and green energy will become relatively more important, though the reliability issues of the latter means that conventional thermal generation (especially in light of the decommissioning in nuclear power) is likely to be retained as an important source of energy.

Large electricity companies seem likely to continue to acquire assets in other countries, though the process is now rather more focussed upon consolidating positions in regional zones such as for instance, the concentration of German companies in Northwestern Europe. For the

foreseeable future, this will increase the number of multi-market contacts that the companies have, and thus might encourage tacit collusion in these markets.

While this pan-European trend of consolidation and vertical (re)integration is somewhat worrisome, we feel that the more immediate and most important issues for Belgium's electricity sector in the EU-wide context have to do with horizontal concentrations. As long as generation and supply are unconcentrated, then the negative impacts of vertical integration between generation and supply will be of second order. The more worrisome trends are that the benefits of transnational market integration will be muted by horizontal concentration combined with vertical integration. Electrabel now owns significant generation capacity in Holland and France, and EdF now owns generation capacity in Belgium, while maintaining a virtual monopoly in France.

While there is considerable talk about developing a pan-European electricity market, interconnector capacity limitations over the foreseeable future imply that, in Belgium given the current policy trend, the dominant player's market position is unlikely to change substantially in the next few years. Moreover, even if full electricity market integration were achieved in a not too distant future, say a French-Belgian-Dutch market, the latter would still be characterised by relatively high concentration in generation.

Barriers to entry

Belgium's electricity markets are not functioning well in terms of achieving workable competition. A single company controls approximately 80% of the generation market, and this company is vertically integrated, with significant market shares, across all areas of the supply chain.

Far and away, the biggest impediments to achieving competition in Belgium are structural. Among the structural problems, two stand out as particularly onerous. First, is Electrabel's near monopoly position in generation and supply, and second is Electrabel's high degree of vertical integration through all parts of the supply chain, especially the degree of vertical integration from generation into supply, and the natural monopoly elements, such as transmission. In addition, there is a high degree of interaction between these two structural features—effective monopoly in generation and supply, and vertical integration; the later reinforces the former. It has been recognized, and generally accepted since the early days of competition policy enforcement, that effective upstream monopoly could impair downstream competition even if these markets (supply and trading) were likely to be potentially competitive on their own.

In addition to the two major structural problems, other economic factors exist in the markets that will impact entry negatively. In generation, economies of scale, uncertainty, and current wholesale prices are such that greenfield CCGT entry is unlikely to occur – with current prices being consistent with limit pricing. The case for entry via CHP is positive, though only if high load

factors and thermal efficiencies are achieved. Also, although economies of scope and scale in generation may make entry difficult at current price levels, this is not to say that entry should not be expected to occur with sustainable moderate wholesale price increases.

In trading, lack of liquidity and opacity (i.e. lack of benchmark price) are likely the key entry deterrents. The vertical integration of Electrabel is probably also an important factor. High financial risks are likely to be important economic barriers to entry into the trading market while fixed costs are not.

Finally, with regards to supply, timelines and availability of reliable data, lack of competitively supplied commodity, lack of opportunities to manage risk (through a transparent market place), and an expensive balancing mechanism are likely the most critical factors affecting entry into the market. Economic entry barriers into the supply market are probably the lowest of all three markets. Nevertheless, margins are low and risks are substantial.

Remedies

Several remedies are considered and proposed. The difficulty is weighing priorities and likely impacts versus costs. There will usually be trade-offs; for example, PPA auctioning might limit short-term market power of Electrabel's generation, but could lock in high prices for the long term.

The first remedial step is to complete/bolster the unbundling of the monopoly elements of electricity from the potentially competitive ones. This was a priority step in almost every successful liberalisation programme globally. We recommend ownership unbundling between generation and transportation and distribution, and further unbundling between all other parts of the business, including regulatory accounting separation and managerial/governance separations. The next step is to put into place a full regulatory programme, including schedules and goals for trading arrangements (PX), new balancing arrangements, and market monitoring.

Full considerations of market design issues and decisions regarding a power exchange for Belgium should be made. If this is not feasible within a reasonable timescale, then interim-trading arrangements, along with schedules for consultations and completions on the final arrangements should be put in place. Interim trading arrangements should include complete accounting separation of Electrabel's vertically integrated businesses, and vesting contracts or trading formulae by which Electrabel trades with itself and despatches plant.

The final piece of the strategy will be to address the market dominance of Electrabel. Their dominance in the most important market, generation, is greatest. Divestiture is the most complete option, and the one that is most likely to fully address market power problems—above all, the ability to raise the wholesale price of electricity. Our modelling shows that dividing Electrabel into 3-4 equal pieces, along with some secondary measures, would

be sufficient to control prices in the range of €35 to €40.. If divestiture is not an option, there are a number of other possibilities. One would be to greatly expand the VPP contract regime. Another would be to implement a scheme of contractual sale of long-term energy rights through auctioning PPAs. Finally, if these options were not feasible, effectively regulating price in the sector would be the other option. This could be done via some form of long-term contracts or outright price controls of either the RPI-X form or cost of service type.

Monitoring

Effective monitoring of the sector will be difficult and will require monitoring both market structures and market outcomes. Monitoring will probably require the cooperation of some market participants, possibly including Elia and/or the owner-operators of any new PX. There will still be considerable judgment required, and a range of measures, discussed in detail in Chapter 7, should be considered together.

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Glossary of acronyms

Glossary of acronyms	
Acronym	Description
APX	Amsterdam Power Exchange
ARP	access responsible parties (BE)
BPI	Belgian Power Index
CA	California
CAISO	California ISO
CalPX	California Power Exchange
CCGT	Combined cycle gas turbine
Cfd	contract for differences
CHP	combined heat and power
COB	California Oregon Border
CRn	the n-firm concentration ratio
DOJ	Department of Justice
DSO	distribution system operators
Dte	Dutch energy regulator
EdF	Électricité de France
EEX	European Energy Exchange
ETSO	European Transmission System Operators
FCO	Federal Cartel Office (Germany)
FERC	Federal Energy Regulatory Commission (USA)
GHG	greenhouse gas
GWh	Gigawatt hour
HHI	Herfindahl-Hirschman index
IFIEC	International Federation of Industrial Energy Consumers
IPE	International Petroleum Exchange
IPP	Independent power producer
ISO	Independent system operator
ISO-NE	New England ISO

Glossary of acronyms	
Acronym	Description
LPX	Leipzig Power Exchange
Mibel	Iberian electricity market
MWh	Megawatt hours
NEPOOL	New England Power Pool (USA)
NETA	new electricity trading arrangements (England and Wales)
NGC	National Grid Company (UK)
NordPool	Scandinavian Power Pool
NTC	net transfer capability
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
OCGT	Open cycle gas turbine
Ofgem	Office of gas and electricity markets (England and Wales)
Ofreg	Office of regulation for electricity and gas (Northern Ireland)
OLS	ordinary least squares
OTC	Over the counter
PJM	Pennsylvania New Jersey Maryland Interconnect
PMC	price cost margin
PPA	power purchase agreement
PX	power exchange
RSI	residual supply index
SCP	structure conduct performance
SMP	significant market power
SMP	system marginal price
TenneT	Dutch electricity transmission company
TSO	Transmission system operator
TWh	Terawatt hours
UCTE	Union of the Coordination of the Transmission of Electricity
VPP	Virtual power plant
WYBIWYG	what you bid is what you get

Annex 1 Terms of reference

Introduction

The aim of the liberalisation of the electricity market is the introduction of competition in the markets for the production, trading and supply/sale of electricity with the ultimate goal of enabling the customer to buy electricity under the best conditions. Thus it is generally assumed that the introduction of competition will result in the former monopoly prices (deemed to be too high on account of alleged monopoly profits) being replaced by competitive prices. It is also assumed that in the long run competition will increase the efficiency of the market players given that the more efficient market players will drive the less efficient ones out of the market.

The ultimate objective does not relate to the national electricity markets, but consists in the creation of a single European internal electricity market.

The CREG wishes to verify whether and to what extent the current federal regulation and its (possible) application contributes to these objectives, and whether and to what extent it can do so in the long run. The first general question is whether the current federal regulation already makes the markets for the production, trading and supply/sale of electricity competitive at this stage, - or whether it can make them competitive and, in the latter case, within what time perspective it can do so. If the current regulation does not or cannot do this, the first general question is why and on what points the current regulation falls short, or can be remedied in this respect and, if so, how.

Following on from this, the second general question sounds out the expected structure of the Belgian electricity market in the light of the merger trend that can now already be observed in several European countries. The question is how this merger trend may affect the above-described objective of the liberalisation of the electricity market.

The project presupposes an economic analysis of the (evolution of the) electricity market in Belgium as part of the core area of the European transmission system (this being, in addition to Belgium: Germany, France, Luxembourg, the Netherlands, Austria and Switzerland), and of the regulation's efficiency in meeting the set objectives. This economic analysis should take account of the technical characteristics of the production, transmission, distribution and consumption of electricity.

Detailed description of the project

The project concerns an analysis of the following three liberalised product markets:

- the market for the production of electricity;
- the market for the trading of electricity;

- the market for the supply / sale of electricity to free customers.

The project concerns all customers, irrespective of whether they are connected to the transmission or distribution system.

The project therefore does not concern an analysis of the product markets as regards electricity transmission or distribution. Obviously the analysis should bear in mind the situation on and the regulation of the markets for electricity transmission and distribution.

The project also does not concern an analysis of the captive markets. Here, too, the analysis should take account of the effects which the captive markets may have on the above-mentioned liberalised product markets.

The project concerns an analysis of the relevant geographical market of which the totality or a part of Belgian territory forms a part.

However, given that the ultimate objective is the creation of a European internal electricity market, this analysis should take account of the European context. It should therefore take into consideration the current situation and developments (such as mergers) to be expected in the other European countries, chiefly those belonging to the core area of the European transmission system (see above), and which could affect the structure and functioning of the relevant geographical market to be studied here. The analysis should thereby pay special attention to the fact that the major players on the product markets concerned in Europe have Belgium's two large neighbours, i.e. France and Germany, as their (major) domestic market. Thus the analysis should provide an answer to the question as to how an effective liberalisation - combined with the likely developments as regards mergers in this sector – will affect the structure and functioning of the product markets concerned in Belgium.

The analysis should give a detailed description of the current structure and the functioning of the product markets concerned in Belgium. The evolution of the structure and functioning of these product markets in Belgium since 1999-2000 should also be described in detail. This analysis will be used as a basis for the analysis of the possible entry barriers described below.

This description will in any case concern:

- the various suppliers and customer categories on the product markets concerned;
- the ratio between total production capacity and demand;
- the import of electricity into Belgium from other countries, and vice versa;
- the degree of utilisation of the individual existing installations;
- the time needed to enter the market;
- the degree of concentration on the market;
- the competitiveness of the prices on the market, including the relationship between the prices on the three product markets concerned;
- the degree of liquidity of the market;

- the switching conduct of the customers;
- the duration of the contracts for the sale of electricity on the three product markets concerned and the termination possibilities.

On the basis of the theory of contestable markets, the analysis should verify as comprehensively as possible whether there are entry barriers (and if so what these are) that result in the product markets concerned not being contestable markets in Belgium.

The found entry barriers should be described in detail and their existence in Belgium should be illustrated on the basis of concrete data. Here a distinction should be made between market-compliant, economically acceptable entry barriers dictated by the technical characteristics of the activity concerned (such as economies of scale and sunk costs) and artificial, economically unacceptable entry barriers (such as regulations restricting competition).

The analysis will check whether the possible entry barriers are higher for completely new or small market players than for incumbent and/or dominant market players in the other countries of the European Union, especially in Belgium's neighbouring countries.

In any case this analysis will examine (although not exclusively) whether the following entry barriers do or do not exist:

- the nature of the investment costs (sunk costs);
- the limitations of the transmission system (interconnections, but also domestic lines);
- limited availability of balancing and back-up capacity at reasonable prices for other than the incumbent electricity producers;
- spatial limitations for new investments (available land and rights of ownership thereof, as well as population density);
- existing horizontal and vertical integration (electricity/electricity, production/supply and electricity/natural gas);
- the competitive advantages of the incumbent market players, including the means they have at their disposal to influence the regulation and its application;
- the lack of complete market transparency;
- the influence of regulation on market access (including sector-specific regulations, urban development and town and country planning, the environment), including the regulation risk;
- the perception of the population of new investments in the electricity market (nimby syndrome);
- the perception of new and potential market players of the risks on the electricity market in Belgium.

The analysis should examine whether the current federal regulation and its (possible) applications are sufficient to bring about the removal of the artificial, economically unacceptable entry barriers and, should that be the case, the time perspective within which the removal of these thresholds can

be expected. If the current federal regulation allows applications which have not been used so far and these applications (help to) ensure that the current federal regulation is sufficient, these possible applications should be described.

If the analysis shows that not all artificial, economically unacceptable entry barriers will be removed with the current federal regulation, it should give a general overview of the measures needed to lift each of these entry barriers, indicating the probable time span within which these measures will have full effect. If measures are proposed that have already been taken in other countries, a list should be given of the effects that these have had on the structure and functioning of the relevant product markets in these countries.

The analysis should concentrate on a critical analysis of the federal regulation only. The regional regulation should only be taken into consideration as an invariable.

In both hypotheses (the current federal regulation is sufficient or not sufficient for the removal of all entry thresholds) the analysis should take account of the influence of the developments in other European countries on the structure and functioning of the relevant product markets in Belgium.

The proposed measures must directly remedy the entry barriers rather than act on their symptoms. Only when such direct remedies do not exist or cannot be implemented for insurmountable reasons, measures may be proposed which only act on the symptoms of the entry barriers.

The analysis should clearly describe the methodologies used, including the assumptions on which they are based. The analysis should also clearly state the strong and weak points of the methodologies used.

The analysis should also pay special attention to the problem of the availability of the information which may be needed to apply these methodologies and to implement the proposed remedies, if any.

Annex 2 Stakeholders' views

In this annex we report the views of the main stakeholders in the Belgian electricity market on the functioning of the market, including regulators, generators, traders, suppliers and industrial users. We also present the views of the TSO and DSOs on various factors improving/inhibiting competition in the market. These views were collected by London Economics through a series of meetings and roundtables with the main players in the market and/or their representatives.

Regional regulators[341] [confidential]

Generation

Electrabel [Confidential]

SPE

Despite having repeatedly asked for a meeting with SPE, we were unsuccessful and did not have an opportunity to seek the views of SPE officials on competition issues in the Belgian electricity sector.

Trading

The key issues raised by traders were illiquidity of the market, unfavourable balancing conditions, lack of transparency and information. The roundtable also discussed a) how the Belgian electricity market could be better integrated into a wider Franco-Belgian-Dutch system and b) the VPP auctions.

As background to the general discussion, traders noted that, in general, the smaller the market the more volatile it will be. This is a particularly acute problem in Belgium. Traders need some incentive to get into that market, otherwise they will just not go there.

Traders noted that the market is illiquid

Traders cannot resell without risking significant loss. This is further aggravated by the transmission constraints across the border with France. Therefore, according to the traders, the first requirement would be to tackle

[341] We note that discussions with these regulators should be considered 'informal' and should not be viewed as official positions of the regulators.

this issue and aim to develop a wholesale market that functions. Competition in supply market requires competitive wholesale and balancing markets

Furthermore, traders believe that for a market to work well it must be possible to trade hourly.

According to traders, end users are also central to stimulate liquidity. Generally, major Belgian electricity users buy directly from producers so these transactions do not bring any liquidity to the market. Typically, a large user is interested in longer-term fixed-price full-supply contract. Such contracts do not exist in the market. Users could trade some of the existing products to get something similar, but this is something that these big users are generally not interested in getting into and generally do not have the capability to do it. It would be better for the market if major users had a more structured buying, and bought in a more transparent way, with products and prices that the market could observe. Some traders noted that, in France, end users can put bids and offers in the balancing market. This is a move in the right direction, although current volumes of this type are extremely marginal. In Belgium, at present, users cannot sell into the market. Traders noted that ARP contract should be simplified to make more end users able to buy and sell into the grid.

Traders also viewed balancing conditions as a problem.

These are judged to be extremely penalising in Belgium. Moreover, according to traders, the current contracts between users and network operators are very one-sided.

For the supply of either balancing or emergency power in Belgium there are only two producers and this is a main reason why this is not competitive According to traders, as a temporary solution it could be ok to put caps or regulate balancing prices. This is not a good long-term solution though, but a temporary solution of this type was used in the French balancing market. Regulation of this type tried to prevent speculative arbitration. To have competition in balancing need to have several players able to provide balancing power or develop mechanisms for sellers from abroad to do it. For example, in France, the Swiss can now compete in the supply of balancing power.

Some traders stated that it was very important to distinguish between a physical imbalance and an imbalance that arises from a trade input error. This latter type has no impact on the physical network. It is essentially a theoretical imbalance. In France these two types are considered the same while in the UK they are treated differently. In Belgium, even an imbalance of the latter type is very heavily penalised. This can contribute to scaring off potential traders. The market would probably benefit from some more flexibility in this respect.

Lack in transparency, difficulties in obtaining relevant information, and regulatory complexities were also viewed as major problems.

According to traders, the French operator provides more information to all players, on grid management, congestion constraints, although less on generation. Players want more info and better info. This will improve liquidity and make traders be less excessively cautious. The French case is a good example of an operator that gives a lot of relevant information in its website. Another problem identified was the lack of hourly prices in Belgium. This is a problem that should be tackled first.

Providing the relevant information is difficult because no competitor in the market wants to be the first one to give information. But this has happened in other countries, as France where the incumbent willingly provided information to the market. EDF for example gives information about nuclear plant maintenance schedules. Electrabel also did this for a while but stopped doing it. This kind of information helps build trust in the market.

Another important problem is there are 2 different regulatory levels in charge of different parts of the grid. Usage measurement is the responsibility of the regional regulators. There are then a lot of problems in transferring this regional measurement information to the TSO. There needs to be a good system for transfer of information between DSOs and the TSO, at the level of infometrics, in particular. Possibly the establishment of a central database should be required. Even if different regulators remain at the different levels, the market has to be unified. As a result of these problems, traders cannot get enough information on their clients. Measurement of clients is a problem. Traders still don't know their imbalance for 2003.

Another problem is Elia's measurements and those of other grid operators will often not match. This has resulted in consumption measurements simply not being sent, leaving market participants with no information about past consumption and instances of out-of-balance situations.

In conclusion, traders said that they have no solid information about supply, nor about generation, and also cannot get anything from outside. It is impossible to trade in a market under these conditions. The different levels need to be much more transparent.

Load factors in Belgium are already published in Elia's website, which is considered very positive. Information on allocated and scheduled border capacity, hourly capacity is also available at the RTF's website. French/Belgium border forecast capacity also is published but it is very unreliable – this is harmful to traders

Lack of predictability

There is lack of a clear view on the long-term tariffs of Elia. This may affect trading of longer-term instruments. But, at preset, longer-term trading is quite insignificant anyway.

Border issues

According to a representative of the Amsterdam Power Exchange (APX), APX is working on a proposal aiming to bring more liquidity to the Belgian market. The idea is to join the three markets – Belgium, France and Netherlands along the lines of the Nordpool model with market splitting but more decentralised.

One issue that this joining of the markets raises is whether the capacity at the borders is sufficient to actually make this work. There is often congestion on the Southern border and, while there is currently no congestion on the Belgium-Netherlands border, some suggested that this may no longer be the case if there is more opening of the France-Belgium border. That being said, one trader noted that the South border is often not fully used – there are regulations preventing the best use of the border capacity.

A number of traders supported the view that the best way to manage efficiently generation capacity is through market coupling of the three countries. However, several different regulators would be involved. Therefore, market coupling may not be that easy to implement. According to one trader the way to start is to first create an intraday market for cross-border trading and then move on to coupling with Netherlands and only later with France

A number of problems with the capacity allocation procedures at the South border were noted. Essentially, the allocation system is a 1st come 1st served system. This is viewed as detrimental to new entrants. Another system based on auctioning of capacity was viewed as more beneficial for competition.

Traders noted that there are strong players in both sides of the Belgian-French border and that there is a potential for manipulation. Regulators need to work hard to try to ensure that large players do not manipulate the usage of border capacity. Again, one would need to develop wholesale market competition before one can reasonably expect to prevent manipulation at the borders.

VPP Auctions

This is viewed as a positive development but without a well-functioning wholesale market it does not solve any of the more fundamental problems facing the Belgian electricity markets.

The product auctioned is not co-ordinated with border capacity so it cannot be used to trade in other markets such as the APX market for example. A spot market in Belgium in isolation from other countries, is probably not viable according to traders.

Traders cannot build a portfolio of customers with VPP products going only to 2008.

The VPP auctions offer a product to traders but do not change the fundamentals in the market – there is no competition, no additional generation capacity being created in this way.

Ways to encourage entry

The following were viewed by traders as a way forward to encourage entry into the Belgian electricity sector, especially the generation market:

- Improving the balancing mechanism, as discussed;
- Reviewing the brownfield / greenfield regulations to facilitate siting of new generation plants;
- Provision of better information;
- Legislative predictability; and
- Establishment of conditions such that potential entrants are reassured that Electrabel will not exercise market power.

Without entry, competition can also be enhanced if the situation at the borders is improved through better management of existing capacity and capacity enhancement at the South border.

The traders concluded that the regulators have to put more pressure on DSOs and Elia with regards to:

- Information provided to market participants;
- Contracting standards used by Elia – very one-sided and "unfair" for grid users; and
- Elia's tariffs, namely for transit and export of electricity.

Transmission and distribution

Elia [confidential]

DSOs

IT and information sharing issues were among the key issues addressed at the roundtable. The representatives of the DSOs also raised their concerns about the allocation of reconciliation responsibilities between the DSOs and Elia, and the lower than desired level of access tariffs. Finally, they also stressed that the key to improving competition in the Belgian electricity market was to increase competition in the generation market.

IT issues

IT problems are a significant issue.

Before liberalisation, the IT systems where fully integrated across the supply chain. Liberalisation has posed some problems in this respect as it requires the untangling of these IT systems.

IT problems arise also from the fact that technical expertise remains within Electrabel. As a result everybody else still needs to work with Electrabel to get something done in this respect.

Moreover, there are still significant problems with IT, data, servers, at the level of clearing house whose development began in 2001 in Flanders, profiting from the experience in the Scandinavian countries

Information sharing

The representatives of the DSOs stressed that, for commercial reasons, they could not give their full database with all their clients to all potential suppliers. But, they are willing to give information on particular clients that may be entering negotiations with a supplier.

The clearing-house for a number of DSOs will have all customer data that needs to be transmitted to new suppliers when customers change – all system of supply change is automated. But, the DSOs remain the owners of the data.

The representatives of the DSOs noted that, while a number of start-up problems occurred, one should remember that the clearing-house system really only became operational in July 2003. Initially, some of the requested data was not sent for a long time because, due to some small mismatches, the IT people decided not to release the data until the whole information was perfect. A change in business culture is required and is slowly taking place.

It takes time to develop and improve data exchange systems – this is the main remaining problem. Data exchange is a particular problem. It will take some years, probably, to get everything to work 100%. In Flanders, full liberalisation occurred only 9 months ago and, so far, the retail market in Brussels and Wallonia are not yet liberalised. Internal IT systems, data cleaning, customer data, all these things are so complex that everybody underestimated the difficulty of the task.

Moreover, during the first months Elia infeed was not working either. DSOs didn't even know how much electricity they were using.

According to the representatives of the DSOs, the suppliers try to use "the excuse" that imbalances only occur because the distributors have not given them the information they need.

Distributors do not agree with the suppliers' point of view that, due to lack of information, suppliers are unable to make good estimates of consumption and power needs. They note that there will always be some uncertainty even if all the past consumption usage was known precisely.

According to the representatives of the DSOs, suppliers say that all their problems come from inadequate data from the DSOs, but the suppliers themselves are also quite behind in terms of IT.

Reconciliation

According to the representatives of the DSOs, a major issue facing currently DSOs is the allocation of reconciliation responsibilities in case of mismatch between DSOs and Elia's figures. These are still not clear. At the present time, DSOs bear this cost that is incorporated in the distribution tariff. Ideally, people should look for an economically sensible solution and DSOs should only be responsible for the delivery to the end-user.

Moreover, putting a lot of the cost and special charges at the DSOs level also creates a problem because the larger customers have the ability to by-pass the DSOs and get electricity directly from the TSO. As a result, big customers, directly connected to the transport grid are paying less than they would if they took their power from the DSOs.

As costs have been moved down from transport to distribution, big customers escape them by connecting directly to the transport grid.

Level of tariffs

The representatives of the DSOs are very concerned that, to keep access tariffs low, the depreciation rate of their assets has been increased from 20 to 40 years. In their view, over the longer run this endangers security of supply and hence liberalisation because not enough funds might be available to maintain and upgrade the distribution networks.

Improving competition in the Belgian electricity sector

The representatives of the DSOs were of the view that to increase competition in the Belgian electricity sector, the key would be to have more competition in the generation market. Physical divestiture would be the best approach. Virtual divestiture through VPP is 2nd best and should be expanded quickly in magnitude.

Meanwhile it may be a good idea to return to the old system of cost control, even if only temporarily, while there still is no competition. As well, there capacity on the South border should be increased.

Supply

EDF Supply[342] [confidential]

Other suppliers

The key issues raised by suppliers are illiquidity of the market, lack of competition in generation, problems with obtaining metering information, difficulties with switching, high transportation costs and other charges, lack of proper Chinese walls at DSOs still partially owned by Electrabel and general policy uncertainty.

Illiquidity of the market

The Belgian market is not liquid enough, because, essentially, there is only one electricity supplier. All suppliers agreed that the Virtual Power Plant capacity auctions (VPP) is potentially a useful measure, but the way the auctions had been implemented was unsatisfactory:

- The amount auctioned was too small. An independent report by Deloitte recommended a higher volume of virtual capacity to be auctioned.
- The starting price had been too high.
- Not enough peak load was offered.
- The suppliers were requested to provide bank guarantees that in many cases was not necessary and increased their costs.

Suppliers suggested increasing the VPP volume two or three times (4000MW was viewed radically altering the situation).

Lack of competition in power generation

According to suppliers, there are no suitable sites left for installing new generation capacity because Electrabel owns all the sites were new plants could be installed. The suppliers expressed concerns that the incumbent is "blocking" potential new entrants.

To increase competition in the generation market a number of suppliers suggested that the incumbent should be forced to divest some of the production capacity

[342] We only talked to the EDF supply.

Metering information

According to suppliers, metering information systems have not yet been properly separated and remain effectively under the control of Electrabel. The suppliers complained that the information they receive is of low quality, and made available only with long delays (sometimes six months). As a result, suppliers are unable to estimate the consumption volume of the client. The whole system is chaotic and this benefits the incumbent. Suppliers noted that this uncertainty increases their costs because they have to bear a higher risk.

Suppliers suggested that there should be a "clearing-house" (an independently regulated body) where suppliers could have access to the information. As well, the regional regulators should have the power to impose substantial fines in the case of unsatisfactory communication of essential information.

Difficulties with switching

According to some suppliers, it takes quite a long time to switch end-users. The DSO are not properly organised to switch customers. However some suppliers did not see this a major problem as they were achieving some important numbers of switchings.

Transportation costs and other charges.

According to suppliers, the transport operator is not independent but is still indirectly owned by the incumbent. The transportation tariffs are too high. Suppliers are claiming that because the incumbent is vertically integrated it is squeezing the margin at the supply level and recovering it with higher prices somewhere else along the supply chain. As a result, suppliers claim that the supply market is selling below cost.

Complex regulatory systems and lack of clarity and predictability

Suppliers noted that they face a large amount of administrative and regulatory paperwork in the supply market. The companies need to hire extra personnel just to deal with these bureaucratic aspects. Suppliers estimate that elimination of unnecessary paperwork would improve efficiency by 50%. The complex system of taxes/charges system with many different charges and taxes also adds complication and costs.

Suppliers suggested that the administrative information requirements be streamlined and that the system of taxes and charges be more predictable and simple.

Lack of proper Chinese walls at the DSOs still partially owned by Electrabel

According to suppliers, Electrabel has an unfair advantage over other suppliers because the IT systems used by the mixed DSOs are still managed and run by Electrabel. As a result, Electrabel is able to access commercially sensitive information on its competitors' clients.

General policy uncertainty

According to suppliers, the Belgian electricity sector as a whole faces considerable policy uncertainty at both the federal and regional level. It is not clear what the implications of Kyoto and carbon emission reductions will be for the sector even so this is critical for taking decisions regarding new generation investment. Another aspect of concern are the frequent changes of the rules regarding green energy.

Industrial users

Industrial consumers in Belgium are of the view that they do not have much choice to meet their requirements in terms of power supply. This is particularly the case of those users that have a high annual consumption of electricity (above 100 GWh/year). Baseload power is generally available from several suppliers, but Electrabel is the only provider of peak power. High concentration in generation seems to be the cause of the lack of choice in Belgium.

The trading market is relatively thin. Only few trades are done per day and the market is highly volatile. Lack of development of the trading market is also perceived as a consequence of low competition in generation. The balancing system is considered as excessively penalising. Electrabel is the only company who seems to be willing to enter into balancing arrangements.

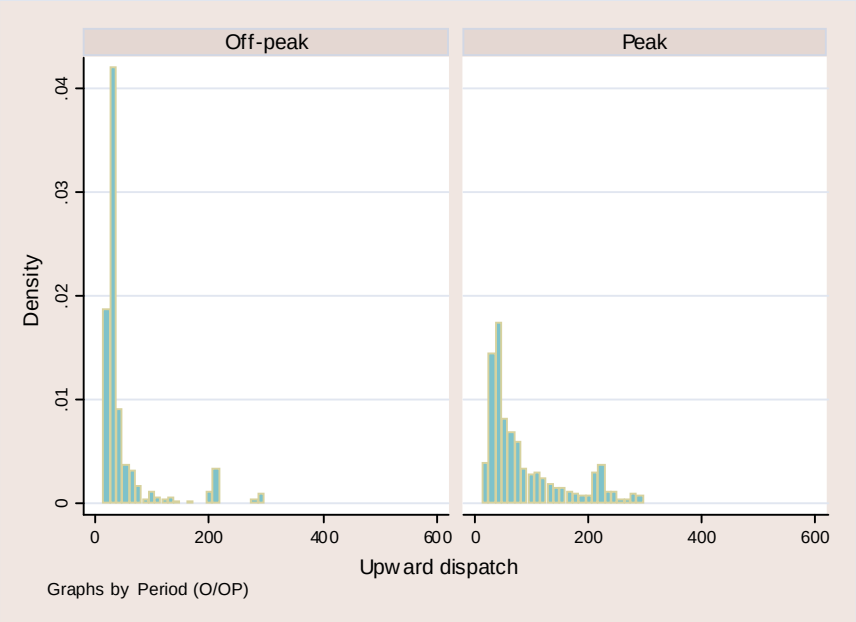
Entry in generation is particularly difficult because of lack of sites suitable for power generation. Electrabel seems to have purchased all the sites suitable for sizeable CCGT and CHP installations before liberalisation. Moreover, wholesale prices are perceived as excessively low and highly volatile to justify building of new capacity.

Simplifying existing rules and legislation, lessening the administrative burden, reducing political and regulatory uncertainty, and adopting a 'clear' approach on nuclear decommissioning are all seen as important conditions for building new capacity. Clarifying the current (and future) regime for green certificates is also expected to have a positive effect on new entry. Finally, more import capacity on the South border complemented with a more transparent and 'reliable' allocation system would be of great benefit to them.

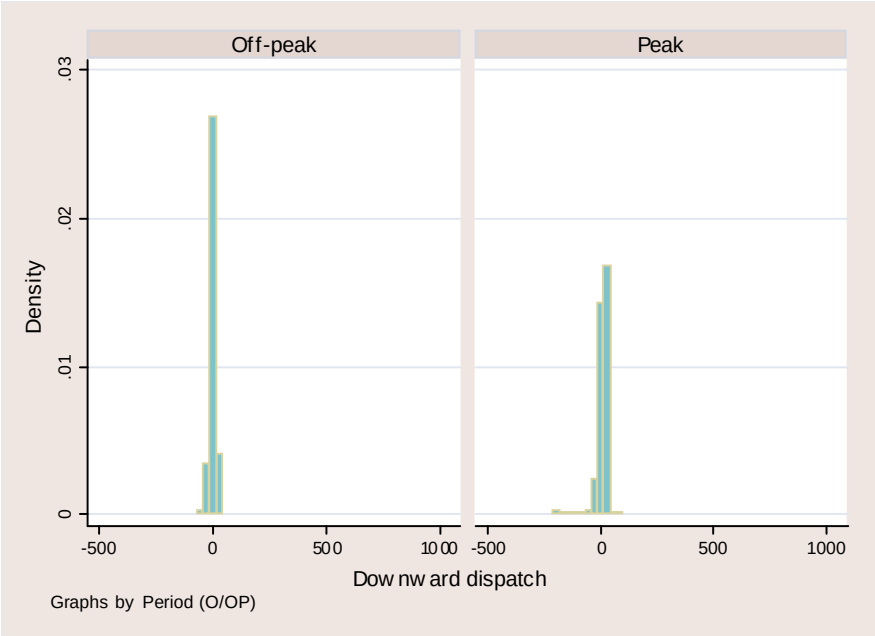
Annex 3 Volatility in the Dutch and NETA Balancing Mechanisms

In this annex we show the full distribution of imbalance prices of the Dutch balancing market and of NETA's. The shape of the histograms clearly indicates that the Dutch imbalance prices are much more volatile than NETA's.

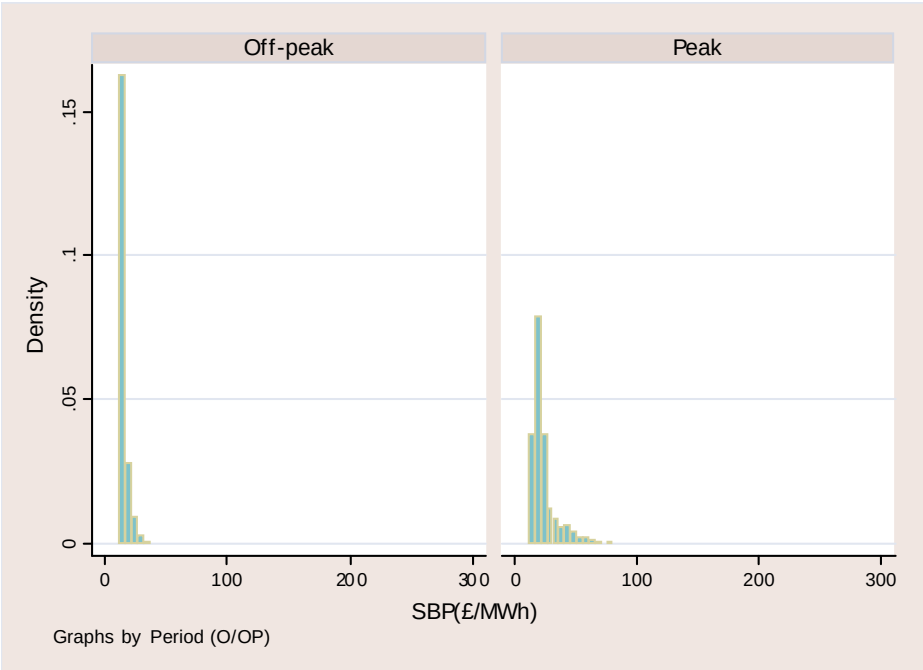
Dutch BM: negative imbalance (€/MWh)



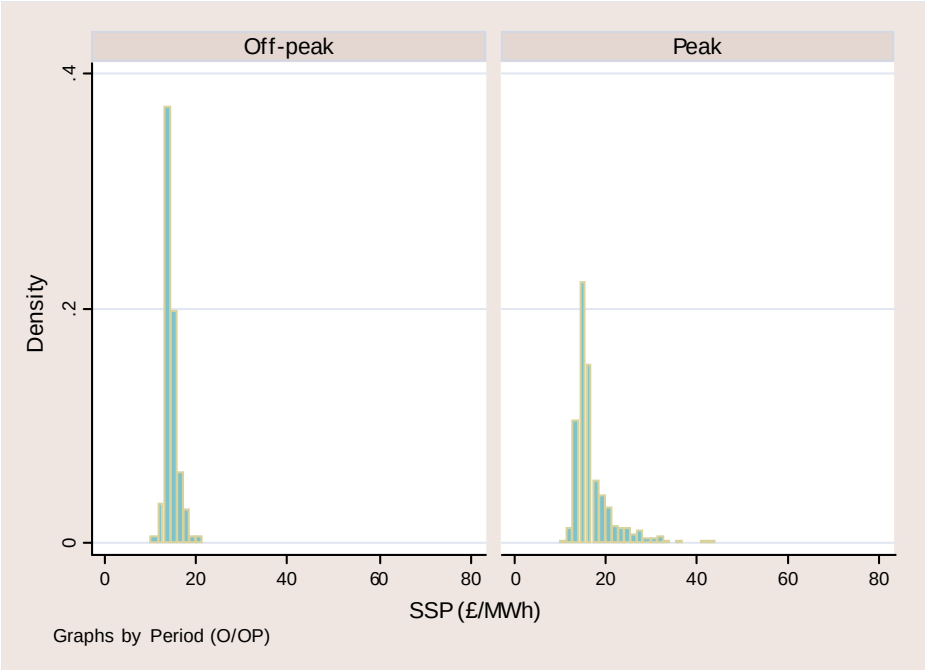
Dutch BM: positive imbalance (€/MWh)



NETA BM: negative imbalance (£/MWh)



NETA BM: positive imbalance (£/MWh)



Annex 4 Mechanisms to allocate capacity on the French border

Monthly capacity (from Elia website)

Capacity available for monthly allocation is jointly determined by Elia and RTE. RTE and Elia will publish on their respective website an indicative value of the capacity available for monthly allocation in the direction from France towards Belgium on the first workday of the month preceding the month for which capacity is allocated. The final value of the capacity available for the monthly allocation will be fixed by RTE and Elia on the 20th day of the month preceding the month for which capacity is allocated.

The capacity is guaranteed by the two TSO's for the whole of the month but one day and except the cases of "force majeure".

Reception of applications

Elia is the operational contact for reception of applications for monthly capacity in name of RTE and Elia. Applications for capacity can be introduced by ARP's that also have subscribed a participation agreement to the rules for access for imports/exports and a contract for the use of the France-Belgium interconnection for exports in France. The applications must be received by Elia between the 1st and 20th day (at 00h00) of the month preceding the month for which capacity is allocated. Applications shall be formalized according to Elia's ARP contract.

Handling of applications

This capacity can be acquired by access responsible parties in blocks of maximum 25 MW. The blocks are allocated as follows:

- Every access responsible party can submit up to four applications for blocks of maximum 25 MW.
- All applications are given a value: the application for the first block of 25 MW is given a value of 4; the application for a second block of 25 MW is given a value of 3; the application for a third block is given a value of 2; and the application for a fourth block is given a value of 1.
- All the applications of all access responsible parties are then ranked.
- The available capacity is initially allocated to those applications with a value of 4; if there is any capacity left over, the applications with a value of 3 are processed; then those with a value of 2 and finally those with a value of 1. Capacity is allocated among applications that have the same value according to a ranking list updated by Elia on the basis of the time

at which the initial application of each access responsible party concerned was submitted ("first in, first served" principle).

§ The "use it or lose it" principle is applied according to the recommendations of the European Commission: when an Access Responsible Party has used less than 65% of the capacity of a bloc of a given value, during the last three months for which he has obtained this capacity, he loses, for this bloc, his position in the ranking list for the following months. The Access Responsible Party nevertheless keeps the right to submit an application for a new bloc of the same value and obtain a new position in the ranking list; this application will be treated by Elia according to the date and hour of reception by Elia of the written application for this new block.

Nominations

By 08h00 at the latest on the day before the day for which capacity is allocated, holders of monthly capacity and holders of long term contracts send their nomination programme (schedules) to Elia in both directions of the interconnection and according to the mechanism applied by Elia. Those values are final and capacity holders will nominate the same values at RTE's according to rules applied by RTE. Any consequence or responsibility ensuing from differences in the values nominated at Elia's and RTE's will to the charge of the capacity holders.

Congestion fee

Elia applies a fixed congestion fee applied to monthly capacity, i.e. 500 Euro per month and allocated MW and 0,5 Euro/MWh scheduled between 07h00 and 22h00

Daily capacity (from Elia website)

Capacity available for daily allocation is fixed jointly by Elia and RTE. RTE will publish on its website, two days before the day for which capacity is allocated (i.e. at 22h00 on D-2) the indicative value of the net capacity proposed for day D in the direction from France to Belgium. The final value of the capacity available for daily allocation is fixed by RTE and Elia before 08h30 the day before the day for which capacity is allocated. The allocated capacity is guaranteed except cases of "force majeure".

Reception of applications

RTE is the operational contact for reception of applications for daily capacity in name of RTE and Elia. The day before the day for which capacity is allocated, before 08h30 (i.e. before 08h30 on D-1) the holders of export transactions towards Belgium and of ARP contracts apply for capacity at RTE's according to rules for access for imports/exports.

Handling of applications

Before 09h30 on the same day RTE, on the account of the two TSOs, accepts totally or partially, or rejects those applications according to rules for access for imports/exports.

The following rules are being applied:

- Applications for daily access towards Belgium addressed to RTE may not exceed 25 MW;
- A user may not present more than four simultaneous applications;
- Before presenting a new application, the user may not have more than three unused applications;
- Pre-existing access application are levelled out of the maximum nomination submitted between 1 February and 31 May 2002 and limited to 25 MW.

Nominations

Until 14h00 on D-1, capacity holders can nominate a lesser value at RTE's. Capacity holders will nominate the same values to Elia's according to the rules applied by Elia. Any consequence or responsibility ensuing from differences in the values nominated at Elia's and RTE's will be to the charge of the capacity holders.

RTE will publish on its website after 19h00 on D-1 the global results of nominations.

Congestion fee

Elia invoices the daily quantities nominated in the period 07h00 – 22h00 against a fixed congestion price of 0,5 Euro/MWh.

Annex 5 Modelling details: assessing the economics of entry for generation, supply, and trading

This annex explains the details of the entry models used for generation, trading, and supply.

When there are fixed costs in an industry that must be recovered, due to the technology of the sector, then the most common economically justifiable barrier would be that current price levels might be too low to justify. The margins might be insufficient to cover the fixed costs. While several of the market participants from our private consultations suggested current price levels were too low, London Economics also undertook some detailed modelling of entry prices and compared them with prices observed.

An important note on the interpretation of these models is appropriate at the beginning. The models all use several parameter inputs that are estimated with uncertainty. This means that it cannot be said that entry is unequivocally predicted or not. However, the models do account for uncertainty, either explicitly, in the generation case, or implicitly, in the WACC applied to all the models.

The interpretation of a model's prediction against entry is different than the interpretation of a prediction of entry. This is because there are potentially other barriers to entry. If entry is not supported by the economic fundamentals, then any other potential barriers merely weigh more heavily against entry. If entry is predicted to be supported by the economic fundamentals, then the other potential barriers might still block entry—thus the prediction that entry is supported by the fundamentals is not a prediction that entry *will occur, per se.*

Cost of capital

The basic model of entry, as described in the text on barriers, is the discounted cashflow view. In such as model, entry should occur, absent all other barriers, if the discounted value of expected revenues from the project exceed the discounted value of costs, including upfront investment costs. While there are of course more complicated models, starting with the DCF approach is very informative.

The basic input into the DCF approach is the cost of capital. The almost universally accepted basic cost of finance approach is the weighted average cost of capital, or WACC. The WACC approach we use is the same for all three models. We also used the same inputs for all three models—this is for simplicity and for comparisons sake. Likely, some smaller companies would have a higher WACC, and some larger companies a lower WACC, but getting too detailed into the cost of finance would be beyond the scope of this report.

The cost of capital is seen as the opportunity cost of capital to the firm. This is the firm's true economic cost of financing its operations. This includes interest expense on debt plus the opportunity cost of equity. The equation then shows the relation between the economics of physical and financial capital.

Under the traditional view of corporate finance, the firm issues new shares to finance its operations at the margin. The firm also issues debt. The result is that the economic cost of capital is the weighted-average cost of capital (WACC) to the firm. The WACC weights are formed by the levels of gearing, or the proportions of firm value on debt and equity.

The actual (true) WACC for the firm is then the proper discount rate for any project the firm undertakes. The WACC thus also forms the "hurdle rate" for the internal rate of return of any project. As such, any project with an internal rate of return that exceeds the hurdle rate creates value for shareholders of the company, while any project undertaken with a rate of return below the WACC destroys shareholder value.

The discount rate, *WACC*, is the weighted-average cost of capital to the firm. The WACC in its simplest form can be written:

Equation A5.1 $WACC = g \cdot r_d(1-t) + (1-g)r_e$

Where: g is the level of gearing, i.e. the value of debt as a proportion of debt plus equity;

r_d is the company's cost of debt finance; and

r_e is the company's cost of equity finance.

The building blocks of the cost of capital are then seen to be broken down into the cost of equity and the cost of debt. The cost of equity is most commonly estimated using the capital asset pricing model, CAPM. While there are many problems with CAPM, and many subsequent variations, the basic CAPM remains the most widely used method by regulators and practitioners.

If the CAPM is inserted into the WACC, and the cost of debt is defined as the risk free rate plus a debt premium, reflective of the probability of default on corporate debt of the firm, the following relationship is found:

Equation A5.2 $$WACC = g(r_f + DP)(1-t) + (1-g)[r_f + \beta(r_m - r_f)]$$

Where: r_f is the risk-free rate of return;

DP is the debt premium paid by the company;

r_m is the market rate of return—(r_m-r_f) is often referred to as the equity risk premium;

β is the measure of the risk premium required by investors to hold the company's equity. Under CAPM, it is a measure of risk relative to the market;

g is the level of gearing, i.e. debt as a proportion of debt and equity; and

t is the marginal corporate tax rate.

Table A5.1: WACC parameters		
Detail	Rate	Note
Risk free rate--10 year EU average, average since (1-1-2001)	4.06%	Long term MFI rates for Belgium from ECB—update quarterly
Beta EU market	0.8	LE previous report for private client: average for EU utilities, data from Bloomberg—update annually
Total equity return	13.5%	Ibottson, US market 50 year average – update only every several years
Gearing	60%	LE estimate, consistent with Ofgem, CER, Ofreg, etc – update annually
Expected market (equity) risk premium world	9.4%	Endogenous
Corporate tax rate	33.99%	Statutory rate Belgium-update as needed
Debt premium basis points	250	LE reports on cost of capital, consistent with current Bond yields for corporate utilities – update quarterly

Source: LE and various sources

The resulting WACC is 10.23%. The inflation rate of 2%, the ECB target rate, is then subtracted from this to get 8.23%. This is the discount rate used in the annuity formula, or payment function (see MS Excel help – PMT(.) calculates the annuity payment needed to pay off an upfront cost over a period in equal instalments.) It is important to use this WACC correctly. It is a nominal after tax WACC. To convert this to a real WACC, an expected inflation rate can be

subtracted off. Using the ECB target rate of 2%, gives 8.23%. We assume that the general rate of inflation for costs will be the same as the general rate of inflation for revenues. In this case, each of the power cost and the power revenue grow at the inflation rate, and so the gap between them also grows at this rate, but the real difference between them remains the same. Thus, the correct WACC is the real WACC, i.e., including a discount for inflation, because the margin or gap includes the inflation effect.

Generation

To study the wholesale energy price that would trigger entry into generation, we used two models, one that was based on the straight "discounted cashflow" method of determining the entry price, and one based on the model of investment under uncertainty developed by Dixit and Pindyck[343] (1994). The model essentially assumes 400MW nameplate capacity CCGT with 55% thermal efficiency and 90% load factor achieved.[344] We also did sensitivity analysis on some of the key parameters. The low case corresponds to an initial investment in a CCGT corresponding to €200m, while the high case corresponds to a €250m.[345] Under uncertainty, the low case also uses a lower volatility for electricity prices, which corresponds to a value of 0.1, whereas the high case corresponds to a volatility in electricity prices of 0.2.[346] The two models were used in unison, and the results were combined to give a minimum price, below which entry almost certainly would not occur, and a maximum price, above which entry almost certainly (without other barriers) occur. The results are found in the table below.

[343] Dixit, A, and R. Pindyck (1994).

[344] This corresponds well with the station database obtained from the CREG for recent CCGT in Belgium. It also corresponds with international studies of new entrant prices in Australia (IPART, 2004), the UK (Coolkeragh study by London Economics 1997), and Ireland (see CER Best New Entrant Price 2002: the Commission's Decision www.CER.ie)

[345] An investment cost of €250m for a 400MW, or about €625/kw capacity power plant is corresponds closely to the higher values of recent asset sales globally. For example, USAEE materials suggest that at the height of power companies' merger and acquisitions in 2001-02, assets were selling for around $600/kw capacity.

[346] Volatility was calculated from the daily peak average prices from the APX for 2003. This is the standard deviation of the natural log of the prices. We also did not assume a "spark spread type model", where the gas price was allowed to be volatile and the spread between the electricity and gas prices is the relevant price, because this would have likely reduced the effective volatility since gas and electricity price should be positively correlated. Reducing volatility would reduce the spread between the uncertain and the certainty case. Since our goal was to calculate an "upper bound" above which we would expect entry absent other barriers, the spark-spread model was not used.

Table A5.2: Comparison entry prices and wholesale prices€/MWh		
Name	Low case	High case
DCF trigger price	€ 34.17	€ 35.84
Trigger price with waiting due to uncertainty	€ 41.99	€ 50.41
Difference uncertainty	€ 7.82	€ 14.58
APX avg 2002-2003	€ 41.21	€ 41.21
BPI avg (Electrabel) 01/03 to 31/05 2004	€ 29.49	€ 29.49
Platts BE OTC year ahead avg. Jan-June 2004	€36.86	€36.86

Source: London Economics, APX, and Electrabel (website)

Our current findings suggest that current wholesale prices, when considering uncertainty, are likely to be just below the price that would trigger entry. The average price needed to attract entry is at €41.99 per MWh in the low case and € 50.41/MWh in the high case, while the APX price is €41.21/MWh in the cases that include uncertainty. We consider the most appropriate comparator to be the APX price because evidence suggests that the BPI tracks the APX price very closely, but the BPI price index is not available for a whole, or even half a year (Electrabel's website).

Uncertainty plays an important part in the entry decision process. This is evidenced, in part, by the theoretical background on the theory of investment under uncertainty. There is a value to waiting that increases with uncertainty. The model can be formulated so that the value of waiting acts as an "adder" on to the standard DCF price/MWh. The evidence that uncertainty is important is empirically demonstrated by the estimates. The difference between the pure DCF model and the uncertainty model is between €7.82 and €14.58/MWh. Recall that this is mostly due to changing the volatility estimates from 0.1 to 0.2. It is also true that participants with whom we consulted all emphasized the importance of uncertainty.

The estimates do not entirely suggest that entry is totally blockaded purely on an economic basis. The pure DCF modelled price in the low case, at €34.17/MWh, is below the APX average price of €41.21/MWh. This suggests that, if the investment under uncertainty model were not correct, then one might expect entry under current market conditions *in the absence of other entry barriers*. It is true, that the pure DCF model *does* account for *some uncertainty* in that the parameters of the discounting scheme may vary with risk. The main parameter here is the beta of the capital asset pricing model

(CAPM). However, the beta only accounts for diversifiable risk[347], and the opportunity cost of investing is only diminished under intense competition. We therefore believe that it is interesting that the DCF model predicts entry, but that the uncertainty models are the more appropriate models.

An important input into our study of entry is the expected wholesale price of power (the price a generator would receive) relative to the cost of power. There are several things to consider. First, one naturally needs a dynamic forecast of such parameters. Next, one needs a dynamic forecast of the relative sizes. This could be considerably complicated. There are a number of options, including an econometric forecast (structural), a time series forecasting approach, or studying forward curves for commodities as a market-based forecast approach. We employ two assumptions, however, that are quite simplifying, but we feel very reasonable.

The assumptions are as follows. First, that the natural gas price follows a well-known stochastic process, that is, a geometric Brownian motion, or random-walk with drift. This is the same process that is the most widely accepted model of stock prices in efficient markets. This means that natural gas prices tend to be unpredictable, with the exception of a long-run drift rate, or growth rate. There is significant research on this, including Pindyck (1999).[348] The second assumption is that natural gas prices will continue to set the equilibrium marginal cost of power for the next 10-20 years. This is consistent with almost all resource planning for power systems, including ETSO.

Thus, in conclusion, the analysis suggests that current wholesale price levels are either just or somewhat below a level that would be required to attract entry. Thus, under the current situation the expectation would be that new greenfield CCGT entry would not occur even if other entry barriers were removed. This is not unequivocal, as the DCF-based new entry trigger price is below current prices, but we believe the prices adjusted upwards for uncertainty are the more appropriate benchmarks.

The on-going discussion in Belgium on accessing on a grand scale the "cheap" French power compounds the entry problem discussed above, as any gas-fired plant will be unable to compete against such an alternative source of power. Given this risk, it is currently difficult to justify building a new gas-fuelled generation plant in Belgium.

LE entry model: electricity trading market in Belgium

LE has developed a model of market entry for the Trading sector in Belgium. Based on a small number of assumptions and estimates of various parameters

[347] This is theoretically the only risk that will earn a premium in efficient capital markets, however, the assumptions of the investment under uncertainty model explicitly assume that the opportunity to invest is "owned" by a particular market player, and so the two views are not inconsistent.

[348] Pindyck, Robert S. (1999).

of entry, LE has modelled the entry decision for a potential entrant into the Belgian trading market. By updating this information on, say an annual basis, the spreadsheet tool could be used to provide the CREG with an ongoing indicator of the economics of entry into the Belgian trading market.

The model provides an indicator of the likelihood of entry, and comes with the usual caveats of models with uncertain parameters. In addition, we emphasize that the usefulness of models is more often with respect to estimating the impact of a "potential change, ceteris paribus". This is because input parameter estimation might be (in spite of the users best efforts) biased in the levels, but not *differentially* biased.

Thus the CREG will be able to continually have an updated forecast as to whether entry into trading is at least feasible based on the economic and financial fundamentals and assumptions of its choosing.

Assumptions

Underpinning the trading entry model is a set of key assumptions. We discuss these assumptions below.

- We assume that the number of MWhs traded per annum for an electricity trader in Belgium equals 1,952,500 MWhs. This assumption has been informed by a study completed by Strecker & Weinhart.[349]
- We have modelled the Weighted Average Cost of Capital based on estimated parameters (described in detail above).[350] We estimate the appropriate real WACC parameter to be 8.23%, which is the figure used to amortise the fixed investment costs in the trading model. We assert that the productive life of investment is 10 years.
- Finally, we assume that the cost of energy to the trader is €40.00 per MWh, based on APX average prices and LE modelled prices.

Sources of information used in the model

In order to complete this original piece of analysis, LE has collected information from a wide range of sources. In this subsection we detail the source of the information used to form the model.

The source of much of the information concerning fixed costs is a report completed in 2002 for the DTI.[351] Estimates of: IT for non-physical trading; UKPX, APX and broker connections; 24/7 IT; Risk Management System costs;

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[349] Strecker, S. & Weinhart, C. "Wholesale Electricity Trading in the Deregulated German Electricity Market", http://www.econbiz.de/archiv/ka/uka/information/wholesale_electricity_trading.pdf (2002).

[350] See 'Capital | TRADING' worksheet of the model workbook.

[351] ILEX Energy Consulting (2002).

and Back Office expenses were obtained from the DTI report. However, as the report was commissioned by the DTI, all estimates are quoted in £sterling in the report. Therefore, all figures used from this report have been converted to €uro for the model using PPP (Purchasing Power Parity) exchange rates for Belgium, published by the OECD. Information pertaining to the new business registration costs and the minimum capital requirements for a private limited company in Belgium was obtained from the World Bank and added to the trading desk setup costs.

Similarly, much of the information used for variable costs is sourced from the DTI report. Estimates of: trading team costs[352]; back office costs; and NETA control resource costs have been obtained from the DTI report and converted to €euro using Belgian PPP exchange rates, published by the OECD. From these figures, an estimate of operating costs per MWh per year is calculated by dividing total operating costs per year by the number of units (MWhs) traded per annum.

Energy Costs per MWh of €40.00 is used, based on the energy cost per MWh assumption, outlined above.

We use a gross margin of 2.3% in the model. This percentage is the midpoint of a range (0.0%-4.5%) quoted by J. R. Stephenson, Chartered Financial Analyst.[353]

How the model works

The aim of the trading entry model is to simulate the decision facing a potential entrant into the electricity trading market in Belgium. That is, would entry be profitable given the defined market conditions? The model answers this question as described below.

All components of fixed and variable costs are summed to give total fixed (investment) costs and total variable costs, respectively. Total fixed (investment) costs are amortised over 10 years at real WACC of 8.23%. Dividing the amortised fixed costs by the number of MWh units the trading firm trades per annum, gives an estimate of fixed cost per unit (MWh)per year.

Total variable costs are divided by the number of MWh units the trading firm trades per annum, giving an estimate of variable cost per unit (MWh)per year.

The % gross profit margin is applied to (average variable cost plus energy costs per MWh) to give a per MWh margin, given the parameters defined in the model.

[352] Based on 5-6 staff, shift manager, generation trading manager and IT support staff.

[353] See: http://www.reportonmoney.com/articles/energytradingsuccess.htm.

The culmination of the model is the entry decision, which gives an indication of whether entry is likely into the trading market given defined market conditions. According to industrial organisation theory, firms will enter a market up to the point where *ex post* entry profits are equal to zero. Therefore, if the gross profit margin achieved exceeds or equals the fixed cost per unit (MWh)per year, entry will occur.

The model also includes a feature that allows flexibility in one of the parameters of entry. That is, it allows the CREG to model the impact of a change in one parameter, ceteris paribus. The two such examples included in the spreadsheet are: what would be the lowest margin necessary to entice entry?; and what would be the lowest volume (MWh) necessary to support entry? The results of these questions are obtained using the 'Goal Seek' tool in Excel, which computes the % margin, or volume, necessary to satisfy the condition {[(€ Margin per MWh) - (Setup Cost per MWh)] = 0}.

Scope for entry in the supply market

We examine the economic fundamentals of the supply market entry decision. Because entry is a complex process, there are a number of models describing investment decisions under various conditions.[354] Nonetheless, the fundamentals of entry remain the same and can be reduced to a discounted cashflow model. We do not calculate a model under uncertainty, because the volatility of the margins received by suppliers is unobservable. We further expect volatility (of the net price received by suppliers, not the energy price) to be low.

The models we have developed use the discounted cashflow trigger price theory, which is the basic model used for investment decisions. Under this model, entry should occur if the expected average total cost of running the business is less than the expected price. That is, the revenues over time (discounted to its present value) are enough to cover for the fixed and variable costs. The cost of running the business includes the opportunity cost of capital. An alternative and equivalent way of looking at this is to say that if operating profits contain a margin sufficient to pay-off investment costs, amortised at the weighted average cost of capital, then entry is feasible.

When the investment includes fixed costs that must be recovered, too low prices might act as a barrier to entry. This is because the margins that can be obtained are insufficient to cover for the fixed costs. To analyse whether prices constitute a barrier to entry, we estimate a model of entry comparing the minimum prices to recover the fixed costs and the expected market prices. We have used two models of entry: one for suppliers selling to large medium (i.e. 6GWh/year), and another one for suppliers of smaller customers (i.e. 4,000kWh/year). The investment requirements and operating costs are different in both cases, and we expect the entry decisions may be different

[354] These are described in more detail in the chapter or barriers to entry.

between these two subclasses of market. The process of estimating new entrants' costs is sensitive to many assumptions, and thus the results must be interpreted with care.

Entry in the supply of small customers

The entry model for small customers is calculated using the details of the Flanders market, which is the only market in Belgium where small users are eligible to choose their supplier. We have estimated the number of households in Flanders as 2,368,421. We then allowed a supplier to gain a market share of 0.15%[355] of the eligible market. This leads to 3,553 households with an estimated annual consumption of 4000kWh.

From Ofgem we obtained the cost of customer acquisition[356] and estimated the total investment costs as €319,138. Finally, we assume the investment depreciates in 5 years.[357]

We then estimated the operating costs per customer per year as €43.5 using models developed for IPART (2004)[358], wholesale prices were set at €46.40/MWh—using data from Global Insight's report to CREG. Distribution and transmission costs were obtained from Global Insight and were set at €cents 5.92 per kWh.

We studied entry under two different scenarios. The low case corresponds to an investment of €319,138, as discussed above. The high case corresponds to an initial investment of €500,000. Finally, we estimated new entrant suppliers could make a profit margin of 4.4%.[359]

[355] This is the market share (household connection points) that Elektriciteitsbedrijf Merksplas, Ecopower or Netbeheerder have (see http://www.vreg.be/vreg/marktgeving/statistieken%20marktgegevens/11356.pdf). Essentially, we assume that this level of entry is consistent with a minimum market share attainable by an entrant.

[356] We assumed a customer acquisition rate of 80%, i.e. the supplier needs to target 10 people in order to get 8 customers.

[357] The five-year investment time-frame for supply customer acquisition is generally accepted methodology, and is used by Ofgem.

[358] IPART (2004).

[359] Global Insight (2004).

Table A5.3: Trigger price entry model: small customer supply		
	Low case	High case
Investment	€319,138	€500,000
DCF trigger price (€/MWh)	122.44	125.81
Price with 4.4% margin (€/MWh)	121.59	121.59
Entry?	NO	NO

The findings suggest that entry is unlikely to occur under current conditions in both the low and high case scenarios. We note, however, that the low case is very close to the price with the currently estimated margin. If margins were in fact just a bit higher, or if customer acquisition costs were a bit lower, then this could change. In the low case scenario, the average trigger price to attract entry is €122.4, which is more than the price with a 4.4% margin (€121.6). We have also computed that under the low case entry would be possible with a minimum margin of above 5.1%. It is difficult to say if 5% operating profit margin for retail supply of small customers is unlikely to be sustainable. Evidence studied by regulators internationally suggests that competitive margins in this market are lower, but the margin that results in a competitive market will in fact be endogenous to the long run entry conditions.

The high case scenario shows similar results—since entry is not predicted in the low case. Entry is unprofitable because the price that would be required to enter (€125.8) cannot be achieved with a 4.4% profit margin (price of €121.59). Our computations show that for entry to be profitable prices would need to be set with an 8% margin.

Entry in the supply of large customers

We also developed a model of entry for medium to large customers. The models are virtually the same, with only the parameter inputs changing. An important choice in the model is the minimum market share that might be acquired. The model assumes a 1% attainable market share of the total market of medium sized final customers. It has also been assumed that the potential entrant supplies to customers that consume annually an average of 6GWh—this is the midpoint of 2-10GWh.. The distribution and transmission charges have been estimated at €22.0 per MWh[360], and payroll and other operating expenses are of the order of €0.67 per MWh (estimated after assuming a salary of €40,000 per employee and 10 customers per employee). Finally, wholesale prices are set at €46.40/MWh (Global Insight data).

[360] Global Insight (2004).

We studied entry under two different scenarios. The low case corresponds to an initial investment of €1.5m[361], while the high case corresponds to a €3m (both cases assume the investment depreciates in 5 years).[362] Finally, using Global Insight data we estimated suppliers could make profit margin of 13%.

Table A5.4: Trigger price entry model: large customer supply

	Low case	High case
Investment	€1,5m	€3m
DCF trigger price (€/MWh)	70.05	78.05
Price with 13% margin (€/MWh)	78.05	71.06
Entry?	YES	YES

The findings suggest that, absent other barriers, entry is likely to occur under either case scenario. The average trigger price to attract entry is €70.06 while the price with a 13% margin is €78. We have also computed that entry could occur with a minimum margin of just above 1.4%. Or alternatively, entry would still be profitable with attaining only a 0.11% market share (instead of our assumed 1%). Thus the entry prediction is not very sensitive to the margin or market share assumptions, and our current best assumptions are far from the limits of where entry would not be predicted.

Our findings for the high-case scenario show that entry may still occur if an investment of €3m is needed to enter the market. Moreover, under this scenario, entry will still be possible if the suppliers could make a profit margin of 2.89% or, alternatively, if they could achieve a market share of at least 0.22%.

[361] This is the total investment, excluding debt, of former entrant SourcePower.

[362] The five-year investment time-frame for supply customer acquisition is generally accepted methodology, and is used by Ofgem.

Annex 6 Description of CustomBid

CustomBid is a model of strategic behaviour in wholesale electricity markets built by an economist. It is an essential modelling tool for anyone in the business of wholesale electricity markets. The model makes extensive use of Game Theory to calculate annual prices and pay-offs for player portfolios. CustomBid is used to assess the effects of mergers and de-mergers, optimal plant portfolio holdings, the effect of new entry into the wholesale generation market and whether a player has market power or not.

CustomBid was originally developed by London Economics, the economics consultancy, but it is for anyone analysing wholesale electricity markets.

Analysing deregulated power markets requires a detailed understanding of strategic behaviour. To date, production cost models ('merit-order' despatch) have been the primary tool for developing an understanding of these markets. Such models tend to underestimate observed wholesale prices because their estimates reflect only least cost despatch, subject to technical constraints. In most wholesale electricity market the larger generators have the ability to sustain bids above variable cost, enabling them to recover some or all of their fixed costs. This section describes the theoretical background to the way CustomBid analyses strategic behaviour.

CustomBid applies game theory to wholesale electricity markets. We briefly describe some of the basic game theoretic concepts in this section. A full description of the underlying theory is provided in the documentation.

Bertrand competition

There are generally two principal types of competition in any market. One is price competition (known as Bertrand); the other is quantity competition (known as Cournot). Bertrand competition occurs when players maximize their profits by maximizing their market share. Bertrand competition is often used in the study of duopoly. Under certain conditions Bertrand competition implies that although only two players dominate the market, the Nash Equilibrium is competitive. Since the two suppliers compete only on the basis of price, and all market share goes to the lowest cost supplier, both will attempt to undercut until both are bidding marginal costs.

Since electricity is a homogeneous good, that is, supply from one player is perfectly substitutable by supply from another player, many electricity pools were expected to behave in a competitive manner.

Cournot competition

Bertrand competition does not hold in wholesale electricity markets because players own more than one unit with different variable costs associated with each unit. They submit a supply curve of bids (a series of price, quantity pairs) rather than a single price and quantity. This means that a player may

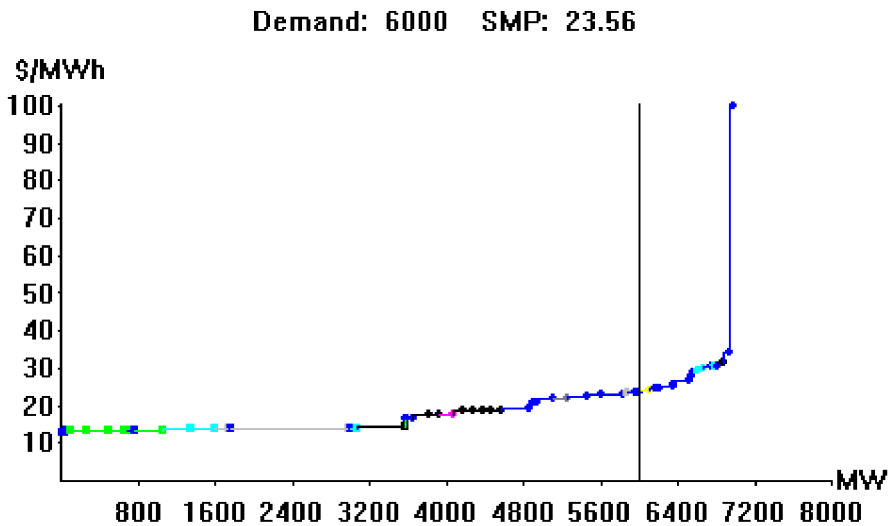
be prepared to sacrifice the output of one or more units for the benefit of a higher price on the remaining units.

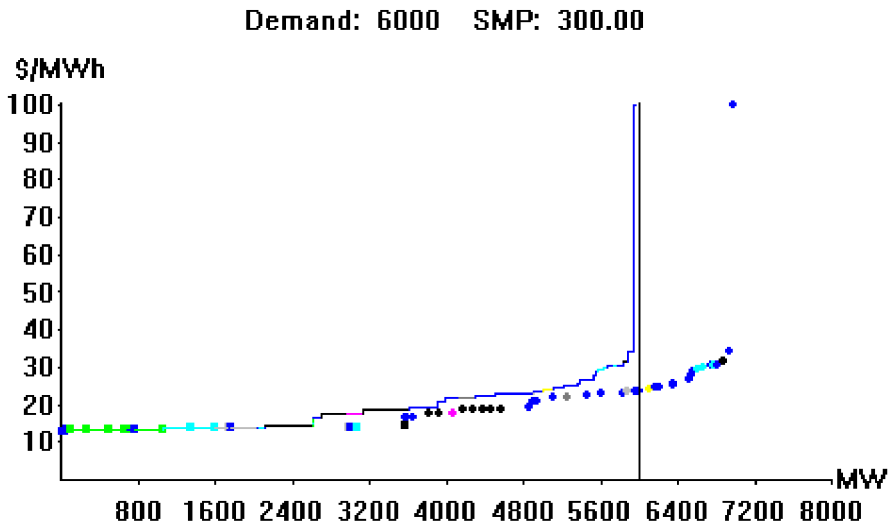
CustomBid effectively assumes Cournot-style competition, i.e., competition in quantities rather than prices (the one will always be endogenous to the other). CustomBid begins for each player with a competitive supply curve of bids, reflecting the underlying variable costs. It then asks the question, "If everyone is bidding variable cost, is there anything else I could do to increase my profit?" The answer in many cases is "Yes, by withdrawing my most expensive infra-marginal bids." This way a more expensive bid will set system marginal price. So long as the price received for output from my remaining operating units goes up sufficiently to overcome the lost revenues on the units I withdraw, I make a greater profit. CustomBid calculates what the optimal amount of withdrawal is.

Types of strategic behaviour - MiniMax strategy

The pay-offs reported in CustomBid are the MiniMax strategies. There is a theorem in economics that says that if everyone plays their minimax strategy, then this will be a Nash equilibrium. The MiniMax strategy is the withdrawing strategy that maximizes my payoff if everyone else bids competitively. It is so-called because it is the worst (min) I can do if I play the best strategy I can (max). The figure below illustrates this idea with an example of a strategy for a player that withdraws 998MW. The price rise to $300 more than offsets the fall in output. Essentially, there is an overlap between Cournot strategies and the MiniMax strategies. The outcomes in CustomBid are thus the profit maximising MiniMax strategies for the players that gain the most profit from withdrawal. This is likely to be a Cournot-Nash equilibrium, but it need not be. The strategies are thus, Cournot-type, in that they are quantity competition, but they are not necessarily the Cournot equilibrium outcome, as the MiniMax is a more restrictive concept.

Figure A5.1: Example of CustomBid screens





CustomBid takes as data the forecasted hourly system demand, and the forecasted hourly system supply curve. Different zones can be defined within the area to allow for congestion. Different marginal prices within each zone can be calculated. The programme takes as inputs into the supply curve the unit variable cost, the capacity, and the outage and maintenance characteristics of each production unit. The programme also takes as inputs from the user parameters such as degree of contract cover, maximum withdrawal, and demand elasticity. The demand elasticity is possibly set as a kinked demand curve, and so the user can set both the slope of the curve at different points, as well as the points where the curve should have a kink.