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ORIGINAL ARTICLE

Inefficient arbitrage in inter-regional electricity transmission

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Abstract This paper analyzes the efficiency of an explicit ex ante auction for network access to facilitating trade between two separate, but linked, electricity wholesale markets. It is generally assumed that greater regional interconnection will mitigate the exercise of local market power by dominant generators, but we show analytically that when a dominant player has access to a more competitive neighboring market, and is also the lowest cost producer, the exercise of market power becomes attractive and can have negative consumer welfare implications. For an empirical analysis, we use a unique data set of daily company-level flow nominations on the Anglo-French Interconnector (IFA). This provides a clear case study, "free of loop flows" (with the IFA being the only link between the UK and France). We are able to identify evident inefficiencies in the market behavior, for which several explanations, including market power, may contribute.

Keywords Auctions · Electricity · Transmission · Market power

JEL Classification L95

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1 Introduction

Motivated both by the liberalization ambitions to facilitate more extensive, efficient wholesale trading, and the system reliability benefits of wider integration, the operation of electricity interconnectors[1] between separate markets has become an active topic in both theoretical research and policy deliberations. The benefits of increased interconnectivity may include, as Turvey (2006) notes, the deferral of investment in generation, increased security and reliability, substitution of expensive by cheaper generation, reduction of congestion and ancillary service costs as well as the potential mitigation of market power. Of these, the system operations benefits of greater transmission capacities have been proven in practice for many years, but the potential market efficiency effects are still subject to extensive theoretical discussion, with very little empirical evidence. Although Borenstein et al. (2000) have demonstrated that market power mitigation could be achieved in a system of "*nodal prices*" by increasing the transmission capacity even for uncongested lines, Stoft (1999), Joskow and Tirole (2000) and Gilbert et al. (2004) have shown that, depending upon various circumstances, the *ex ante* allocation of financial transmission rights in congested networks might either enhance or mitigate market power. Consequently, despite the conventional wisdom that greater interconnection creates a larger market and should therefore increase competition, the achievement of increased market efficiency in theory (and presumably in practice) appears to depend upon the details of the particular market and its mechanisms. It is from this perspective that the detailed practical case study analyzed in this paper seeks to add new insights.

This paper also seeks to analyze a second widely held conventional view that one would usually expect market forces to direct trading from a low to a high price area. The basic framework for devising financial transmission rights generally assumes this to be the case, following considerations of efficient arbitrage. However, we explore theoretically the circumstances under which an agent may choose to export power against the direction of efficient arbitrage. This result is a function of market power and marginal cost differences between two regions. However, in practice, manifestations of this theoretical behavior are elusive. In most markets it is difficult to associate physical power flows with trading because of the loop flows that exist in any meshed, synchronized electric power system. Thus, we have chosen to analyze data from trading across the Anglo-French Interconnector (IFA), which is the single, substantial, but unsynchronized DC link between these two markets, and as such its power flows do not suffer from loop flow complications. From daily, company-level, flow-nomination data, we have been able to identify trades against the price differential, which would be consistent with the theoretically attractive strategies open to some of the market participants. This effect is in addition to the economic rents that any dominant players could acquire through buying to withhold transmission rights.

The paper is structured as follows. In the next section, the theoretical considerations for the exercise of market power in interconnector auctions are developed. The subsequent section describes alternative explanations of market inefficiency,

[1] We use "interconnector" in the definition of Turvey (2006, p. 1457). "An interconnector, in the case of electricity, is a cable or overhead line connecting two separate markets or pricing areas."

arising from the practical market microstructure of inter-regional transmission auctions. Then section four introduces the IFA data and in the fifth section the empirical analysis is presented. Finally we conclude, highlighting the policy implications of our study.

2 Inefficient export

We envisage an electricity generating company, dominant in its "domestic" market, but also actively generating in a "foreign" market, where physical transmission between each market is available through a limited capacity interconnector. It can sell electricity at $p_d(q_d)$ in the domestic market and at $p_f(q_f)$ in the foreign market. The company's production cost function is $C(q_d + q_f)$, and the profit function is thus given by:

$$\Pi = p_d(q_d)\,q_d + p_f(q_f)\,q_f - C(q_f + q_d). \tag{1}$$

From first order conditions, the well known optimal 3rd degree price discrimination rule,[2]

$$\frac{\partial p_d(q_d)}{\partial q_d} q_d + p_d \overset{!}{=} \frac{\partial p_f(q_f)}{\partial q_f} q_f + p_f \overset{!}{=} \frac{\partial C}{\partial (q_f + q_d)}, \tag{2}$$

can be deduced. Consequently the optimal price in the domestic market is higher than that in the foreign market $\left(p_d(q_d^*) > p_f(q_f^*)\right)$ if

$$\frac{\partial p_d(q_d^*)}{\partial q_d^*} q_d^* < \frac{\partial p_f(q_f^*)}{\partial q_f^*} q_f^*. \tag{3}$$

As the price depends negatively on the offered quantity, the domestic prices are, ceteris paribus, higher when, in equilibrium, either the company sells more in the domestic than in the foreign market $\left(q_d^* > q_f^*\right)$ or when prices react more strongly to volumes in the domestic than in the foreign market. Both conditions apply if the company features as a dominant player in the domestic market and as a fringe player in the foreign market. In the extreme case, the company is a monopolist on the domestic market (the residual demand curve is equal to the actual demand curve, i.e., almost vertical for electricity markets) and is a price taker on the foreign market (the residual demand curve is horizontal). Under these conditions, the foreign price would serve as the opportunity cost for domestic supplies.

If we were to assume adequate transmission capacities between both countries and production being possible at cost $C_d(q)$ in the domestic market and at $C_f(q)$ in the foreign market, the production decision is independent of the share of total quantity sold in each market. Further, if there is significantly larger domestic than foreign

[2] C.f. Pindyck and Rubinfeld (1996).

inframarginal production capacity, but domestic prices are, for the above reasons, higher, the monopolist would export against the price differential.[3]

Thus, it is plausible that a dominant player, under special conditions, has an interest in exporting electricity from the high to the low price area. For consumers and arbitrageurs, by contrast, it would be profitable to trade electricity in the opposite direction. Thus, if no trade barriers exist, prices would equalize. Limited interconnector transmission capacities would, however, pose a physical congestion constraint. As transmission lines can only be used in one direction at a time and electricity is a homogenous good, the effect of capacity constraints on electricity flows and prices depends crucially on the treatment of opposing flow nominations.[4] Currently transmission rights between many countries are auctioned separately in each direction, without any "netting" (i.e., cancellation of positive and negative flow nominations) which would be necessary in order to ensure full capacity utilization (see Fig. 1).

Assuming an interconnector of fixed[5] capacity $\boldsymbol{K}$ between an oligopolistic domestic market with pricing function, $p^o = 1 - Q^o$, and an adjacent foreign competitive market with $p^c \geq 0$, it is shown below that:

1. A dominant player will nominate electricity against the price differential.
2. If all acquired transmission rights have to be used (no withholding), the electricity flow direction depends on the number of traders.
3. Irrespective of the number of traders a dominant player will buy all importation rights and withhold them (if allowed) and electricity will flow against the price differential.

Proof A dominant player, M, exists in an oligopolistic market and can produce up to a capacity of $Q \geq q_d + q_f > 1$ with zero cost, where q_d represents the domestic sales and q_f the foreign sales. Additionally n symmetric traders $T_1 \cdots T_n$ exist. All

[3] International trade influences the welfare distribution between domestic and foreign consumers and producers. The dominant player would produce more in the domestic market if it can export. Thus its marginal cost and domestic prices would increase and its domestic sales decrease. Domestic customers would lose welfare and the domestic company would gain. Foreign consumers would gain, partly at the expense of foreign suppliers. Besides these direct welfare effects arising from flows against the price differentials, second order effects decrease the dynamic efficiency of the system. For example, price signals for investments in the more competitive market would be reduced.

[4] Essentially two procedures could exist for dealing with counterflow nominations:
Ex ante netting:
(1) All market participants submit their flow nominations to the interconnector operator; (2) the interconnector operator balances imports and exports; (3a) if the balance is below the capacity constraint all nominations are accepted and only the net flow materializes; (3b) if the balance is above the capacity constraint, electricity flows at full capacity in the net direction. All nominations against the dominant direction are accepted. In the dominant direction, the nominations are allocated to the market participants by the interconnector operator (e.g., by auctions or pro rata).
No netting:
(1) All market participants submit their flow nominations to the interconnector operator; (2) in each direction only nominations up to the line capacity are allowed. Thus, the capacity in each direction is allocated separately to the respective bidders (e.g., by auctions or pro rata). Therefore, no electricity will flow if export and import demands are higher than the line capacity.

[5] In contrast to Hoeffler and Wittmann (2006), who assume the capacity to be chosen by a profit maximizing auctioneer, we assume the capacity to be fixed.

companies can buy and sell in both markets with I_j being the net imports of trader j. The profit functions are defined by:

$$\Pi_M = \left(1 - q_d - \sum_{i=1}^{n} I_i\right)(q_d) + p^c q_f \tag{4}$$

$$\Pi_{T(j)} = \left(1 - q_d - \sum_{i=1}^{n} I_i\right)(I_j) - p^c I_j \tag{5}$$

In the absence of congestion all players would behave, in this market, as oligopolists with cost p^c selling $q_d = I_j = \frac{1-p^c}{n+2}$. Thus, the price in the oligopolistic market $p^o = 1 - \frac{(n+1)(1-p^c)}{(n+2)}$ will converge to the price in the competitive market if more traders enter the market. Because of its cost advantage the dominant player will sell all remaining production $q_f = Q - q_d$ in the competitive market. As $q_f > \frac{n}{n+2}(1 - p^c)$, electricity would flow from the high price to the low price region. □

If, in the presence of congestion ($k < Q - q_d$), the capacities are auctioned separately in each direction, no electricity would flow, as long as $k < \frac{n}{n+2}(1 - p^c)$. This is because the traders will buy all importation rights and import at $\sum_{i=1}^{n} I_i = k$, while the dominant player will buy all exportation rights and export at $q_f = k$.

If the dominant player were allowed to buy importation rights and not use them (withholding), the question arises whether this would be a profitable strategy. Assuming an auction for the importation rights, this is equivalent to asking whether a dominant player has a higher marginal willingness to pay for the importation rights than a trader:

$$-\frac{\partial \Pi_M}{\partial I_i} > \frac{\partial \Pi_T}{\partial I} \tag{6}$$

From $-\frac{\partial \Pi_M}{\partial I_i} = q_d$ and $\frac{\partial \Pi_T}{\partial I_i} = 1 - q_d - (n+1) I_i - p^c$ it follows that: $2q_d > 1 - (n+1) I_i - p^c$. The optimal strategy for the dominant player is, therefore: $q_d^* = \frac{1-nI_i-p^c}{2}$. Thus the monopolist will buy and withhold all importation rights as long as: $1 - nI_i - p^c > 1 - (n+1) I_i - p^c$. This obviously holds for any number of traders.[6]

Given the above consideration of a low cost dominant player in the domestic market with capacity constrained access to a more competitive foreign market, following the theoretical analysis above, one would therefore expect to see the following market characteristics in practice:

1. *First*, a dominant generator may be observed in practice to be exporting against the price differential, but not importing against the price differential.

[6] Note, that the price of export rights should be zero because only the dominant player has an interest to export. The price of import rights should be in the interval $\left[P^O - P^C, \frac{1-k-p^c}{2}\right]$, i.e., between the maximum willingness to pay of the trader and that of the dominant player, depending on the auctioning mechanism.

2. *Second*, a trader should always trade from the low to the high price area and thus sometimes against the dominant's trading direction.
3. *Third*, if withholding is allowed, the dominant player will only withhold import rights.
4. *Fourth*, traders will not withhold transmission rights.

These propositions are advanced as market characteristics, for in reality electricity markets are complex and dynamic. For example a producer might be a natural monopolist in the off-peak but only an oligopolist during peak time. Nevertheless, by having a capacity constrained link between a concentrated market with an occasionally low cost dominant player and an occasionally more competitive market, two testable hypotheses can be deduced:

1. *First*, the dominant player will behave asymmetrically, predominantly withholding in the import direction and trading against the price differential mainly in the export direction.
2. *Second*, the dominant player's behavior will be distinctly different from those of the non-dominant generators and traders.

The above analysis is consistent with a general view, e.g., Bonardi (2004), which suggests that dominant incumbents, following sector deregulation, seek to maximize monopoly rents at home whilst acting opportunistically abroad.

3 Auction mechanism and microstructure effects

Apart from the abuse of market power by dominant participants, studies on the performance of capacity auctions for allocating interconnector transmission rights have discussed the inefficiencies that result from market design and microstructure effects. Thus, in Europe, where ex ante auctions have become the prevalent cross-border congestion management scheme between separate power markets, which for political, proprietary, regulatory or other reasons, cannot be easily unified into extended nodal pricing regions, a number of studies have looked at their design effectiveness, e.g., ETSO (2004), CONSENTEC and Frontier Economics (2004) and the EC (2007). These auctions for interconnector capacity may take place annually, quarterly and weekly for blocks of time, and then close with day-ahead prices. If they work well, the interconnectors would operate to capacity, at prices that reflect the arbitrage value of trading physical power between the two connected spot markets. However this has not generally been the case and, as a consequence, various design deficiencies have been identified:

1. In many cases, apart from the single Anglo-French link, a meshed system makes the calculation of available capacities at each link a challenging task. Thus, significant security margins have to be included, reducing the real transmission capacity. Thus according to Glachant and Pignon (2005, p. 153) "TSOs, therefore, define the congestion signal on a variable, complex and non-transparent constraint and may manipulate it". Further, Hoeffler and Wittmann (2006) suggest that profit maximizing auctioneers (e.g., TSOs) in such auctions would lead to welfare losses.

2. Uncertainty arises from the timing sequence of transmission and energy markets. The transmission auctions usually precede the energy markets. As shown empirically by Zachmann (2005) and theoretically by Ehrenmann and Smeers (2005), prediction errors on the electricity energy market spreads lead to inefficient prices in the prior transmission capacity auctions. These temporal uncertainties can be further confounded by different closing times for the two linked energy spot markets.
3. Flows are usually allowed to be nominated up to their physical capacity in each direction, without adequate consideration of how counter-nominations will reduce the net flows. Thus, separate auctions of capacity in both directions may fail to induce full interconnector usage.
4. Some market mechanisms do not require participants to return to the day-ahead market, any forward capacity reservations which they do not intend to use on the next day.
5. Markets may not be sufficiently liquid to induce efficient prices. Spot prices might be easily moved by small trades and traders may not have the confidence that they can close out final positions at a fair price.
6. System Operators on one or both sides of the link may need to be active in scheduling cross-border flows for congestion and system balancing purposes. These activities would generally be expected to take place in the real-time system balancing process, after the trading markets had closed, and constitute a further reason why substantial capacity is withheld from the market.
7. The main energy market reference prices may not fully reflect locational prices for taking or delivering power at the ends of the interconnectors. Even without nodal prices, there may be different locational supplements to reflect system losses.
8. Local congestion close to the ends of the link might induce local generators to anticipate domestic output constraints and compensate by nominating some power for export.
9. Electricity may not be a homogenous commodity on one or both sides of the link. For example, some countries have special supplements for delivering power from renewable sources, e.g., The Netherlands, UK. These would not be apparent in the wholesale market prices, and the non-transparency of "green" volumes could distort the implied direction of arbitrage.

Thus, there are many confounding factors underlying the empirical analysis of market data on interconnector effectiveness. However, all of the above issues, with the exception of the last two, would affect all market participants in a similar way. The main propositions which we identified in the previous theoretical section relate to the way the individual companies may behave differently in their nominations for interconnector usage, and so, with many microstructure effects being features in common, an empirically based analysis of distinctly dominant behavior may still be possible.

4 Data from the Anglo-French interconnector

The Anglo-French electricity Interconnector (IFA) consists of four 45 km submarine direct current (DC) cables between Calais and Folkstone that allow the transmission of 2000 MW in either direction, and is jointly operated by the French (RTE) and British (NGC) grid operators.[7] In 2005 the absolute electricity flows totaled 12 TWh and traders were willing to pay more than Euro 125 Million for the usage of this vital link.[8]

The economics of the IFA have not been extensively studied. Inderst and Ottaviani (2004) provide a general description of the IFA, assembling information on the linked markets, the auctioning mechanism, and the ownership of the IFA. However, they do not make use of the very extensive, publicly available data to analyze whether the IFA actually achieves efficient arbitrage. Turvey (2006) provides some graphical evidence that the electricity exports from France to the UK are occasionally directed against the price difference, as does the EC Sector Inquiry (2007), and CONSENTEC and Frontier Economics (2004) shows that the link between price differential and flows is significant but low.

Three data sets are used in this study: the electricity "spot" prices on both sides of the IFA, the results of the IFA-capacity auctions, and the IFA-flow nominations. The sample period consists of 1,011 working days from 2002 to 2005. Hourly wholesale electricity prices for France were obtained directly from the French power exchange Powernext© whereas the half hourly electricity prices for the British power exchange UKPX were downloaded from Datastream©. Since neither country used locational pricing, one single price for electricity applied in each country. One substantial shortcoming of the data is the low liquidity of both market places. Only about 2% of the national electricity consumption is traded on the UKPX and just over 3% on the PNX.[9] In fact, more "spot" trading in the UK takes place via brokers (OTC day-ahead trade accounts for about 9%) than via the UKPX. In the Appendix we therefore compare OTC with UKPX prices, and are reassured to find that price deviations between both OTC and UKPX prices are insignificant during both base and peak periods. In contrast to the UKPX, where trading takes place continually until one hour ahead of real time, the PNX applies a single stage auction the day before delivery. This raises the question of whether the ex post price differential is a valid measure for the efficiency of traders' arbitrage operations. One could suppose that, at the margin, a profitable deal in the day ahead market (e.g., buy in F at $p(F,t)$ and attempt to sell in the UK at $p(UK,t) > p(F,t)$) may, ex post, be unprofitable as the UKPX price may fall somewhat after the completion of the first deal. Even if this effect were noticeable and traders were not able to forecast it, this bias should be a minor concern for our analysis, as it would occur symmetrically in both directions and affect all market participants.

Another issue when analyzing arbitrage operations is the associated transaction cost. For the IFA it consists of at least five components:

1. Balancing Services Use of System (BSUoS) Charges: Depending on the market situation these costs can change from day to day and the underlying cost-

[7] This has led to discussions in the UK on how to properly regulate the interconnector, since French law does not allow OFGEM to regulate RTE (DTI 2005).

[8] "Absolute flows" refer to 11.4 TWh imports to the UK and 0.8 TWh exports from the UK. The presented figure for the willingness to pay only accounts for annual (800 MW), seasonal (300 MW), quarterly (300 MW) and monthly (350 MW) auctions and is thus ignoring weekend and daily auctions.

[9] EC (2007).

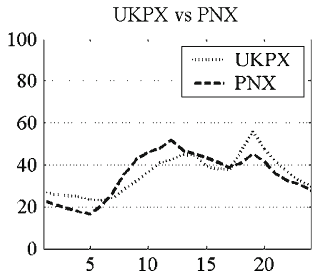

Fig. 1 Average electricity prices at each hour of the day in € (2002–2005)

formula depends on various factors. Thus, it is both difficult to forecast the BSUoS charges and to asses how they influence the traders' transaction costs. They were not considered in the analysis as their effect on arbitrage operations is unclear.

2. Balancing market (ELEXON) participation fees: Those fees are independent of traded volumes and thus not important for our analysis. However, they may create a barrier to entry.
3. A symmetric loss factor of 1.17% is applied for all IFA flow nominations, i.e., when trading 100.00 MWh into market A, one has to take 101.17 MWh from market B. In all subsequent analyses we take account of this loss factor.
4. Transmission Network Use of System (TNUoS) charge: The TNUoS is different for bringing electricity from England to France (TNUoS Demand) than from the opposite direction (TNUoS Generation). The TNUoS Demand Pass Through Charge only has to be paid by an interconnector user if it, and the entire IFA, were nominating electricity to France during at least one of the three "Triad Charging Half Hour Periods".[10] The individual charge is then calculated according to: Average interconnector imports during the three Triad Periods times the Zonal Demand Tariff (ZDT)[11] times the individual share of the Triad imports. Therefore the TNUoS Demand Pass Through Charge is not entirely predictable. We approximated the effect of this charge as expected importing cost (ZDT/(number of potential half hours)) in GBP/MWh for those peak half hours with significantly above average peak prices during winter. The TNUoS Generation Charge is levied on export (France to the UK) capacity holders. The total payable amount of 2,630,056.41 GBP (2005/06) is distributed to the users according to their export capacity holdings. Assuming 90% of the available capacity being allocated (not ultimately used), each export capacity holder has to bear 0.17 GBP/MWh export capacity held. This charge is also included in the analysis.
5. The most significant transaction cost associated with IFA trades is the capacity charge for obtaining unidirectional transmission rights (this is the main capacity auction price). The capacity at the Anglo-French Interconnector is sold to interested parties via a sequence of auctions. Table 1 indicates that auction results (ignoring daily auctions) are volatile—ranging from 4.3 to 22.5 €/MWh for

[10] Those are the three ex post deduced periods of highest electricity peak demand during November to February. Note, that each of these TCHHPs has to be separated by at least 10 days from the previous one.

[11] 2005/06 in the South-East, Zone 11: 15,989.41 GBP/MWh.

Table 1 Summary of products and prices at the IFA

Product	Auction date	F→ UK volume (# of bids)	Price in €/MWh	UK→F volume (# of bids)	Price in €/MWh
Daily 9 Apr 06	10 Apr 06	50 100	9.88 (0.13)[a]	150	9.83
Weekend 8–9 Apr 06	7 Apr 06	100	17.5	0	0
Monthly 4/2006	9 Mar 06	150 (4)	6.28	150 (5)	0.74
	21 Mar 06	150 (6)	10.77	150 (4)	0.55
Quarterly 4/06–6/06	16 Mar 06	150 (4)	7.50	150 (4)	0.61
	7 Mar 06	150 (6)	6.30	150 (5)	1.22
Seasonal summer 06	2 Mar 06	175 (6)	4.28	175 (5)	1.26
	14 Mar 06	175 (4)	6.83	175 (4)	0.71
Annual (Apr–Mar) 4/06–3/07	7 Feb 06	175 (6)	15.76	175 (6)	0.61
	28 Feb 06	175 (6)	9.00	175 (4)	0.77
Annual (Jan–Dec) 2006	8 Nov 05	250 (7)	16.50	250 (4)	0.43
	29 Nov 05	250 (7)	22.50	250 (8)	0.47

[a] Second price reported here because it differed significantly from the first price. In all other cases the prices of all winning bids differed only by few cents/MWh

exports and 0.43 to 1.26 €/MWh for imports.[12] Most of the bids per auction (number of winning bids in brackets) arise from a variety of firms. It should be noted that the distribution of the total volume for the products offered at the auctions varied across the sample period. Therefore Table 1 is not representative for the entire sample period, but just indicative.

When comparing the prices, the frequency of large differences between auctions for the same period are particularly striking (e.g., the prices of the two import auctions for 2006 held on 8th and 29th of November 2005 differ by 36 %).[13] These large differences make it unlikely that the results are only based on a change of expectations or open positions of individual market players. It might be that in some circumstances the auction mechanism and the limited number of participants allowed traders to conceal their true willingness to pay and thus to achieve lower prices. The open bid auction can explain why the winning bids are so close (e.g., for the annual auction of 8th November the winning bids were: 144.5, 144.3, 144.25, 144.2, 144.15, 144.12 and 144.1 thousand Euro, i.e., in the range of 0.2 %).

All auction data are obtained from the French grid operator RTE which provides extensive coverage of the IFA data on its website.[14] Our sample consists of 1,011 workday auctions in the years 2002–2005. In general, prices for imports to France (average 0.5 €/MWh) are lower than for exports to the UK (average 2.0 €/MWh). Figure 2 illustrates that the volatilities of the price series are highly clustered and that imports are generally more expensive in winter. The very significant spike in the

[12] Imports and exports are defined—throughout the paper—with respect to France, i.e., exports occur if electricity is brought from France to the UK.

[13] Practitioners link this increase to the coincidental gas price increases. The NBP price of UK gas futures for 2006 increased from 53.5 to 61 p/th (14%) in the same period.

[14] http://www.rte-france.com/htm/fr/vie/historiques_angleterre.jsp.

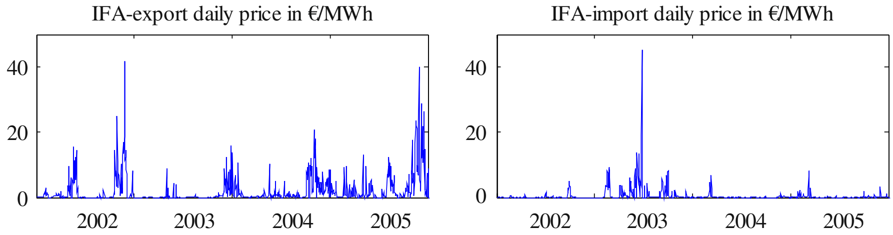

Fig. 2 Results of daily IFA-auctions

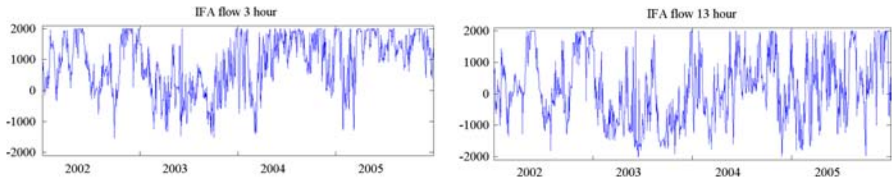

Fig. 3 Aggregated flows (Daily pattern)

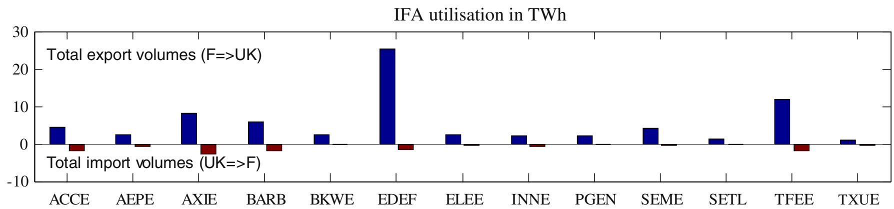

Fig. 4 Company level usage. The full company names are to be found in the Appendix

import price series in 2003 is explained by the enormous prices on the continent during that extraordinarily hot summer.

Finally half hourly company level data reporting of the usage of the IFA was acquired. In the sample period, 27 companies were active in trading across the channel. The interconnector market is somewhat concentrated as the five largest players together account for 72% of the exports (HHI: 1570) and 71% of the imports (HHI: 1155); whereas the linked energy markets are quite disparate. The French market is dominated by EdF with a market share of over 90%, whereas, the British generation market is competitive with many generators and an HHI below 900. Figure 3 indicates that whilst off-peak electricity mainly flows from France to the UK, in peak periods both flow directions occur with almost equal probability. Although the flows generally respond to the price differences, it is striking that the capacities are rarely fully used (Fig. 4).

5 Empirical analysis

Figure 5 plots the physical electricity exchange between the UK and France versus the corresponding price difference for representative off-peak (3h) and peak hours

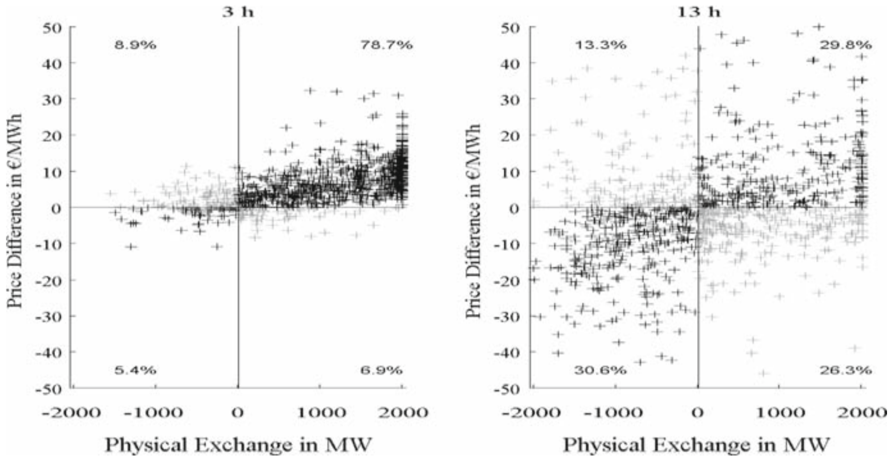

Fig. 5 Physical exchange vs. price difference

(13h). During off-peak, electricity flows from France to the UK in 86% of the 1,011 h. Electricity is thus mainly flowing from the low to the high price area but the capacity is rarely fully used even when significant price differentials persist.

Whilst electricity flows in the right direction 84% of the times during off-peak, in peak times, electricity flows against price differential in about 40% of the cases. The almost random distribution of the dots in the second part of Fig. 5 indicates that the statistical link between flows and price differential is very weak during this peak time (correlation coefficient is 17%).

To measure this, we calculate an inefficency indicator. For each hour we calculate the product of the arbitrage potential[15] and the unused capacity in the profitable direction.[16] Thus, the result is a positive value in Euros. In the extreme case, high price differentials persist even though much of capacity remains unused. When price differentials are zero, or the capacity is fully used in the arbitrage direction, the inefficiencies are zero by definition.[17] This gives a static value of the unused capacity.[18] The daily results of this indicator are plotted in Fig. 6 indicating that the inefficiencies are rather volatile and occasionally peaked when prices in one country or the other were unusually high. Total inefficiencies amounted to € 289 M between 2002 and 2005. Most inefficiencies at the IFA occur when the price differential suggest that France should import electricity (€ 200 M). This import, however, does not often happen and electricity is, instead, traded against the market force.

[15] The arbitrage potential is the price differential taking account the loss factor and the TNUoS charges.

[16] Note that the unused capacity can even exceed the total capacity when the IFA is used against the market force.

[17] Observations where flows are exactly zero are assumed to indicate that unused capacities are zero due to technical disruptions e.g., maintenance, accident or flow switching.

[18] Note, that the true value should be lower because the correct usage of the interconnector would result in price convergence.

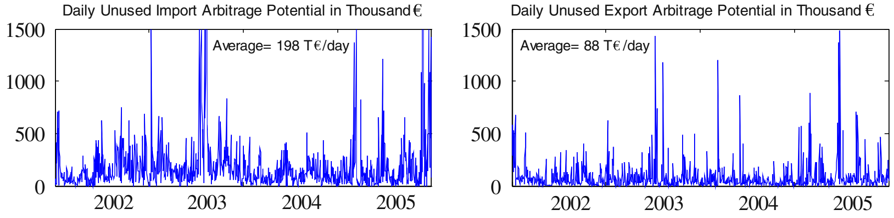

Fig. 6 Inefficiency indicator

In the case of the IFA the major technical reason for below-capacity usage of an electricity interconnector—namely the loop flows that occur in meshed AC grids—can be ruled out. Other technical difficulties leading to a reduction of available transfer capacity are rare and cannot explain the significant deviations from efficient interconnector use. Thus, reasons for the observed capacity under-usage could include:

First, one or both of the French and the UK power exchanges fail to provide the relevant price signals for their respective markets.[19]

Second, risk averse behavior of traders in the uncertain cross-border markets might impede full arbitrage.[20]

Third, the absence of netting causes the capacity not to be fully used when companies nominate opposing flows. The effects of a lack of netting are easily quantified. The unused capacity due to netting is the capacity in the flow direction that can additionally be freed when flows in the opposite direction are considered. Overall, 808 GWh of importing capacity, worth 6.6 M€, and 816 GWh exporting capacity, worth 2.9 M€, could have been freed in the years 2002–2005 if ex ante netting were applied.[21] That, however, is only slightly more than one percent of the total capacity in each direction.

Fourth, strategic players may intentionally trade against the price differential to influence prices.

Fifth companies block capacities by neither using nor returning acquired transmission rights.

The last two points are closely related to the testable propositions suggested in Sect. 2. Therefore, withholding and trade against the price direction are examined more fully, below.

5.1 Withholding

Although the "use it or lose it" principle is implemented, in theory through the requirement of a day-ahead (6.00 am) confirmation and reallocation notice (CAR Notice),

[19] The reasons are, inter alia, the trading dynamics, transaction costs, hidden locational pricing and green power support schemes.

[20] Risk aversion of traders in explicit auctions is an issue. As traders sequentially have to buy the capacity, buy the electricity in one and sell the electricity in another market, they need to hold open positions. Only when they accomplished the last of the three operations do they know how much money they have earned/lost.

[21] The value is computed with respect to the corresponding arbitrage potential.

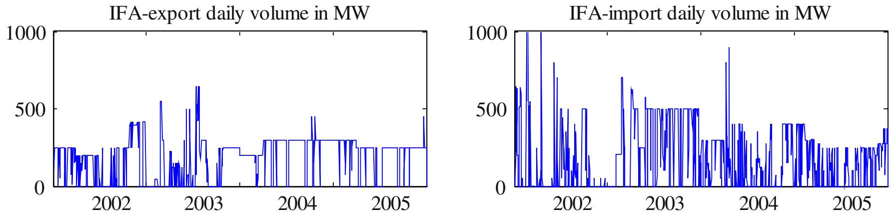

Fig. 7 Volumes offered in daily IFA auctions

it remains unclear whether this has any binding power. So, if a trader announces that he intends to use the whole capacity acquired from the periodic auctions, he will not be forced to return it to the auctioneer who would then reallocate it in the daily auctions.[22] In fact, the capacities seem to be hardly ever returned. Despite capacity in either direction remaining mainly underused, the capacities at the daily auction are rarely larger than the size of the custom auction, indicating that no capacity has been returned to the auctioneer (see Fig. 7). At this point, two reservations have to be made: *Firstly*, deviations from the use-it-or-lose principle are not faulty in general as they may, for example, give traders increased flexibility, and *secondly*, a part of this apparent withholding might be due to the daily nature of the auction covering multiple trading periods. If for example a trader intends to use a certain capacity only in a single half-hour of the day, the remaining 47 half-hours cannot be sold in daily auctions.

The magnitude of withholding can only be analyzed by knowing the share of transmission rights each company owns. This, however, is private information. But, given that secondary market operations on the IFA-capacity rights are infrequent we can approximate the capacity rights each company holds by using its half-hourly IFA-nominations. The idea is that the maximal nomination of a month minus the volume of the daily auction is the lower bound for the quantity of capacity rights a company holds in this month. We calculate this monthly quantity for each company.

The value of withheld capacities (weighted with the arbitrage potential) is significant and totals € 65 M in exports and € 100 M in imports. Further checking confirms that this value is consistent for exports as the total capacity owned by companies averages 1400 MW and only for 1 month surpasses the 2000 MW threshold. For imports, however, the total capacity owned is estimated at only 740 MW. This is due to the fact that, although all capacity is sold in auctions, some capacities are never fully employed. Thus we know that some companies own these importation rights without either using them or returning them to the daily auctions.

Figure 8 indicates that the share of import rights (75%) significantly exceeds the share of export rights (40%) that are not used despite being profitable. The German E.ON (PGEN) and the French EDF (EDEF) are the players that forfeit the highest share of profitable import rights. As the French and German markets are rather concentrated

[22] "If Users notify the operators around 36 h in advance that surplus capacity is not required, it will be offered in the daily auction and if sold, the User will receive the proceeds (with some adjustments). However, in order to avoid blocking, if capacity is neither used nor notified as not required, it will be lost—the principle of 'Use It or Lose It'." [FAQ-website of NGC on the IFA]. The question is, who will then use such "lost capacities". The firmly binding capacity notifications are the so-called Mid Channel Nominations (MCN). Those have to be submitted at 11 pm (d − 1) i.e., after the end of the daily auctions.

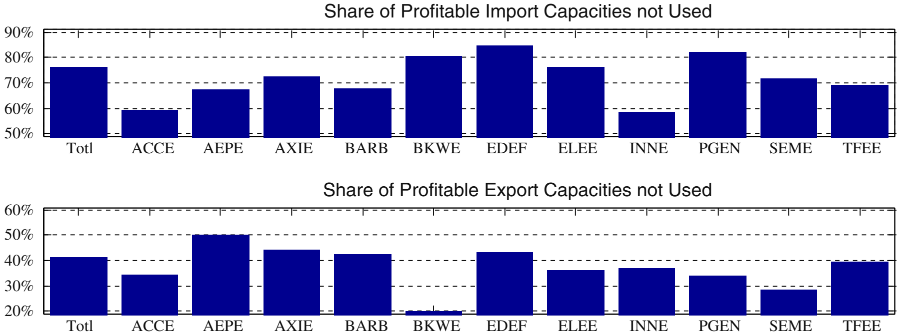

Fig. 8 Withholding of the 11 largest interconnector users

the results for E.ON and EDF are in line with the hypothesis that those companies have the strongest interest to withhold import rights to protect their domestic markets. In fact, both types of postulated withholding asymmetries occur: The two companies withhold a higher share of profitable import rights than their peer group and they also withhold more import than export rights (even when corrected for the common bias).[23] An alternative explanation however is that EDF and E.ON prefer to own some import rights as assurance against becoming short in their domestic market. Although, both companies might have plausible reasons for owning surplus import rights, not using them fully raises a question of market abuse.

5.2 Inefficient arbitrage

Export against the arbitrage occurs more often than over-importation (see Fig. 5). To explore whether this over-exporting is partly driven by strategic considerations, it is interesting to identify if only certain companies (low cost domestic dominants generators) tend to occasionally over-export with respect to their peer group. In the previous section, we identified EDEF and PGEN as the two companies with the highest share of unused import capacities. In addition, both companies are found to over-export significantly more than they over-import. Within the entire sample the ratio of exports against the price differential to imports against the price differential is 5.57, but it is 16.95 for EDEF and 14.08 for PGEN. Thus, we test whether the trading decisions of EDEF and PGEN are significantly different from those of the other companies. We establish a binary-variable, panel-data model of each company-level import/export decision (with $T_{i,t} = 1$ standing for an export and $T_{i,t} = 0$ for an import):[24]

$$T_{i,t} = \alpha + \alpha^{\Delta} D + \beta \Delta p_t + \beta^{\Delta} D \Delta p_t + \gamma \bar{\eta}_{i,t} + \gamma^{\Delta} D \bar{\eta}_{i,t} + \varepsilon_{i,t} \tag{7}$$

In (7), each trading decision depends on a common constant (α), the common impact of the price differentials ($\beta \Delta p_t$) and the common impact of the trading decisions

[23] The five companies with above average ratio of share of import rights withholding divided by share of export rights withholding are: BKWE, SEME, PGEN, ELEE and EDEF.

[24] For each company, all dates where this company did not trade the interconnector were excluded from the sample.

Table 2 Results of the panel-data logit model of each company-level import/export decision

	Coefficient estimate	t-Statistic	t-Prob
α	−0.063	−5.648	0.000
α^{Δ}	1.468	57.575	0.000
β	0.043	82.436	0.000
β^{Δ}	−0.014	−14.918	0.000
γ	0.441	179.397	0.000
γ^{Δ}	−0.118	−23.318	0.000

McFadden R-squared = 0.5869
LR-ratio, 2*(Lu–Lr) = 106,471
Log-likelihood = −37, 463
Nobs, Nvars = 153,830, 6
# of 0's; # of 1's = 42,532; 111,298

of all other companies $\left(\gamma\bar{\eta}_{i,t}\right)$. Thereby, $\bar{\eta}_{i,t}$ is the sum of trading decisions of all other companies not explained by the price differential, i.e., the residual vector of the ancillary (ordinary) regression $ST_{i,t} = \phi_1 + \phi_2\Delta p_t + \bar{\eta}_{i,t}$, with $ST_{i,t} = \sum_{i\neq j} T_{j,t}$.[25] To identify the deviations of EDEF and PGEN from the average trading strategy, the three terms, $\alpha^{\Delta}D$, $\beta^{\Delta}D\Delta p_t$ and $\gamma^{\Delta}D\bar{\eta}_{i,t}$, are included in the logit estimation. Thus, D is a Dummy vector with ones for i being EDEF or PGEN and zeros otherwise. Testing whether those two companies' behaviours deviate from the average trading strategy is carried out by checking if either some or all of the group-specific coefficients (α^{Δ}, β^{Δ}, γ^{Δ}) are significantly different from zero.

The results in Table 2 provide strong evidence for the hypothesis that the two companies' trading behaviours deviate markedly from the average strategy in the market. In contrast to the average trader, EDEF and PGEN feature significant exports unexplained by price differentials and common trading decisions (α^{Δ} = 1.47***); they react less on prices than their competitors (β^{Δ} = −0.014***) and trade less in line with the trading decision off all other companies (γ^{Δ} = −0.118***). This implies that those two companies' trading decisions are particularly affected by company-specific considerations that overrule pure electricity market arbitrage incentives.

The result that EDEF is significantly over-exporting compared to the others, gives empirical evidence consistent with the model presented in section two, as the key assumptions of the presented theoretical framework are satisfied. *Firstly*, EDEF is a quasi monopolist in France (∼90% of generation) and a small player in the UK (∼9%).[26] Further, the French market price is sensitive to the interconnector volumes (London Economics 2007). *Secondly*, the British market is generally considered to be significantly more competitive than the French market. And *thirdly*, generation costs

[25] The explained variable $ST_{i,t}$ is thus an integer corresponding to the number of companies exporting minus the number of companies importing.

[26] EdF considers itself as being able and willing to profitably withhold. When Pierre Gadonneix (Chairman and CEO of EDF) presented on February 23, 2006 the Consolidated Annual Results of 2005 he explicitly asserted that "Priority is given to margin against market share". [http://www.edf.fr/70945d/Homecom/Press/BookPresseRA20030226VAPDF].

of EDEF (mainly nuclear) are usually considerably lower than British prices (usually set by gas-fired generation). The same argumentation also holds for PGEN (E.ON has a generation market share of 24% in Germany). Thus, the theoretical possibility that dominant companies would markedly over-export from the continent and electricity may thereby flow from the high price to the low price areas, does materialize in this analysis to a plausible extent.

However, various alternative explanations for the irregular flows have to be considered:

First, IFA-flows might be partially driven by intra-country dispatching considerations. Here it is worth noting that northern France is an exporting area with installed capacity exceeding local demand whereas south-eastern England (including Greater London) is an importing area. There is no substantial evidence, however, that significant congestion exists in northern France to restrict the output of plants in the region, and London Economics (2007) did not identify this as a reason for the reduced outputs of French nuclear plants observed in their sample for analysis. There is evidence of system operator motivated trades against the price differential for balancing purposes, but not of generators making inefficient nominations in the expectation of being constrained off.
Second, Market microstructure effects, as discussed previously, might be responsible for the ex post impression of flow nominations against the price differential. This, however, would fail to justify why over-exportation is much more widespread than over-importation.
Third, Because of the British green power support schemes, continental companies could have an interest to export electricity from France to the UK even if French wholesale power prices are higher. In the UK, commercial electricity consumers usually have to pay a climate change levy (CCL) on each unit of electricity consumed (4.3 GBP/MWh in 2005). An exemption on this tax is granted if a supplier can show that the electricity consumed has been produced from renewable energy sources. For this purpose, levy exemption certificates (LECs) are issued for each MWh of green electricity generated and consumed under this scheme. Furthermore, overseas power plants can produce these LECs, if the electricity is generated according to the rules, and consumed within the UK. To be granted LECs, an overseas generator has to assure the regulator that the corresponding amount of green electricity has been produced by the certified power station and that the company had credible transmission access from the source station to the British consumer. Estimates indicate that on average about a quarter[27] of the import capacity of the IFA should have been used for such "green power flows", and given the nature of renewables, the output profile could be quite variable. The trades are not tagged, however, and the generators only have to produce aggregate monthly accounts. Thus, the LECs cannot be precisely linked as supplements to the energy price spreads in particular trading periods. Unless generators are claiming a large fraction of LECs in their total exported power to Britain, it would not appear that it necessarily motivates inefficient arbitrage. Therefore the manifest effect that electricity flows into the UK against the price differential might be

[27] Source: Ofgem website. On average 458 MWh of LECs were produced in each hour between April 2004 and October 2006. Of these, EdF held 19%, E.ON 2% and RWE 2%, with the remainder being widely distributed.

due to the additional exportation incentives from the continental LECs, but the nature of its accounting suggests that it may not be the substantial reason.

Overall, it would appear that it is possible that some local congestion may motivate nominations, and probable that the benefits of green CCL-exempt supplements encourage a significant amount of trading, but together they do not appear to offer complete explanations for the amount of inefficient arbitrage. This leaves open some scope for the theoretically attractive explanation of dominant market power, for which our empirical evidence is circumstantially persuasive. In this context, the Sector Inquiry of the European Commission (EC 2007) contains a relevant pricing sensitivity analysis by London Economics (2007), which faced difficulties in reconciling the declared and actual output of EdF nuclear plants, and concluded "one must consider the possibility that this company has engaged in behaviour consistent with the systematic withdrawal of nuclear capacity in this market" (*op cit*, p. 252), and in March 2009, the European Commission did open up an official investigation into possible abuse of a dominant position by EdF in its domestic wholesale market.[28]

6 Conclusions

Whether the reason for inefficient arbitrage across the Anglo-French interconnector is local congestion in northern France, the UK Climate Change Levy Exemptions, the dominant behavior of EdF, or (most likely) a mixture of all three, it is apparent that expecting transparent market efficiency in the relationship of auction prices to energy spot market spreads is too ambitious. The sequential nature of the transmission capacity auctions and spot energy trading undermines the simple arbitrage relationship, the presence of obscure green supplements differentiates the commodity, and locational factors differentiate the cost of access to markets. Against this background, it is difficult for regulatory authorities to monitor conduct.

However, we suggest that conduct can be an issue in these auctions, not just through capacity withholding, but through inefficient arbitrage with a dominant generator, under special circumstances, creating electricity flows from a high to a low price area. As the special circumstances of the analysis are satisfied in the case of the Anglo-French Interconnector, we provide evidence that such flow reversions do occur in reality. Furthermore we show that the dominant French generator is apparently exporting electricity to the UK, despite French prices appearing to be higher, whilst most other players trade in the opposite direction. There are several possible explanations for this, with the circumstantial appeal of market conduct being rather persuasive.

The total inefficiencies of under-using or misusing the interconnector amounted to € 289 M over this 4 year period. The largest share of this was due to intentional or accidental withholding. We were able to show that a significant amount of physical

[28] Bloomberg, March 11, 2009, "Electricite de France SA, Europe's biggest power producer, was raided yesterday by antitrust officials. EDF may have broken EU rules by abusing its dominant market position through price increases on the French wholesale electricity market, the European Commission said in a statement today" http://www.bloomberg.com.

transmission rights (worth € 100 M in importing and € 65 M in exporting direction) was bought but neither used nor returned to the auctioneer. This is evidence that the use-it-or-lose-it principle is not properly applied in the Anglo-French interconnector. Another source of inefficiencies—the lack of ex ante netting—turned out to have minor effects. Only 808 GWh importing capacity, worth 6.6 M€, and 816 GWh exporting capacity, worth 2.9 M€, could have been released by ex ante netting in the years 2002–2005.

Finally it should be noted that a substantial part of these inefficiencies occur because the energy and transmission markets are decoupled through the ex ante nature of the capacity auctions. Implicit auction approaches with nodal pricing, together with harmonized pricing of renewable power, would preclude the inefficiencies identified here. However, these could also be achieved in an ex ante auction setting by enforcing the use-it-or-lose-it principle, allowing ex ante netting and increasing the number of traders. Despite the vulnerability of explicit ex ante auctions to these inefficiencies, for pragmatic reasons, especially in international settings without supranational regulatory institutions, they may be the most practical way to implement interconnector trading, at least initially, but, as a consequence, need particularly careful market mechanism design, harmonization, monitoring and liquidity incentives.

Acknowledgments The authors would like to thank the National Grid Company and Jan Abrell.

Appendix

(See Tables 3, 4, 5 and 6 and Fig. 9)

Table 3 Company names

1	ACCE—Accord Energy	10	CARE—Cargill PLC	19	MSCG—Morgan Stanley
2	ARON—J.Aron & Company	11	DUKE—Duke Energy International Ltd	20	PGEN E.ON UK plc
3	AELE—Aquila Energy Ltd (Npower Limited)	12	DYNE—Dynegy UK Ltd	21	SEME—Sempra Energy Europe Ltd
4	AEPE—AEP Energy Services Ltd	13	EDEF—EDF GENERATION TRADING	22	SETL—Shell Energy Trading Limited
5	AXIE—Merrill Lynch Commodities LTD	14	ELEE—Electrabel SA	23	STAT—Statkraft Markets Gmbh
6	BARB—Barclays Bank plc	15	FHCE—First Hydro Company	24	TFEE—Total Gas & Power Ltd
7	BKWE—BKW FMB Energie AG	16	INNE—RWE NPOWER PLC	25	TXUE—TXU Europe Energy Trading BV
8	BHPB—BHP Billiton Marketing AG	17	GASE—Gaselys	26	VATT—Vattenfall AB
9	BPGE—BP Gas Marketing Limited	18	LPAS—El Paso Merchant Energy Europe	27	WILE—Williams Energy Europe

Table 4 Aggregated company level nominations

	# of export nominations	Total export nominations in MWh	Avg export nomination in MWh	# of import nominations	Total import nominations in MWh	Avg. import nomination in MWh
ACCE	8,686	1,267,968	146.0	5,504	847,178	153.9
ARON	2,137	167,835	78.5	59	3,595	60.9
AELE	771	70,719	91.7	24	2,132	88.8
AEPE	3,415	661,461	193.7	2,148	345,238	160.7
AXIE	10,668	2,067,320	193.8	5,482	1,259,711	229.8
BARB	8,313	1,650,806	198.6	4,291	913,155	212.8
BKWE	5,781	764,245	132.2	1,041	78,042	75.0
BHPB	0	0		12	612	51.0
BPGE	1,242	76,185	61.3	152	9,296	61.2
CARE	2	2	0.8	177	14,029	79.3
DUKE	100	4,900	49.0	48	3,060	63.8
DYNE	1,221	65,153	53.4	463	27,625	59.7
EDEF	14,193	6,606,480	465.5	3,378	725,144	214.7
ELEE	8,350	614,233	73.6	2,761	158,405	57.4
FHCE	462	36,957	80.0	280	24,868	88.8
INNE	6,331	551,856	87.2	3,914	390,220	99.7
GASE	3,377	248,941	73.7	290	19,192	66.2
LPAS	154	13,185	85.6	1,086	161,810	149.0
MSCG	0	0		586	24,398	41.6
PGEN	8,771	581,831	66.3	1,124	66,572	59.2
SEME	10,643	1,053,666	99.0	4,596	261,220	56.8
SETL	3,477	347,502	99.9	791	49,289	62.3
STAT	2,463	168,649	68.5	1,004	62,501	62.3
TFEE	12,791	3,145,247	245.9	4,056	883,895	217.9
TXUE	1,972	248,395	126.0	1,220	151,467	124.2
VATT	448	23,890	53.3	381	15,247	40.0
WILE	0	0		24	1,800	75.0

Table 5 Summary statistics

	Mean	Var	Min	Max
PNX3	19.4	77	0.5	66
PNX13	46.8	1,486	7.9	1,000.1
UKPX3	25.4	96	5.2	86.7
UKPX13	45	785	19.3	399.3
IFA_V3	893.8	800,348	−1,541	2,000
IFA_V13	160.3	1,105,163	−1,998	2,001
IFA_P	47.6	10,595	0	1,000
IFA_P	12.9	2,565	0	1,085

Table 6 Panel data logit regression of $T_{i,t} = \alpha_i + \beta_i \Delta p_t + \gamma_i \bar{\eta}_t + \varepsilon_{i,t}$ (see Sect. 5.2)

Variable	Coefficient	t-Statistic	t-Probability
a_ACCE	−0.689	−19.8	0.000
a_AEPE	−0.225	−3.3	0.001
a_AXIE	0.005	0.2	0.851
a_BARB	−0.328	−8.9	0.000
a_BKWE	0.160	2.8	0.005
a_DYNE	0.034	0.4	0.709
a_EDEF	1.358	49.3	0.000
a_ELEE	1.036	19.3	0.000
a_FHCE	−1.395	−7.8	0.000
a_INNE	−0.728	−14.1	0.000
a_GASE	1.359	12.7	0.000
a_PGEN	1.576	36.7	0.000
a_SEME	0.132	3.9	0.000
a_SETL	−0.388	−4.4	0.000
a_STAT	−1.413	−11.3	0.000
a_TFEE	0.690	19.6	0.000
a_TXUE	−0.912	−11.6	0.000
a_VATT	−2.480	−8.0	0.000
b_ACCE	0.046	28.2	0.000
b_AEPE	0.072	21.8	0.000
b_AXIE	0.029	30.7	0.000
b_BARB	0.028	18.2	0.000
b_BKWE	0.064	24.0	0.000
b_DYNE	0.071	12.5	0.000
b_EDEF	0.037	26.1	0.000
b_ELEE	0.041	19.7	0.000
b_FHCE	0.081	10.5	0.000
b_INNE	0.078	33.5	0.000
b_GASE	0.055	9.8	0.000
b_PGEN	0.015	7.7	0.000
b_SEME	0.042	35.9	0.000
b_SETL	0.071	18.0	0.000
b_STAT	0.113	18.2	0.000
b_TFEE	0.048	38.5	0.000
b_TXUE	0.151	21.3	0.000
b_VATT	0.182	9.7	0.000
c_ACCE	0.433	62.3	0.000
c_AEPE	0.743	35.5	0.000
c_AXIE	0.357	68.0	0.000
c_BARB	0.449	57.9	0.000
c_BKWE	0.344	36.8	0.000
c_DYNE	0.295	14.5	0.000
c_EDEF	0.329	58.6	0.000
c_ELEE	0.575	44.7	0.000
c_FHCE	0.279	13.2	0.000
c_INNE	0.493	49.4	0.000
c_GASE	0.411	21.7	0.000
c_PGEN	0.311	39.8	0.000
c_SEME	0.516	61.1	0.000
c_SETL	0.404	29.2	0.000
c_STAT	0.504	25.2	0.000
c_TFEE	0.560	60.7	0.000
c_TXUE	0.623	27.4	0.000
c_VATT	0.713	12.4	0.000

Logit maximum likelihood estimates
McFadden R-squared = 0.62
Estrella R-squared = 0.68
LR-ratio, 2*(Lu–Lr) = 112,451
LR p-value = 0.0000
Log-likelihood = −34,473
# of iterations = 9
Convergence criterion = 2.1047073e-007
Nobs; Nvars = 153,830; 54

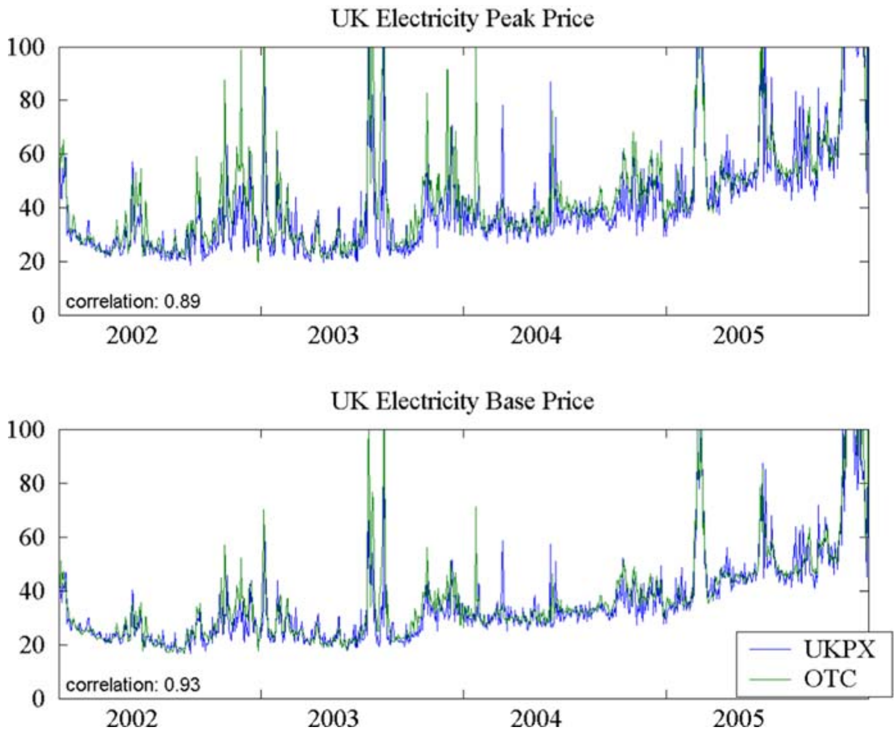

Fig. 9 Comparison of UK OTC and power exchange prices

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