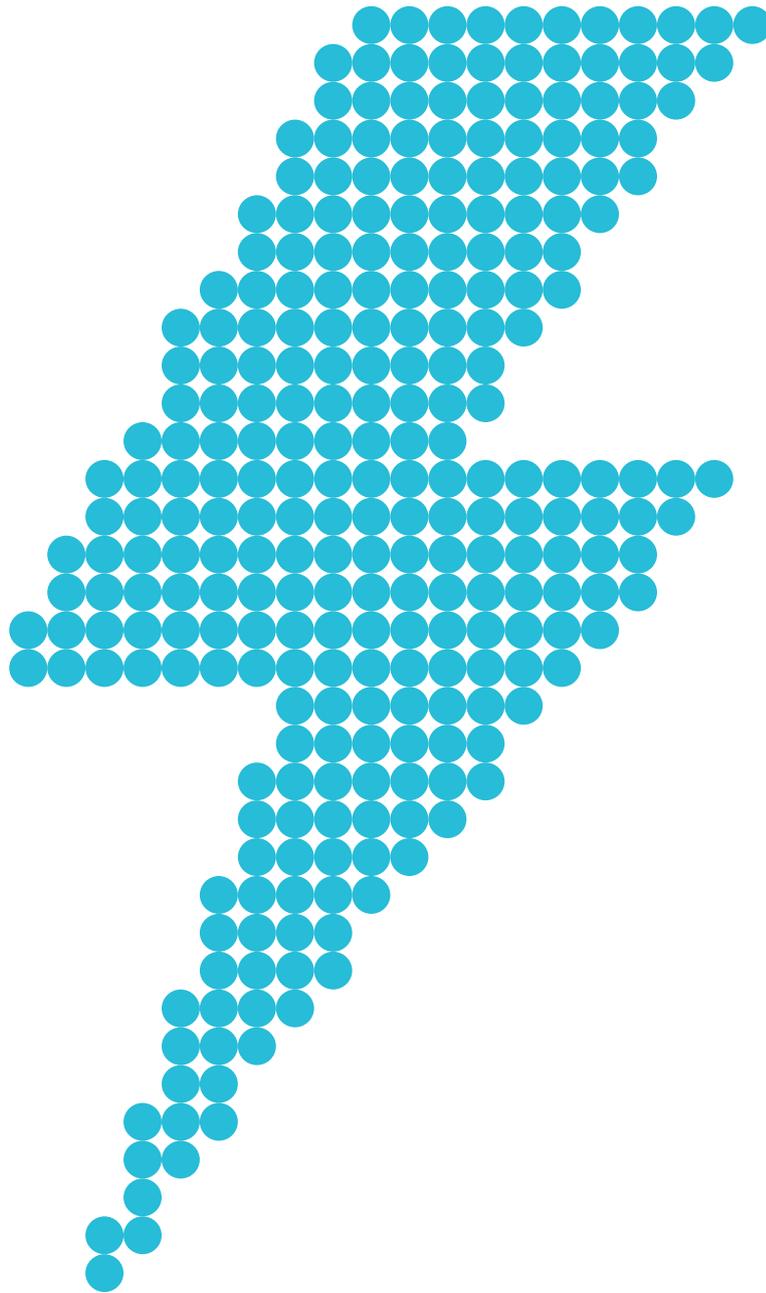


SEPTEMBER 2021

POLICY BRIEFING 

# DELIVERING COMPETITIVE INDUSTRIAL ELECTRICITY PRICES IN AN ERA OF TRANSITION





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## EXECUTIVE SUMMARY

In recent years, concerns have grown that UK industry pays too much for its electricity, particularly compared to other European and international competitors. Close examination shows a more nuanced picture, but also highlights some important differences between how the UK and some of its continental neighbours approach pricing for industrial electricity consumption, and how various costs are recovered from different parts of industry and society.

Until 2012, industrial electricity prices in the UK remained close to the EU average. However, between 2012 and 2016, the gap widened, peaking in 2015, as a result of four key factors:

-  **Changing fossil fuel prices**, with natural gas as the dominant generator in the UK becoming more expensive, and coal more extensively used on the continent becoming cheaper;
-  The **need for new investment throughout the ageing UK system**, including transmission upgrades, with costs recovered across all UK electricity consumers, rather than weighted away from energy-intensive industry and toward domestic and smaller industrial consumers, as in Germany, France and Italy;
-  **Exchange rates**, with rising Sterling up until December 2015, followed by sharp decline relative to the Euro;
-  A **more integrated approach to the energy transition in some continental countries** including the form and balance of policy costs (e.g. renewables support relative to carbon pricing) and their recovery.

**By 2016, industrial electricity prices in the UK were 36% above the EU average (although some major industrial consumers in the UK were able to recover a greater proportion of electricity costs through compensation mechanisms than in other countries).** By 2019, electricity prices had increased across much of the continent, including Germany and France, driven by a combination of increasing coal and gas prices,<sup>1</sup> a rising carbon price for electricity generated by fossil fuels under the EU ETS, and the policy cost of legacy renewable deployment subsidies from the early 2000s to the mid-2010s (recovered through levies on electricity prices).

Prices in the UK have also increased. However, depending on interpretation of apparently anomalous data reported by Eurostat from government submissions, UK industrial electricity prices to 2019 **either further diverged, reaching up to 44% above the EU average, or increased only slightly, narrowing the gap, which however would still be 25% above the EU average.** It remains unclear whether the discrepancy is due to statistical accounting difficulties or some degree of double counting (see box 1). Either way, the net electricity cost to companies previously receiving compensation for renewables support costs have increased markedly.

Electricity generated from fossil fuels faces a greater carbon price in the UK than on the continent, and while large industrial consumers in key EU economies are heavily shielded from the costs of upgrading, maintaining and operating networks and supporting renewable energy, such costs in the UK are more evenly spread across all electricity consumers. The UK industrial price in 2016 included all renewable support costs, with large consumers subsequently receiving compensation. By 2019 this had changed, such that many of these consumers received exemptions from many of these renewables support costs in the prices they paid, increasing comparability with treatment in the EU.

The role of carbon pricing and increasing renewable penetration on electricity prices is complex. The liberalised electricity markets in UK and EU typically run on a marginal (mainly fuel) cost basis, with implications explained below. The UK's Carbon Price Floor (CPF), introduced to underpin a weak EU ETS in 2013, has been instrumental in driving the fastest rate of electricity generation decarbonisation seen anywhere in the world. It did so by pushing coal, which is around twice as CO<sub>2</sub>-intensive as natural gas, from the bedrock of UK electricity generation to the margin alongside natural gas in just a few years. This placed upward pressure on electricity prices, particularly in 2015/16. However this picture is rapidly changing. Coal is now less than 2% of UK generation, and will be entirely absent from 2024, meaning **the influence of a given carbon price on the wholesale electricity price is now substantially weaker.**

<sup>1</sup> At the time of writing (September 2021), energy prices across Europe, including the UK, are surging also because of sharp increases in both gas and coal prices, which can also impact EU ETS prices.



**Most forms of renewables, which generate electricity from the wind, sun or water, have zero fuel (and thus near-zero marginal) costs, meaning they are usually first to enter the electricity market when they generate.** This pushes the most expensive generator out of the market, at a given level of demand, reducing the wholesale price for electricity (known as the ‘Merit-Order Effect’). However, historically, renewable energy has been much more expensive to build than fossil fuel generators and subsidised by governments with costs recovered by often substantial levies on electricity bills. The net effect has so far been to increase electricity prices for most consumers in the UK, and for small industrial and domestic consumers in particular in other countries – however, as discussed below, this trend is soon likely to move into reverse.

historically, renewable energy has been more expensive to build than fossil fuel generators and subsidised by governments with the investment costs recovered by often substantial levies on electricity bills. The net effect has so far been to increase overall electricity prices for most consumers in the UK, and for small industrial and domestic consumers in particular in other countries.

however, the cost of many renewables has plummeted in recent years (resulting in large part from economies of scale and learning driven by earlier deployment policies), and approaches to policy support have become more sophisticated. Many new renewables are now cheaper than fossil fuel generations, which under the existing UK support systems means that the overall impact on electricity prices could also start to move into reverse (see Box 1.2), and which opens possibilities for much cheaper electricity (see recommendations).

The future evolution of industrial electricity prices in the UK, and their differential with continental prices, will depend crucially on:

the relative carbon prices applied to UK and continental generation through the UK ETS (and Carbon Price Floor) and EU ETS, respectively, alongside the future role of coal in generation mixes (although absent by the end of 2024 in the UK, coal generation may continue much longer in Germany), and relative coal and gas prices;<sup>2</sup>

<sup>2</sup> Coal phase-out in Germany is only committed by 2038, though an increasing number of plants are already retiring under the economic impact of higher carbon prices and rapidly rising renewables penetration.

the rate at which renewable energy penetration increases and their costs continue to reduce, and how legacy costs are recovered; and

how electricity networks – including interconnection – are expanded and operated in the future and their costs recovered, to manage and facilitate the growing penetration of variable renewables on the power system and the increasing electrification of the economy.

Given this context, below we set out specific options the UK government could consider to moderate the price of electricity available to UK industry, and drive convergence with those available in Western Europe, and beyond. **Many of these policy options would benefit not just large, electro-intensive consumers, but also help reduce electricity prices for small industrial, commercial and domestic consumers.** These proposals also aim to support the widespread electrification of the economy as a core pillar of rapid decarbonisation, and to deliver it in a cost-effective, fair and equitable way.

**1 Restore and maintain an efficient investment framework for the cheapest mature renewables, with foresight on a rising carbon price in the 2020s to reduce investor risk:** The government should launch a full-scale review of policy towards onshore renewables, recognising they no longer require subsidy if political risk is minimised, and that developers have confidence that the full value of their investment may be recovered. Offshore wind should be further supported through investment in surrounding supply chains and infrastructures.

**2 Establish an integrated approach to network development, funding and pricing:** Independent Future System Operator Objective(s) should include more coordinated oversight of future generation and network developments, to minimise costs and facilitate a transition to Net Zero. The role of Distribution Network Operators must also be clarified. Revenues from the UK’s carbon pricing mechanisms could also be ringfenced and used to help fund key network investments.



### **3 Support continued growth of interconnection (through Ofgem's cap-and-floor revenues system) and offshore grid development, and reduce friction in electricity trade:**

Each 1GW of interconnection capacity can reduce UK wholesale electricity prices by 1–2% by making available low cost, low carbon imports from other markets, and can facilitate balancing of increasingly variable supply and increasing demand. As a priority outcome for the arrangements to be put in place by April 2022 pursuant to the EU-UK Trade and Cooperation Agreement, the government should seek to restore UK participation in the day-ahead electricity markets with neighbouring EU countries, the absence of which is estimated to result in £45 million in lost trade in 2021. It should also seek to re-engage with the North Seas Energy Cooperation (NSEC) group, to encourage and facilitate widespread expansion of offshore wind in around the UK's North Sea waters.

### **4 Facilitate cross-border electricity contracting incorporating UK carbon prices:**

The government should establish a new structure for direct cross-border industrial electricity purchases, charging UK carbon prices on purchased electricity to avoid carbon-intensive generation in other markets having an unfair advantage in the UK market. Such arrangements should be considered in light of the EU's new Carbon Border Adjustment Mechanism (CBAM), which will cover trade in electricity.

### **5 Support industrial involvement in the Capacity Market and other electricity service markets:**

The government should ensure that the Capacity Market (and other electricity service markets) are efficient and fit to encourage demand-side response, thereby encouraging industrial participation in these mechanisms, and help industrial consumers to realise the economic value of these services to both reduce overall system costs and offset the cost of their electricity consumption.

### **6 Establish a market for long-term, zero carbon and tradable electricity contracts.**

In the medium term, standardised structures of long-term, tradeable zero-carbon electricity contracts should be made available to business consumers, grounded in the declining cost of unsubsidised renewable electricity sources. Consumers holding these contracts would thereby avoid the indirect costs of carbon prices, and the volatility of fossil fuel prices. This could be facilitated through a 'green power pool', operated in parallel to the electricity spot market.

### **7 Investigate options for spreading historic policy costs more evenly across energy sources, including moving some policy costs from electricity prices to gas prices over time.**

Domestic and industrial consumers of gas typically pay lower prices than many of their European counterparts. For sectors where gas is currently the main fuel and a shift to electricity is not possible in the short term, government should explore interim mechanisms to ensure these sectors remain competitive during the gradual transition towards electrification or other low-carbon fuel.

### **8 Improve scrutiny, transparency and understanding of reported electricity price data.**

Most analysts and commentators take for granted prices as reported, and typically assume that separately reported components (wholesale and supply costs, network costs, and taxes and levies) are additive and independent. However the entire structure and drivers of prices are changing, are interdependent, and some are transitional depending on the evolution of the system as well. In order to effectively assess why and by how much electricity prices faced by UK industrial consumers are changing, both over time and relative to international competitors, reliable data is crucial with transparent assignment of component drivers.



## INTRODUCTION

In recent years, concerns have grown that UK industry pays too much for its electricity, particularly compared to other European and international competitors. Close examination shows a more nuanced picture, but also highlights some important differences between how the UK and some of its continental neighbours approach pricing for industrial electricity consumption, and how various costs are recovered from different parts of industry and society.

At a time when the UK government is focused on charting its future outside the European Union and driving economic recovery in the wake of the COVID-19 pandemic, this briefing summarises the extent to which industrial electricity prices in the UK are different to some of our key continental neighbours (Germany, France and Italy), sets out the key trends that explain those differences, and suggests recommendations to moderate the electricity prices paid by UK industry in the future.

This briefing summarises and updates the detailed insights and policy recommendations described in our previous report for the Aldersgate Group, '[UK Industrial Electricity Prices: Competitiveness in a Low Carbon World](#)' published in February 2018. While the 2018 report focused on 2016 data, this briefing examines data for 2019.<sup>3</sup> Key changes to electricity prices, their drivers and future prospects are examined, and policy recommendations to moderate prices and drive convergence with key competitors in Europe and beyond, are offered.

## LOOKING BACK: HAVE UK INDUSTRIAL ELECTRICITY PRICES BEEN EXCEPTIONAL?

Since 2000, UK<sup>4</sup> wholesale electricity prices have been mainly determined by the cost of operating gas plants built in the 1990s, given the UK's highly liberalised version of electricity markets. Network costs were driven down by a simple regulatory formula. There was surplus capacity, no capacity-related payments, and little investment. Consequently, prices remained low as long as gas prices did – and rose sharply as fossil fuel prices escalated from 2004.

In parallel, the historic tensions between the government drive to introduce renewables and the regulated expenditure on electricity networks also led to congestion on the network, resulting in renewables (mainly in Scotland) paid compensation when not permitted to generate at their full capacity. **This approach contrasted with some continental systems, where renewable support policies were better coordinated with investment in the overall network infrastructure and were more cost effective.**

Between January 2008 and 2012, UK electricity prices for large industrial consumers rose in a way that broadly mirrored the impact of the gas price on the UK wholesale electricity price and remained close to the EU (and German) average over that period. Between 2012 and 2016, the gap with the continent widened, peaking in 2015, as a result of the following four key factors:

• **Changing fossil fuel prices**, with natural gas in the UK becoming more expensive, with coal more extensively used on the continent becoming cheaper;

• The **need for new investment throughout the ageing UK system**, including transmission upgrades, with costs recovered across all UK electricity consumers, which differs from the cost recovery approaches in Germany, France and Italy, where costs are more heavily loaded onto smaller commercial and domestic consumers;

• **Exchange rates**, with rising Sterling up until December 2015, followed by sharp decline relative to the Euro;

• A **more integrated approach to the energy transition in some continental countries** including the form and balance of policy costs (e.g. renewables support relative to carbon pricing) and their recovery.

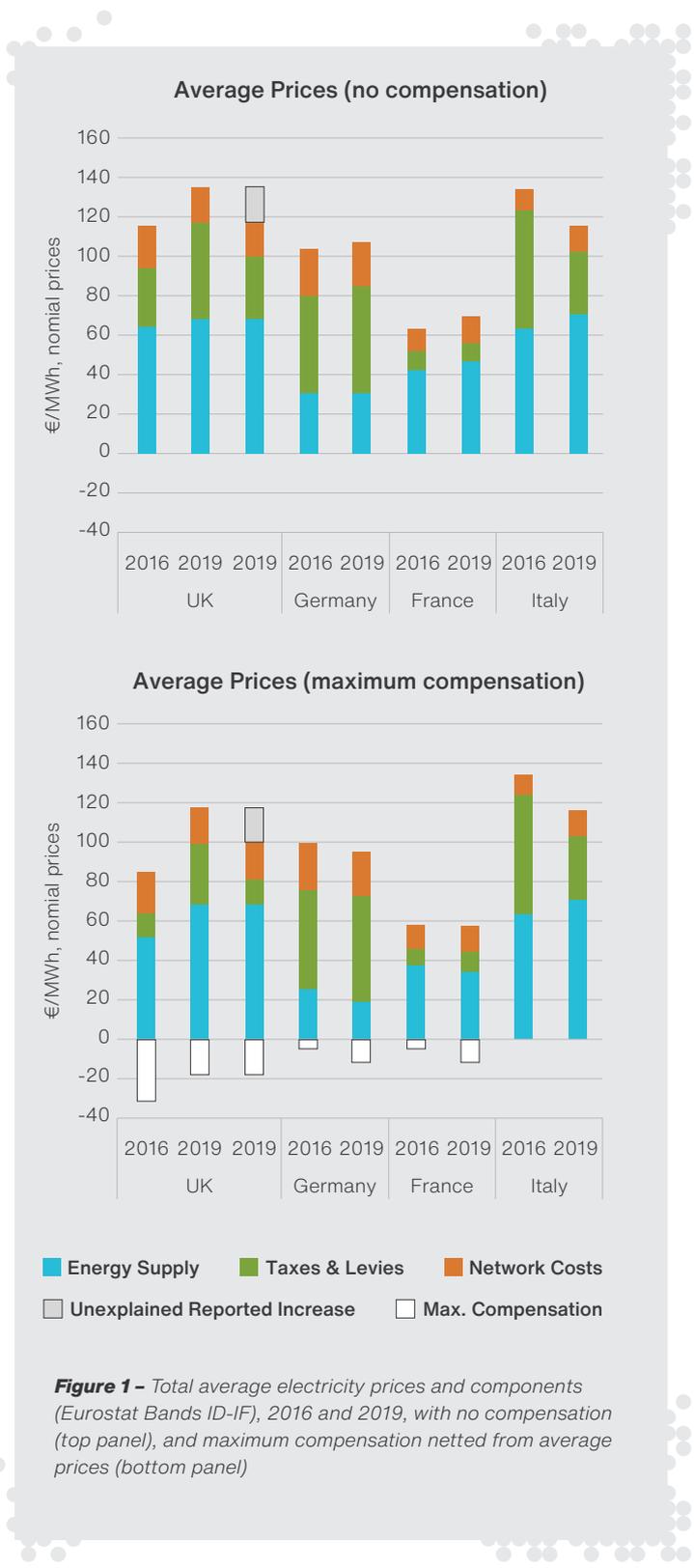
<sup>3</sup> This analysis is based on data from the EU's statistical agency, Eurostat. Delays in reporting mean that the most recent year with complete data is typically at least two years prior.

<sup>4</sup> In this briefing, data presented for the UK often reflects GB only (excluding Northern Ireland), reflecting the separation between electricity markets in GB and Northern Ireland (which is part of the Irish Single Electricity Market). However, for the purposes of this report, GB and UK may be considered largely synonymous.



Reported average electricity prices experienced by industrial consumers in the UK in 2016 were 36% above both their level in early 2008,<sup>5</sup> and the EU average (which remained largely stable between 2008 and 2016), but this does not consider the impact of compensation for low carbon policy costs in the UK. Until April 2018, compensation schemes in the UK were much more substantial than those in our key continental neighbours for those processes, businesses and sectors able to receive them. Nevertheless, **those processes, businesses and sectors outside compensation schemes (or that received only limited support) faced higher net electricity prices compared to their counterparts in most European countries.**

Figure 1 (top panel) illustrates the change in reported industrial electricity prices **between 2016 and 2019 for the UK, Germany, France and Italy, including their three main components (each discussed in further detail below). Between 2016 and 2019, reported UK prices increased by 17%, reaching 44% above the EU average. However we also identify changes which seem inconsistent with other data informing our 'bottom-up' estimates, notably concerning taxes and levies.** Extensive discussions with BEIS have not yet yielded a clear explanation for a near doubling of the 'taxes and levies' reported through Eurostat for large energy consumers in the single year from 2018 to 2019 – an increase close to €20. Possible explanations include statistical errors arising from complex changes in the approach to compensation, exemptions, and data collection in the UK, but we have been independently unable to rule out the possibility that carbon prices have been double-counted to some degree (see box 1). The maximum possible rate of this or other double-counting is also illustrated in Figure 1: this would mean that in fact electricity prices for large industrial consumers to 2019 increased by less than in Germany and France (by 3% and 10%, respectively), while prices in Italy reduced by 14%.



**Figure 1** – Total average electricity prices and components (Eurostat Bands ID-IF), 2016 and 2019, with no compensation (top panel), and maximum compensation netted from average prices (bottom panel)

<sup>5</sup> Prices are an average of those reported by Eurostat for industrial consumption Bands ID-IF (annual consumption 2 GWh to 150 GWh). Prices exclude auto-generation. All monetary values in this briefing are nominal.



## ACCOUNTING FOR CARBON PRICING – THE POTENTIAL FOR DOUBLE-COUNTING

Eurostat requires EU member states to report total electricity prices with a breakdown into three components (illustrated in the figure below):

- 1 energy and supply** (generation, distribution and supply costs),
- 2 network costs,** and
- 1 taxes and levies.**

The latter category is relatively straightforward to separate at least in principle for taxes and levies that apply to the consumption of electricity (notwithstanding the fact that they may indirectly reduce wholesale prices through the ‘merit order’ effect).

However, from 2017, the guidance regarding the ‘taxes and levies’ component also flagged other charges, such as carbon pricing as an example of an environmental levy though it is unclear whether (or how) this was intended to include the EU ETS. Carbon pricing is obviously based on the economic principle of making polluters pay, and applied to generators, the costs get passed through broadly into wholesale electricity prices.

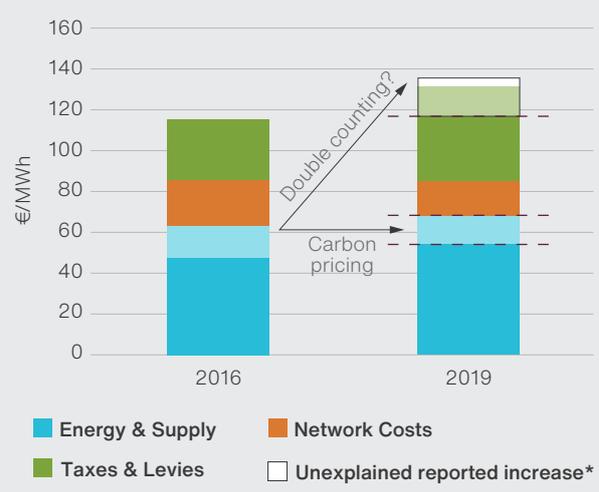
If such carbon costs are simply added into taxes and levies, consequently there would be double-counting, if these costs were not subtracted from the wholesale prices included in energy and supply, as illustrated in Figure 2 below. To make such correction accurately would be very complex because the impact of carbon pricing on the electricity price reflects marginal costs and is thus not identical to the overall carbon cost paid by the generators.

Notwithstanding the change in guidance, we have established that other countries, including Germany, France and Italy, have reported actual energy and supply costs, i.e. including impact of EU ETS there and not as part of ‘taxes and levies.’ The UK BEIS survey

asked electricity suppliers to report carbon prices that apply to electricity generation in the UK alongside taxes and levies placed on consumption. In practice, the extent to which suppliers follow this guidance is uncertain: at the time of writing, one large electricity supplier has confirmed that they do not do this, and BEIS assure us that in practice, they believe no-one has subtracted carbon costs from wholesale prices and added them to taxes and levies.

However we have not been able to rule out the possibility that in some cases, carbon costs have also been included in taxes and levies – thus ‘double counting’ – as an element in the discrepancies we observe in taxes and levies data (see Figure 6 and associated discussion).

We estimate the maximum value of the impact of carbon pricing on energy & supply costs in 2019 to be around €14/MWh, based on estimates of marginal impacts of carbon pricing on wholesale prices; whether (or how much) any ‘double counting’ might add to reported prices remains unclear.





In the UK, Germany and France, increasing prices between 2016 and 2019 were driven by a combination of increasing fossil fuel (coal and gas) prices, but particularly increasing carbon prices on electricity generated by these fuels, and cost recovery mechanisms for legacy renewable deployment policies. However, the net influence of carbon pricing and renewable deployment on electricity prices in different countries is complex, as discussed below. In Italy, the price reduction is the result of a new discount on taxes and levies afforded to energy-intensive industrial consumers, also discussed below.

Further complications arise from the exemptions and compensations that some major industrial sectors receive. Figure 1 (bottom panel) shows the *maximum* value of policy cost compensation available to qualifying industrial (energy-intensive, trade-exposed) consumers, and the effect they have on the *average* reported prices. **Such compensations are not included in reported prices but influence the effective prices consumers pay for electricity.** In the UK, Germany and France, this compensation includes the indirect cost of the EU ETS applied to electricity generation, and in the UK, the Carbon Price Floor (discussed below). In 2016, the UK also provided compensation for the cost of renewable energy support mechanisms, but in 2018 these compensations became exemptions, which are now included in reported prices (and are discussed further below).

Much of the UK debate on electricity prices has been at a level of either technical detail or sweeping (and often questionable) generalisations. However, **the way in which the four factors highlighted above have affected industrial electricity prices – and in particular, differentials with the continent – are often complex and multi-faceted, and reflect wider choices in terms of policy and regulatory approaches.**

## THE COMPLEX INFLUENCES OF CARBON PRICING AND RENEWABLES

In competitive electricity markets, generators are typically brought online according to their position within the 'merit order': the ranking of available generators according to the price they offer to the market in order to connect a given capacity. Generators are contracted based on ascending price, until connected capacity matches demand. All generators then receive the price of the final connected (marginal) generator for a given contracted period. Competitive pressures mean that generators tend to submit offers at or near their marginal costs of generation, driven primarily by underlying fuel prices, but also any applicable carbon prices.

### ***The EU ETS and the UK's Carbon Price Floor: impact to 2016***

Since 2005, all electricity generation (and direct emissions from industry) in the EU – until 31<sup>st</sup> December 2020, including the UK – has been subject to a carbon price under the EU's Emissions Trading System (EU ETS). A carbon price increases the cost of generation from coal more than it does from natural gas, due to its greater CO<sub>2</sub> intensity. In 2016, hard coal (anthracite) plants were the dominant price-setting generators in Germany. In Italy, it was natural gas, while in France it was a combination of hard coal and gas at times of high demand, and nuclear and hydroelectricity at other times (with France often acting as a net exporter of electricity). The low EU ETS price in 2016 had little influence on this, with an implied additional cost of generation at €4/MWh and €1.9/MWh for hard coal and natural gas respectively, and zero for nuclear and hydropower (and other renewables). Consequently, the EU ETS is likely to have had a small influence on wholesale electricity prices in these countries to 2016.

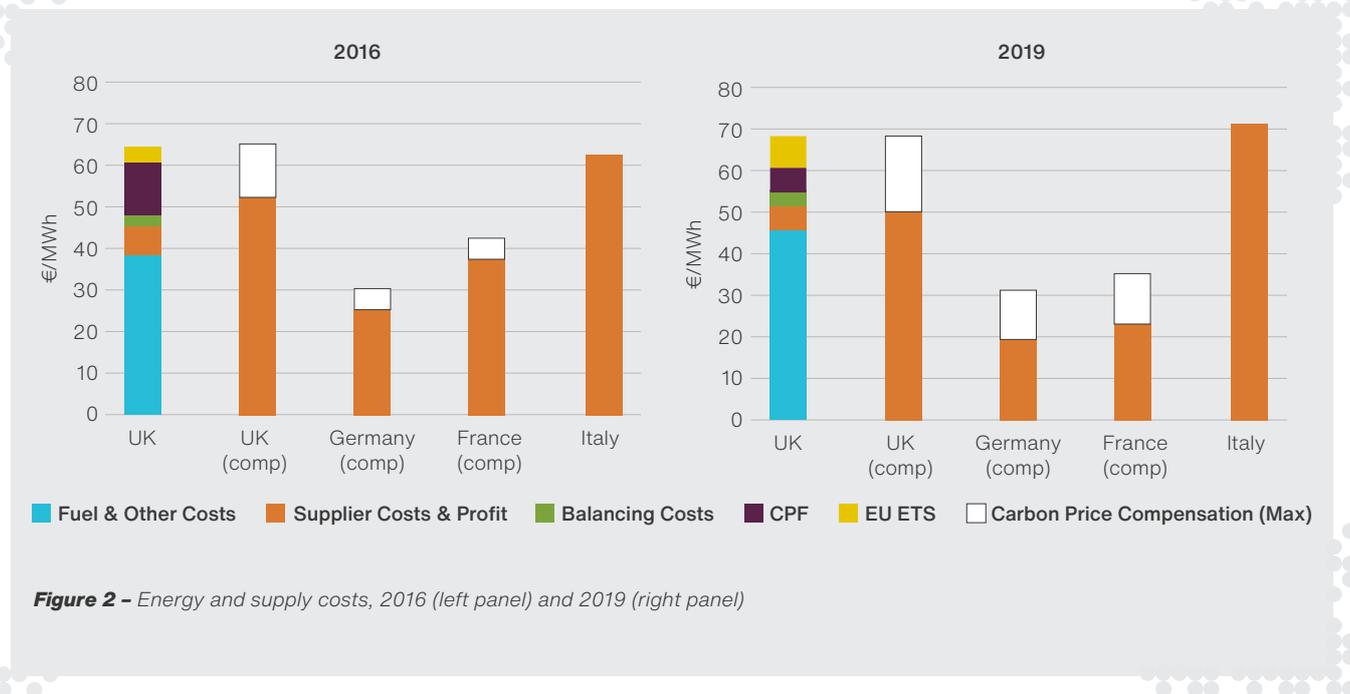


In 2013 the UK introduced a unilateral 'Carbon Price Floor' (CPF) for CO<sub>2</sub> emissions from electricity generation, initially set at £9/tCO<sub>2</sub> but rising to £18/tCO<sub>2</sub> in April 2015, and payable in addition to the EU ETS. Reasons for its introduction included the collapse in EU ETS prices (which created an even larger divergence of the price paid from the estimated social cost of climate damages), a desire to give industry greater certainty about the direction of carbon prices for planning, and specifically to offer a more consistent context for supporting low carbon investment. Between 2000 and 2015, cheap coal provided the foundation of the UK's electricity generation, with more expensive natural gas the dominant marginal price-setter. With the introduction of the CPF, the cost of coal-based generation increased substantially, and it began to move increasingly down the merit order to the price-setting margin along with gas, with this trend accelerating from 2015.

Between 2013 and 2016, coal generation decreased from over 36% of (largely baseload) electricity supply to just 9% (of largely marginal) supply. As the CPF from 2015 placed an additional cost of around €17/MWh and €8/MWh on generation from hard coal and natural gas respectively, **the much greater total carbon price placed on electricity generation in the UK has had a substantially larger influence on wholesale electricity prices, compared to the other countries examined.** This was due both to the larger overall carbon price, making generation from both coal and gas more expensive compared to the other countries examined, but also to the rapid marginalisation of coal generation it induced. While in the short term, the increasing use of coal as a marginal generator in the UK will have increased wholesale electricity prices more than if gas remained the dominant price-setter, in the medium term, as coal is progressively eliminated from the generation mix, this effect is reversed and eventually eliminated. As discussed below, this reversal is already well underway.



**The EU ETS and the UK's Carbon Price Floor: changes between 2016 and 2019**



**Figure 2** – Energy and supply costs, 2016 (left panel) and 2019 (right panel)

Figure 2 illustrates the ‘energy and supply’ components of electricity prices in 2016 and 2019, with estimates of the contributions of its various sub-components.

**Between 2016 and 2019, the UK’s CPF rate remained static, while the EU ETS price, following various reforms, increased substantially, reaching an average of around €25/tCO<sub>2</sub>** (with the value of potential compensation increasing largely in tandem). This is the primary driver behind the continuing, rapid reduction in the use of coal-based generation in the UK, which declined to just 2.1% of generation by 2019, with natural gas reclaiming its position as the dominant price setting generator.

The increase in energy and supply costs in Italy is likely due to a combination of increasing gas and EU ETS carbon prices. However, a strengthened EU ETS appears to have had relatively little effect on wholesale electricity prices in France, as might be expected given its generation mix (but also see below for details on industrial electricity price contracts in France). The effect seems to be also limited in Germany, where the carbon price led natural gas to displace hard coal, overall electricity demand fell, and renewable electricity generation continued to grow<sup>6</sup> – all placing downward pressure on wholesale electricity prices and the role of carbon prices within it.

**Since 2019**, the UK’s CPF has remained static, but the EU ETS price has continued to rise, reaching over €50/tCO<sub>2</sub> since mid-2021. However, the UK ceased its participation at the end of 2020, and in its place, has launched the UK ETS. The UK ETS has a similar design to the EU ETS, and has set similar prices following its first permit auction in May 2021. The relative effect these carbon pricing instruments will have in future in the UK, Germany, Italy and France will primarily depend on three factors:

- 1** The degree to which their prices track or diverge from one another.
- 2** The extent to which CO<sub>2</sub>-intensive coal generation remains on the grid, and act as marginal (price-setting) generators. In the UK, coal-based generation will cease entirely in 2024, while in Germany, coal phase-out is targeted for 2038. (though under current trends and economic conditions many may retire much earlier).
- 3** The extent to which renewable energy, with its near-zero marginal cost of generation, populates the merit order stack below.

<sup>6</sup> Hein et al. (2020) *The German Power Market: State of Affairs in 2019*, Agora Energiewende, Berlin



### Renewables, the ‘Merit-Order Effect’ and deployment cost recovery

Germany’s Energiewende (Energy Transition) has been the world’s most ambitious programme of renewable energy deployment; the large initial investments have led to major cost reductions, in both onshore and offshore renewables. The UK has also played a substantial role in driving down the cost of offshore wind in particular, through targeted programmes of investment and deployment.

**Generators of renewable electricity often have zero fuel costs, as the energy they convert to electricity usually comes directly from the wind, sun or flowing water.<sup>7</sup>**

**As such, they have near-zero marginal costs, and so when they are available, they are typically first in the merit order. For a given level of demand, this displaces more expensive marginal (price-setting) generators at the end of the merit order, thus reducing the market clearing price. Consequently, as renewable electricity penetration increases, wholesale electricity prices generally decrease.** This is known as the ‘merit order effect’, and is conceptually illustrated in Figure 3.

In 2016, renewable power accounted for 32% of generation in Germany, and 24% in the UK (in Italy and France, it was 34% and 19%, respectively, and dominated by hydroelectricity in both cases). In Germany, this led to a reduction in average wholesale prices of €14–16/MWh for 2016,<sup>8</sup> and around £6/MWh (€7/MWh) in the UK since 2004.<sup>9</sup> The deployment of wind and solar PV in Italy reduced average wholesale prices by around €16/MWh in 2013.<sup>10</sup> **Electricity generation from renewables increased significantly between 2016 and 2019 in Germany and the UK, reaching 41% and 35%, respectively (but remaining largely stable in France and Italy). The merit order effect is thus likely to have grown in influence, reducing wholesale prices further below what they otherwise might have been, and is likely to continue to grow as renewables continue to take a larger share of generation markets.**

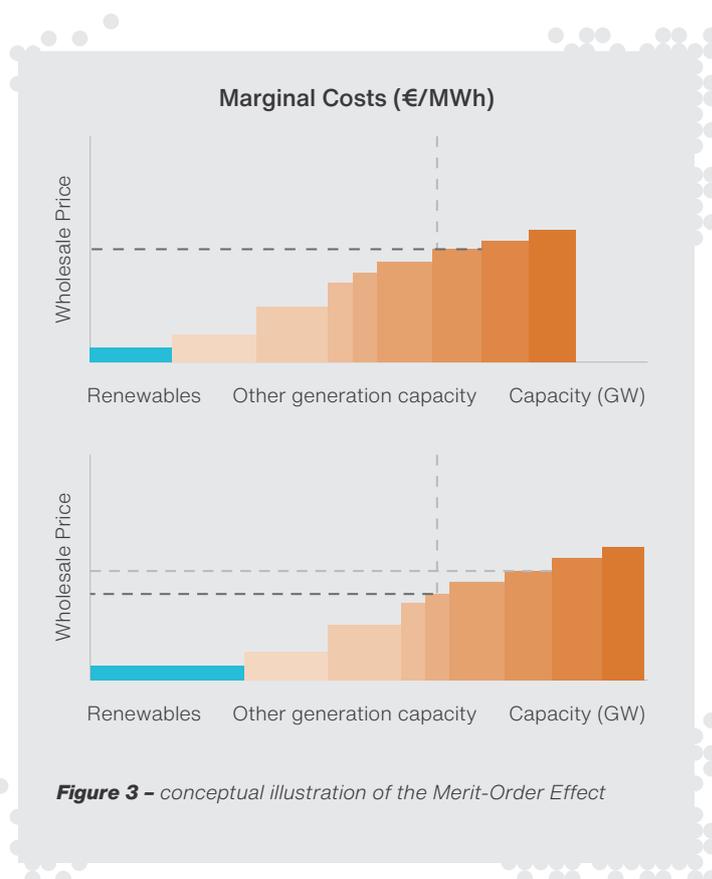


Figure 3 – conceptual illustration of the Merit-Order Effect

However, public subsidy mechanisms to encourage the deployment of renewables have, until recently, placed substantial upward pressure on the *final* prices paid by the consumer, as the costs of such mechanisms are recovered through levies on electricity consumption. This was particularly the case for the first iterations of support mechanisms for renewables deployment in Europe in the early years of the new millennium, when technology costs were substantially higher than they are today, and policy design was less sophisticated. However, as renewable technology costs have plummeted and policy design has become more advanced, the picture is now radically different (see below).

7> A key exception is biomass.

8> Cludius, J *et al.* (2014) The merit order effect of wind and photovoltaic electricity generation in Germany 2008–2016: Estimation and distributional implications, *Energy Economics*, 44, 302–313

9> CCC (2017) *Energy Prices and Bills – impacts of meeting carbon budgets*, Committee on Climate Change, London

10> Clò, S. *et al.* (2015) The merit-order effect in the Italian power market: The impact of solar and wind generation on national wholesale electricity prices, *Energy Policy* 77, 79–88



## ELECTRICITY SYSTEMS IN FRANCE, GERMANY AND ITALY ARE MUCH MORE INTEGRATED THAN IN THE UK...

The UK electricity market has **few contracts with duration beyond a couple of years ahead, thus exposing UK industries more to the volatility of energy prices more than some of their continental competitors**, where some power generators and consumers contract much further ahead. **Continental electricity networks are also more integrated with each other via interconnectors**, allowing the cross-border trade of electricity. Interconnection allows for improved security of electricity supply, and for price arbitrage between markets. Able to connect a given capacity to the market at a given price, interconnectors may be considered domestic pseudo-generators. When and whether they are utilised depends on demand, and their position in the merit order.

In 2016, Germany and France had interconnection capacity with neighbouring countries equivalent to around 10% of domestic generation capacity, with Italy at around 7%. In 2016 **the UK had four interconnectors with a combined capacity equivalent to just 4.5% of domestic generation capacity** with key interconnectors further constrained by temporary factors, limiting the ability to import low cost electricity (from France, in particular). In January 2019, a fifth 1 GW interconnector to Belgium began operation ('Nemo Link'), increasing total interconnector capacity to 5GW. Net imports to the UK (including Northern Ireland) as a proportion of total electricity consumption increased from around 5.7% of total electricity consumption in 2016, to around 7% in 2019.<sup>11</sup>

**Over the coming years, the UK's interconnection capacity will increase substantially, potentially allowing the import of much greater volumes of low cost, low carbon electricity.**

However, since the end of the UK's Brexit Transition Period in December 2020, new barriers exist to the efficient cross-border trade in electricity (discussed below).

Since 2014, new interconnectors to the UK are primarily contracted under a 'cap-and-floor' regime, which regulates how much money a developer can earn once the interconnector is in operation (through congestion revenues), providing developers with a minimum return (floor) and a limit on the potential upside (cap) for a 25-year period.<sup>12</sup> In January 2021, a new interconnector

to France (IFA2) began operation, with construction of a 1.4GW link to Norway recently completed and undergoing testing. A further 8.5GW of capacity has received approval and is due to become operational by 2025, with most new capacity connecting to France and Norway – markets dominated by low cost nuclear and hydropower, respectively.

In continental countries, interconnectors are mostly treated as part of the regulated networks. In contrast, **UK interconnections to the continent have been built and operated more as commercial assets, mediating flows between wholesale markets and with little direct contracting between users and foreign generators.** All EU countries are also part of the Single Day Ahead Coupling (SDAC) mechanism. The SDAC operates via application of a common algorithm that automatically combines the prices at which generators, traders and retailers across the EU wish to buy and sell electricity, to maximise the transfer of electricity from lower priced areas to higher priced areas, and to make use of the interconnectors in the most economically-efficient way.

**Following the end of the Brexit Transition Period on 31<sup>st</sup> December 2020, the UK is no longer part of the SDAC.**

This means that the cross-border purchase and sale of electricity and the payment for the use of interconnector capacity must now be completed separately, meaning that traders must buy the right to use interconnector capacity before the market price for electricity on either side is known, risking the outcome that the differential is insufficient to make the trade worthwhile (and vice versa).

**Initial estimations put the value of lost electricity trade as a result of exclusion from the SDAC at around £45 million in 2021.<sup>13</sup>**

<sup>11</sup> Data derived from Digest of UK Energy Statistics (DUKES).

<sup>12</sup> Ofgem (2021) *Interconnectors*, [Online] Available at: <https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/interconnectors> [accessed 03/09/2021]

<sup>13</sup> Roberts, D. (2021) *An initial assessment of the extent of inefficiency in electricity trade*, [Online] Available at: <http://www.frontier-economics.com/uk/en/news-and-articles/articles/article-i8192-brex-it-and-interconnectors-a-45m-problem/> [accessed 03/09/2021]



## ...AND THEIR PRICING STRUCTURES MORE ACTIVELY MODERATE PRICES FOR ENERGY-INTENSIVE INDUSTRIES

Beyond the broad regulatory approaches taken to recover network and policy costs, discussed below, each of the UK's three biggest European neighbours have found different routes to proactively moderate electricity prices for their largest industrial consumers. Although German industrial consumers on average paid higher rates for network charges and other taxes and levies than in the UK in both 2016 and 2019, its charging systems apply much finer-grained, negotiated distinctions in the rates that businesses pay depending on sector and consumption intensities.

**In France, a huge industrial consortium of 27 electro-intensive industries** (known as 'Exeltium') **negotiated a collective 24-year electricity contract** with the nuclear-based Electricité de France (EDF) for a fixed level of supply priced at around €42/MWh, **thus securing a low, predictable electricity price in ways that would be incompatible with the UK's historic approach to promoting competition between industries.**

**In Italy, to deal with generally high industrial electricity prices, the government has facilitated large industrial consumers to purchase electricity at the (lower) baseload wholesale price of neighbouring countries, in return for co-financing a series of new physical interconnectors.**

This electricity is supplied by 'virtual shippers'; energy suppliers in Italy purchase power in neighbouring markets, and sell generation to the equivalent domestic capacity to electricity-intensive companies, at the same price.

Virtual shippers and specific capacity are contracted through annual auctions operated by the Italian TSO (Terna), with prospective shippers submitting bids typically at a value equal to the spread between (lower) baseload prices in a given neighbouring country, and the (higher) market prices in Italy for the year ahead, plus a profit margin. Such contract costs are recovered from electricity consumers. However, the virtual interconnector mechanism ceases in 2021.

## THE UK'S PHILOSOPHY OF SPREADING NETWORK COSTS RELATIVELY EVENLY ACROSS ALL ELECTRICITY CONSUMERS HAS CONTRASTED WITH THE FOCUS ON INDUSTRIAL STRATEGY TAKEN BY OUR NEIGHBOURS.

In 2016, the **overall cost of the electricity networks appeared remarkably similar across the UK, Germany, France and Italy**, at €32–34 per MWh electricity consumed across all users (see Figure 4, left panel), **but the way in which these costs were recovered markedly differed.**

**In the UK, industrial electricity consumers face network charges according, primarily, to their location and time of consumption.** For transmission tariffs, charges are based on the 'Triad'; the three half-hourly periods with highest electricity demand between November and February (and separated by at least ten full days), determined after the event. Industrial consumers can minimise their network costs by minimising or avoiding consumption in these periods. Although incentivising such avoidance is the objective of the approach, Triad periods are becoming more difficult to predict, due to flattening demand profiles resulting from Triad avoidance strategies (e.g., switching to auto-generators). However, as discussed further below, this approach to network charging will soon change.

**In Germany, network tariffs** are also partly based on location, but primarily on consumption, with the **applicable tariff decreasing with likely annual consumption of the consumer.** In France and Italy, tariffs are primarily set by the voltage and capacity of the connection, with rates per unit of consumption decreasing and voltage and capacity increasing. **In France,** tariffs are also influenced by consumption within pre-defined time periods, except for the **largest users, who pay a low, fixed rate, per unit of consumption.** In Italy, the rates paid by consumers with high voltage connections are substantially reduced, while those with very high voltage connections pay a fixed annual rate, independent of their actual consumption. In addition, **in Germany and France, industrial consumers may also apply to receive explicit discounts on their standard tariffs – up to 90%** for the highest and most energy-intensive consumers.

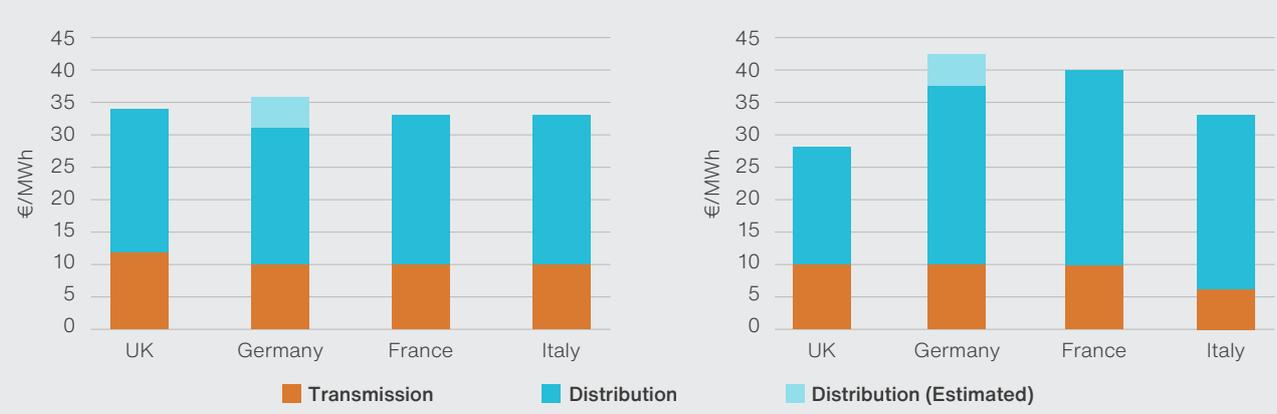


Figure 4 – Average network costs per unit of electricity consumption, 2016 (left panel) and 2019 (right panel)

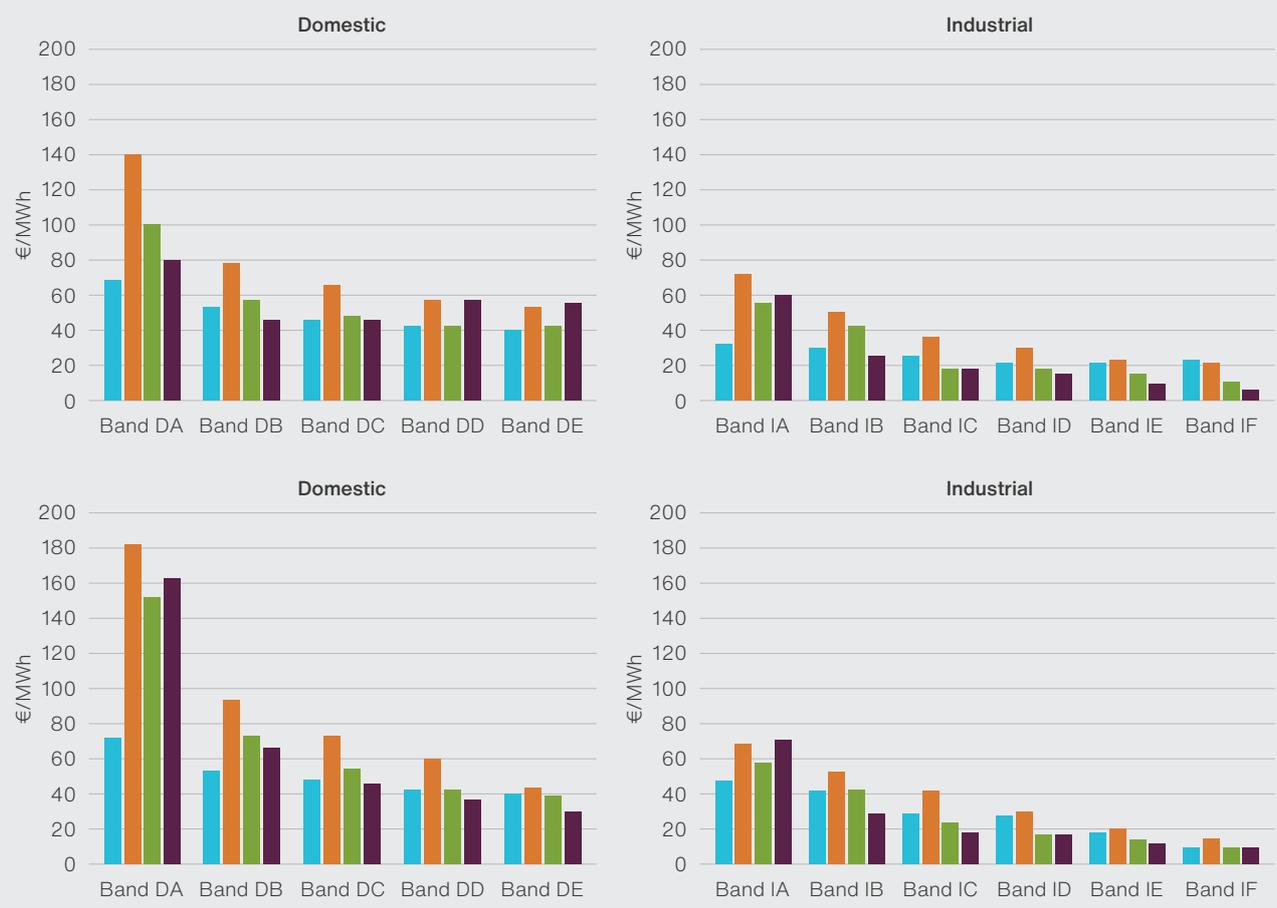


Figure 5 – Network costs per Eurostat electricity consumption band, 2016 (top row) and 2019 (bottom row)



**As such, the design of the tariff systems in Germany, France and Italy, and the further discounts available in the former two, mean that network costs are structurally designed to be minimised for energy-intensive consumers to a much greater degree than in the UK.** However, this means that costs must therefore be recovered to a much greater degree from other consumers – namely, smaller industrial and commercial consumers, and households. This is clearly demonstrated in 2016 by Figure 5 (top row). Although the smallest domestic consumer in the UK in 2016 paid a network tariff of just over 3 times that of the largest industrial consumer, in Italy they paid nearly 16 times more.

As also illustrated by Figure 4 and Figure 5, **between 2016 and 2019, total network costs in Germany and France increased by €6–7 per MWh of electricity consumed across all users, with the increase disproportionately loaded onto smaller domestic consumers,** further increasing the disparity with large industrial consumers (costs for Band IF industrial consumers in Germany actually reduced by around a third). Total costs and their distribution in Italy remained largely stable, although tariffs for both the largest industrial and smallest domestic consumers both doubled.

**By contrast, costs in the UK decreased by around €5 per MWh of electricity consumed across all users** (see Figure 5, bottom row). However, although domestic network tariffs remained stable, those applied to industrial Band IE and IF decreased, while those in Bands IA–ID increased. It thus appears that larger industrial consumers successfully continued to apply Triad avoidance strategies, to the indirect detriment of smaller industrial and commercial consumers, from whom the avoided costs were instead recovered.

As the costs of distributed renewable electricity and storage technologies reduce, consumers – particularly large industrial consumers – are likely to increase investment in them to reduce their use of the electricity network, in response to temporal price signals. As system costs do not reduce through such avoidance strategies, these costs must be increasingly recovered from a more limited pool of other users, furthering the disparity described above.

As a result, in 2017, Ofgem launched its Targeted Charging Review (TCR) to propose reforms to cost recovery approaches to prevent such distortions accelerating. Following the Review, from either April 2022 or 2023, the Triad system for network charging will largely cease and be replaced in large part by fixed network charges based on voltage and capacity of connection (although industrial electricity consumers will continue to pay a locational charge based on Triad demand). This will mean that industrial consumers who currently adopt Triad avoidance strategies will see their network tariffs increase (UK Steel estimate that steel producers will see an increase of 200–300%<sup>14</sup>). However, those that do not (or cannot) avoid Triad periods will see their costs reduce. The effect of this reform will vary substantially between sectors and even individual sites.

**As the economy becomes increasingly electrified, network costs are likely to increase as investment is poured into the system to increase its capacity and resilience. However, the form and size of the investment required depends substantially on how the interaction between supply and demand is managed in the future,** including the use of ‘smart’ technologies and systems, international interconnection and electricity storage technologies, and the extent to which decentralised generation (connected directly to demand or distribution grids) accounts for total supply.

<sup>14</sup> UK Steel (2021) *Closing the Gap: How Competitive Electricity Prices Can Build a Sustainable Low-Carbon Steel Sector*, UK Steel



## SUCH PHILOSOPHICAL DIVERGENCE ALSO APPLIES TO SOME DEGREE TO THE RECOVERY OF POLICY COSTS, AND THE APPLICATION OF OTHER TAXES AND LEVIES.

Figure 6 provides an estimated breakdown of the various taxes and levies applied to industrial electricity prices in each country in 2016 and 2019, combining Eurostat data with our estimations. For the UK in 2016 (bottom panel), this includes an estimate of the contribution of the maximum compensation for the costs of renewable levies available to qualifying consumers, but these have since been replaced by exemptions.

In 2016, taxes and levies in each country were dominated by **mechanisms to recover the cost of renewable energy deployment support**. Such costs were particularly high for Germany and Italy. However, **in Germany, France and Italy, the cost of these (and other) mechanisms for large or electricity-intensive consumers are often capped to an absolute value, a value equal to a gross value-added (GVA) threshold, or fall to zero over a given consumption level.** Such limits, along with those applied to other taxes and levies, mean that effective rates may continually decrease with increasing consumption. This approach reduced the cost for the largest and most electricity-intensive consumers to a much greater degree than the mechanisms of compensation for the costs of the Renewables Obligation and Feed-in Tariffs (FiTs) in the UK.

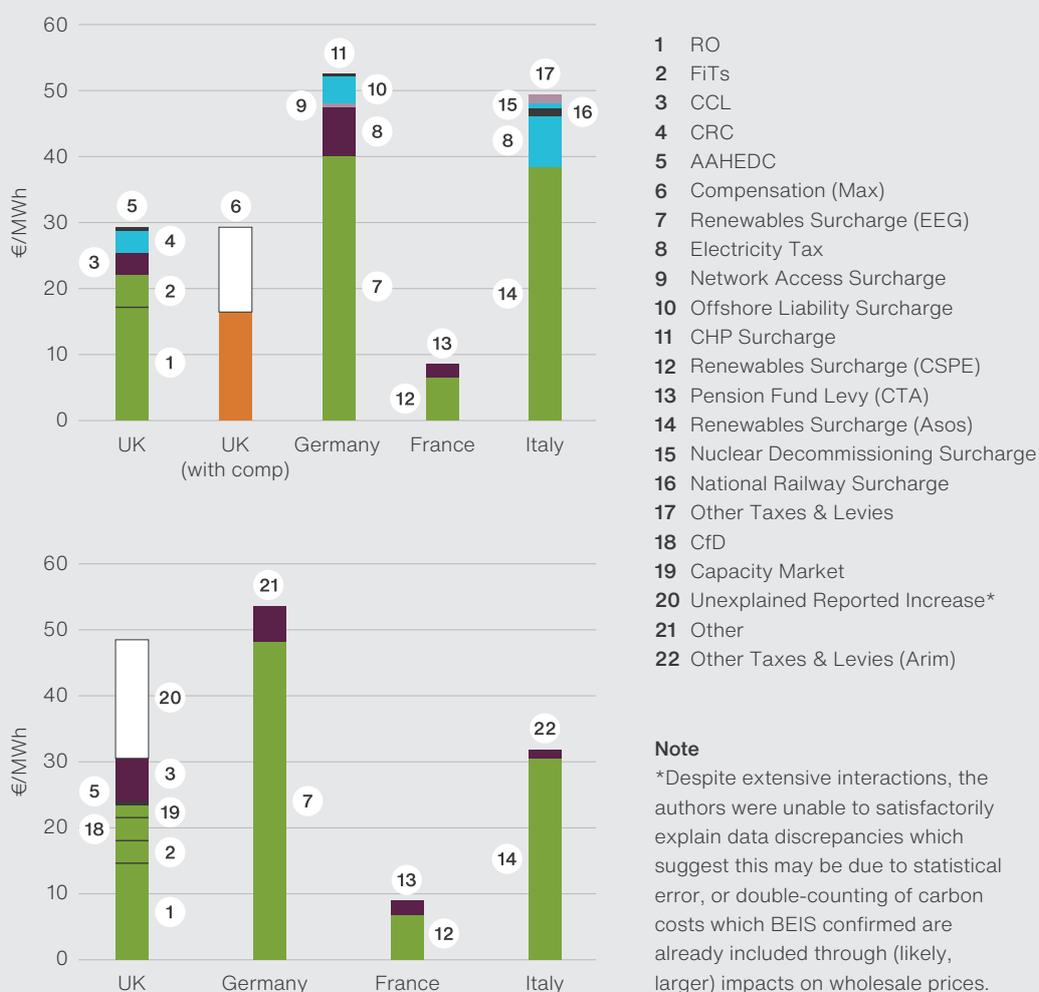


Figure 6 - Taxes and levies costs, 2016 (top panel) and 2019 (bottom panel)



In all countries examined, the value of discounts and compensation are recovered either by higher rates on other electricity consumers or by the taxpayer, with smaller commercial and domestic consumers in Germany and Italy paying substantially higher rates than their UK counterparts. This means that while all consumers benefit from reducing wholesale electricity prices delivered by increasing renewable generation, smaller commercial and domestic consumers in these countries have paid a much greater share of the initial investment cost than large energy-intensive consumers.

In 2019, this broad picture remains much the same. Outside the UK, the most notable change is in Italy, which in 2017/18 consolidated its taxes and levies into two components, and introduced a new discount for energy-intensive industrial consumers. Industrial consumers may now receive discounts on the  $A_{SO5}$  element to pay the equivalent of 0.5% of their GVA, if they have annual consumption of 1 GWh, and either have an electricity intensity of 20% GVA and have a sector trade intensity of at least 4%, or if they belong to the extractive, food, plastics, glass, steel, textiles and paper industries.<sup>15</sup>

**In the UK there have been three main developments.<sup>16</sup>**

The first is the introduction of **cost recovery from the ‘Contracts for Difference’ (CfD) renewable support mechanism**, introduced to replace the RO (discussed further below). The second development, as noted above, is the **introduction of exemptions to the RO, FiTs and now CfDs** for qualifying consumers, in place of compensation previously awarded, and now in line with the approach taken in other countries. This is the driver behind the estimated reduction in the contribution of the RO and FiTs in Figure 6, despite a substantial increase in the total cost of these policies.

The third development is the **introduction of the UK’s Capacity Market**, under which electricity capacity is contracted to be available to generate at times of low supply and high demand. Electricity storage and demand-side response, where large electricity consumers shift their consumption to reduce demand on the grid when supply margins are thin, are also able to be contracted. However the large majority of payments go to established generators, and additional capacity procured under the Capacity Market should, at minimum, reduce the risk and severity of price spikes – thus reducing wholesale costs on average.

As with renewables costs, the costs of the capacity market are recovered through a levy on electricity prices, applied equally to all consumers. Together with the introduction of the capacity market, these components are estimated to have increased the headline costs of these various policies by up to €20 per MWh of electricity consumed by all users over 2016–2019. However exemptions introduced in 2017, which are – contrary to compensation – included in price data, should have offset much of this increase for large industrial consumers. We observe this in the Eurostat data for 2017 and 2018, but apparently not in 2019 which saw a large and unexplained jump.

To emphasise interpretations of this complex picture: multiple factors have increased overall electricity costs in both the UK and EU. The headline cost of the various UK renewables cost-recovery and capacity market policies did increase substantially from 2016 to 2019. Carbon prices, under the EU ETS, to which the UK was still subject, rose across all European systems (with an impact depending on the carbon intensity of their fuel mix), which remains partially compensated for large industrial consumers but not others.

<sup>15</sup> Specific values reported in Figure 5 have changed through a combination of changing values, updated assumptions on how to divide the total reported taxes and levies values between individual components, and changes to the Eurostat accounting system, which from 2017 requires more detail than was available for 2016.

<sup>16</sup> In addition, the CRC ceased in April 2019, although the Climate Change Levy (CCL) increased to compensation. Industrial consumers in receipt of a Climate Change Agreement (CCA) received an increased discount on the industrial CCL of 93% (from 90%). The CCL rate and associated discount has subsequently reduced.



Most of the factors outlined in our previous report, which account for UK prices being above the EU, persist. However, given the move to exemptions for many renewable support costs, and the fact that carbon price impacts are included through wholesale prices in 'energy and supply', we remain unable to explain a large and sudden jump of the 'taxes and levies' component reported for large industrial consumers from 2018 to 2019, of the approximate magnitude indicated in Figure 6 (right hand panel). In detail, different sectors may face different situations. It remains unclear to us whether the comparative position of UK industrial electricity prices overall has worsened or marginally improved, but it is clear that UK electricity is part-way through a fundamental transition, which, as well as facing these challenges, holds considerable promise.

## THE CONTINUED SHIFT TO AN ELECTRICITY SYSTEM DOMINATED BY RENEWABLES HOLDS CONSIDERABLE OPPORTUNITY, BUT ALSO SOME RISKS, FOR POLICY COSTS AND WIDER ELECTRICITY PRICES IN THE UK

The role of renewables in reducing wholesale electricity prices was discussed above, and this influence will grow as renewables increase further. During the early years of widespread public financial support for the deployment of renewable electricity (since around 2000, and the decade or so following), renewable technologies were substantially more expensive than the fossil fuel incumbents. This generated rapidly increasing costs as deployment increased, recovered from electricity consumers, at rates that outweighed the reduction in wholesale electricity prices they delivered. Such support was typically delivered through 15–20-year contracts. As such, consumers are still paying for these legacy costs, but as these contracts begin to expire, so will their policy cost to consumers.

**However, the cost of many renewable technologies has drastically reduced in recent years, largely as a result of the learning and economies of scale delivered by this early deployment.** The UK government estimates that the average newly-commissioned **large-scale solar PV and onshore wind generators will cost about the same per unit of electricity generated as the current electricity wholesale price** (~£45/MWh), with many therefore potentially costing less. Recent evidence suggests that **even offshore wind farms can also meet this threshold** under favourable conditions. Doggerbank A, the first phase in what will be the world's largest offshore wind farm, is scheduled to begin generating in 2023 with a required electricity price of just £40/MWh – far lower than the £140/MWh required for Hornsea 1, the world's current largest windfarm, completed in just two years earlier in January 2021.<sup>17</sup>

### The structure of supporting policies has also evolved.

The RO, in place from 2002 to 2017, provided renewable generators a subsidy in addition to the wholesale market price. Its design also meant that it did not moderate the subsidy available in response to evolving technology costs and wholesale market prices, and did not encourage competition to drive down and reveal these costs. While this had benefits in helping to develop less mature technologies such as offshore wind, it meant that the policy cost rapidly escalated. **As renewable generators entered into the RO with 20-year contracts, these costs will be borne until 2037 (albeit decreasing over time).**

<sup>17</sup> These values are the 'strike prices' agreed under the Contracts for Difference (CfD) mechanism, discussed below.



In 2013 the RO began to be replaced by CfDs, through which renewable generators bid through an auction process to receive a 'strike price', fixed for 15 years of generation. If the wholesale price of electricity falls below the strike price, the government pays the difference. If the market price exceeds the strike price, the generator pays the government the difference. **At costs approximating wholesale prices, as is now the case with the average new solar PV and onshore wind, and some offshore wind, deployment of renewables under the CfDs are therefore effectively 'subsidy-free', and add little to no policy cost. However, with costs and strike prices agreed below the wholesale price, new renewables would generate *negative* subsidy, and work to reduce the existing policy cost generated by the CfDs** (or offset the costs of supporting immature but promising new technologies, such as floating offshore wind). **It is likely that contracts generating negative subsidy will be awarded in the next CfD auction round (AR4) opening for applications in December 2021. As the cost of renewables continues to decline, this phenomenon is likely to increase in frequency and impact, at least in the medium-term.**

But, with the increasing penetration of variable renewable energy, effectively matching supply and demand may become a growing challenge. Although there are a range of options for tackling this problem, including expanding interconnection to other markets and an increasingly 'smart' grid, the UK's primary approach to tackling this problem is through the Capacity Market, in which existing gas-based generation capacity has been the primary beneficiary, at relatively low cost. However, costs are beginning to increase as more expensive and less technologically-mature options, such as battery storage, are awarded contracts. Such costs will be recovered through an increased levy on electricity prices. However, the extent to which capacity market costs may increase is uncertain, as battery costs – in particular – continue to rapidly decline.



## LOOKING AHEAD: POLICY RECOMMENDATIONS FOR AN ERA OF TRANSITION

Given this context, below we set out specific options the government could consider moderating the price of electricity available to UK industry, and drive convergence with those available in Western Europe, and beyond.

**Many of these policy options would benefit not just large, electro-intensive consumers, but also help reduce electricity prices for small industrial, commercial and domestic consumers.** These proposals also aim to support the widespread electrification of the economy as a core pillar of rapid decarbonisation, and to deliver it in a cost-effective, fair and equitable way.

### 1 Restore and maintain an efficient investment framework for the cheapest mature renewables, with foresight on a rising carbon price in the 2020s to reduce investor risk.

Variable renewables need to reach 60% of total electricity generation by 2030 in the UK, and 80% by 2050, to meet net zero emission ambitions.<sup>18</sup> **A key pillar of this transformation will be offshore wind**, for which a target capacity of 40 GW by 2030 was set in November 2020 as part of the Ten Point Plan (from around 10 GW today). To ensure offshore wind costs continue to fall, the government must continue to support the industry through investment in supply chain skills and infrastructure, grid infrastructure and management, R&D in collaboration with developers, and by cementing a long-term, secure policy environment to ensure continued private investment in the industry.

However, the role of onshore wind and solar PV, which currently offer even lower costs of electricity generation, is also critical.

Although onshore wind and solar PV will be re-introduced into the CfD mechanism in its fourth allocation round (AR4) in December 2021 ('Pot 1'), following their exclusion from the mechanism in 2017, the government should launch a full-scale review of policy towards onshore renewables. This should be based on the recognition that, broadly, they no longer require subsidy if:

- a** political risk is minimised, and
- b** developers have confidence that the full value of their investment may be recouped.

This is particularly important as such technologies move increasingly into wholesale markets, in part as previous contracts under the RO expire.

To ensure (b) is achieved, clarity on the future carbon price faced by fossil fuel-using competitors is important. At the same time, the mechanisms for compensating electro-intensive industries for the impact of carbon prices should be regularly reviewed to ensure that these industries receive appropriate support. This recommendation is synergistic with Recommendation 6, in particular.

### 2 Establish an integrated approach to network development, funding and pricing.

In January 2021, Ofgem recommended that the GB electricity system operator is made fully independent from the transmission network owner (National Grid). Such an Independent System Operator (ISO) could include responsibilities for providing independent advice to government and Ofgem on new electricity (and gas) network investment requirements to achieve Net Zero, balancing costs and benefits to consumers; take a more direct role in balancing supply and demand across the network; and hold responsibilities for planning new infrastructure, including the offshore network. In July 2021 the government launched a consultation on such an independent 'Future System Operator' (FSO), which would 'take on a number of key roles in electricity and gas to facilitate net zero while maintaining a resilient and affordable system.'<sup>19</sup>

An independent FSO that delivers coordinated oversight of future generation and network developments is crucial if a decarbonised electricity system is to be delivered alongside rapidly increasing electricity demand, and if network and wider system costs are to be effectively managed. Such co-ordination includes the interaction between transmission and distribution system development, operation, access and pricing (and is linked to the objectives of Ofgem's current Access and Forward Looking Charging Significant Code Review). As such, the role of Distribution Network Operators (DNOs) with respect to the new FSO must also be clarified and, if appropriate, strengthened in parallel.

<sup>18</sup> CCC (2020) *The Sixth Carbon Budget: The UK's path to Net Zero*, Committee on Climate Change, London

<sup>19</sup> BEIS (2021) *Energy Future System Operator Consultation*, Department for Business and Industrial Strategy, London



Revenues from the UK's carbon pricing mechanisms, which accrue to the UK Treasury, could also be ringfenced and used to help fund key Strategic Wider Works (large network developments that would be beneficial to the wider system, but were not factored in when setting network operator price controls, and thus, without supplementary funding or source of revenue, network operators are not incentivised or able to build). This would have the effect of reducing the costs to be recovered directly from electricity consumers.

### **3 Support continued growth of interconnection (through Ofgem's cap-and-floor revenues system) and offshore grid development, and reduce friction in electricity trade.**

The existing cap-and-floor-system has proven effective at encouraging new interconnectors to the GB market. As such, the government should underline its commitment to support Ofgem's cap-and-floor returns regime to maintain investment momentum (in June 2021 Ofgem published a working paper under its Interconnector Policy Review, in which it concluded that the cap-and-floor approach remains appropriate, but proposing improvements<sup>20</sup>). At the same time, and **as a priority outcome for the arrangements to be put in place by April 2022 pursuant to the EU-UK Trade and Cooperation Agreement, the government should seek to restore UK participation in the day-ahead electricity markets with neighbouring EU countries**, or ensure similar arrangements, to maximise cost-effective electricity trade to and from the GB electricity market.

Expanding interconnection capacity and reducing barriers to trade across them can help reduce wholesale electricity prices by allowing the import of low cost nuclear, hydropower and increasingly renewable generation. Each 1GW of new capacity could reduce UK wholesale prices by 1–2% in doing so.<sup>21</sup> In addition, interconnection provides an efficient option to balancing UK electricity supply and demand, reducing reliance on domestic back-up capacity currently contracted through the Capacity Market.

**Following the end of the Transition Period on 31<sup>st</sup> December 2020, the UK left the North Seas Energy Cooperation (NSEC) group, which supports and facilitates the development of offshore transmission infrastructure in the region**, and comprises Belgium, Denmark, France, Germany, Ireland, Luxembourg, the Netherlands, Norway, Sweden and the European Commission. The UK government should seek to re-engage with this group, to encourage and facilitate widespread expansion of offshore wind around the North Sea waters.

### **4 Facilitate cross-border electricity contracting incorporating UK carbon prices.**

The government should establish a new structure for direct cross-border industrial electricity purchases, which (as with the Californian CO<sub>2</sub> cap-and-trade system) should charge UK carbon prices on purchased electricity. Such arrangements should be considered in light of the EU's new Carbon Border Adjustment Mechanism (CBAM) which will cover trade in electricity.

**UK generators would be at a disadvantage if carbon-intensive electricity generated with lower carbon prices (e.g. German coal through the planned NeuConnect interconnector, in particular<sup>22</sup>) competed in the UK market.** Consequently, the UK should consider applying its carbon price to electricity imports, in the way that California applies its carbon price to imports from other US states. In principle there are at least two options for this. For general trade through interconnectors, the CO<sub>2</sub> intensity of the generation mix in the source country could be applied. The alternative would focus on specific contracts with generators abroad, with emissions as monitored and priced under the EU ETS.

If the UK were to foster a market in long-term low carbon power electricity contracts (Recommendation 6), it should seek to include cross-border electricity contracts, with zero-rated carbon prices. The EU electricity system already includes certificates of Guarantees of Origin for low carbon power generation, which should facilitate the implementation of such a system irrespective of the precise nature of the future relationship between the UK and the EU's Single Electricity Market.

<sup>20</sup> Ofgem (2021) Interconnector policy review: Working paper for Workstream 1 – review of the cap and floor regime, [Online] Available at: <https://www.ofgem.gov.uk/publications/interconnector-policy-review-working-paper-workstream-1-review-cap-and-floor-regime> [accessed 03/09/2021]

<sup>21</sup> National Grid (2014a) *Getting more connected: The opportunity from greater electricity interconnection*, National Grid, London

<sup>22</sup> NeuConnect is a planned 700km, 1.4GW HVDC interconnector between England and Germany, with completion targeted for 2024.



## 5 Support industrial involvement in the Capacity Market and other electricity service markets.

The value of system-related services like demand-shifting and frequency support is rising, whilst the cost of providing such services from industrial energy users is declining. UK industry in 2019 accounted for 27% of electricity consumption. Significant parts of such demand could, in principle, have some flexibility, associated with inbuilt storage (e.g., thermal), more flexible cogeneration of heat and power, and/or other flexibilities (e.g., in scheduling of manufacturing activities). With Capacity Market prices increasing as new-build generation and storage capacity is incentivised, the value of these services would be much enhanced.

However, the Capacity Market was designed with a view to support new generation capacity, with demand-side response, so far, only accounting for a small proportion of contracted capacity. The government is taking steps to improve demand-side participation in the Capacity Market, and is committed to allowing demand-side response to bid for 15-year agreements and to reduce the minimum capacity threshold from 2MW to 1MW.<sup>23</sup> **By ensuring that the capacity market (and other electricity service markets) is efficient and fit for purpose for demand-side response, the government could encourage industrial participation in these mechanisms, and help industrial consumers to realise the economic value of these services to both reduce overall system costs and offset the cost of their electricity consumption.** This would also help reduce potential reliance on fossil fuel capacity for backup generation, reducing the CO<sub>2</sub> intensity of contracts awarded under the Capacity Market.

## 6 Establish a market for long-term, zero carbon and tradable electricity contracts

In the medium term, standardised structures of **long-term, tradeable zero-carbon electricity contracts** should be made available to industrial consumers, grounded in the declining cost of unsubsidised renewable electricity sources (solar PV and onshore wind, and increasingly offshore wind). Consumers holding these contracts would thereby **avoid the indirect costs of carbon prices, and the volatility of fossil fuel prices.**

The use of green Power Purchase Agreements (PPAs) in the UK electricity market has been increasing in recent years, as numerous major companies declare commitments to increase their use of renewable energy. **Long-term contracts, whether delivered by PPAs or public support mechanisms such as CfDs, are currently the best approach for providing confidence to investors in new renewable capacity.** As such, the government should consider options for a 'regulated dual market' approach, with a market for long-term, zero-carbon power contracts (a 'green power pool'), alongside a spot and frequency market.

A 'green power pool' would not only provide confidence in the market for new, unsubsidised renewable capacity, but it would also allow businesses to contract low cost renewable supply at low risk, as contracts would be tradeable. It would also minimise collective system balancing and backup costs, as these would be contracted for the pool as a whole, rather than duplicated by individual contracts, and consumers offering demand flexibility and other system balancing services would reduce the need to draw on such services from the rest of the electricity system, further reducing costs.

**The most relevant public body (potentially the Low Carbon Contracts Company or an independent Future System Operator) should be charged with examining the steps required for such a system to develop at scale in the mid-2020s.** A key question will be to understand how to facilitate the evolution of such a market, including its specific design and the role of the government, its agencies, or the regulator in determining and overseeing its design and operation.

<sup>23</sup> BEIS (2020): *Capacity Market: Government response to consultations on future improvements, emission limit and coronavirus easements*, Department for Business, Energy and Industrial Strategy, London



**7** To incentivise electrification and more evenly distribute the costs of the low carbon transition, the government should **investigate options for spreading historic policy costs more evenly across energy sources, including moving some policy costs from electricity prices to gas prices over time, with interim competitiveness support for major gas users unable to electrify or transition to low carbon fuels in the short term.**

The low carbon transition is a challenge for our entire energy system. Given the remarkable progress in renewable electricity sources (and storage), an important feature of the transition is likely to involve electrification. Not only would this be impeded by high electricity prices, but also, this implies that the benefits of the large investments in renewables and strengthening our electricity system will also accrue in other sectors.

The current strategy – in the UK and elsewhere – puts the costs of the policies employed to decarbonise electricity onto electricity consumers through levies on prices. For electro-intensive industrial consumers this can lead to mounting concerns around competitiveness. However, at the time same, consumers of all types must be encouraged and supported to shift the energy they use for a wide range of processes and services from fossil fuels to increasingly low carbon electricity. **Increasing the prices of electricity relative to those of fossil fuels runs directly counter to the aim.**

The government should therefore explore options for moving some policy costs currently loaded onto electricity prices, to those of other fuels – principally natural gas. Industrial consumers of natural gas in the UK typically pay lower prices than their European counterparts. Shifting policy costs in this way would (a) contribute to reducing competitiveness concerns of electro-intensive industries; (b) adjust price signals to help encourage increasing electrification, and (c) ensure the costs of delivering a decarbonised UK energy system are more evenly spread across consumers of different forms of energy, rather than focused on consumers of electricity.

However, such a reform must be delivered with care and, where appropriate, active support. For example, **UK industries currently heavily reliant on gas consumption must also be guarded against undue competitiveness concerns in the short term** (through, for example, time-limited compensation, or a phased shift in policy costs), and be supported to transition to low carbon fuels or feedstock (including electricity and hydrogen) in the medium term, by the broader policy framework.

## **8** Improve scrutiny and transparency of reported electricity price data

In order to effectively assess the degree to which electricity prices faced by UK industrial consumers are changing, both over time and relative to international competitors, reliable data is crucial. As illustrated above, we were unable to resolve apparent inconsistencies in data on the development of electricity prices over the past three years, with possible statistical errors or double counting. As part of Quality Assurance we recommend a review of how this data is requested, collected and reported by BEIS.

Until the end of 2020, electricity price data were collected and reported by the Department for Business, Energy and Industrial Strategy (BEIS) to Eurostat, and published – using different, less granular consumer definitions, and alongside prices in key international competitors – on the BEIS website. Following the end of the Brexit Transition Period, data is no longer reported to Eurostat. To improve scrutiny, transparency and comparability, particularly with respect to industrial electricity prices and their drivers in other European countries, it may be advantageous for the UK to, in future, adopt the definitions and categories adopted and reported by Eurostat for the data collected and reported by BEIS.

Alongside this, a full understanding of the price impacts of the energy transition will need to account for the complex relationships between carbon pricing, renewables, capacity market, and wholesale prices as explained in our report – so that the costs in different categories are understood as interacting, partly complementary, and not purely additive.



The Aldersgate Group is an alliance of major businesses, academic institutions, professional institutes, and civil society organisations driving action for a sustainable and competitive economy. Our corporate members, who have a collective turnover in excess of £550bn, believe that ambitious and stable low carbon and environmental policies make clear economic sense for the UK.