Renewable and Sustainable Energy Reviews 183 (2023) 113498

Contents lists available at ScienceDirect

Renewable and Sustainable Energy Reviews

journal homepage: www.elsevier.com/locate/rser

The impacts of consumer-funded renewable support schemes in the UK: From the perspective of consumers or the electricity sector?

Jing Shao [a], Jinke Li [a,*], Guy Liu [b]

[a] Department of Economics, School of Social Sciences, Swansea University, United Kingdom
[b] HSBC Business School, Peking University, China

ARTICLE INFO

Keywords:
Electricity sector
Imports of fossil fuels
Greenhouse gas emissions
Coal-fired generation
Wind generation
Renewables obligation
EU ETS

ABSTRACT

Increased renewable electricity reduced electricity prices but the costs of consumer-funded support schemes were added to utility bills. Previous studies compared these two components to understand the impacts on consumers. This paper constructs a framework for the electricity sector and provides a new angle to examine the impacts of renewable support schemes on consumers and the sector, respectively. Any negative gain to consumers was offset by the positive gain received by renewable generators (and suppliers), leaving the sector unaffected. In contrast, the increase in renewable electricity brought positive gain to the sector as a whole through reduced fossil fuels imports and greenhouse gas (GHG) emissions. We examine the structural change in the generation mix from 2006 to 2020 in the UK and suggest that wind generation replaced coal-fired generation rather than gas-fired generation on the longer horizon. Therefore, using coal-related coefficients and a contribution share of 38.6% for renewable subsidies, we suggest that wind generation supported by the RO scheme brought positive net gain to the sector, exceeding £800 million per annum in 2018–19 and 2019–20. Therefore, the discrepancy in payoffs from the perspective of consumers and the sector imposed a difficult challenge for policymakers, as criticism would be raised if the analysis was done on consumers only.

1. Introduction

Decarbonisation, affordability, and security are referred to as the energy 'trilemma' for the energy policy of the UK government. Regarding decarbonisation, the total estimated territorial greenhouse gas (GHG) emissions were 454.8 million tonnes of carbon dioxide equivalent (MtCO2e) in 2019, 43.8% lower than the 1990 level. In particular, the estimated GHG emissions from power stations were 58 MtCO2e in 2019, 65.5% lower than the 1990 level [1].

The electricity generation mix in the UK has changed dramatically in the last two decades. In terms of electricity supply, electricity generated from fossil fuels (coal, gas, and oil) decreased from 73.01% in 2006 to 35.70% in 2020, in which coal-fired generation had the largest drop (36.73%–1.67%).[1] Meanwhile, renewable-sourced electricity (wind, solar, bioenergy, and hydro) increased from 4.74% to 40.80% [2]. The increase in investment in renewable capacity was supported by a series of consumer-funded schemes. An important one was the Renewables Obligation (RO) scheme implemented between 2002 and 2017 to support large-scale renewable electricity projects. The RO scheme is a tradable green certificate system, which requires electricity suppliers to supply a certain proportion of their total sales from renewable sources.[2]

Relating to affordability, the impacts of consumer-funded renewable support schemes are twofold for consumers. On the one hand, due to lower marginal costs of operation, the increase in renewable electricity reduced the electricity prices via the merit order effect.[3] On the other hand, the costs of consumer-funded schemes were passed to end-users

* Corresponding author. Department of Economics, School of Social Sciences, Swansea University, Swansea, SA1 8EN, United Kingdom.
E-mail address: jinke.li@swansea.ac.uk (J. Li).

[1] According to National Grid, 21 April 2017 was the first full day without using coal power to generate electricity in Britain since the Industrial Revolution. Two years later, in May 2019, a full week without coal power was achieved.

[2] The TGC system originated from the Renewable Portfolio Standard, which is a state-mandated program in the United States. For recent studies see Refs. [3,4]. Similar schemes were also implemented in countries such as the UK [[5–9]], Australia [10], Belgium [11], Sweden [12], Norway [13], India [14], and China [15]. See Ref. [16] for a review on TGC schemes.

[3] The empirical evidence of the merit order effect has been found in many countries, and recent studies include the UK [17], Germany [18], Spain [19], Italy [20], Denmark [21], Ireland [22], and Australia [23].

https://doi.org/10.1016/j.rser.2023.113498
Received 29 June 2022; Received in revised form 25 February 2023; Accepted 22 June 2023
Available online 28 June 2023

directly through higher utility bills. Therefore, as these two impacts had different directions, the net impacts on consumers remained ambiguous: the scheme generated positive gain to consumers if the reduced spending on electricity was greater than the costs of the scheme, and vice versa. Studies have compared the reduction of spending on electricity and the costs of support schemes, but the results are not conclusive. For example, positive gain to consumers is found for wind and solar in Spain [[24,25]], wind in Italy [20], and wind in Ireland [22]. In contrast, negative gain to consumers is also found for solar in Italy [20] and wind in Australia [26].[4] Regarding the UK [17], find that the wind power generation supported by the RO scheme brought negative gain to consumers in most financial years from 2009–10 to 2019-20 because the reduction in spending on electricity was lower than the costs of the scheme attributed to wind farms.[5] The negative gain to consumers reached £2 billion per annum between 2017/18 and 2019–20.

This paper provides a new angle to examine the different impacts of renewable policies on consumers and the electricity sector. Our first contribution is to construct a framework for the electricity sector with three players (consumers, traditional generators, and renewable generators) and three markets (a domestic electricity market, an international fossil fuel market, and an international carbon market). The scheme may bring negative gain to consumers, as [17] indicate, but we suggest that this negative gain was transferred to (or offset by) the positive gain received by renewable generators (and suppliers), leaving no impact on the sector. Our analysis shows that the costs of support schemes were considered when discussing the gain to consumers but became irrelevant when addressing the net gain to the sector.[6] Further, we suggest that the transition to renewable electricity brought positive net gain to the electricity sector from two aspects. First, as the UK was dependent on the imports of fossil fuels, a decrease in the electricity generated by traditional generators should reduce the costs of importing from the international market, reducing energy dependence and improving energy security in the UK. Second, as the UK was included in the EU Emissions Trading System (EU ETS), lower GHG emissions meant that UK traditional generators were not required to buy additional allowances or could sell their abundant allowances to installations in other countries under the system.

The second contribution of this paper is to calculate the avoided costs from fewer imports and reduced GHG emissions that can be attributed to wind generation supported by the RO scheme, using coal-related coefficients and the contribution share by renewable subsidies.

The negative impacts of renewable energy on GHG emissions (through less consumption of fossil fuels) are well documented in the literature [43–46]. The concept of marginal displacement factors (MDF) was used to measure the impacts of wind generation on GHG emissions.[7] As the first paper to examine the MDF in the UK [48], suggest that the MDF varied between 0.49 kg/kWh to 0.66 kg/kWh using half-hourly data between 2009 and 2014, after taking load-specific emissions factors into account. Similar results were found in related studies [49]. indicate that one kWh of wind generation reduced GHG emissions by 0.39 kg, using half-hourly data of electricity generation and emissions from individual generation units between 2008 and 2017 [50]. estimate that the MDF was 0.41 kg/kWh using data from 2012 to 2017.[8]

When the analysis is based on short-term high-frequency data, coefficients estimated may be reflected the difference between the GHG emissions of gas-fired generation and wind generation, as peaking gas-fired plants are switched off when wind farms begin to operate. For example, in Ref. [49], the MDF was 0.39kg/kWh, which was close to the difference between the GHG emissions of gas (0.394kg/kWh) and wind (0kg/kWh).

If the generation mix is examined on a longer horizon, the role of wind generation may be different. We examine the electricity generation between 2006 and 2020 and suggest that the changes were influenced by two effects. The first effect came from the decreased supply, leading to lower generation from all sources if the mix remained the same. The second effect came from the structural change in the generation mix. We construct a hypothetical generation in 2020 and remove the effect of the decreased supply. According to the effect of the structural change, we suggest that wind generation replaced coal-fired generation rather than gas-fired generation on a longer horizon, so coal-related coefficients should be used to calculate the avoided costs from fewer fossil fuels imports and reduced GHG emissions.

However, the transition from coal to wind was a joint result of renewable support schemes and other policies, so we should not attribute all associated benefits to the former. An important policy for this transition was carbon prices and, in particular, the Carbon Price Support introduced in 2013 to impose an additional carbon tax on generation using fossil fuels in the UK.[9] [50] confirm that the impacts of wind generation on GHG emissions were different under the scenarios with/without the carbon price support. These policies together help the UK government to meet the deadline of ending coal-fired generation in 2024 [51], but their entangled influences make the evaluation of individual policies less straightforward.

To overcome this difficulty, we follow the analysis by Ref. [52], which suggests that among the total estimated emission reductions of 622 million tonnes of carbon dioxide equivalent from 2010 to 2018, 51.8% were contributed by carbon prices and 38.6% were contributed by renewable subsidies.[10] Therefore, based on this contribution share, our results suggest that the RO scheme brought positive net gain to the electricity sector from 2009–10 to 2019–20 and exceeded £800 million per annum in 2018–19 and 2019–20. Although [17] suggest that such wind generation brought negative gain to consumers, we should not consider the net gain to the sector as compensation for the negative gain to consumers because the latter was transferred to the positive gain received by renewable generators (and suppliers) within the sector already.

This paper will be constructed in the following way. Section 2 provides background. Section 3 illustrates the framework of the electricity sector, and Section 4 discusses the application to the UK. Finally, section 5 concludes the paper.

[4] A related stream of studies is about techno-economic models, which analyse the technical and economic performance of a project [27]. These techno-economic models have been widely used in the energy sector: wind and solar [[28–30]], biomass [[31–33]], hydro [34], transportation fuels [35], storage [36], hydrogen [37], and heating [38–41].

[5] Our analysis considers financial years which were used in annual reports of the RO scheme (April to March).

[6] In a related study [42], compare savings from fewer energy imports and GHG emissions with support costs in Spain, but our analysis suggests that these two terms should not be compared directly. The second difference with our study is that, the replacement of gas-fired generation with renewable generation is assumed by Ref. [42], but we provide a detailed analysis of the structural change in the generation mix in the UK from 2006 to 2020.

[7] In an early work by Ref. [47], the marginal emissions factor (MEF) is estimated to measure the impact of a change in demand on emissions using data from 2002 to 2009 for GB.

[8] Besides the MDF in the short run given the existing wind capacity [50], also discuss the long run impacts of wind generation, taking the committed increase in wind capacity into account.

[9] As the EU carbon price was too low to encourage low carbon investment, the UK government introduced the Carbon Price Floor policy in April 2013. The policy imposes carbon price support rates on top of the carbon price from the EU ETS. The carbon price support rates were £4.94 in 2013–14, £9.55 in 2014–15, £18.08 in 2015–16, and then remained at £18 from 2017 to 2020. As the policy was applied to domestic installations, the trading of allowances under the EU ETS was not affected.

[10] These two percentages were measured from Table 5.10 in the State of the Energy Market 2019 [52]].

2. Background

2.1. The UK coal industry

Since the Industrial Revolution, coal production in the UK increased dramatically in the 19th century as a fuel for steam engines. Coal production peaked at 292 million tonnes (Mt) in 1913, providing 1.1 million jobs [53]. Until the early 1960s, coal production remained above 200 Mt.[11] Since the 1960s, the coal mining industry has been on a long declining trend mainly due to cheaper substitutes such as oil, gas, nuclear, imported coal, and recently, renewables.[12]

In the last two decades, from 2000 to 2020, as Fig. 1 shows, coal production declined from 31.2 Mt to 1.7 Mt. After the last deep coal mine, Kellingley Colliery in Yorkshire, closed on December 18, 2015, coal was extracted from open-cast mines.[13] While domestic production was falling, the UK started to import coal in 1970, and the imports of coal peaked at 52 Mt in 2006, mainly from Russia (45.0%) and the Republic of South Africa (25.2%) [55]. After that, coal imports were on a decreasing trend, to 5 Mt in 2020 [53].

The falling domestic production and imports indicated that the demand was weakening. One contributing factor to the decreasing demand for coal in the last two decades was reduced usage from coal-fired power plants. The share of coal in electricity generation has decreased from 36.73% in 2006 to 1.67% in 2020 [2]. In terms of usage of coal, from 2006 to 2020, the quantity of coal used in coal-fired power stations for electricity generation decreased from 57 Mt (out of 67 Mt) to 2 Mt (out of 7 Mt) [53].

2.2. The international coal price

In terms of the global total primary energy supply in 2018, the share of coal was ranked second at 26.88%, between oil (32.11%) and natural gas (22.84%) [56]. In the global coal market in 2020, the largest exporter of coal was Indonesia (405 Mt), followed by Australia (390 Mt), while the largest importers were China (309 Mt) and India (211 Mt) [57].[14]

The costs of importing coal by UK fossil fuel generators were influenced by international coal prices. Fig. 2 shows the movement of daily coal prices in the European market, known as the API#2 index, which is the benchmark price reference for coal imported into Europe.[15] Coal price was on a rising trend in the 2000s and peaked at £112/tonne in July 2008. Then the prices fell largely with economic downturns starting in 2008. Since 2009, coal prices have been rising and then entering a 5-year bear market due to falling demand and the shift toward cleaner energy sources. From 2016, following the ban on the opening of new coal mines in China, coal prices began to pick up. In 2019, coal prices declined due to increased supply as producers reacted to early higher prices and weakened demand, such as import restrictions in China and the worldwide pandemic of Covid-19. In late 2020, due to a resurgence of demand after the depths of the pandemic, prices started to recover and reached £87.41/tonne in June 2021.

2.3. The EU ETS and the carbon price

The EU Emissions Trading System (EU ETS) started in 2005 is the first major carbon trading market covering around 11,000 installations (power stations and industrial plants) across EU Member states and airlines operating internally.[16] The EU ETS covers around 40% of the EU's greenhouse gas emissions, and it was the crucial legislation that contributed to the reduction of GHG emissions by 31% below 1990 levels in 2020, exceeding the target of 20% [58]. Further, in 2020, the target was extended to 55% by 2030, compared to 1990 levels [59].

The EU ETS adopted the cap-and-trade system, in which a cap is set on the total amount of certain greenhouse gases that can be emitted. By reducing the cap gradually, the system ensures that total emissions fall over time. Each allowance gives the holder the right to emit: one tonne of carbon dioxide (CO2) or the equivalent amount of other greenhouse gases, measured as tonne of carbon dioxide equivalent (tCO2e). Each year, an installation should surrender adequate allowances according to its emissions, and penalties are imposed on any quantity of allowances missed. After paying the penalty, installations are still obliged to surrender missed allowances in the following year. If an installation reduces its emissions, its spare allowances can be sold to another installation that needs additional allowances. The value of allowances imposes costs on GHG emissions and encourages investment in low-carbon and renewable technologies. The daily price of emissions allowances is shown in Fig. 3.

Phase 1 (2005–2007) was operated as an experiment, with a cap of 2096 million in 2005 [60]. In Phase 1, allowances were given to installations for free, and the penalty for non-compliance was €40 per tonne. Phase 1 has established a price for carbon and free trade in emission allowances across the EU, but the price of allowances fell to zero in 2007 due to excess issuance of allowances. Phase 2 (2008–2012) started with a cap of 2011 million in 2008 [60]. The proportion of free allocation fell to around 90%, and the penalty for non-compliance was increased to €100 per tonne. However, the 2008 economic crisis led to unexpected emissions reductions, resulting in a large surplus of allowances that put downward pressure on the carbon price.[17]

In Phase 3 (2013–2020), the cap for stationary installations was 2084 million, and the cap decreased each year by a linear reduction factor of 1.74%, to a cap of 1816 million in 2020 [58]. Auctioning became the default method for allocating allowances, with 57% of allowances auctioned over the entire trading period. All power stations are required to purchase their allowances via auction or trading. At the start of Phase 3, a surplus of 2.1 billion allowances had built up from Phase 2, and this problem was first addressed temporarily by delaying the auction volume of 900 million in 2014–16 until 2019–20. In 2015, the market stability reserve (MSR) was designed to take allowances out of circulation to reduce the downward pressure on prices due to over-supply [61].[18] Since the MSR became operational in January 2019, the price gradually raised to €30 in September subsequently.

After auctioning became the default method of allocating allowances in Phase 3, the total revenues generated in this phase exceeded €68

[11] For example, in 1960, 204 Mt of supply was mainly allocated to electricity (26.0%), industry (17.6%), domestic (17.6%), and Coke Ovens & MSF (15.7%) [53].

[12] The UK and Norway are the two major beneficiaries of the extraction of North Sea oil and gas from the 1960s. In terms of electricity generation, the share of oil and gas increased from 1.4% in 1956 to 30.7% in 1997, and then fluctuated mainly between 30% and 40% afterwards [54].

[13] In October 2020, the Whitehaven coal mine in Cumbria became the first approved new deep coal mine in the UK in 30 years, but the Cumbria County Council suspended its decision in February 2021.

[14] In 2020, the world total coal production was 7575 Mt, and the top five producers were China (3764 Mt), India (760 Mt), Indonesia (564 Mt), the United States (485 Mt), and Russia (398 Mt), see Ref. [57].

[15] Other examples of Argus/McCloskey's Coal Price Index include the API#4 index is the benchmark price reference for coal exported from South Africa and the API#8 index is the benchmark price reference for the import delivered to South China.

[16] The EU ETS remained the largest carbon trading market until the launch of China's national Emissions Trading Scheme in July 2021.

[17] The aviation sector was brought into the EU ETS on 1 January 2012 (not including flights to and from non-European countries). Aviation was given separate caps from stationary installations: 32.5 million in 2013 and 42.8 million in 2020 [58].

[18] If demand for allowances is greater than expected, causing the number of allowances in circulation to fall, the release of allowances from the MSR back into the market will contain carbon prices.

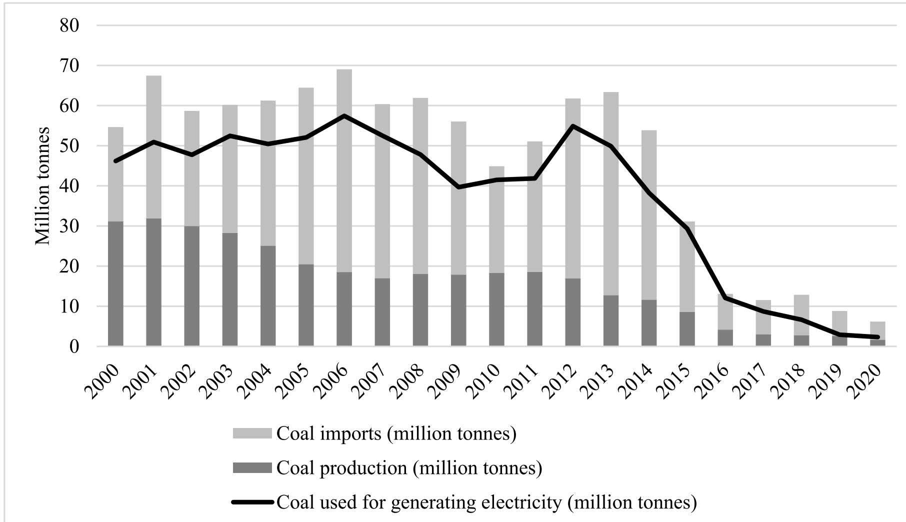

Fig. 1. The UK coal industry. Source: [53].

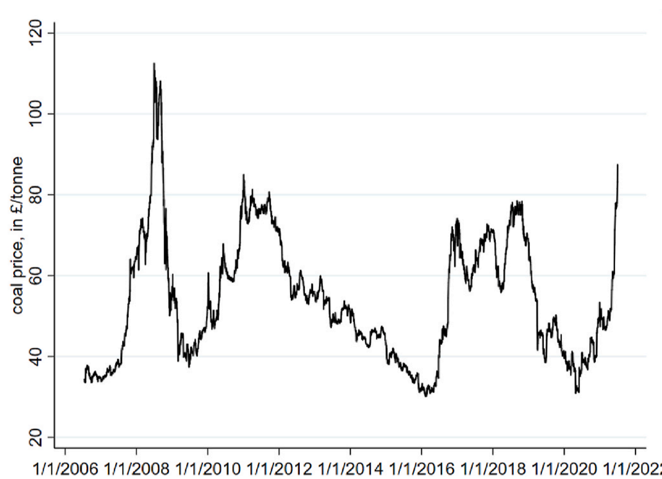

Fig. 2. The movement of daily coal prices (£/tonne, in British sterling) in the European market, converted to British sterling using daily exchange rates, from July 2006 to June 2021. Source: DataStream.

Fig. 3. The movement of daily carbon prices (£/tonne, in British sterling) in the EU ETS, converted to British sterling using daily exchange rates, from April 2005 to June 2021. Source: DataStream.

billion [58].[19] In the EU ETS, the Member States are responsible for auctioning allowances and managing collected revenues. From 2013 to 2020, on average, Member States spent 75% of their revenues on climate- and energy-related purposes, above the threshold of 50% under the EU regulation [58].

The EU ETS has entered Phase 4 (2021–2030) from January 2021, and the cap in 2021 for stationary installations is at 1572 million allowances, with an annual linear reduction factor of 2.2%. Prior to Phase 4, a more ambitious target was agreed upon to cut greenhouse gas emissions by at least 55% by 2030 from the 1990 level, replacing the existing target of 40%. The higher targets pushed the price of allowances to £48.23 per tonne in June 2021.

2.4. *The UK in the EU ETS*

The UK has participated in the first three Phases of the EU ETS from 2005 to 2020. Around 1000 UK power stations and industrial plants were covered in the EU ETS. The number of allowances allocated to the UK in Phase 3 decreased from 174.04 million in 2013 to 159.08 million in 2020 [60].[20] Fig. 4 shows net trading by UK installations under EU ETS from 2008 to 2019 [1]. The positive values indicate that UK installations purchased additional allowances from installations in other countries under the EU ETS. The negative values indicate that UK installations sold spare allowances to the counterparties. The largest number of allowances purchased was 59.1 million in 2014, and the largest number of allowances sold was 27.6 million in 2017.[21]

As the UK left the EU and the EU ETS on December 31, 2020, after the end of the Brexit transition period, the UK has not participated in Phase

[19] From 2013 to June 2020, the revenue from auctions in the UK was €5.0 billion [58].

[20] UK installations are required to surrender their allowances to the Emissions Trading System Workflow Automation Program (ETSWAP) and become liable for the penalty paid to local regulators [62]. There are multiple EU ETS regulators in the UK: the Environment Agency (England), Scottish Environment Protection Agency, Northern Ireland Environment Agency, Natural Resources Wales, the Department for Business, Energy & Industrial Strategy (BEIS) for offshore installations [63].

[21] The number of allocated allowances and surrendered units can be found on the EU Emissions Trading System (ETS) data viewer [60]. Regarding sector-specific values, the number of surrendered units was available but not the number of allocated allowances.

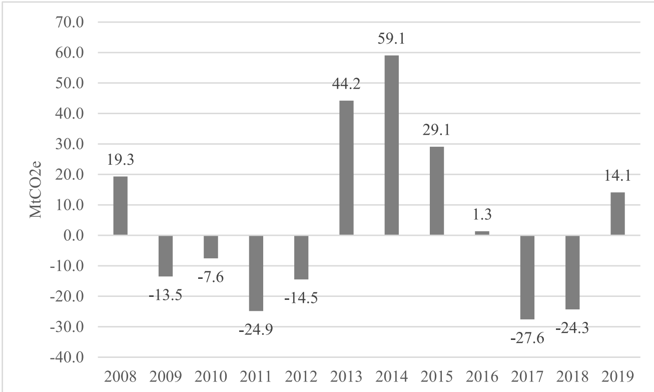

Fig. 4. Net purchases/sales by UK installations under the EU ETS. Source: Final UK greenhouse gas emissions national statistics, BEIS [1].

4 of the EU ETS.[22] Instead, a UK Emissions Trading Scheme (UK ETS) replaced the UK's participation in the EU ETS on January 1, 2021 and continued to provide a carbon pricing system, covering GHG emissions from electricity and heat generation, industry and aviation.

Given the UK's commitment to reaching net-zero emissions by 2050, the UK ETS show greater climate ambition. The cap has been set 5% below the notional share that the UK would have had if it had stayed in Phase 4 of the EU ETS [64]. The cap sets the limit on allowances is 155.6 million in 2021. Auctions are held every two weeks, and the first auction was held in May 2021, with 6.1 million allowances and an auction reserve price of £22 [65].[23]

3. A framework of the electricity sector

3.1. Players and markets

This section illustrates a framework of the electricity sector, as shown in Fig. 5. The framework includes three players (consumers, traditional generators, and renewable generators) and three markets (a competitive domestic electricity market, an international market for fossil fuels, and an international carbon market). The electricity sector may include both wholesale and retail markets, which are jointly represented by a domestic market, so suppliers (retailers) are not included for simplicity. However, renewable generators may sign Power Purchase Agreements (prices tend to be fixed but below the average market price) with suppliers, so some of the benefits from support schemes were realised by suppliers rather than generators.

Traditional generators require fossil fuels to generate electricity, so they need to purchase fossil fuels from the international market if the country is dependent on imports. Also, if the country is included in an international carbon trading system, traditional generators are obliged to purchase carbon allowances if there is any shortage.[24] In contrast, renewable generators use renewable sources such as wind, solar, and biomass with lower operating costs.

In the competitive domestic electricity market, both traditional generators and renewable generators compete to sell electricity to consumers. Assuming that power plants are dispatched by increasing operating costs, the electricity price is determined by the operating costs of the marginal generator, which is the most expensive one that needs to be running to match the total demand. This is known as the merit order.[25] Therefore, given the lower operating costs of renewable electricity, traditional generators face residual demand after the realisation of generation from renewable generators.

Here we illustrate two periods, as shown in Table 1. In the first period, before the development of renewable generation, only traditional generators supply electricity in the market. Consumer expenditure only includes spending on electricity

$$\mathbf{E_1} = \mathbf{p_1}\mathbf{Q^d} \# \quad (1)$$

where $\mathbf{p_1}$ is the electricity price and $\mathbf{Q^d}$ is the demand for electricity.

Traditional generators supply electricity, $\mathbf{Q_1^T}$, to consumers and receive revenue as $\mathbf{p_1 Q_1^T}$. Meanwhile, traditional fossil fuel generators import fossil fuels from the international market and purchase GHG emission allowances. These costs are denoted as $\boldsymbol{\alpha}\mathbf{Q_1^T}$ and $\boldsymbol{\beta}\mathbf{Q_1^T}$, respectively, where $\boldsymbol{\alpha}$ and $\boldsymbol{\beta}$ are the coefficients of associated costs for each unit of electricity generation, depending on the type of sources.[26] These coefficients depend on the types of fossil fuels in the discussion. Assume that the price is greater than the coefficients of costs, $\mathbf{p_1} > \boldsymbol{\alpha} + \boldsymbol{\beta}$. Therefore, the profit of traditional generators is

$$\boldsymbol{\pi_1^T} = (\mathbf{p_1} - \boldsymbol{\alpha} - \boldsymbol{\beta})\mathbf{Q_1^T} \# \quad (2)$$

The market-clearing condition is given as

$$\mathbf{Q_1^T} = \mathbf{Q^d} \# \quad (3)$$

which shows that the electricity supplied is equal to the electricity demanded.

In the second period, after the development of renewable electricity supported by subsidies, electricity price falls via the merit order effect.

Assume that the consumption of electricity remains the same for simplicity, as the demand tends to be inelastic to the price in the electricity sector [67, 68]. Consumer spending on electricity falls to $\mathbf{p_2 Q^d}$, as the price is lower, $\mathbf{p_2} < \mathbf{p_1}$, but consumers need to pay the costs of subsidies, $\mathbf{S^R}$, so the total expenditure is,

$$\mathbf{E_2} = \mathbf{p_2 Q^d} + \mathbf{S^R} \# \quad (4)$$

Renewable generators receive both revenues from selling electricity, $\mathbf{p_2 Q^R}$, and subsidies, $\mathbf{S^R}$, so their profit function is

$$\boldsymbol{\pi_2^R} = \mathbf{p_2 Q^R} + \mathbf{S^R} \# \quad (5)$$

where $\mathbf{Q^R}$ is the quantity of electricity supplied by renewable generators. Note that in reality, part of this profit was realised by suppliers through Purchasing Power Agreements with prices lower than the market average.

Traditional generators face a lower price and a lower quantity supplied, and their profit from selling electricity is

$$\boldsymbol{\pi_2^T} = (\mathbf{p_2} - \boldsymbol{\alpha} - \boldsymbol{\beta})\mathbf{Q_2^T} \# \quad (6)$$

where the electricity they supplied is the residual between demand and the supply from renewable generation,

$$\mathbf{Q_2^T} = \mathbf{Q^d} - \mathbf{Q^R} \# \quad (7)$$

which is also the market-clearing condition.

[22] However, pursuant to the Protocol of Ireland and Northern Ireland, the EU ETS still applies to electricity generation located in Northern Ireland.

[23] It remains undecided whether the UK ETS will operate as a standalone scheme or be linked to the EU ETS. Swiss ETS, a much smaller scheme than UK ETS, linked with ET ETS in January 2020, so Swiss ETS participants can benefit from the liquid and transparent European emissions trading market [66].

[24] The UK left the EU and the EU ETS in December 2020, but our analysis of the EU-wide carbon market remains valid for the situation before that.

[25] In reality, the GB electricity market is also influenced by network constraints. Wind generation might be the cheaper form of generation, but it might be constrained off due to inadequate transmission capacity.

[26] Costs of operation and maintenance are not included in this section, but will be explained in Section 4.5.2. These costs may not represent outflow payments from the electricity sector, as these costs may become the revenues received by domestic service providers.

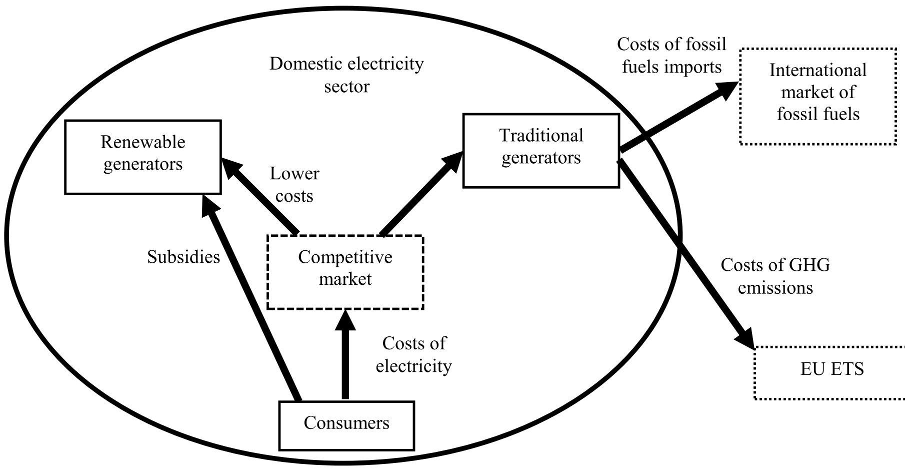

Fig. 5. The framework of the electricity sector. The solid boxes represent players, and the dashed boxes represent markets.

Table 1
The periods before and after the development of renewable generation.

		1st period (before)	2nd period (after)
Consumers	Spending on electricity	$\mathbf{p_1Q^d}$	$\mathbf{p_2Q^d}$
	Costs of subsidies	–	$\mathbf{S^R}$
Traditional generators	Revenue from selling electricity	$\mathbf{p_1Q_1^T}$	$\mathbf{p_2Q_2^T}$
	Costs of importing fossil fuels	$\boldsymbol{\alpha}\mathbf{Q_1^T}$	$\boldsymbol{\alpha}\mathbf{Q_2^T}$
	Costs of GHG emissions	$\boldsymbol{\beta}\mathbf{Q_1^T}$	$\boldsymbol{\beta}\mathbf{Q_2^T}$
Renewable generators	Revenue from selling electricity	–	$\mathbf{p_2Q^R}$
	Subsidies received	–	$\mathbf{S^R}$
Market clearing		$\mathbf{Q_1^T = Q^d}$	$\mathbf{Q_2^T + Q^R = Q^d}$

3.2. Gain to consumers

The framework helps understand if consumers are better off after the development of renewable electricity supported by subsidies. The conclusion can be drawn based on the comparison between the reduced spending on electricity and the costs of schemes.

For consumers, the expenditure only includes spending on electricity, $\mathbf{p_1Q^d}$, in the first period. In the second period, both spending on electricity and costs of subsidies, $(\mathbf{p_2Q^d + S^R})$, are included. Therefore, the change in the expenditure is

$$\mathbf{\Delta E = E_2 - E_1 = \left(p_2Q^d + S^R\right) - p_1Q^d}\# \tag{8}$$

If the expenditure is smaller in the second period, i.e., the change in the expenditure is less than zero, consumers are better off or receive positive gain, as

$$\mathbf{\Delta E < 0 \leftrightarrow S^R < (p_1 - p_2)Q^d}\# \tag{9}$$

where indicates that the costs of subsidies, $\mathbf{S^R}$, is less than the reduced spending on electricity, $(\mathbf{p_1} - \mathbf{p_2})\mathbf{Q^d}$. Recall that the spending on electricity in the second period is lower due to lower prices via the merit order effect.

In contrast, if the expenditure is larger in the second period, i.e., the change in the expenditure is greater than zero, consumers are worse off or receive negative gain, as

$$\mathbf{\Delta E > 0 \leftrightarrow S^R > (p_1 - p_2)Q^d}\# \tag{10}$$

which indicates that the costs of subsidies are greater than the reduced spending on electricity.

Therefore, the impacts of support schemes on consumers can be discussed based on the comparison explained above, but these schemes may have different impacts on the sector as a whole.

3.3. Net gain to the sector

This section discusses how the framework also helps understand if the sector is better off after the development of renewable electricity. Before referring to the framework, we first consider the situation of a closed domestic electricity sector, i.e., coal is produced domestically and the domestic GHG emissions trading system is isolated from other countries. If coal is produced in the UK, the costs of purchasing coal present payments from traditional generators to coal producers. Similarly, if the GHG emission market is nationwide, any trading of allowances presents payments between domestic generators. Therefore, there is no leakage from the sector (and the country), so schemes supporting renewable electricity re-distribute gain among players within the sector, leaving the sector as a whole unaffected.

However, in an open electricity sector, there may be leakages from the sector. That is, if the country is dependent on imports of fossil fuels and included in an international emissions trading system, the costs of importing fossil fuels and purchasing allowances from other countries represent outflow payments from this country. Therefore, a transition to renewable electricity could affect the sector as a whole by changing the total leakage or the total payoffs of players in the domestic electricity sector.

3.3.1. Changes in the payoffs of players

We first look at the change in payoffs of three players in the domestic electricity sector when the sector moves from the first period to the second period. Still assuming the demand remains the same across two periods. For consumers, as discussed in Eq. (8), the change in the payoff is the change in total expenditure as

$$\mathbf{\Delta E = E_2 - E_1 = \left(p_2Q^d + S^R\right) - p_1Q^d = (p_2 - p_1)Q^d + S^R}\# \tag{11}$$

which can be positive (negative gain to consumers due to increased expenditure) or negative (positive gain to consumers).

For renewable generators, as they began to operate in the second period, the change in their payoff is simply the profit in the second period,

$$\boldsymbol{\Delta\pi^R = \pi_2^R} = \mathbf{p_2Q^R + S^R > 0}\# \tag{12}$$

For traditional generators, the change in their payoff can be written as the change in their profit,

$$\boldsymbol{\Delta\pi}^{\mathbf{T}} = \boldsymbol{\pi}_2^{\mathbf{T}} - \boldsymbol{\pi}_1^{\mathbf{T}} = (\mathbf{p_2} - \boldsymbol{\alpha} - \boldsymbol{\beta})\mathbf{Q}_2^{\mathbf{T}} - (\mathbf{p_1} - \boldsymbol{\alpha} - \boldsymbol{\beta})\mathbf{Q}_1^{\mathbf{T}} = (\mathbf{p_2} - \mathbf{p_1})(\mathbf{Q^d} - \mathbf{Q^R}) - (\mathbf{p_1} - \boldsymbol{\alpha} - \boldsymbol{\beta})\mathbf{Q^R} < \mathbf{0}\# \tag{13}$$

The first term in Eq. (13) shows the change in profit on the residual supply. If the merit order effect exists, $\mathbf{p_2} < \mathbf{p_1}$, the first term is negative, i.e., the change in the profit from the residual supply is negative. The second term is negative and shows the loss of profit from the part of their previous supply taken by renewable generators. Therefore, the change in the payoff of traditional generators is negative, so they are worse off because they supply a smaller quantity of electricity at a lower price. The larger the quantity of electricity generated from renewable generators, the larger the negative payoff occurred to traditional generators.

3.3.2. Net gain to the sector

Then combining the changes from three players together, we have the net change to all three players in the sector or the net gain to the sector,[27]

$$\boldsymbol{\Delta\Pi}^{\mathbf{E}} \equiv -\boldsymbol{\Delta}\mathbf{E} + \boldsymbol{\Delta\pi}^{\mathbf{R}} + \boldsymbol{\Delta\pi}^{\mathbf{T}} = (\boldsymbol{\alpha} + \boldsymbol{\beta})\mathbf{Q^R} > \mathbf{0}\# \tag{14}$$

Eq. (14) shows that the net gain to the sector is positive, and it depends on the quantity of renewable generation and the cost coefficients of importing fossil fuels and purchasing GHG emissions allowances, $\boldsymbol{\alpha}$ and $\boldsymbol{\beta}$ in Eq. (2). Therefore, it is crucial to identify the sources of fossil fuels that are replaced by renewables, as the source-specific cost coefficients help determine the size of the net gain to the electricity sector.

The net gain to the domestic electricity sector came from fewer imports of fossil fuels and fewer requirements for GHG emission allowances. Crucially, as Eq. (14) indicates, this net gain to the sector is independent of the impacts on consumers. In other words, costs of subsidies and reduced spending on electricity were considered in the gain to consumers in Eq. (11), but they become irrelevant when calculating the net gain to the sector.[28]

3.3.3. Distribution of gain among players

The transition to renewable electricity brings net gain to the sector, as shown in Eq. (14). Here we explain how this net gain is shared among three players.

As Eq. (13) indicates, traditional generators receive negative gain. Therefore, the net gain to the sector and the negative gain to traditional generators should be shared by consumers and renewable generators. However, if consumers also receive negative gain in the situation of Eq. (10), renewable generators receive the transfer of gain from consumers and traditional generators in addition to the net gain to the sector. To show this, we rewrite Eq. (14) as

$$\Delta\pi^{\mathrm{R}} = \Delta\mathrm{E} - \Delta\pi^{\mathrm{T}} + (\alpha + \beta)\mathrm{Q}^{\mathrm{R}}\# \tag{15}$$

which shows that the positive gain to renewable generators is the sum of the negative gain to consumers ($\Delta\mathrm{E} > 0$), the negative gain to traditional generators ($\Delta\pi^{\mathrm{T}} < 0$), and the net gain to the electricity sector.

Eq. (15) also illustrates that the negative gain to consumers is already converted to the positive gain received by renewable generators, so the net gain to the sector should not be considered as compensation for the negative gain to consumers.

[27] Consumers are better off if the change in expenditure is negative, so here we impose a negative sign on it when adding up the payoffs from all three players.

[28] In the static term, the net gain to the sector depends on the quantity of renewable generation (and thus the installed capacity). In contrast, in the dynamic term, the installed capacity may be positively related to the amount of subsidies. $\mathrm{dQ^R}/\mathrm{dS^R} > 0$. That is, if consumers are required to pay a larger amount of subsidies, the sector will have larger positive net gain due to a larger quantity of renewable generation, but maybe at the expense of larger negative gain to consumers.

4. The application to the UK

As the UK was dependent on imports of fossil fuels and included in the ET ETS, the framework discussed in Section 3 suggests that the sector should be better off from fewer imports and emissions from the transition from fossil fuels to renewables. Meanwhile, as Section 3.3.2 explains, to understand the impacts of the renewable support schemes on the UK electricity sector, we should identify the sources of fossil fuels that have been replaced by renewable electricity in order to find the cost coefficients related to imports of fossil fuels and GHG emissions.

If the analysis is based on hourly data, as peaking gas-fired plants are switched off when wind farms begin to operate, it is likely to conclude that wind generation replaces gas-fired generation. Nonetheless, we examine the structural change in the generation mix to see if this conclusion still holds on a longer horizon.

4.1. Compare the generation in 2006 and 2020

Table 2 compares electricity generation in 2006 and 2020. As the total electricity supply decreased from 405.24 TWh to 329.91 TWh, any change in the generation reflected the effects of both decreased supply and increased renewable electricity, as Column 5 shows.[29] For example, coal-fired and gas-fired generation declined by 143.35 TWh and 29.4 TWh, respectively, in this period, but it remains unclear if the decreases were caused by the decreased supply or the transition to renewable sources.

Therefore, to correctly identify the effect of the transition to renewables, we distinguish it from the effect of the decreased supply in the following way. Column 1 shows the generation in 2006, and Column 2 shows the associated percentages (generation mix). After applying the percentages to the electricity supply in 2020 at 329.91 TWh, Column 3 shows the hypothetical generation in 2020 if all technologies declined proportionately. As shown in Column 6, the difference between the hypothetical generation in 2020 and the actual generation in 2006 can be seen as the effect of the decreased supply, as the generation mix remained the same. In contrast, the difference between the actual generation in 2020 and the hypothetical generation can be seen as the effect of the structural change because these changes were caused by changes in the generation mix, as shown in Column 7.

For example, as shown in Table 2, coal-fired generation decreased from 148.85 TWh in 2006 to 5.5 TWh in 2020, and the decrease was contributed by the decreased supply and the structural change in the generation mix. In 2006, coal-fired generation represented 36.73% of the total supply. If all technologies decline proportionally, the hypothetical value of coal-fired generation should be 121.18 TWh in 2020. The difference, −27.67 TWh, represents the decrease in coal-fired generation due to the decreased supply. However, the actual value was 5.5 TWh in 2020, so the further difference, −115.68 TWh can be seen as the effect of the structural change in the generation mix, i.e., the replacement of coal-fired generation by other sources such as renewables.

As expected, the decreased supply brought declines in electricity generated from all sources, shown in Column 6. In contrast, the effect of the structural change in the generation mix was different, as shown in Column 7. From 2006 to 2020, electricity generation from non-renewable sources experienced declines from the effect of the structural change: gas (−3.22 TWh), oil (−4.19 TWh), and nuclear (−11.15 TWh). In contrast, renewable sources have shown structural increases: wind (71.92 TWh), bioenergy (30.85 TWh), solar (13.16 TWh), hydro

[29] Demand is equal to supply in the electricity market, but supply, rather than demand, is used in the analysis as it is more closely related to generation in terms of definition.

Table 2
Changes in electricity generation by sources in 2006 and 2020.

	(1)	(2)	(3)=(2)*329.91	(4)	(5)=(4)–(1)	(6)=(3)–(1)	(7)=(4)–(3)
	2006 (in TWh)	2006 (in %)	Hypothetical 2020 (in TWh)	2020 (in TWh)	Total changes (in TWh)	Effect of the decreased supply (in TWh)	Effect of the structural change (in TWh)
Electricity Supply	405.24	100.00%	329.91	329.91	−75.33	−75.33	0.00
Coal	148.85	36.73%	121.18	5.50	−143.35	−27.67	−115.68
Oil	6.17	1.52%	5.03	0.83	−5.34	−1.15	−4.19
Gas	140.83	34.75%	114.65	111.43	−29.40	−26.18	−3.22
Nuclear	75.45	18.62%	61.43	50.28	−25.17	−14.02	−11.15
Hydro	4.59	1.13%	3.74	6.75	2.16	−0.85	3.01
Wind	4.24	1.05%	3.45	75.37	71.13	−0.79	71.92
Solar	0.00	0.00%	0.00	13.16	13.16	0.00	13.16
Bioenergy	9.93	2.56%	8.46	39.31	29.38	−1.47	30.85
Other fuels	7.22	1.78%	5.88	9.36	2.14	−1.34	3.48
Net imports	7.52	1.85%	6.12	17.91	10.39	−1.40	11.79

Source: authors' own calculation based on data from BEIS [2].

(3.01 TWh), and other fuels (3.48 TWh).[30] Besides, net imports of electricity increased by 11.79 TWh due to the structural change.

4.2. The role of wind generation in the structural change

Therefore, by separating the effect of structural change from the effect of the decreased supply, we are able to identify the sources of fossil fuels that were replaced by renewable electricity. To be consistent with the analysis in Ref. [17], here we focus on the role of wind generation from RO wind farms (see Table 3 Column 1) in the structural change of the generation mix from 2006 to 2020.

Structurally, nuclear decreased by 11.15 TWh. Following [69,70], as baseload generation, the decrease in nuclear could be covered by part of the structural increase in the bioenergy, 30.85 TWh.

Therefore, the structural increase in wind (71.92 TWh) was used to replace part of the structural declines in coal (−115.68 TWh), oil (−4.19 TWh), and gas (−3.22 TWh). For simplicity, as the declines in oil and gas were relatively small, we assume that wind generation was used to cover the decline in coal.[31] In this case, the structural declines in gas, oil, and the rest of coal were covered by the structural increases of other renewable sources. Once we have identified that wind generation has replaced coal-fired generation in the long term, coal-related coefficients can be used to calculate the avoided costs from fewer imports and reduced GHG emissions, However, the transition from coal to wind was the joint result of renewable subsidies and other policies such as carbon prices (and in particular, the Carbon Price Support), so the avoided costs should not be fully attributed to the former [52]. suggests that the contribution share from renewable subsidies was 38.6% in terms of reducing carbon emissions between 2010 and 2018. Therefore, we first calculate the avoided costs from the transition from coal to wind, and then multiply by the contribution share to reflect the contribution from the RO scheme.

Table 3
Avoided costs from fewer coal imports for wind generation from RO wind farms. Units are re-specified among columns.

Financial year	(1)	(2)=(1) *0.513	(3)	(4)=(2)* (3)	(5)=(4) *38.6%
	Wind generation from RO wind farms (GWh)	Avoided usage of coal, 0.513 t/MWh (million tonnes)	Coal prices, annual average (£/tonne)	Avoided costs from fewer coal imports (£ million)	Avoided costs from fewer coal imports attributed to RO scheme (£ million)
09–10	9420	4.83	45.14	218	84
10–11	11,480	5.89	65.93	388	150
11–12	16,934	8.69	72.90	633	244
12–13	21,985	11.28	56.60	638	246
13–14	29,288	15.02	50.18	754	291
14–15	32,847	16.85	43.87	739	285
15–16	36,497	18.72	34.98	655	253
16–17	37,367	19.17	53.03	1017	392
17–18	46,354	23.78	64.58	1536	593
18–19	49,232	25.26	68.05	1719	663
19–20	51,669	26.51	43.15	1144	442

Sources: authors' own calculation based on data from DataStream, EIA, Ofgem, and [17].

4.3. Avoided costs from fewer coal imports

First, we calculate the avoided costs from fewer coal imports. According to the US Energy Information Administration, 0.513 tonnes of coal is needed to generate one MWh of electricity [71]. Table 3 Column 2 shows the avoided usage of coal from 2009 to 2020, calculated as the product between wind generation from RO wind farms and the coefficient of 0.513 tonnes per MWh.[32] This is the amount of coal that needs to be imported if there is no such wind generation supported by the RO scheme. Then multiplying the avoided usage with annual coal prices (in financial years), Column 4 gives the avoided costs from fewer coal imports. For example, in 2019–20, wind generation from RO wind farms was 51,669 GWh, so the avoided usage of coal was 26.51 million tonnes and the avoided costs from fewer coal imports were £1144 million, given the coal price was £43.15 per tonne. These amounts can be seen as benefits to the UK electricity sector as fewer coal imports were purchased from the international market. After multiplying these avoided costs by the contribution share of 38.6%, Column 5 gives the part of the avoided costs from fewer coal imports that can be attributed to the RO scheme, with £442 million in 2019–20.

[30] Other fuels include coke oven gas, blast furnace gas, waste products from chemical processes, non-biodegradable wastes, pumped storage, and wave/tidal [55]. Electricity generated from wave and tidal was only around 0.01 TWh in 2020 so we include it into other fuels instead of considering it separately.

[31] On the other end of the spectrum, we can assume the structural increase in wind (71.92 TWh) was used to cover gas (−3.22 TWh) and oil (−4.19 TWh) first, and then coal (−64.51 TWh). In this case, the associated avoided costs from importing fossil fuels and GHG emissions will be slightly different. However, as the majority of wind (89.7%) was still used to replace coal, the difference should remain limited.

[32] Annual wind generation from wind farms accredited in the RO scheme is collected from Ref. [17].

4.4. Avoided costs from reduced GHG emissions

Second, we calculate the avoided costs from reduced GHG emissions. The GHG emissions are measured as carbon dioxide equivalent (CO_2e), which stands for a unit based on the global warming potential of different greenhouse gases. According to the estimate, the GHG emissions are 0.936kgCO_2e/kWh for coal-fired plants and 0.00kgCO_2e/kWh for wind generation [49].[33] Therefore, by replacing one kWh of electricity from coal-fired plants with that from wind farms, GHG emissions were reduced by 0.936 kg.

Therefore, as we suggest in Section 4.2 that wind generation replaced coal-fired generation from 2006 to 2020, the coefficient of 0.936kg/kWh can be used to calculate reduced GHG emissions. Table 4 Column 2 shows the avoided GHG emissions after multiplying the coefficient by wind generation from RO wind farms. Then multiplying the avoided GHG emissions with annual EU carbon prices (in financial years), Column 4 shows avoided costs from reduced GHG emissions. For example, in 2019–20, the reduced GHG emissions were 48.36 million tonnes, and the avoided costs from reduced emissions were £1018 million, given the carbon price was £21.06 per tonne. These amounts can also be seen as benefits to the UK electricity sector as spare carbon allowances can be sold to installations in other countries under the EU ETS. Next, after multiplying these avoided costs by the contribution share of 38.6%, Column 5 gives the avoided costs from reduced GHG emissions that can be attributed to the RO scheme, with £393 million in 2019–20.

4.5. Discussion

4.5.1. Different impacts on consumers and the electricity sector

The transition from coal-fired generation to wind generation brought net gain to the UK electricity sector through avoided costs from fewer coal imports and reduced GHG emissions, as shown in Table 5 Column 1. After multiplying by the contribution share of 38.6%, Column 2 shows the net gain attributed to the RO scheme, exceeding £800 million in 2018–19 and 2019–20. In contrast, based on the calculation by [17], the RO scheme brought negative gain to consumers, around £2 billion in the same period, shown in Column 3. However, as we discussed in Section 3.3.1, the net gain to the electricity sector should not be considered as compensation for the negative gain to consumers. This is because the negative gain to consumers was converted to the positive gain received by renewable generators (and suppliers), leaving no impact on the electricity sector as a whole. Therefore, these avoided costs were the net gain to the UK electricity sector for its transition from coal to renewable electricity because this sector was dependent on the imports of fossil fuels and included in an international emissions trading system.

4.5.2. Costs of operation and maintenance

In the analysis in Section 3, costs of operation and maintenance (O&M) were not considered in the profit functions of traditional and renewable generators. We consider the O&M costs here and discuss their implications.

The coefficients of the O&M costs are denoted as γ^T and γ^R for traditional generators and renewable generators, respectively.[34] Note that these coefficients depend on the types of sources in the discussion.

The profits of traditional generators in both periods were given in Eq. (2) and Eq. (6), but are revised after considering the O&M costs,

$$\pi_1^T = (p_1 - \alpha - \beta - \gamma^T)Q_1^T \# \tag{16}$$

and

$$\pi_2^T = (p_2 - \alpha - \beta - \gamma^T)Q_2^T \# \tag{17}$$

Meanwhile, the profit of renewable generators in the second period was given in Eq. (5) and here is revised as

$$\pi_2^R = (p_2 - \gamma^R)Q^R + S^R \# \tag{18}$$

Consequently, the net gain to the three players becomes

$$\Delta\Pi^E = -\Delta E + \Delta\pi^R + \Delta\pi^T = (\alpha + \beta)Q^R + (\gamma^T - \gamma^R)Q^R \# \tag{19}$$

The first term in Eq. (19) is the net gain to the sector without the inclusion of the O&M costs, as Eq. (14) illustrates. The second term is the change in the O&M costs of generation when fossil fuels are replaced by renewables. According to the costs of generation suggested by DECC, the O&M costs for projects started in 2012 were £8/MWh for coal-fired generation and £26.5/MWh for wind generation [73].[35] Therefore, as renewable generation is more expensive in terms of the O&M costs, the second term in Eq. (19) is negative, reducing the net gain to the three players. In Table 6 we apply these coefficients for the scenario of RO wind farms, for example, in 2019–20, wind generation from RO wind farms was 51,669 GWh, so the increase in the O&M costs was £956 million.[36]

The O&M costs were considered as the reduction of net gain to the three players, but we should be cautious about its impacts on the sector. If these services were provided by foreign firms, these costs represent outflow payments and thus reduce the net gain to the domestic electricity sector. However, if these services were provided by domestic firms, these costs do not represent outflow payments from the electricity sector and so do not reduce the net gain to the sector. Instead, the fourth player, domestic service providers, which receive the payments for O&M from generators, should be included in the electricity sector. The same logic was applied to the scenario of domestic coal producers in the closed domestic sector discussed in Section 3.3.

4.5.3. Net imports of electricity

Another element representing outflow payments from the electricity sector is the net imports of electricity. Table 6 also shows costs related to net imports of electricity. For example, based on data from BEIS, the net imports were 20.36 TWh in 2019–20, leading to a payment of £637 million to generators outside the UK, as the average wholesale electricity price was £31.31/MWh. But at the same time, similar to wind generation, the increased net imports help reduce imports of fossil fuels and GHG emissions. If net imports were used to cover coal-fired generation, the associated avoided costs from fewer coal imports and GHG emissions were £451 million and £401 million, respectively.[37] So the avoided costs were higher than the outflow payments, bringing positive impacts on the electricity sector.

This study aims to understand the impacts of the transition to renewable electricity, but net imports were not included in our framework because its relationship with the rise of renewable sources is not clearly identified. It remains unclear if the increased net imports were the result of increased intermittent renewables or because it is a cheaper alternative to domestic electricity generation.

---

[33] The estimated GHG emissions per kWh by coal ranged from 0.903gCO2e to 0.997gCO2e between 2009 and 2020 [55]. Besides [72], confirm that the GHG emissions by wind generation were as low as 0.004gCO2e/kWh.

[34] The O&M costs include fixed and variable components.

[35] The coefficient for coal was taken from IGCC technology, and the coefficient for wind was taken as an average between onshore wind (>5 MW in the UK, £20/MWh) and offshore wind (Round 2 sites, £33/MWh) [73]. In a more updated 2016 version, detailed costs were provided for projects commissioned in 2020, which were less relevant to the period we are discussing in this study.

[36] This value is calculated by multiplying the wind generation of 51,669 GWh with the increase in O&M costs, £18.5/MWh (=£26.5/MWh - £8/MWh), when generation shifts from coal to wind.

[37] These two avoided costs were calculated by multiplying net imports of 20.89 TWh by coal-related coefficients (0.513 t/MWh and 0.936kgCOe/kWh) and prices of coal and carbon from Tables 3 and 4.

Table 4
Avoided costs from reduced GHG emissions for wind generation from RO wind farms. Units are re-specified among columns.

Financial year	(1) Wind generation from RO wind farms (GWh)	(2)=(1)*0.936 Avoided GHG emissions, 0.936kgCOe/kWh (million tonnes)	(3) Carbon prices, annual average (£/tonne)	(4)=(2)*(3) Avoided costs from reduced emissions (£ million)	(5)=(4)*38.6% Avoided costs from reduced emissions attributed to RO scheme (£ million)
09–10	9420	8.82	12.08	106	41
10–11	11,480	10.75	12.67	136	53
11–12	16,934	15.85	9.77	155	60
12–13	21,985	20.58	5.40	111	43
13–14	29,288	27.41	4.05	111	43
14–15	32,847	30.75	5.11	157	61
15–16	36,497	34.16	5.17	176	68
16–17	37,367	34.98	4.25	149	57
17–18	46,354	43.39	7.78	338	130
18–19	49,232	46.08	18.63	858	331
19–20	51,669	48.36	21.06	1018	393

Sources: authors' own calculation based on data from DataStream, Ofgem, and [17].

Table 5
Total avoided costs from the transition from coal-fired generation to wind generation from RO wind farms, and the total avoided costs can be attributed to the RO scheme.

Financial year	(1) Total avoided costs (£ million)	(2)=(1)*38.6% Total avoided costs attributed to RO scheme (£ million)	(3) Gain to consumers (£ million)
09–10	325	125	−37
10–11	524	202	15
11–12	788	304	269
12–13	749	289	114
13–14	865	334	−110
14–15	896	346	−489
15–16	831	321	−726
16–17	1165	450	−506
17–18	1873	723	−2527
18–19	2577	995	−2031
19–20	2162	835	−2487

Sources: authors' own calculation based on data from DataStream, Ofgem, and [17].

5. Conclusion and policy implications

The electricity generation mix in the UK has changed dramatically in the last two decades, but the transition to renewables was supported by subsidies from consumer-funded schemes. While renewable electricity brought down the electricity prices via the merit order effect, the costs of subsidies were passed to consumers directly through higher electricity bills.

We constructed a framework for the electricity sector and suggested that we need to distinguish the impacts of renewable support schemes on consumers and the electricity sector. From the perspective of consumers, support schemes brought negative gain to consumers if the reduced spending on electricity was less than the costs of the scheme. From the perspective of the electricity sector, as the UK was dependent on imports of fossil fuels from abroad and included in the international emissions trading system (EU ETS), the transition to renewable electricity brought positive net gain to the sector from two aspects: (i) avoided costs from fewer imports of fossil fuels and (ii) avoided costs from reduced GHG emissions.

After comparing the electricity generation in 2006 and 2020, we suggested that changes in all sources came from two effects: the decreased supply and the structural change in the generation mix. We constructed a hypothetical generation in 2020 using the percentages in 2006 to distinguish these two effects. Based on the effect of the structural change from 2006 to 2020, we suggested that wind generation replaced coal-fired generation rather than gas-fired generation on the longer horizon, and then we calculated the avoided costs from fewer imports of fossil fuels and reduced GHG emissions using coal-related coefficients.

However, the transition from coal to wind in the UK was a joint result of renewable subsidies and other policies such as carbon prices (in particular, the Carbon Price Support). The entangled influences of these policies make the evaluation of individual policies less straightforward. Therefore, according to Ref. [52], a contribution share of 38.6% was adopted to attribute the total gain of the transition to renewable

Table 6
Costs related to (i) operation and maintenance and (ii) net imports of electricity.

Financial year	Costs of O&M		Net imports of electricity				
	(1) Wind generation from RO wind farms (GWh)	(2)=(1)*18.5 Change in the O&M Costs (£ million)	(3) Net imports (GWh)	(4) Average wholesale electricity price (£/MWh)	(5)=(3)*(4) Costs of net imports of electricity (£ million)	(6) Avoided costs from fewer imports of fuels (£ million)	(7) Avoided costs from reduced emissions (£ million)
09–10	9420	174	2811	27.92	78	65	32
10–11	11,480	212	3552	37.76	134	120	42
11–12	16,934	313	7633	40.78	311	285	70
12–13	21,985	407	12,506	39.26	491	363	63
13–14	29,288	542	15,953	40.90	653	411	60
14–15	32,847	608	20,666	35.53	734	465	99
15–16	36,497	675	20,265	33.74	684	364	98
16–17	37,367	691	16,999	35.29	600	462	68
17–18	46,354	858	15,847	40.51	642	525	115
18–19	49,232	911	19,623	50.08	983	685	342
19–20	51,669	956	20,355	31.31	637	451	401

Sources: authors' own calculation based on data from DataStream, Ofgem and BEIS.

subsidies.

Focusing on the wind generation supported by the RO scheme in the UK, [17] find that the increased wind generation from RO wind farms brought negative gain to consumers in most years from 2009–20 to 2021–20 as the reduction in spending on electricity was less than the costs of the RO scheme. However, we suggested that the negative gain to consumers was converted to the positive gain received by renewable generators (and suppliers), leaving the sector unaffected. We further suggested that the scheme brought positive net gain to the electricity sector from 2009–10 to 2019–20. For example, in 2019–20, the avoided costs from fewer coal imports and reduced GHG emissions that can be attributed to the RO scheme were £442 million and £393 million, giving a total net gain of £835 million to the UK electricity sector. Therefore, the development of wind generation in the UK through the RO scheme brought different impacts on consumers and the sector as a whole.

Regarding policymaking, it is crucial to identify the different impacts on consumers and the sector. The net gain to the sector should not be compared directly with reduced spending on electricity and/or support costs faced by consumers. Also, the net gain should not be considered as compensation for the negative gain to consumers as the latter was transferred to the positive gain received by renewable generators (and suppliers) within the sector already. Therefore, the discrepancy in the payoffs of consumers and the sector imposed a difficult challenge for policymakers, as criticism could be raised if the analysis was done on consumers only.

We considered the framework with simplified assumptions to capture the key conclusions for our analysis. First, we combined the wholesale and retail electricity market and did not include suppliers (retailers), but we acknowledged that parts of the gain received by renewable generators were realised by suppliers through Power Purchase Agreements with lower-than-average prices. Also, the electricity market was assumed to be competitive, but market power may exist in the UK energy market. Second, the costs avoided from fewer coal imports and reduced GHG emissions can also be considered as gain to the country, but we contain our analysis in the electricity sector because the transition to renewable electricity may have more profound impacts on the wider economy, such as decreases in health care expenditure due to improved environmental quality.

Credit author statement

Jing Shao: Methodology, Conceptualization, Formal analysis, Writing – original draft. Jinke Li: Methodology, Conceptualization, Validation, Writing – original draft, Writing – review & editing. Guy Liu: Supervision, Writing – review & editing.

Funding

This research did not receive any specific grant from funding agencies in the public, commercial, or not-for-profit sectors.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

Acknowledgements

We are deeply indebted to two excellent referees for their helpful and constructive comments.

References

[1] BEIS. Final UK greenhouse gas emissions national statistics: 1990 to 2019. 2021. Retrieved from, https://www.gov.uk/government/statistics/final-uk-greenhouse-gas-emissions-national-statistics-1990-to-2019.
[2] BEIS. Energy Trends, various years. 2021. Retrieved from, https://www.gov.uk/government/collections/energy-trends.
[3] Upton GB, Snyder BF. Funding renewable energy: an analysis of renewable portfolio standards. Energy Econ 2017;66:205–16. https://doi.org/10.1016/j.eneco.2017.06.003.
[4] Young D, Bistline J. The costs and value of renewable portfolio standards in meeting decarbonization goals. Energy Econ 2018;73:337–51. https://doi.org/10.1016/j.eneco.2018.04.017.
[5] Li J, Liu G, Shao J. Understanding the ROC transfer payment in the renewable obligation with the recycling mechanism in the United Kingdom. Energy Econ 2020;87:104701. https://doi.org/10.1016/j.eneco.2020.104701.
[6] Shao J, Li J, Liu G. Vertical integration, recycling mechanism, and disadvantaged independent suppliers in the renewable obligation in the UK. Energy Econ 2021;94:105093. https://doi.org/10.1016/j.eneco.2020.105093.
[7] Woodman B, Mitchell C. Learning from experience? The development of the renewables obligation in england and Wales 2002–2010. Energy Pol 2011;39(7):3914–21. https://doi.org/10.1016/j.enpol.2011.03.074.
[8] Wood G, Dow S. What lessons have been learned in reforming the Renewables Obligation? An analysis of internal and external failures in UK renewable energy policy. Energy Pol 2011;39(5):2228–44. https://doi.org/10.1016/j.enpol.2010.11.012.
[9] Bunn D, Yusupov T. The progressive inefficiency of replacing renewable obligation certificates with contracts-for-differences in the UK electricity market. Energy Pol 2015;82:298–309. https://doi.org/10.1016/j.enpol.2015.01.002.
[10] Nelson T, Nelson J, Ariyaratnam J, Camroux S. An analysis of Australia's large scale renewable energy target: restoring market confidence. Energy Pol 2013;62:386–400. https://doi.org/10.1016/j.enpol.2013.07.096.
[11] Verhaegen K, Meeus L, Belmans R. Towards an international tradable green certificate system—the challenging example of Belgium. Renew Sustain Energy Rev 2009;13(1):208–15. https://doi.org/10.1016/j.rser.2007.01.021.
[12] Bergek A, Jacobsson S. Are tradable green certificates a cost-efficient policy driving technical change or a rent-generating machine? Lessons from Sweden 2003–2008. Energy Pol 2010;38(3):1255–71. https://doi.org/10.1016/j.enpol.2009.11.001.
[13] Finjord F, Hagspiel V, Lavrutich M, Tangen M. The impact of Norwegian-Swedish green certificate scheme on investment behavior: a wind energy case study. Energy Pol 2018;123:373–89. https://doi.org/10.1016/j.enpol.2018.09.004.
[14] Shrimali G, Tirumalachetty S. Renewable energy certificate markets in India—a review. Renew Sustain Energy Rev 2013;26:702–16. https://doi.org/10.1016/j.rser.2013.06.034.
[15] NDRC. Notice on trial implementation of green power certificate issuance and voluntary subscription trading system for renewable energy. National Development and Reform Commission; 2017. China Retrieved from, https://policy.asiapacificenergy.org/node/4124.
[16] Darmani A, Rickne A, Hidalgo A, Arvidsson N. When outcomes are the reflection of the analysis criteria: a review of the tradable green certificate assessments. Renew Sustain Energy Rev 2016;62:372–81. https://doi.org/10.1016/j.rser.2016.04.037.
[17] Shao J, Chen H, Li J, Liu G. An evaluation of the consumer-funded renewable obligation scheme in the UK for wind power generation. Renew Sustain Energy Rev 2022;53:111788. https://doi.org/10.1016/j.rser.2021.111788.
[18] Kyritsis E, Andersson J, Serletis A. Electricity prices, large-scale renewable integration, and policy implications. Energy Pol 2017;101:550–60. https://doi.org/10.1016/j.enpol.2016.11.014.
[19] Ciarreta A, Espinosa MP, Pizarro-Irizar C. Is green energy expensive? Empirical evidence from the Spanish electricity market. Energy Pol 2014;69:205–15. https://doi.org/10.1016/j.enpol.2014.02.025.
[20] Clò S, Cataldi A, Zoppoli P. The merit-order effect in the Italian power market: the impact of solar and wind generation on national wholesale electricity prices. Energy Pol 2015;77:79–88. https://doi.org/10.1016/j.enpol.2014.11.038.
[21] Jónsson T, Pinson P, Madsen H. On the market impact of wind energy forecasts. Energy Econ 2010;32(2):313–20. https://doi.org/10.1016/j.eneco.2009.10.018.
[22] Di Cosmo V, Valeri L. Wind, storage, interconnection and the cost of electricity generation. Energy Econ 2018;69:1–18. https://doi.org/10.1016/j.eneco.2017.11.003.
[23] Bell WP, Wild P, Foster J, Hewson M. Revitalising the wind power induced merit order effect to reduce wholesale and retail electricity prices in Australia. Energy Econ 2017;67:224–41. https://doi.org/10.1016/j.eneco.2017.08.003.
[24] Gelabert L, Labandeira X, Linares P. An ex-post analysis of the effect of renewables and cogeneration on Spanish electricity prices. Energy Econ 2011;33:S59–65. https://doi.org/10.1016/j.eneco.2011.07.027.
[25] Gil HA, Gomez-Quiles C, Riquelme J. Large-scale wind power integration and wholesale electricity trading benefits: estimation via an ex post approach. Energy Pol 2012;41:849–59. https://doi.org/10.1016/j.enpol.2011.11.067.
[26] Cludius J, Forrest S, Macgill I. Distributional effects of the Australian Renewable Energy Target (RET) through wholesale and retail electricity price impacts. Energy Pol 2014;71:40–51. https://doi.org/10.1016/j.enpol.2014.04.008.
[27] Perez C. Technological revolutions and techno-economic paradigms. Camb J Econ 2010;34(1):185–202. https://doi.org/10.1093/cje/bep051.
[28] Qolipour M, Mostafaeipour A, Tousi OM. Techno-economic feasibility of a photovoltaic-wind power plant construction for electric and hydrogen production: a case study. Renew Sustain Energy Rev 2017;78:113–23. https://doi.org/10.1016/j.rser.2017.04.088.

[29] Belmili H, Haddadi M, Bacha S, Almi MF, Bendib B. Sizing stand-alone photovoltaic–wind hybrid system: techno-economic analysis and optimization. Renew Sustain Energy Rev 2014;30:821–32. https://doi.org/10.1016/j.rser.2013.11.011.
[30] Al-Sharafi A, Sahin AZ, Ayar T, Yilbas BS. Techno-economic analysis and optimization of solar and wind energy systems for power generation and hydrogen production in Saudi Arabia. Renew Sustain Energy Rev 2017;69:33–49. https://doi.org/10.1016/j.rser.2016.11.157.
[31] Kargbo H, Harris JS, Phan AN. "Drop-in" fuel production from biomass: critical review on techno-economic feasibility and sustainability. Renew Sustain Energy Rev 2021;135:110168. https://doi.org/10.1016/j.rser.2020.110168.
[32] Lo SLY, How BS, Leong WD, Teng SY, Rhamdhani MA, Sunarso J. Techno-economic analysis for biomass supply chain: a state-of-the-art review. Renew Sustain Energy Rev 2021;135:110164. https://doi.org/10.1016/j.rser.2020.110164.
[33] Segurado R, Pereira S, Correia D, Costa M. Techno-economic analysis of a trigeneration system based on biomass gasification. Renew Sustain Energy Rev 2019;103:501–14. https://doi.org/10.1016/j.rser.2019.01.008.
[34] Deane JP, Gallachóir BÓ, McKeogh E. Techno-economic review of existing and new pumped hydro energy storage plant. Renew Sustain Energy Rev 2010;14(4):1293–302. https://doi.org/10.1016/j.rser.2009.11.015.
[35] Navas-Anguita Z, García-Gusano D, Iribarren D. A review of techno-economic data for road transportation fuels. Renew Sustain Energy Rev 2019;112:11–26. https://doi.org/10.1016/j.rser.2019.05.041.
[36] Yang T, Liu W, Kramer GJ, Sun Q. Seasonal thermal energy storage: a techno-economic literature review. Renew Sustain Energy Rev 2021;139:110732. https://doi.org/10.1016/j.rser.2021.110732.
[37] Lee J-S, Cherif A, Yoon H-J, Seo S-K, Bae J-E, Shin H-J, et al. Large-scale overseas transportation of hydrogen: comparative techno-economic and environmental investigation. Renew Sustain Energy Rev 2022;165:112556. https://doi.org/10.1016/j.rser.2022.112556.
[38] Poppi S, Sommerfeldt N, Bales C, Madani H, Lundqvist P. Techno-economic review of solar heat pump systems for residential heating applications. Renew Sustain Energy Rev 2018;81:22–32. https://doi.org/10.1016/j.rser.2017.07.041.
[39] Esen H, Inalli M, Esen M. Technoeconomic appraisal of a ground source heat pump system for a heating season in eastern Turkey. Energy Convers Manag 2006;47(9–10):1281–97. https://doi.org/10.1016/j.enconman.2005.06.024.
[40] Esen H, Inalli M, Esen M. A techno-economic comparison of ground-coupled and air-coupled heat pump system for space cooling. Build Environ 2007;42(5):1955–65. https://doi.org/10.1016/j.buildenv.2006.04.007.
[41] Esen M, Yuksel T. Experimental evaluation of using various renewable energy sources for heating a greenhouse. Energy Build 2013;65:340–51. https://doi.org/10.1016/j.enbuild.2013.06.018.
[42] Ortega M, Del Río P, Montero EA. Assessing the benefits and costs of renewable electricity. The Spanish case. Renew Sustain Energy Rev 2013;27:294–304. https://doi.org/10.1016/j.rser.2013.06.012.
[43] Cullen J. Measuring the environmental benefits of wind-generated electricity. Am Econ J Econ Pol 2013;5(4):107–33. https://doi.org/10.1257/pol.5.4.107.
[44] Novan K. Valuing the wind: renewable energy policies and air pollution avoided. Am Econ J Econ Pol 2015;7(3):291–326. https://doi.org/10.1257/pol.20130268.
[45] Oliveira T, Varum C, Botelho A. Wind power and CO2 emissions in the Irish market. Energy Econ 2019;80:48–58. https://doi.org/10.1016/j.eneco.2018.10.033.
[46] Kaffine DT, McBee BJ, Lieskovsky J. Emissions savings from wind power generation in Texas. Energy J 2013;34(1). https://doi.org/10.5547/01956574.34.1.7.
[47] Hawkes AD. Estimating marginal CO2 emissions rates for national electricity systems. Energy Pol 2010;38(10):5977–87. https://doi.org/10.1016/j.enpol.2010.05.053.
[48] Thomson RC, Harrison GP, Chick JP. Marginal greenhouse gas emissions displacement of wind power in Great Britain. Energy Pol 2017;101:201–10. https://doi.org/10.1016/j.enpol.2016.11.012.
[49] Jansen M, Staffell I, Green R. Daily marginal CO2 emissions reductions from wind and solar generation. In: 15th international conference on the European energy market (EEM); 2018. https://doi.org/10.1109/eem.2018.8469873.
[50] Chyong CK, Guo B, Newbery DM. The impact of a carbon tax on the CO2 emissions reduction of wind. Energy J 2020;41(1). https://doi.org/10.5547/01956574.41.1.cchy.
[51] BEIS. End to coal power brought forward to October 2024. 2021.
[52] Ofgem. State of the energy market. 2019. Retrieved from, https://www.ofgem.gov.uk/publications/state-energy-market-2019.
[53] BEIS. Historical coal data: coal production, availability and consumption. 2021. Retrieved from, https://www.gov.uk/government/statistical-data-sets/historical-coal-data-coal-production-availability-and-consumption.
[54] BEIS. Historical electricity data: 1920 to 2020. 2021. Retrieved from, https://www.gov.uk/government/statistical-data-sets/historical-electricity-data.
[55] BEIS. Digest of UK energy statistics, various years. 2021. Retrieved from, https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes.
[56] IEA. World energy balances. 2020. Retrieved from, https://www.iea.org/reports/key-world-energy-statistics-2020/energy-balances.
[57] IEA. Coal information: overview. 2021. Retrieved from, https://www.iea.org/reports/coal-information-overview.
[58] European Commission. Report on the functioning of the European carbon market, various years. 2021. Retrieved from, https://ec.europa.eu/clima/system/files/2021-10/com_2021_962_en.pdf.
[59] European Commission. Stepping up Europe's 2030 climate ambition. 2020. Retrieved from, https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52020DC0562.
[60] European Environment Agency. EU emissions trading system (ETS) data viewer. 2021. Retrieved from, https://www.eea.europa.eu/data-and-maps/dashboards/emissions-trading-viewer-1.
[61] European Parliament and Council. Concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading scheme. Official Journal of the European Union; 2015.
[62] Environmental Agency. European union emissions trading system (EU ETS) phase III: guidance for installations. Retrieved from, https://www.gov.uk/government/publications/how-to-comply-with-the-eu-ets-and-small-emitter-and-hospital-opt-out-scheme; 2018.
[63] BEIS. Participating in the EU emissions trading system (EU ETS). 2013. Retrieved from, https://www.gov.uk/guidance/participating-in-the-eu-ets.
[64] BEIS. The future of UK carbon pricing - UK government and devolved administrations' response. Retrieved from, https://www.gov.uk/government/consultations/the-future-of-uk-carbon-pricing; 2019.
[65] BEIS. UK emissions trading scheme markets. 2021. Retrieved from, https://www.gov.uk/government/publications/uk-emissions-trading-scheme-markets/uk-emissions-trading-scheme-markets.
[66] House of Commons Library. The UK emissions trading scheme. 2021. Retrieved from, https://commonslibrary.parliament.uk/research-briefings/cbp-9212/.
[67] Würzburg K, Labandeira X, Linares P. Renewable generation and electricity prices: taking stock and new evidence for Germany and Austria. Energy Econ 2013;40:S159–71. https://doi.org/10.1016/j.eneco.2013.09.011.
[68] Cludius J, Hermann H, Matthes FC, Graichen V. The merit order effect of wind and photovoltaic electricity generation in Germany 2008–2016: estimation and distributional implications. Energy Econ 2014;44:302–13. https://doi.org/10.1016/j.eneco.2014.04.020.
[69] Matek B, Gawell K. The benefits of baseload renewables: a misunderstood energy technology. Electr J 2015;28(2):101–12. https://doi.org/10.1016/j.tej.2015.02.001.
[70] BEIS. Biomass policy statement. 2021. Retrieved from, https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1031057/biomass-policy-statement.pdf.
[71] EIA. How much coal, natural gas, or petroleum is used to generate a kilowatthour of electricity?. 2021. Retrieved from, https://www.eia.gov/tools/faqs/faq.php?id=667&t=6.
[72] Pehl M, Arvesen A, Humpenöder F, Popp A, Hertwich EG, Luderer G. Understanding future emissions from low-carbon power systems by integration of life-cycle assessment and integrated energy modelling. Nat Energy 2017;2(12):939–45. https://doi.org/10.1038/s41560-017-0032-9.
[73] DECC. Electricity generation cost. 2012. Retrieved from, https://www.gov.uk/government/publications/electricity-generation-costs.