THE DEVELOPMENT OF A SPOT MARKET EXCHANGE INFRASTRUCTURE FOR BELGIUM

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Executive Summary

The Amsterdam Power Exchange (APX) and Elia have asked us to analyse the conditions required for the successful introduction of a Belgian day-ahead market in electricity. We focus on:

- Determining whether the conditions exist in Belgium for the introduction of a successful day-ahead market.
- Determining the appropriate geographic boundaries of the day-ahead market: whether Belgium should integrate with France, the Netherlands or neither.
- Performing quantitative analyses relevant to the potential integration among markets.

To determine whether conditions exist for a successful day-ahead market in Belgium, we examine both the supply-side and demand-side. On the demand-side, the key issue is the progress of market opening, which will create customers who could potentially participate in the day-ahead market. On the supply-side, we focus on the concentrated ownership of generation capacity in Belgium and the current dearth of potential participants.

The Belgian electricity market faces a choice concerning potential cross-border integration. Belgium can form a day-ahead market that is only national in scope, or that is integrated with a neighbouring electricity market. France and the Netherlands are natural candidates for integration.

Interconnector constraints may set the boundaries of the Belgian market. If there is insufficient interconnector capacity between two neighbouring markets, attempted integration will produce either frequent market splitting or extreme re-despatch costs. We examine interconnector capacity and constraints on the Belgian border with France and the Netherlands. We first consider the introduction of a separate, stand-alone Belgian day-ahead market, in which the price is formed by Belgian supply and demand and interconnector flows. We then consider potential integration of the Belgian market with a neighbouring market, either via a Single Product or via a Market-Coupling mechanism.

We also analyse the potential effects of market power. We use the term market power to describe the ability to raise prices for electricity, without losing so much despatch to competing generators as to render the strategy unprofitable. The incumbent generating company in Belgium owns a large share of available capacity, and the capacity of the existing interconnectors limits the potential market share of foreign generators. These factors give rise to market power. We do not claim that the incumbent currently charges unreasonable prices, or has a business strategy of dominating the market. We simply note that the incumbent's ability to raise prices will be of natural concern to regulators and market participants. Market power would limit market liquidity, and would affect the potential for successful integration of the Belgian market with neighbouring countries. We perform computer simulations that illustrate the potential effects of market power on both Dutch and Belgian consumers.

A Separate Belgian Market

On the demand-side, the Belgian market shows potential for the successful introduction of a trading product. Electricity market liberalisation is proceeding relatively rapidly, and the proportion of eligible Belgian customers now stands at 52%. Elia report that there is already an active Belgian OTC market, with volumes approximating over 70% of current APX trading.

However, there are two potential barriers to the introduction of a successful Belgian day-ahead market. The first is the potential for the principal incumbent generator to exercise market power. The incumbent controls, by a conservative estimate, approximately 69% of the capacity available to serve Belgian consumers. We simulate various scenarios in which the incumbent exercises market power by raising its asking price for electricity relative to the marginal cost of generation. We conclude that the incumbent could profitably raise prices in the generating market above competitive levels.

Although the introduction of a Belgian day-ahead market does not change the incumbent's ability and incentive to exercise market power, concerns over market power may dissuade market players from participating in the Belgian exchange. Potential market power may limit liquidity and trading volumes.

To address the market power problem, we recommend the divestiture of generating capacity. We recommend either selling generating plant or auctioning capacity to create Virtual Independent Power Plants (VIPPs). A subsequent study will investigate the optimum quantity of divestiture.

The second issue would be the replacement of the current Belgian balancing charges with a balancing market. This market could be organised in a similar way to the current Dutch balancing market. For this balancing market to function properly, the participation of Dutch generators should be facilitated, and could constitute a first step towards a fully-harmonised Benelux balancing market.

Integration with France

The Franco-Belgian interconnector has a history of congestion in the direction of France to Belgium. We predict that congestion will persist until at least 2006. The primary cause of congestion is the abundance of French nuclear plant with low marginal costs. We estimate that excess French generating capacity will persist, with the reserve margin in France exceeding 20% until at least 2009. A planned 1,000-MW expansion of Franco-Belgian interconnector capacity should relieve some of the congestion in 2006, although due to the time needed to obtain the required permits in France and/or Belgium, the new capacity may be only operational in 2009. Even after additional capacity is added, a possible reversal of flow on the France-UK interconnector may reduce the amount of net transfer capacity.

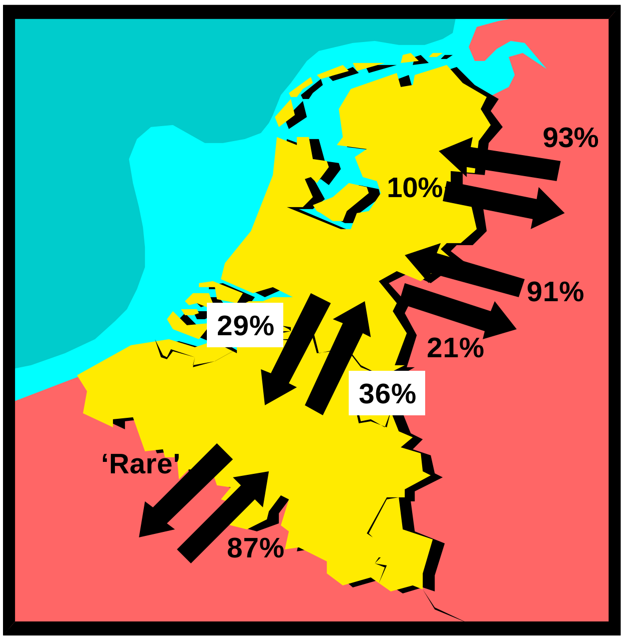
Frequent constraints on the Franco-Belgian border, supplemented by large marginal-cost differences between the two countries, would produce extremely high re-despatch costs in the event of market integration. We estimate re-despatch costs of €225 million per year, which if socialised among Belgian consumers would increase transmission tariffs by between 15% and 25%. In addition to paying higher transmission costs, French consumers would face higher wholesale prices. Moreover, the French market independently raises market power concerns. Creation of a successful Franco-Belgian market would likely require further divestment of French plant, which may face serious political challenges and be difficult to implement. We conclude that *the creation of a single Franco-Belgian market will remain impractical until at least 2006, and it is likely that the actual date will be 2009 or later.*

Integration with the Netherlands

In contrast with the Franco-Belgian interconnector, the Dutch-Belgian interconnector has experienced contractual congestion only infrequently. Figure 1 illustrates the difference. Although Belgium is a net exporter to the Netherlands, there are significant physical flows in both directions, indicating similarities between the cost of generation in the Netherlands and Belgium. Further evidence comes from the low price realised for annual interconnector capacity between Belgium and the Netherlands. In 2003 the auction price for annual interconnector capacity from Belgium to the Netherlands was only €0.25/MWh.

Integrating with the Netherlands would also appear attractive because Dutch generating capacity is distributed quite broadly. Only Belgian divestiture would be required to create a competitive generation market. Competition in generation would stimulate day-ahead trading.

Figure 1: Percentage of the time contractual constraints exist in the Benelux region



Mode of Integration

We consider two different products that could integrate the Dutch and Belgian markets. One is a Single Product that treats Belgium and the Netherlands as a single market. The Single Product would generate one price for electricity whether generated or consumed in Belgium or the Netherlands. The interconnector auctions would cease, and the interconnector would be treated the same as any part of the domestic transmission networks, with constraints managed by TSO re-despatch of generating plant. The Single Product represents a major change in policy. TenneT and Elia could implement the policy only after obtaining the consent of DTe and CREG.

The second product is a Market-Coupling mechanism as used in Nordpool. This would produce a common price for Belgium and the Netherlands whenever the interconnector was not constrained, and would generate a separate price for each country during constrained periods.

A key issue in the integration of the Dutch and Belgian electricity markets is the potential reduction of competition in the Netherlands. Dutch consumers might fear a reduction in competition because of the large market share that the Belgian incumbent would control. The two different products vary in their ability to mitigate any market power concerns.

With a Single Product, the capacity of the Dutch-Belgian interconnector would no longer limit the Belgian incumbent's influence over Dutch consumers. The Belgian incumbent would control at least 52% of the capacity available to serve Dutch and Belgian consumers combined, which can be viewed as a dominant position in the Benelux market. We calculate an HHI for the Benelux market of 3,000, above the standard for a concentrated market.

We would recommend the divestiture of generating capacity to address potential market power under a Single Product. A Single Product would require less divestiture than a separate Belgian product, because a Single Product presents the Belgian incumbent with increased competition from Dutch generators.

Market Coupling would reduce the incentive and ability of the incumbent to exercise market power over Dutch consumers. Day-ahead interconnection auctions currently occur before announcing the APX day-ahead results. This presents the potential for sub-optimal interconnector use, which reduces the risk that a dominant incumbent in Belgium might lose market share to foreign rivals as a response to excessive day-ahead bids. Greater harmonisation under Market Coupling would therefore reduce the potential to exercise market power.

Under Market Coupling, one theoretical way to mitigate market power would be to regulate the incumbent's bids, but only whenever the market split. However, our quantitative modelling indicates that bid regulation would be ineffective, as the incumbent could mark-up prices by 50% above marginal costs before provoking frequent market splitting. We conclude that divestiture would be a superior way to address market power.

We do not recommend divestiture as a remedy to perceived market abuse, since we have not seen any evidence of such abuse. The goal of divestiture would be to increase the number of Belgian supply-side participants and to instil trust in price formation. This in turn will foster market liquidity.

Conclusions

Integrating a Belgian market with a neighbouring day-ahead market would offer several advantages. From the perspective of Belgian consumers, the most important advantage would be increased competition in generation. Increased competition would reduce the quantity of capacity divestiture required to address market power concerns.

Our analysis indicates that Belgium and the Netherlands form a natural transmission island, with borders delineated by frequent constraints on the French-Belgian and Dutch-German borders. Attempting to form a single Franco-Belgium market would lead to high re-despatch costs and a significant rise in Belgian transmission charges in the case of the Single Product, or frequent market splitting under Market-Coupling. The high concentration of generating capacity in France also makes Franco-Belgian integration less attractive than integration with the Netherlands.

We recommend the introduction of a Market-Coupling mechanism between the Netherlands and Belgium, as an intermediate step towards an integrated Benelux market. Market Coupling reduces the scope for the exercise of market power over Dutch consumers, which would likely prove attractive to DTe. We recommend reforming the Belgian balancing regime to create a balancing market, providing that Dutch generators could offer balancing power to the Belgian TSO. In a later phase, we would recommend integrating both balancing markets. After implementing appropriate divesture we would also recommend to integrate the day-ahead markets of Belgium and the Netherlands.

1 The Belgian Day-Ahead Market

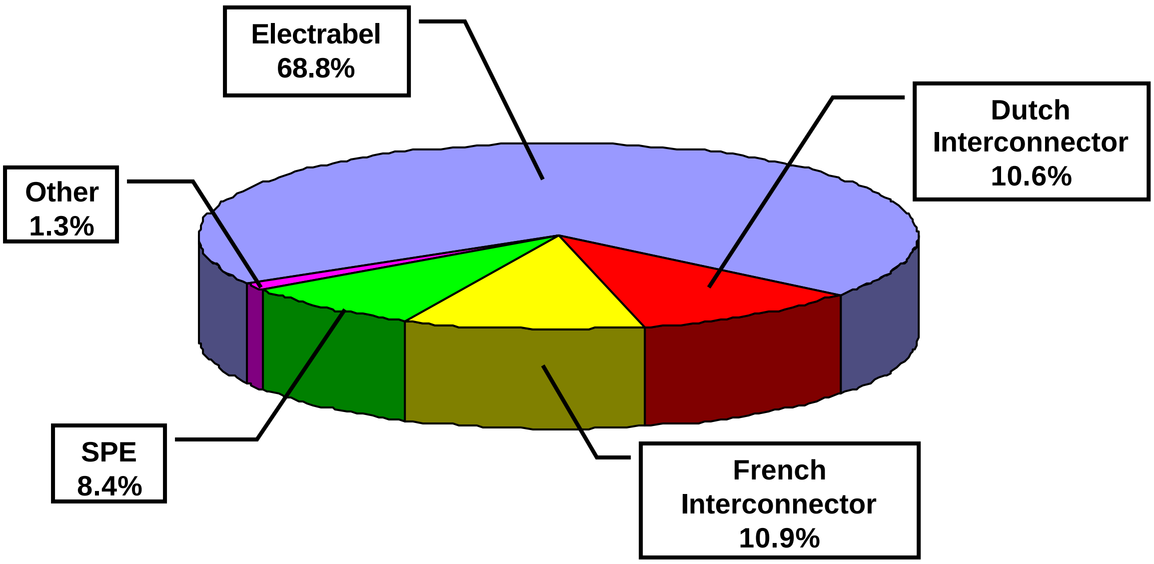
1.1 The Belgian Generating Market

Table 1 shows the ownership of capacity for the Belgian power market. The dominant position of the incumbent generator is a notable feature of the market. Excluding Combined Heat and Power and industrial auto-production, the incumbent controls approximately 11 GW of generation capacity, which constitutes 69% of the capacity available to serve Belgian consumers. Figure 2 shows the market shares of the Belgian generation market.

Table 1: Ownership of Belgian capacity

	Capacity, MW	% of Capacity
Electrabel	11052	69%
Dutch Interconnector	1700	11%
French Interconnector	1750	11%
Soc. Co-op Prod. D'Elec. (SPE)	1350	8%
Other	206	1%
Total	16058	100%

Figure 2: Market shares in the Belgian generating market



Moreover, the interconnectors offer little potential for competition from imported power. The Belgian incumbent has capacity in both the Netherlands and France that it could import via the interconnectors, effectively increasing its share of the Belgian market even further and increasing the HHI. For example, the incumbent owns 4,650 MW of capacity in the Netherlands. The incumbent could theoretically utilise the entire Dutch-Belgian interconnector capacity of 1,700 MW, if not prevented by existing interconnector auction rules.[1] The Belgian incumbent also own some 1,200 MW of generation in France, which in principal would be available for export to Belgium via the Franco-Belgian interconnector.

In summary, the incumbent has a dominant position in the Belgian electricity generation market, and there is limited potential for significant competition from either France or the Netherlands via the interconnectors.

1.2 The Belgian Demand Side

Liberalisation of the Belgian market will drive demand for a Belgian day-ahead product. Liberalisation – or market opening – will increase the number of eligible Belgian consumers who can participate in a day-ahead market. Further market opening should, given the right conditions, prompt increased trading volumes on a Belgian power exchange.

The need for federal and regional legislation has complicated the liberalisation process in Belgium. Federal legislation covers the high-voltage customers (above 70kV), while regional decrees govern customers connected to the low-voltage network. Four different legislative processes are therefore relevant: one at the federal level and three at the regional levels. The complex legislative process is bounded by the need to complete 100% market opening by July 1st 2007 once the new draft electricity Directive is passed.[2]

To estimate the future annual energy consumption of eligible Belgian consumers (Figure 3), we multiply annual Belgian energy consumption by the percentage of the market that is eligible.[3] Market opening in Belgium will provide a large pool of eligible demand that could participate in a day-ahead market. The major issue with a separate Belgian power exchange remains on the supply side.

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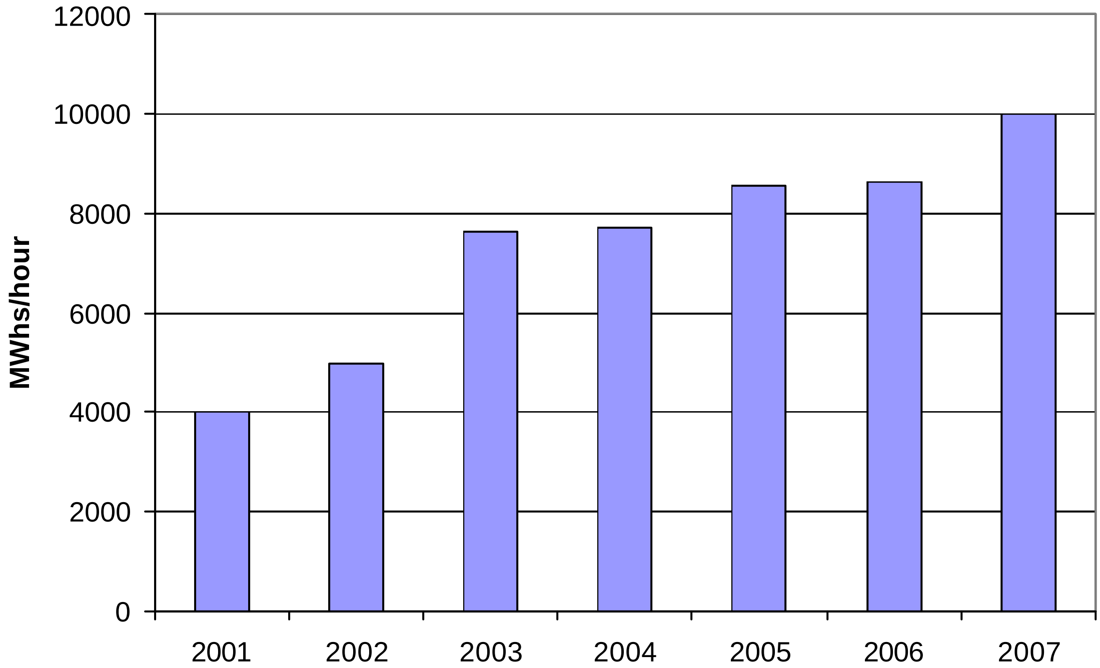
[1] Auction rules forbid any one party obtaining more than 400 MW of interconnector capacity.

[2] On 25th November 2002 the European Council of Ministers came to a political agreement to replace the existing electricity Directive (96/92/EC) with a new draft electricity Directive. The draft Directive would require the opening of all retail markets by 1st July 2007.

[3] We estimate annual Belgian energy consumption by taking the 2001 gross Belgian electricity demand, which according to the Statistical Year book UCTE 2001 was 83.6 TWhs, and assuming annual demand growth of 0.75% until 2005 and then 0.92% thereafter. These annual demand growth numbers are based on the *BFP Study:* Christophe Courcelle and Dominique Gusbin, (Le Bureau fédéral du Plan), *Perspectives énergétiques 2000-2020, Scénarios exploratoires pour la Belgique,* January 2001, and are consistent with our earlier work for TenneT (Market Survey 2003-2009: Cross-border power flows across Dutch interconnectors*, The Brattle Group*, May 2002).

Figure 3: Estimated consumption of eligible Belgian consumers



1.3 The Potential for Market Power Abuse

We have not seen any evidence to date that the incumbent generator in Belgium has exercised market power, or that Belgian prices significantly exceed those in comparable countries. We understand that wholesale electricity prices in Belgium are lower than in the Netherlands. The IEA indicate higher household prices in Belgium than in neighbouring countries, but lower electricity prices for industrial customers than in the Netherlands or Germany.[4]

Several factors may explain the failure to exercise market power to date, such as current management policy or the threat of price regulation by CREG. However, these factors are difficult to assess and subject to change. Market participants would logically focus on the evidence in section 1.1 concerning the high concentration of the Belgian market, which gives the incumbent a persistent *incentive and ability* to exercise market power. Concerns over the future exercise of market power could persuade market participants to avoid a day-ahead market in which the incumbent participates, severely reducing market liquidity. High concentration itself implies a limited number of supply-side participants who could provide liquidity.

The issue of market power therefore merits considerable analysis. We construct a model of the Dutch and Belgian generation markets to quantify the potential effect of market power on prices. Appendix 1 describes the model in detail.

[4] IEA, Energy Policies of Belgium, 2001 review.

The model generates a Market Clearing Price (MCP) and the amount of plant despatched, based on a supply curve and demand data. We use data on power generation plant, and estimate the marginal cost of generation for each plant to derive a supply curve. We assume that demand varies by hour, but is not responsive to price (*i.e.* it is inelastic). The intersection of the demand curve with the supply curve generates the MCP of electricity. We calculate the MCP, and we perform the calculation for every hour of one year. The model assumes despatch of all plant with bids equal to or below the MCP. We model Benelux as two market areas, with trading between them. If the equilibrium between supply and demand implies different prices in each market area, the model assumes exports from the low-priced region to the higher-priced region, until either the prices equalise or a transmission constraint arises.

As a benchmark we adopt the ideal of a competitive market, in which generators offer to despatch plant at a price equal to the marginal cost of generation. Under ideal competition, our model predicts that average Belgian prices would be lower than in the Netherlands, prompting exports from Belgium. Our model predicts that exports would constrain the interconnector only 30% of the time, with prices in Belgium and the Netherlands identical for the remaining 70%. Consequently, year-average prices in Belgium and the Netherlands are similar.

However, a generator with market power may find it more profitable to raise the MCP by "marking up" bids over marginal costs. Our model does not predict the optimal mark-up as a function of market concentration. However, a mark-up of 50% above the marginal cost of generation is realistic in a highly concentrated generating market.[5] To investigate market power we assume that the incumbent applies such mark-ups to the marginal costs of its generating units. We simultaneously assume that competition in the Netherlands motivates all generators to offer electricity at marginal cost.

If the incumbent applied 50% mark-ups, prices in both the Netherlands and Belgium would increase. The spread between Dutch and Belgian prices would reduce, because the Belgian mark-ups would offset the slight cost advantage of Belgian generation. Belgian power would become more expensive than Dutch power. Belgian exports would decrease, which would reduce the frequency of interconnector constraints.

1.4 Belgian Balancing Charges and Demand Elasticity

In this section we explain how the current Belgian balancing regime could influence market power by making demand less sensitive to price. We note that, in the absence of a liquid Belgian power market, the current system of Belgian balancing charges is perfectly reasonable, relying as it does on the prices in neighbouring power markets. The point we make in this section is that the current system of Belgian balancing charges will not be suitable for *future* developments in the Belgian power market.

[5] This assertion is based on our work on the mid-1990's electricity market of England and Wales. See "A report on Generator Market Power in the Electricity Market of England and Wales", Volume I, November 1997, Table 1.4, pp 11.

Electricity consumers may wish to buy power in the day-ahead market, to address expected shortfalls. However, the day-ahead market can impose significant commercial risks on Belgian consumers. If they fail to procure sufficient power they must rely on the Belgian balancing regime.[6] Belgian balancing charges are based on a mark-up over day-ahead prices on two foreign power exchanges (APX and Powernext), subject to a price cap. This mark-up provides an incentive to market actors to maintain their balance in the Belgian area instead of choosing to 'go-short' when prices on the Dutch or French market are higher than the balancing charges. For small imbalances, a price cap reduces the risk for the market actors.

The price cap varies according to the time of day and season. The cap is €25/MWh for summer night-time periods, and €60/MWh for winter day-time periods. For simplicity our discussion focuses solely on the winter day cap of €60/MWh.

Applying the balancing mark-up to the day-ahead price implies balancing charges that frequently approximate €60/MWh.[7] To avoid a €60/MWh balancing charge, consumers who relied on a day-ahead market would tend to accept very high prices—somewhere close to €60/MWh.[8] The structure of the Belgian balancing charges therefore could distort demand on the day-ahead market (either by the influence of the price in the French and Dutch day-ahead market for large imbalances or the influence of the cap charge for small unbalance). Demand could be insensitive to price (demand is "inelastic"), as long as the price is below €60/MWh.

On a Belgian day-ahead market, a generator with market power could exploit insensitive demand. The generator could raise the price to just under €60/MWh, and be confident that the high price would not affect demand significantly. Rather than risk paying high prices, consumers would likely sign longer-term "full requirements" contracts with the incumbent that prevent exposure to high charges at short notice. Consequently, in the presence of market power we could expect that:

- Informal ("OTC") day-ahead trading in Belgium will remain illiquid under current market conditions.
- A Belgian day-ahead exchange would suffer from low liquidity.[9]

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[6] This would not of course apply to consumers who can self-supply or shed load at reasonable cost. However, in an actively traded day-ahead market these consumers would probably be "infra-marginal", which is the technical term for saying that they would have limited influence on prices.

[7] The balancing charge would reach €60/MWh when the day-ahead price on the French or Dutch market multiplied by the 10% mark-up is higher that the Belgian cap charge for an imbalance of less than 5%.

[8] If a consumer's alternative to the day-ahead market is to pay €60/MWh, then the consumer would be better off buying in the day-ahead market at any price up to €60/MWh.

[9] One might expect that with a Belgian PX the balancing rules would change to set the price as a mark-up over the Belgian day-ahead price. However, this would simply increase the incentive to bid high in the day-ahead market, because bidders would know that whatever they end up paying on the day-ahead market, the balancing price would "automatically" be higher (or as high, if capped).

Note the contrast to the Netherlands, where a balancing *market* operates, with a relatively diverse set of participants. Any generator's attempt to raise bids on the day-ahead market would likely prompt a large loss in demand, either to other generators in the day-ahead market, or to the balancing market. Although Dutch balancing market prices are more volatile than day-ahead prices, the average balancing price is lower than the average day-ahead price.

For a similar balancing market to be possible in Belgium, offers of balancing power to the Belgian TSO must be sufficiently diversified so as to avoid the influence of market power. In order to achieve this, we recommend that Dutch generators could offer balancing power to the Belgian TSO. In a later phase, we would recommend integrating both balancing markets.

1.5 Conclusions

The dominant position of the Belgian incumbent is the main problem with a potential Belgian day-ahead exchange. The small number of suppliers would reduce liquidity, as would concerns with market power. The current balancing regime could also influence the working of the Belgian power exchange.

To increase confidence and participation in a Belgian day-ahead market, we make two recommendations. First, the incumbent should divest generating capacity, either physical or "virtually". Second, the Belgian balancing regime should be replaced with a balancing market similar to the Dutch balancing market.

Capacity Divestiture

We recommend that the Belgian incumbent generator divest capacity, either through the sale of generating units or by selling "call options" for capacity, analogous to Electricité de France's (EdF's) Virtual Independent Power Plant auctions.

An auction to create Virtual Independent Power Plants (VIPPs) would "divest" capacity through the sale of long-term contracts representing physical "call options". For example, the owner of a 10 MW contract would have the right to demand delivery, in any hour, of up to 10MWh of power to the Belgian grid, in return for a "strike price" written into the contract. The owner of the contract would not have control over any particular generating unit in the country.

EdF uses VIPP auctions in France, as does the incumbent generator ESB in Ireland. VIPP auctions offer several advantages relative to selling generating units. In particular, VIPP auctions avoid some of the difficulties involved in selling nuclear plants, which include security issues, responsibility for clean-up costs, and political risk. VIPP auctions can also create smaller tranches of capacity than the sale of generating units. A large nuclear power plant can only be sold to one company, but call options on the plant's capacity can be sold to several different companies. VIPP auctions can therefore offer a larger reduction in market concentration per unit of capacity divested.

Further study would be required to calculate the exact amount of capacity that should be divested to address market power. Analyses should consider which particular plants to divest, to ensure a diversity of peak and base-load plant. If VIPPs are used, analyses should consider the design of call options that approximate the performance of baseload and peak plant[10], and the appropriate amount of capacity for each type of option.

Less divestiture would be required in a fully-integrated Benelux (or Franco-Belgian) market, as the socialisation of interconnector constraints would dilute the incumbent's market power. Section 5.3 discusses this in detail.

Reform of the Belgian Balancing Charges

We recommend introducing a Belgian balancing market provided that Dutch generators may offer balancing power to the Belgian TSO. An appropriate balancing market would make demand in the day-ahead market much more sensitive to price, reducing the incumbent's ability to exercise market power and therefore encouraging market participation.

We make two further recommendations to encourage competition in the Belgian balancing market. First, the Belgian balancing rules should facilitate the participation of Dutch generation.[11] Second, an appropriate divestiture strategy should consider either: a) the divestiture of flexible generating plant that can participate actively in a Belgian balancing market, or b) the design of VIPPs that can participate meaningfully in a Belgian balancing market.[12] These measures are not essential, but would help reduce market power concerns and promote liquidity.

[10] For VIPPs, the strike price is the equivalent of variable cost for a physical plant. Baseload capacity therefore corresponds to a call option with a relatively low strike price, peaking plant to capacity with a relatively high one. The challenge would therefore be to set the right mix of call options.

[11] This would in effect require a single Benelux control area. We recognize that implementation of the proposal may therefore require careful consideration since the law, grid codes and operational procedures will need to be modified in both countries.

[12] To participate in a balancing market, generating plant must be able to increase production (ramp-up) quickly and at short notice. For a VIPP, the corresponding feature would be contracts callable at very short notice.

2 Cross-Border Integration of the Belgian Day-Ahead Market

Here we consider the arguments for integrating the Belgian market with one or more neighbours. Integration would have two principal effects on the Belgian market:

- An integrated Franco-Belgian or Benelux exchange would facilitate exports by foreign generators to Belgium. They would avoid the need to identify potential customers, the need to negotiate with customers, and the need to purchase interconnector capacity. All three needs present transaction costs and commercial risks. Cross-border integration would therefore lower the costs of imports to Belgium, increasing competition with the Belgian incumbent.

- If "integration" implies the creation of a single transmission area, with interconnector constraints "hidden" and socialised, then the integrated area will become a single geographic market. In this case, the market share of the Belgian incumbent would dilute significantly. However, the eventual competitiveness of the integrated market would also depend on the concentration of generation capacity in the neighbouring geographic area. Socialised interconnector constraints might also prompt significant "redespatch costs." We examine both issues in detail later in the report.

We suspect that the issues of redespatch costs and competition in a single geographic market will be more important than reducing the transaction costs for exports to Belgium. We therefore focus on these issues when considering the choice of partner for integration: France or the Netherlands.[13] Below we examine each potential candidate for integration.

[13] Given the complexities and specificities of the German market we do not view integration with Germany (or with one or more German control areas) as a realistic option.

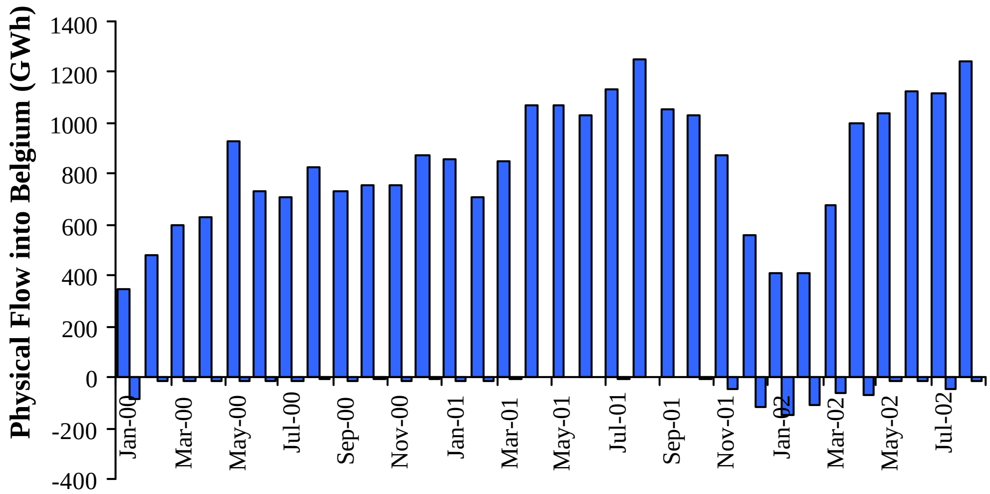
3 Integration with France

For cross-border integration to succeed, sufficient interconnection capacity must be available. Insufficient interconnection capacity would prompt large redespatch costs or frequent market splitting. Transmission constraints are therefore crucial for considering geographic integration. In this section we examine current and projected transmission constraints on the Franco-Belgium border.

3.1 Flows and Congestion on the Franco-Belgian Border

Figure 4 shows that French exports dominate the Franco-Belgium interconnector. Sustained French exports[14] reflect the low marginal cost of generating electricity in France, where nuclear power produces almost 80% of electricity (the highest proportion in the world).[15] Significant excess capacity also contributes to French exports.[16]

Figure 4: Exports of French power to Belgium



French exports frequently congest the Franco-Belgian interconnector. Limited interconnector capacity is the key factor restraining exports.

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[14] The dip in Belgian imports of French power in January 2002 was caused by very high loads in France due to unusual winter conditions.

[15] IEA France 2000 Review.

[16] We examine France's reserve margin in more detail in section 3.2.

Current Congestion

There are several ways to measure interconnector congestion. The optimal method depends on the availability of data and the capacity allocation mechanism:

- Physical flow data could be used to measure physical congestion.
- Where capacity is allocated on a "first-come, first-served" basis, an excess of requests over available capacity indicates congestion.
- Where capacity is allocated via auction, or a liquid secondary market exists, a high price for interconnector capacity indicates scarcity and therefore the potential for congestion.

We do not use physical data in this report, primarily because it was not available, and because its interpretation would raise a number of difficult issues. For the Franco-Belgian border we apply the second of the above approaches, measuring congestion by comparing capacity requests to the amount of available capacity.

Table 2: Frequency of congestion on the Franco-Belgian interconnector

		Percentage of Time Congested	
		Peak	Off-peak
RTE-Elia	[1]	87%	91%
Elia-RTE	[2]	Rare	Rare

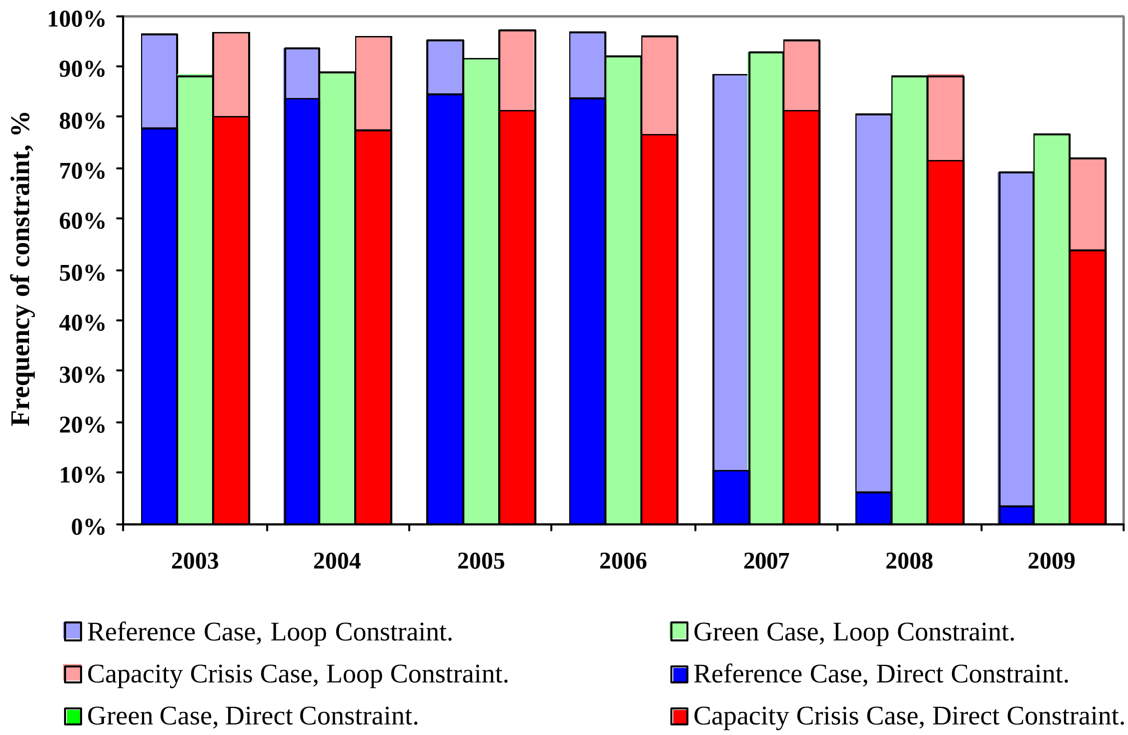
Notes:
Peak Hours are from 07:00 to 23:00
Statistics based on data from 25/09/02-25/10/02.

Table 2 shows the frequency of congestion for the period examined. Although some capacity was unsold, more capacity was requested than was available approximately 90% of the time. Elia have confirmed that in their view the Franco-Belgian interconnector is heavily congested and almost all capacity available is sold.

Projected Congestion

We conclude that for now the Franco-Belgian interconnector is highly congested. If congestion could be expected to ease in the medium term then the formation of a single Franco-Belgian day-ahead market might be attractive. We therefore model future cross-border flows to predict future congestion levels. Figure 5 below shows that our analysis predicts *sustained congestion* under a number of different scenarios.

Figure 5: Predicted frequency of congestion for the Franco-Belgian interconnector



Note that Figure 5 distinguishes between "direct" and "loop" congestion. We define direct congestion as arising when flows on a specific interconnector reach the maximum rated capacity. Loop congestion describes an interconnector that is not directly congested, but that cannot accept more power without creating loop flows that would congest another interconnector directly.[17] With either direct or loop congestion, it is *physically impossible* to flow an extra MW of electricity across an interconnector in the desired direction, and therefore prices in the adjacent areas may diverge.

Description of Scenarios

The three scenarios indicated above reflect different combinations of demand, new capacity, transmission capacity, fuel prices, and competition.

Reference Scenario

- New capacity is built in all countries to maintain reserve margins of 20%;
- Renewable and CHP investments match current forecasts;[18]

[17] Appendix 3 gives some examples of different loop flow congestion which can occur.

[18] Taken from: Energie Markt Trends 2001, ECN Beleidsstudies, available from www.ecn.nl in Dutch language only; Wind Direction, July 2001, European Wind Energy Association, www.wea.org; and "The Future of CHP in the European Market - The European Cogeneration Study", May 2001. Available from www.cogen.org..

- The proposed interconnector between the Netherlands and the UK is built, and capacity increases by 1,000MW on the French-Belgian interconnector in 2006;
- The proposed interconnector between the Netherlands and Norway is not built;
- Gas prices remain at current levels relative to other fuels, and generator mark-ups are calibrated to produce average prices that match current IEA reported industrial prices, using current demand and supply levels.

Green Scenario

The Green Scenario is the same as the Reference Scenario, except that:

- A Carbon Tax is introduced with immediate effect.
- Demand grows at a slower rate, reflecting an emphasis on energy conservation;
- New plant investments concentrate on renewable energy, causing investment in renewable energy to hit EC targets in all countries but the Netherlands;

Capacity Crisis Scenario

The Capacity Crisis scenario is the same as the Reference Scenario, except that:

- Reserve margins are allowed to fall towards 8% in all countries, because less new capacity is constructed.
- The capacity on the interconnector between France and Belgium is not increased;
- The interconnector between the Netherlands and the UK is not built;
- Mark-ups are constant in all countries.

Table 3 summarises the scenarios.

Table 3: Scenarios used in IREMM modelling

	Capacity Crisis	Reference	Green
Demand Growth	IEA/BFP growth rates, adjusted for changes in GDP growth.		Half the Reference Case growth rate.
Renewables and CHP	Current "Present Policies" projections from EWEA and COGEN.		EU Renewable targets and "Post-Kyoto" projections from COGEN.
Gas Price	Current Fuel Prices.		Carbon tax switches merit order of Gas and Coal fired plants.
Interconnector Capacity	No new interconnectors, and no expansion of capacity.	France – Belgian interconnector increased by 1000 MW, and UK – Netherlands interconnector built.	
New Capacity	8% Reserve Margin	20% Reserve Margin	
Competition	Identical Mark-ups in all countries.	Mark-ups set to match 2001 wholesale prices.	

The IREMM Model

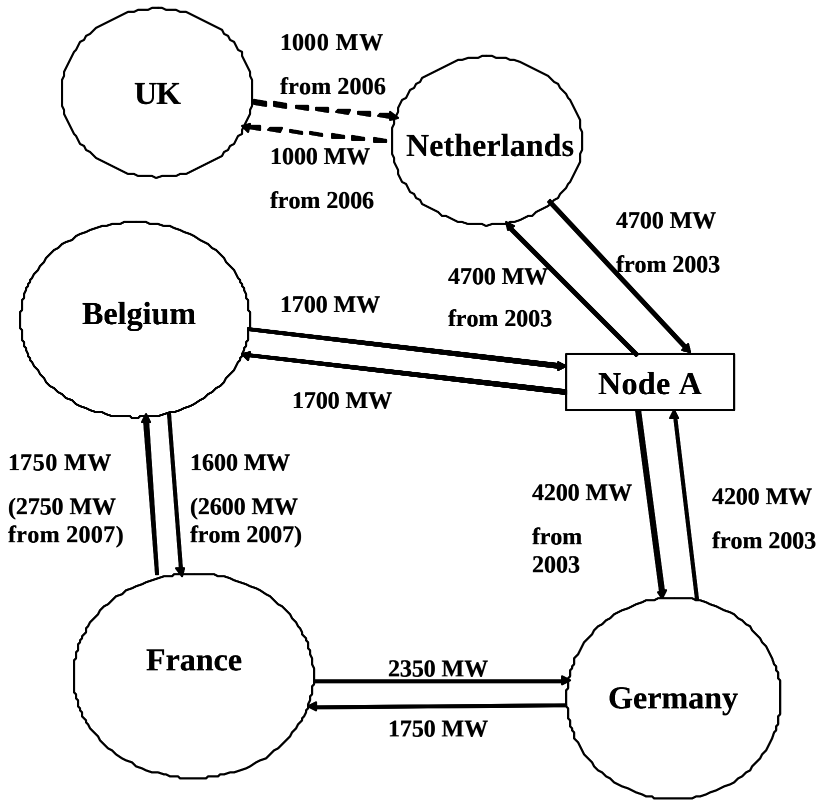
We use the Inter-Regional Electricity Market Model (IREMM) model to analyse supply, demand, and interconnector flows. IREMM takes information such as available capacity of individual generation plant and hourly demand, and matches supply and demand in the most efficient manner until all demand is met or until an interconnector constraint prevents further exchange between countries.

Transfer of power between countries occurs through all possible routes, and IREMM allows us to account for 'loop-flow' effects in a simplified manner. For example, the model assumes that power transferred from France to the Netherlands travels via both Belgium and Germany. The relative impedance of each route determines the amount transferred via each route. We give a full description of the IREMM model in Appendix 2.

Figure 6 shows the transmission network model used in our analysis.[19]

[19] The France-UK interconnector is not shown in the diagram. We model France-UK flows as a "modifier of load".

Figure 6: Transmission Network Model



Concluding Remarks

A chief result of our analysis is the expectation of continued high congestion levels on the Franco-Belgian border at least through the end of this decade. Under the Reference scenario, the Franco-Belgian interconnector is *directly congested* for 80% of the time on average, although this congestion is largely relieved by the construction of 1000 MW of capacity in 2006. New interconnector capacity also alleviates loop-flow congestion somewhat, but it remains above 80% through 2009. The Capacity Crisis scenario assumes that no new interconnector capacity will be added, which would cause direct congestion to persist until at least 2009.

Note for the Green scenario *all the congestion involves loop-flows*. Assuming the implementation of a carbon tax would make coal-fired power stations more expensive than gas-fired power stations, switching their position in the merit order. Germany has a relatively large amount of coal-fired generation, so the carbon tax would increase the cost of German-generated electricity relative to France and the Netherlands, who have more gas and nuclear generation. German consumers would therefore increase their imports of 'cheap' power from France, increasing congestion on the French-German border. Increased congestion on the French-German border would reduce the spare capacity for loop flows, consequently limiting flows on the Franco-Belgian interconnector. French exports to Belgium would not be limited by the Franco-Belgian interconnector, but by problems on the French-German border.

3.2 The French Reserve Margin

In section 3.1 we noted that excess capacity in France helps motivate exports that currently constrain the Franco-Belgian border. Potential declines in the French reserve margin could reduce the frequency of constraints, making Franco-Belgian integration more attractive.

Table 4: Estimated French reserve margin 2002 to 2009

Year	Peak Domestic Demand (MW)	Capacity (MW; adjusted for exports, retirements etc.)	Reserve Margin
2002	66,406	98,784	49%
2003	67,173	98,898	47%
2004	67,949	98,246	45%
2005	68,734	98,578	43%
2006	69,458	98,220	41%
2007	70,189	97,189	38%
2008	70,929	95,419	35%
2009	71,675	92,452	29%

Table 4 shows our estimates of the French reserve margin from 2002 to 2009. Our estimates assume that no new French generating capacity is added throughout the period, with the exception of 93 MW per year of renewable capacity to meet French environmental commitments.[20] We have also included the effect of plant retirements.[21] Debate may surround the appropriate weight to assign potential imports and exports in defining the reserve margin. Exports decrease the amount of capacity available for domestic use, but interconnectors offer 'emergency' imports that could be viewed as contributions to the reserve margin. We consider forecasts for French electricity exports, and in calculating the reserve margin we deduct the implied export capacity from domestic French capacity.[22] Box 1 summarises the reserve margin calculation.

[20] Based on forecasts from IEA publication "Electricity Information 2001".

[21] Expected retirements calculated from UDI database 2000, with typical lifetimes of plants taken from the Analysis of the Means of Production of Electricity and the Restructuring of the Electricity Sector (AMPERE) Report, AMPERE Commission, 2001.

[22] Export forecast from data from Eurelectric Statistics and Prospects, 28th edition (EUROPROG 2000). P 155-156,160, 166. We have converted TWhs of exports to MW of capacity assuming that exports are generated at a load factor of 1.

Box 1: Calculation of the Reserve Margin

$$\textit{Adjusted Installed Capacity (MW)} = \textit{Installed Capacity (MW)} - \textit{Retirements (MW)} - \textit{Exports (MWhs/hour)}$$

$$\textit{Reserve Margin} = (\textit{Adjusted Installed Capacity (MW)} / \textit{Native Peak Demand (MW)}) - 1$$

Our analysis indicates that the French reserve margin will exceed 25% until beyond 2009. We conclude that France will retain the ability to export significant amounts of electricity until at least 2009, which will contribute to constraints on the Franco-Belgian interconnector.

3.3 Redespatch Costs for a Franco-Belgian Market

Attempting to create a single market with a heavily-constrained interconnector would produce large redespatch costs. In this section we estimate redespatch costs for a theoretical Franco-Belgian market.

We assume redespatch rules as illustrated in Box 2: all unconstrained units are paid the MCP for their power. Constrained-off plants are paid the difference between the MCP and their bid, to compensate them for lost profits due to transmission constraints. Constrained-on plants are paid their bid price. We assume that TSOs impose a surcharge on transmission fees to recover the redespatch costs from consumers.

We construct despatch curves for France and Belgium using the model described in section 1.3 and Appendix 1. We calculate MCPs, the quantity of plant constrained-on and off for each hour of one year and the subsequent redespatch costs that the TSOs would have to pay.

Box 2: Redespatch Costs Example

On a particular day the single day-ahead market clears and results in French generators being scheduled for 50 000 MW and Belgium generators for 5 000 MW. If demand in Belgium is 12 000 MW, then 7 000 MW of imports are required into Belgium. However, if the physical interconnector capacity is only 1 500 MW, 5 500 MW of plant will be "constrained-off" in France. In Belgium, 5 500 MW of plant which was not originally scheduled to run will be "constrained-on", *i.e.* it will be despatched because of the constraint, and despite the fact that cheaper French plant on the other side of the constraint is available to run.

The TSO may compensate constrained-off plant for not being able to run due to the constraint, and the constrained-on plants must be paid for the power which they produce. The constrained-off plant is paid the Market Clearing Price minus their original bid price, multiplied by the 5 500 MW of constrained-off capacity. The constrained-on plant would be paid their original bid, multiplied by the 5 500 MW of constrained-on capacity.

In estimating redespatch costs, we assume that both the French and Belgian power markets are competitive: all generators bid in at marginal cost, and no generator deliberately manipulates bids to increase the compensation for being constrained-on or off. We assume that nuclear plant is 'must-run' and therefore bids in at €0/MWh.

We estimate annual redespatch costs of €225 million. Assuming hypothetically an equal division of redespatch costs between RTE and Elia, Belgian system users (and ultimately, Belgian consumers) would pay an additional €1.4/MWh in transmission surcharges.

A combined Franco-Belgian market might reduce Belgian prices and raise French prices. Belgian consumers may therefore accept the redespatch costs estimated above, in return for lower wholesale electricity prices. However, French consumers might not tolerate the combination of higher wholesale prices and higher transmission fees, which can be viewed as subsidising Belgian consumers. The potential for high redespatch costs could hinder the formation of a single Franco-Belgian market.

3.4 Generator Market Power in France

We have already discussed the potential need for divestiture in Belgium, to create the foundation for a successful day-ahead market and balancing market. We confined the discussion largely to the consideration of a national Belgian market. Here we consider the implications of market power in France. Electricité de France (EdF) controls a high percentage of French generating capacity, even after accounting for the recent VIPP auctions of EdF plant. We doubt that an integrated Franco-Belgian day-ahead or balancing market could succeed unless EdF divested additional generating capacity. Capacity divestiture in Belgium would not suffice, because the total amount of capacity in

Belgium is only a small fraction of available capacity in France. The French market is so large that perhaps wide-scale divestiture by the French incumbent could obviate the need for any divestiture in Belgium. However, most industry observers would see political impediments to implementing such divestiture in France. We conclude that it would not be responsible to advocate the integration of the French and Belgian markets without considering the possible political and operational challenges to implementing further divestment in France.

3.5 Conclusions for a Franco-Belgian Market

French electricity exports currently congest the Franco-Belgian interconnector. We forecast that congestion will persist until at least 2010. Any attempt to form a single Franco-Belgian market would produce extremely high re-despatch costs, which if socialised could translate into significant surcharges for transmission. Successful integration would likely require symmetrical divestiture programmes in France and Belgium, which may be difficult to achieve. We conclude that the formation of a single Franco-Belgian market would not be practical until at least 2010.

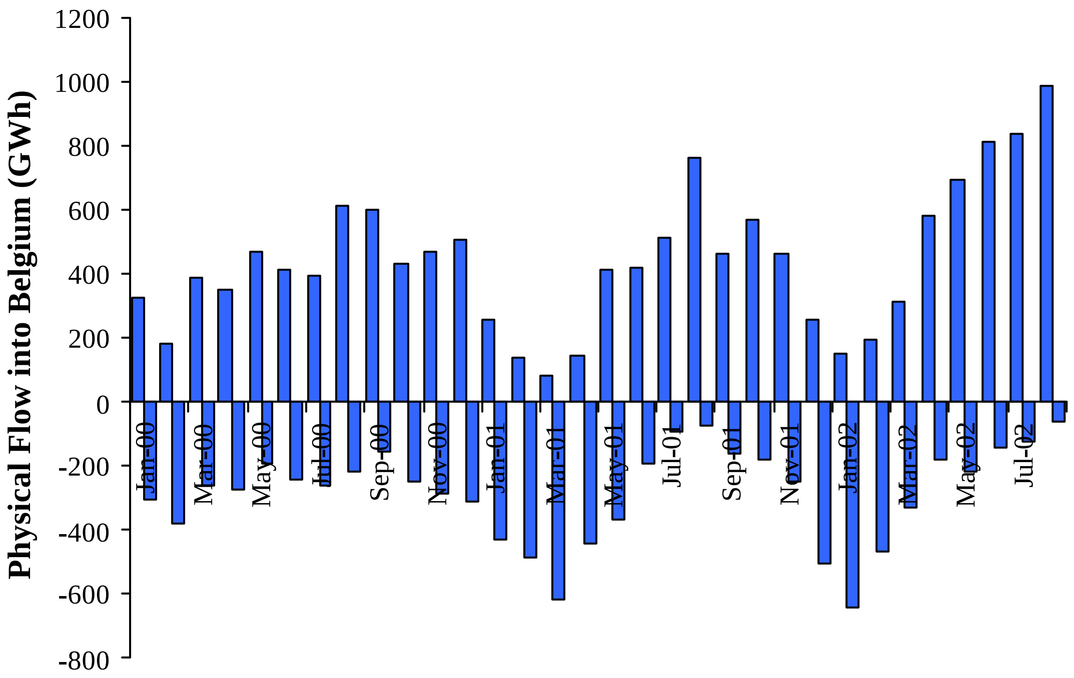
4 Integration with the Netherlands

The Netherlands is a natural alternative to France for integration with a Belgian day-ahead market. In this section we examine past and future congestion on the Dutch-Belgian interconnector, and we consider the feasibility of a single Dutch-Belgian day-ahead market.

4.1 Current Cross-Border Flows and Congestion

In contrast to the flows between France and Belgium, Figure 7 shows that physical flows between Belgium and the Netherlands are much more balanced. In 2001 Belgium exported 4487 GWhs to the Netherlands, and the Netherlands exported 3802 GWhs to Belgium. Between January 2000 and August 2002, Belgium exported an average 444 GWhs per month to the Netherlands, and imported an average 284 GWhs per month. French exports to Belgium averaged 842 GWhs/month over the same period. Given the similar Net Transfer Capacity on the Franco-Belgian and Dutch-Belgian interconnectors, this data implies that the French-Belgian border is much more congested.

Figure 7: Flows between Belgium and the Netherlands



As discussed earlier, there are several ways to measure congestion. For the Dutch-Belgian interconnector we measure congestion by reference to the prices realised in capacity auctions. We analyse data from the Dutch-Belgian daily interconnector auctions for 2001, splitting the data by season and into peak[23] and off-peak hours.

Table 5: Frequency of constraints and prices for direction Belgium to the Netherlands

Season	Peak/ Off-Peak	Average Price €/MWh	Standard Deviation €/MWh	Maximum Price €/MWh	No. of Hours Congested	% of Time Congested
Winter	Peak	0.01	0.01	0.05	483	47%
Winter	Off-peak	0.01	0.10	1.00	101	9%
Spring	Peak	0.12	0.56	**3.61**	506	48%
Spring	Off-peak	0.07	0.44	**3.61**	160	14%
Summer	Peak	0.01	0.09	3.00	147	14%
Summer	Off-peak	0.00	0.01	0.20	8	1%
Autumn	Peak	0.39	1.38	**11.00**	362	35%
Autumn	Off-peak	0.11	0.61	**5.80**	88	8%
Annual	Peak	0.13	0.76		1,498	36%
Annual	Off-peak	0.05	0.38		357	8%

Table 6: Frequency of constraints and prices for direction Netherlands to Belgium

Month	Peak/ Off-Peak	Average Price €/MWh	Standard Deviation €/MWh	Maximum Price €/MWh	No. of Hours Congested	% of Time Congested
Winter	Peak	0.01	0.06	1.00	386	38%
Winter	Off-peak	0.03	0.15	1.00	411	36%
Spring	Peak	0.07	0.24	**1.60**	451	43%
Spring	Off-peak	0.02	0.10	**1.00**	509	44%
Summer	Peak	0.15	0.92	16.02	211	20%
Summer	Off-peak	0.02	0.18	5.00	116	10%
Autumn	Peak	0.01	0.06	**1.00**	148	14%
Autumn	Off-peak	0.01	0.02	**0.50**	163	14%
Annual	Peak	0.06	0.48		1,196	29%
Annual	Off-peak	0.02	0.13		1,199	26%

In 2001, congestion occurred between the Netherlands and Belgium arose only one-third of the time, far less frequently than between France and Belgium.

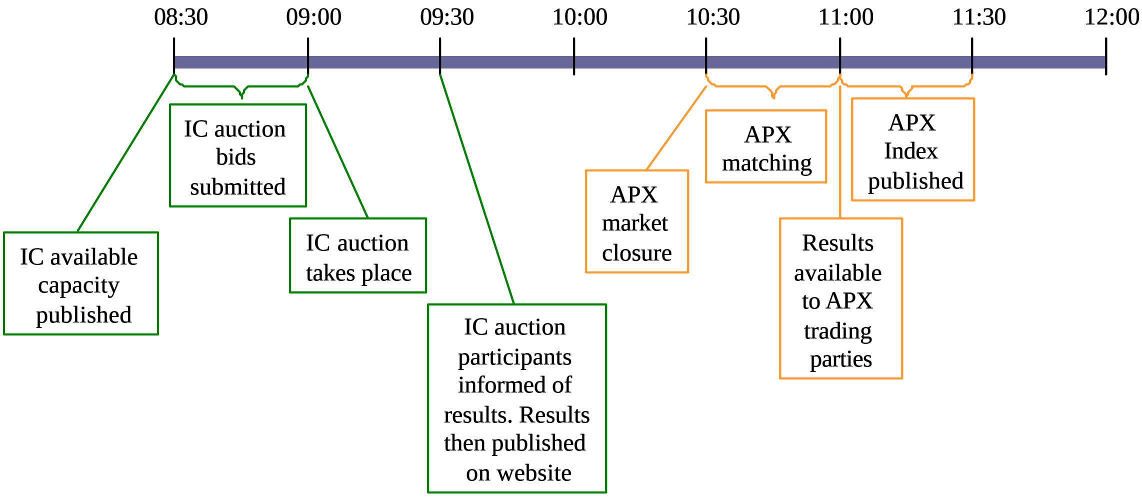
[23] Peak hours are weekdays between 07:00 and 23:00.

4.2 Interconnector Prices and Cross-Border Price Differentials

Our analysis considers both historical congestion and its sensitivity to market conditions. If an interconnectors remains un-congested under divergent market conditions, then the situation will not likely change any time soon. We examine the price differentials between the Netherlands and Belgium as indicators of divergent market conditions.

Unfortunately, we find it difficult to reconcile the prices in interconnector auctions with the price differentials observed between Belgium and the Netherlands. In theory the market price of interconnector capacity should approximate the cross-border price differential. This theory should apply particularly well to the day-ahead auctions, when market players should have a good sense of day-ahead power prices (Figure 8 shows the timing of these auctions and the APX).

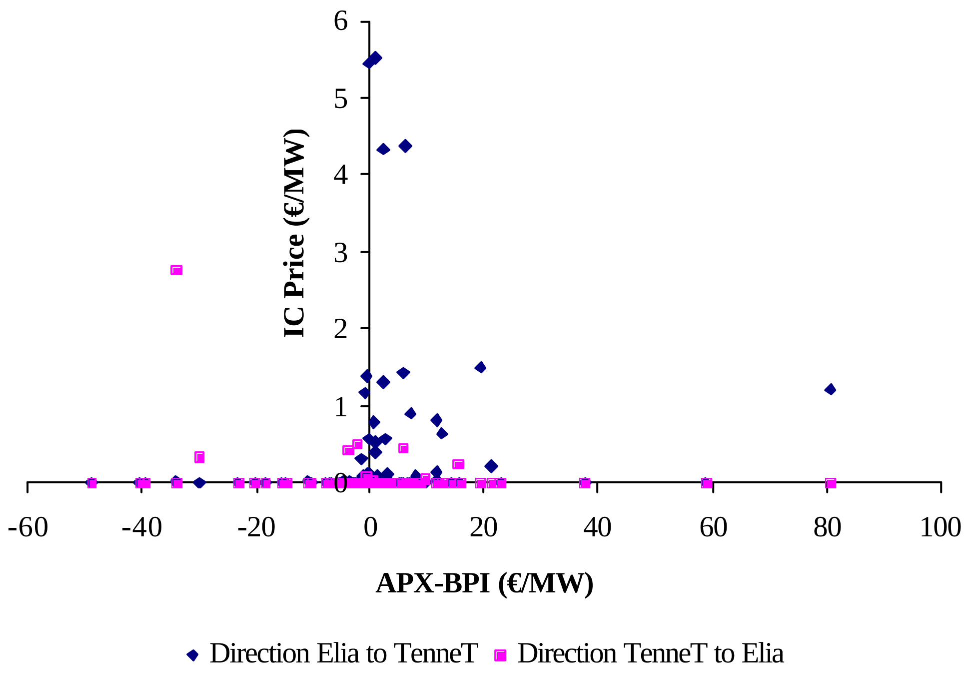
Figure 8: Time-schedule on D-1 for interconnector capacity auctions and APX



In Figure 9 we plot the price paid for hourly interconnector capacity, against the wholesale price differential between Belgium and the Netherlands. As Belgium has no power exchange at present, we use the incumbent generator's Belgium Price Index[24] (BPI) as a proxy for Belgian wholesale prices. One would expect to see the blue dots cluster around "y=x", and the pink dots cluster around "y= -x". However, on several occasions the price of interconnector capacity was over €1/MWh while there was almost no difference between Dutch and Belgian prices. The price of interconnector capacity has at times been zero despite APX prices exceeding the BPI by over €50/MWh.

[24] Since March 2002, Electrabel has published a Belgian Price Index (BPI). The price on the index is established by auctioning off 100 MW of power, one day ahead, in blocks of 25 MW (i.e. participants are bidding for blocks of 600 MWhs). The top four bids win 25 MW of generating capacity each, and the highest price accepted sets the BPI price.

Figure 9: Interconnector prices vs. Belgian-Dutch wholesale price difference



Perhaps the BPI index does not reveal short-term Belgian prices accurately. We check for this possibility by omitting the BPI index from the analysis, focussing only on the relationship between interconnector prices and APX prices. We would expect the average APX price to be relatively high when exports from Belgium to the Netherlands congest the interconnector. However, Table 7 shows that the average APX price is actually *lower* at such times. Conversely we would expect relatively low APX prices when there is no congestion in the direction Belgium to the Netherlands. Table 7 shows that this prediction is consistent with the data, although the difference in prices is rather small.

Table 7: Average APX prices with and without interconnector congestion

	Interconnector Direction	
	Elia to TenneT	TenneT to Elia
Average APX Price with congestion, €/MWh	31	32
Average APX Price without congestion, €/MWh	34	34

Perhaps the precise timing between the interconnector auction and the APX auction could explain our results. As Figure 8 illustrates, market participants must submit bids for interconnector capacity before the APX prices are published. Hence market participants cannot respond to large price differences between BPI and APX prices by offering higher bids for interconnector capacity. We use statistics to analyse the potential effect of timing.

We regress the day "D-1" wholesale price differences against day "D" interconnector prices. If timing were important, large differences in wholesale prices might provoke high prices for interconnector capacity a day later. However, we do not see this relationship among the statistics.

In summary, we find no meaningful relationship between prices for interconnector capacity and the Dutch-Belgian wholesale price differential. A full investigation lies beyond the scope of this report, but some possible explanations involve issues that are typical of markets that are not yet sufficiently competitive or integrated:

- The incumbent Belgian generator may not face sufficient competition for the purchase of interconnector capacity for exports to the Netherlands.[25] The incumbent might be able to buy interconnector capacity cheaply even when APX prices are high relative to the BPI, if no other Belgian generator has power available for export to the Netherlands. Divestiture in Belgium would resolve this problem.

- Dutch generators may hesitate to export electricity to Belgium on a short-term basis, because they find it difficult to find Belgian customers. Purchasing interconnector capacity is risky if uncertainty surrounds the identification of customers in Belgium. The creation of a Belgian exchange would resolve this problem.

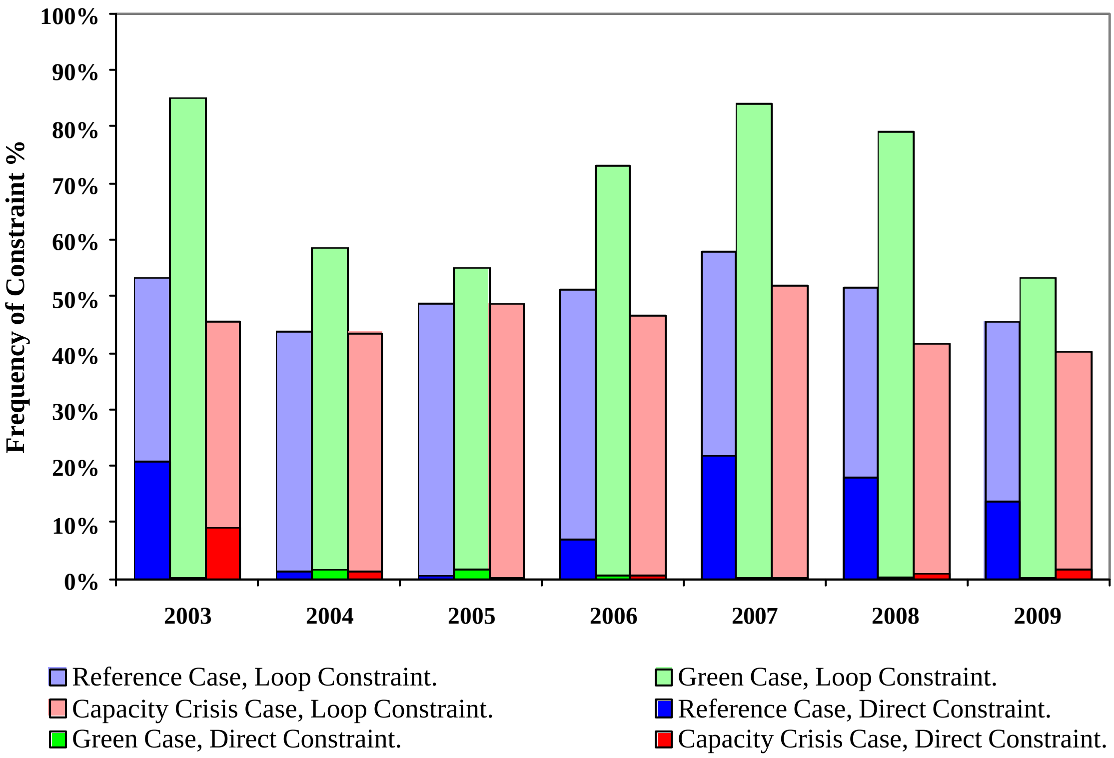
- The way that market participants use information may be complicated, and affected by the relatively new and illiquid status of markets. The timing of the APX price announcements may interact in a complicated way with the interconnection auctions, rendering our one-day lag analysis inadequate.

4.3 Predicted Future Congestion

We use IREMM to determine whether the relatively low congestion on the Dutch-Belgian interconnector will continue. We use the same methodology and scenarios as described previously. Figure 10 shows the results.

[25] In formal economic terms, we would describe the situation as "monopsony power" over the purchase of interconnector capacity.

Figure 10: Predicted frequency of congestion for the Dutch-Belgian interconnector



Under all scenarios considered, we predict less future congestion on the Dutch-Belgian interconnector than on the Franco-Belgium connector. The frequency of *direct congestion* averages about 15% in the Reference scenario, and is never higher than 33% even in the Capacity Crisis scenario. The estimated frequency of direct congestion for 2001 matches closely with the observed 2001 congestion of around 30%. Indirect congestion averages 50%. Indirect congestion is especially high in the Green scenario, because of the higher congestion that would arise on the French-German border.

Under the Reference scenario, the commissioning of phase-shifters on the Dutch-German interconnectors in 2003 relieves almost all congestion until 2006. For 2006 we anticipate completion of the 1,000 MW Netherlands-UK interconnector, which would increase congestion between Belgium and the Netherlands. In 2007 we anticipate an increase in the capacity of the Franco-Belgian interconnector, which would further increase Dutch-Belgian congestion, by allowing more cheap French electricity to flow to the Netherlands. The Capacity Crisis scenario produces similar results to the Reference scenario up to 2006. The Capacity Crisis scenario does not forecast increased congestion in 2006 or 2007, because this scenario assumes that no new transmission infrastructure will be built.

Direct congestion remains low for all the years investigated under the Green scenario. The Green scenario predicts increased electricity exports from France to Germany, which would cause congestion on the French-German interconnector, indirectly constraining the Belgian-Dutch interconnector. The Belgian-Netherlands interconnector would rarely reach full capacity as a result.

4.4 Competition in the Netherlands

The Dutch generating market currently has four main players: Eon, Reliant, Electrabel Nederland and EPZ. No one firm has more than a 27% market share, and we calculate an HHI for the Netherlands Generation market of 1,530, indicating a moderately concentrated market. The level of competition has already been sufficient to motivate the development of the APX. The Netherlands would not have to undertake divestiture to support the formation of an integrated day-ahead or balancing market with Belgium.

4.5 Conclusions for a Benelux Market

Interconnector flows between Belgium and the Netherlands are more balanced than between Belgium and France. The Belgian-Dutch interconnector has experienced congestion approximately one-third of the time. In the absence of the exercise of market power, the frequency of congestion should remain relatively low until at least 2009.

Lower congestion levels on the Belgian-Dutch interconnector would make the Netherlands a better candidate for integration than France. Redespatch costs would be relatively low in a single market. Use of a Market Coupling mechanism should produce prices that diverge infrequently. Active competition in the generating market would also make the Netherlands a more logical candidate for integration with Belgium than France. We discuss the details of a single Benelux market, including estimated redespatch costs, in the next section.

5 Alternative Forms of Benelux Market Integration

In this section we examine the structure of a theoretical Benelux electricity market, the alternative forms of integration and the measures required to promote liquidity for any market created.

5.1 Alternative Trading Products

We consider two different trading products: a Single Product and a Market Coupling product.

Single Product

The salient features of the Single Product are:

- The Market Clearing Price for Dutch and Belgian electricity in the day-ahead market would be identical at all times.
- There would be no charge for use of cross-border interconnector capacity. The interconnector auctions would stop, and the interconnector would be treated the same as any part of a domestic transmission network.

A Single Product would reduce the transaction costs for Dutch generators serving Belgian consumers, and for Belgian generators who wish to sell to Dutch consumers. At present, Dutch exports to Belgium require a number of transactions. First, exports require the purchase of interconnector capacity at an auction. This involves a cost and a risk that the capacity purchased will be too large or too small. Second, the exporter must identify a suitable Belgian counter-party. Without an established market this process could be time-consuming and uncertain.

With a Single Product, Dutch exports would be as simple as using the APX to sell electricity to a Dutch consumer. A Dutch exporter would simply need to enter a sell bid on the exchange. The exchange would automatically identify customers willing to accept the Dutch exporter's price, whether the customer be Belgian or Dutch. There would be no need to purchase interconnector capacity. To summarise, the Single Product would reduce the costs of Belgian-Dutch trades to the same level as Dutch-only transactions.

Market Coupling

We consider a Market Coupling mechanism that would be similar to the Nordpool approach.

- The day-ahead market would be treated initially as a single market. A single price would apply to both countries in the absence of constraints. If market clearing would produce transmission constraints across the interconnector, then the two markets would clear separately, while considering cross-border flows. Prices in both countries would then diverge.

- There would be no sale of daily interconnector capacity, and the TSOs would retain the rents from the interconnector.[26] It might be possible to reserve some interconnector capacity for long-term (i.e. monthly or yearly) contracts, either physical or financial.

Market coupling would help reduce the transaction costs of Dutch-Belgian transactions, much like a Single Product. Dutch generators would not have to buy interconnector capacity, since they could automatically serve Belgian consumers in the absence of transmission constraints.

The continued sale of some interconnector capacity would permit long-term cross-border transactions. Such transactions could also occur using so-called Contracts-for-Differences.

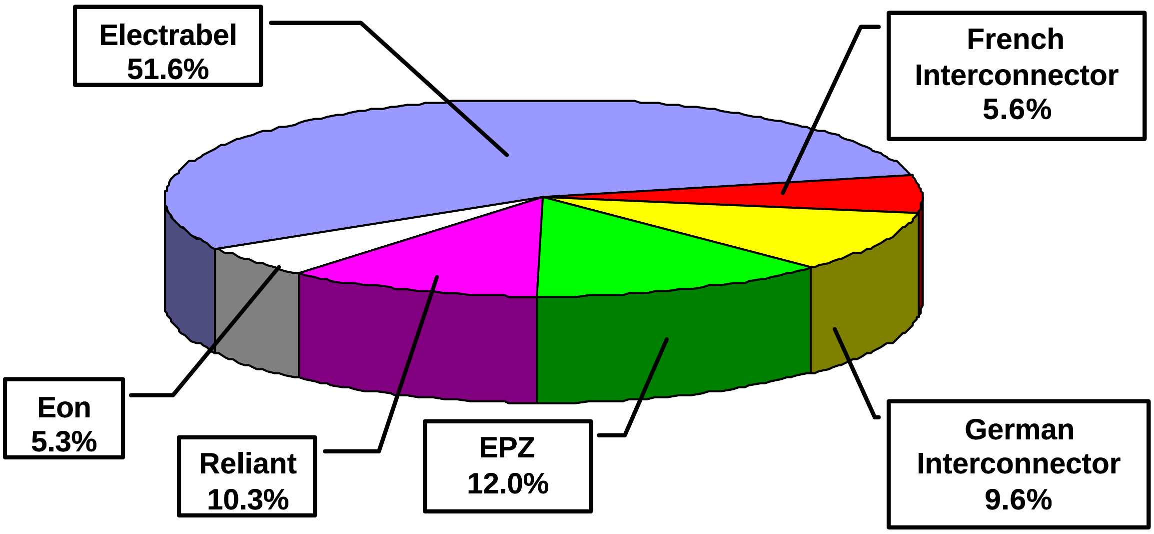
5.2 Benelux Market Structure

An integrated Benelux market would dilute the dominant position of the incumbent Belgian generator, due to increased competition from Dutch generators. However, the dominant position of the Belgian generator might compromise the relatively competitive structure of the Dutch market. We calculate that, excluding the planned interconnectors from the UK and Norway to the Netherlands, the Belgian incumbent generator would control 52% of the generating capacity available to serve Benelux consumers. Assuming centralised management of the incumbent's Belgian and Dutch capacity, we calculate an HHI for the Benelux market of 2,960. In the absence of capacity divestiture a single Benelux market would therefore be highly concentrated[27]

[26] The rents would be set aside for new investment in interconnector capacity, thereby reducing future cross-border charges.

[27] Two new interconnectors are currently in the early planning stages: a 1,000 MW connection between the UK and the Netherlands, and a 600 MW connection between Norway and the Netherlands. Including both interconnectors in the HHI calculation would reduce the outcome to 2,680, which would still indicate high concentration.

Figure 11: Generator shares in a Benelux market



A market share of 40% is often cited as a benchmark for a dominant position. The European Commission is currently considering new guidelines that state: "very large market shares – in excess of 50% - may be in themselves, save in exceptional circumstances, evidence of the existence of a dominant market position."[28] Given the high HHI calculated for the Benelux market, and Electrabel's control 52% of the available Benelux capacity, *we conclude that the formation of a single Benelux market could create potential market power problems.* Market integration would dilute but maintain the incumbent's dominant position, broadening its scope from Belgium to the Benelux area. Dutch consumers would witness a transition from moderate market concentration to extremely high concentration. We would therefore expect DTe to object, because of its natural concern with competition in the Dutch electricity market.

In the following sections we investigate the potential effects of the incumbent's market power, and measures that could mitigate these effects.

5.3 Market Power with a Single Product

A Single Product would fundamentally change the potential exercise of market power in the Benelux market, by making TSO redespatch responsible for handling cross-border transmission constraints. Market power could have two related effects. The first is the potential manipulation of redespatch, described above in section 3.3 and Box 2, to maximise profits for a dominant generator. The second is a more straightforward exercise of market power to increase prices. We investigate both effects separately below.

Redespatch Costs

Redespatch costs depend on the frequency of constraints. Such costs could be particularly high if a dominant player *deliberately created constraints*, to enhance profits.

[28] Financial Times, December 18th 2002.

For example, the incumbent could enter very high offer bids for its Belgian units. The plants might not be despatched in the unconstrained schedule, which could produce unfeasibly large Dutch exports to Belgium. Interconnector constraints could arise, which would require despatch of the incumbent's plants to preserve system stability. The plants would then be paid their high bid costs. Some Dutch generators who bid below the market-clearing price would not run, but could receive compensation. Belgian consumers would not pay the full costs. The redespatch costs would be socialised in the single Benelux price paid by both Dutch and Belgian consumers.

In practice, the profit-maximising strategy to exploit redespatch would depend on supply and demand conditions in Belgium and the Netherlands. As an indicative exercise, we compare five hypothetical strategies:

- *Current Mark-ups:* Continue with the status quo, which we model by assuming a level of mark-ups that would produce results consistent with current observed prices;
- *Belgium Below Cost:* The Belgian incumbent bids its plant at 50% *below* cost. Belgian plant is constrained off, and receives compensation;
- *Belgium Above Cost:* The incumbent bids its plant at a 50% mark-up over marginal cost. Redespatch profits arise if Belgian units are constrained-on;
- *Belgium Very High:* Belgian plant bids at a 100% mark-up over marginal cost;
- *Electrabel Nederland High:* Electrabel Nederland bids at a 50% mark-up, and is Constrained-On in the Netherlands.

We estimate the payoff to each strategy, and identify the most profitable strategy for a variety of different demand levels. We then estimate redespatch costs under the optimal strategy mix that emerges from our analysis. As a benchmark, we also calculate redespatch costs assuming that all generators bid in at marginal cost. The results suggest that market power abuse could raise redespatch costs by €5 million per year relative to perfect competition, from €2.4 million to €7.4 million per year. The redespatch costs would still constitute only a few percent of TenneT's or Elia's operating costs. The redespatch costs would not imply a significant percentage increase in transmission charges. These results contrast sharply with our estimates for a potential Franco-Belgian market. We conclude that *even in the presence of significant market power, redespatch costs for a single Benelux market would be relatively low.*

Market Power and Prices

Independent of redespatch costs, the exercise of market power could produce high prices that harm consumers. We therefore investigate prices in a single Benelux market under the following scenarios:

- *Competitive Bidding:* all generators bid in at the marginal cost of generation.

- *Belgian Market Power:* The incumbent bids in all Belgian plant at a 50% mark-up above marginal costs.
- *Benelux Market Power:* The incumbent bids in all its Belgian and Dutch plant at a 50% mark-up.

The two market-power scenarios imply prices significantly above competitive levels. The most damaging situation involves 50% mark-ups over both Belgian and Dutch plant.

5.4 Market Power with Market Coupling

Under Market Coupling, the incumbent's incentive and ability to exercise market power would approximate the current situation with separate Belgian and Dutch markets. With separate Dutch and Belgian markets, prices should still equalise whenever there is no constraint on the interconnector. Prices should only diverge in the presence of constraints, as under Market Coupling.

The main impact of Market Coupling Product involves institutional arrangements. With separate markets, market participants must bid for daily interconnector capacity before day-ahead wholesale prices are announced (see Figure 8). The actual utilisation of interconnector capacity might not track market needs. Separate markets can therefore permit the emergence of price differences without constraints. In other words, the absence of an intra-day market may prevent market participants from arbitraging away some price differences.[29]

In contrast, the Market Coupling mechanism will arbitrage away price differences between the two markets as part of the clearing process. If there is sufficient interconnector capacity, the Market Coupling product will deliver a single price.

Consequently, *Market Coupling could actually reduce market power problems relative to separate Dutch and Belgian markets*. With a separate market, a dominant player could raise prices, and the difficulty of conducting within-day trades would reduce the risk of market-share losses to rival foreign generators. We do not seek to measure this effect, but do not believe that it could have a significant effect on prices. However, Market Coupling should not provoke market power complaints, since the potential for market power abuse would be the same as now under separate markets, or could be slightly less.

5.5 Prerequisites for Benelux Market Integration

In this section we describe prerequisites for a successful and liquid Single product and a Market Coupling Product.

[29] In principal private intra-day trades could be arranged, but the lack of an established intra-day market means that the transactions costs of finding a counter-party for an intra-day trade would be extremely high.

Single Product

Section 5.2 highlights that a single Benelux electricity market could raise market power concerns, especially from DTe. We would propose the same solution discussed above for a separate Belgian market: divestiture. However, the required divestiture would be less than under a separate Belgian market. Less divestiture would be necessary, because the capacity controlled by Dutch generators would dilute the market power of the Belgian incumbent generator.

In addition to divestiture, we recommend replacing the current Belgian balancing regime with a Belgian balancing market in which Dutch generators could participate. This would be a first step toward the full harmonisation of the Dutch and Belgian balancing markets.

Market Coupling

Since Market Coupling would only reduce the potential to exercise market power, concerns over prices to Dutch consumers would not provide any basis to insist on capacity divestiture. However, market power in Belgium may undermine liquidity by deterring the participation of the Belgian demand side.

One way to mitigate the incumbent's potential market power would be to regulate the incumbent's bids, but only when the market is de-coupled. This would dissuade the incumbent from submitting very high bids, which would subsequently prompt large amounts of Dutch imports, splitting the market and prompting regulation. Although this theory is sound, our quantitative analysis suggests that *a regulated bid scheme would have relatively little practical effect*. Congestion from the Netherlands to Belgium would not likely arise often. To create frequent market splitting, the incumbent would need to mark-up bids by over 100%, a level that does not seem realistic. A 50% mark-up would constrain Dutch exports to Belgium just 8% of the time. The incumbent would therefore retain scope to engage in anti-competitive behaviour without creating constraints.

We conclude that divestiture remains the best way to address market power. The required amount of divestiture would lie somewhere between the amounts necessary under a Single Product and a Separate Product.

Appendix 1: Modelling of Power Generation

Calculation

Despatch Curves

From fuel price and heat rate information, we estimate generation costs for powers stations in both Belgium and the Netherlands. We apply mark-ups to create bids, and allow different companies to have different mark-ups. We create despatch curves for Belgium, the Netherlands, and the Benelux region by ranking the bids for all plants in each region.

Desired Interconnector Flow

Using the Benelux despatch curve, and demand data from UCTE, we calculate the amount of power that would be despatched in both Belgium and the Netherlands in the absence of constraints. We calculate the implied interconnector flow by subtracting Dutch Demand from Dutch Generation, or Belgian Demand from Belgian Generation. If the desired flow across the interconnector exceeds the interconnector capacity, then the difference is the amount of constraint.

Interconnector Capacity

We assume that interconnector capacity is always 1700 MW, and that it is all freely available. We ignore the existence of long-term capacity holdings, and seasonal fluctuations in interconnector capacity.

Constrained-On and Constrained-Off

If efficient despatch of Benelux plants would imply 2,200 MW of Belgian exports to the Netherlands, and the capacity of the interconnector was only 1,700 MW, then a 500-MW constraint would exist. 500 MW of previously 'undespatched' Dutch plants would have to be despatched (constrained on), and 500 MW of previously 'despatched' Belgian plants would have to be switched off (constrained off). Our model switches plants on and off in the order of their national despatch curves, cheapest first.

Market Clearing Price

In a joint market, the Market Clearing Price is set prior to calculating constraints – it is the bid of the plant that would be marginal in the absence of constraints. Some plants may receive more than the MCP because they are constrained on.

As long as the interconnector is not congested, the Market Clearing Price is the same throughout the Benelux region even if the markets have not been integrated: in the absence of constraint power can be sourced from either country, making the marginal price universal. However, if the interconnector is congested then the marginal plant in each country will differ, and different prices will result.

Demand Elasticity

We assume perfectly inelastic demand. Demand changes from hour-to-hour, but is insensitive to price.

Appendix 2: A Description of the IREMM Model[30]

Overview

IREMM is a powerful, comprehensive computer model that performs the functions typically associated with electric power production simulation programs, such as unit dispatching, maintenance scheduling, cost accounting, and report preparation. However, IREMM's functionality far surpasses other simulation programs, because IREMM calculates market-clearing prices and identifies economic energy transactions resulting from the interaction of supply and demand. Its focus on price helps distinguish IREMM from traditional planning and operations models.

In a competitive market, each participant attempts to maximize its economic gain, which consists of net profits on sales and savings on purchases. IREMM's objective function maximises gains over all companies comprising each interconnected system, within the constraints of supply and demand.

IREMM uses a game-theory framework, assuming an ideal market in which all participants have access to price information. Within this framework, strategies can be tested, and gains and losses evaluated. IREMM provides a means to quantify and analyse the relative market power of buyers and sellers.

IREMM employs a unique methodology to auction relatively low-cost energy resources to the highest bidders. The auction results in forecasts of prevailing bulk-power market-clearing prices for energy transactions, assuming a level playing field for all participants. The predicted prices represent those prevailing for energy as a kWh commodity. However, they may not reflect the prices actually paid for energy, for several reasons. First and foremost, the actual market is not perfectly competitive as it exists today, and information about prices is not always readily available. In addition, a transaction may be associated with other ancillary service attributes that provide value over and above the value of the economy energy.

Conventional production costing models lack IREMM's strategic perspective. Production costing models typically study limited sections of the interconnected system. Because they do not represent all companies within an entire interconnected system, production costing models must make simplifying assumptions about the price and availability of bulk power.

Conversely, many large-scale econometrics models favor analytical breadth over detail. They neglect unit and/or company-level data in their estimation of regional energy production, fuel consumption, plant emissions or cost-of-electricity forecasts. These models are useful for macroeconomic analysis, but they are inadequate for assessing market opportunities.

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[30] The IREMM description is taken from *Inter-Regional Electric Market Model (IREMM) Documentation and Users Manual*, Revision 1.17, July 2001, pp1-2 to 1-6.

IREMM Principles

IREMM's methodology relies on the following concepts:

1. Market-Clearing Prices;

2. Supply and Demand in competitive markets;

3. Incremental Production Costs

IREMM presumes that market forces determine prevailing bulk power prices. IREMM initially despatches generating units to meet the loads of individual market areas. Once these loads are served from available resources, IREMM calculates the amount of surplus energy available for sale at various price levels, or the amount of energy imports that would be demanded in specific areas at various price levels. These calculations provide supply and demand curves for each market area. Assuming that each market area in the interconnected system attempts to maximise profits by trading, these supply and demand curves, plus the cost of transmitting energy, determine market-clearing prices. IREMM determines the prices that would produce an equilibrium between supply and demand.

The supply and demand curves are based on the incremental cost of producing an additional MWh of energy. To minimise costs, a company must despatch its lowest-cost generating units first. In the bulk power market, a profit-maximising company produces energy as long as its incremental generating costs are less than the revenue it receives from incremental sales. If the company can sell energy externally for more than its incremental cost of production, the company will continue to produce after meeting its own load needs. On the other hand, if the company can buy the energy needed to meet its load for less than the cost of self-generation, then the company will maximise profits by purchasing.

A unit's incremental cost of production includes the cost of fuel, its heat rate, the cost of ash disposal, and incremental operation and maintenance costs (e.g. flue gas conditioning, fuel handling and limestone reagents used in scrubbers, the value of sulfur dioxide Allowances consumed, etc.) For IREMM's purposes, the incremental cost of fuel is represented by the spot price. Contract costs for fuel generally are considered to be sunk.

Fixed costs, such as fixed operation and maintenance (O & M), or capital investments are not factored into despatch decisions. These costs are incurred whether or not the unit is despatched, and they do not affect the market-clearing price. However, IREMM allows units to earn contributions to incremental costs either because they are infra-marginal or because their owners offer the units at a certain mark-up above marginal costs.

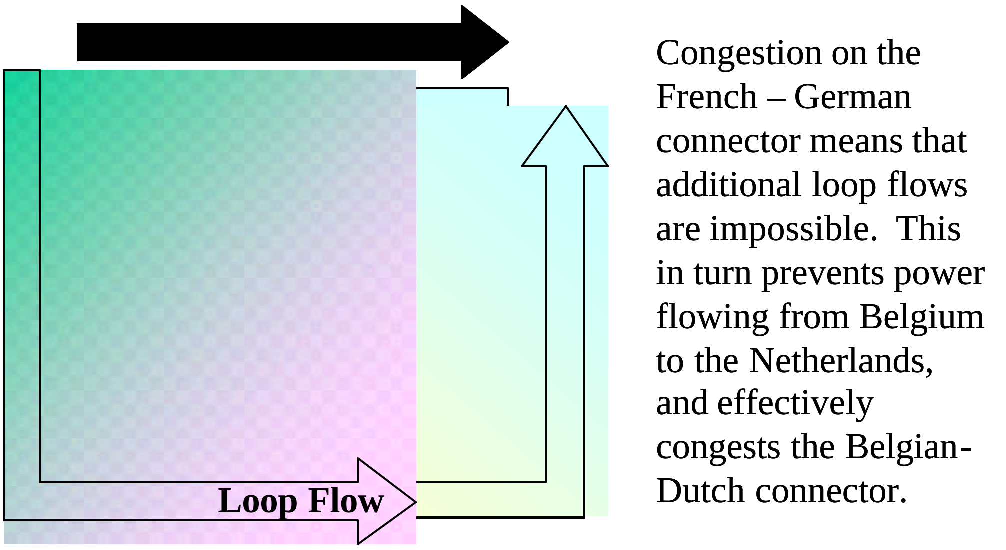
Transmission constraints curtail energy transfers from a region with surplus low-cost energy to a purchasing area. Constraints produce lower market-clearing prices for sellers and higher prices for buyers. Once a constraint is reached, the market areas on either side have no further impact on each other.

IREMM helps examine the economic forces that affect the price and availability of energy as a commodity. IREMM does not analyse directly the ancillary service attributes that may add value to transactions and influence the price ultimately paid by a purchaser.

Appendix 3: Example Loop Flows

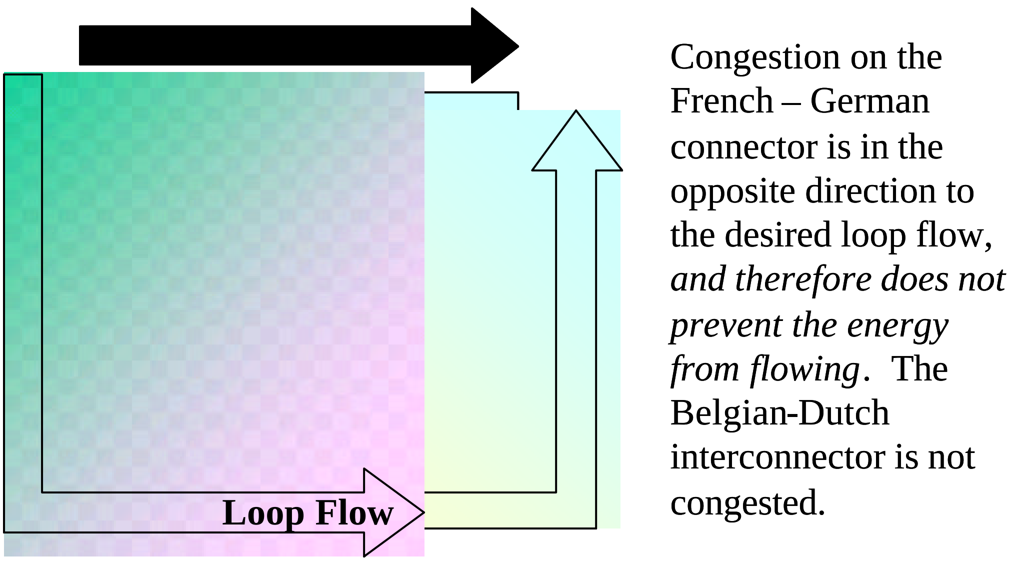
Example 1: The Belgian-Dutch interconnector is not directly congested, but the German-French interconnector is. The congestion on the German-French interconnector prevents the flow of additional power between Belgium and the Netherlands.

Figure A 1: Loop Flow Example 1



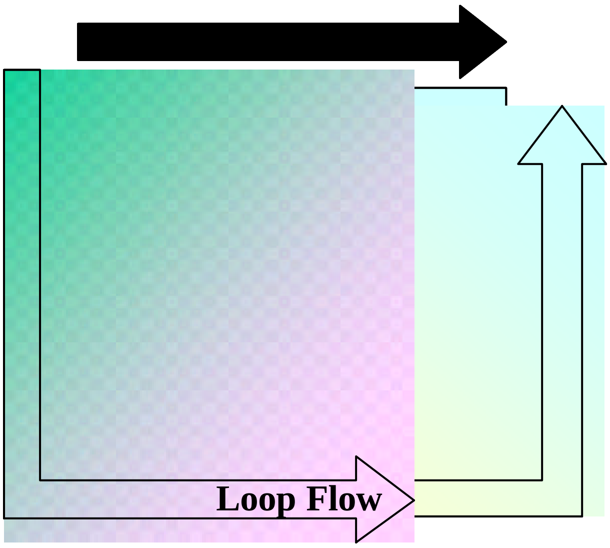
Example 2: The Belgian-Dutch interconnector is not directly congested, but the German-French interconnector is. The congestion on the German French interconnector *does not* prevent the flow of additional power between Belgium and the Netherlands.

Figure A 2: Loop Flow Example 2



Example 3: The Belgian-Dutch interconnector is directly congested. Loop flows are possible, but the direct congestion prevents the flow of additional power between Belgium and the Netherlands.

Figure A 3: Loop Flow Example 3



The Loop Flow route is not congested, but Belgium may not export power to the Netherlands via France and Germany since to do so would also increase the flow across the directly congested Belgian – Dutch connector.