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The Impact of Unilateral Carbon Taxes on Cross-Border Electricity Trading

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Keywords Carbon tax; Interconnectors; Cost-benefit analysis; M-GARCH

JEL Classification Q48; F14; D61; C13

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The Impact of Unilateral Carbon Taxes on Cross-Border Electricity Trading*

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May 31, 2019

Abstract

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Keywords: Carbon tax; Interconnectors; Market Coupling; Cost-benefit analysis; MGARCH

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1 Introduction

Interconnectors link two electricity systems and create value by enabling the market with the higher price to import cheaper electricity from its neighbour. Efficient systems dispatch generation units in increasing offer price order, with fossil plant typically at the margin. A carbon tax increases the cost of fossil generation and we would expect this to raise their offer prices.

From April 2013 the UK government has imposed an carbon tax (in addition to the EU carbon price, see Figure 2) on generation fuels in GB (but not Northern Ireland). This paper studies the impact of asymmetries in carbon taxes between connected countries on cross-border electricity markets. It takes Great Britain as a case study and demonstrates how the unilateral imposition of a carbon tax affects electricity prices, interconnector flows, congestion income (from the difference in price across congested interconnectors), and deadweight loss. The paper uses econometric methods to estimate the extent to which the carbon tax increases domestic wholesale prices. Our model allows us to identify the impact on price differentials across interconnectors and to estimate the extent to which the carbon tax distorts trade and impacts the social and private benefits of interconnectors. The paper draws critical policy implications that are useful for designing carbon taxes, cost-optimal electricity markets, and efficient electricity trading.

1.1 Literature review

The value of interconnectors and the benefit of market coupling have been widely studied (e.g. National Grid, 2014; Policy Exchange, 2016; Redpoint, 2013; Pöyry, 2016). Newbery et al. (2019a) examine the efficiency and value of trading of GB interconnectors over different timescales. They find that market coupling made trading over IFA and with the SEM much more efficient and discuss the importance of harmonising carbon taxes across the EU. Other studies (e.g. Gugler et al., 2018; Keppler et al., 2016) focus on the integration of electricity prices across the European electricity markets. They find that the increasing penetration

of renewable energy counters the trend of increasing price convergence, and building more interconnectors would improve price convergence.

Previous studies concerning carbon taxes have so far focused on their impact on wholesale prices (e.g. Wild et al., 2015; Castagneto Gissey, 2014; Freitas & Da Silva, 2013; Jouvet & Solier, 2013; Kirat & Ahamada, 2011; Fell, 2010; Sijm et al., 2006), on the fuel mix and greenhouse gas emissions (e.g. Di Cosmo & Hyland, 2013; Chyong et al., 2019; Staffell, 2017), and on investment decisions within the power sector (e.g. Richstein et al., 2014; Green, 2018; Fan et al., 2010).

To the best of our knowledge, there is no *ex-post* econometric estimation of the effect of a carbon tax on cross-border electricity trading after market coupling, nor of the deadweight loss involved when applying carbon taxes asymmetrically across two electricity markets.

1.2 Research questions

The CPS increases GB electricity prices, which increases imports from France and the Netherlands. Since the GB price was on average higher than both the French and Dutch prices before the implementation of the CPS, the main effect of the CPS on cross-border trading is to widen price differentials and increase congestion income. This paper investigates the impact of the British CPS on GB day-ahead market prices and cross-border electricity trading. It also considers how a unilateral carbon tax would affect congestion income, the degree to which this additional cost of carbon has been passed through to the cross-border markets, and its deadweight cost.

1.3 Electricity trading between connected markets

Interconnector capacities are sold forward in auctions for Transmission Rights held at various timescales ranging from year-ahead, to season-ahead, quarter-ahead, month-ahead and day-ahead. Once markets are coupled, the day-ahead market becomes an implicit auction cleared

with other wholesale markets. The price realised in this implicit auction is then used to clear all forward contracts, with physical contracts reverting to financial rights. In addition, adjustments after the closure of the day-ahead market (DAM) are cleared in the intraday markets.[1]

Electricity is also traded forward in each country on power exchanges and over-the-counter (OTC). The standard forward contract where there is a liquid spot market is the Contract-for-Difference (CfD), which specifies a quantity, M, and a strike price, s. Denoting the spot price as p, the seller sells in the spot market at p and receives $s - p$ from the buyer (a possibly negative amount, in which case $p - s$ is paid for the M units).

If the markets are not coupled, the holder of the Physical Transmission Right (PTR) for the right to import into GB will look at the day-ahead spot prices in France and GB, and exercise the option to import if the French price is below the GB price, and will abstain from nominating flows otherwise. If the importer has already bought French electricity ahead of time at a favourable price and has sold forward in GB at a price exceeding the PTR price, the importer may choose to import even if the spot price difference is unfavourable. In this case, one would observe a Flow Against Price Difference (FAPD). Given the risks involved in trading in three markets (two power exchanges and one interconnector auction) at different times, risk-averse traders may not purchase the full capacity on the interconnector auction unless its price is sufficiently below the forward price differences. Similarly, the risks of buying ahead on power exchanges before the interconnector auction clears may inhibit trade up to the interconnector's full capacity. In both cases, interconnectors will be inefficiently under-used or will flow in a wrong economic direction.

Once the markets are coupled, the spot markets and the interconnector are cleared in a simultaneous auction designed to maximise overall social surplus (the excess of willingness to pay over the cost of supply) and hence make efficient uses of the interconnectors (ACER,

[1] Article 51 of Commission Regulation (EU) 2016/1719 establishing a guideline on Forward Capacity Allocation sets out the harmonised allocation rules for long-term transmission rights, which may be either physical or financial. A more detailed example on interconnector trading can be found at https://www.ofgem.gov.uk/ofgem-publications/98321/proofofflowundermarketcoupling-europeeconomicreport-pdf.

2017).

2 Market coupling

Starting from 4 February 2014, electricity market coupling in North Western Europe went live. Great Britain, France, and the Netherlands took part in this initiative, while on the island of Ireland the Single Electricity Market (SEM) was not integrated until 1 October 2018. Following market coupling, bids to buy and offers to sell are fed into a European-wide auction, which operates using the EUPHEMIA algorithm.[2] Each market operator solves for its own area price at which the area's supply and demand equate. When different market prices across the interconnector occur, EUPHEMIA yields a "price-independent purchase" in the low-priced area and a "price-independent sale" in the high-priced area, corresponding to the interconnector's Net Transfer Capacity (NTC). As a result, prices in the higher-priced market decrease, and prices in the lower-priced market increase. If the prices do not converge, then the entire NTC is allocated and prices remain different in the two zones, but if the prices can be equilibrated with a smaller flow than NTC, that flow is allocated to create a single price zone across the interconnector, namely the connected markets are *integrated*.

Figure 1 plots the day-ahead commercial forecast of the net imported flow via the interconnector between GB and France, before and after market coupling. There are four cables of 500 MW each for a total of 2 GW, hence the horizontal bands of observations at multiples of 500 MW are due to one or more cables under maintenance or because of network limitations. In 2013, before market coupling (Figure 1a), capacity was inefficiently used with many FAPDs, while after market coupling (Figure 1b) available capacity was efficiently used with no FAPDs.

The day-ahead commercial forecast that allocates capacity to the DAM can differ from the final recorded cross-border physical flows because market players can buy and sell intraday

[2]The EU Pan-European Hybrid Electricity Market Integration Algorithm (EUPHEMIA) solves trading inefficiencies containing hundreds of thousands of orders and thousands of block and complex bids in less than ten minutes, in line with day-ahead operational timing.

(a) Pre-coupling, 2013 (b) Post-coupling, 2017

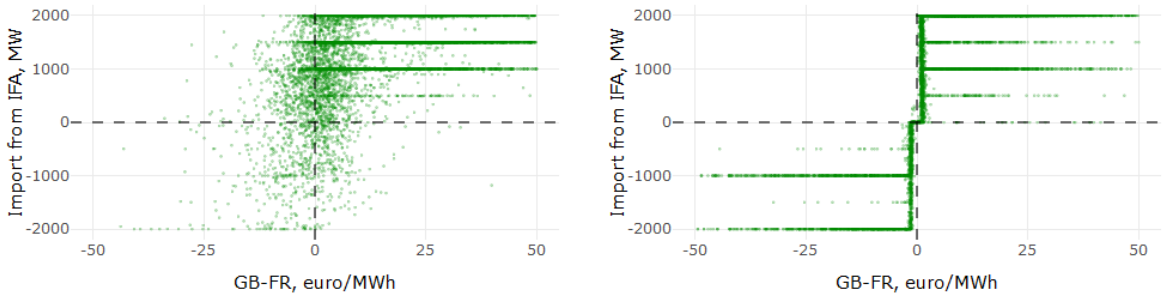

Figure 1: Commercial forecasts of IFA flows v.s. GB-FR price differentials, before and after market coupling

Source: Commercial forecasts from RTE; day-ahead GB prices from Nord Pool; day-ahead French prices from EPEX Spot.

capacity as they receive updates on renewable generation, demand changes or plant outages. The System Operators may also intervene to balance one or both systems, although balancing markets are mostly not yet fully coupled through cross-border markets.[3,4] The actual flow will be the sum of the day-ahead, intraday and balancing flows, and any difference between the day-ahead and actual flow should corresponds to intraday nominations. Intraday flows may be hedged by buying and selling in the intraday market, or settled in the balancing market. In this paper, we focus on the day-ahead market and on the GB interconnectors that have been coupled since 2014 (i.e. IFA and BritNed).

2.1 The British Carbon Price Floor

The British Carbon Price Floor (CPF) was announced in the 2011 Budget and came into effect in April 2013. It was intended to make up for the failure at that time of the EU ETS to give

[3]The SEM and GB do operate a joint balancing market.

[4]A project named Trans European Replacement Reserves Exchange (TERRE) was approved by ENTSO-E as an Implementation Project in 2016. The project aims to fulfil a European legal requirement imposed by the European Electricity Balancing Guideline. The project is expected to go live in the fourth quarter of 2019.

adequate, credible and sufficiently durable carbon price signals. The CPS was implemented by publishing a GB[5] Carbon Price Support (CPS) that is added to the EU ETS price to increase it to the projected CPF. The CPS grew from £4.94/tCO_2 in 2013 to £18/tCO_2 in 2015 (and has been frozen at £18/tCO_2 since then). The total GB carbon price has risen from £5/tCO_2 in early 2013 to nearly £40/tCO_2 by the end of 2018. Figure 2 shows the evolution of the (nominal) GB and the EU carbon costs in £/tCO_2. The two curves start diverging in 2013, with the gap becoming wider in 2014 and 2015. The dashed line represents the GB carbon cost target when the CPF was announced. It was not until late 2018 that the GB carbon cost finally met the initial trajectory, thanks to the reform of the EU ETS, which introduced a *Market Stability Reserve* that removes excess EUAs and increases the EUA price (Newbery et al., 2019b).

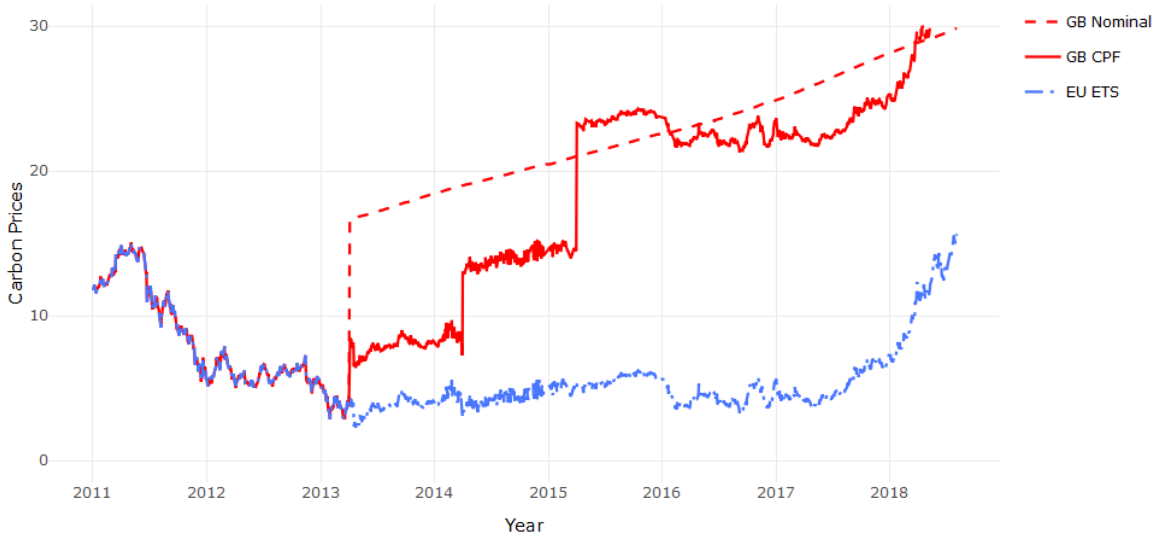

Figure 2: Evolution of the European Allowance (EUA) price and CPF, £/tCO_2

Source: Chyong, Guo and Newbery (2019).

The CPS raises the cost of fossil-fuelled electricity generation. Figure 3 plots the 28-day moving average (MA) of the day-ahead prices for GB, France (FR), and the Netherlands (NL),

[5]Northern Ireland, which is part of the Single Electricity Market of the island of Ireland, is exempt to preserve an equal carbon price there.

as well as the price differentials between the two connected markets. It also shows the variable cost for Combined Cycle Gas Turbines (CCGTs) with 50% (LHV) efficiency with EUA prices included (but excluding the GB CPS) as a measure of Continental gas generation costs.

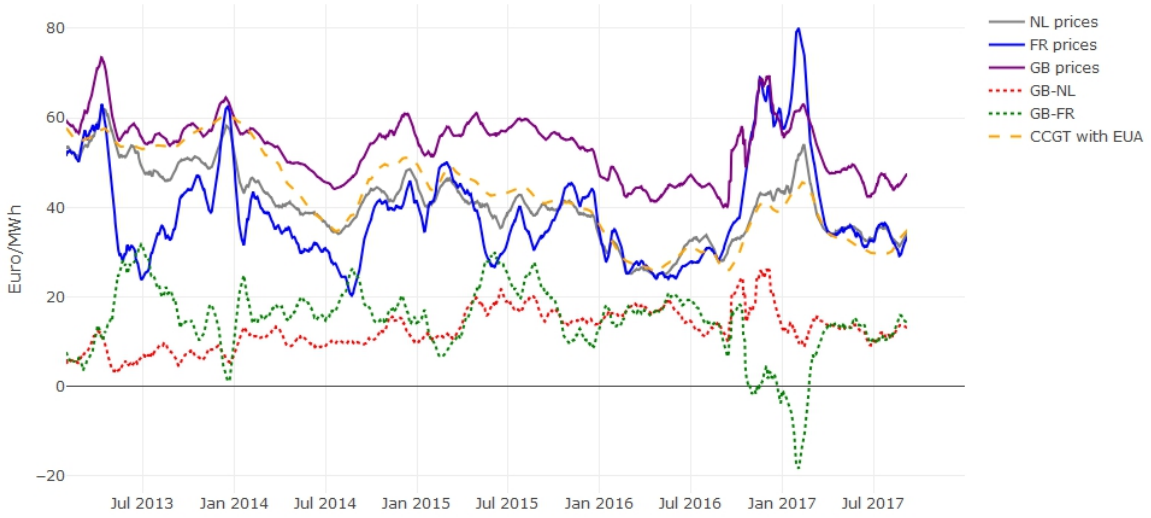

Figure 3: 28-day lagged Moving Average wholesale prices, 2013-2017

In general, while GB prices are typically higher than NL prices, the CPS widens the GB-NL price differential. French prices are much more volatile than that in GB and the Netherlands mainly because nearly 80% (in 2015)[6] of its gross electricity generation comes from nuclear power stations, meaning that its electricity system is not as flexible as that in GB and the Netherlands, resulting in more volatile prices. Another reason for the high volatility is that French prices are very weather-sensitive given their high domestic electrical heating load. In the winter of 2016 and 2017, France experienced nuclear outages,[7] which explains the negative GB-FR price differential during that period. The variable cost for CCGTs partially explains the patterns of prices for the three markets, and best fits the dynamics of the Dutch prices, where gas is likely to be the marginal fuel much of the time.

The higher GB carbon price (equivalently, the lack of an EU-wide CPS) distorts trade and

[6]From Eurostat at: https://ec.europa.eu/energy/en/news/get-latest-energy-data-all-eu-countries.
[7]See https://www.ft.com/content/f86a3c6c-9c60-11e6-a6e4-8b8e77dd083a.

could harm price convergence from market integration between the GB and Continental electricity wholesale markets.

2.2 The impact of a carbon tax

This section illustrates the diagrammatic illustration of the impact of a carbon tax on domestic prices, the offers into the day-ahead market (DAM) and the resulting cross-border electricity flows. Generators offering into the DAM will likely mark-up their offers above the short-run marginal cost to recover start-up and fixed costs (and possibly further if exercising market power). Adding the CPS increases short-run marginal costs but generators may absorb some of the tax by marking up their offers by a smaller amount. In the absence of any trade, the cost pass-through of the CPS would then be less than 100%. Chyong et al. (2019) estimated the increase in marginal costs by finding the system marginal CO_2 emissions factor in each hour and multiplying it by the CPS. This paper uses econometric methods to measure the increase in the GB wholesale price resulting from the CPS holding interconnector flows constant. This allows us to measure the domestic cost pass-through as a percentage of the system marginal cost increase. If the cost pass-through rate is less than 100% and domestic demand is insensitive to wholesale prices, the domestic impact of the CPS will be to reduce the deadweight loss of imperfect competition. If domestic demand is reduced with increased wholesale prices, then there will be an additional and off-setting increase in consumer deadweight loss.

Interconnectors complicate this simple single market story. The increase in GB offer prices into the DAM will change the market clearing price and hence the congestion revenue. If the CPS does not change flows (because before and after the CPS the interconnector capacity remains fully used in the same direction) there will be no additional distortion but there will be a transfer of revenue to the foreign owners of the interconnectors (both IFA and BritNed are shared 50:50 with the foreign TSO). If flows change then there will be an additional deadweight loss. Again if demand is inelastic, the deadweight loss will be the difference in the total cost of

generation with and without the CPS.

Figure 4 shows the result of imposing the CPS on GB generators when the import capacity over IFA from France (FR) is KL. If there were no interconnector, the GB price would be P_0^{GB} where the GB net supply GHI meets demand D_0 at I. With the interconnector, the GB net supply curve meets the FR net supply curve at point H, with prices equalised (P_1^{GB}=P_1^{FR}), no congestion revenue and imports ML. Under the assumption of zero consumer demand elasticity (i.e. vertical demand curves), the gain in surplus created by the interconnector is entirely due to a reduction in GB generation costs, offset by a small increase in FR cost, with the net cost reduction shown as the triangle labelled "original market surplus", or HIJ.

After the introduction of the CPS, the GB supply curve shifts upward to AN and the interconnector is now fully utilised with imports KL. The GB wholesale (or consumer post-tax) price is P_C^{GB} but the producer price (before tax) is PP_C^{GB}. The FR price rises to P_C^{FR} and the congestion revenue equals KL $\times$ ($P_C^{GB}-P_C^{FR}$), or the rectangle ABCE. However, while the GB generation costs has fallen, the FR cost has risen and the total increase in cost is the triangle HEG, which corresponds to a deadweight loss.

The deadwight loss can be estimated if we can measure the price differential with the carbon tax (or AE in Figure 4) and the impact of the CPS on GB prices (or AG in Figure 4). Under the assumption of linear net supply curves, given the increase in import is KM, then the deadweight loss is 1/2$\times$(AG-AE)$\times$KM. It is also worth noticing that the base of the triangle, AG-AE or EF is the sum of the reduction of the GB price due to the increase in imports ($P_1^{GB}-PP_C^{GB}$) and the increase in the FR price due to its increase in exports ($P_C^{FR}-P_1^{FR}$). We name this the CPS pass-through via the interconnector, and its ratio to the impact of the CPS on GB prices, or EG/AG, is the CPS pass-through rate.

The typical way to estimate deadweight loss is the distortion (e.g. the tax wedge AG) times the change in output (KM), assuming consumption and production are equal (the standard closed-economy model). However, in this case consumption remains unchanged at D_0 (because

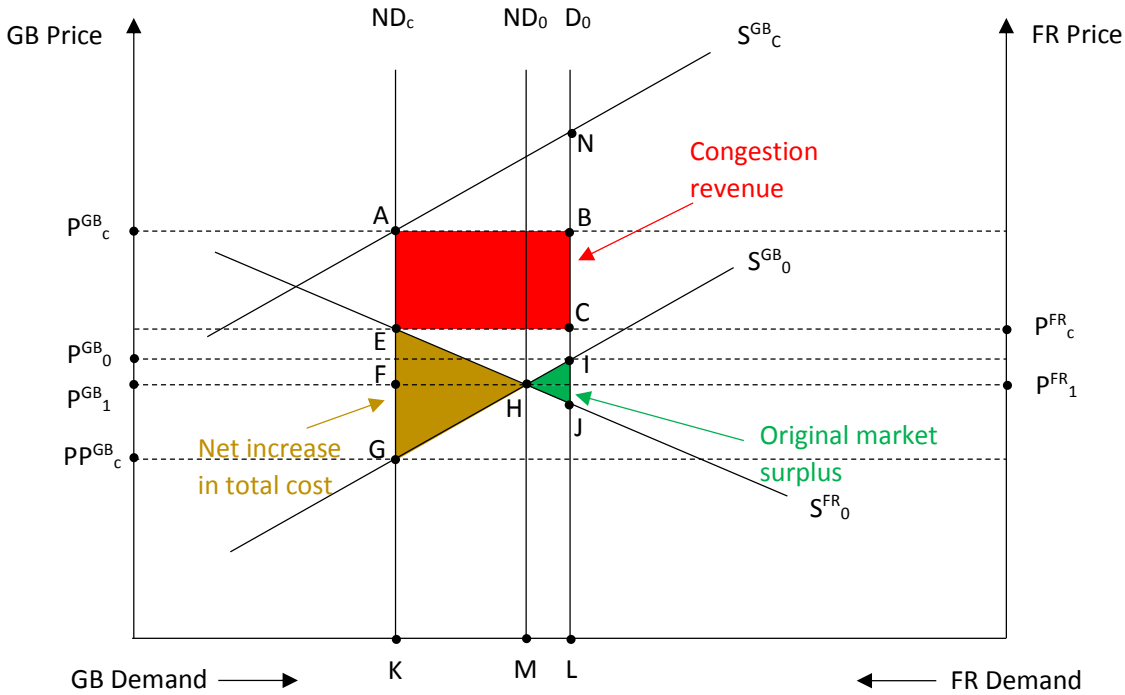

Figure 4: Impact of CPS on Imports and Surpluses, GB Imports from Partial to Full Capacity

of its assumed inelasticity) while GB production falls by KM and FR production increases by the same amount, giving the total deadweight loss as the triangle HEG.

The carbon tax also leads to an increase in congestion revenue increases but half of this increase goes to the French TSO, the half-owner of IFA. French prices rise from P_1^{FR} to P_C^{FR} increasing FR generator profits by less that the increase in consumer costs (the difference being the French share of the total deadweight loss).

Similar diagrams can be drawn for other cases (GB initially exporting, the direction of trade flows changed but not reversed, etc.), but the cost-benefit principles remain the same. Details of other cases can be found in the Appendix. If we ignore differences between offer prices and marginal costs and assume inelastic final consumer demand, then the benefits of the interconnectors are the total reduction in generation costs, which correspond to the fall in the importer's (higher) cost less the increase in the exporter's (lower) cost. The CPS changes this and reduces this gain as it substitutes some higher actual cost imported generation for some

lower actual but higher tax-plus GB generation cost. This is with the proviso that all costs should be measured with the correct carbon prices, and we have assumed that the no-CPS equilibrium trade is the same as the correctly carbon-charged trade.

2.3 Estimating the impact of the CPS

Figure 5 plots the Price Differential Duration Schedules (PDDS) of IFA (GB *minus* FR, or PD^{IFA}) before (2013) and after (2017) market coupling. The difference between the two curves is that after market coupling, the price differentials cluster around the horizontal line at zero (Figure 5b). The reason is that there are many hours for which there is sufficient capacity to equalise GB and French prices, while it is most unusual for prices to be the same for the uncoupled 2013 PDDS (Figure 5a). The line at $PD^{\text{IFA}} = 0$ is not perfectly horizontal because the prices are equated based on Mid Channel nominations and then adjusted at each end by a loss factor to give prices in each country. In this study, the unadjusted price differential is used in our econometric analysis as it reflects the direction of flows.

(a) Pre-coupling, 2013 (b) Post-coupling, 2017

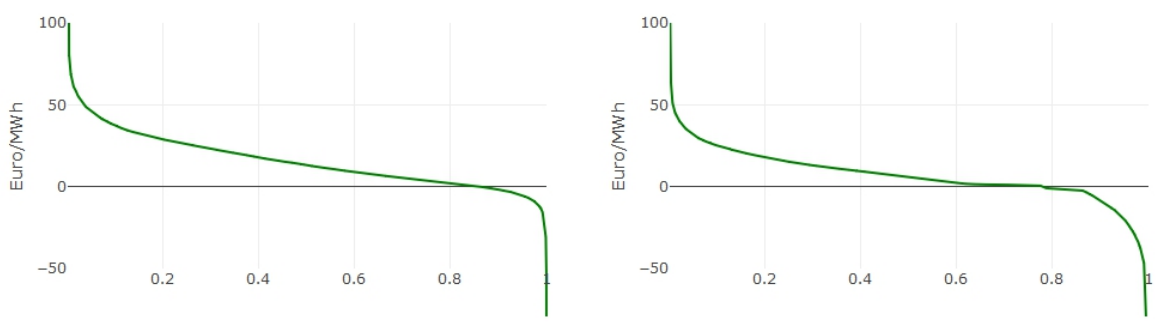

Figure 5: Price Differential Duration Schedules for IFA Price Differential (GB-FR) , 2013 v.s. 2017

Source: Day-ahead GB prices from Nord Pool; day-ahead French prices from EPEX Spot.

Without the British CPS (while keeping the interconnector flow constant) the entire PDDS

curve for 2017 (Figure 5b) would shift downwards, as illustrated in Figure 6. If the market is then coupled, GB would keep exporting with full capacity at a price difference AB and keep importing with full capacity at price difference CD. The outcome is more complex at price difference BC, where with CPS, GB was either importing or exporting at less-than-full capacity. At price difference BC, if the maximum 4 GW switch (from 2 GW to -2 GW) of the interconnector flow is sufficient to integrate the prices, the price differential for that hour would cluster at zero. If instead the 4 GW is insufficient to equalise the prices, GB would be exporting at full capacity and the price differential would fall to a negative value. For instance, suppose that the impact of flows on PD^{IFA} is €2/MWh/GW and that with the CPF applying, for a particular hour GB imports 0.5 GW and the GB and French markets are integrated. Now, if without the CPS the GB price would fall by €7/MWh, GB would be exporting at full capacity (2 GW) in that hour. The resulting 2.5 GW shift in the interconnector flow would, as a result of price changes, lead to PD^{IFA} falling back to €-2/MWh ($= -7 + 2.5 \times 2$).

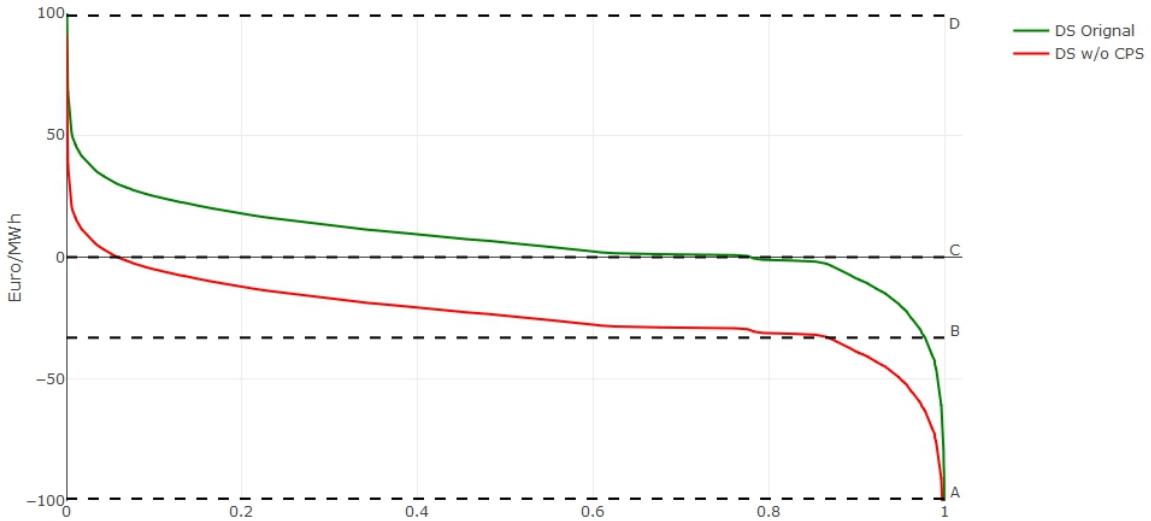

Figure 6: The Price Differential Duration Schedules with and without the CPS

The example in Figure 6 warns us against determining the impact of the CPS on interconnector flows without considering the impact of flows on the price differential. Chyong et al.

(2019) examine how the CPS affected flows via IFA in 2016, and find that it raised the GB system marginal cost by roughly £7/MWh,[8] which, if translated into an equal price increase would result in an increase in IFA's congestion revenue of about €76 million for 2016. However, this estimate assumes a 100% CPF pass-through rate to the GB wholesale price, a plausible but testable assumption for a workably competitive market like GB (CMA, 2016).

In contrast to Chyong et al. (2019), we relax the 100% CPF pass-through rate assumption and use econometric methods to estimate that impact. Specifically, we first estimate the impact of interconnector flows and the CPS on the IFA and BritNed price differentials, thereby obtaining the proportion of CPS that has been passed through to the GB day-ahead price. Using the regression results, we implement the following three-stage process. First, we estimate PDDS's without the CPS *holding flows at its original value*. Second, we re-couple the interconnector markets, with any changes in flows further influencing the price differentials. Third, using the estimated price differentials and flows without the CPS but under market coupling, we evaluate the impact of the CPS on net imports, congestion income, the carbon cost pass-through rate to the cross-border market, and deadweight loss. We estimate he impacts on both interconnectors, providing evidence for carbon pricing policy.

The first challenge is that the day-ahead capacity auction is an implicit auction, which means both day-ahead market prices and day-ahead flows are determined simultaneously, resulting in simultaneous equation issues. Finding proper instrumental variables for the day-ahead flows is difficult because under market coupling, the day-ahead flows are only determined by the price differentials between day-ahead prices, which are the dependent variables. We address this by using the day-ahead forecast of net transfer capacity (NTC) as regression covariates instead of the day-ahead flow. NTC is only influenced by outages, maintenance or network limitations and so can be treated as exogenous. The estimated impact of NTC on the market spread allows us to estimate how flows would affect price differentials. For example,

[8] Chyong et al. (2019) estimated the marginal CO_2 emission factor and multiplied this by the CPS to calculate the increase in the system marginal cost

suppose 1 GW of *IFA capacity* lowers the price differential, PD^{IFA}, by €1/MWh, and the average IFA flow is 1.2 GW. If the average NTC for IFA is 1.5 GW (i.e. GB net imports are on average 80% of average NTC), then a 1 GW change *in the flow* would result in a €1/MWh/(80%) = €1.25/MWh change in PD^{IFA}.

The second challenge is that the econometric model only allows us to estimate the *partial* effects of the CPS on price differentials *conditional on the NTC* and the *partial* effects of the NTC on price differentials *conditional on the CPS*. Therefore using regression results to calculate the second-stage (in the three-stage) process could be invalid. We deal with this issue by assuming that the impacts of interconnector flows on price differentials are independent of the CPS.[9] In other words, we assume that with the CPS, a 1 GW flow would have an identical impact on the price differential as it would on the price differential without the CPS.[10]

3 Econometric Models

In this section, we study the impact of interconnector flows and the British CPS on the day-ahead price differentials between the connected market (in €/MWh).[11] As electricity supply has to meet demand at every second, prices are highly volatile, and so are price differentials. To deal with this, we implement the Multivariate Generalised Auto-Regressive Conditional Heteroskedasticity (M-GARCH) model (Silvennoinen & Teräsvirta, 2008), which accounts for variations in both the mean and volatility of electricity prices. The model has been widely used

[9] Chyong et al. (2019) used the three-stage processes but in a different order: they first estimate the duration schedule curve without the interconnector and then estimate the impact of the CPS on the price differential. This is justified under the assumption of a 100% CO_2 pass-though, which is not conditional on the IFA transfer capacity.

[10] This assumption can be challenged by the fact that the CPS might change the merit order of fossil plants. In later econometric analysis, we implement Likelihood Ratio (LR) tests to test the null hypothesis that the impact of NTC on the price differential is independent of CPS, see Appendix. All tests do not reject the null.

[11] An alternative is to study those impacts for each country separately, but that may raise the following issues: first, we use the estimation results to estimate the impact of the CPS on cross-border trading, which is only determined by price differentials between the two connected markets. Estimating the effects on each country and then combining the results is less efficient than directly estimating the impact on price differentials. Second, it ignores the price comovements between the connected countries caused by variables that are not included in the regression (such as temperature). Third, due to the limited variation in the CPS, directly estimating the impact of the CPS on France and the Netherlands would deliver results that are not statistically significant.

to model day-ahead electricity prices (e.g. Kirat & Ahamada, 2011; Anna-Phan & Roques, 2018).

Hourly prices for the next day are all set simultaneously in the day-ahead auction. As a result, within a day the price for any hour does not carry much information about the next hour (Keppler, 2014; Würzburg et al., 2013; Sensfuss et al., 2008), hence neither does the day-ahead price differential. As a result, instead of treating the price differentials as an hourly univariate time series, we treat them as daily multivariate time series. In this paper, to substantially reduce the number of parameters to be estimated, we assume that during peak hours the electricity system exhibits similar scheduling behaviour and so it does during off-peak hours. Therefore, we distinguish the hourly price differentials by peak (06:00-22:00 UTC) and off-peak (22:00-06:00 UTC) periods of a day.[12] For each interconnector, there are two time series (peak and off-peak) describing the price differentials. Then, the models we estimate are bivariate GARCH models (i.e. $n = 2$) whose *mean equation* can be specified as,

$$\boldsymbol{y}_t = \boldsymbol{\mu} + \sum_{i=1}^{m} \boldsymbol{\Phi}_i \boldsymbol{Y}_{t-i} + \boldsymbol{\Gamma} \boldsymbol{X}_t + \boldsymbol{\varepsilon}_t, \tag{1}$$

and where

$$\boldsymbol{y}_t = \boldsymbol{PD}_t^{\text{IFA}} = \begin{pmatrix} PD_t^{\text{IFA,PEAK}} \\ PD_t^{\text{IFA,OFF}} \end{pmatrix} \quad \text{or} \quad \boldsymbol{y}_t = \boldsymbol{PD}_t^{\text{BN}} = \begin{pmatrix} PD_t^{\text{BN,PEAK}} \\ PD_t^{\text{BN,OFF}} \end{pmatrix}$$

where

$$PD_t^{\text{IFA},i} = P_t^{\text{GB},i} - P_t^{\text{FR},i}$$

[12]Peak and off-peak hours are referenced from https://customerservices.npower.com/app/answers/detail/a_id/179/~/what-are-the-economy-7-peak-and-off-peak-periods%3F. Figure A.1 in the Appendix presents the standardised average daily load curves for the three markets during the years of studying, and the two dashed vertical lines represent borders between peak and off-peak. The estimation results change little when the time band slightly varies.

for IFA, and

$$PD_t^{\mathrm{BN},i} = P_t^{\mathrm{GB},i} - P_t^{\mathrm{NL},i}$$

for BritNed. PD_t represents spot price differentials, $i \in \{\mathrm{PEAK},\mathrm{OFF}\}$, t represents days, and P_t's are day-ahead prices.

$\boldsymbol{X}_t$ is a $k \times 1$ vector of deterministic variables consisting of two types: period-specific covariates and shared covariates. Specifically, period-specific covariates are covariates that are different for different periods, and only variables recorded in the same period as the dependent variable are included. Period-specific covariates include the day-ahead forecast of renewable generation for the connected countries, the day-ahead forecast of net generation (net of imports and renewables) for the connected countries and the day-ahead forecast of the net transfer capacity (NTC) of IFA and BritNed. We control for nuclear generation as it can impact the day-ahead price, especially for France (see Figure 3 for the case where when nuclear outage occurs in France). All period-specific covariates can be regarded as exogenous: renewable generation and net demand are exogenous as renewable generation depends on weather conditions; once the NTC has been controlled for, demand is exogenous as it is inelastic to prices in the very short-run (Clò et al., 2015); the day-ahead NTC does not meet its maximum capacity if one or more lines are unavailable. Finally, one may argue that nuclear generation can be affected by the period of the day (i.e. peak and off-peak), but since we have separated each day into peak and off-peak periods, that part of the endogeneity has been removed and the variable becomes exogenous. We would expect renewable and nuclear generation for GB to reduce the GB price and hence the price differential and that for France and the Netherlands to have the opposite effect. GB demand is likely to raise the GB DAM price and so further raise the price differential, and French and Dutch demand is likely to reduce the price differential. Furthermore, since GB has consistently been a net importer via IFA and BritNed, we would expect the day-ahead NTC to lower the price differential.

The shared covariates have the same values for different periods of the same day, which

includes variable costs for coal and gas plants (excluding carbon costs), the EUA prices, the British CPS in Euro (using the daily exchange rate), and dummies for each season. Although some studies have found that dynamic interactions among fuel, carbon, and electricity prices may play an important role in the price formation process of electricity wholesale markets (Knittel and Roberts, 2005), we argue that fuel and carbon costs are more likely to be affected by the EU wholesale prices than by a single or couple of countries. The impact of fuels costs on the price differential would depend on the (marginal) fuel mixes in the two connected markets. In relation to IFA, studies have shown that during 2013-2017, fossil fuel provided more than 80% of GB's marginal generation (Chyong et al., 2019; Staffell, 2017), while the marginal generation in France has heavily relied on hydro and import, with non-fossil plants setting the price 89% of the time (Castagneto Gissey et al., 2018). Therefore, one would expect fuel costs and EUA prices to have stronger impacts on the GB DAM price than the French DAM price. Yet this may not be necessarily true as France is consistently trading large amounts of electricity with the Continent. Prices in other fossil-fuel intensive Continental markets (e.g. Germany, Italy, and Spain) could significantly affect the French price making the impact of fuel costs and EUA on the GB-FR price differential ambiguous.

In relation to BritNed, we would expect the GB-NL price differential to be negatively correlated with the cost of coal and positively correlated with the cost of gas because the Netherlands is more coal-intensive[13] compared to GB. However, as NL also trades with other Continental European countries at scale, the impact of fuel costs on the price differential may differ from our expectations.

Finally, as other EU countries have not yet followed the British CPF, we would expect the CPS to have a positive impact on price differentials for both interconnectors in both periods. Note that here we estimate the impact of the CPS on the price differential *conditional* on (the capacity of) the interconnector flow, which is potentially the only way in which the CPS affects

[13]The latest data from Eurostat shows that the fuel mix generation in the Netherlands (UK in brackets) was 35% (22%) coal and 45% (30%) gas.

the cross-border market prices. Therefore, the coefficients for the CPS also estimates the impact of the CPS on the GB DAM price. Consequently, we would expect the estimated impact of the CPS on the price differentials from both regressions (for IFA and BritNed) to be close. We can then use the result to test whether the CPS has a 100% pass-through rate in relation to the GB DAM price.

In equation (1), $\boldsymbol{\Phi}_1, ..., \boldsymbol{\Phi}_m$ are 2×2 matrices of parameters capturing the spill-over effects across and within markets at period $t - i$, where $i = 1, ..., m$, and $\boldsymbol{\Gamma}$ is an $2 \times k$ matrix with each element capturing the impact of the corresponding covariates on the dependent variables. $\boldsymbol{\mu}$ and $\boldsymbol{\varepsilon}_t$ are 2×1 vectors representing the constant terms and the error terms.

In order to control for heteroskedasticity and estimate the impact of the corresponding covariates on the volatility of the price differential, we assume $\boldsymbol{\varepsilon}_t$ is conditionally heteroskedastic:

$$\boldsymbol{\varepsilon}_t = \boldsymbol{H}_t^{1/2} \boldsymbol{\eta}_t \tag{2}$$

given the information set $\mathbf{I}_{t-1}$, where the 2×2 matrix $\boldsymbol{H}_t = [\sigma^2_{ij,t}], \forall i, j = 1, 2$, is the conditional covariance matrix of $\boldsymbol{\varepsilon}_t$. $\boldsymbol{\eta}_t$ is a normal, independent, and identical innovation vector with zero means and a covariance matrix equalling to the identity matrix, i.e. $E\boldsymbol{\eta}_t \boldsymbol{\eta}_t' = \boldsymbol{I}$.

We use the Constant Conditional Correlation (CCC)[14] GARCH(1,1) model proposed by Bollerslev (1990), where the conditional correlation matrix, $\boldsymbol{H}_t$, can be expressed as:

$$\boldsymbol{H}_t = \boldsymbol{D}_t^{1/2} \boldsymbol{R} \boldsymbol{D}_t^{1/2}, \tag{3}$$

where $\boldsymbol{R} = [\rho_{ij}]$ is a 2×2 time-invariant covariance matrix of the *standardised* residuals $\boldsymbol{D}_t^{-1/2} \boldsymbol{\varepsilon}_t$. $\boldsymbol{R}$ is positive definite with diagonal terms equal to 1, or $\rho_{ii} = 1$. $\boldsymbol{D}_t = [d_{ij,t}]$ is a diagonal matrix consisting of conditional variances with $d_{ii,t} = \sigma^2_{ii,t}$, and $d_{ij,t} = 0$ for $i \neq j$.

The model assumes the conditional variances for the price differentials follow univariate

[14] The LM tests reject the null of varying conditional correlations.

GARCH(1,1) models and the covariance between price differentials is given by a constant-correlation coefficient multiplying the conditional standard deviation of the price differentials:

$$\sigma^2_{ii,t} = \exp(\boldsymbol{\gamma}_i \boldsymbol{z}_{i,t}) + \alpha \varepsilon^2_{i,t-1} + \beta \sigma^2_{ii,t-1}, \tag{4}$$

$$\sigma^2_{ij,t} = \rho_{ij} \sqrt{\sigma^2_{ii,t} \sigma^2_{jj,t}}, \tag{5}$$

where $\boldsymbol{z}_{i,t}$ is a $k' \times 1$ vector of deterministic variables.[15] In our case, $\boldsymbol{z}_{i,t}$ contains a constant term as well as all variables in $\boldsymbol{X}_t$ in the mean equation (1). As domestic wind might depress the volatility of both domestic and cross-border DAM prices (Annan-Phan and Roques, 2018), its impact on the volatility of the price differential is unclear. We would also expect the day-ahead NTC to lower price volatility as interconnectors facilitate convergence between the connected markets. Fuel costs have an ambiguous impact on the volatility of price differentials as it depends on the fuel mix, merit order and demand between the connected markets. Lastly, we expect the CPS to raise GB day-ahead price volatility as it pushes the less flexible coal generation from baseload to mid-merit (Chyong et al., 2019), thereby raising the volatility of the GB-FR (or GB-NL) price differentials.

In equation (4), $\boldsymbol{\gamma}_i$ is a $1 \times k'$ vector of parameters capturing the impacts of deterministic variables on the conditional variance, $\sigma^2_{ii,t}$, of $y_{i,t}$. In addition, α is the ARCH parameter capturing short-run persistence and β is the GARCH parameters capturing long-run persistence.

One advantage for the M-GARCH model is that it allows for missing data, where the missing dynamic components are substituted by the unconditional expectations. The model is estimated by Maximum Likelihood Estimation (MLE). The number of lags m of the dependent variables will be determined by the Akaike Information Criterion (AIC) and the Bayesian Information Criterion (BIC).

[15] We take an exponential to guarantee positive volatility.

3.1 Data

Day-ahead market (DAM) price data are collected from the ENTSO-E Transparent Platform, except for GB, which is collected from the Nord Pool Market Data Platform.[16] ENTSO-E also provides the day-ahead forecast of scheduled net generation (net of imports and renewables), renewable generation (wind and solar), and net transfer capacities (NTC). For nuclear generation, due to data availability we use the *ex-post* real data as proxies for the day-head forecast. As nuclear is highly inflexible, we would expect the forecast on nuclear generation to be reasonably close to actual generation.

The daily coal and gas prices as well as the EUA price are collected from the InterContinental Exchange (theice.com). The appropriate prices are the daily prices one day ahead when offers are submitted. In order to calculate the delivered coal and gas costs into power stations, quarterly averages of the daily prices are subtracted from the BEIS quarterly "average prices of fuels purchased by the major UK power producers".[17] The daily data are then adjusted by adding this margin. All sterling prices are converted to Euro using daily exchange rates. We assume the thermal efficiency for coal-fired power plants to be 35.6% and 54.5% for CCGTs (Chyong et al., 2019). This gives the variable fossil costs for coal and gas plants in €/MWh$_e$ without accounting for the carbon cost.

The CPS increased from £9.55/tCO_2 to £18/tCO_2 on 1 April 2015. The lack of variation can potentially result in large standard errors on the estimated coefficients. We deal with this by converting the CPS from £ to €, using the daily exchange rate, which is assumed a good forecast for tomorrow's rate. This also allows us to capture the short-run effect of policy shocks such as Brexit referendum on cross-border electricity trading.

Table 1 gives summary statistics for all variables. Descriptive statistics of the DAM prices can be found in the Appendix. Outliers for price differentials are defined as values exceeding

[16] ENTSO-E does provide the GB DAM price in £ but Nord Pool conveniently uses the daily exchange rate to convert it from sterling to Euro.

[17] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/790152/table_321.xlsx

Table 1: Summary Statistics, Day-ahead Markets

Variable	Unit	Abbr.	Mean	S. D.	Min.	Max.
IFA Peak diff.	€/MWh	$PD^{\text{IFA,PEAK}}$	13.55	14.82	-70.63	240.05
IFA Off-peak diff.	€/MWh	$PD^{\text{IFA,OFF}}$	11.18	10.21	-38.48	48.36
BritNed Peak diff.	€/MWh	$PD^{\text{BN,PEAK}}$	15.24	10.90	-36.41	245.52
BritNed Off-peak diff.	€/MWh	$PD^{\text{BN,OFF}}$	12.51	5.38	-6.83	33.36
Peak GB renew.	GW	$R^{\text{GB,PEAK}}$	6.63	2.86	0.95	15.47
Off-peak GB renew.	GW	$R^{\text{GB,OFF}}$	4.85	2.83	0.37	13.87
Peak FR renew.	GW	$R^{\text{FR,PEAK}}$	3.90	1.62	0.90	11.99
Off-peak FR renew.	GW	$R^{\text{FR,OFF}}$	2.54	1.52	0.54	10.90
Peak NL renew.	GW	$R^{\text{NL,PEAK}}$	1.35	0.84	0.09	5.42
Off-peak NL renew.	GW	$R^{\text{NL,OFF}}$	1.03	0.75	0.04	4.19
Peak GB net gen.	GW	$G^{\text{GB,PEAK}}$	38.60	5.62	25.44	54.10
Off-peak GB net gen.	GW	$G^{\text{GB,OFF}}$	27.26	4.42	17.63	38.84
Peak FR net gen.	GW	$G^{\text{FR,PEAK}}$	64.11	10.01	42.99	89.61
Off-peak FR net gen.	GW	$G^{\text{FR,OFF}}$	57.20	9.27	37.84	81.91
Peak NL net gen.	GW	$G^{\text{NL,PEAK}}$	15.56	3.11	7.45	25.87
Off-peak NL net gen.	GW	$G^{\text{NL,OFF}}$	14.03	2.10	8.44	21.46
Peak GB nuclear	GW	$N^{\text{GB,PEAK}}$	7.37	0.69	4.31	8.99
Off-peak GB nuclear	GW	$N^{\text{GB,OFF}}$	7.38	0.68	5.18	8.98
Peak FR nuclear	GW	$N^{\text{FR,PEAK}}$	45.04	6.56	30.03	61.27
Off-peak FR nuclear	GW	$N^{\text{FR,OFF}}$	44.07	6.46	29.89	60.54
Peak NL nuclear	GW	$N^{\text{NL,PEAK}}$	0.45	0.20	0	0.55
Off-peak NL nuclear	GW	$N^{\text{NL,OFF}}$	0.45	0.20	0	0.55
IFA peak cap.	GW	$NTC^{\text{IFA,PEAK}}$	1.77	0.38	0.33	2.00
IFA off-peak cap.	GW	$NTC^{\text{IFA,OFF}}$	1.78	0.37	0.50	2.00
BritNed peak cap.	GW	$NTC^{\text{BN,PEAK}}$	1.00	0.13	0.00	1.06
BritNed off-peak cap.	GW	$NTC^{\text{BN,OFF}}$	1.01	0.10	0.00	1.04
Coal plant var. cost	€/MWh$_e$	VC^{COAL}	29.03	5.92	17.02	43.07
Gas plant var. cost	€/MWh$_e$	VC^{CCGT}	35.32	6.90	20.52	55.15
EUA price	€/tCO_2	EUA	8.835	4.85	3.99	25.25
CPS	€/tCO_2	CPS	21.32	2.82	12.17	25.95

four standard deviations of the sample mean, and are removed and treated as missing data.

Table 2: ADF and Ljung-Box Tests on Price Differentails (in €/MWh), Lags=7

Variable	Abbr.	ADF test		Ljung-Box test	
		Statistic	P-value	Statistic	P-value
IFA Peak diff.	$PD^{\text{IFA,PEAK}}$	-6.107	0.000	164	0.000
IFA Off-peak diff.	$PD^{\text{IFA,OFF}}$	-5.249	0.000	1760	0.000
BritNed Peak diff.	$PD^{\text{BN,PEAK}}$	-9.283	0.000	167	0.000
BritNed Off-peak diff.	$PD^{\text{BN,OFF}}$	-6.608	0.000	45	0.000

Table 2 shows the Augmented Dickey-Fuller (ADF) and Ljung-Box test results. The ADF tests for the existence of a unit root (**I**(1) process) and the test statistics suggest that all price differentials have no unit root. The ADF test for DAM prices are provided in the Appendix, which also suggests no unit root for all prices, in agreement with other research (see e.g., Annan-Phan and Roque, 2018; Tashpulatov, 2013).[18] The Ljung-Box test uses the square of the demeaned dependent variables to test for the existence of heteroskedasticity (Harvey, 1993). The test results reject the null of homosketatic variance, and ensures the validity of controlling for heteroskedasticity.

4 Results

4.1 Trading in the Day-ahead Market

Table 3 presents the estimation results for key parameters for both IFA and BritNed.[19] Both AIC and BIC suggest the order of the autoregressive process m in the conditional mean described by equation (1) to be 7 for both interconnectors, equivalent to a weekly cycle, and helps to control for weekly periodicity. Likelihood Ratio (LR) tests determine whether the more complicated Dynamic Conditional Correlation (DCC) model instead of the proposed Constant

[18]There is also research showing the existence of a unit root on the DAM price, such as Freitas and da Silva (2013) and Fell (2010).

[19]The estimation results for other parameters are shown in the Appendix.

Conditional Correlation (CCC) model is needed (Tse & Tsui, 2002). The test statistics for both regressions suggest using the CCC model. Estimates of the correlation coefficients, ρ_{ij} in equation (3) are within the interval of $(-1, 1)$, and estimates of the conditional variance matrices, $\boldsymbol{H}_t, \forall t$ are positive definite, ensuring the validity of the M-GARCH model.

As expected, because renewable generation lowers electricity prices, GB renewable generation (R^{GB}) reduces the normally higher GB price and hence reduces the price differential. French and Dutch renewable generation (R^{FR} and R^{NL}) increase the price differential. The coefficients on renewable generation are all statistically significant. R^{FR} and R^{NL} have a higher impact on the price differential (in magnitude) than R^{GB}. The reason might be that CCGT sets the price over 50% of the time in GB (Castagneto Gissey et al., 2018; Chyong et al., 2019), much more than its neighbours. This means that GB has a more flexible electricity system,[20] so GB prices are less affected by the variability of renewable generation. On average, 1 GW in domestic wind generation reduces the GB-FR price differential $PD^{\mathrm{IFA},i}$ (the GB-NL price differential $PD^{\mathrm{BN},i}$ in parenthesis) by €0.31 (0.27)/MWh during off-peak and by €0.41 (0.57)/MWh during peak periods, while 1 GW of cross-border domestic generation increases in $PD^{\mathrm{IFA},i}$ ($PD^{\mathrm{BN},i}$) by €1.80 (1.86)/MWh during off-peak and by €1.86 (2.15)/MWh during peak periods.

Because GB typically imports from France and the Netherlands, higher IFA and BritNed NTCs improve arbitrage and reduce price differentials for both interconnectors, though their effects are only statistically significant during peak hours. This is not surprising if both markets have convex and monotonically increasing marginal cost curves, as illustrated in the Appendix. During off-peak periods, electricity systems are running at base load with a relatively flat marginal cost curve, so a change in net demand has little impact on prices for both markets. In general, IFA NTC has a much smaller impact on the price differential than BritNed's NTC because the French market is more than triple the size of the Dutch market (see Table 1), so IFA capacity is a smaller proportion of French total load compared to BritNed's capacity share

[20] CCGTs are more flexible than coal-fired power plants.

Table 3: M-GARCH Results

Mean Equations				
	IFA Price Diff.		BritNed Price Diff.	
	$PD^{\text{IFA,PEAK}}$	$PD^{\text{IFA,OFF}}$	$PD^{\text{BN,PEAK}}$	$PD^{\text{BN,OFF}}$
R^{GB}	-0.41^{***}	-0.31^{***}	-0.57^{***}	-0.27^{***}
	(0.06)	(0.05)	(0.06)	(0.05)
R^{FR} or R^{NL}	1.86^{***}	1.80^{***}	2.15^{***}	1.86^{***}
	(0.10)	(0.12)	(0.20)	(0.20)
NTC	-1.26^{**}	-0.19	-3.34^{*}	-0.82
	(0.45)	(0.36)	(1.40)	(1.22)
VC^{COAL}	-0.35^{***}	-0.20^{***}	-0.15^{***}	-0.07^{**}
	(0.04)	(0.03)	(0.03)	(0.02)
VC^{CCGT}	0.32^{***}	0.28^{***}	0.16^{***}	0.14^{***}
	(0.03)	(0.03)	(0.03)	(0.03)
EUA	-0.14^{**}	-0.10^{*}	-0.24^{***}	-0.13^{***}
	(0.05)	(0.04)	(0.04)	(0.03)
CPS	0.23^{***}	0.22^{***}	0.24^{***}	0.15^{***}
	(0.06)	(0.05)	(0.05)	(0.04)

Conditional Variance Equations				
	IFA Price Diff.		BritNed Price Diff.	
	$PD^{\text{IFA,PEAK}}$	$PD^{\text{IFA,OFF}}$	$PD^{\text{BN,PEAK}}$	$PD^{\text{BN,OFF}}$
α	0.41^{***}	0.24^{***}	0.15^{***}	0.20^{***}
	(0.07)	(0.05)	(0.04)	(0.04)
β	-0.09^{**}	0.10	-0.01	0.13
	(0.03)	(0.10)	(0.06)	(0.08)
R^{GB}	-0.08^{***}	0.06^{**}	-0.11^{***}	0.12^{***}
	(0.02)	(0.02)	(0.02)	(0.03)
R^{FR} or R^{NL}	-0.03	0.18^{***}	0.04	0.30^{**}
	(0.03)	(0.04)	(0.08)	(0.09)
NTC	-0.02	-0.13	-0.58	-0.31
	(0.13)	(0.15)	(0.36)	(0.59)
VC^{COAL}	0.06^{***}	-0.01	0.07^{***}	-0.05^{***}
	(0.01)	(0.01)	(0.01)	(0.01)
VC^{CCGT}	0.00	0.04^{**}	-0.00	0.06^{***}
	(0.01)	(0.01)	(0.01)	(0.01)
EUA	-0.03	0.02	-0.05^{***}	-0.00
	(0.02)	(0.02)	(0.02)	(0.02)
CPS	0.05^{**}	0.01	0.05^{**}	0.03
	(0.02)	(0.02)	(0.02)	(0.02)

The summary statistic for the variables is in Table 1.

$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

in the Netherlands. During peak periods, a 1 GW increase in the IFA NTC on average reduces $PD^{\mathrm{IFA},i}$ by €1.26/MWh, while a 1 GW increase in the peak BritNed NTC on average reduces $PD^{\mathrm{BN},i}$ by €3.34/MWh.

The estimates show that coal prices have a negative influence on price differentials for both interconnectors, yet the impact is higher for IFA than BritNed and for peak compared to off-peak periods. On the other hand, gas prices have a positive effect on price differentials. As before, the coefficients are twice as large for IFA relative to BritNed, but with a negligible difference between peak and off-peak. One reason is that the CPS made coal more expensive than gas in GB, causing the share of coal to fall drastically (Chyong et al., 2019), which was not the case for the rest of the EU (at least until the end of 2017). The fact that the GB electricity system is relying more heavily on gas means than coal prices have a greater impact abroad and thus negatively affect the price differential, while gas prices have a positive impact. Taking IFA as an example, a €1/MWh increase in the variable cost of coal generation is associated with a *decline* in the peak price differential by €0.35/MWh; while a €1/MWh increase in the variable cost for gas generation would *raise* the peak price differential by €0.32/MWh.

The estimated negative impact of the EUA price on price differentials is also intuitive. The CPS forces GB to become less carbon-intensive than other EU countries, hence the EUA price will have a lower impact on GB prices relative to other EU countries. If we assume EUA prices are fully passed through to DAM prices for both markets, the coefficients on the EUA price should be the difference between the marginal emission factors (MEF) of the two markets. Under this assumption, it is estimated that the MEF for Netherlands is 0.24 tCO_2/MWh higher than that for GB during peak hours, which occurs because of its much higher share in coal generation.

The CPS raises the GB price and so should increase the price differential. Taking the weighted average of peak and off-peak estimates, a €1/tCO_2 increase in the CPS would increase the GB-FR price differential by €0.22/MWh (s.e.=0.05), or increase the GB-NL price

differential by €0.21/MWh (s.e.=0.04). These impacts on price differentials are *conditional on* cross-border electricity trading (i.e. holding Continental prices constant), and so can be regarded as estimates (from two regressions) of the impact the CPS on the GB DAM price, holding flows constant.

Using the GB marginal emission factors (MEFs) estimated from Chyong et al. (2019) we can estimate that during 2015-2018[21] a €1/MWh increase in the CPS increases the system marginal cost of electricity by €0.374/MWh (s.e.=0.005). This is significantly different from our estimates of the impact of CPS on the GB DAM price. We can therefore reject the hypothesis of a 100% carbon cost pass-through to the GB DAM price. Assuming the estimates of this paper and Chyong et al. (2019) are independent,[22] the 95% confidence interval for the CPS pass-through rate is 35-85% using estimates for the IFA price differential, or 35-80% from estimates of the BritNed price differential.[23]

Many studies emphasise the depressive effect of wind generation on price volatility (e.g. Würzburg et al., 2013; Jensen and Skytte, 2002, and Sensfuss et al., 2008). That does not mean that wind would reduce the volatility of price differentials because wind generation between the two connected markets are strongly positively correlated in our data, offsetting a depressive effect in a single country. Our results suggest that off-peak renewable generation in both markets increases the volatility of price differentials while GB peak renewable generation (R^{GB}) reduces it. The positive effect is easy to explain because renewable generation (just wind as there is no off-peak solar generation) is unpredictable day-ahead. The negative effect during peak periods might be because high GB prices are less likely to occur during days with high renewable generation.[24]

Although statistically insignificant, both regressions suggest that NTC reduces the volatility

[21] Chyong et al. (2019)'s period of estimation is 2012-2017, here we assume the MEF for GB in 2018 is the same as that in 2017.

[22] These research uses different datasets.

[23] See http://www.stat.cmu.edu/~hseltman/files/ratio.pdf for computing the confidence intervals.

[24] Evidence can be found from the data, where when the peak GB price exceeds the sample mean by more than two standard deviations when GB renewable generation is only 70% of its sample mean.

of the price differential, in agreement with Annan-Phan and Roques (2018). Finally, the CPS raised the volatility of price differentials, with a statistically significant impact during peak hours, when both coal and gas plants are operating. The CPS then amplifies price variability.

4.2 Trading via IFA without a carbon tax

During the period under study, 2015–2018, the average peak (off-peak in parentheses) IFA flow was 1,332 MW (1,206 MW) and the average peak (off-peak) NTC was 1,773 MW (1,783 MW). Given the estimated impacts of NTC on price differentials ($PD^{\mathrm{IFA},i}$) in Table 3, we can further estimate the average impact of IFA flows on $PD^{\mathrm{IFA},i}$ as €-1.68/MW and €-0.29/MW for peak and off-peak, respectively.

The coefficients on CPS in Table 3 shows the estimated impact of a €1/tCO_2 increase of the CPS on the price differential. Given this, we implement the three-stage processes set out in Section 2.3. The actual price differential duration schedule (PDDS) curve of IFA from April 2015 to December 2018[25] as well as the estimated PDDS curve without the CPS are shown in the Appendix.

Table 4 shows the average annual GB-FR price differential, GB annual net import, GB tax revenue loss from the CPS, congestion income, the CPS pass-through rate to the cross-border market, and the deadweight loss from the CPS for each UK *electricity* year (from 1 April to 31 March). The terms are defined in Section 2.2. The difference (wherever available) between the two CPS specifications are also listed (in the columns denoted with Δ). As expected, the CPS has increased the GB-FR price differential, which further raised net imports into GB. During the three years, GB imported 11.6 TWh more electricity from France due to the CPS. A total amount of €57 million of carbon-tax revenue has been lost due to the reduction in the electricity generation from GB generators over these three years, or €19 million/year.

The £18/tCO_2 CPS also increased congestion income by €75 million between 2015 and

[25] Here the analysis starts from April 2015 because the CPS is fixed at £18/tCO_2 since then.

Table 4: Statistical Measurements for IFA: with and without the CPS

Electricity years	**GB-FR Price Diff. (€/MWh)**			**GB Net Import (TWh)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€18.76	€13.60	€5.16	€15.51	€12.48	€3.03
2016-2017	€8.54	€4.18	€4.36	€8.16	€4.32	€3.84
2017-2018	€10.49	€6.44	€4.05	€11.31	€6.58	€4.73
	GB Tax Rev. Loss (m €)			**Congestion Income (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€16.53	—	—	€318	€243	€75
2016-2017	€18.07	—	—	€197	€169	€28
2017-2018	€21.47	—	—	€211	€172	€39
	CPS PT* **(€/MWh (%)))**			**Deadweight Loss (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	- €0.36 (6%)	—	—	€3.50	—	—
2016-2017	- €0.44 (9%)	—	—	€3.20	—	—
2017-2018	- €0.53 (12%)	—	—	€4.19	—	—

* The CPS pass-through (rate) to the cross-border market, see Section 2.2.

2016, by €28 million between 2016 and 2017, and by €39 million between 2017 and 2018, half of which is transferred to the French TSO.

The changes in the price differential under different levels of the CPS are different from and lower than the estimates from Table 4 because the implementation of the CPS has increased net imports into GB, increasing price convergence in the cross-border prices and offset the initial impact of the CPS on the price differential. Specifically, due to different exchange rates, the British CPS on average raised the IFA price differential by €5.51 /MWh in 2015-2016, by €4.81 /MWh in 2016-2017, and by €4.58 /MWh in 2017-2018, while re-coupling the interconnector has on average reduced that increase by €0.44 /MWh (9%) over the three years.

Finally, for each hour, as long as the interconnector flow has changed due to the CPS, deadweight losses are produced, as illustrated in Section 2.2. In total, the deadweight loss from IFA equals €11 million during the three years, or €3.6 million/year.

4.3 Trading via BritNed without a carbon tax

To the best of our knowledge, there is no freely available public data source that provides the day-ahead commercial exchange for BritNed, which makes it challenging to estimate cross-border trading over BritNed without the CPS. However, under market coupling, one would always expect the day-ahead NTC to be fully utilised if the capacity is not sufficient to integrate the market, and the NTC to be partially used if the markets are integrated. Given this, we can simulate the hourly BritNed day-ahead commercial exchange based on the following algorithm:

- if both the unadjusted price differential (UDF) and adjusted price differential (APD)[26] are greater (or smaller) than zero, the NTC will be fully used for importing (or exporting);
- if the APD is zero and the UPD is positive, then the day-ahead commercial exchange would be randomly (uniformly) allocated within the interval between zero and the NTC;
- if the APD is zero and the UPD is negative, day-ahead flows would be randomly (uniformly) allocated as a negative number between *minus* NTC and zero;
- if the APD and UPD have different signs, we assume the direction of flows follows that in the previous hour, and the volume of the flow is randomly taken from the uniform distribution between zero and the NTC.

The PDDS curve for BritNed between April 2015 and December 2018 with and without the CPS are shown in the Appendix. Table 5 shows that the CPS results in higher GB-NL price differentials, more net import into GB, and higher congestion income. Specifically, without the CPS, congestion income from BritNed would fall by €39 million in 2015-2016, by €32 million in 2016-2017, and by €30 million in 2017-2018. This amount is equally shared by the Dutch and British TSOs. The impact of the CPS on BritNed's congestion income is more stable relative to IFA because the price differential between GB and NL is less volatile than that between GB and FR (recall Figure 3).

[26] Adjusted by the BritNed loss factor of 3%, see https://www.britned.com/about-us/operations/.

Table 5: Statistical Measurements for BritNed: with and without the CPS

Electricity years	**GB-NL Price Diff. (€/MWh)**			**GB Net Import (TWh)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€17.00	€12.22	€4.78	€8.27	€6.85	€1.42
2016-2017	€15.78	€11.70	€4.08	€7.85	€6.42	€1.43
2017-2018	€12.82	€9.03	€3.79	€7.71	€6.08	€1.63
	GB Tax Rev. Loss (TWh)			**Congestion Income (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	€7.47	—	—	€148	€109	€39
2016-2017	€6.60	—	—	€137	€105	€32
2017-2018	€7.26	—	—	€113	€83	€30
	CPS PT* **(€/MWh (%)))**			**Deadweight Loss (m €)**		
	£18 CPS	£0 CPS	Δ	£18 CPS	£0 CPS	Δ
2015-2016	- €0.46 (9%)	—	—	€1.87	—	—
2016-2017	- €0.48 (11%)	—	—	€1.67	—	—
2017-2018	- €0.56 (13%)	—	—	€1.85	—	—

* The CPS pass-through (rate) to the cross-border market, see Section 2.2.

More imports result in a loss of carbon-tax revenue equal to €21 million during the three years, or €7 million/year. Furthermore, as GB imports more electricity from the Netherlands, the CPS has been passed through to the cross-border trading market. On average, the increase in GB imports reduced the price differencial by €0.50/MWh, which corresponds to 11% of the initial impact of the CPS on GB prices (holding interconnector flows unchanged). This is even higher compare to IFA because the GB-NL price differential is more sensitive to interconnector flows compared to the GB-FR price differential (results from Table 4). We can then use the CPS pass through to estimate the deadweight loss from CPS, with the three-year average at €1.8 million/yr for BritNed.

5 Trading in the intraday and balancing market

Differences between the day-ahead and the physical flows are due to intraday and balancing market trading. Newbery et al. (2019a) find that GB would rather reduce its day-ahead import

from IFA during early morning and early afternoon hours because the cost of ramping fossil plants down and then up could be higher than the intraday cost of reducing its imports, which provide a flexible and cheaper alternative. We find similar results for BritNed by comparing the simulated day-ahead commercial exchange with the physical flow, as demonstrated by Figure 7.

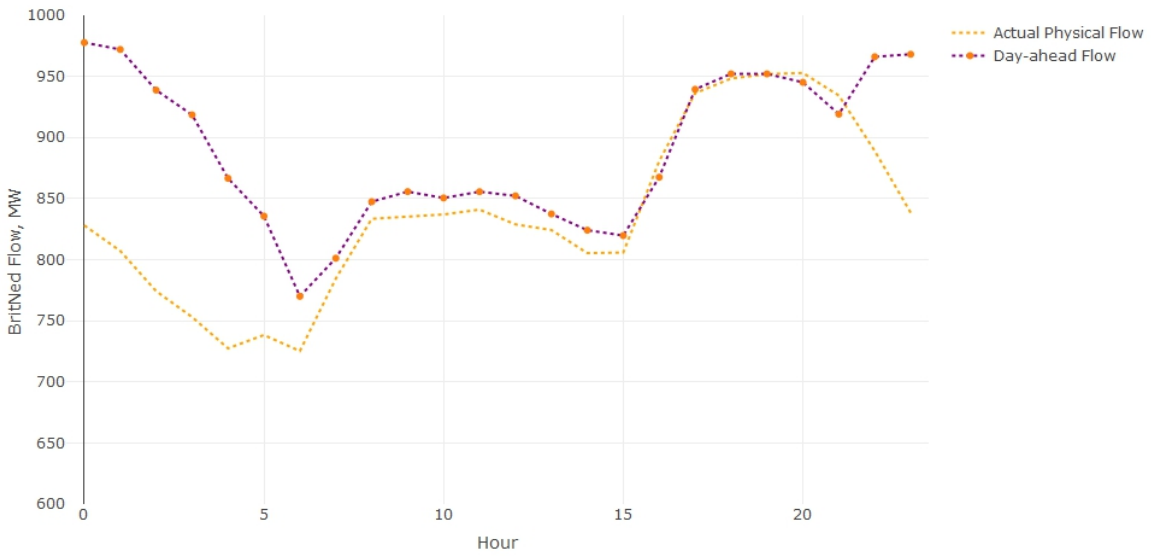

Figure 7: Day-ahead *v.s.* Actual BritNed Commercial Exchange, 2015-2018

By comparing the day-ahead and the physical flows, we calculate that during the year 2015-2016, an equivalent of €13 million (4%) in IFA congestion income was retained and used to finance the reverse flow. The value is similar for 2016-2017 (€15 million, or 8%) and 2017-2018 (€18 million, or 9%) despite the non-trivial difference in congestion income across the years. For BritNed, the values are about half that for IFA, namely €4 million (3%) for 2015-2016, €8 million (6%) for 2016-2017, and €8 million (7%) for 2017-2018.

While investigating the main drivers of the difference between the day-ahead and the actual flows would be interesting, we have left this for further study. If the difference were due to account for intraday trading, one would need intraday prices between the two connected market as well as the volumes nominated on the intraday markets since the intraday cross-

border exchanges are also coupled. If the difference were due to balancing actions, not only would one need to compare imbalance prices between the two markets, but would also need to investigate the hours in which the imported flows were to be restricted for the early morning ramp-up, and this may depend on the hour of the day and month of the year, as well as net generation.

6 Conclusions and Policy Implications

Market coupling ensures the efficient use of interconnectors so that the higher-priced market always imports electricity from the lower-priced market. Unilaterally introducing a carbon tax in one of the markets distorts trade if the increased cost of electricity on one side of the interconnector alters the flows, resulting in deadweight losses. In all cases, carbon taxes transfer revenue abroad at a cost to the domestic economy.

This paper investigates the impact of such a carbon tax on cross-border trading of electricity, both theoretically and empirically. We provide a social cost-benefit framework showing how the carbon tax impacts cross-border trade. Empirically, taking the British Carbon Price Floor (CPF) and its additional Carbon Support Price (tax) (CPS) as a case study, we use econometric methods to estimate the influence of the CPS and interconnector capacity on the price differentials between GB and its Continental neighbours France, through IFA, and the Netherlands, through BritNed. Our results isolated the price differential that would have arisen without the CPS, allowing an estimate of interconnector flows without the CPS. Comparing observed flows and prices (with the CPS) with this counterfactual (without the CPS), provides a quantitative estimate of the impact of the British CPS on net imports, congestion income, deadweight loss, and the amount of British carbon tax passed through to the cross-border market over both interconnectors.

The empirical results suggest that during electricity years 2015-2018, only 35-85% of the carbon tax has been passed through to the GB day-ahead market (DAM) price, and 9% (11%)

of the increase in the GB DAM price has been passed through to the IFA (BritNed) cross-border market. The British CPS is estimated to have increased GB imports from France by 3.9 TWh/yr and by 1.5 TWh/yr from the Netherlands, increased IFA's congestion income by €49 million/yr and BritNed's congestion income by €35 million/yr. The deadweight loss due to the CPS was estimated to be €3.6 million/yr for IFA and €1.8 million/yr for BritNed.

The results confirm that the British CPS raised the GB spot price, reduced the convergence of cross-border electricity prices and increased GB imports of electricity. Second, the CPS has not been fully passed through to the GB DAM price, indicating that the CPS reduced the deadweight loss of imperfect domestic competition. Third, the increase in congestion income (mostly) comes from GB electricity consumers but is equally allocated to both of the Transmission System Operators of the connected markets. This increased congestion income could over-incentivise further investment in additional interconnectors. Fourth, as a small proportion of the increase in GB DAM price caused by the CPS was passed through over the interconnectors, both French and Dutch day-ahead prices have been slightly increased, and this has not only raised producer surplus for the two countries but also increased electricity costs to consumers. Fifth, the objective of the British CPS is to reduce British greenhouse gas (GHG) emissions and incentivise low-carbon investment, which may be partly offset by increased imports of more carbon-intensive electricity. Finally, asymmetric carbon pricing in two connected countries incur deadweight losses, resulting in less efficient cross-border trading.

Despite the CPS distorting cross-border electricity trading, it has significantly reduced GB's GHG emissions from electricity generation. On 21 April 2017, GB power generation achieved the first ever coal-free day. When the UK introduced the CPF, the hope was that other EU countries would follow suit to correct the failures of the Emissions Trading System, at least for the electricity sector. The case for such an EU-wide carbon price floor is further strengthened by the desirability of correcting trade distortions.

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A Appendices

A.1 Figure Appendix

Figure A.1 shows the average daily load curves for GB, France, and the Netherlands during 2015-2018, at Coordinated Universal Time (UTC). To facilitate comparison, we standardise each curve by dividing its hourly loads by its maximum load.

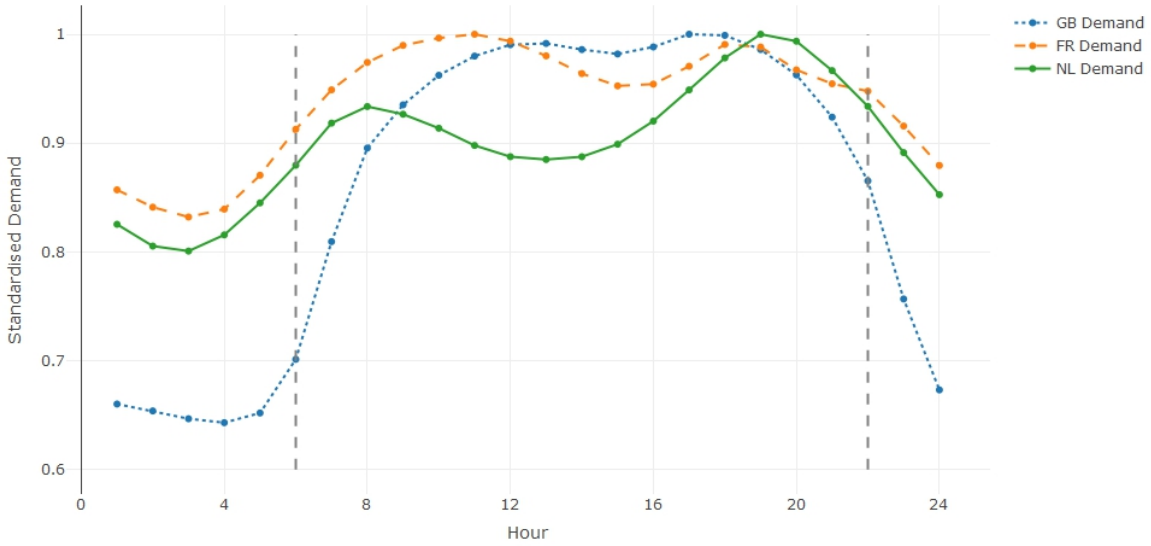

Figure A.1: Standardised Daily Average Load Curves, 2015-2018, UTC

Figure A.2 plots an electricity market with a convex supply curve, where during off-peak periods during which excess exports shift demand from ND_0^{OFF} to ND_1^{OFF}, the spot price decreases by only a small amount.

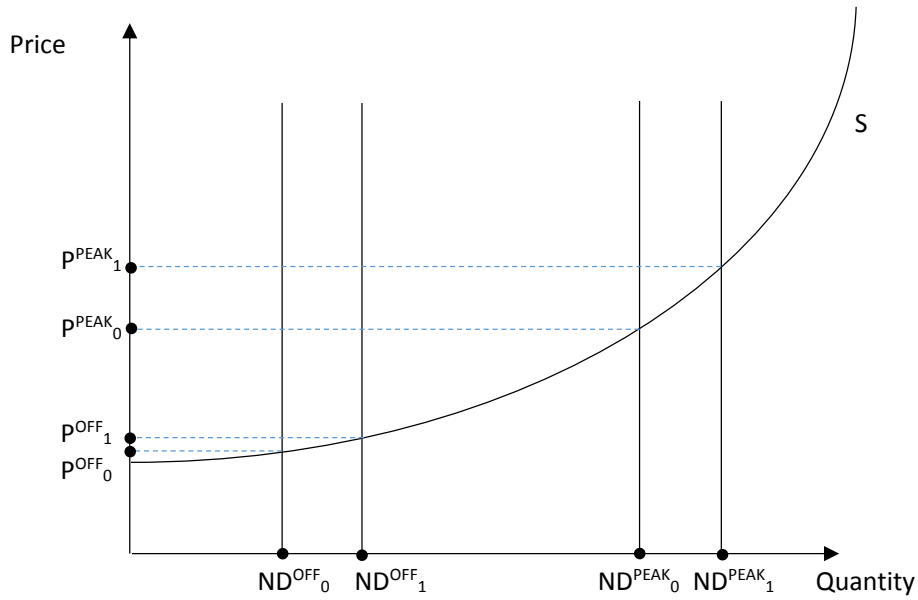

Figure A.2: A Market with a Convex Supply Curve

The price differential duration schedule (PDDS) curves for IFA and BritNed, with and without the CPS, are shown in Figures A.4 and A.3. These use unadjusted price differentials,[27] so the IFA price differentials cluster *around* instead of *at* zero.

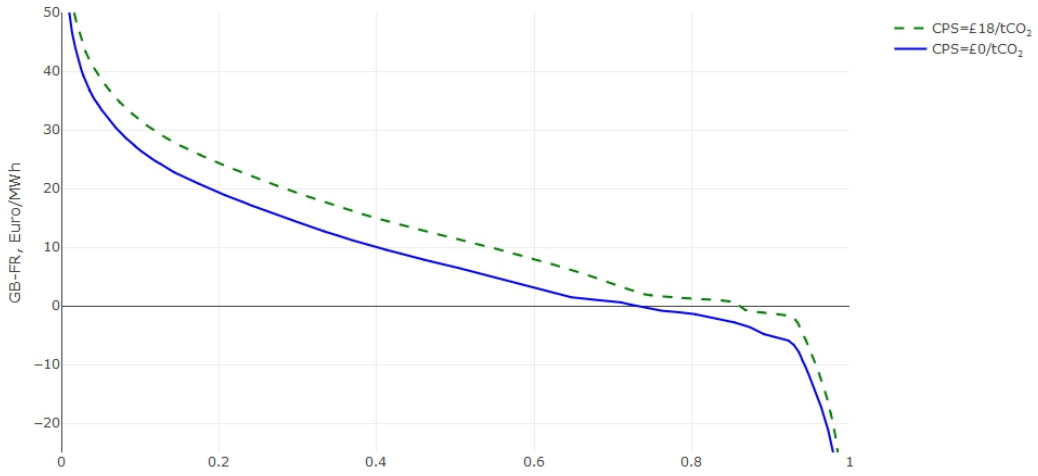

Figure A.3: The DS Curves for IFA with Different CPS, April 2015 - December 2018

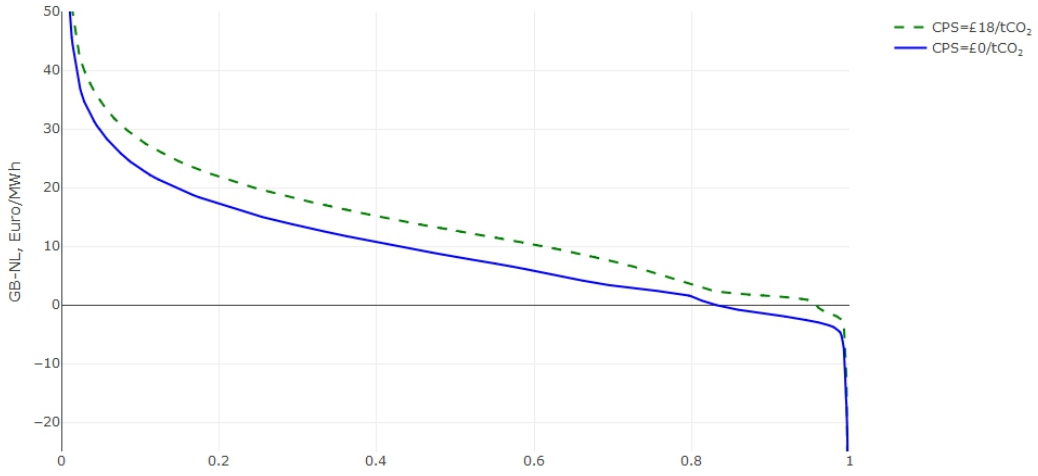

Figure A.4: The DS Curves for BritNed with Different CPS, April 2015 - December 2018

[27] Unadjusted for losses. See https://www.nationalgrideso.com/sites/eso/files/documents/Border_Specific_Annex_IFA_Interconnector_0.pdf and http://ifa1interconnector.com/media/1022/ifa-loss-factor.pdf

A.2 Table Appendix

Table A.1 presents summary statistics for day-ahead market (DAM) prices for GB, France, and the Netherlands. The hourly data is aggregated by periods (peak and off-peak) of the day, and the statistics presented are for the daily averaged peak and off-peak prices for each market.

Table A.1: Summary Statistics, Day-ahead Markets, 2015-2018

Variable	Unit	Abbr.	Mean	Std. Dev.	Min.	Max.
Peak GB DAM price	€/MWh	$P^{\text{GB,PEAK}}$	60.06	13.16	35.75	284.01
Off-peak GB DAM price	€/MWh	$P^{\text{GB,OFF}}$	45.96	9.39	17.3	79.48
Peak FR DAM price	€/MWh	$P^{\text{FR,PEAK}}$	46.53	18.35	6.98	165.42
Off-peak FR DAM price	€/MWh	$P^{\text{FR,OFF}}$	34.73	12.64	-5.02	89.61
Peak NL DAM price	€/MWh	$P^{\text{FR,PEAK}}$	44.84	12.48	16.87	108.74
Off-peak NL DAM price	€/MWh	$P^{\text{FR,OFF}}$	33.40	9.20	7.97	64.44

Table A.2 shows the Augmented Dickey-Fuller tests on the DAM prices, all tests reject the null of the existence of a root unit.

Table A.2: ADF Tests for DAM Prices (in €/MWh), Lags=7

Variable	ADF test	
	Statistic	P-value
Peak GB DAM price	-6.039	0.000
Off-peak GB DAM price	-3.434	0.047
Peak FR DAM price	-5.055	0.000
Off-peak FR DAM price	-5.335	0.000
Peak NL DAM price	-4.133	0.006
Off-peak NL DAM price	-3.714	0.022

Table A.3 shows the M-GARCH results for other covariates included in the regression. We also test whether the impact of NTC on the price differential is independent with the CPS. We assume the coefficients for NTC are (linear and quadratic) functions of the CPS, and likelihood ratio (LR) tests do not reject the null hypothesis that the impact is independent with the CPS.

Table A.3: M-GARCH Results (Cont'd)

Mean Equations				
	IFA Price Diff.		BritNed Price Diff.	
	$PD^{\text{IFA,PEAK}}$	$PD^{\text{IFA,OFF}}$	$PD^{\text{BN,PEAK}}$	$PD^{\text{BN,OFF}}$
D^{GB}	-0.57^{***}	-0.42^{***}	-0.26^{***}	-0.07
	(0.06)	(0.06)	(0.04)	(0.04)
D^{FR} or D^{NL}	-0.53^{***}	-0.44^{***}	-0.11	-0.12^{*}
	(0.05)	(0.05)	(0.07)	(0.05)
N^{GB}	-0.26	-0.13	-0.51^{*}	-0.28
	(0.24)	(0.19)	(0.23)	(0.15)
N^{FR} or N^{NL}	0.70^{***}	0.41^{***}	1.88^{*}	1.28^{**}
	(0.07)	(0.06)	(0.80)	(0.46)
SPRING	1.05	-0.37	-1.71^{***}	-0.79^{*}
	(0.63)	(0.51)	(0.41)	(0.32)
SUMMER	-2.46^{***}	-3.26^{***}	-3.23^{***}	-1.23^{**}
	(0.71)	(0.60)	(0.45)	(0.41)
FALL	-3.59^{***}	-4.25^{**}	-1.84^{***}	-0.99^{**}
	(0.68)	(0.53)	(0.45)	(0.33)

Conditional Variance Equations				
	IFA Price Diff.		BritNed Price Diff.	
	$PD^{\text{IFA,PEAK}}$	$PD^{\text{IFA,OFF}}$	$PD^{\text{BN,PEAK}}$	$PD^{\text{BN,OFF}}$
D^{GB}	0.07^{***}	0.03	0.07^{***}	-0.06^{**}
	(0.02)	(0.03)	(0.01)	(0.02)
D^{FR} or D^{NL}	0.01	-0.06^{**}	-0.03	-0.12^{***}
	(0.02)	(0.02)	(0.03)	(0.03)
N^{GB}	-0.08^{***}	0.08	-0.12	0.16
	(0.02)	(0.08)	(0.08)	(0.09)
N^{FR} or N^{NL}	-0.03	-0.00	-1.11^{***}	0.42
	(0.03)	(0.03)	(0.25)	(0.28)
SPRING	-0.05	-0.06	0.45^{**}	-0.00
	(0.24)	(0.18)	(0.16)	(0.16)
SUMMER	-0.41	-0.73^{***}	0.45^{***}	-0.36
	(0.28)	(0.24)	(0.16)	(0.21)
FALL	-0.29	-0.79^{***}	0.67^{***}	0.04
	(0.24)	(0.20)	(0.13)	(0.16)

$^{***}p < 0.001$, $^{**}p < 0.01$, $^{*}p < 0.05$

A.3 Cost-benefit analysis, an extension

Figure A.5 shows another case when the CPS alters the interconnector flow, where GB was initially exporting at partial capacity, LM, and the prices of the two markets are integrated at P_1^{GB}=P_1^{FR}. Without the interconnector the GB price would be P_0^{GB}. The market surplus is again the producer (GB) surplus plus the consumer (FR) surplus, HIJ, and there is zero congestion income.

The CPS shifts the GB supply curve upward from S_0^{GB} to S_C^{GB}, and that switches GB from being a net exporter to a net importer. Similar to the case in Figure 4, the deadweight loss is the triangle HEG, which can be calculated as the half of the product of the swing of the interconnector flow, KL, and its impact on the cross-border price differential, $(P_C^{FR}-P_1^{FR})+(P_1^{GB}-PP_C^{GB})$, or EG. Hence EG/AG is the CPS pass-through rate.

The loss in carbon tax revenue is again AG$\times$KM, and the congestion income under the CPS is ABCE, half of which goes to the French TSO.

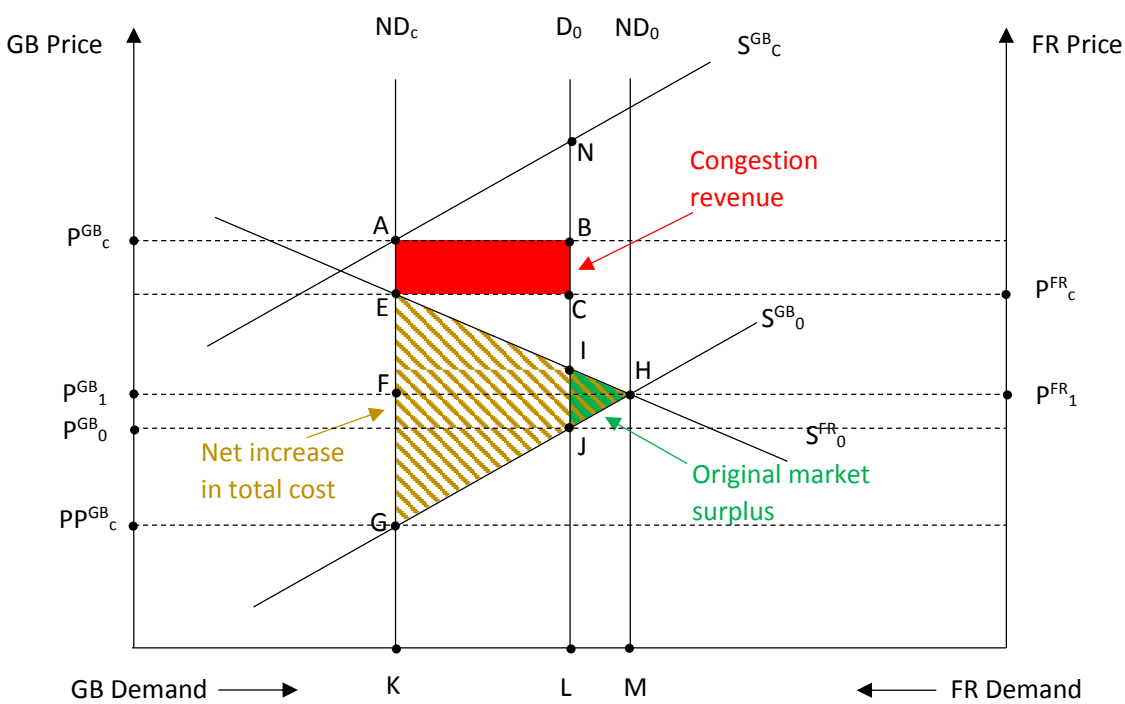

Figure A.5: Impact of CPS on Imports and Surpluses, GB from Exporting to Importing

The final case where the CPS changes interconnector flows is shown as Figure A.6. Without the CPS, GB was initially exporting at full capacity, KL, and the market clearing price was P_1^{GB} for GB and P_1^{FR} for France. The market surplus is the green area HEG+ABC and the congestion revenue is the red rectangular BCEH.

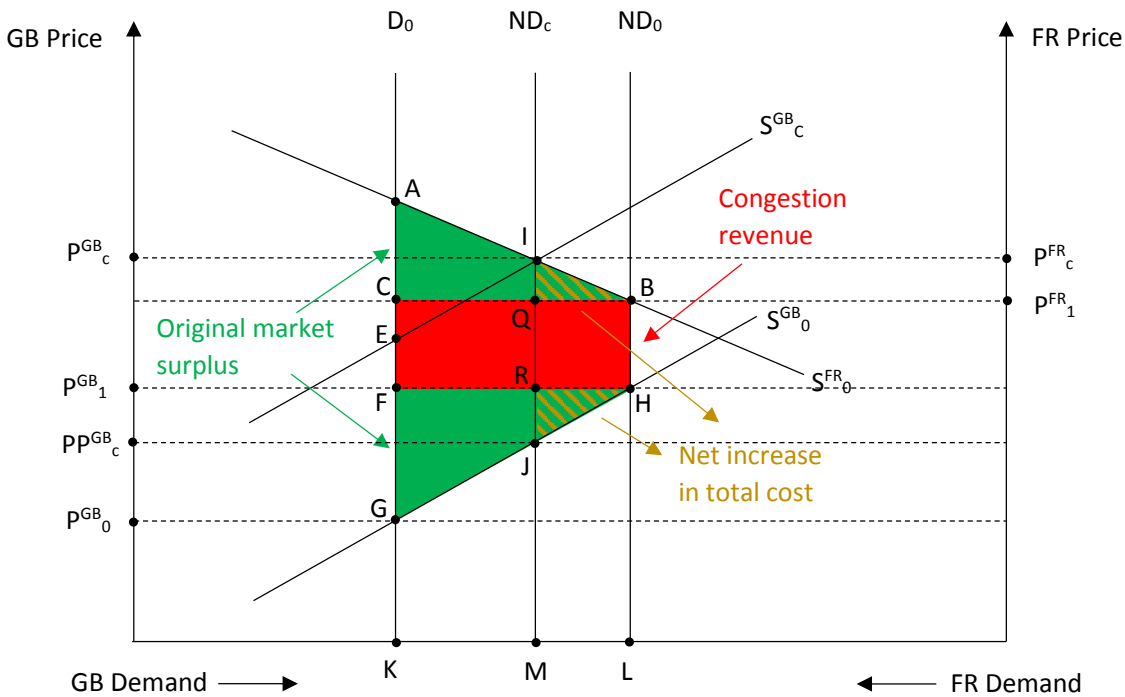

Figure A.6: Impact of CPS on Imports and Surpluses, GB Exports from Full to Partial Capacity

The CPS shifts the GB supply curve from S_0^{GB} to S_C^{GB}. While still exporting, the amount GB exported has been reduced to KM. Consequently, the deadweight loss caused by the CPS is the shaded area BIQ+HJR, or half of the change in the interconnector flow, ML, multiplied by the change in the price differential (due to the change in the interconnector flow), IQ+JR. The CPS PT ratio in this case is (IQ+JR)/EG.

The loss in carbon tax revenue is ML×EG, and there is no congestion revenue under the CPS.