Lacking balancing market harmonisation in Europe: room for trader profits at the expense of economic efficiency?

By

Leen Vandezande, Electrical Engineering Department, Katholieke Universiteit Leuven, Belgium
Marcelo Saguan, Groupe Réseaux – Jean Monnet, Paris XI, France
Leonardo Meeus, Electrical Engineering Department, Katholieke Universiteit Leuven, Belgium
Jean-Michel Glachant, Groupe Réseaux – Jean Monnet, Paris XI, France
Ronnie Belmans, Electrical Engineering Department, Katholieke Universiteit Leuven, Belgium

Leen Vandezande, PhD researcher
Katholieke Universiteit Leuven, Electrical Engineering Department, Research Group Electa
Kasteelpark Arenberg 10 – PB 2445, B – 3001 Heverlee
Phone: +3216321722/Fax: +3216321985/Email: leen.vandezande@esat.kuleuven.be

Abstract

Following several regional initiatives on the day-ahead and intra-day stage, integrating real-time balancing markets constitutes a logical next step in the process towards an Internal Electricity Market (IEM) in Europe. So far, real-time balancing market designs significantly differ between European countries and a coordinated approach for cross-border exchange of balancing services is non-existent. This paper aims to illustrate that the current lack of balancing market harmonisation – in combination with an increasingly integrated day-ahead and intra-day trade – can be profitably exploited by traders. More specifically, trading strategies taking advantage of structural design differences in the imbalance settlement of two countries are identified and assessed. The paper analyses detailed data of the Belgian and French power system using statistics in order to verify the profitability of different trading strategies between both countries. Some of the identified trading strategies are found to be significantly profitable; others turn out to be loss-making. On average, France was the most attractive country for traders to be long in 2008; Belgium to be short. Profitable trading strategies can usally be carried out without any expense as cross-border capacities available at the intra-day stage are currently far from being used and no value is attributed to them. However, some profitable trading activities resulting from market design imperfections may induce economic inefficiencies.

1. Introduction – wholesale market integration in Europe

Wholesale electricity markets in Europe have been designed (partly) differently than in North America. While the Pennsylvania – New Jersey – Maryland market design (PJM) – which is based on a quasi *mandatory* auction or so-called power pool running one day ahead of delivery – is serving as an example in North America, electrical energy trading in Europe is organised mainly bilaterally via over-the-counter (OTC) markets, often supplemented with *voluntary* day-ahead auctions. As discussed in Meeus and Belmans (2007), European day-ahead auctions do not determine – contrary to North American ones – the generation schedule for the next day, implying that day-ahead commitments and actual deliveries are only weakly linked (similar to the former California market design). The day-ahead stage is used for portfolio fine-tuning as every MWh eventually being delivered has already been physically traded several times. Generators decide themselves upon their generation schedule – considering their commitments from trading in a variety of markets – and submit their intentions at a fixed point in time, called gate closure, to the system operator. Furthermore, wholesale trading arrangements in Europe do not take into account internal network constraints. Instead, these constraints are considered in real-time and occasional re-dispatch costs are socialised among grid users. As a result, most European countries are single priced zones (*zonal* pricing). North American power pools by contrast deal with intra-zonal network constraints, meaning that in case network constraints are binding every node can have a different price (*nodal* pricing).

Since the launch of electricity sector liberalisation in Europe, the European Union (EU) has pursued – and increasingly continues to pursue – the creation of an Internal Electricity Market (IEM). Following the first market reforms – both on wholesale and retail level – initiated by Directive 96/92, the adoption of Directive 2003/54 and Regulation 1228/2003 and the recent approval of a third legislative package have put in place a more stringent regulatory framework towards achieving this ultimate goal (EC, 2007). As discussed in Meeus and Belmans (2008), full market integration is currently far from being accomplished, given for instance the significant wholesale price differences and scarce interconnection capacity between European countries. However, a number of successful initiatives has been launched on a regional level[1]:
(1) *The Nordic market* – comprising Norway, Sweden, Finland, Denmark and partly Germany – with its common day-ahead power exchange NordPool, initiated in 1995, and its advanced harmonisation of intra-day and real-time balancing market systems;
(2) *The Central Western European Market* – comprising Belgium, France, Germany, Luxemburg and the Netherlands – with its Trilateral Market Coupling (TLC) initiative, coupling the day-ahead power exchanges of Belgium (Belpex), France (Powernext) and the Netherlands (APX) in a decentralised way since 2006, and its proposals on the coordination of intra-day trade;
(3) *The Iberian market* – comprising Spain and Portugal – with MIBEL, a common market initiative dividing responsibilities for the organisation of day-ahead and futures trade between the Spanish (OMEL) and Portuguese (OMIP) power exchange since 2007.
Given that regional market integration efforts so far mainly focused on the day-ahead and intra-day stage, implementing real-time balancing markets spanning national frontiers constitutes a logical next step towards completing the IEM. Balancing market designs currently significantly differ between European countries and a coordinated approach for cross-border exchange of balancing services is non-existent. The

[1] Note that the European Commission (EC) actively promotes this regional approach as a necessary interim step towards achieving the IEM.

EC increasingly recognises the importance of opening balancing markets to foreign countries, as shown by its recently commissioned study on the optimal design and effective implementation of cross-border balancing markets in Europe (Tractebel Engineering and K.U.Leuven, 2009) and the amendments to Regulation 1228 included in the third legislative package which allow for the adoption of binding guidelines on balancing market integration.

This paper aims to illustrate that the current lack of balancing market harmonisation – in combination with an increasingly integrated day-ahead and intra-day trade – can be profitably exploited by traders. More specifically, trading strategies taking advantage of structural design differences in the imbalance settlement of two countries are identified and assessed. As an introductory example, consider two countries A and B. Assume country A settles imbalances through a price system with so-called penalties. Penalties are added to the imbalance or real-time price in many countries for several reasons, including as a means of motivating BRPs to avoid negative imbalances. Penalties are typically larger for short positions than for long ones. Country B, on the other hand, relies on a price system without penalties. As a result, one may expect structurally higher negative imbalance prices in country A compared to B. Traders with a short position in country A can now profitably move their short position to country B by buying energy in B and selling it in A using the intra-day market, conditionally to sufficient available interconnection capacity at the intra-day stage. This way, traders achieve a balanced position in country A and face a negative imbalance in country B. Assuming intra-day capacity can be used without compensation, traders consequently gain the difference in negative imbalance prices between A and B. If these transactions take place on a large scale, an overall migration of imbalances from country A to B can be observed, affecting system operators in performing their task of guaranteeing system security. More specifically, the system operator of country B will have to activate more balancing services and/or contract more reserves – the cost of which is often partly borne by the own grid users – to deal with the increased system imbalances.

The analyses in this paper concern Belgium and France – two adjacent countries whose electricity markets have been successfully integrated so far up to the day-ahead – and increasingly the intra-day – stage. At the day-ahead stage, electrical energy and interconnection capacity are allocated simultaneously through TLC (cf. supra). At the intra-day stage, capacity between Belgium and France is on the contrary allocated via an explicit pro-rata mechanism at several moments of the day (12 so-called gate closures). The allocated intra-day capacity is free for participants. As indicated by CRE (2008), the usage rate of intra-day capacities between both countries has however been particularly low. In 2007[2], the average intra-day capacity available from France to Belgium and vice versa amounted to 758 MW and 2042 MW, of which respectively 1.8% and less than 1% was used for intra-day trade. In the real-time, the exchange of services between both countries is so far restricted to emergency cases and consequently rather exceptional. In 2007, the real-time volume activated by the Belgian system operator Elia in France amounted to 8075 MWh (± 0.1% of the total traded volume on Belpex day-ahead in 2007); the volume activated by the French system operator RTE in Belgium was limited to 890 MWh (± $2*10^{-5}$% of the total traded volume on Powernext day-ahead in 2007) (CRE, 2008). Given the important share of interconnection capacity that remains currently unused by market operators, the development potential for cross-border balancing trades is however significant. In 2007, the average unused capacity from France to Belgium amounted to 1180 MW – with an available capacity above 500 MW during 70% of the hours –

[2] Note that intra-day capacities between Belgium and France were first allocated since 22 May 2007.

and from Belgium to France 2280 MW – with an available capacity above 500 MW during 99% of the hours (CRE, 2008).

The remainder of this paper is organised as follows. Section 2 provides a basic insight into the main characteristics of balancing markets in Belgium and France and identifies differences in their design. Section 3 describes the dataset used. Section 4 identifies possible trading strategies and analyses their profitability. Section 5 discusses the results of our analysis and their implications for society.

2. Characteristics of balancing markets in Belgium and France

Balancing markets in Europe are made up of two basic components, i.e. procurement and settlement. In order to safeguard system security, system operators procure balancing services in the balancing market from Balancing Service Providers (BSP). To limit the amount of services needed, system operators furthermore discourage market parties from relying on the real-time delivery of balancing services or, in other words, deviating from their announced generation and consumption schedules. They therefore transfer part of their balancing obligation to market participants or their chosen representatives – known as Balance Responsible Parties (BRP) – by making them responsible for keeping their own portfolio balanced over a given time-frame via the imbalance settlement. Figure 1 gives a graphic representation of procurement and settlement and the central role of the system operator in both.

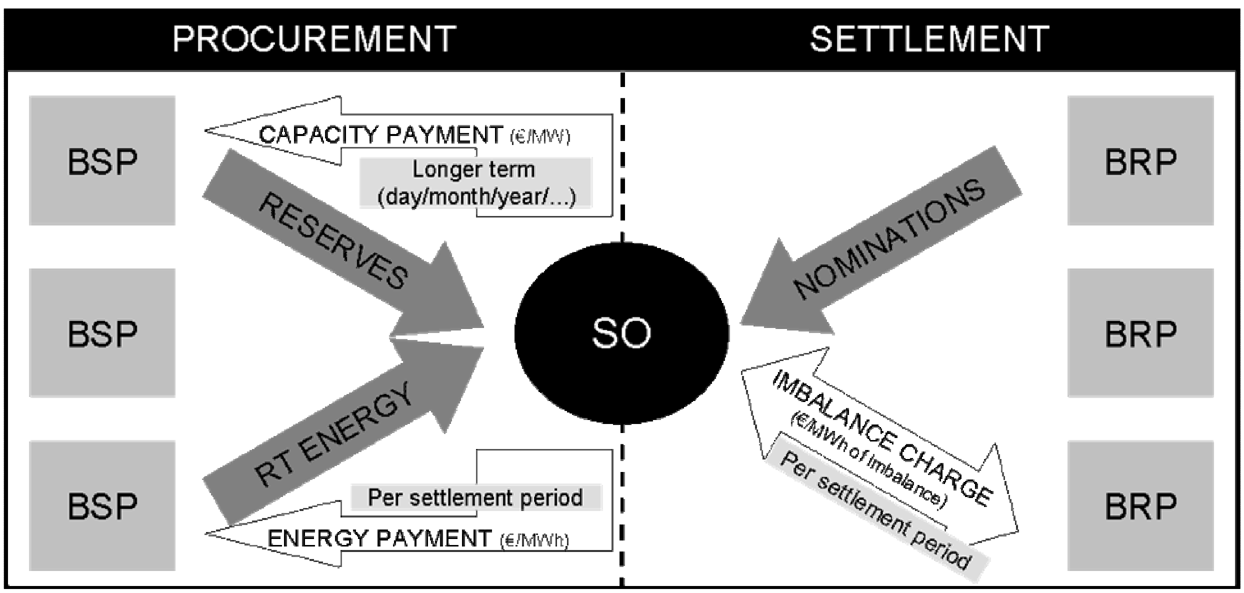

Figure 1: Balancing services procurement and imbalance settlement by SO

BSP = balancing service provider; BRP = balancing responsible party; RT = real-time

Procurement of balancing services

To ensure continuous and sufficient availability, TSOs often make reservations beforehand by not only paying for the delivery of balancing services via the real-time market (energy or utilisation payments – on a settlement period basis – through auctions) but also for holding reserves via the reserve market (capacity or availability payments – on a longer term basis – through bilateral contracts or tenders). As illustrated in Rebours et al. (2007), the method of procurement and remuneration for similar services differs significantly between European countries. In addition, the time period for capacity reservations varies from an hourly to a more than one year basis. Other than procuring services from generation, services can be purchased from power consumers or even ‘obtained’ – via an obligation in the grid code – from grid users, the latter being known as compulsory provision. In Belgium and France, methods for remuneration and procurement of different services are quite similar but the time period for capacity reservations differs (Vandezande et al., 2008). As discussed in Tractebel Engineering and K.U.Leuven (2009), insufficient harmonisation of remuneration methods can entail economic efficiencies, which are however not considered in this paper.

Imbalance settlement

SOs partially pass their balancing responsibility on to market participants by designating BRPs[3], which are made responsible for keeping their own portfolio balanced over a given timeframe, i.e. the settlement period, via the so-called imbalance settlement mechanism. The imbalance or real-time price encourages these BRPs to match their injections and off-takes. Remaining short or long positions in real-time can only be handled by the SO as the single buyer of balancing services. Figure 2 illustrates this process for UCTE, the synchronous zone encompassing continental Europe, including Belgium and France.

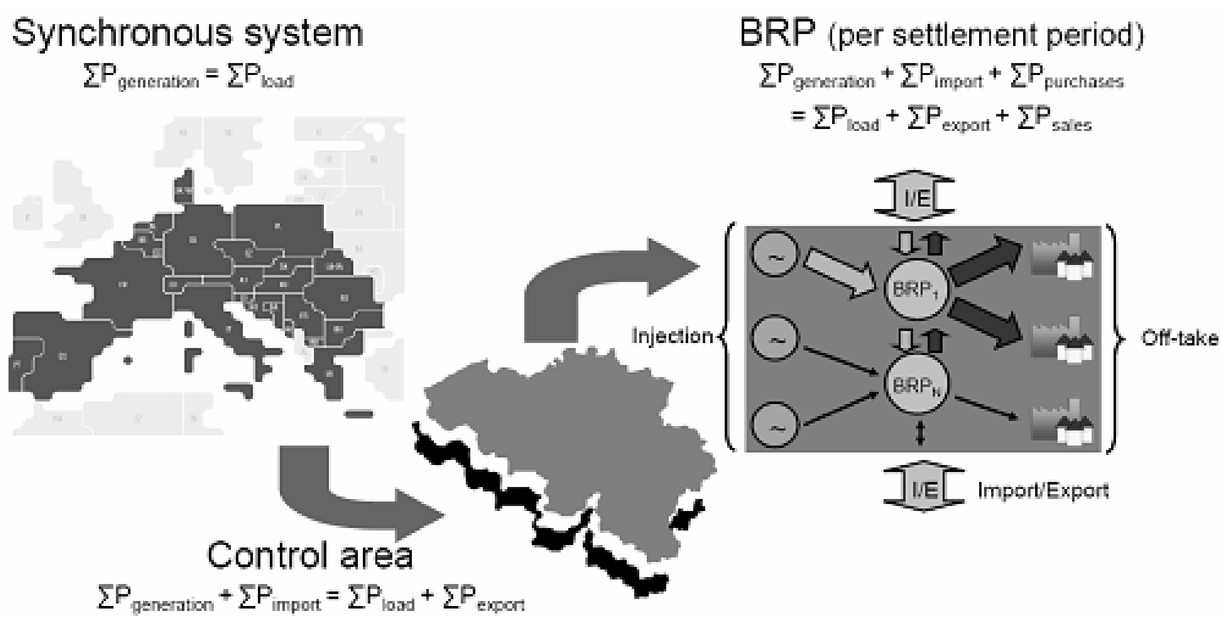

Figure 2: SO versus BRP responsibility in the synchronous area UCTE

More specifically, a BRP portfolio can consist of generation, energy purchases and imports on the one hand (injections), and industrial and residential customers, energy sales and exports on the other (off-takes). Generally speaking, a portfolio is balanced if the following equation – expressed in MW – holds over the settlement period as defined by the TSO of the relevant control area:

$$\left(\sum_{BRP} P_{\text{generation (G)}} + \sum_{BRP} P_{\text{import (I)}} + \sum_{BRP} P_{\text{purchases (P)}}\right) = \left(\sum_{BRP} P_{load\,(L)} + \sum_{BRP} P_{\text{export (E)}} + \sum_{BRP} P_{\text{sales (S)}}\right)$$

At gate closure – the time at which wholesale trade between market participants ceases – each BRP is required to declare its scheduled imports, exports and energy exchanges between BRPs and power

[3] Note that each market participant can decide for itself whether to become a BRP or outsource the task of portfolio-balancing to another BRP.

exchanges, known as 'nominations'. These nominations have to be balanced in all European countries, except for Great-Britain. Remaining short or long positions in real-time are denoted as the BRP's negative and positive imbalances. Depending on the BRP imbalances incurred, an imbalance charge (€/MWh) is imposed per settlement period on the BRPs concerned. Consequently, BRPs can weigh up whether to maximise hedging against imbalances by purchasing energy in the wholesale market or pay for imbalances in real time. However, given the higher volatility and unpredictability of real-time prices, BRPs exhibit a natural tendency to contract beforehand via wholesale markets rather than relying on the real-time market.

Imbalance or real-time prices are usually based on the up- and downward regulating power offers accepted by the SO for real-time balancing. They are based on either the price of the *marginally* accepted up- or downward regulating offer (MP_u and MP_d)or the *average* price of all accepted up- or downward regulating offers (AP_u and AP_d), depending on how BSPs are remunerated. Apart from the choice between marginal and average pricing, a difference also exists between single and double imbalance pricing schemes. Table I and Table II represent a typical one- and two-price system.

Table I: Imbalance pricing through a typical one-price system

		System imbalance	
		NEGATIVE (short)	POSITIVE (long)
BRP imbalance	NEGATIVE (short)	+ MP_u	+ MP_d
	POSITIVE (long)	- MP_u	- MP_d

MP_u = marginal price of upward regulation; MP_d = marginal price of downward regulation

Table II: Imbalance pricing through a typical two-price system

		System imbalance	
		NEGATIVE (short)	POSITIVE (long)
BRP imbalance	NEGATIVE (short)	+ AP_u*(1+ $penalty_u$)	+ P_{DA}
	POSITIVE (long)	- P_{DA}	- AP_d/(1+ $penalty_d$)

AP_u = average price of upward regulation; AP_d = average price of downward regulation; P_{DA} = day-ahead power exchange price

Under a single imbalance pricing scheme or one-price system, real-time or imbalance prices correspond to the marginal procurement price of balancing services, i.e. either upward or downward regulating services depending on the overall status of the system. The same imbalance price – although with a different sign – is applied for remaining short and long positions, making the imbalance settlement a zero-sum game for the SO. Under a double imbalance pricing scheme or two-price system on the contrary, a different imbalance price is applied for positive and negative BRP imbalances. While BRP imbalances contributing to the system imbalance are settled at prices based on the – usually average – procurement costs of balancing services, BRP imbalances counteracting the system imbalance are settled on the basis of wholesale price indices, typically power exchange prices. Compared to a one-price system, under which settlement of BRP imbalances opposing the system imbalance is based on marginal costs – i.e. the additional cost the SO would have incurred if the BRP concerned was not imbalanced – the latter is often implemented to avoid generators speculating on the direction of the system imbalance – i.e. creating a short position if they expect the system imbalance to be long and vice versa. Imbalance prices in a two-price system typically also include a multiplicative component or so-called penalty that affects BRPs with regard to their position before real-time. This penalty typically affects negative imbalances more than positive ones, thus encouraging BRPs to avoid short positions. Other than for BRP motivation to be balanced – and associated security safeguarding – penalties are imposed for practical reasons such as accounting. Given the presence of power exchange prices and penalties, a two-price system no longer implies a zero-sum game for the SO.

Imbalance price schemes in Belgium and France are represented in Table III and Table IV. Both are two-price systems, based on the average procurement price of balancing services and including day-ahead power exchange prices and a penalty (α and γ in Belgium; k in France). However, the magnitude of this penalty and its impact on the final imbalance price differs. Moreover, the Belgian imbalance pricing system turns into a one-price system in case the balancing market is tight (i.e. the activated regulation volume exceeds +/-450MW).

Table III: Imbalance pricing system in Belgium (2008) (source: www.elia.be)

		System imbalance	
		NEGATIVE (short)	POSITIVE (long)
BRP imbalance	NEGATIVE (short)	Max(α *AP_u; $AP_u + \beta$ *(MP_u- AP_u)	1.08* P_{DA} (Belpex)
	POSITIVE (long)	- 0.92* P_{DA} (Belpex)	- Min(γ *AP_d; $AP_d + \delta$ *(MP_d- AP_d)

AP_u = average price of upward regulation; AP_d = average price of downward regulation; MP_u = marginal price of upward regulation; MP_d = marginal price of downward regulation; P_{DA} = day-ahead power exchange price; α = 1.08; β = min (1; gross regulation volumeu/450); γ = 0.92 (AP_d > 0) or 1.08 (AP_d < 0); δ = min (1; gross regulation volumed/450)

Table IV: Imbalance pricing system in France (2008) (source: www.elia.be – www.rte-france.com)

		System imbalance	
		NEGATIVE (short)	POSITIVE (long)
BRP imbalance	NEGATIVE (short)	AP_u*(1+k) (and $\geq P_{DA}$)	P_{DA} (Powernext)
	POSITIVE (long)	- P_{DA} (Powernext)	-AP_d/(1+k) (and $\leq P_{DA}$)

AP_u = average price of upward regulation; AP_d = average price of downward regulation; P_{DA} = day-ahead power exchange price; k=0.05

Figure 3 and Figure 4 show the evolution of positive and negative imbalance prices in Belgium and France in 2008. The difference or so-called spread between the imbalance prices is also represented on the right axis. Table V summarises the average values and spread between positive and negative imbalance prices for both countries. The significant differences in spread (57% in Belgium versus 39% in France) point to a different intensity of penalties in both countries and consequently underlying structural differences in their imbalance settlement (Saguan, 2007). Note that also the settlement period differs between both countries: 1/4[th] hour in Belgium versus 1/2[nd] hour in France.

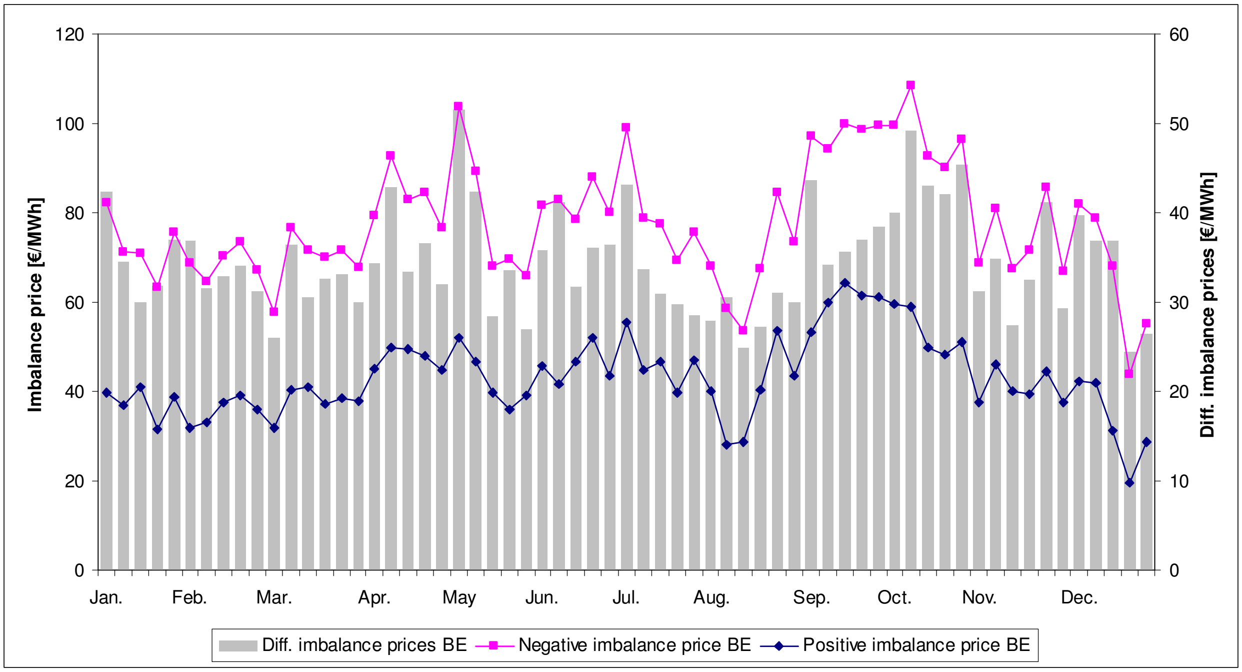

Figure 3: Imbalance prices in Belgium in 2008 (weekly moving average – source: www.elia.be)

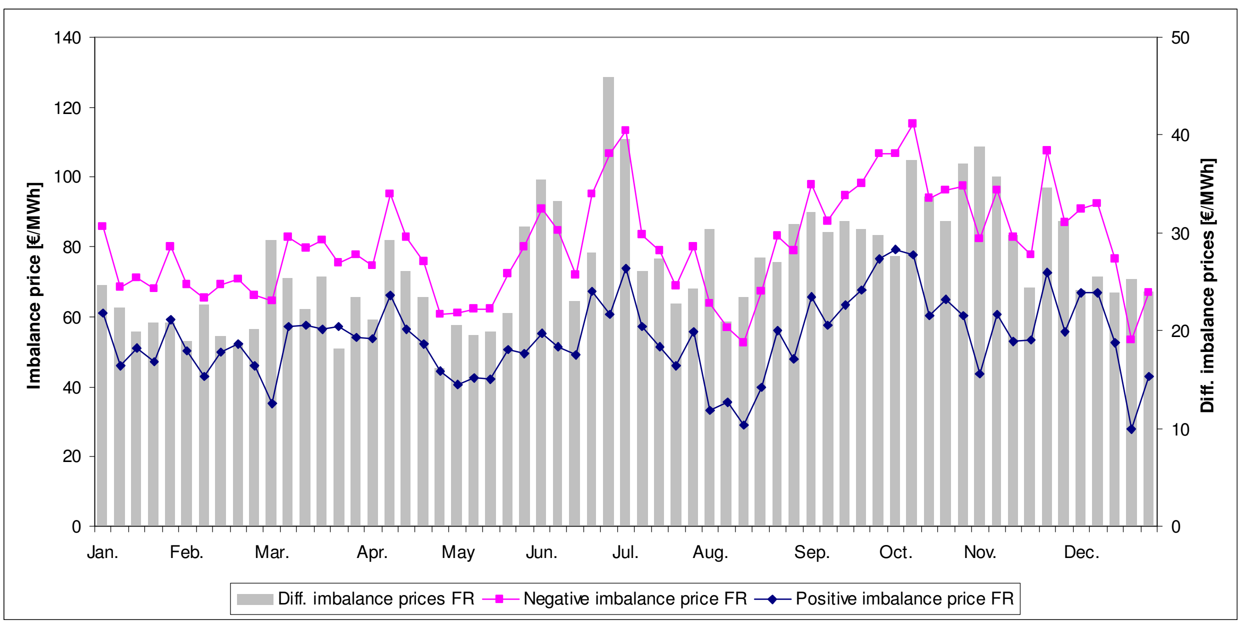

Figure 4: Imbalance prices in France in 2008 (weekly moving average – source: www.rte-france.com)

Table V: Average imbalance prices in Belgium and France in 2008 (source: www.elia.be – www.rte-france.com)

	Negative imbalance price (€/MWh)	Positive imbalance price (€/MWh)	Difference imbalance prices (€/MWh)	Difference imbalance prices[4] (%)
Belgium	78.05	43.29	34.76	57 %
France	80.77	54.40	26.37	39 %

3. Data description

The dataset used comprises day-ahead and imbalance prices for Belgium and France as well as intra-day available interconnection capacities between both countries. The dataset covers the year 2008 and all data included are converted to a 1/2nd hour basis:

- *Positive and negative imbalance prices* (source: www.elia.be – www.rte-france.com)
  Given the different settlement period in Belgium (1/4th hour) and France (1/2nd hour), data of Belgium are averaged on a 1/2nd hour – i.e. the least common multiple – basis. For instance, Belgian imbalance prices for 00:00-00:15 and 00:15-00:30 are averaged to a single imbalance price for half hour 1 (00:00-00:30).
- *Day-ahead power exchange prices* (source: www.belpex.be – www.powernext.fr)
  As imbalance prices are given at a higher frequency than those on the day-ahead market (1 hour), half-hourly day-ahead prices are constructed. For instance, the day-ahead price for hour 1 (00:00-01:00) is used for both half hour 1 (00:00-00:30) and 2 (00:30-01:00).
- *Available interconnection capacities at the intra-day stage* (source: www.rte-france.com)
  Cross-border capacities available at the 1:00 PM intra-day gate closure are used and converted from hourly into half-hourly values.

Table VI, Table VII and Table VIII present summary statistics for Belgian and French imbalance prices, Belpex and Powernext prices for the whole period of 2008 as well as on a monthly basis.

Table VI: Summary statistics of Belgian and French imbalance prices, Belpex and Powernext prices (in €/MWh) for the year 2008

	FR positive imbalance	Powernext	FR negative imbalance	BE positive imbalance	Belpex	BE negative imbalance
Mean	54.40	69.15	80.77	43.29	70.62	78.05
SD	28.94	28.57	35.03	27.00	30.82	31.75
Kurtosis	1.06	1.21	2.75	10.46	15.48	18.62
Min	0.00	3.49	3.49	0.00	0.01	0.01
Max	250.00	250.00	364.37	460.00	500.00	540.00

On average, France was the most attractive country for traders to be long – i.e. with the relatively highest positive imbalance price; Belgium to be short – i.e. with the relatively lowest negative imbalance price. As the monthly figures indicate, negative imbalances were most advantageously charged in Belgium during 7 months; positive imbalances were most highly remunerated in France during each month.

[4] The average difference of imbalance prices in terms of percentage represents the relative importance of the (absolute) difference of imbalance prices with respect to the average imbalance price level. It is calculated by dividing the (absolute) difference of imbalance prices by the average of both positive and negative imbalance prices.

Table VII: Summary statistics of Belpex and Belgian imbalance prices (in €/MWh) per month for the year 2008

	Mean			SD			Kurtosis			Min			Max		
	+	BPX	-	+	BPX	-	+	BPX	-	+	BPX	-	+	BPX	-
Jan	37.25	65.20	71.80	21.42	22.85	23.20	3.89	4.00	5.15	0.01	3.9	10.9	184	210.13	226.94
Feb	36.08	62.81	68.85	18.65	15.74	16.90	-0.04	-0.10	1.82	0	13.98	15.1	184	210.13	226.94
Mar	38.91	64.50	71.59	19.29	20.93	21.05	1.74	23.01	29.77	0.01	8.17	17.07	183.99	300	324
Apr	47.85	76.10	84.16	31.82	38.47	40.23	35.59	47.12	52.80	0	9.97	13.05	460	500	540
May	41.46	68.39	76.08	30.51	39.27	40.69	26.00	19.97	23.28	0	6.02	6.5	460	500	540
Jun	46.31	74.33	82.49	28.65	34.89	35.30	1.60	0.55	0.88	0	5.98	8.45	177.97	200	216
Jul	46.09	70.68	79.00	24.27	28.45	27.72	1.95	1.41	2.25	0.01	3.49	5.94	169.28	184	198.72
Aug	37.99	59.11	66.39	24.90	26.45	25.28	-0.71	-0.60	-0.36	0	7.91	8.63	109.11	118.6	128.09
Sep	60.04	89.52	97.56	29.71	27.64	28.91	-0.36	-0.72	-0.68	0.01	14	15.12	151.35	167.2	180.58
Oct	52.97	88.79	97.20	30.07	33.16	35.46	0.23	-0.77	-0.39	0	0.01	0.01	179.7	195.33	238.65
Nov	42.13	68.51	75.83	24.21	26.816	27.46	1.29	1.84	2.46	0	7.52	8.12	174.8	217.78	235.2
Dec	32.71	59.83	65.98	23.77	27.11	28.01	1.42	4.08	4.91	0	1.37	7.89	144.07	250	270

Table VIII: Summary statistics of Powernext and French imbalance prices (in €/MWh) per month for the year 2008

	Mean			SD			Kurtosis			Min			Max		
	+	PXT	-	+	PXT	-	+	PXT	-	+	PXT	-	+	PXT	-
Jan	52.01	65.18	73.62	24.27	22.77	26.71	2.08	4.07	6.24	2.9	3.90	8.17	200	210.13	272.59
Feb	47.93	62.17	68.08	18.25	15.15	18.30	-0.28	-0.04	1.18	3.21	13.98	13.98	200	210.13	272.59
Mar	56.25	63.08	79.36	20.71	18.61	25.31	-0.23	3.69	0.74	0.35	8.17	8.17	112.19	199.99	199.99
Apr	55.61	70.36	79.73	25.41	26.68	30.80	2.69	1.59	1.64	0.7	7.97	7.97	199.16	199.16	246.97
May	45.66	56.43	68.44	23.10	23.59	29.19	-0.17	-0.49	1.63	0.35	6.02	6.02	138.99	138.99	197.61
Jun	56.12	72.85	87.16	34.516	35.54	43.87	0.96	0.52	0.49	0.52	5.98	5.98	193.45	200.00	269.57
Jul	55.87	70.27	83.42	32.44	28.47	37.08	0.81	1.32	1.19	0	3.49	3.49	184	184	245.46
Aug	39.99	58.67	65.31	27.76	26.63	31.57	-1.15	-0.66	0.028	0	7.91	7.91	110.04	118.61	175.25
Sep	64.85	88.43	95.64	30.92	29.45	34.44	0.03	-0.26	0.19	0.44	7.41	7.41	164.93	164.93	220
Oct	67.72	91.74	101.57	32.27	31.84	36.77	-0.68	-0.74	-0.60	1.86	18.05	19.95	170.46	195.33	213.01
Nov	59.21	57.62	90.65	31.21	26.62	41.77	0.75	0.28	7.20	0.27	6.41	7.53	217.78	153.46	364.37
Dec	51.72	72.99	76.39	29.56	25.27	35.08	3.11	5.79	4.41	0.04	7.53	6.41	250	250	269.1

Typically, imbalance prices for short and long positions are respectively above and below the day-ahead power exchange price. This was on average always the case in both countries, except during November in France. The higher kurtosis for Belgian prices finally points out that more of the variances are due to infrequent extreme deviations, as opposed to more frequent modestly-sized deviations in France.

Table IX and Table X present summary statistics for the available interconnection capacities between Belgium and France at the 1:00 PM intra-day gate closure. As mentioned in Section 1, significant capacity is still available – and remains unused – at the intra-day stage. Average available capacities substantially differ from month to month.

Table IX: Summary statistics of intra-day available interconnection capacities (in MW) between Belgium and France for the year 2008

	Intra-day capacity BE → FR	Intra-day capacity FR → BE
Mean	1888.65	1414.27
SD	1037.55	1123.42
Kurtosis	-0.83	-0.21
Min	0	0
Max	4301	4599

Table X: Summary statistics of intra-day available interconnection capacities (in MW) between Belgium and France per month for the year 2008

	Mean		SD		Kurtosis		Min		Max	
	BE-FR	FR-BE	BE-FR	FR-BE	BE-FR	FR-BE	BE-FR	FR-BE	BE-FR	FR-BE
Jan	2357.53	1600.63	912.036	818.10	-0.62	-0.56	125	0	4301	4095
Feb	2616.61	1002.39	811.70	800.16	-0.73	0.03	417	0	4301	4095
Mar	2685.14	993.66	788.78	735.77	-0.64	-0.62	0	0	4183	2986
Apr	2600.80	464.05	484.89	477.47	1.20	1.00	1512	0	4099	2495
May	2567.57	591.21	422.03	575.78	1.65	0.16	857	0	3702	2643
Jun	2479.25	693.28	593.81	523.53	1.69	0.07	0	0	3694	2623
Jul	1712.33	1263.77	814.27	854.46	-0.74	-0.78	0	0	3207	3200
Aug	1488.76	1264.85	902.45	881.50	-1.24	-0.91	0	0	3000	3201
Sep	1758.95	1288.52	748.37	766.57	-0.66	-0.75	0	0	3070	3201
Oct	593.83	2033.86	586.94	652.45	0.23	-0.06	0	0	2814	3474
Nov	1096.97	2444.43	825.59	1220.75	-0.81	-0.73	0	0	3373	4400
Dec	807.93	3242.70	752.77	1032.25	-0.42	1.94	0	0	3219	4599

4. Identification and profitability analysis of trading strategies

To take advantage of the structural differences in the imbalance settlement and, associated with this, the imbalance price differences between Belgium and France, 9 possible trading strategies – carried out at the intra-day stage – can be identified:

- *Strategy 1: Optimal arbitrage short position*

This strategy consists in moving short positions on a half-hourly basis to the country with the most advantageous – i.e. lowest – negative imbalance price at that moment. The resulting profit per MWh amounts to the difference between the negative imbalance prices in both countries;

- *Strategy 2: Optimal arbitrage long position*
  This strategy consists in moving long positions on a half-hourly basis to the country with the most advantageous – i.e. highest – positive imbalance price at that moment. The resulting profit per MWh amounts to the difference between the positive imbalance prices in both countries;
- *Strategy 3: Optimal arbitrage short and long position*
  This strategy consists in creating a long position in France and a short position in Belgium or vice versa during each half hour the positive imbalance price in the former is higher than the negative imbalance price in the latter or – vice versa – the negative imbalance price in the former is lower than the positive imbalance price in the latter. The resulting profit per MWh amounts to the difference between the positive imbalance price in France, respectively Belgium, and the negative imbalance price in Belgium, respectively France;
- *Strategy 4: Always short position in France – Balanced position in Belgium*
  This strategy consists in continuously creating a short position in France and in that way avoiding imbalances in Belgium. The resulting profit/loss per MWh amounts to the difference between the negative imbalance prices in both countries;
- *Strategy 5: Always short position in Belgium – Balanced position in France*
  This strategy consists in continuously creating a short position in Belgium and in that way avoiding imbalances in France. The resulting profit/loss per MWh amounts to the difference between the negative imbalance prices in both countries;
- *Strategy 6: Always long position in France – Balanced position in Belgium*
  This strategy consists in continuously creating a long position in France and in that way avoiding imbalances in Belgium. The resulting profit/loss per MWh amounts to the difference between the positive imbalance prices in both countries;
- *Strategy 7: Always long position in Belgium – Balanced position in France*
  This strategy consists in continuously creating a long position in Belgium and in that way avoiding imbalances in France. The resulting profit/loss per MWh amounts to the difference between the positive imbalance prices in both countries;
- *Strategy 8: Always long position in France – Short position in Belgium*
  This strategy consists in continuously creating a long position in France and a short position in Belgium. The resulting profit/loss per MWh amounts to the difference between the positive imbalance price in France and the negative imbalance price in Belgium;
- *Strategy 9: Always long position in Belgium – Short position in France*
  This strategy consists in continuously creating a long position in Belgium and a short position in France. The resulting profit/loss per MWh amounts to the difference between the positive imbalance price in Belgium and the negative imbalance price in France;

Profits that could have been realised from implementing the above strategies during 2008 are analysed[5]. Implementation on a whole year time span as well as on a monthly basis is considered. Analyses take into account the intra-day availability of interconnection capacities, implying that, whenever intra-day capacity amounts to zero, trading strategies cannot be carried out.

[5] Note that the analysis consists in testing the ex-post profitability (profit/MWh) of each strategy. While traders consider conditional ("ex ante") means and variances of trading profits, the analysis looks at unconditional ("ex-post") moments. It is assumed that traders make unbiased forecasts so that ex-ante and ex-post statistics correspond.

As indicated in Table XI, 5 out of 9 strategies would have been profitable if implemented during the whole year 2008. Strategy 1 to 3 – i.e. the optimal arbitrage strategies – avoid losses by only carrying out profitable actions. However, these strategies are relatively much more difficult to implement. While strategy 1 and 2 entailed gains during most half hours, profitable situations for strategy 3 occurred only to a limited extent. Profitable half hours most of the time (>11%) coincided with congestion – and consequently different prices between both countries – at the day-ahead stage. Given that negative and positive imbalance prices are usually respectively higher and lower than the day-ahead price (cf. supra), this result is rather logical: negative imbalance prices of one country being lower than positive imbalance prices of another rarely occurs at moments day-ahead prices of both countries are equal. The profitability of strategy 5 and 6 confirms the finding of Section 3 that, in 2008, France was on average the most attractive country to be long; Belgium to be short. Note that the average gains of both strategies are little smaller than the average losses, but on average more half hours with gains occur. Strategy 4, 7, 8 and 9 generate losses more often than gains. Moreover, when gains occur, they are on average lower than the mean losses, resulting in a negative total profit.

Table XI: Profitability of strategy 1 to 9 and average gains/losses (in €/MWh) for the year 2008

	Str. 1	Str. 2	Str. 3	Str. 4	Str. 5	Str. 6	Str. 7	Str. 8	Str. 9
Total gains/losses (€/MWh)	252453	27410	37901	-98720	100634	13651	-12968	-500879	-398508
% of 1/2nd h with gains	93%	95%	15%	33%	62%	53%	42%	3%	12%
Average gain (€/MWh)	15.38	16.44	14.56	21.75	21.34	15.82	17.22	9.57	15.90
% of 1/2nd h with losses	0%	0%	0%	61%	34%	43%	52%	93%	82%
Average loss (€/MWh)	0	0	0	-21.04	-22.20	-17.42	-18.97	-31.04	-29.95

Table XII confirms the profitability of strategies 1 to 3, 5 and 6 if implemented during the entire year 2008. The 5% quantile of the profit distribution indicates that the likelihood to observe lower profits/higher losses is 5% and is sometimes referred to as the 95% historical Value at Risk (VaR). Together with the mean profit its size gives an indication of the riskiness of a trading strategy. For instance, the 5% quantile of -32.13 for strategy 6 indicates that losses are above 31.13 € per MWh 5% of the time. This can be seen as a high risk in the light of the relatively low mean profit of 0.78 €/MWh.

Table XII: Summary statistics for strategy 1 to 9 prices (in €/MWh) for the year 2008

	Str. 1	Str. 2	Str. 3	Str. 4	Str. 5	Str. 6	Str. 7	Str. 8	Str. 9
Mean	14.37	15.56	2.16	-5.62	5.73	0.78	-0.74	-28.51	-22.68
SD	20.24	21.38	12.67	36.33	36.67	26.64	25.91	38.02	32.07
Kurtosis	113.89	279.34	760.94	85.86	78.93	129.0	143.38	133.91	34.10
Min	0	0	0	-794.19	-348.34	-718.34	-355.5	-896.34	-415.44
Max	479	718.34	624.19	348.34	794.19	355.5	718.34	221.41	624.19
5%	0	0	0	-40.98	-39.82	-32.13	-33.277	-68.92	-75.28

Table XIII: Summary statistics for strategy 1 to 9 (in €/MWh) per month for the year 2008

	Mean									SD								
	Str. 1	Str. 2	Str. 3	Str. 4	Str. 5	Str. 6	Str. 7	Str. 8	Str. 9	Str. 1	Str. 2	Str. 3	Str. 4	Str. 5	Str. 6	Str. 7	Str. 8	Str. 9
Jan	10.63	18.72	1.65	-2.91	2.91	0.91	-0.69	-33.7	-30.93	10.85	16.94	8.91	34.01	34.23	25.25	25.13	27.75	34.79
Feb	8.66	19.48	1.87	9.91	-10.27	8.44	-7.46	-27.69	-41.67	9.41	18.44	9.39	36.83	38.22	25.82	24.51	29.27	37.56
Mar	15.28	15.07	1.51	3.45	-3.4	0.53	-0.6	-32.99	-32.35	16.71	14.72	6.47	33.75	37.65	22.59	19.77	26.52	35.68
Apr	14.79	11.75	1.76	-9.65	12.75	-3.95	3.02	-31.93	-14.01	31.31	12.18	7.45	22.91	24.4	17.56	16.4	22.32	20.45
May	19.07	11.46	1.46	-8.42	9.53	-1.89	1.87	-27.12	-12.97	30.01	11.26	6.66	17.42	18.96	17.14	15.33	18.94	17.47
Jun	17.95	15.13	2.37	-9.13	10.08	-0.18	0.28	-29.86	-18.46	22.69	15.38	9.56	36.75	37.57	22.38	21.1	37	23.97
Jul	15.23	24.85	3.74	-9.97	9.43	0.19	0.77	-43.56	-32.32	17.78	44.7	20.16	65.5	66.26	51.22	49.01	84.85	53.21
Aug	11.01	11.88	2.53	-12.49	11.83	-0.7	0.17	-25.13	-14.52	14.72	10.78	6.29	18.06	17.82	15.77	16.56	16.46	20.77
Sep	13.21	16.23	1.15	-4.06	4.24	6.76	-6.84	-21.09	-23.59	14.19	13.26	5.04	18.31	18.38	19.85	19.87	16.29	21.86
Oct	11.94	14.43	4.01	-16.42	12.9	-3.83	3.92	-25.09	-11.88	16.29	19.06	15.82	37.96	31.9	21.13	24.43	33.49	25.13
Nov	19.48	15.41	3.51	-7.67	8.93	-2.46	1.73	-28.76	-19.14	25.03	33.91	28.16	52.87	53.42	37.75	37.31	55.39	38.13
Dec	15.09	12.48	0.29	0.69	-0.81	5.91	-5.42	-15.07	-21.08	16.97	12.43	1.9	15.51	15.64	16.64	16.25	16.39	18.58

	5%								
	Str. 1	Str. 2	Str. 3	Str. 4	Str. 5	Str. 6	Str. 7	Str. 8	Str. 9
Jan	2.11	1.66	0	-45.17	-51.57	-35.13	-40.79	-81.62	-91.84
Feb	0	0.22	0	-33.09	-70.4	-28.63	-45.36	-67.58	-107.53
Mar	0	0	0	-44.7	-65.25	-36.76	-31.18	-81.52	-102.48
Apr	0	0	0	-42.51	-25.08	-33.85	-19.58	-63.4	-52.47
May	0	0	0	-35.44	-18.08	-31.61	-19.87	-62.04	-43.24
Jun	1.15	0.3	0	-54.83	-27.63	-38.01	-29.35	-79.56	-59.16
Jul	1.94	0.54	0	-63.03	-61.51	-56.39	-45.3	-158.11	-116.77
Aug	0.73	0	0	-42.02	-17.05	-27.93	-29.76	-52.17	-50.43
Sep	3.36	0.92	0	-26.7	-26.65	-25.22	-42.21	-46.67	-64.48
Oct	0	0	0	-61.94	-14.46	-33.45	-25.24	-70.34	-46.38
Nov	0	0	0	-39.82	-31.34	-34.01	-30.18	-69.06	-62.51
Dec	0.27	0.64	0	-18.56	-27.33	-17.49	-32.05	-37.88	-54.35

Table XIII presents some summary statistics of the profits resulting from implementing strategies on a monthly basis. While loss-making on a whole year time span, strategies 4 and 7 turn out to be on average profitable during some months.

Note that the above analyses do not take into account that the implementation of a trading strategy may have an impact on the imbalance prices or, in other words, that arbitrage leads to a convergence of prices and thus lower profits. Moreover, abstraction is made of possible transaction costs of intra-day trading, which certainly have a negative impact on the profitability of trading strategies.

Other than the identified trading opportunities between Belgian and French imbalance prices, profitable arbitrage may be possible between day-ahead and imbalance prices within a country (Boogert, 2005). Arbitrage strategies consist in either (1) selling electrical energy on the day-ahead market (Belpex/Powernext) and "buying" it on the balancing market – i.e. being short – or (2) buying electrical energy on the day-ahead market and "selling" it on the balancing market – i.e. being long. The resulting profit per MWh respectively amounts to (1) the difference between the Belpex/Powernext price and the negative imbalance price and (2) the difference between the positive imbalance price and the Belpex/Powernext price. Optimal arbitrage thus involves implementing strategy 1 if the day-ahead price is higher than the negative imbalance price and strategy 2 if the day-ahead price is lower than the positive imbalance price. Table XIV indicates that, while no profits could be made in Belgium, both optimal arbitrage strategies would have been profitable in France in 2008 during ±5% of the time with average gains equalling about 22 €/MWh.

Table XIV: Profitability of optimal arbitrage between the day-ahead and balancing market (in €/MWh) for the year 2008

	Belgium		France	
	Sell@BPX Buy@Elia	Buy@BPX Sell@Elia	Sell@PXT Buy@RTE	Buy@PXT Sell@RTE
Total gains (€/MWh)	0	0	18512.08	19702.84
% of 1/2nd hours with gains	0%	0%	4.81%	5%
Average gain (€/MWh)			21.91	22.70

5. Discussion and conclusions

The analyses in Section 4 pointed out that some trading strategies are significantly profitable; others turn out to be loss-making. Trading strategies can be implemented at any cost during most of the time as substantial cross-border capacities between Belgium and France are usually still available at the intra-day stage. The usage of these capacities is currently not subject to any compensation. However, the profitability of certain strategies indicates they have a significant value.

Given the outcome of the analyses, it can be questioned why traders did not massively proceed with the implementation of certain strategies on a large scale. First, actual profits may be substantially lower due to possible transaction costs of intra-day trading. Also information costs might negatively impact the profitability of trading strategies. While some strategies can be implemented without much effort (strategy 4 to 9), others require a superior forecasting expertise and/or the development of a trading department (strategy 1 to 3). Furthermore, traders must face the risk that implementing either strategy will move imbalance prices unfavourably, i.e. in a way that reduces their profits. Also the large volatility of profits can make trading strategies less attractive. Finally, the threat of regulatory intervention – because their actions could be considered as speculation or market power abuse – may restrain traders from implementation.

The implications for society of implementing the identified trading strategies are not clear-cut. As mentioned before, the large scale implementation of a strategy may affect system operators in performing their task of guaranteeing system security. For instance, it may imply that some system operators will have to activate more balancing services and/or contract more reserves – the cost of which is often partly borne by the own grid users – to deal with increased system imbalances. An overall quantification of economic inefficiencies resulting from a strategy implementation is difficult as it requires an appropriate benchmark against which the current situation should be evaluated. Depending on what one wants to ultimately achieve with market integration, possible benchmarks could be: (1) harmonised balancing market designs – allowing for cross-border procurement of services and netting of system imbalances – but separate control areas or, more advanced, (2) a completely integrated balancing market and one overall control area. It should further be kept in mind that, apart from arbitrage due to structural design differences as discussed in this paper, other arbitrage may take place due to differing underlying costs. This second type of arbitrage is on the contrary beneficial for society and contributes to the overall economic efficiency. Anyway, the analyses make clear that a harmonisation of imbalance settlements and more in general, balancing market designs, will ensure more efficiently functioning cross-border markets.

The last updated version of this paper is available at http://www.esat.kuleuven.be/publications/search.php. Further research could for instance include an identification of those factors (e.g. the system state, congestion at the day-ahead stage,…) significantly influencing the profitability of trading strategies.

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