

Elecxit: The Cost of Bilaterally Uncoupling British-EU Electricity Trade

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Abstract

The UK's withdrawal from the European Union could mean that it leaves the EU Single Market for electricity (Elecxit). This paper develops methods to study the longer-term consequences of this electricity market disintegration, and in particular the end of market coupling. Before European electricity markets were coupled, different market closing times forced traders to commit to cross-border trading volumes based on anticipated market prices. Interconnector capacity was often under-used, and power sometimes flowed from high- to low-price areas. A model of these market frictions is developed, empirically verified on 2009 data (before market coupling) and applied to estimate the costs of market uncoupling in 2030. A less efficient market and the abandonment of some planned interconnectors would raise generation costs by €560m a year (1.5%) compared to remaining in the Single Electricity Market. Sixty percent (€300m) of these welfare losses occur in Great Britain.

Keywords: Electricity Trading, Market Coupling, Brexit

JEL Codes: L94, F13, F15

1. Introduction

Electricity traders sometimes make mistakes, and they know it. To reduce the expected cost of mistakes, risk-averse traders scale back their actions when the direction of trade that maximises profit is unclear. The benefits of interconnecting electricity markets are significantly reduced if capacity is under-used, and sometimes used in the wrong direction. The European Union's Internal Electricity Market is designed to maximise the benefits of interconnection among member states. In particular, market coupling between 19 countries in North-Western Europe uses algorithms to ensure that as much electricity as possible is traded from lower- to higher-priced markets. This has brought significant welfare gains. The British electricity market is one of the 19, but may de-couple itself from the system as a possible consequence of Brexit – the UK's decision to leave the EU. We wish to calculate the cost of this Elecxit.

The European Union's plan to create an internal electricity market started with the deregulation of national electricity markets in the 1990s. The vision of a cross-border market design had been largely implemented by 2015 in the form of the Electricity Target Model (ETM)(ACER, 2015). In particular, market coupling implies that day-ahead wholesale markets clear simultaneously and transmission capacity is automatically allocated so that electricity can flow from low- to high-priced areas until prices are equalised or capacity is fully used. Trade between Member States is now only limited by capacity constraints of the infrastructure. To tackle this, the EU has set the goal to expand interconnector capacities to 10% of each national electricity generation capacity by 2020 and 15% by 2030.

Until recently, it seemed highly unlikely that the integration of Europe's electricity industry would be reversed, but Great Britain is in the process of leaving the EU. The EU and Great Britain are currently negotiating the conditions of this exit and their future relationship. The outcome of the negotiations is currently (April 2019) highly unpredictable, given their breadth, depth and political circumstances.

The complexity of the negotiation is evident in the electricity sector (Mathieu *et al.*, 2018). In addition to the institutions of electricity trading or tariff and non-tariff trade barriers, any readjustment of the emissions trading system, Euratom regulation or the Renewable Energy Directive might have indirect consequences for the electricity sector. Again, the result is not foreseeable. Nevertheless, Brexit scenarios have been developed to help stakeholders prepare and to underpin their bargaining positions. Two significant design principles and conclusions from them are presented as examples:

- A number of Brexit scenarios build on the GB Government's rejection of jurisdiction by the European Court of Justice. A UKERC/Chatham House Report¹ suggests that the rejection of this institution excludes British actors from the institutions controlled by them, amongst others the single electricity market. In particular, GB electricity markets could not remain coupled with their continental counterparts.

The resulting uncertainties about the profitability of trading and a reduction of EU funds could hinder the expansion of the trade infrastructure between GB and the continent (in the context

¹ Froggatt et al. (2017), page 18: "Following the UK's decision to leave the EU, it is still unclear whether UK will remain part of current and future market coupling arrangements. This is because these require the active collaboration of GB interconnection counterparts, and market coupling was mostly developed through European legislation (e.g. the European Network Codes on capacity allocation and congestion management (CACM), and on forward capacity allocation (FCA))."

mentioned above) from 4 to 10 GW by 2021 (Froggatt *et al.*, 2017), especially those currently in the planning phase.

- The European Commission has published a scenario for the case that negotiations would not succeed by the date of withdrawal (DG ENER, 2018). Then, Great Britain would become a 'third country' and 'EU rules in the field of energy market regulation will no longer apply to the United Kingdom'. As consequences of this, the Commission foresees not only market uncoupling, but also the necessity to charge an interconnector usage fee for trade with Great Britain. Whether the latter equals a tariff is not yet obvious.

Alternatively, GB's government has proposed that the country remains in a Customs Union for goods, and this approach – if accepted by the EU – might also cover the internal electricity market. In this context, where uncoupling may not be inevitable, it is useful to estimate the cost of de-coupling Great Britain from the internal electricity market, and of halting the expansion of interconnectors.

For this purpose, the welfare losses are not simply the inverse of the welfare benefits previously gained from European market integration, projected one-to-one into the future. The electricity sector is changing too much for that approach to give realistic estimates. In particular:

1. Before market coupling, trading decisions frequently proved to be uneconomic *ex post*, but their impacts were limited by small interconnector capacities. Interconnector capacity is rising substantially, and future mistakes would have greater opportunity costs than those prevented by market coupling in the past.
2. The structure of electricity generation will change dramatically as more intermittent renewables will enter the market. A higher share of renewable generation will make international coordination more valuable and a lack of coordination costlier.
3. Generation mixes will be adjusted to the higher share of intermittent renewable generation and a change in the load profile. These changes in national supply might also affect the sensitivity of the market price to traded electricity and thus alter the effect of reduced market coordination.

We base our estimates on scenarios for 2030 to show the longer-term opportunity costs of Elecxit. Since an analysis of the costs of market decoupling in 2030 is likely to be unreliable if it is based only on past estimates of the benefits from market coupling, we create a structural model of trading in uncoupled markets that allows us to take account of the three changes above. We assume that the inefficiencies of decoupled markets are solely caused by uncertainties resulting from the separation of auctions of cross border transmission capacities and day-ahead markets. This explanation is supported by survey answers of market participants (European Commission, 2007, pp183-6), and is considered as most important by other authors, e.g. Newbery *et al.* (2016). Perhaps most importantly, it enables simulations of trading patterns of decoupled markets in the past that fit well to observed data.

Mahringer (2014) simulates inefficiencies in trading as due to imperfect anticipation of price dynamics, but uses a continuous stochastic process that is not easily adapted for the econometric estimates needed to calibrate our model. Instead, we present a simple but micro-founded two-country trade model.

With market coupling, all markets for delivery at time X close at the same time C and trade can be optimised.² If the markets are uncoupled, one of them (D) closes earlier than C. Traders then have to supply and to demand energy and to acquire transmission rights on sequentially closing markets. Trading economically therefore requires price expectations to be formed for the ‘not yet closed’ markets. As future demand and intermittent renewable generation are uncertain, prices are also uncertain and trade can only be adjusted optimally to an expected (average) scenario. This trading volume is however suboptimal in many *ex post* cases, causing welfare losses. In extreme cases the direction of trading can even be reversed by the anticipation error. We calibrated the model with generation, load and trading data for Great Britain and France in 2009, when their markets were uncoupled, allowing us to estimate the underlying anticipation error and a possible reduction of the optimal trading volume. We assume that the market design after the market decoupling corresponds to that used for calibration, so that the variance of this basic anticipation error does not change due to changes in the length of forecasting intervals.

With the quantified model, our initial estimate of the benefits of market coupling in 2010 was 50% above values in the literature. This can be explained by the implicit assumption of the standard approach that the trading pattern on uncoupled markets is independent of market rules. While the standard assumption is that arbitrage traders are risk-neutral, our empirical results strongly suggest that traders in uncoupled markets are risk-averse, and that this discourages trade. This increases the gains from market coupling.

Second, we simulate the costs (in 2030) of dis-integrating the British electricity market from France (representing Continental Europe), against the background of the ENTSO-E 2030 vision 3 scenario. Load profiles, generation capacities and costs are taken from this scenario, with wind and solar output profiles taken from Renewables.ninja (Pfenninger and Staffell, 2016). With significantly higher levels of wind and solar generation, we find that the same underlying anticipation error would lead to trading errors twice as large (in MW terms) as in 2009.

We compare a business-as-usual reference case, “Soft Elecxit”, with continued market coupling and an increase to 10 GW of interconnector capacity with a “Hard Elecxit”, where the British and French markets are decoupled and interconnector capacity only rises marginally to 5 GW. This raises the cost of generation in both countries by €560m or 1.5% of the market value, compared to the reference case. We find that most of these costs are due to market decoupling, as the net benefits of adding interconnector capacity are low if this simply allows traders between decoupled markets to make greater mistakes. Among the costs of market decoupling, the reduction of trading volumes due to risk aversion is more important than trading errors based on imperfect information.

Following this introduction, the second section presents an overview of the effects of decoupled electricity markets and discusses their causes. On this basis, Section 3 sets out a model of rational trade in decoupled electricity markets. The model developed is then applied in section 4. First it is conditioned for empirical treatment in section 4.1 and econometrically estimated for 2009 data in 4.2. The quantified model is used to estimate the benefits of market coupling in 2009 *ex post*. In section 4.3 Elecxit scenarios between GB and France in 2030 are simulated and welfare effects estimated. Finally, in section 5 conclusions are drawn.

² Even though there is residual load uncertainty between C and the time of delivery X we are only interested in additional uncertainties of market closure prior to C.

2. What is wrong with uncoupled electricity markets?

In general, two markets can be defined as uncoupled if market rules exclude a conditioning of supply and demand in each of the markets on the price of the other market. This might be caused by different market closure times, by the necessity to submit unconditional demand or supply prices to the auctioneer or it might simply be forbidden to receive the relevant information. While in general this lack of information reduces allocative efficiency, it should be pointed out that market coupling increases transactions costs, in particular those of communications infrastructure,³ and it complicates the search for an integrated market equilibrium. Whether markets should be coupled or not is thus a quantitative question of costs and benefits. In electricity market equilibrium, arbitrageurs in coupled markets fully equilibrate competitive prices, as far as allowed by transmission capacity constraints.⁴ This maximises short-run welfare, and should be compared with the outcome when markets are not coupled.

2.1. Uncoupled Markets

While adjoining electricity control areas typically exchanged power, the early wholesale markets were uncoupled. To trade power between two adjacent markets, a company would need to reserve transmission capacity on the interconnector between them, buy power in one market, and sell it in the other. Much transmission capacity was sold in advance in long-duration blocks, and the quantity available in each direction was limited to the maximum capacity of the interconnector. There was often no mechanism for releasing additional capacity to the market if the holder did not want to use their rights, or if electricity flowing in the other direction created spare capacity on the lines (easily possible in an AC network).

If one market publishes its results before the deadline for submitting bids to the other,⁵ traders would at least know whether they now have to buy or sell power in the second market, or if they came away from the first auction with nothing. However, the time difference between the two markets' deadlines means that new information on demand and generators' availability, and hence on expected prices, is likely to arrive after the first set of bids are submitted. The trader may now be committed to selling power into a market newly expected to have a surplus, and therefore face a loss.

But even if the market deadlines are identical, so that all bids will be based on the same information set, individual traders will only know part of it, and so the only way to be sure of not having unmatched commitments is to submit one unconditional bid to buy and one unconditional offer to sell. This ensures trade, whatever the price combination on the two markets. When price differences are large and systematic, this strategy may be consistently successful, but if the two markets have similar prices, a trader who is unlucky in the individual information will commit to a trade that turns out to be unprofitable. It is unlikely that arbitrageurs could gather all the information needed to prevent this.

³ NAO (2003) estimates the additional infrastructure cost for the 'new electricity trading arrangements (NETA)' in England and Wales at £116 million for the first 5 years and £30 million per year thereafter.

⁴ The algorithm for determining local market prices under Euphemia contains the optimal trading strategy of an arbitrageur. To further investigate this strategy, we explicitly introduce this actor, although under Euphemia there is no longer any physical counterpart.

⁵ A detailed description of market rules can be found in Madlener and Kaufmann (2002).

2.2. Coupled markets

If the markets are coupled, the system operators take over the role of cross-border traders. The markets close at the same time, so all bids and offers are drawn from the same information set. Computer algorithms move power from a lower- to a higher-priced market until the prices are equalised or interconnector capacity is fully used. All generators and buyers face the price in their local market, and the difference between those prices creates revenue for the interconnector owners. Since all market participants' information is used to derive all prices, this should increase market efficiency, although market coupling also increases transactions costs.

However, equilibrating prices is not possible if the capacity limit of the transmission infrastructure is reached: i.e. either prices in both markets are the same and the trade volume is below capacity or prices are not equal and there is no unused capacity available. This “ideal trading” pattern takes the form of a step function in terms of price differences and utilisation of the trading capacity (the red curve in Figure 1).

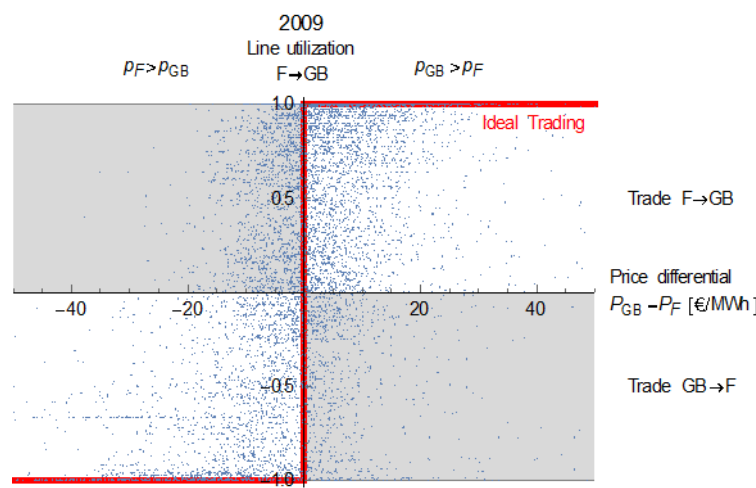


Figure 1: GB France trading pattern – before market coupling: hourly capacity utilization of the France GB interconnector vs. hourly price differentials on the day ahead markets in 2009. Grey shaded areas indicate trading against the price differential. Sources of all market data are given in table 3.

However, in uncoupled markets (e.g. between France and GB in 2009), frequent and strong deviations from this ideal trading pattern are found (blue dots, Figure 1). Price differentials persisted for a large number of trading periods without binding capacity restriction. It is clear that the trading potential was often not used efficiently. In 30% of periods, electricity was bought in the market with higher prices and sold on the market with the lower prices. At these times, simply not trading would have been welfare-enhancing. Ehrenmann and Smeers (2004) and Bunn and Zachmann (2010) discussed possible reasons for the under-utilisation of interconnector capacity:

1. Uncertainties from the separation of transmission and energy markets. Transmission auctions usually preceded the energy markets,
2. System operators may have need to be active in scheduling cross-border flows for congestion and system balancing purposes and
3. Strategic trading by generators with market power (generators would trade against the price differential, selling into a cheaper market to raise demand and price in their home market).

The impact of uncertainties caused by separating the allocation of transmission capacity and local electricity markets are well documented. To quote the European Commission's Energy Sector Inquiry (2007, p. 184), “the deadline for interconnector nominations occurs after the French (Powernext)

energy market clears, while the UKPX (the leading GB power exchange) is open and prior to gate closure⁶ in respect of GB’s balancing mechanism.” Under these market rules market participants confirmed in a poll “that they faced uncertainty since they had to place auction bids based on expected wholesale market prices.” (p. 185)

Market coupling would remove uncertainties due to separated markets, and make trading against the price differential impossible. Therefore, the past welfare losses of uncoupled markets (and short-term welfare gains from market coupling) could simply be estimated by comparing the observed trade pattern to the ideal pattern and evaluating the differences.

In the simplest form applied by ACER (2013), interconnector utilisation was artificially increased to 100% at existing price differences, while the advanced version (Newbery et al, 2016) also took account of price convergence due to higher utilisation. The uncoupled and ideal allocations could then be compared by welfare measures based on local supply and demand. ‘Before and after’ estimates of day-ahead market prices quantify a price drop that induces a welfare gain of 0.25-0.5% of the wholesale market value (Newbery *et al.*, 2016). Further estimates are summarised in table 1. It is implicitly assumed that the willingness to trade is independent of market coupling, an assumption challenged by our estimates in section 4.2.

System wide estimates

Newbery et al. (2016)	Considering price changes	<ul style="list-style-type: none"> ▪ Day-ahead market coupling 0.25–0.5% wholesale value day ahead ▪ Intra-day and balancing benefits €1.3bn/yr. ▪ Total benefits including removing unscheduled flows could be €3.4bn/yr
Mansur and White (2009)	Compare prices before and after a bilaterally cleared zone joined PJM's market area to estimate price spreads and welfare gains	0.7% wholesale value

Single interconnectors

Meeus (2011)	Compare flows and determine welfare gains on the Denmark-Germany Kontek cable with no coupling and one-way market coupling.	Welfare gain €10m/yr or €17m/GWyr, >> Mansur and White (2009) estimates
SEM Committee (2011)	Estimate welfare gains of coupling the interconnectors between GB and the Single Electricity Market (SEM) of Ireland (950/910 MW imports/580 MW exports)	€30m/yr for import capacity of 930 MW, €32m/GWyr, >> Meeus (2011) estimates
National Grid (2015)	Sharing reserves over interconnectors might reduce capacity needs by 2.8 GW	With 2014 capacity auction price of 19.40/kWyr: €15m/GWyr = Meeus (2011) estimates.

Table 1: Overview of estimates of market integration benefits.

These estimates have motivated regulators to gradually couple European electricity markets, until all the markets of north-west Europe with 19 countries and 85% of the European power consumption were coupled by 2015 (epexspot.com, market coupling; Table 2).

⁶ Gate closure is the point at which trading must cease, except for balancing trades with the system operator as counter-party (Madlener and Kaufmann, 2002).

1996	Nordpool: Norway Sweden					
1998	+ Finland					
2000	+ Denmark					
2006		Tri-Lateral Market				
2007		Coupling TLC: France, Belgium, Netherlands, (Luxemburg)	MIBEL Spain Portugal			
2010	Central West Europe (CWE)			Germany Austria	Poland, Latvia, Lithuania Estonia	
2011						+ GB
2014	North Western Europe (NWE)					
2015						+ Italy Slovenia
						4M (CEE): Hungary, Romania, Czech Republic, Slovakia

Table 2: Stepwise integration of European electricity markets.

Indeed, the trading pattern for the implicitly auctioned net daily inter-connector capacity on the France-GB border and the hourly price differential between UKPX and EPEX in 2017 (Figure 2) closely fits the ideal trading pattern. As described above, either the prices are practically equilibrated⁷ or the capacity restriction binds.

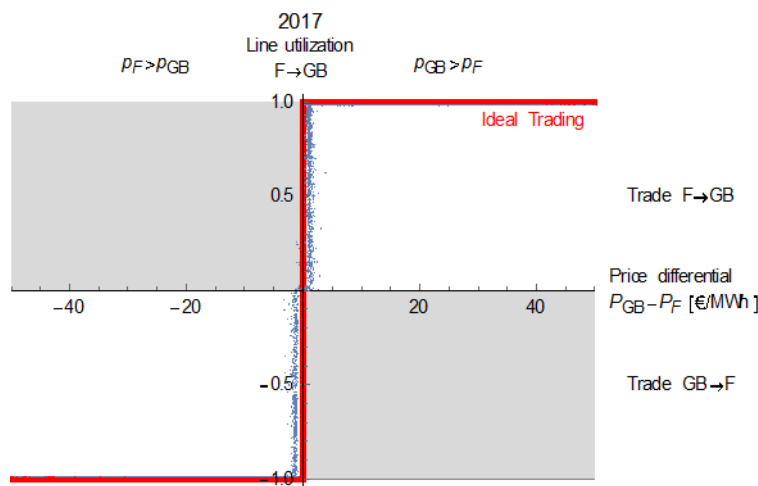


Figure 2: GB France trading pattern – under coupled markets: hourly capacity utilisation of the France GB interconnector vs. hourly price differentials on the day-ahead markets in 2017.

As market coupling resolved almost all possible reasons for inefficiencies and transformed the observable allocation from distorted to ideal, it was not necessary to evaluate the actual sources of inefficiency when estimating the gains from coupling. We cannot simply take the reverse of these gains as an estimate of the cost of market uncoupling from Elecxit, as the conditions will differ strongly in a future sustainable electricity system with higher shares of renewables, higher transmission capacities and adjusted generation structures. To improve accuracy, it is necessary to model the counterfactual of decoupled markets. This is different in principle to the modelling of market coupling as the ideal allocation is the ‘business as usual’ and the distorted inefficient allocation must be constructed actively. Therefore, the reason for the inefficiencies of uncoupled

⁷ There are small fees to cover the electricity lost on the DC interconnector and at the AC-DC conversion stations, and so a small price difference is needed to cover these and make trading worthwhile – the EU market allocation algorithm takes account of this, as shown in Figure 2.

markets must be made explicit. We interpret the wide geographical extent of trading inefficiencies when explicit interconnector capacity auctions close before at least one electricity market as evidence that uncertainty is the most important cause of inefficiency, and focus our analysis on this.

Data	2009	2017
Day ahead prices GB	APX	APX
Day ahead auction prices F	EPEX France	EPEX France
Trade F-GB	RTE	RTE
Interconnector Capacity	RTE	N2EX Market Coupling Capacities
Load GB	Elxon / National Grid	Elxon / National Grid
Load F	RTE	RTE

Table 3: Data sources used in this study. Réseau de transport d'électricité (RTE) is the French transmission system operator.

3. Trade equilibrium in uncoupled markets

We develop a model of profit-maximising bilateral trade between France (F) and Great Britain (G) in uncoupled day-ahead markets with trading losses and capacity constraints. First, a trading equilibrium in coupled markets is defined (3.1). Then in (3.2) we study its structural properties graphically and based on these an algorithm for its computation is derived. We then introduce uncoupled markets (3.3) with anticipation errors and show how to modify the previous analysis.

The trading volume T_h is defined as the net energy imported into GB (for $T_h > 0$); exports from GB are shown as negative values of T_h . Due to losses (equal to a proportion τ of the traded electricity) France would have to export $T_h/(1 - \tau)$ units of energy in order to deliver T_h in GB. If GB is exporting T_h units of electricity, then $(1 - \tau)T_h$ units of energy can be sold in France. If we define transmission capacity symmetrically ($\underline{K}_h = \overline{K}_h$) in terms of the energy entering the exporting conversion station (that is, before losses), GB imports are restricted to no more than $(1 - \tau)\overline{K}_h$ and exports to no more than \underline{K}_h . The function $\varphi(T) = (1 - \tau)^{\text{sign}(T)}$ simplifies the notation significantly.

3.1. Trading equilibrium with losses

We first describe an equilibrium model of optimal bilateral trade in uncoupled day-ahead markets. To keep things simple, we do not consider the allocation of interconnector capacity among traders but assume the existence of a representative price-taking trader (arbitrageur). A trading equilibrium is a vector of French and British prices and a trading volume $(p_{F,h}^*, p_{G,h}^*, T_h^*)$ in every hour h such that: 1. The price-taking arbitrageur maximises its profits and 2. Given the prices, the induced supply and trade equal local load.

Demand in each market is given by $L_{G,h}$ and $L_{F,h}$, known in advance and unaffected by price. All markets are perfectly competitive thus marginal costs of generation equal market prices. Market supply can be described by $C'_{G,h}{}^{-1}(L)$ and $C'_{F,h}{}^{-1}(L)$, the inverses of the aggregated marginal cost functions $C'(L)$. The underlying cost functions C are assumed to be monotonous and at least twice differentiable. To cover seasonality of the supply,⁸ C' depends on h . In our estimation and simulations, we use 8 half-seasons.

⁸ Maintenance is concentrated in the summer months. Ofgem, 2012 (page 27, figure 3.1) reports that coal fired power plants are 26% more available in winter than in summer - respectively gas CCGT (+17%), OCGT (+14%) and nuclear (+12%). Gas prices are also seasonal.

Furthermore, we assume that there is short term information $\varepsilon_{G,h}$ and $\varepsilon_{F,h}$ known to all market participants that shifts the supply curve. These supply curve residuals are distributed normally with standard deviation σ_G and σ_F . Market clearing on the two markets implies

$$C'_{G,h}{}^{-1}(p_{G,h} - \varepsilon_{G,h}) = L_{G,h} - T_h \quad (1)$$

$$C'_{F,h}{}^{-1}(p_{F,h} - \varepsilon_{F,h}) = L_{F,h} + \varphi(T_h)T_h \quad (2)$$

The calculus of the profit maximising, representative, price-taking arbitrage trader that shifts T British units of energy from France to Great Britain restricted by a transmission capacity K is

$$\begin{aligned} \max_T \pi_h^{Arb} &= (p_{G,h} - \varphi(T)p_{F,h})T \\ \text{s. t.} &: -\underline{K}_h \leq T \leq (1 - \tau)\bar{K}_h \end{aligned} \quad (3)$$

The optimal trade is a set-valued mapping from the prices $p_{G,h}, p_{F,h}$ to the admissible trade levels

$$T^*(p_{G,h}, p_{F,h}) = \begin{cases} (1 - \tau)\bar{K}_h & p_{G,h} > p_{F,h}(1 - \tau)^{-1} \\](1 - \tau)\bar{K}_h, 0[& p_{G,h} = p_{F,h}(1 - \tau)^{-1} \\ 0 & (1 - \tau)^{+1} < p_{G,h}/p_{F,h} < (1 - \tau)^{-1} \\]-\underline{K}_h, 0[& p_{G,h} = p_{F,h}(1 - \tau)^{+1} \\ -\underline{K}_h & p_{G,h} < p_{F,h}(1 - \tau)^{+1} \end{cases} \quad (4)$$

3.2. Equilibrium analysis

The structure of the equilibrium can be analysed graphically using the price relation $p_h = p_{G,h}/p_{F,h}$. With this definition (4) can be simplified to the trade demand (set-valued mapping) $T^*(p_h)$. A trade supply can be derived by inverting market balancing conditions (1) and (2) for the local prices

$$p_{G,h}(T) = C'_{G,h}(L_{G,h} - T) + \varepsilon_{G,h} \quad (5)$$

$$p_{F,h}(T) = C'_{F,h}(L_{F,h} + \varphi(T)T) + \varepsilon_{F,h} \quad (6)$$

and plugging (5) and (6) into the definition of p_h . The trade supply derived from (5) and (6) and the optimal set (derived from 4) are shown in Figure 4. It is straightforward to see that there exists exactly one equilibrium and that it can be determined with an algorithm to check which section of the demand has an intersection with the supply.⁹ Check whether there is a no-trade-equilibrium. If not, determine the trading volume that equilibrates marginal costs (net of trading losses). If this volume is within capacity constraints then it is the trading equilibrium. If not, the binding capacity is the equilibrium trading level.

⁹ As unique intersections of a step curve and a monotonic line have to be identified a case distinction is required. The order of the cases can be chosen freely. Our chosen order gives a formalism that is suitable for a common econometric treatment. We could equally well reverse the second and third steps to reduce the number of computationally demanding solutions of an implicit equation.

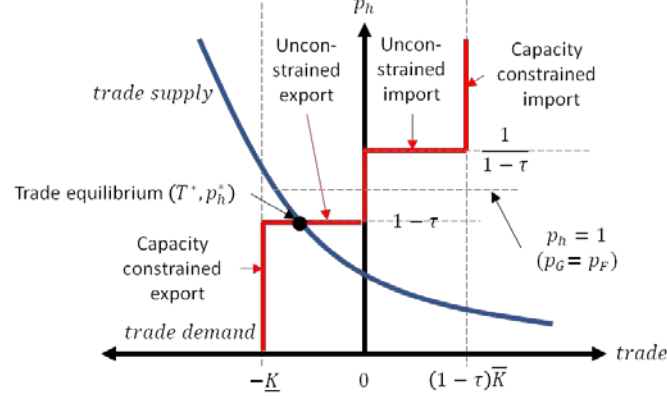


Figure 4: The structure of the trade equilibrium induced by trade demand and trade supply. Note that p_h is a price relation and thus supply and demand are graphical representations but not conventional demand or supply.

This algorithm can be expressed more formally with the unconstrained latent equilibrium trade volume T_h^L , which would equalise prices (net of losses) in the absence of capacity constraints, implicitly defined as:

$$0 = F(T_h^L) := \begin{cases} dp(T_h^L, -1) & dp(0, -1) > 0 \\ T_h^L & dp(0, +1) < 0 < dp(0, -1) \\ dp(T_h^L, +1) & dp(0, +1) < 0 \end{cases} \quad (7)$$

$$dp(T_h^L, s) = p_{G,h}(T_h^L) - (1 - \tau)^s p_{F,h}(T_h^L)$$

In the presence of capacity constraints, T_h^L (latent trade) will not be observed directly but instead the capacity-censored ($(1 - \tau)\bar{K}_h > 0 > -\underline{K}_h$) equilibrium with trading volume T_h^*

$$T_h^* = \begin{cases} (1 - \tau)\bar{K}_h & T_h^L > (1 - \tau)\bar{K}_h \\ T_h^L & \text{else} \\ \underline{K}_h & T_h^L < \underline{K}_h \end{cases} \quad (8)$$

Thus, the trade equilibrium with losses and capacity constraints can be determined by solving equations (5)-(8) for different loads, cost functions and short term information.

How well does this model fit to the trade measured in a coupled market environment in 2017? To provide a first impression eight equally long half-seasons during the year were considered reflecting the seasonal structure of generation capacity that supports high prices with low capacity available in low demand summer. For each of these half-seasons a supply curve ((5) and (6)) has been estimated with 2017 data (sources in table 3) by nonlinear estimation of exponential supply curves $C_h'(L) = e^{a_h + b_h L}$ for France and GB. These supply curves are shown in Figure 5 for France (red) and GB (blue) as dashed curves. With these cost functions, 2017 loads and short term information T_h^L was simulated with (7).

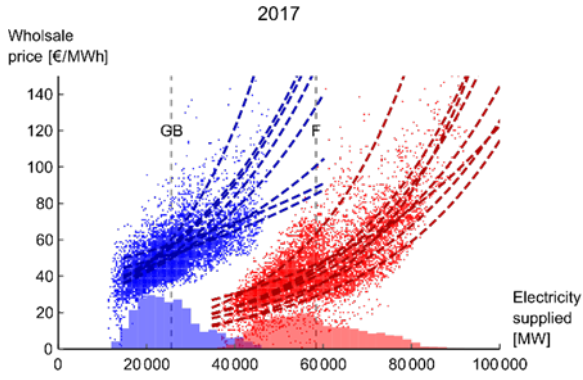


Figure 5: Day-ahead electricity prices in 2017 in France (red) and GB (blue) dots; 8 estimated half-seasonal supply curves and the load distribution without axes labels; average annual load in France and GB shown by black dashed lines.

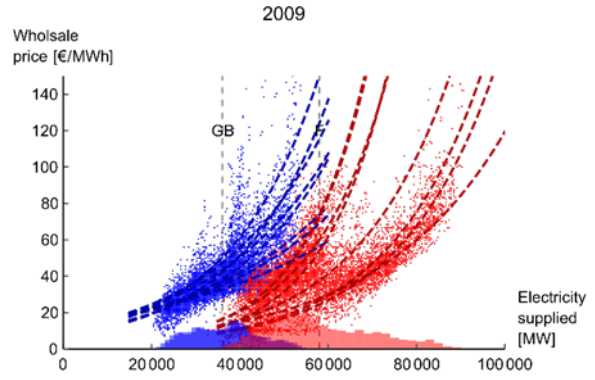


Figure 6: Day-ahead electricity prices in 2009 in France (red) and GB (blue) dots; 8 estimated half-seasonal supply curves and the load distribution without axes labels; average annual load in France and GB shown by black dashed lines.

Figure 7 shows the observed trade in 2017 (under coupled markets) against the simulated latent trade T_h^l . The horizontal bands reflect the available transmission capacity, normally 2,000 MW but sometimes less.¹⁰ The latent trade exceeds the observed trade in 80% of the periods, so that censoring is required. The observed unconstrained trade matches the simulated trade perfectly, as all data points lie on the identity function. To derive this perfect alignment the loss factor was calibrated to $\tau = 0.023$. This loss factor will be used throughout the rest of the paper.

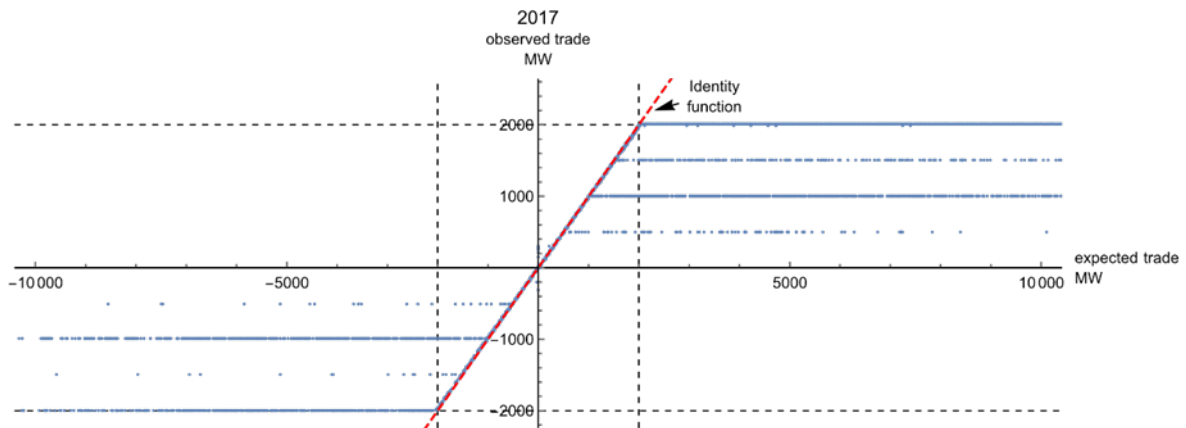


Figure 7: Observed trade in 2017 vs simulated trade with calibrated loss factor $\tau = 0.023$.

Figure 8 shows the result of applying the trade model to the uncoupled markets of 2009, although the assumption of complete information is inappropriate for that setting. Supply curves for 2009 are presented in Figure 6. The simulated latent trade deviates significantly from the observed trade, even when capacity constraints are not binding and censoring is unnecessary. To understand this, a model of trading between uncoupled markets is developed in the next section.

¹⁰ The interconnector with France has two 1,000 MW bipoles, but with four pairs of cables (two pairs damaged during 2016-17) the possibility of losing 500 MW increments of capacity should be obvious.

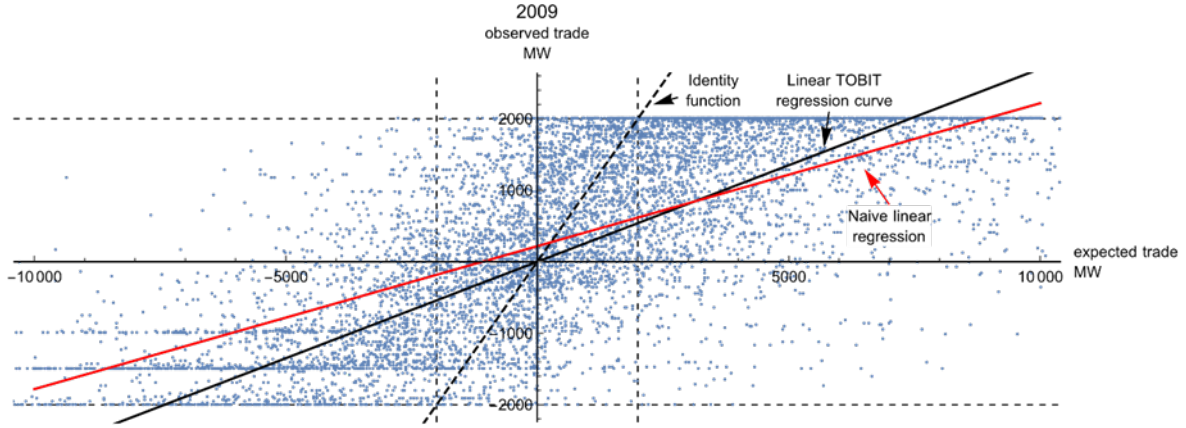


Figure 8: 2009 latent trade with losses and observed trade data. Regression curves are going to be explained in section 4.2.

3.3. Optimal trading between uncoupled markets

When the markets were not coupled, the French market closed first, forcing traders there to anticipate British prices. As traders bid in the French market they commit to delivery, while the British market could still respond to late-arriving information, so that its price is uncertain. We treat the price difference between the markets as the (normally distributed) return on a risky investment. We assume that traders have mean-variance utility,¹¹ maximising a weighted combination of their expected return μ and its variance σ^2 : $EU = \mu - \frac{1}{2} \lambda \sigma^2$. A risk-averse trader with constant absolute risk aversion has $\lambda > 0$. In a two-asset portfolio consisting of ‘trade’ and a risk- and return-less ‘opt-out’ option, the expected return and its variance depend on the trading volume. The trader optimally ‘diversifies’ as he perceives opt-out as valuable risk limitation and thereby reduces trading. To simplify the analysis there is no option to fulfil or cancel a day-ahead commitment through intraday trades.

To determine the expected return and the variance of the portfolio we need the expected British price. We assume the trader correctly anticipates short term information such that $\mathbb{E}\varepsilon_{G,h} = \varepsilon_{G,h}$, but anticipates load incorrectly as $\mathbb{E}L_{G,h} = L_{G,h} + \varepsilon_h$ with $\varepsilon_h \sim N(0, \sigma^2)$.¹² Furthermore, we assume that $C'_{U,h}$ is sufficiently linear to use certainty equivalence, so that the expected version of (6) becomes

$$\mathbb{E}p_{G,h}(T_h, \varepsilon_h) \approx C'_{G,h}(L_{G,h} + \varepsilon_h - T_h) + \varepsilon_{G,h} \quad (9)$$

The anticipation error is therefore also normally distributed and its standard deviation translates to the standard error of the value of a sold unit of electricity as $C''_{G,h}(L_{G,h})\sigma$. Optimal trade maximises the trade/opt-out portfolio with losses:

$$\max_T \mathbb{E}U_h^{Arb} = T(\mathbb{E}p_{G,h} - \varphi(T)p_{F,h}) - \frac{\lambda}{2} (TC''_{G,h}\sigma)^2 \quad (10)$$

By substituting the British price by its expectation in the optimal trading condition (4) we find optimal trading \hat{T} under risk aversion ($\lambda > 0$):

¹¹ The deviation of the mean-variance representation of the portfolio with normally distributed returns can be found e.g. in Sargent, 1987, p. 154.

¹² This can be interpreted as an incorrect estimate of the amount of distributed variable renewable generation that will be subtracted from the overall load to give the amount that must be met in the wholesale market.

$$\hat{T}(\mathbb{E}p_{G,h}, p_{F,h}) = \begin{cases} (1-\tau)\bar{K}_h & (1-\tau)\bar{K}_h \leq \theta \\ \theta & 0 \leq \theta < (1-\tau)\bar{K}_h \\ 0 & (1-\tau)^{+1} < p_{G,h}/p_{F,h} < (1-\tau)^{-1} \\ \theta & -\underline{K}_h < \theta \leq 0 \\ -\underline{K}_h & \theta \leq -\underline{K}_h \end{cases} \quad (11)$$

$$\theta = \frac{\mathbb{E}p_{G,h} - \varphi(\theta)p_{F,h}}{\lambda(C''_{G,h}\sigma)^2}$$

This is equivalent to equation (4) in the limiting cases of risk neutrality ($\lambda = 0$), linear supply curves ($C''_{G,h} = 0$) or no uncertainty ($\sigma = 0$). If loss-adjusted prices differed in those cases, traders would want to send unlimited amounts of electricity to the higher-priced market, but would be constrained by transmission capacity. With risk-aversion and uncertainty, traders balance the expected profit from additional flows against the impact of a greater loss if the British price makes the trade unprofitable. This suppresses trade, although if the expected profit is high enough, trade will increase so that capacity limits finally bind. While risk-neutral arbitrageurs eliminate expected price differences until they become constrained, figure 6 shows that risk-averse traders reduce trading and price equilibration even when they are unconstrained.

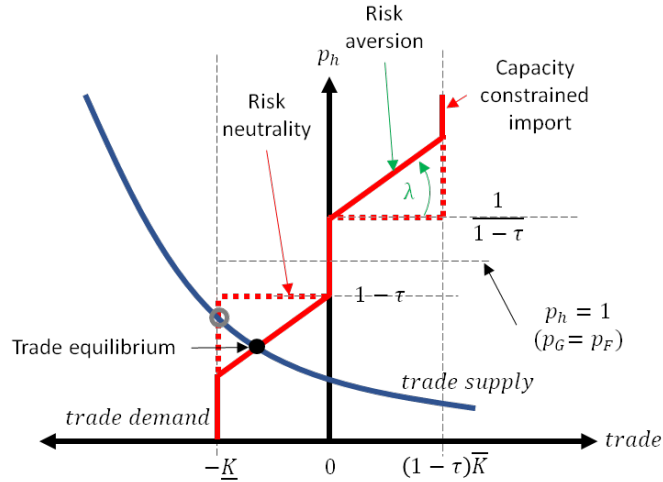


Figure 9: The transition from coupled (perfect foresight) to uncoupled market equilibrium (risk averse trading). The transition from risk neutrality to risk aversion reduces unconstrained trading and price equilibration (p_h is a price relation).

The unconstrained latent equilibrium trade $T_h^L(\varepsilon_h)$ can be defined in a similar way to (7) for $\lambda \geq 0$ as:

$$0 = F_E(T_h^{EL}, \varepsilon_h) := \begin{cases} dp(T_h^{EL}, \varepsilon_h, -1) & dp(0, \varepsilon_h, -1) > 0 \\ T_h^{EL} & dp(0, \varepsilon_h, +1) < 0 < dp(0, \varepsilon_h, -1) \\ dp(T_h^{EL}, \varepsilon_h, +1) & dp(0, \varepsilon_h, +1) < 0 \end{cases} \quad (12)$$

$$dp(T_h^{EL}, \varepsilon_h, s) = \mathbb{E}p_{G,h}(T_h^{EL}, \varepsilon_h) - (1-\tau)^s p_{F,h}(T_h^{EL}) - \lambda T_h^{EL}(C''_{G,h}\sigma)^2$$

Again, due to censoring by the available transmission capacity $T_h^{EL}(\varepsilon_h)$ will not be observed directly but the censored trade equilibrium $T_h^{E*}(\varepsilon_h)$ is given by:

$$T_h^{E*}(\varepsilon_h) = \begin{cases} (1-\tau)\bar{K}_h & T_h^{EL}(\varepsilon_h) > (1-\tau)\bar{K}_h \\ T_h^{EL}(\varepsilon_h) & \text{else} \\ \underline{K}_h & T_h^{EL}(\varepsilon_h) < \underline{K}_h \end{cases} \quad (13)$$

The equilibrium trade with anticipation error, losses and capacity constraints can then be determined by equations (5), (9) and (12), (13). Note that the coupled market model is a special case of the uncoupled market model (12) if $\lambda = 0$ or $\sigma = 0$.

4. Application

Our model implies that the noise clearly present in the trading in Figure 8 is due to anticipation errors and that risk aversion should reduce trading. We now use the observed trade data in 2009 to determine the parameters σ and λ that characterise trading in an uncoupled market environment before simulating trading in uncoupled markets in 2030. However, the uncoupled market model developed so far is not well suited for the estimation of Elecxit costs as the necessary econometric quantification of the parameters is impeded by the implicit definition of the trading error. We will now 1. develop an approximation of the equilibrium trading level well suited for an econometric estimation, 2. estimate the anticipation error parameters and 3. use the estimated parameters to simulate Elecxit costs in 2030.

4.1. Simplification: Disentangling the anticipation error

To simulate the trading error, latent trade $T_h^{EL}(\varepsilon_h)$ can be determined by solving the implicit equation (12). This problem is numerically solvable for an equilibrium simulation, but for the quantification of the trade error we wish to estimate (13) as standard censored model (TOBIT). This requires an exogenous distortion as additive term. Unfortunately, the trading level in (12) depends on the anticipation error. Fortunately, the solution of (12) can be approximated by linearisation of $T_h^{EL}(\varepsilon_h)$ to disentangle the anticipation error and apply the TOBIT model. For this purpose, we briefly assume $\tau = 0$ to avoid the no-trading case

$$0 = F_E(T_h^{EL}, \varepsilon_h) = \mathbb{E}p_{G,h}(T_h^{EL}, \varepsilon_h) - p_{F,h}(T_h^{EL}) - \lambda T_h^{EL} (C_{G,h}'' \sigma_{GB})^2 \quad (14)$$

This implicitly defines the trade level depending on the anticipation error $T_h^{EL}(\varepsilon_h)$. The implicit function theorem then tells us that (for small ε_h and T_h error)

$$\left. \frac{dT_h^{EL}}{d\varepsilon_h} \right|_{\varepsilon_h=T_h=0} = \frac{1}{1 + \frac{C_{F,h}''(L_{F,h})}{C_{G,h}''(L_{G,h})}} := \omega_h \quad (15)$$

and with respect to risk aversion λ (on average to eliminate time dependency besides T_h^L)

$$\left. \frac{dT_h^{EL}}{d\lambda} \right|_{\varepsilon_h=\lambda=0, T_h^{EL}=T_h^L} = -\frac{\sigma^2 T_h^L}{2} \omega_h C_{G,h}''(L_{G,h}) \approx -\frac{\sigma^2 T_h^L}{2} \frac{1}{H} \sum_{h=1}^H \omega_h C_{G,h}''(L_{G,h}) \quad (16)$$

This gives rise to the desired approximation by starting with the undistorted trading level T_h^L (still based on the correct value of $\tau > 0$) and adding the impact of the anticipation error $\omega_h \varepsilon_h$ and risk aversion λ as

$$T_h^{EL}(\varepsilon_h) \approx T_h^L + \frac{dT_h^{EL}}{d\lambda} \lambda + \frac{dT_h^{EL}}{d\varepsilon_h} \varepsilon_h \approx \beta T_h^L + \omega_h \varepsilon_h \quad (17)$$

with

$$\beta = 1 - \frac{\sigma^2 \lambda}{2} \frac{1}{H} \sum_{h=1}^H \omega_h C_{G,h}''(L_{G,h})$$

(17) is additively separated in the anticipation error and heteroscedastic with known weights ω_h . This simplification not only enables the estimation of the model in a linear TOBIT specification (as estimation equation and for jumping above capacity thresholds) but it also reveals how differently a

load anticipation error transforms into a trading error depending on the difference in the slopes of generation marginal costs, driven by the generation structure and risk aversion. Furthermore it becomes apparent that risk aversion reduces trade, but only if there is indeed uncertainty.

Figure 10 (red curve) shows that the amplifier ω_h varies strongly, with a seasonal trend of lower values (0.1) during the autumn 2009 and higher values in the summer (0.6) and a high hourly variance. It is more difficult to anticipate the optimal trade during the summer than it is during the winter even though the load anticipation variance is constant.

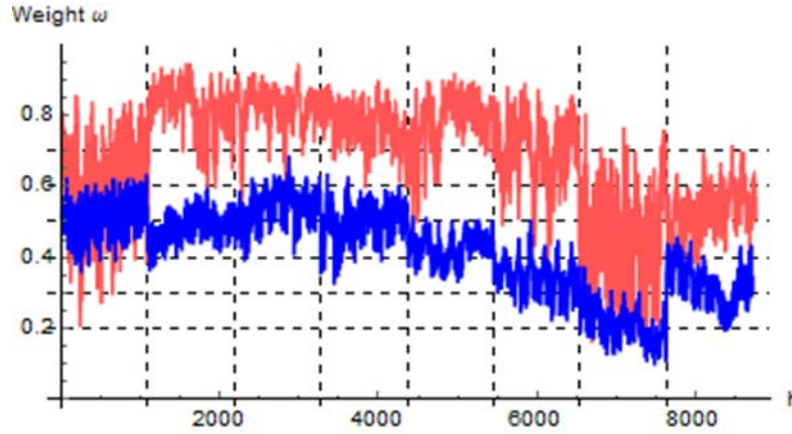


Figure 10: Hourly amplifiers (weights) of the load anticipation error to the trade error in 2009 (red curve) and 2030 (blue curve). The calculation is based on load data and estimated supply curves presented in fig. 8 for 2009 and a scenario analysis for 2030 (fig. 11).

Optimal censored equilibrium trading T_h^{E*} then becomes

$$T_h^{E*}(\varepsilon_h) = \begin{cases} (1 - \tau)\bar{K}_h & \beta T_h^L + \omega_h \varepsilon_h > (1 - \tau)\bar{K}_h \\ \beta T_h^L + \omega_h \varepsilon_h & \text{else} \\ \underline{K}_h & \beta T_h^L + \omega_h \varepsilon_h < \underline{K}_h \end{cases} \quad (18)$$

Equations (5)-(7) could be used to determine latent trade T_h^L and (18) for the distorted censored trade with weights defined in (15).

4.2. Estimating trading distortions in 2009 (uncoupled markets)

β and the distortion parameter σ can be estimated as a heteroscedastic censored model. To do so, the supply curves estimated at the end of section 3.2 have been used to determine the weights ω_h with (15) and in (5)-(7) to simulate latent trade T_h^L as explanatory variable in (18) for the observed censored trade $T_h^{E*}(\varepsilon_h)$. A constant α has been added to the threshold in (18) to allow testing for asymmetries between export and import. The trading error results from the weighted (ω_h) anticipation error that makes (18) heteroscedastic. Fortunately, this can be handled with the standard TOBIT model by normalising the explanatory variable, regressors and capacity limits with the weights¹³. In this way two TOBIT models for 2009 and 2017 were estimated with LIMDEP 5. The TOBIT maximum likelihood estimator relaxes the necessity to minimise the sum of squared residuals to the uncensored share of the data only, but the likelihood function is amended by the probability

¹³ We exploit the fact that theory predicts a specific heteroscedastic structure. In this case, the BLUE of a linear model equals the OLS estimator of the homoscedastic linear model with weighted data (Greene, 2007). Equally, the ML estimator of a TOBIT model with ex ante known heteroscedastic error structure equals the ML estimator of the homoscedastic TOBIT model with weighted data. This can easily be concluded from a comparison of the FOC's of the according likelihood functions. Each likelihood function depends on standardised probability density terms for non-censored data and standardised cumulative terms for censored data.

that the censored data indeed exceeds the censoring limits. The latter tends to put upward pressure on β .

Because trade and interconnector capacity are reported in different ways (sources in table 3), we treated trade observations as censored if they were within 50 MW of the available capacity. The model enables us to fully account for the dynamics of the capacity already mentioned in section 3.2. The parameter estimates are presented in Table 4.

Generalised anticipation error model				
	Censored Model 2009		Censored Model 2017	
Observations	8713		8704	
AIC Information Criterion	133087.1		19037.3	
AIC/N	15.275		2.187	
ANOVA fit measure	0.19		11.12	
DECOMP fit measure	0.16		0.49	
Log likelihood function	-66540		-9515	
	Parameters	Standard Error	Parameters	Standard Error
$\hat{\alpha}$	-0.33	12.35	4.57***	0.55
$\hat{\beta}$	0.27***	0.003	0.99***	0.0005
$\hat{\sigma}$	3035.60***	26.64	67.10***	0.79

Table 4: Parameter estimates (** - 5% level, *** - 1% level)

The results for the coupled market in 2017 are completely in line with the model of sections 3.1 and 3.2 – as already expected from figure 7. This can be concluded from the very small $\hat{\alpha}$ (4.57 MW, when trade can be up to 2,000 MW in either direction),¹⁴ the almost perfect predictive power of the equilibrium trade level for the observed unconstrained trade levels ($\hat{\beta} = 0.99$) and the very low standard deviation ($\hat{\sigma} = 67.1$, again in MW). The value of $\hat{\beta}$ confirms the absence of any risk and related trading reduction.

Without market coupling in 2009 the constant still had a small (insignificant) value. But the estimate of $\hat{\beta}$ suggests traders would aim to achieve only 27% of the coupled equilibrium trade level the anticipation error has a very large standard error ($\hat{\sigma}$) of 3035 MW. The regression curve is shown in Figure 8. The relative risk aversion of the trader can be determined from (17) with $\hat{\beta}$ and $\hat{\sigma}$ by scaling the implicitly estimated absolute risk aversion λ with the average hourly trading revenue in 2009. The value of 2.61 is reasonable in terms of Ljungqvist & Sargent (2004, p. 426) as it lies in the interval [2,3]. It can be concluded that there is a significant risk of losses for traders and in anticipation they only take advantage of a small share of the opportunities a risk neutral trader would. We will refer to this effect as a trade crunch.

4.3. Simulation of Elecxit cost in 2030

We will now estimate the welfare effects of uncoupling the British electricity market from Europe. The analysis is based on the scenario ENTSO-E Vision 3 2030 (“National Green Transition”; ENTSO-E, 2015). The scenario is characterised by high CO₂ prices of 71€/tonne and low fuel prices. France halves its nuclear generation capacity (-30GW), builds up 60 GW renewables and doubles gas (+8GW). GB abandons coal (-16GW) and builds 57 GW renewables. This results in a merit order with

¹⁴ Our estimates are statistically significant, though this level of precision is quite common with 8,760 hourly observations per year.

gas before coal. Electricity is generated with a high share of renewables while electricity demand stagnates at the values of 2020 (details regarding France and Great Britain can be found in Appendix 2). For the simulation the step cost function of the scenario has been interpolated with an exponential function as in the previous section (capacities and marginal costs; figure 11). Load profiles and capacities for France and GB were taken from ENTSO-E. The Renewables.ninja dataset was used for national average capacity factors of solar PV (Pfenninger and Staffell, 2016) and wind (Staffell and Pfenninger, 2016).

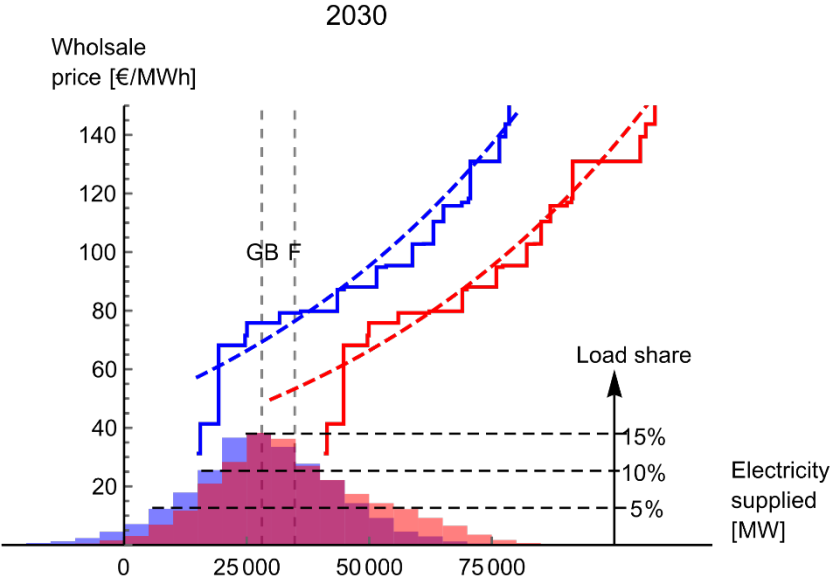


Figure 11: Marginal step cost curve of generation technologies from the scenario ENTSO-E Vision 3 in 2030 in France (red) and GB (blue); load distribution net of intermittent renewables from DESTINEE without axis labels; average annual load in France and GB as black dashed line.

We simulated generation costs for two-by-two market design and interconnector expansion scenarios for Europe and Great Britain in 2030. In the ‘Soft Elecxit’ scenario it is assumed that interconnector capacity will be expanded as planned to 10 GW and the day-ahead markets remain integrated. Effectively, this is a ‘Business as Usual’ scenario, but against a changing generation and demand background. In contrast, in the ‘Hard Elecxit’ Scenario interconnector capacity will expand only slightly, to 5 GW (see introduction)¹⁵ and the British day-ahead market will be decoupled using the Anglo-French market design of 2009. In particular, we assume that the markets close at the same times in 2030 as in 2009, which allows us to apply the estimates of the anticipation error based on 2009 data. We consider two subsidiary interconnector capacity scenarios: 3 GW of interconnection as in 2010 and - to estimate the cost of capacity constraints - a purely theoretical case with unlimited capacity (the last, rarely used, increments would never be economic).

A standard normally distributed anticipation error was drawn for every hour of 2030. To simulate the trade on uncoupled markets this basic error was scaled with 1. the estimated standard deviation (3000) from the previous section, 2. a scaling factor of 2 that reflects the higher share of difficult to predict renewable generation in 2030 (method and results in appendix I) and 3. the hourly weights ω_h that reflect the amplification of the anticipation error to the trading error via the structure of the residual load and the generation capacities in 2030. For the latter Figure 10 (blue curve) shows that the weights in 2030 on average exceed the weights in 2009.

¹⁵ The reduction in transmission capacity expansion is not due to a reduced profitability of the interconnectors, but an assumption that builds on higher project costs due to reduced EU venture financing.

The anticipation error was then used in (17) to simulate trading in uncoupled markets. To separate the impact of the anticipation error and the trade crunch, uncoupling was split into two steps (market design and reaction scenarios). Starting from ‘integrated markets’ ($\sigma = 0$, implying $\beta = 1$) first the anticipation error $\sigma = 3000$ was introduced and $\beta = 1$ was maintained (‘uncertainty’). This is equivalent to risk-neutral trading. Then β was lowered to 0.27 reflecting the transition to risk-averse trading. The latent trade was censored with the fully utilised transmission capacities, which depend on our capacity scenario. To reduce the impact of the specific draw of uncertainty, we took the average of results from the same 100 (yearly) draws across all scenarios.

As load is assumed not to react to price changes, country-specific hourly welfare is the sum of (negative) generation costs and half of the surplus from trade (we assume this is shared equally between the two transmission companies):

$$W_G(T) = -C_G(L_G - T) - \begin{cases} 1 & T \geq 0 \\ 1 - \tau & T < 0 \end{cases} T \frac{p_F(\varphi(-T)T) + p_G(T)}{2} \quad (19)$$

$$W_F(T) = -C_F(L_F + \varphi(-T)T) + \begin{cases} 1 & T \geq 0 \\ 1 - \tau & T < 0 \end{cases} T \frac{p_F(\varphi(-T)T) + p_G(T)}{2} \quad (20)$$

Overall welfare is the sum of country-specific welfare. Thus, the welfare effect of market coupling can be expressed as the difference in welfare between allocations.

The results of the simulations are shown in Table 5. Our two most important cases are shaded for emphasis. All costs are given relative to their values with integrated markets operating 10 GW of interconnector capacity. This represents pre-referendum expectations for 2030. As it remains a possible outcome of the process to decide the long-term position of the UK, we refer to it as “Soft Elecxit”. We refer to the worst case, with market uncoupling, little transmission expansion and reduced trading, as “Hard Elecxit”. This gives total generation costs which are 1.51% higher than with the business as usual “Soft Elecxit”.

		Trade specification		As in 2017 3 GW	Interconnector capacity		Theoretical Unlimited			
		Share of optimal trade β	Anticipation error st. dev. σ		Elecxit scenarios					
					5 GW	10 GW				
Market design and reaction	Uncoupled markets	U2 Trade crunch	27%	2 × 3000	GB + F Cost	€617m	Hard Elecxit	€563m	€516m	€511m
					%Δ from base	1.66%		1.51%	1.39%	1.37%
					GB Cost	€358m		€325m	€295m	€290m
		F Cost	€259m	€238m	€222m	€220m				
		U1 Uncert- ainty	100%	2 × 3000	GB + F Cost	€444m		€290m	€75m	€25m
					%Δ from base	1.19%		0.78%	0.20%	0.07%
	GB Cost				€264m	€175m	€42m	-€2m		
				F Cost	€180m	€114m	€33m	€27m		
	Integrated markets (I)	100%	0	GB + F Cost	€418m	€248m	0€	-€117m		
%Δ from base				1.12%	0.67%	0%	-0.31%			
GB Cost				€250m	€152m	0€	-€81m			
			F Cost	€168m	€96m	0€	€35m	Soft Elecxit		

Table 5: GB and France annual generation cost in 2030, relative to the Base Case (Soft Elecxit) scenario; the expected market value is €37.1Bio. Expectations have been generated as the mean of 100 random draws of the anticipation error in each hour of our annual series.

Comparing the entries along a row shows the impact of changing transmission capacity, holding trading uncertainty constant. With continued market coupling, expanding capacity from 3 GW to 10 GW would cut generation costs by 1.1% of their predicted 2030 level; further expansion until there were no constraints would save an additional 0.3%. Without market coupling, in contrast, expanding capacity from 3 GW to 10 GW would only reduce generation costs by 0.3%, and further expansion would bring practically no benefit.

Comparing the entries along a column shows how the cost of generation depends on the level of uncertainty facing would-be arbitrageurs. We find that the costs of uncoupling the British market are greater the more transmission capacity is available, but that the cost of uncoupling with a trade crunch brought about by risk aversion is noticeably higher than the additional cost brought about by increasing uncertainty by 2030.

We infer that when transmission capacity is low, this reduces both the benefits from trades in the correct direction and the costs of trades that are based on anticipation errors and the reduction of trade. Adding capacity increases the size of potential cost-saving trades, but our calibrated model suggests that trading errors will offset these gains. The gross saving per GW of additional capacity falls rapidly as capacity is added if markets are uncoupled, even before considering the costs of that capacity. If Britain is to give up the most effective mechanism for coordinating cross-border electricity trade, we should not invest too much in trying to increase the volume of that trade. Low interconnector capacities limit the damage that can result from anticipation errors.

Splitting the results by country, GB carries 60% of the efficiency losses. This slightly higher share results from the higher import dependency of the UK. Generally, figure 10 shows that while residual load differs only little between GB and France in 2030, France's continued use of 37 GW nuclear generation means UK prices (frequently) exceed French prices. Therefore, reducing trading opportunities tends to force GB to use its more expensive generation and increases GB costs. Compared to the Soft Elecxit, a Hard Elecxit scenario would reduce British welfare by over €300m while French welfare would fall by over €200m per year.

5. Conclusion

To calculate the costs of Great Britain's possible departure from the EU's internal electricity market, we start by designing a microeconomic model of the decoupled markets between Great Britain and France in 2009. Due to different market closing dates in these countries, an early commitment and the anticipation of market prices was required to determine interconnector capacity demand. Therefore, the demand on the spot markets is not completely common knowledge at the time when trades across the interconnector must be decided, and traders must consider the risk of anticipation errors. The resulting uncertainty is added to the load as a zero mean, normally distributed disturbance, with variance that is a measure of the extent of the trade barrier. While certainty equivalence applies to expected profits, it is optimal for risk-averse traders to scale back their desired quantities to reduce the variance of their profits.

In practice, the errors mean that desired trades will be too great or too small, but the effect of these errors will be limited by the need to respect interconnector capacity constraints. If the desired trade is far greater than the available capacity, then the actual trade would be sub-optimal only if there had been a very large error in the information on which it was based. We use a TOBIT regression to estimate the level of uncertainty in 2009 between the two uncoupled markets. We find an anticipation error equivalent to load mis-forecasting with a standard deviation of 3GW and find

strong evidence of risk averse trading. Thus trade ‘crunches’ to 27% of risk neutral trading opportunities.

We adjust these estimates for the greater uncertainty that high penetrations of wind and solar generators will induce by 2030 and apply our model to the ENTSO-E Vision 3 scenario for 2030. We estimate that a “Hard Elecxit”, with little interconnector expansion and decoupled markets, would raise generation costs by €560m per year (1.5% of the common market value), relative to a “Soft Elecxit” which retains business as usual, with coupled markets and interconnector capacity rising to 10 GW. Building more interconnector capacity creates little value if trading arrangements lead to substantial trading errors and strongly reduced trading. 60% or €300m of these welfare losses occur in Britain.

Our estimate is based on extrapolating errors in the bilateral trading between France and Great Britain from 2009, and scaling these to represent future conditions. In practice, Great Britain already has interconnectors to three EU countries (France, Ireland and The Netherlands). More are planned, and those in the near-term are still anticipated to go ahead regardless of the Brexit outcome (Mathieu *et al.*, 2018). This suggests that a multilateral model might be useful to capture the interactions between these, although trading errors would all be driven by the same incorrect expectation of British net demand. We plan to use such an approach in future work, which will also allow us to focus on the island of Ireland, where the Irish Republic and Northern Ireland currently share a joint market. Disruption to that market might be significantly costlier, in proportion to the industry’s turnover, than a British Elecxit.

Our analysis focuses on day-ahead markets only. An anonymous referee has pointed out that forward contracts, either Financial Transmission Rights or matched Contracts for Differences to buy power in one country and sell it in the other, might provide the risk hedging needed to increase the volume of trade. The social value and pricing of such contracts deserves further study. In the short-term markets, National Grid (2015, table 1) concludes that sharing reserves over interconnectors might reduce capacity needs by several GW. Further research should extend our analysis to intraday, balancing and reserve markets to further refine our estimates of the possible cost of Elecxit.

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Appendix I: Variance of the anticipation error

We have extensively used the anticipation error of residual load ε_h with $\varepsilon_h \sim N(0, \sigma^2)$. We now provide a background for its variance σ that enables a systematic derivation of a scenario dependent anticipation error. Residual load in a specific country and hour h , L_h consists of the load l_h reduced by wind generation G_h^{Wind} and solar generation G_h^{Solar}

$$L_h = l_h - G_h^{Wind} - G_h^{Solar} \quad (a)$$

Each component is uncertain, and we assume has an independent normal distribution with a standard deviation proportional to its expected level in each period. We break the per-unit uncertainty into two, so that the anticipation error for load is equal to $\varepsilon_{l,h} \sigma_l l_h$ where $\varepsilon_{l,h}$ is a standard normal variable and σ_l is the constant per-unit standard deviation of the anticipation error. We use ε_{Solar} and ε_{Wind} to denote the random components while σ_s and σ_w are the constant per-unit standard deviations of solar and wind generation, respectively. Under these conditions expected residual load can thus be expressed with the residual a_c as (omitting the hour index h):

$$L_h + a_h = l_h(1 + \sigma_l \varepsilon_{l,h}) - G_h^{Solar}(1 + \sigma_s \varepsilon_{Solar,h}) - G_h^{Wind}(1 + \sigma_w \varepsilon_{Wind,h}) \quad (b)$$

It is straightforward to show that the residual $a_h \sim N(0, l_h \sigma_l + G_h^{Wind} \sigma_w + G_h^{Solar} \sigma_s)$. In this sense we use $\sigma_h = l_h \sigma_l + G_h^{Wind} \sigma_w + G_h^{Solar} \sigma_s$. Unfortunately, σ depends on the time varying generation levels. To simplify the analysis, we approximate with a least squares estimation with $a_{wl} = \frac{\sigma_w}{\sigma_l}$ and $a_{sl} = \frac{\sigma_s}{\sigma_l}$ to get the static

$$\sigma_h \approx \sigma = \sigma_l \frac{\sum_{h=1, \dots, H} (l_h + G_h^{Wind} a_{wl} + G_h^{Solar} a_{sl})}{H} = \sigma_l (\bar{l}_{UK} + a_{wl} \bar{G}_h^{Wind} + \bar{G}_h^{Solar} a_{sl}) \quad (c)$$

As we have already estimated the standard deviation of this anticipation error in section 4.2 we do not need the absolute value of σ but rather the ratio between 2009 and 2030. With the parameters in Table A1, we obtain for GB:

$$\frac{\sigma^{2030}}{\sigma^{2009}} = \frac{\bar{l}^{2030} + a_{wl} \bar{W}^{2030} + a_{sl} \bar{S}^{2030}}{\bar{l}^{2009} + a_{wl} \bar{W}^{2009} + a_{sl} \bar{S}^{2009}} \approx 2^{16} \quad (d)$$

The change in generation structure with more renewables will double the anticipation error in 2030 compared to 2009. 2030 values are the annual averages of load and generation for renewables from the scenario in appendix II.

Parameter GB		2009	Scenario 2030 ^{d)}
Average annual load (GW)	\bar{l}	37.1	40.5
Average annual wind generation (GW)	\bar{W}	1.01	18.2
Average annual solar generation (GW)	\bar{S}	0	1.7
Relative forecasting error wind	a_{wl}		4 ^{a)}
Relative forecasting error solar	a_{sl}		2 ^{b)}

Table A1: Model parameters.

^{a)} Hodge et al (2012).

^{b)} Lew et al (2013).

^{d)} Scenario data from appendix II, table A2

¹⁶ The value of 2.8 was rounded down to incorporate advances in forecasting accuracy.

Appendix II: Parameters of the scenario ENTSO-E Vision 3 – 2030

	Generation Capacity [GW]				Annual generation [GWh]	
	France		GB		GB	France
	2017	2030	2017	2030	2030	2030
Gas	6,696	14,051	34,400	36,616	75,370	15,077
Hard coal	2,930	1,740	16,704	0	22,260	60,092
Hydro	23,522	27,200	4,360	7,682	0	0
Nuclear	63,130	37,646	9,361	9,022	61,632	255,886
Oil	5,300	819		75	0	0
Other non-RES		5,400		4,110	10,413	12,826
Solar	378	24,100	2,172	15,560	15,316	30,191
Wind	1,578	36,600	6,814	51,090	159,785	87,438
Other RES		4,800	5,964	8,420	39,120	18,123
Annual demand					354,408	479,198

Table A2: Assumed generation capacity and mix. RES = Renewable energy sources. Source: ENTSO-E, 2015: "TYNDP 2016, Scenario Development Report", European Network of Transmission System Operators for Electricity (ENTSO-E). Data UK 2017: National Statistics Digest of UK Energy Statistics (DUKES): electricity DUKES chapter 5: statistics on electricity from generation through to sales. <https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes>. Data France, 2017: RTF.

Nuclear	0.46	€/GJ
Hard Coal	2.8	€/GJ
Gas	7.23	€/GJ
Light oil	13.26	€/GJ
Heavy oil	9.88	€/GJ
Oil shale	2.3	€/GJ
CO ₂ Price	71	€/tonne

Table A3: Assumed fuel and carbon prices. Fuel quoted against net calorific content (lower heating value).