# The Cost of Carbon Leakage: Britain's Carbon Price Support and Cross-border Electricity Trade[1]

## Bowei Guo[a,b] and David Newbery[a]

**EPRG Working Paper 2005**

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**Abstract**

Carbon taxes create global benefits unless offset by increased emissions elsewhere. An additional carbon tax in one country may cause leakage through imports and will also increase costs by creating a wedge between economic marginal costs in different markets, causing an offsetting deadweight loss. We estimate the global benefit, carbon leakage and deadweight cost of the British Carbon Price Support (CPS) on GB's cross-border electricity trade with France and The Netherlands. Over 2015-2020 the unilateral CPS created €72±20 m/yr deadweight loss, about 31% of the initial economic value created by the interconnector, or 2.5% of the global emissions benefit of the CPS at €2.9±0.1 bn/yr. About 16.3±3.5% of the CO2 emissions reduction is undone by France and The Netherlands, the monetary loss of which is about €584±127 m/yr.

**Keywords** Carbon tax; Bilateral trading; Carbon leakage; Electricity market.
**JEL Classification** Q48; F14; D61; C13

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[1]This replaces an earlier version of EPRG WP 1918, which seriously under-estimated the deadweight loss. This paper substantially extends, updates and replaces the earlier EPRG WP 2005 *The Cost of Trade Distortion: Britain's Carbon Price Support and Cross-border Electricity Trade.*

# The cost of carbon leakage: Britain's Carbon Price Support and cross-border electricity trade*

Bowei Guo† David Newbery‡

December 8, 2021

**Abstract**

Carbon taxes create global benefits unless offset by increased emissions elsewhere. An additional carbon tax in one country may cause leakage through imports and will also increase costs by creating a wedge between economic marginal costs in different markets, causing an offsetting deadweight loss. We estimate the global benefit, carbon leakage and deadweight cost of the British Carbon Price Support (CPS) on GB's cross-border electricity trade with France and The Netherlands. Over 2015-2020 the unilateral CPS created €72±20 m/yr deadweight loss, about 31% of the initial economic value created by the interconnector, or 2.5% of the global emissions benefit of the CPS at €2.9±0.1 bn/yr. About 16.3±3.5% of the $CO_2$ emissions reduction is undone by France and The Netherlands, the monetary loss of which is about €584±127 m/yr.

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*This version differs from the earlier version in estimating values of the marginal emission factors (MEFs in $tCO_2$/MWh) for France and The Netherlands. In the new version, we assume that the Continental market is competitive with the EU Allowance prices being fully passed through to the day-ahead price, hence we use the estimated marginal effects of the EUA on the French and Dutch day-ahead price as their MEFs. However, in the old version, we estimated the MEF from some separate regression hence the results are less plausible. Now, the estimated marginal effects of the EU Allowance price on the French and Dutch prices (hence the estimates of the MEFs) are about 0.9 for France and 0.8 for The Netherlands, which is consistent with other empirical estimates such as Fell et al. (2015) and Hintermann (2016), (though Hintermann (2016) estimates Germany which is heavily interconnected with France). We also updated our economic cost of carbon to €80 instead of €45 as in the working paper, which naturally increase the estimate of monetary loss of this carbon leakage.

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# 1 Introduction

The legally binding COP-21 Paris Agreement came into force on 4 November 2016. "Its goal is to limit global warming to well below 2, preferably to 1.5 degrees Celsius, compared to pre-industrial levels. To achieve this long-term temperature goal, countries aim to reach global peaking of greenhouse gas emissions as soon as possible to achieve a climate neutral world by mid-century."[1] In response the European Union published its *Green Deal* with its "ambitious target of a 55% reduction in carbon emissions compared to 1990 levels by 2030, and to become a climate-neutral continent by 2050."[2]

For economists, the natural policy instrument to reduce $CO_2$ emissions is a price on carbon, preferably via a tax rather than a tradable permit, given the persistence of $CO_2$ and uncertainties about cost and damage functions (e.g. Nordhaus, 2013; Weitzman, 2015; Andersson, 2019). There are strong arguments for additional performance and emission standards (as distributionally more acceptable, or more acceptable to lobby groups, and as a powerful incentive to develop more efficient and lower emitting technologies, see Stern, 2018). Direct innovation support, or indirect demand-pull through renewables targets also play their part. The EU's *Clean Energy Package* encourages Member States to support renewable energy at "the lowest possible cost to consumers and taxpayers" using '(M)arket-based mechanisms', such as tendering procedures" (Directive (EU) 2018/2001 §19). *Mission Innovation* and Carbon Pricing Leadership Coalition (2019) similarly call for global support for innovation.

Although a carbon tax may create considerable carbon benefit to the world, its impact can be reduced by leakage through carbon-intensive imports without offsetting measures such as a Border Tax Adjustment on carbon-intensive traded goods (e.g. Babiker, 2005; Elliott et al., 2010; Aichele and Felbermayr, 2015). To address these concerns, the EU has proposed its Carbon Border Adjustment Mechanism as "a climate measure that should prevent the risk of carbon leakage and support the EU's increased ambition on climate mitigation, while ensuring WTO compatibility."[3] Until that has been agreed, regional schemes like the EU Emissions Trading Scheme (ETS) partially mitigate leakage by agreeing a uniform carbon price within the EU for the covered sector (about half total EU's emissions). Initially the EU ETS delivered plausible carbon prices, rising to nearly €30/tonne $CO_2$, but with the end of the first trading period in 2007 and no banking, prices fell to zero. The second period started well, but the 2008 financial crisis and increased renewables targets reduced demand for allowances (EUAs), causing prices to fall, reaching their lowest level in 2011.

The failure of the EU ETS to give adequate, credible and sufficiently durable carbon price signals for long-term investment caused increasing concern. The UK was leading the world in imposing legally-binding emissions targets through the *Climate Change Act 2008*[4] and faced an increasingly urgent need for new generation investment. As part of the evolving *Electricity Market*

[1]UNFCCC at https://unfccc.int/process-and-meetings/the-paris-agreement/the-paris-agreement.
[2]https://ec.europa.eu/commission/presscorner/detail/en/qanda_21_3661.
[3]EU Commission, 14 July 2021 at https://ec.europa.eu/commission/presscorner/detail/en/qanda_21_3661.
[4]See http://www.legislation.gov.uk/ukpga/2008/27/contents.

*Reform*, in 2011 the UK Government announced plans for a Carbon Price Floor (CPF) from April 2013 to raise the carbon price gradually to £30/t$CO_2$ by 2020 and to £70/t$CO_2$ by 2030, intended to make up for the failure of the EU ETS. The CPF was implemented by publishing a GB[5] Carbon Price Support (CPS) added to the EUA price for generation fuels to increase it to the projected CPF. The CPS grew from £4.94/t$CO_2$ in 2013 to £9.55/t$CO_2$ in 2014, and has been stabilized since 2015 at £18/t$CO_2$.

Figure 1: The European and GB carbon prices in power sectors, £/t$CO_2$


Source: Sandbag at https://sandbag.be/index.php/carbon-price-viewer/.

Consequently, the total GB carbon cost rose from £5/t$CO_2$ in early 2013 to nearly £40/t$CO_2$ by the end of 2018, and continued to rise once the ETS reforms encouraged the EUA price to increase from 2019. Figure 1 shows the evolution of the (nominal) GB and the EU carbon prices. 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 its price (Newbery et al., 2019).[6] As the EU's commitment to radical decarbonisation became more credible, the EUA price has continued to rise, exceeding €55/$CO_2$ by mid 2021. The UK left the ETS in 2021, but replaced it with its own ETS, trading in mid 2021 at £50/t$CO_2$ (or €59/t$CO_2$), so that the carbon

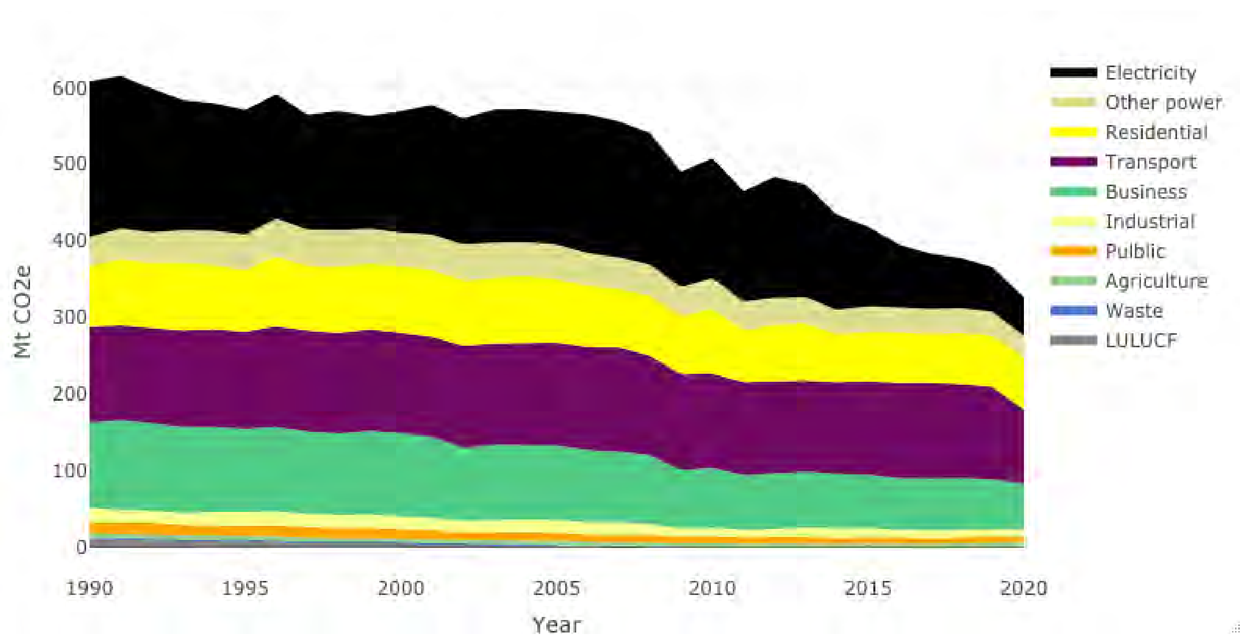
[5]Northern Ireland, which is part of the Single Electricity Market of the island of Ireland, is exempt to preserve an equal carbon price on the island.

[6]Martin et al. (2014) show that another UK carbon tax (the Climate Change Levy) has a similarly dramatic impact on the energy intensity and electricity consumption in UK manufacturing industry.

price for GB generation fuel was £68/t$CO_2$ (or €80/t$CO_2$) in mid 2021.

While the EU ETS harmonizes carbon prices and thus reduce distortions within the EU, it is still prone to leakage to the rest of the world. The main industries affected by carbon leakage are carbon-intensive traded goods such as steel, aluminium and cement (Fowlie et al., 2016). The electricity sector is, however, considerably more carbon intensive and in the EU-28 accounted for just over 20% of total greenhouse gas (GHG) emissions in 2018, with very little decrease since 1990. Figure 2 shows considerable fluctuations for the UK, remaining higher than the EU until the recent sharp decrease as coal has been driven out of the system by the CPS.

Figure 2: UK $CO_2$ emissions by sectors, 1990-2020




Source: Department for Business, Energy and Industrial Strategy (BEIS): Provisional UK greenhouse gas emissions national statistics.

The electricity sector is therefore of central importance when studying the impact of differential carbon prices. It has the added advantage that electricity is not widely traded outside the boundary of the EU, but within the EU, Great Britain (GB) faces potentially a 13% import share (and an actual share of 6.4% in 2018).[7] A study of differential carbon prices within EU's Integrated Electricity Market[8] therefore isolates the impact, and allows us to ignore the rest of the world, except, crucially, for the impact on global emissions.[9]

[7]Potential share is if the interconnector is used flat out importing 100% of time, while the actual share is what actually was imported.

[8]The EU's Integrated Electricity Market opens national wholesale and retail electricity markets to trade and competition across the EU.

[9]Electricity prices will feed through to other exporting industries and will give rise to some additional leakage, ignored in the present paper.

This article develops a cost-benefit methodology for quantifying the impact of an asymmetric carbon tax on electricity trade within a closed region such as the EU or North America, illustrated using the GB carbon tax, the CPS. While it is relatively simple to characterize the qualitative impact – an increase in domestic and foreign wholesale electricity prices, an increase in imports, etc., any serious policy analysis also needs to quantify these impacts, to judge whether they are sufficiently large to justify policy action, and that is the purpose of this article.

We assume that the CPS has a first order impact on global emissions through its impact on electricity prices and generation fuel mix, but we ignore second order effects via possible consequential changes in the prices of other goods. If $W$ is global welfare, then $\Delta W$ is the change in global welfare that increases from a fall in total emissions. If the economic cost of carbon (SCC) is $C$, and deadweight loss is $L$ (whose measurement is described below), then,

$$\Delta W = (\Delta E + \varepsilon) \cdot C - L, \tag{1}$$

where $\Delta E$ denotes the emissions reduction due to changes in GB's fuel mix (holding imports fixed), and $\varepsilon$ denotes the emissions reduction (or increases if negative) due to GB's increased imports from interconnected countries due to the GB-only carbon tax.

This article quantifies the costs and benefits of cross-border electricity trade between interconnected countries in the presence of asymmetric carbon taxes during 2014-2020, the entire and complete period when GB participated the EU Integrated Electricity Market. While cross-border trade can deliver appreciable benefits if prices are efficient in both countries, distorted prices in one country can reduce and could even reverse these benefits. It is clearly important to establish whether this is the case and that requires quantifying the impact of the asymmetry in carbon prices. It takes GB as a case study and quantifies the impact of the CPS on electricity prices, interconnector flows, congestion income (from buying low and selling high), and the economic value from trade. It also estimates the resulting deadweight loss and carbon leakage. This has implications for the design and ideally harmonization of EU and UK carbon prices and taxes to improve the efficiency of electricity trade.

One obvious criticism of the ETS is that any carbon reductions within the covered sector will be completely offset by extra emissions in other sectors or countries, as the ETS sets an overall cap on total EU emissions. A carbon tax without an emissions cap would avoid this waterbed effect. In this article we treat both the CPS and all EU emission allowances, EUAs, as carbon taxes, for several reasons. First, both carbon taxes and emission allowances provide emitters with financial incentives to reduce $CO_2$ emissions, or put another way, internalise the externality of $CO_2$ emissions. Second, policies introduced after setting the last price cap that subsequently (and unexpectedly) reduced emissions (like the EU Renewables targets) put pressure on the EU to tighten future caps, or to cancel excess EUAs, as with the Market Stability Reserve. In addition, policies that have lasting effects on emissions, such as investment in zero carbon generation that displaces fossil fuels, are included in the trajectory to net-zero by 2050 and will enjoy the rapid increase in

EUA prices that reflect that commitment. In this article we therefore treat EUAs as carbon taxes, particularly given the workings of the Market Stability Reserve.

We estimate that over 2015-2020 when the CPS stabilized at £18 ( €20) /t$CO_2$, the CPS increased global welfare by €2.9±0.1 billion/year (mainly through displacing GB coal), but the asymmetric carbon taxes created deadweight losses of €72±20 m/yr, 2.5% of the global emissions reduction benefit. It raised the GB day-ahead price by an average of €10.3±1.1/MWh (24% of the GB wholesale price), raised French prices by 3.4% and Dutch prices by 3%. The CPS increased GB imports by 14±1.8 TWh/yr (5% of the GB annual electricity demand). The deadweight loss was 31% of the economic value of interconnectors of €231 m/yr, which is appreciable but not enough to wipe out the gains from trade. Finally, about 16% of the $CO_2$ emissions reduction is undone by trade with France and The Netherlands, and the monetary loss of this carbon leakage is about €584±127 m/yr.

Section 2 briefly reviews the literature, Section 3 describes the electricity trading regime. Section 4 sets out the model and identifies the parameters to quantify. Section 5 and 6 present the econometric methods and data sources, respectively. Section 7 presents and discusses the results, and section 8 concludes.

## 2 Literature review

The difficulty of reaching international climate change agreements and temptation to free-ride results in carbon leakages (Barrett, 2005). In the long run, this may also relocate capital and international firms (e.g. Markusen, 1975; Hoel, 1994; Rauscher et al., 1997; Elliott et al., 2010). A second-best solution is to set tariffs or border taxes. Böhringer et al. (2016) show that the use of carbon tariffs is a credible and effective threat in terms of inducing uncommitted countries to adopt emission controls, while Böhringer et al. (2017) show that these can be replaced by an equivalent consumption tax (on energy-intensive trade-exposed goods) combined with output-based rebating.[10]

The earlier literature mostly focused on the impact of unilateral carbon taxes on the macro-level bilateral trade and carbon leakage under the 1997 Kyoto Protocol. Elliott et al. (2010) use a computable general equilibrium model suggesting that uncommitted countries would undo 20% of the Kyoto-committed reductions, and that adding full border tax adjustments would eliminate the leakage. Babiker (2005) models a leakage rate that could be 130%, resulting in higher global emissions. Aichele and Felbermayr (2015) conduct an empirical *ex-post* evaluation of the protocol and find that committed countries increased carbon imports by 8% with the emission intensity of imports increasing by 3%. Harstad (2012) argues that allowing countries to trade emission allowances reduces distortions.

[10]This is a standard result in trade theory of equivalence between trade taxes and a suitable combination of consumption taxes.

Fowlie et al. (2016) look at the domestic distortions arising from the oligopolistic nature of the cement market, where at high carbon taxes domestic market power is increased. Leakage makes matters worse, but both effects can be counteracted by suitable policies, including a Border Tax Adjustments (BTA). Metcalf (2009), in designing a politically acceptable carbon tax for the US, proposes a BTA to offset trade distortions, and an earned income tax credit designed to be distributionally neutral. Bovenberg and Goulder (1996) look at environmental tax distortions in a closed economy, finding that a full corrective environmental tax (that fully internalizes the externality) would create additional distortions if there are other distorting revenue-raising taxes, arguing for a lower-than-Pigouvian tax on such externalities. As the GB carbon tax does not carry any BTA it can be expected to have distortionary impacts on trade, while its interactions with the rest of the tax system will be ignored here (as demand for electricity is assumed inelastic in the short run). In support, Carbon Pricing Leadership Coalition (2019, p.9) claims that "There is little evidence to date that carbon pricing has resulted in the relocation of the production of goods and services or investment in these products to other countries."

Studies of carbon prices and electricity markets have so far focused on their price impacts (e.g. Fabra and Reguant, 2014; Sijm et al., 2006; Fell, 2010; Kirat and Ahamada, 2011; Jouvet and Solier, 2013; Wild et al., 2015), on the fuel mix and greenhouse gas emissions (e.g. Di Cosmo and Hyland, 2013; Cullen and Mansur, 2017; Staffell, 2017; Chyong et al., 2020), and on investment decisions within the power sector (e.g. Green, 2008; Fan et al., 2010; Richstein et al., 2014). Fowlie (2009) is perhaps the most useful for this paper in that the author uses a numerical model to simulate $CO_2$ emissions from California's electricity industry, suggesting that it is much more expensive to reduce emissions under a carbon tax that excepts out-of-state producers than a carbon tax levied on all producers.

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

# 3 EU electricity trading arrangements

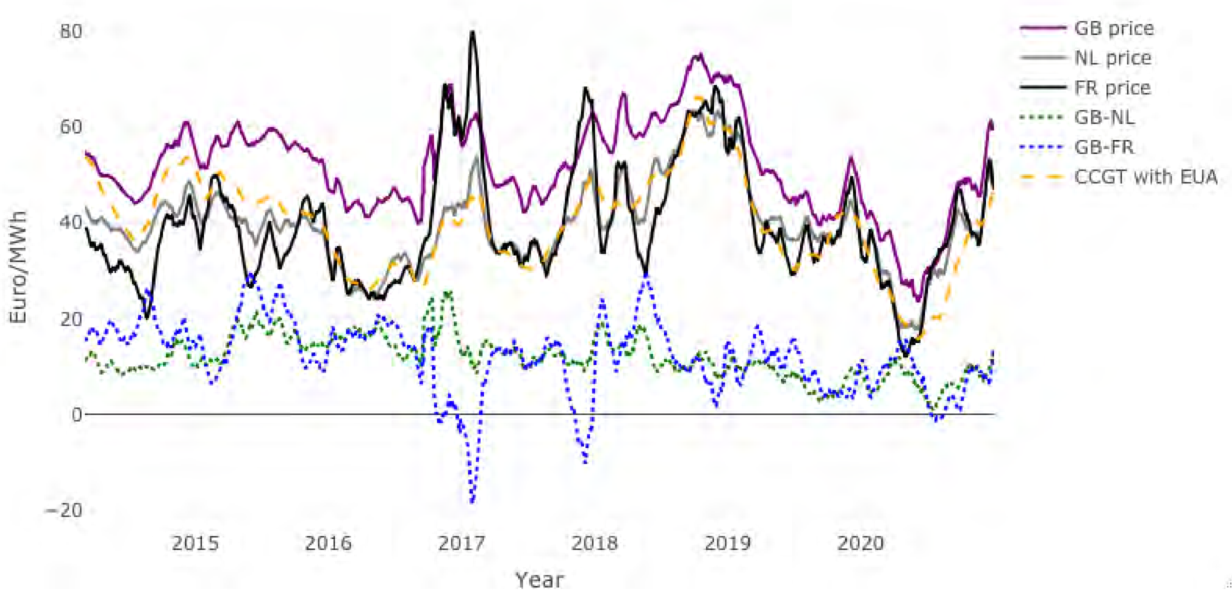
The EU's *Third Electricity Directive* (2009/72/EC) came into force in 2014, requiring market coupling of interconnectors. Before market coupling, traders had to buy interconnector volume and direction before knowing the market clearing price at each end, often resulting in inefficient trades. Market coupling ensured that interconnector capacity would be cleared at the same time as electricity markets. If market prices can be equilibrated without violating interconnector capacity constraints, prices at each end will be the same. Otherwise, trade will be set at full capacity and prices will diverge.

GB, The Netherlands and France have all been coupled since early 2014, while the interconnector between GB and the Single Electricity Market of the island of Ireland (comprising Northern

Ireland, part of the UK, and the Republic of Ireland) was only coupled in October 2018. The interconnector to Belgium was commissioned in 2019. At the end of 2020, the UK left the EU Single Market, and thereafter, GB's interconnectors were no longer coupled with the rest of the EU (nor with the island of Ireland). Most of the analysis is therefore restricted to GB's trade with France and The Netherlands from early 2014 to late 2020, before GB left the EU Integrated Electricity Market.

Market coupling ensures that the high-price country always imports and the interconnector capacity is fully used if prices diverge, and otherwise ensures price equality. Coupling therefore simplifies the analysis of the distortionary impact of the British CPS. All EU Member States, together with GB until the end of 2020, are members of the EU Emissions Trading System (ETS) designed to deliver a common carbon price. GB generators, however, have to pay the CPS.

Figure 3: 28-day lagged moving average day-ahead prices, 2014-2020




Source: Epex Spot and Nord Pool.

The CPS hence further raises the cost of fossil-fuelled electricity generation. Figure 3 plots the 28-day moving average of the day-ahead prices for GB, France, and The Netherlands, as well as their price differences with GB. It also shows the variable cost (i.e. the short-run marginal cost) for Combined Cycle Gas Turbines (CCGTs) with 48%[11] thermal efficiency with EUA prices included (CPS excluded) as a proxy of Continental gas generation costs.

GB prices were typically higher than Dutch prices but the CPS further widened the price differ-

[11] Measured at Lower Heating Value (LHV), as in Statista at https://www.statista.com/statistics/548943/thermal-efficiency-gas-turbine-stations-uk/.

ence between the two markets. French prices are much more volatile mainly because nearly 80%[12] of its gross electricity generation comes from inflexible nuclear power stations. In addition, French prices are very weather-sensitive given their high domestic electrical heating load. During Q3-Q4 2016 and Q4 2017, France experienced major nuclear outages, explaining the much higher French prices then. From Q2 2020, Covid-19 seriously disrupted markets, causing wild fluctuations in fuel prices and frequent negative day-ahead prices in all three countries. The variable cost for CCGTs partially explains the normal patterns of prices for the three markets.

# 4 A cost-benefit model of the cost of trade distortion

Consider two EU countries $H$ (Home country, GB) and $F$ (Foreign country) connected by an interconnector with capacity $K$. Without the CPS (but with the EUA price), wholesale electricity prices in each country are initially $p_0^i$, $i = \{H, F\}$ (subscript $j = 0$ indicates without the CPS, and 1 with the CPS), and net import to $H$ is $m_j$ ($-K \leq m_j \leq K$). Applying the CPS ($\tau > 0$) in $H$ raises its wholesale price by $\Delta p^H$. The higher price in $H$ induces more net imports ($\Delta m \geq 0$), changing electricity generation in each country, with impacts on marginal costs (of electricity generation) in $H$ and $F$ and in turn wholesale electricity prices. The first task is to estimate $\Delta p^H$, $\Delta m$ and then $p_0^i$, $i = \{H, F\}$.[13] The estimated $\Delta p^H$ gives an estimate of how much of the CPS is passed on to $H$'s wholesale prices.

In our analysis, demand is assumed inelastic in the short-run. Changes in prices and imports have no obvious impact in that hour's intermittent renewable[14] and nuclear power generation, so residual demand (total demand minus renewable and nuclear generation) does not change with the carbon price. Therefore, increased net imports imply the same reduction (increase) in fossil generation in $H$ ($F$).[15] These supply changes, given the asymmetry in carbon taxes, will have first order welfare effects. The second task is to measure this welfare loss.

Changes in trade influence emissions in $H$ and $F$, with implications for global emissions and welfare. The third task is to estimate the carbon leakage of the CPS via interconnectors, as well as the total $CO_2$ emissions reduction and its associated monetary value (in a world where individual country changes lead to global changes, as they would for carbon taxes, which as argued above is assumed for the ETS).

[12] From Eurostat at: https://ec.europa.eu/energy/en/news/get-latest-energy-data-all-eu-countries.

[13] $p_1^i$, $i = \{H, F\}$ are observed. Note $p_0^H + \Delta p^H \geq p_1^H$, because $\Delta p^H$ measures the effect of the CPS on $H$'s wholesale price with the net import fixed at $m_0$, while $p_1^H$ is $H$'s wholesale price after considering the change in net import $\Delta m$.

[14] Increased exports might allow an increase in constrained-off surplus wind, but these are only likely when the country is already exporting and limited by interconnector capacity.

[15] In the very short run, it may induce changes in the pattern of storage, but assuming that storage is efficiently used over the course of the day its total will not change and so will not affect the argument.

## 4.1 The CPS cost pass-through

Adding the CPS raises short-run marginal costs of electricity generation, but generators in $H$ may absorb some of the tax by marking up their offers by a smaller or larger amount if the market is imperfectly competitive, depending on the shape of the residual demand curve. In this case and in the absence of any cross-border trade, the cost pass-through of the CPS would then differ from 100% (Ritz, 2019). Under proportional mark-up pricing (Newbery, 2018), any cost shock would also be marked up, and the cost pass-through would be more than 100%.

Our post-econometric analysis allows us to estimate $\Delta p^H$, the increase in the GB wholesale price when no trade takes place. This enables us to measure the domestic cost pass-through as a percentage of the system marginal cost increase. A pass-through rate significantly different from 100% would cast doubt on the competitive assumption and possibly change domestic deadweight losses as output responds to the CPS. Fortunately, we cannot reject the competitive (100%) pass-through so this complication does not arise. Appendix A [16] gives the algebraic details of the model on how we use the estimated $\Delta p^H$ to further estimate the CPS pass-through, where we assume that markets are competitive.

## 4.2 Impact on electricity trade

Interconnectors complicate the simple single market story. Without capacity limits, the increase in $H$'s electricity price will change flows until the prices in both markets equate. With capacity limits and if flows do not change due to an existing capacity constraint, there will be no additional distortion. However, if flows do change, there will be additional deadweight losses. If demand is inelastic, the deadweight loss will be the difference in the total cost of generation[17] with and without the CPS.

There are five possible cases where the CPS may influence cross-border electricity trade:

(a) trade is constrained without the CPS but is unconstrained with the CPS ($H$ exports without the CPS): $p_0^H < p_0^F$ and $p_1^H = p_1^F$;

(b) trade is constrained with and without the CPS, but the direction of flow changes: $p_0^H < p_0^F$ and $p_1^H > p_1^F$;

(c) trade is unconstrained with and without the CPS: $p_j^H = p_j^F$;

(d) trade is unconstrained without the CPS but constrained with the CPS: $p_0^H = p_0^F$ and $p_1^H > p_1^F$;

(e) trade and its direction are unaffected by the CPS, as it is constrained by interconnector capacity: $p_j^H > p_j^F$, or $p_j^H < p_j^F$.[18]

[16] All appendices are available in the Supplemental Material or from the working paper, Guo and Newbery (2020)

[17] The cost from burning fuels plus the cost of environmental externality from $CO_2$ emissions. The economic cost of carbon is assumed to be equal to the British carbon prices (CPS plus ETS).

[18] In this case, even though the interconnector flow will not be affected by the CPS, the congestion income will.

Figure 4: Impact of CPS on imports and deadweight losses, Case (a)

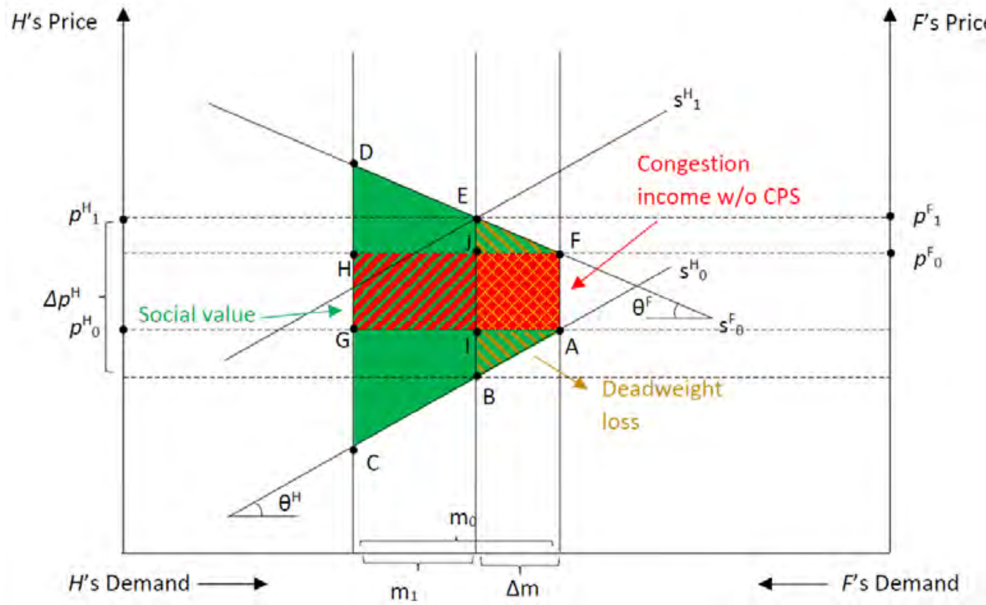



Figure 4 gives a geometric exposition of Case (a), where the horizontal axis represents the (inelastic) total electricity demand for countries $H$ and $F$, and the left and right vertical axes respectively represent the electricity wholesale prices for the two countries. Without the CPS, $H$'s net supply schedule to the EU Single Day-ahead Coupling auction[19] is represented by the line CA, labelled $s_0^H$ and $F$'s supply curve is represented by $s_0^F$. $H$ exports to $F$ at the full interconnector capacity $m_0 = -K$, with $H$'s price ($p_0^H$) lower than $F$'s price ($p_0^F$) and congestion income equals $R_0 = (p_0^H - p_0^F) \cdot m_0$, or the rectangle AGHF.[20] Under the standard assumption of zero consumer demand elasticity (i.e. vertical demand curves),[21] the interconnector creates an initial surplus (gains from trade) which is entirely due to a reduction in $F$'s generation costs (the area under $F$'s net supply curve from D to F), offset by an increase in $H$'s cost (the area under $H$'s net supply curve from C to A), or the area of the trapezium ACDF, made up of importer's and exporter's surplus (triangles DFH and ACG, respectively) and the congestion income without the CPS (rectangle AGHF). If the slopes of the net supply curves are $\theta^H$ and $\theta^F$ over the relevant range,[22] the economic value of trade (when there is no CPS to distort trade) is thus

$$S = \frac{1}{2} \cdot (\theta^H + \theta^F) \cdot m_0^2 + m_0 \cdot (p_0^H - p_0^F). \tag{2}$$

[19] The supply from fossil fuels.

[20] The congestion income is the arbitrage gain from buying low and selling high, defined as the product of the interconnector flow and price difference between $H$ and $F$.

[21] Short-run elasticities are very low. Assuming a non-zero elasticity would reduce the impacts slightly but greatly complicate quantification.

[22] Both are positive due to upward-sloping supply curves.

With the CPS, $H$'s supply curve shifts upward to HE, $s_1^H$. Although $H$ is still exporting, the interconnector is now uncongested and net import increases by $\Delta m$ (i.e., $H$ is exporting less). The deadweight loss is the difference between $F$'s increased generation cost (the area under $F$'s net supply curve from F to E) and $H$'s reduced generation cost (the area under $H$'s net supply curve from A to B). Given $\theta^H$ and $\theta^F$, the deadweight loss $L$ is the trapezium ABEF,[23] made up of triangles EFJ and ABI and rectangle AIJF . Algebraically,

$$L = \frac{1}{2} \cdot (\theta^H + \theta^F) \cdot \Delta m^2 + \Delta m \cdot (p_0^F - p_0^H). \tag{3}$$

In this case, there is no congestion income with the CPS applying, so the change in congestion income is

$$\Delta R = (p_1^F - p_1^H) \cdot m_1 - (p_0^F - p_0^H) \cdot m_0, \tag{4}$$

where in this case, $p_1^F - p_1^H = 0$.

In Case (b)-(e) similar arguments apply. The economic value of the interconnector is the reduction in the importer's generation costs offset by an increase in the exporter's cost where there is no trade distortion, and the deadweight loss is the difference between $F$'s increased generation cost and $H$'s reduced generation cost following the asymmetric carbon tax. Finally, the congestion income is the product of the price difference and flow. Appendix E gives detailed expositions for each case.

To sum up, in all cases the economic value of interconnector is given by equation (2), the deadweight loss from the asymmetric carbon tax is given by equation (3), and the change in congestion income is given by equation (4). Both the economic value and deadweight losses are (linearly) positively correlated with the price difference when the CPS is not applied, and (quadratically) positively correlated with the interconnector capacity (which determines the magnitudes of $m_0$ and $\Delta m$). The change in congestion income depend on flows and price differences with and without the CPS.

## 4.3 Global impact

The CPS substantially reduced GB electricity $CO_2$ emissions as Figure 2 showed. However, changes in trade between $H$ and $F$ could potentially undo some part of $H$'s $CO_2$ emissions reduction. For simplicity, we assume that the fuel mix and the marginal fuel shares abroad do not change with net exports (i.e. they are unaffected by the CPS). This is plausible if there were no internal transmission constraints on the Continent, as changes in their exports would be a very small fraction of total generation. Given this, the foreign country's Marginal Emissions Factor[24] (MEF,

[23] It is noteworthy that in this article, the benchmark for estimating the deadweight loss is where neither country implements the CPS. An alternative is to use the scenario where both countries implement the CPS as the benchmark, which may slightly alter the estimated results.

[24] The $CO_2$ released from the last unit of electricity generated in tonne $CO_2$/MWh.

$\mu^F$) remains unchanged and the slope of its net supply curve is also unchanged. Also assume that the CPS has little short-run impact on non-EU countries other than through changing global emissions.

$\Delta W$ is the change in global welfare given in equation (1) above. The key terms that need evaluation are the deadweight loss, $L$, defined in (3), the emissions reduction due to changes in $H$'s fuel mix (holding imports fixed), $\Delta E$, the emissions reduction due to $H$'s increased import from $F$ due to the GB-only CPS, $\varepsilon$, and the economic Cost of Carbon (SCC), $C$. Chyong et al. (2020) use a unit commitment dispatch model to estimate GB's emissions reduction from CPS in 2015 when holding imports fixed, while this study focusses on the second part of emissions reduction, $\varepsilon$. With the CPS, the MEFs for $H$ and $F$ are $\mu_1^H$ and $\mu^F$, so the emissions reduction from trade is

$$\varepsilon = (\mu_1^H - \mu^F) \cdot \Delta m. \tag{5}$$

The next task is to quantify the effective SCC. The US estimate ranges from $\$_{2018}14$/t$CO_2$ ($5^{th}$ percentile, uprated by the CPI) to $\$_{2018}130$/t$CO_2$ ($95^{th}$ percentile) with an average at 3% discount rate of $\$_{2018}45$( €38)/t$CO_2$ (USEPA, 2016). At the lower discount rate preferred by Stern (2007) and many others, the SCC would be higher. The UK Government's figure for sectors not covered by the ETS (i.e. the full SCC) in 2020 was $£_{2018}70$ ( €79)/t$CO_2$.[25] Stiglitz et al. (2017) in their *Report of the High-Level Commission on Carbon Prices* conclude that "the explicit carbon-price level consistent with achieving the Paris temperature target is at least US\$40–80/t$CO_2$ by 2020 and US\$50–100/t$CO_2$ by 2030, provided a supportive policy environment is in place." Carbon Pricing Leadership Coalition (2019) repeats this earlier conclusion.

By mid 2021 the average GB carbon price for fossil generation was £68/t$CO_2$ ( €80; US\$95), greater than both the average US SCC and the EU ETS level of €55 (US\$65)/t$CO_2$. (The GB price is high as the CPS has been retained even though the total carbon price is now well above the Carbon Price Floor, reflecting the adage that no Finance Minister willing lowers a tax unless forced to do so.) The 2021 EUA price of €80 is thus within the Paris target-consistent range, and will be taken as the SCC. Clearly it is simple to adjust $\Delta W$ for other values of the SCC, $C$ in equation (1).

## 4.4 Other distributional impacts

There are other distributional impacts from the CPS. As prices increase in both countries, some producers gain and consumers lose.[26] In the home country, the government receives additional tax revenue from the CPS, and both countries receive EUA revenues that change with output (as we are assuming that the *Market Stability Reserve* cancels excess allowances). Estimating these

[25] See *Current (2020) UK government guidance on the social value of carbon* at https://www.forestresearch.gov.uk/research/review-of-approaches-to-carbon-valuation-discounting-and-risk-management/current-uk-government-guidance-for-social-value-of-carbon/.

[26] $H$'s marginal fossil suppliers may not gain from the higher domestic wholesale price but $H$'s other suppliers such as wind and nuclear generators will gain.

distributional impacts in detail requires knowledge about market structures of both markets, and is left for future research.

## 4.5 Steps in the cost-benefit calculation

The cost-benefit analysis requires us to estimate the counterfactual prices that would prevail without the CPS, and the change in the volume of imports caused by the CPS, or, equivalently, the level of net imports without the CPS. The steps needed to estimate the counterfactual are:

1. Using econometrics to estimate the impact of interconnector flows on prices ($\theta^H$ and $\theta^F$), as well as the impact of the CPS on domestic prices, allowing for their impact on interconnector flows.
2. Derive gradually in steps the prices without cross-border trade but with the CPS, prices without the electricity trade and the CPS, and prices without the CPS but with cross-border trade, and eventually the flow without the CPS ($m_0$) and the change in flow $\Delta m$ (more details are given in the associated Appendix F).
3. Insert the various parameter estimates into equation (2)-(4) to determine impacts of the CPS on the economic value of interconnectors, the deadweight loss, and the congestion income.
4. The estimated changes in the interconnector flow (in Step 2) also allow us to estimate the impact of the CPS on the CPS tax revenue, which is manifested as the emissions reduction in GB, $\mu_1^H \cdot \Delta m$ times the CPS. The quarterly MEF in GB between 2014-2017 is taken from Chyong et al. (2020), and between 2017-2020 is estimated quarterly in this article by implementing Chyong et al. (2020)'s linear estimation methods.
5. Estimate the change in emissions in each country, assuming the MEFs in all neighbouring countries are unchanged by the CPS, to determine the impact on global welfare as in equations (1) and the extent of carbon leakage denoted as $\mu^F \cdot \Delta m$. The foreign MEFs are estimated from the econometrics in Step 1, where we assume that the ETS is fully (100%) passed on to the foreign prices, hence the estimated marginal effect of the ETS on the foreign electricity price is the estimated MEF for that country.

The parameters from the econometric estimation have standard errors, so in the cost-benefit calculation the actual values of those parameters are randomly drawn from a jointly normal distribution, whose mean and variance-covariances equal to the estimated values from the econometrics. We then apply a Monte Carlo technique to take 500 random draws from the jointly normal distribution, and for each draw, repeat Steps 2-5. The resulting means and standard deviations of the cost-benefit calculation are reported.

# 5 Econometric Models

The task is to estimate the impact of electricity load, renewables, fuel costs as well as carbon prices on domestic and foreign day-ahead electricity prices. Data availability[27] makes IFA (Interconnexion France Angleterre, the interconnector between GB and France) the most reliable source, with some less reliable estimates for BritNed, the link between GB and The Netherlands. Therefore, this section provides the specification used to model IFA (i.e., the day-ahead prices for GB and France). The analysis runs from February 2014, when the North-Western Europe market coupling went live, to December 2020, when GB left the EU Integrated Electricity Market and was uncoupled from the Continent. Over the period, fuel prices vary and renewable penetration increased substantially; in addition, the British CPS rose from £4.94/t$CO_2$ to £9.55/t$CO_2$ and then stabilized at £18/t$CO_2$, and the EU ETS rose from €6/t$CO_2$ to €30/t$CO_2$, providing sufficient observations for different fuel prices, renewable, CPS, and EU ETS levels. This section presents the simplest specification with neither peak and off-peak heterogeneity nor interaction terms. Section 6 provides data sources and summary statistics. Section 7 gives the results and also examines heterogeneity between peak and off-peak and includes interaction terms.

One major challenge is to estimate the impact of cross-border flows on electricity prices. Because the day-ahead market is an implicit auction in which domestic and foreign prices and the interconnector flows are determined simultaneously, to estimate the effect needs suitable instrumental variables for the day-ahead flows, which is not available because the day-ahead flows are only determined by the day-ahead price differences, i.e. the dependent variables. Therefore, we use the marginal effects of wind on prices as proxies for the marginal effects of flows, which should have similar impacts on fossil generation.

The substantial price volatility is handled by the Multivariate Generalised Auto-Regressive Conditional Heteroskedasticity (M-GARCH) model (Silvennoinen and Teräsvirta, 2009), which accounts for variations in both the mean and volatility of electricity prices. M-GARCH has been widely used to model day-ahead electricity prices (e.g. Kirat and Ahamada, 2011; Annan-Phan and Roques, 2018).

As all day-ahead hourly bids and offers are submitted to the auction at the same time, within that day the price for any hour carries little if any information about the next hour (Sensfuß et al., 2008; Würzburg et al., 2013; Keppler et al., 2016), and therefore hourly prices are aggregated to daily averaged day-ahead prices. The *mean equation* of the M-GARCH model is then

$$\boldsymbol{y}_t = \boldsymbol{\mu} + \boldsymbol{\Gamma} \boldsymbol{X}_t + \boldsymbol{\varepsilon}_t, \;\; \boldsymbol{y}_t = \left(P_t^{GB}, P_t^{FR}\right)', \tag{6}$$

where $\boldsymbol{y}_t$ is a $2 \times 1$ vector of day-ahead GB and French prices, and $t$ represents days. $\boldsymbol{X}_t$ is a $k \times 1$ vector of exogenous covariates that can be categorised into three specific types.

The first type includes electricity load and generation data such as the day-ahead forecast of

[27] We are unable to obtain the complete Dutch data for the period before 2015.

wind generation for both countries, day-ahead forecast of electricity load (i.e. demand) for both countries, and the actual nuclear generation.[28] We also include the day-ahead scheduled interconnector capacity for IFA as it is a key control variable to study interconnectors. All these variables are exogenous. Wind generation depends on weather, and electricity load is inelastic to prices in the short-run (Clo et al., 2015). Nuclear generation is also exogenous as it runs unless an outage occurs.[29] The scheduled interconnector capacity is only influenced by outages, maintenance or network limitations and so is also exogenous. We expect wind and nuclear generation to reduce electricity prices and demand to raise prices. As GB has consistently been a net importer of electricity from the Continent, we expect interconnector capacity to lower GB prices.

The second type includes input costs of electricity generation such as coal and gas costs, the EUA price, and the British CPS. Although some studies have found that dynamic interactions among fuel, carbon, and electricity prices may play an important role in price formation (Knittel and Roberts, 2005), we argue that fuel and carbon costs (EUA prices in this case) are more likely to be affected by EU-wide demand from the much larger covered sector, supported statistically by Guo and Castagneto Gissey (2021). We expect the fuel costs and EUA prices to raise electricity prices, and the magnitude of the impacts to depend on the (marginal) fuel mix in the market. From Chyong et al. (2020), during 2013-2017 fossil fuel provided more than 80% of GB's marginal generation, while the marginal generation in France has heavily relied on hydro and imports. That implies that fuel costs and EUA prices have a stronger impact on GB prices than French prices. However, marginal imports of France come from other fossil-fuel intensive Continental markets (e.g. Germany, Belgium, Spain and Italy), which could also positively influence French prices. The estimates of the CPS impact on prices are conditional on interconnector capacity but *unconditional* on interconnector flows, meaning that the coefficients for the CPS can only be interpreted as the estimates of the diluted (by trade) impact of the CPS on both GB and French prices. Other EU countries lacking a similar additional carbon tax export more electricity to GB, lowering GB prices and raising foreign prices. We expect the CPS to have positive impacts on GB prices. It may also slightly raise the French prices due to its increased export to GB.

The third type includes time dummies for days of week, quarters and years. The inclusion of day-of-week and quarterly dummies allow us to capture weekly and quarterly seasonalities of day-ahead prices. The inclusion of yearly dummies allow us to capture events such as the commission of new interconnectors and Covid-19, the phase-out of fossil (especially coal) plants, and newly applied energy and environmental policies that may directly and indirectly affect the day-ahead prices.

It is not necessary to include auto-regressive terms of the dependent variables in the regression because first, the electricity wholesale markets in GB and France are workably competitive (CMA, 2016; Pham, 2015), hence bidding behaviour is driven by short-run marginal cost, not the market

[28] There is no day-ahead forecast for nuclear generation, hence the actual generation is used as a proxy.

[29] Although the French nuclear power may reduce output off-peak, aggregating the hourly observations to daily can effectively deal with the potential endogeneity.

outcome from previous days. Second, including day-of-week dummy variables allow us to effectively capture the difference in price patterns between weekdays and weekends. Lagged fuel costs and carbon prices are excluded as experienced market participants can observe their daily prices before making bids.

To control for dynamic heteroskedasticity, $\boldsymbol{\varepsilon}_t$ is assumes to be conditionally heteroskedastic. We use the Constant Conditional Correlation (CCC) GARCH(1,1) model proposed by Bollerslev (1990). Details about the dynamics of $\boldsymbol{\varepsilon}_t$ can be found in Appendix B. The model is estimated by Maximum Likelihood Estimation.

# 6 Data

Table 1 gives summary statistics for all variables that are aggregated into daily values. The day-ahead price for France is from Epex Spot, and the day-ahead price for GB from the Nord Pool Market Data Platform. The French System Operator (RTE) provides forecasts of hourly French electricity load and wind generation, as well as the actual hourly French nuclear generation. The forecast of GB load and wind generation between 2015-2020 comes from ENTSO-E Transparency Platform, and for the period before 2015, we use the actual half-hourly data from National Grid as proxies. The half-hourly GB nuclear generation is from the Elexon portal. ENTSO-E Transparency Platform also provides the day-ahead forecasted transfer capacity of interconnectors. All (half-)hourly data are aggregated to daily averages.

Table 1: Summary Statistics for Variables Aggregated into Daily

| Variable | Unit | Abbr. | Obs. | Mean | S. D. | Min. | Max. |
|---|---|---|---|---|---|---|---|
| GB day-ahead price | €/MWh | $P^{GB}$ | 2,521 | 51.39 | 10.73 | -10.44 | 100.79 |
| French day-ahead price | €/MWh | $P^{FR}$ | 2,521 | 39.52 | 15.06 | -9.46 | 125.67 |
| IFA day-ahead capacity | GW | $IC^{IFA}$ | 2,521 | 1.81 | 0.35 | 0.28 | 2.00 |
| GB load | GW | $D^{GB}$ | 2,521 | 33.20 | 4.48 | 22.38 | 46.15 |
| French load | GW | $D^{FR}$ | 2,521 | 53.14 | 10.53 | 34.84 | 88.07 |
| GB wind | GW | $W^{GB}$ | 2,521 | 5.39 | 3.44 | 0.29 | 16.98 |
| French wind | GW | $W^{FR}$ | 2,521 | 2.85 | 2.10 | 0.33 | 14.15 |
| GB nuclear | GW | $N^{GB}$ | 2,521 | 6.81 | 1.07 | 2.66 | 8.99 |
| French nuclear | GW | $N^{FR}$ | 2,521 | 43.73 | 6.90 | 22.02 | 60.66 |
| CPS | €/$tCO_2$ | $CPS$ | 2,521 | 19.70 | 4.12 | 5.88 | 26.06 |
| Coal plant var. cost | €/MWh | $VC^{COAL}$ | 2,521 | 26.41 | 6.80 | 17.10 | 42.08 |
| Gas plant var. cost | €/MWh | $VC^{CCGT}$ | 2,521 | 35.49 | 10.90 | 6.51 | 60.69 |
| EUA price | €/$tCO_2$ | $EUA$ | 2,521 | 13.39 | 8.87 | 3.94 | 33.39 |

The daily Newcastle coal futures, the UK National Balancing Point (NBP)gas price[30] and the EUA price are from the InterContinental Exchange. All fuel prices are first converted to Euros per megawatt hours of heat ( €/$MWh_{th}$) using daily exchange rates (from the real-time FX) and

[30] An alternative is to use the Dutch natural gas price at the Title Transfer Facility (TTF) Virtual Trading Point. However, as the European natural gas markets are rather liquid, the two natural gas prices are extremely close.

conversion factors given in Table 5 in Appendix C. Assuming thermal efficiency for coal-fired power plants and CCGTs (given below Table 5), fuel prices are converted to costs, €/MWh (no subscript *th* indicates megawatt hours of electricity generated). These are the variable costs (i.e. short-run marginal cost) of electricity generated from coal and gas plants excluding the cost of $CO_2$. Appendix C gives more details.

# 7 Results

Outliers for day-ahead electricity prices (values exceeding four standard deviations of the sample mean) are removed and replaced by the four standard deviations of the sample mean. Several tests are applied and reported in Appendix B to confirm the validity of the M-GARCH model. Table 2 presents the estimation results of the mean equations.[31]

Regression (i) ignores the heterogeneity between peak and off-peak behaviour. The result suggests that wind and interconnector capacities lower the day-ahead prices. Both coal and gas costs are positively related to the day-ahead prices, but GB relies more heavily on gas than coal, whereas the matter reverses for France (and the reason will be discussed latter in this section). On average, a €1/t$CO_2$ increase in the CPS raised the GB price by €0.6/t$CO_2$.

Regressions (ii) and (iii) separate peak and off-peak periods. The vector of dependent variable $\boldsymbol{y}_t$ now becomes a $4 \times 1$ vector $(P_t^{GB,P}, P_t^{FR,P}, P_t^{GB,O}, P_t^{FR,O})'$ – daily averaged peak and off-peak electricity prices for GB and France. Peak and off-peak have different demands and fuel mixes affecting the marginal fuel with different marginal effects on electricity prices. Regression (iii) further adds interaction terms between some of the existing covariates and a dummy variable equalling to one when the British CPS was stabilized at £18/t$CO_2$ (after April 2015). This is because the high CPS has switched the merit order between coal and gas within the GB electricity dispatch (Chyong et al., 2020), hence after April 2015, wind might displace different fuel types and have different effects on the GB price. For the same reason, the marginal effects of fuel costs and EUA prices on the GB price could be different before and after April 2015.

Regressions (ii) and (iii) provide evidence that both domestic and foreign wind lowers French prices, as in Annan-Phan and Roques (2018). Higher foreign wind reduces foreign prices and increases domestic net import, reducing domestic prices. Although Regression (ii) suggests French wind has a positive effect on the GB price during peak periods, the magnitudes is small and the effect disappears in Regression (iii).

IFA interconnector capacity reduces GB electricity prices, as GB consistently imports from France. The effect is higher in peak than off-peak, probably because GB has a convex increasing marginal cost curve. Off-peak demand is low with the system running at base load with a relatively flat marginal cost curve, so a change in interconnector capacity (hence import) has little effect on prices.

[31] The rest of the results are given in Table 6.

Table 2: M-GARCH results

| | Unit | (i) | (ii) | | (iii) | |
|---|---|---|---|---|---|---|
| **GB DAM prices** | | | **Off** | **Peak** | **Off** | **Peak** |
| GB wind | GW | $-0.832^{***}$ | $-0.901^{***}$ | $-0.782^{***}$ | $-1.139^{***}$ | $-0.775^{***}$ |
| | | (0.022) | (0.031) | (0.023) | (0.078) | (0.056) |
| GB wind | GW | | | | $0.256^{**}$ | $-0.222^{*}$ |
| ×CPS Dummy | | | | | (0.081) | (0.059) |
| French wind | GW | $-0.027$ | $-0.118^{*}$ | $0.072^{*}$ | $-0.110^{*}$ | 0.083 |
| | | (0.036) | (0.047) | (0.036) | (0.046) | (0.049) |
| IFA capacity | GW | $-0.818^{***}$ | $-0.608^{**}$ | $-0.801^{***}$ | $-0.623^{**}$ | $-0.942^{***}$ |
| | | (0.177). | (0.205) | (0.188) | (0.200) | (0.185) |
| Coal cost | €/MWh$_e$ | $0.290^{***}$ | $0.211^{***}$ | $0.369^{***}$ | $0.595^{***}$ | $0.180^{*}$ |
| | | (0.024) | (0.027) | (0.034). | (0.084) | (0.070) |
| Coal cost | €/MWh$_e$ | | | | $-0.512^{***}$ | 0.099 |
| ×CPS Dummy | | | | | (0.084) | (0.071) |
| Gas cost | €/MWh$_e$ | $0.810^{***}$ | $0.694^{***}$ | $0.843^{***}$ | $0.497^{***}$ | $0.744^{***}$ |
| | | (0.014) | (0.020) | (0.019) | (0.034) | (0.030) |
| Gas cost | €/MWh$_e$ | | | | $0.309^{***}$ | $0.165^{**}$ |
| ×CPS Dummy | | | | | (0.041) | (0.035) |
| EUA | €/t$CO_2$ | $0.304^{***}$ | $0.404^{***}$ | $0.383^{***}$ | 0.484 | $1.438^{***}$ |
| | | (0.029) | (0.041). | (0.036) | (0.267) | (0.219) |
| EUA | €/t$CO_2$ | | | | $-0.211$ | $-1.132^{**}$ |
| ×CPS Dummy | | | | | (0.266) | (0.216) |
| CPS | €/t$CO_2$ | $0.599^{***}$ | $0.581^{***}$ | $0.683^{***}$ | $0.344^{***}$ | $0.540^{***}$ |
| | | (0.024) | (0.038) | (0.027) | (0.083) | (0.062) |
| **French DAM prices** | | | | | | |
| GB wind | GW | $-0.292^{***}$ | $-0.281^{**}$ | $-0.210^{***}$ | $-0.281^{**}$ | $-0.212^{***}$ |
| | | (0.035) | (0.031) | (0.032) | (0.031) | (0.032) |
| French wind | GW | $-1.593^{***}$ | $-1.586^{***}$ | $-1.311^{***}$ | $-1.585^{***}$ | $-1.306^{***}$ |
| | | (0.061) | (0.053) | (0.054) | (0.053) | (0.055) |
| IFA capacity | GW | $-0.276$ | $-1.503^{***}$ | $-0.497$ | $-1.492^{***}$ | $-0.492$ |
| | | (0.349) | (0.328) | (0.382) | (0.327) | (0.377) |
| Coal cost | €/MWh$_e$ | $0.760^{***}$ | $0.747^{***}$ | $0.932^{***}$ | $0.732^{***}$ | $0.912^{***}$ |
| | | (0.036) | (0.039) | (0.043) | (0.039) | (0.043) |
| Gas cost | €/MWh$_e$ | $0.499^{***}$ | $0.347^{***}$ | $0.472^{***}$ | $0.361^{***}$ | $0.486^{***}$ |
| | | (0.028) | (0.028) | (0.030) | (0.028) | (0.031) |
| EUA | €/t$CO_2$ | $0.897^{***}$ | $0.922^{***}$ | $0.980^{***}$ | $0.908^{***}$ | $0.966^{***}$ |
| | | (0.055) | (0.052) | (0.060) | (0.052) | (0.060) |
| No. Obs. | | 2,521 | 2,521 | | 2,521 | |

Standard errors in parentheses. $^{*}p < 0.05$, $^{**}p < 0.01$, $^{***}p < 0.001$.
"Coal cost" and "Gas cost": the short-run marginal cost excluding carbon prices.

Perhaps counterintuitively, interconnector capacity has a negative effect on French prices as well, for rather complicated reasons. Most (80%) of French electricity is nuclear with close-to-zero marginal costs and surplus that is normally exported. Therefore, when the French nuclear stations are producing at full capacity, its electricity supply curve is mostly flat.[32] However, France typi-

[32] Leslie (2018) also finds a counterintuitive result in the electricity market of Western Australia where the introduction of a carbon tax increased short-run emissions, as it was combined with a market restructuring that reduced the market power of the dominant utility and hence increased its more carbon-intensive market share.

cally imports because of high demand relative to nuclear output (cold weather, nuclear outages). Given its limited fossil capacity, the French marginal cost curve can be steep where it meets demand, and importing (or increasing interconnector capacity) can substantially reduce the French electricity price. As a result, one may observe interconnector capacity substantially reducing the French prices, even though France exports to GB most of the time. This is not the case between BritNed's capacity and the Dutch electricity price, as The Netherlands has little nuclear capacity (see Appendix H).

Electricity prices are positively correlated with both coal and gas costs. However, gas costs are found to have a much stronger impact in GB than France because the GB electricity system relies more heavily on gas. This is especially true after April 2015, when the CPS made GB electricity supply less coal-dependent and more gas-dependent, while in France coal remains relatively cheaper. For both countries, the marginal effects of gas costs are significantly higher in peak than off-peak periods, consistent with Chyong et al. (2020), who argue that because peak demand is more variable, the more flexible gas plants respond to wind and demand changes. As GB's electricity generation is less carbon intensive thanks to the CPS, the EUA price has a positive but smaller effects on GB prices than French prices (well-connected to a fossil hinterland).

Regression (iii) shows the marginal effects of wind, fuel costs, and EUA prices are substantially different before and after the 2015 CPS increase. Before then, wind had a very substantial effect on GB's off-peak prices, while the high CPS made it less influential, suggesting a much flatter marginal cost off-peak schedule after April 2015. Because the high CPS has made coal the more expensive fuel to generate electricity, coal plants are gradually phased out, hence we observe coal costs having little effects on the GB price since 2015. On the other hand, the high CPS has made gas the major fossil fuel that responds to load and renewables, hence gas affects the GB price more substantially since 2015.

Subsections 7.1-7.3 use estimates from Regression (iii) to estimate the prices and flows of GB and France without the CPS, the CPS pass-through to the GB electricity price, and the trade distortion between GB and France. Subsection 7.4 discusses the global impact of the CPS, and Subsection 7.5 gives a summary of BritNed, the interconnector between GB and The Netherlands.

## 7.1 Estimating the counterfactual IFA flows

Table 2 gives the estimated impacts of wind (as a proxy for cross-border flows) and the CPS on GB and French prices, both peak and off-peak. Appendix F shows how we use the estimates from Regression (iii) to estimate prices and flows without the CPS (hereafter, the counterfactual).

Table 3 gives average annual (electricity year from 1 April to 31 March) day-ahead GB and French electricity prices, GB's net import, congestion income, and the differences between actual and counterfactual cases (columns headed with $\Delta$). The 2014-2015 counterfactual removes the £9.55/t$CO_2$ CPS; the 2015-2020 removes the £18/t$CO_2$ CPS. The final lines give 2015-2020 averages.

Table 3: IFA: the counterfactual prices, flows, and congestion income

| **Electricity years** | **GB Prices ( €/MWh)** | | | **French Prices ( €/MWh)** | | |
|---|---|---|---|---|---|---|
| | **w. CPS** | **w/o CPS** | **Δ** | **w. CPS** | **w/o CPS** | **Δ** |
| 14-15 | €52.22 | €46.37 | €5.86 | €36.39 | €35.76 | €0.64 |
| | | (0.64) | (0.64) | | (0.08) | (0.08) |
| 15-16 | €53.24 | €41.07 | €12.18 | €34.49 | €33.44 | €1.05 |
| | | (1.28) | (1.28) | | (0.17) | (0.17) |
| 16-17 | €51.76 | €41.31 | €10.46 | €43.22 | €42.13 | €1.09 |
| | | (1.12) | (1.12) | | (0.14) | (0.14) |
| 17-18 | €52.70 | €42.88 | €9.81 | €42.21 | €40.85 | €1.36 |
| | | (1.04) | (1.04) | | (0.18) | (0.18) |
| 18-19 | €64.80 | €55.01 | €9.79 | €51.04 | €49.67 | €1.37 |
| | | (1.03) | (1.03) | | (0.18) | (0.18) |
| 19-20 | €43.72 | €34.24 | €9.48 | €34.24 | €33.13 | €1.92 |
| | | (1.02) | (1.02) | | (0.23) | (0.23) |
| Ave.(15-20) | €53.25 | €42.90 | €10.34 | €41.20 | €39.84 | €1.36 |
| | | (1.10) | (1.10) | | (0.18) | (0.18) |

| | **GB Net Import (TWh)** | | | **Congestion Income (m €)** | | |
|---|---|---|---|---|---|---|
| | **w. CPS** | **w/o CPS** | **Δ** | **w. CPS** | **w/o CPS** | **Δ** |
| 14-15 | 15.21 TWh | 11.14 TWh | 4.07 TWh | €243 | €166 | €77 |
| | | (0.48) | (0.48) | | (7.26) | (7.26) |
| 15-16 | 15.51 TWh | 8.76 TWh | 6.75 TWh | €303 | €150 | €152 |
| | | (1.06) | (1.06) | | (11.76) | (11.76) |
| 16-17 | 8.17 TWh | 1.24 TWh | 6.93 TWh | €185 | €133 | €52 |
| | | (0.85) | (0.85) | | (2.34) | (2.34) |
| 17-18 | 11.32 TWh | 2.62 TWh | 8.70 TWh | €194 | €126 | €68 |
| | | (1.05) | (1.05) | | (4.12) | (4.12) |
| 18-19 | 13.66 TWh | 4.88 TWh | 8.77 TWh | €214 | €121 | €93 |
| | | (1.09) | (1.09) | | (6.12) | (6.12) |
| 19-20 | 12.10 TWh | -0.12 TWh | 12.22 TWh | €129 | €70 | €59 |
| | | (1.35) | (1.35) | | (2.44) | (2.44) |
| Ave.(15-20) | 12.15 TWh | 3.48 TWh | 8.68 TWh | €227 | €132 | €85 |
| | | (1.07) | (1.07) | | (4.91) | (4.91) |

Standard errors in parentheses.

The CPS increases the GB price. Net imports mitigate the GB price rise somewhat and (slightly) increase French prices. Over 2015-2020, the £18/t$CO_2$ of CPS on average raised GB prices by €10.34±1.10/MWh[33] and French prices by €1.36±0.18/MWh.[34] Perhaps unexpectedly, without the CPS, GB's net IFA imports during 2016-2018 and 2019-2020 would be close to zero, as electricity prices would on average converge caused by French nuclear outages and high prices in winters 2016 and 2017 as well as the Covid-19 outbreak in Q2 2020. During 2015-2020, on average GB imported 8.68±1.07 TWh/yr more electricity from France as a result of the CPS, 71% of its actual net French imports. Finally, because the CPS widened the price difference between the two countries, congestion income rose by €85±4.91 m/yr. This congestion income is

[33]This is a notation referring to the mean minus-plus its standard error.

[34]This means, on average, a £1/t$CO_2$ increase in the CPS is associated with a €0.08/MWh increase in the French price.

mostly paid by British consumers, with half transferred to France, owning half of IFA.

### 7.2 The CPS pass-through to the GB day-ahead price

The CPS increases the cost of GB generation and raises day-ahead prices. In a closed competitive economy, the ratio between the increase in the GB price and the increase in the system marginal cost (due to the CPS, holding interconnector flows constant) is the CPS pass-through to the GB day-ahead price, and would be 100% given inelastic demand. Appendix A estimates the actual pass-through rate of the CPS, implying that the CPS pass-through rate to peak prices was 155% with a 95% confidence interval of 118-192%, and to off-peak prices was 70% with a 95% confidence interval of 34-105%.

The weighted average was 120% with a 95% confidence interval of 83-150%. The higher cost pass-through in peak periods compared to off-peak is consistent with most empirical literature (e.g. Sijm et al., 2006; Jouvet and Solier, 2013; Fabra and Reguant, 2014). Guo and Castagneto Gissey (2021) explain this as electricity utilities strategically bid a lower rate than the short-run marginal cost during off-peak periods to avoid the higher shut-down and re-start costs. To compensate the off-peak losses, utilities need to bid above short-run marginal cost during peak periods to be willing to offer for that day. We do not reject the null of a 100% pass-through at 5% significance, consistent with Guo and Castagneto Gissey (2021), who suggest the UK power market is competitive for most hours.

### 7.3 Market distortion from IFA

The counterfactual prices and flows estimated in Section 7.1 provide estimates of IFA's economic value and deadweight losses from asymmetric carbon taxes discussed in Section 4.2. The UK Government's losses in carbon-tax revenue from GB generation displaced by increased imports over IFA are presented in Appendix G.

Table 4 lists the economic value, deadweight loss, and carbon-tax revenue loss. During 2015-2020, the average deadweight loss from the trade distortion was €45.6±10.58 m/yr, 29% of the average economic value ( €159±5.20 m/yr). The average loss in CPS tax revenue was €63±8.13 m/yr in the case of IFA, 6% of the 2017 CPS tax receipts.[35]

### 7.4 Carbon leakage and the impact on global welfare via IFA

IFA's carbon emissions reduction, $\varepsilon$, in (5) is determined by the difference of the MEF between GB and France ($\mu_1^H - \mu^F$) and the change in GB's imports from France ($\Delta m$). Estimating the MEFs for any Continental countries is challenging because most of them are heavily interconnected with others, hence we may not be able to use the "generation by fuel types" data to estimate the MEF in

[35]The total CPS tax receipts can be found at https://commonslibrary.parliament.uk/research-briefings/sn05927/.

Table 4: IFA: surplus, distortion and losses

| **Electricity years** | **Economic Value (m €)** | **Deadweight Loss (m €)** | **GB CPS Rev. Loss (m €)** |
|---|---|---|---|
| 14-15 | €208 | €13.5 | €21.2 |
| | (7.60) | (2.91) | (2.52) |
| 15-16 | €192 | €38.3 | €67.6 |
| | (12.51) | (9.52) | (10.60) |
| 16-17 | €166 | €38.6 | €54.3 |
| | (2.51) | (8.40) | (6.93) |
| 17-18 | €168 | €44.2 | €62.4 |
| | (4.54) | (10.24) | (7.74) |
| 18-19 | €165 | €43.3 | €61.1 |
| | (6.53) | (10.40) | (7.64) |
| 19-20 | €105 | €63.8 | €69.0 |
| | (2.31) | (14.36) | (8.00) |
| Ave. 15-20 | €159 | €45.6 | €63.0 |
| | (5.20) | (10.58) | (8.13) |

Standard errors in parentheses.

France (as Chyong et al. (2020) did to estimate the GB MEF). In this article, because the EU electricity market is integrated and the EU ETS is liquid, we assume that the EU wholesale electricity market is competitive, hence the EU ETS has been fully passed on to the day-ahead prices. Put another way, the estimated marginal effect of the EUA on the French price in Table 2 is the French MEF, or $\hat{\mu}^F = 0.9 \pm 0.055$. Chyong et al. (2020) provide the GB MEF as $\hat{\mu}_1^H = 0.35$.[36]

The carbon leakage to France is about 7.8 $(= 0.9 \times 8.68)$ $mtCO_2$/yr, with a 95% confidence interval of 5.43-10.17 $mtCO_2$/yr. In total, IFA has emitted roughly $4.8 = [(0.9-0.35) \times 8.68](\pm 1.21)$ million tonnes more $CO_2$ per year due to the higher GB import. If we take the British carbon price in mid 2021 as the economic cost of carbon ($C$= €80/$tCO_2$), the economic cost of this increased emissions are about €384±97 million.

Chyong et al. (2020) ran a unit commitment dispatch model of the 2015 GB power system to estimate that the £18/$tCO_2$ CPS reduces emissions by 44.5 $mtCO_2$/year. Thus about 10.7±2.7% of the $CO_2$ emissions reduction from the CPS is undone by France.

### 7.5 BritNed: the interconnector between GB and The Netherlands

Appendix H gives estimates of the impact of the CPS and wind on GB and Dutch electricity prices and the counterfactuals for BritNed. During electricity years 2015-2020, the CPS on average raised Dutch wholesale prices by €1.16±0.17/MWh. Nearly three qaurters (74%, 5.25±0.68 TWh) of GB's actual net import from The Netherlands was due to the CPS, and congestion income doubled (from €46±2.33 m/yr to €92 m/yr). BritNed's economic value was about €72±2.76 m/yr, with

[36]The estimated marginal effects of the EU Allowance price on the French price (hence our estimates of the MEFs) is consistent with other empirical estimates such as Fell et al. (2015) and Hintermann (2016), (though Hintermann (2016) estimates Germany which is strongly interconnected with France).

deadweight losses (from asymmetric carbon taxes) €26±6.34 m/yr, slightly more than half the IFA loss (which has twice the capacity). The UK Government lost €38.2±5.20 million in taxes, 4±0.5% of its 2017 CPF receipts.

Assuming the Dutch electricity market to be perfectly competitive and the EUA price has been 100% passed through to the Dutch price, we can infer from Table 8 that the estimated (weighted average) MEF of The Netherlands was 0.82±0.046 $tCO_2$/MWh. Given this, carbon leakage to The Netherlands was about 4.3±0.37 $mtCO_2$/yr. BritNed's total emissions have increased by 2.5±0.37 $mtCO_2$/yr compared with the zero CPS scenario. This reduction of $CO_2$ emissions is worth about €200±30 m/yr, and again, slightly above the half size of BritNed compared to IFA.

Combining results from both IFA and BritNEd, we estimate from Equation (1) that the total increase in global welfare from the CPS of about €2.9±0.1 bn/yr.

# 8 Conclusions and Policy Implications

Asymmetric carbon taxes distort trade if they alter interconnector flows, resulting in deadweight losses. In all cases, asymmetric carbon taxes transfer revenue abroad at a cost to the domestic economy and raise consumer prices and generator profits. This article investigated the impact of such carbon taxes on cross-border electricity trade theoretically, geometrically and empirically, and discussed their global impact. Empirically, taking the British Carbon Price Support (CPS, an additional carbon tax) as a case study, we estimated the counterfactual (without the CPS) electricity prices and flows of the connected countries, and the CPS impacton GB's net import and congestion income. This allowed an estimate of the economic value of trade, the deadweight loss from asymmetric carbon taxes, the carbon leakage due to untaxed imports, and the global emissions impact of the CPS.

Britain offers an excellent case-study as it is interconnected by controllable DC links to other markets, so that flows can be accurately measured. In a meshed system as on the Continent, cross-border flows are a combination of scheduled flows and consequential uncontrolled flows, making the analysis of a unilateral carbon price harder to observe and therefore study. However, stronger interconnections will lead to larger impacts of unilateral taxes and hence larger distortions, strengthening the case for harmonization.

Our estimates show that during electricity years 2015-2020, the CPS increased GB day-ahead prices €10.3±1.1/MWh (24%) allowing for displacement by cheaper imports. The CPS increased French imports by 8.7±1.1 TWh/yr and by 5.3±0.7 TWh/yr from The Netherlands (together 5% of GB annual demand), thereby reducing carbon tax revenue by €63±8 m/yr from IFA and €38±5 m/yr from BritNed (together 10% of 2017 CPS tax receipts). Congestion income for IFA was increased by €85±5 m/yr and for BritNed's by €46±2 m/yr (together by 74% relative to no CPS). The interconnector economic value was €159±5 m/yr for IFA and €72±3 m/yr for BritNed, but the deadweight loss from asymmetric carbon tax was €46±11 m/yr for IFA and €26±6 m/yr for BritNed. In total, the deadweight loss from the CPS accounted for 2% of the global welfare gain from the CPS (mainly from reduced coal burn in GB) at €2.9 billion/yr. The CPS also raised French wholesale prices by 4% and Dutch wholesale prices by 3%. As foreign electricity did not bear a CPS (and still does not), imports from France undid 10.7±3% of the $CO_2$ emission reduction from the CPS, and imports from The Netherlands undid 5.6±0.8%, with net economic cost of leakage €584±127 m/yr.

The increased congestion income (mostly) comes from GB electricity consumers but is equally allocated to both Transmission System Operators as owners of the interconnectors. This increased congestion income could over-incentivize further investment in additional interconnectors, at least to carbon-intensive markets lacking such carbon taxes. The increase in French and Dutch day-ahead prices raised their producer surplus but increased consumer electricity costs. The objective of the British CPS was to reduce British $CO_2$ emissions and incentivize low-carbon investment, but this was partly subverted by increased imports of more carbon-intensive electricity from the Continent. Finally, asymmetric carbon taxes incur modest, but non-negligible deadweight losses, resulting in less efficient cross-border trade.

Although the UK has now left the EU, at the time of writing there are three interconnectors (between the UK and the Continent) under construction and two more in early development. More interconnectors would, of course, bring substantial economic benefit from trade, but would also further distort the market without removing the carbon price asymmetry. While the total economic value of an interconnector increases with flow, deadweight losses increase as the square of the distorted flow, amplifying the role of carbon price asymmetries.

Despite the CPS distorting cross-border electricity trade, it significantly reduced GB's greenhouse gas emissions: the coal share fall from 35% in 2015 to less than 3% in 2019. On 21 April 2017, GB power generation achieved the first-ever coal-free day. When the UK introduced the CPS, the hope was that other EU countries would follow suit to correct the failures of the Emissions Trading System. As the electricity sector in most countries is the cheapest source of reducing $CO_2$ emissions and as carbon tax is an attractive way to reduce the distorting cost of raising tax revenue, the case for an EU-wide carbon price floor are clear. This case is further strengthened by the desirability of correcting trade distortions. Now that the UK has left the EU, she is free to set a stable carbon price that could be aligned with the EU late 2021 EUA price that is Paris target-compliant.

# A Cost Pass-through in a Competitive Market: Theory and Application

**Theory**

In a closed competitive market, assume that coal and gas are the only marginal fuels. At the margin, the short-run marginal costs (SRMC) of generating electricity from coal and gas (the EUA cost included) are $c_C$ and $c_G$ respectively. Without the CPS, if the marginal share of coal is $\alpha_0$, the competitive electricity price in Country $H$ should be the system SRMC:

$$p_0^H = \alpha_0 c_C + (1-\alpha_0) c_G. \tag{7}$$

The CPS ($\tau$, €/t$CO_2$) raises the system SRMC. If $\tau$ switches the merit order and hence the marginal share of fossil fuels, $H$'s system SRMC with $\tau$ is

$$p_1^H = \alpha_1(c_C + e_C \cdot \tau) + (1-\alpha_1)(c_G + e_G \cdot \tau), \tag{8}$$

where $\alpha_1$ is the marginal share of coal with the CPS, and $e_C$ and $e_G$ are emissions per megawatt hour of electricity ($MWh_e$) generated by marginal coal and gas. In this closed competitive market, the CPS has raised the electricity price by

$$\begin{aligned} p_1^H - p_0^H &= \tau \cdot [\alpha_1 \cdot e_C + (1-\alpha_1) \cdot e_G] + (c_C - c_G) \cdot (\alpha_1 - \alpha_0) \\ &= \tau \cdot \mu_1^H + (c_C - c_G) \cdot \Delta\alpha, \end{aligned} \tag{9}$$

where $\mu_1^H = [\alpha_1 \cdot e_C + (1-\alpha_1) \cdot e_G]$ denotes the Marginal Emission Factor (MEF) of $H$ with the CPS, and $\Delta\alpha = \alpha_1 - \alpha_0$ is the change in the marginal share of coal.

Equation (9) suggests that if the CPS does not change the marginal share of coal hence $\Delta\alpha = 0$, or if the SRMCs of coal and gas are close without the CPS hence $c_C - c_G \approx 0$, the impact of the CPS on the domestic electricity price would be $\mu_1^H \cdot \tau$. Otherwise, given that for most of the time during 2015-2020 coal is the cheaper fuel without the CPS ($c_C - c_G < 0$), and that from Chyong et al. (2020) the marginal share of coal has decreased with the CPS ($\Delta\alpha < 0$), the impact of the CPS on the electricity price should be higher than $\mu_1^H \cdot \tau$. Using the data and results from Chyong et al. (2020), we can estimate both $(c_C - c_G)$ and $\Delta\alpha$ in (the electricity year of) 2017 as a representative year for 2015-2020 (see Table 3 where the average effect of the CPS during 2015-2020 is similar to that in 2017), which enables us to further examine whether the CPS has been fully passed through to the GB's wholesale electricity price.

**Application**

Equation (9) shows the increase in the system SRMC is a function of the MEF with the CPS ($\mu_1^H$), the difference of the SRMCs between coal and gas ($c_C - c_G$), and the change in the coal share at margin ($\Delta\alpha = \alpha_1 - \alpha_0$).

Using the data and results from Chyong et al. (2020), in 2017 the MEFs ($\hat{\mu}_1$) for peak and off-peak were 0.332 and 0.372, respectively.[37] The change in the marginal share of coal ($\widehat{\Delta\alpha}$) during the period is $-0.045$ and $-0.164$ for peak and off-peak, respectively.[38] Finally, $(c_C - c_G)$ is estimated to be €$-0.95$/MWh.[39] Given this, the increase in the system SRMC is €0.375/MWh for peak and €0.528/MWh for off-peak.

The impact of the CPS on the GB electricity price with no cross-border trade from Appendix F is estimated to be $\widehat{\Delta p^H} =$ €0.581/MWh (s.e.$=$ 0.070) for peak periods and $\widehat{\Delta p^H} =$ €0.368/MWh (s.e.$=$ 0.096) for off-peak periods.

Based on this, assuming the estimates from Chyong et al. (2020) have zero standard errors[40] and are independent with this paper, the CPS pass-through rate to GB's peak prices is 155% with a 95% confidence interval of 118-192%, and to GB's off-peak prices is 70% with a 95% confidence interval of 34-105%. The weighted average is 120% with a 95% confidence interval of 83-150%.

# B Controlling for dynamic heteroskedasticity

To control for dynamic heteroskedasticity, assume $\boldsymbol{\varepsilon}_t$ is conditionally heteroskedastic:

$$\boldsymbol{\varepsilon}_t = \boldsymbol{H}_t^{1/2}\boldsymbol{\eta}_t \tag{10}$$

given the information set $\mathbf{I}_{t-1}$, where the $2\times 2$ 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. $E\boldsymbol{\eta}_t\boldsymbol{\eta}_t' = \boldsymbol{I}$.

In the Constant Conditional Correlation (CCC) GARCH(1,1) model proposed by Bollerslev (1990), the conditional correlation matrix, $\boldsymbol{H}_t$, is:

$$\boldsymbol{H}_t = \boldsymbol{D}_t^{1/2}\boldsymbol{R}\boldsymbol{D}_t^{1/2}, \tag{11}$$

where $\boldsymbol{R} = [\rho_{ij}]$ is a $2\times 2$ time-invariant covariance matrix of the *standardized* residuals $\boldsymbol{D}_t^{-1/2}\boldsymbol{\varepsilon}_t$. $\boldsymbol{R}$ is positive definite with diagonal terms $\rho_{ii} = 1$. $\boldsymbol{D}_t = [d_{ij,t}]$ 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 electricity prices follow a univariate GARCH(1,1)

[37] Chyong et al. (2020)'s period of estimation is 2012-2017 reported in the Appendix of their paper. These estimated MEFs use rather low emission factors as they ignore any upstream emissions (from mine/well-head to power station). Using MEFs from other studies may give somewhat different results.

[38] Chyong et al. (2020) demonstrates that the marginal share of coal/gas is a function of SRMC differences between coal and gas. In 2017, the cost differences is €$-2.03$/MWh without the CPS, and €9.86/MWh with CPS. Given this, $\alpha_0 = 0.310$ for off-peak and 0.231 for peak; $\alpha_1 = 0.146$ for off-peak and 0.186 for peak.

[39] Precisely, using the notation in Table 1, $c_j = VC^j + e^j \cdot EUA$, $j \in \{coal, ccgt\}$, where $e^j$ is the emission factor which takes the value of 0.871 for coal and 0.337 for gas, consistent with Chyong et al. (2020).

[40] Estimates in Chyong et al. (2020) have much smaller standard errors, we assume that parameters whose values are taken from them have zero standard error.

process and the covariance between prices is given by a constant-correlation coefficient multiplying the conditional standard deviation of prices:

$$\sigma^2_{ii,t} = s_i + \alpha_i \varepsilon^2_{i,t-1} + \beta_i \sigma^2_{ii,t-1}, \quad (12)$$

$$\sigma^2_{ij,t} = \rho_{ij}\sqrt{\sigma^2_{ii,t}\sigma^2_{jj,t}}, \quad (13)$$

where $s_i$ is a constant term, $\alpha_1$ is the ARCH parameter capturing short-run persistence and $\beta_1$ is the GARCH parameters capturing long-run persistence.

Augmented Dickey-Fuller tests reject the null of day-ahead prices having unit-roots. The estimated $\alpha_i + \beta_i$ is lower than 1; estimates of the correlation coefficients, $\rho_{ij}$ in equation (11) 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.

# C Data Appendix

GB day-ahead price comes from Nord Pool, French day-ahead price is downloaded from Bloomberg. IFA day-ahead capacity comes from ENTSO-E. GB load and wind come from National Grid ESO, nuclear comes from Elexon Portal. French load, wind and nuclear come from RTE. NBP gas price, EUA price, and CME coal price are all downloaded from Bloomberg.

Table 5: Conversion Factors and Thermal Efficiencies of UK power plants

| | **Conversion factors for coal (tonne to MWh$_{th}$)** | **Thermal Efficiencies** | |
|---|---|---|---|
| | | **Coal** | **CCGTs** |
| 2014 | 7.27 | 35.9% | 47.2% |
| 2015 | 7.31 | 35.6% | 48.0% |
| 2016 | 7.29 | 35.0% | 48.9% |
| 2017 | 7.27 | 34.9% | 48.7% |
| 2018 | 7.27 | 34.1% | 48.9% |
| 2019 | 7.41 | 31.9% | 48.8% |
| 2020 | 7.02 | 31.9% | 48.8% |

Note: The conversion factors are collected from the Department for Business, Energy & Industrial Strategy. The thermal efficiencies follow Statista. As the 2020 values are not yet published at the time of writing, we assume they follow the 2019 value.

# D Table 2 Continued

Table 6 shows the M-GARCH results for other covariates and the ARCH and GARCH terms, as a continuation of Table 2.

Table 6: M-GARCH Results (Cont'd)

| **Mean Equations** | | | | | | |
|---|---|---|---|---|---|---|
| | **Unit** | **(i)** | **(ii)** | | **(iii)** | |
| **Great Britain** | | | **Off** | **Peak** | **Off** | **Peak** |
| (Constant) | | $-9.425^{***}$ | $-10.13^{***}$ | $-16.48^{***}$ | 1.310 | $-9.202^{*}$ |
| | | (1.640) | (2.189) | (1.960) | (2.805) | (2.426) |
| GB load | GW | $0.409^{***}$ | $0.279^{***}$ | $0.502^{***}$ | $0.252^{***}$ | $0.540^{***}$ |
| | | (0.043) | (0.075) | (0.038) | (0.071) | (0.039) |
| French load | GW | $0.053^{**}$ | $-0.022$ | $0.056^{**}$ | $-0.036$ | $0.046^{***}$ |
| | | (0.017) | (0.028) | (0.018) | (0.025) | (0.019) |
| GB Nuclear | GW | $-0.819^{***}$ | $-0.758^{***}$ | $-0.689^{***}$ | $-1.023^{***}$ | $-0.625^{***}$ |
| | | (0.085) | (0.109) | (0.100) | (0.103) | (0.102) |
| French Nuclear | GW | $-0.048^{*}$ | $0.183^{***}$ | 0.020 | $0.184^{***}$ | $-0.021$ |
| | | (0.021) | (0.032) | (0.023) | (0.029) | (0.026) |
| Time Dummies | | YES | YES | YES | YES | YES |
| **France** | | | | | | |
| (Constant) | | $-36.69^{***}$ | $-24.81^{***}$ | $-46.43^{***}$ | $-23.93^{***}$ | $-45.16^{***}$ |
| | | (2.950) | (2.598) | (2.801) | (2.586) | (2.807) |
| GB load | GW | 0.132 | $-0.103$ | $0.269^{***}$ | $-0.102$ | $0.266^{***}$ |
| | | (0.096) | (0.094) | (0.071) | (0.094) | (0.071) |
| French load | GW | $0.910^{***}$ | $0.740^{***}$ | $0.851^{***}$ | $0.743^{***}$ | $0.859^{***}$ |
| | | (0.035) | (0.033) | (0.035) | (0.033) | (0.034) |
| GB Nuclear | GW | 0.077 | $-0.309$ | $-0.320$ | $-0.352^{*}$ | $-0.366$ |
| | | (0.163) | (0.161) | (0.199) | (0.161) | (0.194) |
| French Nuclear | GW | $-0.617^{***}$ | $-0.254^{***}$ | $-0.419^{***}$ | $-0.260^{***}$ | $-0.431^{***}$ |
| | | (0.048) | (0.041) | (0.042) | (0.040) | (0.042) |
| CPS | €/t$CO_2$ | 0.042 | $-0.242^{***}$ | $-0.053$ | $-0.249^{***}$ | $-0.062$ |
| | | (0.051) | (0.049) | (0.039) | (0.049) | (0.050) |
| Time Dummies | | YES | YES | YES | YES | YES |

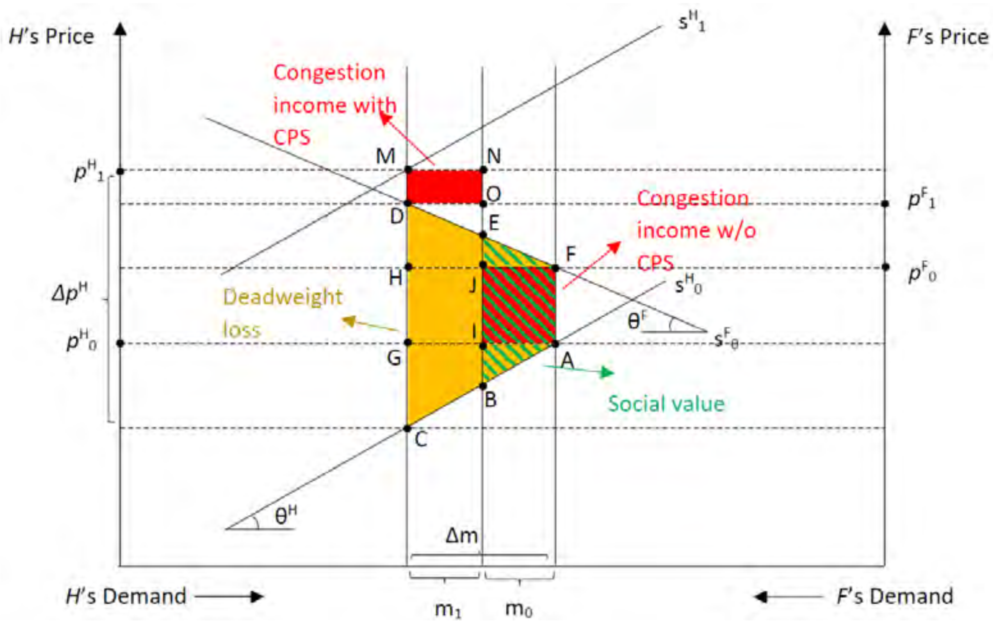
| **Conditional Variance Equations** | | | | | |
|---|---|---|---|---|---|
| **Great Britain** | | | | | |
| (Constant) | $0.922^{***}$ | $6.619^{***}$ | $1.397^{***}$ | $5.960^{***}$ | $1.427^{***}$ |
| | (0.126) | (0.646) | (0.149) | (0.500) | (0.163) |
| ARCH | $0.378^{***}$ | $0.573^{***}$ | $0.410^{***}$ | $0.596^{***}$ | $0.363^{***}$ |
| | (0.035) | (0.054) | (0.042) | (0.049) | (0.031) |
| GARCH | $0.597^{***}$ | $0.131^{***}$ | $0.567^{***}$ | $0.145^{***}$ | $0.591^{***}$ |
| | (0.027) | (0.039) | (0.027) | (0.037) | (0.025) |
| **France** | | | | | |
| (Constant) | $10.66^{***}$ | $9.605^{***}$ | $5.197^{***}$ | $9.100^{***}$ | $5.130^{***}$ |
| | (1.104) | (0.863) | (0.505) | (0.863) | (0.506) |
| ARCH | $0.749^{***}$ | $0.469^{***}$ | $0.304^{***}$ | $0.467^{***}$ | $0.302^{***}$ |
| | (0.054) | (0.040) | (0.022) | (0.039) | (0.022) |
| GARCH | 0.039 | $0.232^{***}$ | $0.578^{***}$ | $0.232^{***}$ | $0.582^{***}$ |
| | (0.047) | (0.049) | (0.024) | (0.049) | (0.024) |

Standard errors in parentheses. $^{*}p < 0.05$, $^{**}p < 0.01$, $^{***}p < 0.001$.

# E Model Extension

Figure 5 presents Case (b). Similar to Cases (a), the deadweight loss is the trapezium ACDF and $L = 1/2 \cdot (\theta^H + \theta^F) \cdot \Delta m^2 + \Delta m \cdot (p_0^F - p_0^H)$. The economic value is the trapezium ABEF and $S = 1/2 \cdot (\theta^H + \theta^F) \cdot m_0^2 + m_0 \cdot (p_0^H - p_0^F)$.

Figure 5: Impact of CPS on imports and deadweight losses, Case (b)




The change in congestion income is also $\Delta R = (p_1^F - p_1^H) \cdot m_1 - (p_0^F - p_0^H) \cdot m_0$, where in this case, $m_1 = -m_0 = K$.

Figure 6 presents Case (c), without the CPS, $H$'s net supply curve meets $F$'s net supply curve at point A, with prices equalized ($p_0^H = p_0^F$), no congestion income, and imports at $m_0$. The economic value is the triangle AEF, or $S = 1/2 \cdot (\theta^H + \theta^F) \cdot m_0^2$ and the deadweight loss is the triangle ABD, or $L = 1/2 \cdot (\theta^H + \theta^F) \cdot \Delta m^2$. As the interconnector flow is unconstrained with and without the CPS, there is no congestion income before or after and hence no change in congestion revenue. In this case, equations (2)-(4) still apply, given $p_j^H = p_j^F$.

Figure 7 presents Case (d), where exactly the same argument as Case (c) can be made. The triangle ABD measures deadweight losses $L$ and the triangle AEF measures economic value $S$. There is an increase in congestion income $\Delta R = (p_1^H - p_1^F) \cdot m_1$, as shown in Figure 7 as the rectangle DGHI. Again, equations (2)-(4) still apply in this case given $p_0^H = p_0^F$.

In Case (e), there is no change in trade or output and hence no distortion, but as $H$'s prices increase, so does the price difference $p_1^H - p_1^F$, with consequential changes in the congestion income $\Delta R = m_0 \cdot (p_1^H - p_0^H)$. As a result, there will be a transfer of revenue from $H$'s consumers to the foreign owners of the interconnectors, who, such as the French system operator, shares 50% of the interconnector revenue. Similar to Cases (a) and (b), the economic value from trade is also

Figure 6: Impact of CPS on imports and deadweight losses, Case (c)

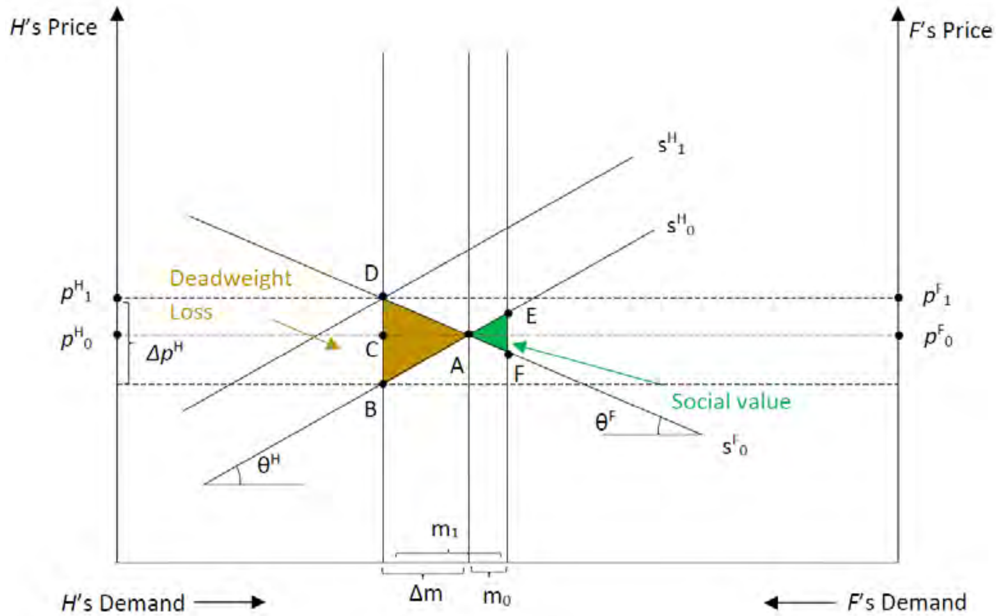
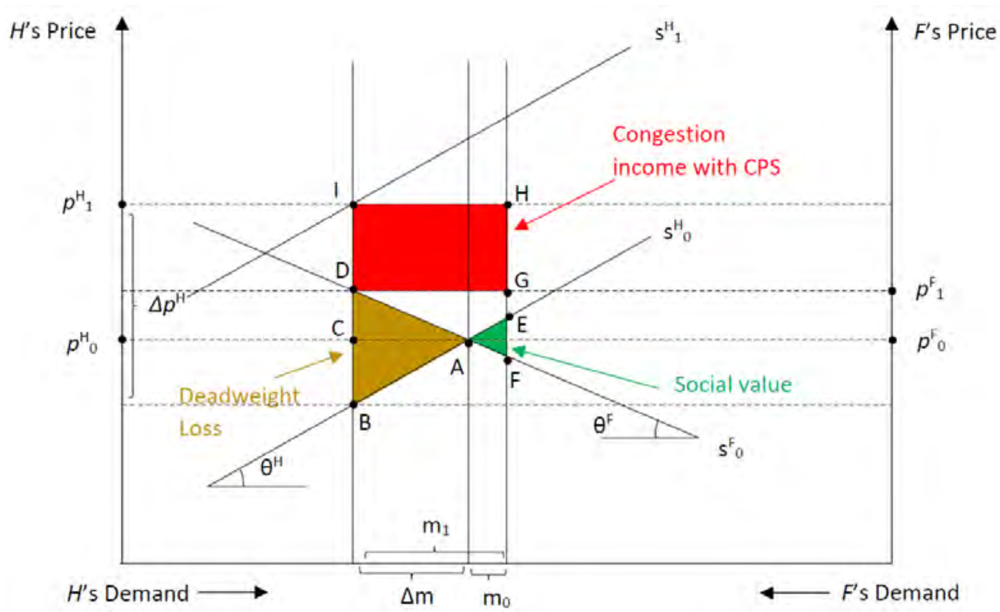



Figure 7: Impact of CPS on imports and deadweigh losses, Case (d)




$S = 1/2 \cdot (\theta^H + \theta^F) \cdot m_0^2 + m_0 \cdot (p_0^H - p_0^F)$. Finally, given $\Delta m = 0$ and $p_0^F = p_1^F$, equations (2)-(4) still apply.

# F Estimating counterfactual flows

Superscripts $H$ and $F$ represent the Home and Foreign countries, and subscripts 1 and 0 with and without CPS. Variables with "$\sim$" above are scenarios with no interconnector trade, and with "$-$" above are period averages. Subscripts representing hours are removed to simplify. The following steps estimate the counterfactual flows:[41]

1. For each hour, given the actual flows[42] ($m_1 > 0$ for importing and $< 0$ for exporting) and prices ($p_1^H$ and $p_1^F$), and the marginal effects of wind on prices ($\theta_1^H$, $\theta_0^H$ and $\theta^F$, different before and after April 2015 for $H$),[43] prices with *no trade* ($\tilde{p}_1^H$ and $\tilde{p}_1^F$) are

$$\tilde{p}_1^H = \begin{cases} p_1^H + m_1 \cdot \theta_0^H, & \text{before April 2015} \\ p_1^H + m_1 \cdot \theta_1^H, & \text{after April 2015} \end{cases}$$
$$\tilde{p}_1^F = p_1^F - m_1 \theta^F.$$

2. Assuming that without trade, €1/t$CO_2$ of the British CPS would raise $H$'s price by $\Delta p^H$,[44] prices *without the CPS* ($\tau$) *and trade*, $\tilde{p}_0^H$ and $\tilde{p}_0^F$, are

$$\tilde{p}_0^H = \tilde{p}_1^H - \Delta p^H \cdot \tau,$$
$$\tilde{p}_0^F = \tilde{p}_1^F.$$

3. Calculate the interconnector flow where the CPS is not applied ($m_0$) under the interconnector capacity constraint ($-K < m_0 < K$), taking the Mid Channel loss factor of the interconnector

[41] The ideal way is to include both IFA and BritNed, but it complicates the matters with negligible gain in terms of making the post-econometric results more robust. Therefore, we analyse IFA and BritNed separately.

[42] The day-ahead scheduled IFA flow is collected from RTE.

[43] From Table 2, for off-peak periods, $\hat{\theta}_1^H = 0.289$, $\hat{\theta}_0^H = 1.162$ and $\hat{\theta}^F = 1.898$; for peak periods, $\hat{\theta}_1^H = 1.047$, $\hat{\theta}_0^H = 0.826$ and $\hat{\theta}^F = 1.485$.

[44] Here we assume that the CPS has no direct impact on the French price other than through trade via IFA, which is supported by our regression results – conditional on interconnector capacities, the CPS had insignificant effects on the French and Dutch prices.

($l$) into consideration[45] as[46]

$$m_0 = \begin{cases} K, & \tilde{p}_0^H \cdot (1-l) > \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad K \leq \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}, \\ \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}, & \tilde{p}_0^H \cdot (1-l) > \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad K > \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}, \\ \frac{\tilde{p}_0^F - \frac{1+l}{1-l} \cdot \tilde{p}_0^H}{\frac{1+l}{1-l} \cdot \theta_0^H + \theta^F}, & \tilde{p}_0^H \cdot (1-l) < \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad -K < \frac{\tilde{p}_0^F - \frac{1+l}{1-l} \cdot \tilde{p}_0^H}{\frac{1+l}{1-l} \cdot \theta_0^H + \theta^F}, \\ -K, & \tilde{p}_0^H \cdot (1-l) < \tilde{p}_0^F \cdot (1+l) \quad \text{and} \quad -K \geq \frac{\tilde{p}_0^F - \frac{1+l}{1-l} \cdot \tilde{p}_0^H}{\frac{1+l}{1-l} \cdot \theta_0^H + \theta^F}, \\ 0, & \text{otherwise.} \end{cases}$$

4. Derive counterfactual prices under counterfactual flows:

$$p_0^H = \tilde{p}_0^H - m_0 \cdot \theta_0^H.$$
$$p_0^F = \tilde{p}_0^F + m_0 \cdot \theta^F.$$

5. Given actual and counterfactual prices for $H$ and $F$, calculate period average actual and counterfactual prices (i.e. $\bar{p}_1^H$, $\bar{p}_0^H$ for $H$, and $\bar{p}_1^H$, $\bar{p}_0^H$ for $F$). Then, given the average CPS during the period ($\bar{\tau}$), the effect of the CPS on $H$'s price, *counting in the effect of interconnector trade*, is $(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$.
6. From Steps 1-5, the only unknown parameters is $\Delta p^H$ in Step 2. Table 2 gives estimates of the marginal effects of the CPS on $H$'s (GB's) prices ($\widehat{\partial p^H/\partial \tau}$). Iteratively adjust $\Delta p^H$ in Step 2 and repeat Steps 2-5, until $(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$ in Step 5 is equal to $\widehat{\partial p^H/\partial \tau}$ from Table 2 Regression (iii).
7. Once $(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$ and $\widehat{\partial p^H/\partial \tau}$ equate, the associated flows and prices are the counterfactual prices and flows.

Because the undiluted (by trade) effect of the CPS on the GB price ($\Delta p^H$ in Step 2) is positively correlated with the diluted effect (($\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$ in Step 6, there is a unique $\Delta p^H$ that equalizes $\widehat{\partial p^H/\partial \tau}$ and $(\bar{p}_1^H - \bar{p}_0^H)/\bar{\tau}$ in Step 6.

In these calculations, $m_1$, $p_1^H$, $p_1^F$, $\tau$, $K$, and $l$ are observed, while $\theta_1^H$, $\theta_0^H$, $\theta^F$ and $\partial p^H/\partial \tau$ are estimated separately from econometrics for peak and off-peak periods.

[45]For IFA, the loss factor is $l = 1.17\%$.

[46]Suppose there is no capacity limit and $\tilde{p}_0^H > \tilde{p}_0^F$, then equalising the prices would require

$$(\tilde{p}_0^H - m_0 \cdot \theta_0^H) \cdot (1-l) = (\tilde{p}_0^F + m_0 \cdot \theta_0^F) \cdot (1+l),$$

or

$$m_0 = \frac{\tilde{p}_0^H - \frac{1+l}{1-l} \cdot \tilde{p}_0^F}{\frac{1+l}{1-l} \cdot \theta^F + \theta_0^H}.$$

The derivation is similarly for $\tilde{p}_0^H < \tilde{p}_0^F$.

Using point estimates of $\theta_1^H$, $\theta_0^H$, $\theta^F$ and $\partial p^H/\partial\tau$ only gives point estimates of the counterfactuals. To circumvent this problem, we assume that the actual values of $\theta_1^H$, $\theta_0^H$, $\theta^F$ and $\partial p^H/\partial\tau$ follow a jointly normal distribution, with mean and variance-covariances equal to the estimated values from Regression (iii). We then apply a Monte Carlo technique to take 500 random draws from the jointly normal distribution, and for each draw, we follow Steps 1-7 to obtain the counterfactual electricity prices and flows and hence the annual average electricity prices, net imports and congestion income. The resulting means and the standard deviations of the counterfactuals are reported in Table 3.

# G Estimating market distortion

In this subsection, we use a Monte Carlo technique to estimate the economic value of trade and deadweight losses from asymmetric carbon taxes discussed in Section 4.2. In addition, as the CPS does not apply to the increased GB imports, we estimate the loss in the GB government's carbon-tax revenue from the reduction in GB generation displaced,.

From Section 7.1 and Appendix F, given $\hat{\theta}_0^H$ and $\hat{\theta}^F$, and the estimated $m_0$, $\Delta m$, $p_0^F$ and $p_0^H$, the economic value is $\frac{1}{2}(\hat{\theta}_0^H+\hat{\theta}^F)\cdot m_0^2+m_0\cdot(p_0^H-p_0^F)$, and the deadweight loss is $\frac{1}{2}(\hat{\theta}_1^H+\hat{\theta}_1^F)\cdot\Delta m^2+\Delta m\cdot(p_0^F-p_0^H)$. Finally, the carbon-tax revenue loss is defined as the product between the change in trading volumes ($\Delta m$) and GB's marginal emission factors (MEFs), $\mu_1^H$, estimated quarterly in Chyong et al. (2020) between 2014-2017, and in this article we replicate Chyong et al. (2020)'s linear regressions to estimate GB's MEF between 2018-2020. The estimated MEF are reported in Table 7.

Table 7: GB's Marginal Emission Factors, 2014-2020

| Year | Quarter | Off-peak | Peak | Year | Quarter | Off-peak | Peak |
|---|---|---|---|---|---|---|---|
| 2014 | Q1 | -0.558 | -0.346 | 2017 | Q3 | -0.365 | -0.307 |
| 2014 | Q2 | -0.524 | -0.393 | 2017 | Q4 | -0.370 | -0.326 |
| 2014 | Q3 | -0.503 | -0.396 | 2018 | Q1 | -0.444 | -0.385 |
| 2014 | Q4 | -0.565 | -0.371 | 2018 | Q2 | -0.346 | -0.312 |
| 2015 | Q1 | -0.551 | -0.382 | 2018 | Q3 | -0.359 | -0.303 |
| 2015 | Q2 | -0.480 | -0.401 | 2018 | Q4 | -0.408 | -0.359 |
| 2015 | Q3 | -0.467 | -0.401 | 2019 | Q1 | -0.360 | -0.341 |
| 2015 | Q4 | -0.441 | -0.397 | 2019 | Q2 | -0.302 | -0.263 |
| 2016 | Q1 | -0.421 | -0.392 | 2019 | Q3 | -0.317 | -0.235 |
| 2016 | Q2 | -0.423 | -0.392 | 2019 | Q4 | -0.360 | -0.263 |
| 2016 | Q3 | -0.384 | -0.357 | 2020 | Q1 | -0.309 | -0.285 |
| 2016 | Q4 | -0.369 | -0.337 | 2020 | Q2 | -0.307 | -0.228 |
| 2017 | Q1 | -0.381 | -0.350 | 2020 | Q3 | -0.305 | -0.226 |
| 2017 | Q2 | -0.371 | -0.345 | 2020 | Q4 | -0.327 | -0.259 |

# H Estimating the impact of the CPS on BritNed

Table 8: M-GARCH Results (Regression (iv)), BritNed

| **Mean Equations** | | | | | |
|---|---|---|---|---|---|
| | | **Great Britain** | | **The Netherlands** | |
| | **Unit** | **Off** | **Peak** | **Off** | **Peak** |
| (Constant) | | $-1.347$ | $-19.43^{***}$ | $-23.99^{***}$ | $-44.70^{***}$ |
| | | (3.210) | (2.429) | (2.509) | (2.964) |
| GB load | GW | $0.419^{***}$ | $0.711^{**}$ | $0.180^{**}$ | $0.397^{***}$ |
| | | (0.072) | (0.042) | (0.059) | (0.052) |
| Dutch load | GW | $0.373^{***}$ | $0.141^{*}$ | $0.704^{***}$ | 0.162 |
| | | (0.103) | (0.066) | (0.074) | (0.087) |
| German load | GW | 0.004 | 0.025 | $0.162^{***}$ | $0.315^{*}$ |
| | | (0.046) | (0.022) | (0.039) | (0.030) |
| GB nuclear | GW | $-1.096^{***}$ | $-0.582^{***}$ | $-0.125$ | $0.476^{**}$ |
| | | (0.137) | (0.120) | (0.108) | (0.172) |
| Dutch nuclear | GW | $-1.838^{**}$ | $-2.323^{***}$ | $-3.597^{***}$ | $-4.927^{***}$ |
| | | (0.546) | (0.528) | (0.532) | (0.701) |
| German nuclear | GW | $-0.207^{**}$ | $-0.127^{***}$ | $-0.213^{**}$ | $-0.094^{***}$ |
| | | (0.080) | (0.065) | (0.068) | (0.016) |
| GB wind | GW | $-0.798^{***}$ | $-0.843^{***}$ | $-0.201^{***}$ | $-0.144$ |
| | | (0.047) | (0.028) | (0.033) | (0.037) |
| Dutch wind | GW | $-0.051$ | 0.073 | $-2.023^{***}$ | $-1.916^{***}$ |
| | | (0.169) | (0.131) | (0.154) | (0.173) |
| German wind | GW | $-0.014$ | 0.006 | $-0.103^{***}$ | $-0.094^{***}$ |
| | | (0.016) | (0.011) | (0.014) | (0.016) |
| BritNed capacity | GW | $-1.662^{**}$ | $-0.723^{***}$ | $2.763^{***}$ | $2.430^{***}$ |
| | | (0.529) | (0.538) | (0.525) | (0.645) |
| Coal cost | €/MWh | $0.131^{***}$ | $0.250^{***}$ | $0.368^{***}$ | $0.298^{***}$ |
| | | (0.034) | (0.040) | (0.025) | (0.035) |
| Gas cost | €/MWh | $0.739^{***}$ | $0.888^{***}$ | $0.441^{***}$ | $0.694^{***}$ |
| | | (0.025) | (0.026) | (0.022) | (0.029) |
| EUA | €/t$CO_2$ | $0.304^{***}$ | $0.388^{***}$ | $0.790^{***}$ | $0.887^{***}$ |
| | | (0.052) | (0.042) | (0.039) | (0.049) |
| CPS | €/t$CO_2$ | $0.503^{***}$ | $0.618^{***}$ | $-0.047$ | 0.087 |
| | | (0.040) | (0.034) | (0.036) | (0.045) |
| Time Dummies | | YES | YES | YES | YES |

| **Conditional Variance Equations** | | | | |
|---|---|---|---|---|
| | **Great Britain** | | **The Netherlands** | |
| | **Off** | **Peak** | **Off** | **Peak** |
| (Constant) | $9.442^{***}$ | $1.687^{***}$ | $2.011^{***}$ | $1.903^{***}$ |
| | (0.646) | (0.196) | (0.372) | (0.317) |
| ARCH | $0.601^{***}$ | $0.259^{***}$ | $0.243^{***}$ | $0.183^{***}$ |
| | (0.074) | (0.030) | (0.035) | (0.020) |
| GARCH | $-0.008^{***}$ | $0.636^{***}$ | $0.604^{***}$ | $0.751^{***}$ |
| | (0.002) | (0.027) | (0.053) | (0.024) |

Standard errors in parentheses. $^{*}p < 0.05$, $^{**}p < 0.01$, $^{***}p < 0.001$.

Data availability limits the analysis of BritNed from January 2015 to December 2020. Electricity load, wind and nuclear generation for The Netherlands and the net transfer capacity of BritNed are collected from the ENTSO-E Transparency Platform. As there is no reliable data source providing BritNed's day-ahead flows (for periods before 2020), the hourly BritNed day-ahead flow are simulated as follows:

- if both the unadjusted price differential (UPD) and adjusted price differential (APD)[47] are greater (or smaller) than zero, the interconnector capacity ($K$) will be fully used for importing (or exporting);
- if the APD is zero and the UPD is positive, then the day-ahead flow would be randomly (uniformly) allocated within the interval between zero and $K$;
- if the APD is zero and the UPD is negative, the day-ahead flow would be randomly (uniformly) allocated as a negative number between $-K$ and zero;
- if the APD and UPD have different signs, the day-ahead flow is zero.

The simulated day-ahead flow is used as an input for post-econometric estimation instead of an input for the regression.

Due to consistency and data quality concerns, the impact of GB's import/wind and the CPS on the GB prices are taken from Regression (iii) in Table 2, and the impact of Dutch wind on its prices is taken from our new estimates for BritNed. On the other hand, because The Netherlands' electricity load is much lower than GB and France but it is heavily interconnected with Germany, when running regression (ii)'s specification on BritNed we also include the day-ahead forecast of German load, renewables and its actual nuclear generation from ENTSO-E. The results are reported in Table 8 as Regression (iv), showing that during off-peak (peak) periods, a 1 GW increase in the Dutch wind generation is associated with a €2.0 (1.9)/MWh reduction in its off-peak (peak) wholesale prices. The magnitudes are higher than those in GB and France mainly because electricity demand in The Netherlands is much lower.

Table 8 can be used as a robustness check for our IFA study in Table 2. Both studies show some similar magnitudes for the slope coefficients of GB wind, coal and gas costs, as well as EU and British carbon price impacts on GB prices. German load, renewables and nuclear generation significantly affect the Dutch prices. Perhaps surprisingly, we find a very strong impact of Dutch nuclear generation on Dutch prices, even though The Netherlands only has one small nuclear plant (0.5GW capacity) supplying less than 5% of the Dutch electricity load. However, this might suggest that the nuclear power plant is pivotal in the Dutch electricity generation system and when it is shut down or under maintenance, the Dutch price would be increased by about €2/MWh.

We find that the EUA price has a much higher impact on Dutch than GB prices, despite that The Netherlands' marginal fuel is gas most of the time. One explanation is that The Netherlands is heavily interconnected with other continental countries such as Germany, whose marginal fuels are mostly coal plants. This is confirmed by the slope coefficients on coal (for Dutch prices). Fell et al. (2015), in estimating the relationship between electricity, fuel and carbon prices in various

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

Table 9: Statistical Measurements for BrtiNed: prices, flows, and congestion income

| **Electricity years** | **GB Prices ( €/MWh)** | | | **Dutch Prices ( €/MWh)** | | |
|---|---|---|---|---|---|---|
| | **w. CPS** | **w/o CPS** | **Δ** | **w. CPS** | **w/o CPS** | **Δ** |
| 15-16 | €53.25 | €41.27 | €11.97 | €36.25 | €35.35 | €0.90 |
| | | (1.28) | (1.28) | | (0.17) | (0.17) |
| 16-17 | €51.76 | €41.41 | €10.36 | €35.98 | €34.98 | €1.00 |
| | | (1.10) | (1.10) | | (0.17) | (0.17) |
| 17-18 | €52.70 | €42.89 | €9.80 | €39.87 | €38.77 | €1.10 |
| | | (1.05) | (1.05) | | (0.16) | (0.16) |
| 18-19 | €64.80 | €55.07 | €9.73 | €53.41 | €52.22 | €1.19 |
| | | (1.05) | (1.05) | | (0.17) | (0.17) |
| 19-20 | €43.72 | €34.15 | €9.58 | €36.71 | €35.09 | €1.61 |
| | | (1.05) | (1.05) | | (0.19) | (0.19) |
| Ave.(15-20) | €53.25 | €42.96 | €10.29 | €40.44 | €39.28 | €1.16 |
| | | (1.10) | (1.10) | | (0.17) | (0.17) |
| | **GB Net Import (TWh)** | | | **Congestion Income (m €)** | | |
| | **w. CPS** | **w/o CPS** | **Δ** | **w. CPS** | **w/o CPS** | **Δ** |
| 15-16 | 7.93 TWh | 3.83 TWh | 4.10 TWh | €127 | €56 | €70 |
| | | (0.71) | (0.71) | | (4.72) | (4.72) |
| 16-17 | 7.64 TWh | 3.31 TWh | 4.51 TWh | €117 | €62 | €55 |
| | | (0.69) | (0.69) | | (3.45) | (3.45) |
| 17-18 | 7.50 TWh | 2.52 TWh | 4.98 TWh | €92 | €44 | €47 |
| | | (0.65) | (0.65) | | (2.89) | (2.89) |
| 18-19 | 6.86 TWh | 1.48 TWh | 5.38 TWh | €75 | €37 | €38 |
| | | (0.66) | (0.66) | | (2.16) | (2.16) |
| 19-20 | 5.56 TWh | −1.73 TWh | 7.29 TWh | €49 | €31 | €18 |
| | | (0.72) | (0.72) | | (2.36) | (2.36) |
| Ave.(15-20) | 7.10 TWh | 1.85 TWh | 5.25 TWh | €92 | €46 | €46 |
| | | (0.68) | (0.68) | | (2.33) | (2.33) |

Standard errors in parentheses.

EU Continental countries, also found that during Phase II of the EU ETS, the marginal effect of the EUA price on Dutch electricity prices is around 0.8, and the marginal effect of coal prices on Dutch electricity prices is significantly positive [p.73] (their estimates are even higher than ours), consistent with our results.

Using the result from Tables 2 and 8, and applying the same steps as Section F, Table 9 reports the GB and Dutch wholesale prices without the CPS (i.e., the counterfactual), as well as the net import and congestion income of BritNed. Our results for BritNed are consistent with our IFA analysis in Sections 7.1-7.3. During electricity years 2015-2020, the CPS on average raised Dutch wholesale prices by €1.16/MWh, or 3%. About 74% (5.25 TWh) of GB's net import from The Netherlands is due to the CPS, and the associated congestion income doubled from €46 m/yr to €92 m/yr.

The effects of the CPS on the Dutch price, GB's net import and congestion revenue from BritNed are more than half of those from our IFA estimates. Although BritNed is half the size of IFA, the slope of the Dutch supply curve (measured by the impact of wind on the Dutch price) is steeper than GB and France because of its lower electricity load. Table 10 further shows that during

Table 10: BritNed: surplus, distortion and losses

| **Electricity years** | **Economic Value (m €)** | **Deadweight Loss (m €)** | **GB CPS Rev. Loss (m €)** |
|---|---|---|---|
| 15-16 | €82 | €19.5 | €41.3 |
| | (5.56) | (5.71) | (7.07) |
| 16-17 | €87 | €20.5 | €35.4 |
| | (4.27) | (5.38) | (5.47) |
| 17-18 | €70 | €22.9 | €35.6 |
| | (3.34) | (5.82) | (4.72) |
| 18-19 | €66 | €25.7 | €37.2 |
| | (2.49) | (6.45) | (4.70) |
| 19-20 | €54 | €39.2 | €41.7 |
| | (2.28) | (8.48) | (4.29) |
| Ave. 15-20 | €72 | €25.6 | €38.2 |
| | (2.76) | (6.34) | (5.20) |

Standard errors in parentheses.

electricity years 2015-2020, the economic value of BritNed is €72 m/yr and the deadweight loss is €25.6 m/yr, slightly above the half size of the IFA loss. The UK Government has lost about €38.2 million worth of tax revenue, 4% of its total 2017 CPF receipts.

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