



# Measuring the progress and impacts of decarbonising British electricity



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## ARTICLE INFO

### Keywords:

Electricity  
CO<sub>2</sub>  
Decarbonisation  
Renewables  
Power sector

## ABSTRACT

Britain's ambitious carbon targets require that electricity be immediately and aggressively decarbonised, so it is reassuring to report that electricity sector emissions have fallen 46% in the three years to June 2016, their lowest since 1960. This paper analyses the factors behind this fall and the impacts they are having.

The main drivers are: demand falling 1.3% per year due to efficiency gains and mild winters; gas doubling its share to 60% of fossil generation due to the carbon price floor; and the dramatic uptake of wind, solar and biomass which now supply up to 45% of demand. Accounting conventions also play their part: imported electricity and biomass would add 5% and 2% to emissions if they were included.

The pace of decarbonisation is impressive, but raises both engineering and economic challenges. Falling peak demand has delayed fears of capacity shortage, but minimum net demand is instead becoming a problem. The headroom between inflexible nuclear and intermittent renewables is rapidly shrinking, with controllable output reaching a minimum of just 5.9 GW as solar output peaked at 7.1 GW. 2015 also saw Britain's first negative power prices, the highest winter peak prices for six years, and the highest balancing costs.

## 1. Introduction

The British electricity system emits around 12,000 tonnes of CO<sub>2</sub> each hour, and must be radically redesigned for the country to meet ambitious national carbon targets: a 50% reduction versus 1990 levels by 2025, and 80% by 2050 (Climate Change Act, 2008; CCC, 2015a). The power sector will be pivotal as the current strategy is to rapidly decarbonise electricity during the 2020s, and then use it to provide an increasing share of heat and transport. The rationale is that there are many ways to generate electricity without carbon emissions, and these are cost-effective relative to the options in heat, transport and industry.

In their Fifth Carbon Budget, the Committee on Climate Change (CCC) recommends that carbon emissions from the power sector must be reduced by 75% of their 2015 levels by 2030, and almost eliminated by 2050 (–95%) (CCC, 2015a). The targets in other sectors are more modest, at 20–40% reduction by 2030 and 25–80% by 2050, with low-carbon electricity providing a third of these reductions by 2030, and half by 2050 (CCC, 2015b).

Achieving these aims will require rapid and substantial changes in the power sector: simultaneously increasing the share of renewables, biomass and nuclear generation; eliminating unabated coal and then gas generation; pushing carbon capture and storage (CCS) beyond the R & D phase; and reducing demand through efficiency measures.

These CCC targets for the power sector translate to a reduction in carbon intensity from around 500 gCO<sub>2</sub> per kWh of electricity consumed, as experienced over the last decade, to 200–250 g/kWh in

2020 and below 100 g/kWh by 2030 (CCC, 2015a). As shown in Fig. 1, this will require an 11% reduction each year of this decade, followed by 9% annually next decade. This is double the rate that was inadvertently seen during the 1990s dash for gas, which saw 100 TWh/year of coal generation (and ~40 million tonnes of fuel) replaced by high-efficiency combined cycle gas turbines (CCGTs) (MacLeay et al., 2016).

Fig. 2 shows that there are tentative signs that the electricity sector turned a corner in 2012 and the required reductions are beginning to materialise. There are several complementary forces at work, which have combined to give a 46% reduction in carbon emissions in the space of just three years:

- Demand is steadily declining by 1–2% per year;
- Coal is being displaced by gas, imported electricity and renewables, so its share has fallen by three-quarters since 2012;
- The share of renewables is growing rapidly: wind, solar and biomass now provide one-fifth of demand.

These changes are not as simple as the headline views may seem. For example, demand has been depressed in recent years due to a succession of mild winters, which cannot be expected to continue indefinitely. The share of coal and gas consumption is influenced by international events. 2012 saw a fall in gas usage as the Fukushima disaster increased Japan's need to import gas, the Arab Spring reduced supplies from the Middle East and American coal provided a cheap alternative as shale gas forced down US power prices. Between 2010

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<http://dx.doi.org/10.1016/j.enpol.2016.12.037>

Received 30 June 2016; Received in revised form 10 November 2016; Accepted 22 December 2016

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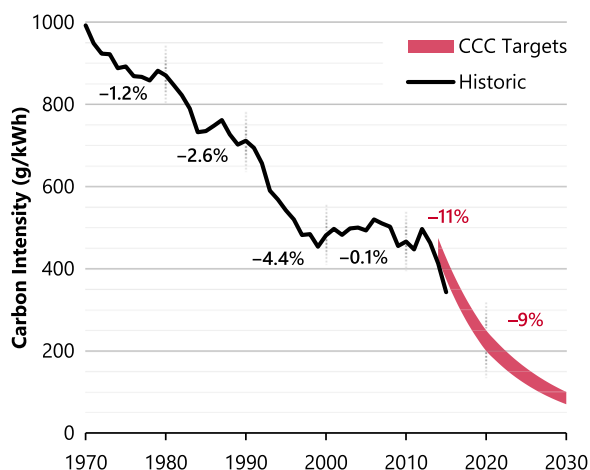


Fig. 1. The historic and required future carbon content of British electricity, highlighting the average year-on-year change during each decade. Data from (CCC, 2015a; MacLeay et al., 2016).

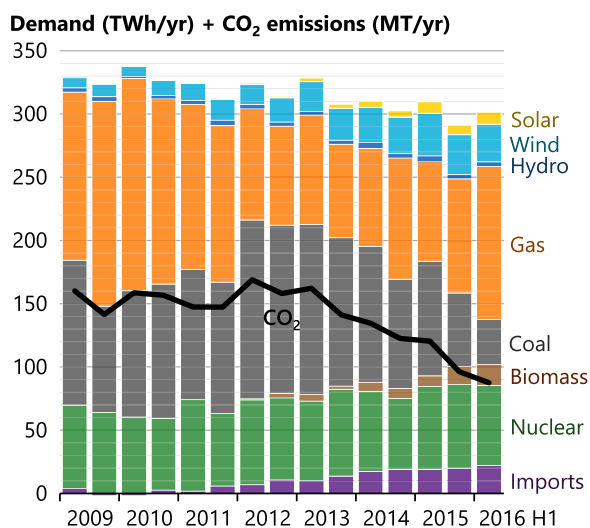


Fig. 2. Biannual generation by type and carbon emissions from the electricity sector.

and 2012 coal prices for British power stations were level whilst gas prices rose 50% (DECC, 2016b).

As seen in Fig. 2, an increasing share of electricity is being imported through interconnectors to France and the Netherlands.<sup>1</sup> This electricity is treated as zero carbon when calculating national emissions inventories, which conveniently neglects the fact Britain now “exports” around 3% of its power sector emissions abroad. This accounting convention implies that importing all of Britain’s electricity is a valid route to decarbonisation, even though French and Dutch fossil power stations release CO<sub>2</sub> to the same atmosphere as British ones.

The growing share of biomass amplifies the uncertainty and lack of understanding that surrounds the carbon intensity of this fuel source. The direct emissions from combusting wood pellets would add 13% to the sector’s total if they were not avoided through sustainable forestry practices.

If understanding the progress towards decarbonisation is complex, the knock-on impacts of it are almost completely concealed when viewed through annual statistics. The intermittency of renewables, structural changes to demand and capacity scarcity cause problems at the extremes, not at the centre, so these can only be understood with high resolution data on the power system.

<sup>1</sup> There are also two interconnectors to the Republic of Ireland and Northern Ireland, but these predominantly exported from Britain during this period.

System operation varies dramatically from hour to hour because of the just-in-time nature of electricity production. Supply and demand must be balanced in real-time with limited recourse to storage and demand-side management (Green and Staffell, 2016). With an increasing share of generation becoming inflexible, semi-controllable and unpredictable, the system must cope with a widening range of conditions that will push both the operational capabilities and the economic rationale of the market.

Britain’s electricity system is approaching several critical tipping points:

- weather-dependent renewables supplying more than 50% of instantaneous demand;
- wholesale prices falling negative in both summer (due to solar) and winter (due to wind);
- solar output forcing minimum net demand below the level of must-run output (nuclear and CHP).

These will no doubt test the capabilities of National Grid to control the system, and may necessitate new markets or services, and the deployment of greater interconnection and storage.

The aim of this paper is to disentangle the various sources of data on the British electricity system to better understand these trends, analyse their impacts on the electricity sector, and comment on whether they can continue contributing to emissions reductions in the coming years. Section 2 outlines the sources of data and calculations employed. Section 3 explores the derived statistics, covering demand, supply, carbon emissions and prices. Section 4 estimates the contributions that individual technologies and external factors have made towards decarbonisation, then Section 5 concludes. Online supplementary material provides further mathematical details.

In an effort to promote transparency and understanding, the data behind all the figures in this paper are made available on ScienceDirect. The processed data can also be explored interactively at [www.electricinsights.co.uk](http://www.electricinsights.co.uk).

## 2. Methods and data

### 2.1. Conventions

The electricity sector has many accounting conventions to be aware of. Power flow is measured in kW / MW / GW; volumes of energy are measured in MWh / GWh / TWh. Producing 1 GW constantly for a year will yield 8.76 TWh, which is enough to power 2.65 million homes according to the common media analogy.<sup>2</sup>

The chemical energy contained within the fuels is typically measured in MJ / GJ / TJ, or as million tonnes of oil equivalent (1 MTOE = 41,868 TJ = 11.63 TWh), or million British thermal units (1 MMBTU = 10 therms = 1.055 GJ) (Staffell, 2011). This energy can be expressed relative to higher heating value (HHV) which is the true thermodynamic definition of energy content, or lower heating value (LHV) which neglects the latent heat of the water vapours produced during combustion. This makes generation efficiencies appear 5–11% higher when presented against LHV, which remains the industry convention<sup>3</sup>; however, HHV is used here as recommended by the IEA (International Energy Agency, 2010).

Electricity demand equals generation minus losses in the transmission and distribution system, and may be defined to include exports and/or in-flows into storage.<sup>4</sup> Generation can either refer to the gross electricity output from a turbine or the net output of a power station, which excludes the electricity consumed by the station itself.

<sup>2</sup> Assuming 3300kWh per year electricity consumption per household (Ofgem, 2011).

<sup>3</sup> LHV was more practical in the 19th century, as heat below 150°C could not be put to work when burning sulphur-rich coal due to sulphuric acid formation (Staffell, 2010).

<sup>4</sup> Commonly known as pumping, due to the prevalence of pumped hydro plants.

Supply and demand are measured in real time by flows into and out of the transmission network. The major power stations that connect into this network are metered, but an increasing amount of generators are now integrated with consumers, making them invisible to national grid. These are classified as embedded renewables (predominantly small wind and solar), and auto-generators (CHP engines and other generators used in industrial and other facilities).

The exclusion of embedded generation from many data sources is an increasing problem, as this discounts much of Britain's wind capacity and all of its solar capacity, both of which have grown significantly. To be specific, larger onshore farms in Scotland and offshore wind farms are connected to the transmissions system and thus are metered by National Grid; all onshore farms in England and Wales are embedded into the distribution system and thus are invisible.

There are also numerous captive power stations, or auto-generators, used in industrial and other large facilities to meet on-site demand. Britain has 4.6 GW of auto-generators, which were estimated to produce 2.2 GW during summer and 2.8 GW in winter 2013 (each 7.4% of gross demand) (Boßmann and Staffell, 2015). These have limited interaction with the electricity network as they meet on-site demand and are not centrally metered, making them effectively invisible to the system. Unlike embedded renewables, there are no half-hourly estimates of the fleet's output to work from, and so auto-generators are excluded from this analysis.

Annual statistics from DUKES could be used to estimate the influence of auto-generators, based on two general trends over the period 2000–2014 (MacLeay et al., 2016). Firstly, auto-generator output has equalled  $9.0 \pm 0.4\%$  of the metered supply from major power producers; and secondly, the composition of auto-generators has been  $65 \pm 3\%$  'conventional thermal' (coal, oil, biomass) and the remainder CCGT. Following from this, auto-generators are estimated to contribute an additional 17 TWh generation from coal and 9 TWh from gas in 2015, and thus 19 million tonnes of CO<sub>2</sub> (compared to 112 MT from major power producers).<sup>5</sup>

The conventions used in this paper are as follows:

- Fuel inputs and efficiencies are measured against HHV;
- Demand is the total load on the system (including exports, storage and losses);
- Electricity generation is net of plant self-consumption;
- Supply includes major power producers and embedded renewables, but not auto-generators;
- Electricity storage is grouped with imports/exports rather than with run-of-river hydro.

## 2.2. Sources

The data used in this report are freely available from National Grid (National Grid, 2016) and Elexon (Elexon, 2016a, 2016b) for supply, demand and prices, and the Hadley Centre for temperatures (Parker et al., 1992). Full details of the data sources and processing are given in the Online Supplement §1.

Data are typically presented from 2009 to the end of June 2016 for half-hourly data, or to 2015 for annual data. 2009 is the earliest whole year when high-resolution generator output is available, and this range also gives a three-year window either side of 2012, which was pivotal as the year of peak carbon from the British electricity system.

<sup>5</sup> In national greenhouse gas statistics, these emissions are attributed to fuel combustion in the industrial and commercial sectors where the auto-generators are located, rather than to electricity production (DECC, 2016c).

## 2.3. Calculating Carbon Emissions

DECC compile national greenhouse gas emissions statistics which are broken down to sectoral level, including electricity generation from power stations (DECC, 2016c). These are available at annual and quarterly resolution, and so cannot be used to estimate the real-time carbon emissions or the contribution of individual generating technologies.

Such calculations require values for the carbon intensity of each generator type, which can be combined with the half-hourly Elexon output data. These intensities are measured in grams of CO<sub>2</sub> per kWh of electricity produced (or equally kg/MWh), and depend on the carbon content of fuel burnt and the average net generating efficiency.

These intensities were estimated using data from DUKES on the historic electricity output and fuel consumption for the period 1995–2015 (Janes, 2005; MacLeay et al., 2016). Efficiencies for nuclear, coal and gas are given directly in Table #5.9; however, the latter is a single efficiency for all gas generation (averaging 47.3%) which groups CCGT and OCGT together.

Using data from #5.5 the net electricity production (gross production minus self-consumption) was divided by fuel input for each generator type. The efficiencies calculated for coal and nuclear agreed with the values from #5.9 to within  $\pm 0.02\%$  each year. The values for gas were separated out into CCGT and OCGT (see Online Supplement 2), and efficiencies for oil and biomass were also calculated. As shown in Fig. 3 (left), the efficiencies for the main generator types have been relatively stable; whereas those for oil and biomass vary significantly from year to year because of their low utilisation.

Oil is consumed when starting up coal plants, but this cannot be separated from consumption in oil generators within the DUKES data, which pulls down the apparent efficiency of oil-fired stations in years they are rarely used. Biomass generation is relatively immature, so both utilisation and efficiency have improved steadily over the last twenty years. Efficiency is rising by 0.6 percentage points per year, and has improved notably since 2013 when the first units of Drax and Ironbridge were converted from coal to biomass. The right panel of Fig. 3 shows that both oil and biomass efficiency increase by 2.4 percentage points (absolute) with each doubling of annual output.

The efficiencies in Fig. 3 appear low relative to the widely quoted 60% for CCGT and >40% for coal. This is partly because they are higher heating value (HHV); the industry convention of lower heating value (LHV) would be a factor of 1.050 higher for coal, 1.058 for oil, and 1.109 for gas (Staffell, 2011). The efficiencies are also net of electricity consumed within the stations, which ranges from 2% of gross generation for gas, to 5% for coal, 9% for nuclear and 11% for biomass and oil (calculated from DUKES data).

Table 1 lists the output-weighted average efficiency of generation in Britain and the corresponding carbon intensity of electricity output, derived using the DUKES emissions factors for fuels.<sup>6</sup> It also lists the estimated carbon intensity of electricity imported from nuclear-rich France and fossil-rich Netherlands and Ireland. These are presented against values used elsewhere, notably the Grid Carbon project, which estimates real-time emissions from the British power system (Rogers and Parson, 2016).

The carbon intensities estimated for OCGT and oil are 35–55% higher than used by Grid Carbon, but this has little impact in practice as these technologies supply <1% of electricity. The values for coal and gas are 3% and 9% higher, which has a more substantive impact. The emissions factors estimated from DUKES are broadly in agreement with other sources (Weisser, 2007; Schlömer et al., 2014), but differ slightly from those presented in DUKES Table 5D as they do not include autogenerators. For validation, multiplying these carbon intensities with the historic DUKES output from major power produ-

<sup>6</sup> 321g/kWh for coal, 267g/kWh for oil and 184g/kWh for gas (MacLeay et al., 2015).

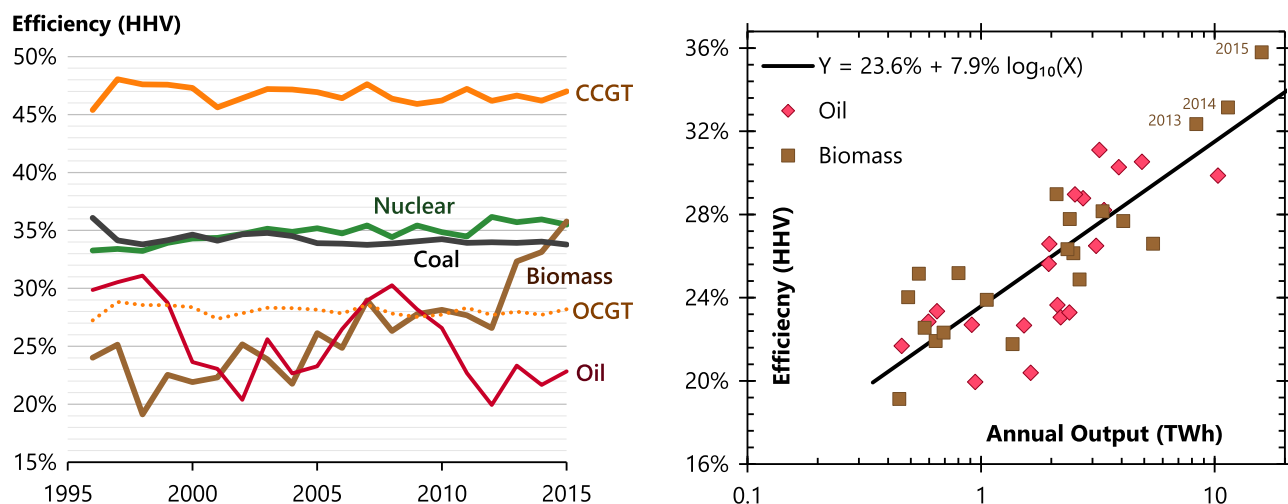


Fig. 3. Historic efficiencies for British power stations (against higher heating value, net of self-consumption). The right panel shows the dependence of peaking plant efficiency on its utilisation.

Table 1

Efficiency and carbon intensity of electricity from different sources in Britain. Plant efficiencies are presented gross and net of self-consumption.

	Efficiency (HHV)		Carbon Intensity (g/kWh)		
	DUKES (gross)	DUKES (net)	Grid Carbon	This Study	Grid Carbon
Coal	36.1 ± 0.6%	34.3 ± 0.5%	35.3%	937 ± 15	910
Oil	32.0 ± 4.2%	28.6 ± 3.6%	43.8%	935 ± 122	610
Gas OCGT	28.8 ± 0.5%	28.3 ± 0.4%	38.3%	651 ± 10	480
Gas CCGT	47.7 ± 0.8%	46.7 ± 0.7%	51.1%	394 ± 6	360
Nuclear	38.2 ± 0.9%	34.8 ± 0.9%			0
Biomass	37.4 ± 4.6%	33.5 ± 4.1%		120 ± 120	300
French Imports <sup>a</sup>				53 ± 14	90
Dutch Imports <sup>b</sup>				474 ± 25	550
Irish Imports <sup>c</sup>				458 ± 15	450

<sup>a</sup> 76% nuclear, 12% hydro, 6% fossil.

<sup>b</sup> 58% gas, 26% coal, 5% each of biomass, nuclear and wind.

<sup>c</sup> 50% gas, 26% coal and lignite, 20% wind.

cers yields total carbon emissions from the UK power sector that agree with DECC to within ±0.9% (±1.4 MT) across 1996–2015, and to within ±0.3% (±0.5 MT) over the last decade.

Multiplying these intensities with Elexon output yields total emissions that are approximately 2% lower than DECC's values. DECC considers the UK (the United Kingdom of Great Britain and Northern Ireland) versus Britain alone: Northern Ireland accounts for around 2.5% of electricity sales (MacLeay et al., 2016) and 2.4% of energy sector carbon emissions (Aether and Ricardo-AEA, 2015).

Transmission and distribution losses averaged  $8.1 \pm 0.6\%$  between 1996 and 2015 (inclusive of 0.3% assumed losses due to theft), and show no discernible trend over time (MacLeay et al., 2016) (#5.1.2). This increases the values in Table 1 by a factor of 1.088 when considering the carbon intensity of electricity consumed (as opposed to electricity generated).

The carbon intensity of nuclear and renewables are taken to be zero, as the life-cycle emissions from constructing power stations are not included for any technology. When calibrating emissions estimates to DECC's national statistics, the carbon intensity of biomass and imports are taken to be zero, following the 'production-based' accounting convention which attributes these emissions to the country of origin. An arguably more natural measure of emissions is to use 'consumption-based' accounting, where emissions attributable to electricity demand are included regardless of where they occur. This approach is now widely used to better understand country-level emissions by accounting for imported goods (Barrett et al., 2013).

The average carbon intensity of imported electricity was calculated

using monthly generation data from ENTSO-E (ENTSO-E, 2016) and annual data from EuroStat (European Commission, 2016), with the technology emissions factors calculated for Britain in Table 1.<sup>7</sup> To test the validity of these data sources, they were used to calculate the carbon intensity of British electricity, which gave agreement to DECC's data to within ±1.2% for ENTSO-E and ±3.3% for EuroStat. For each country, the annual average carbon intensities were calculated, and applied to the relevant year of British imports / exports. Imports from a neighbour add to Britain's carbon emissions, while exports are credited with avoiding production in the neighbouring country, and thus reduce Britain's emissions (as in consumption-based accounting).

Pumped hydro storage does not create CO<sub>2</sub> emissions by itself; however, the electricity it stores is not carbon-free, and it only redelivers this electricity with 73.6% round-trip efficiency (averaged over 2009–15). The carbon intensity of electricity consumed by pumped hydro plants is  $96 \pm 5\%$  that of the time-weighted average. With round-trip losses, these plants deliver electricity with a carbon intensity  $31 \pm 9\%$  above the system average (e.g. 474 g/kWh in 2015). Here these emissions are accounted for when the electricity was first generated, and are attributed to the technologies which produce that electricity.

The net carbon intensity of biomass is difficult to quantify. Burning wood releases in the region of 410 g/kWh of chemical energy (National Greenhouse Gas Inventories Programme, 2006); however this should be absorbed by the next generation of feedstock as it grows (Schlömer

<sup>7</sup> ENTSO-E was the preferred source, with EuroStat used to fill gaps.

et al., 2014). Legislative requirements for sustainable forest management ensure that this cycle of emission and reabsorption is maintained in order to receive subsidies. For example the UK Renewables Obligation requires that biomass harvesting maintains the productivity of the area, and that wood is extracted from the area at a rate which does not exceed its long term capacity to produce wood (The Renewables Obligation Order, 2015).

In line with UNFCCC carbon accounting guidelines, emissions from burning biomass are treated as being zero, as changes in terrestrial carbon stocks are reported separately and most climate change policies (including the EU Renewable Energy Directive and Emissions Trading System) account for lifecycle emissions along the bioenergy supply chain. There is deep disagreement on whether current accounting practices are fit for purpose, as “the magnitudes (and even the sign) of biogenic carbon emissions factors vary considerably over time” (Matthews et al., 2015). Plausible values range from –2000 to +2000 g/kWh depending on the scope of the study and the counterfactual scenario for what would happen to that land and biomass if it were not used for energy (Stephenson and MacKay, 2014; Aether and Ricardo-AEA, 2015). Such counterfactuals are difficult if not impossible to accurately predict, signalling the need for strong oversight of supply chains and forest management (Slade et al., 2014).

Emissions also come from processing and transporting biomass fuel. Drax estimate its carbon intensity according to their specific supply chain; which is predominantly sawmill residues, thinnings and forest residues from the US and Canada. Their average carbon intensity was 114 g/kWh in 2015 and 122 g/kWh in 2014 (Drax Group plc, 2015). As Drax is by far the UK's largest consumer of biomass, this is very close to the UK-wide carbon intensity for biomass electricity, 121 g/kWh, calculated from all consumers of woody biomass, weighted by the quantity of electricity produced (The Renewables Obligation Order, 2015). These values agree with Matthews' estimate of  $127 \pm 120$  g/kWh for ‘typical’ non-biogenic emissions (Matthews et al., 2015), and is at the low end of the IPCC and JRC estimates of  $230 \pm 100$  and  $245 \pm 79$  g/kWh (Schlömer et al., 2014; Giuntoli et al., 2015). Again, the wide uncertainty on these estimates illustrates the complex nature of biomass supply chains, and suggests there is prudence further researching the carbon intensity of biomass as it becomes a more significant contributor to decarbonising electricity.

An extension of consumption-based accounting would be to use the marginal life-cycle emissions, also including the upstream emissions from producing and transporting fossil fuels. This would increase their carbon intensity by around 7–10% for coal and 18–34% for gas (much higher and less precise due to methane leakage) (Schlömer et al., 2014; Staffell et al., 2012; Balcombe et al., 2015). A full LCA approach would also account for emissions due to the construction of the power stations themselves, meaning that nuclear and renewables would be notably greater than zero (10–50 g/kWh) (Schlömer et al., 2014). This is not justifiable though in the short-term, as a windy day will result in more electricity produced from wind farms, but not in more concrete and steel being consumed.

### 3. Results: statistics from the British power sector

#### 3.1. Demand

Net annual electricity demand, as measured by National Grid, has fallen from 315 to 281 TWh between 2009 and 2015, an average rate of 1.9% per year. Part of this is due to embedded renewables, which have grown from 6 to 18 TWh output per year and register as negative demand. Accounting for this, actual electricity demand is still falling by 1.3% per year. Fig. 4 charts the reduction in demand, set against temperature on an inverted scale to highlight their relationship. This is partly due to the 2.75 million homes with electric heating (Palmer and Cooper, 2013).

December's average temperature has risen steadily from 3.2 °C in

2009 to a record-breaking 9.7 °C in 2015, which has contributed to peak demand falling 11% over this period from 59.5 to 53.0 GW. Average winter demand is falling at more than three times the rate of summer demand: with a fall of 6.6 GW since 2009/10 to 36.6 GW in winter 2015/16 (Dec–Feb), compared with a fall of 2.2 to 30.9 GW in summer 2015 (Jun–Aug).

#### 3.2. Capacity

Fig. 5 shows the installed capacity mix over the period, which is dominated by around 32 GW of gas and 28 GW of coal, followed by 11 GW of nuclear and 7 GW of peaking plant at their respective zeniths. Hydro has remained constant at 4 GW (1.1 GW run-of-river and 2.9 GW pumped storage), while interconnection has risen from 2.4 GW (with France and Ireland) to 4.0 GW (with Netherlands and Northern Ireland). Renewables are growing rapidly: wind increased from 2.3 to 14.6 GW over 7½ years, solar from 50 MW at the start of 2011 to 10.5 GW by the end of June 2016, and biomass from nothing to 2.2 GW over the same period.

While combined renewable capacity has grown from 2 to 27 GW, combined fossil capacity has fallen from a peak of 65 GW in 2011 to just 45 GW in 2016. Britain has lost half of its coal in just 3½ years: 13.6 GW of coal closed between January 2013 and June 2016,<sup>8</sup> either because it had opted out of the large combustion plant directive (LCPD) (Gross et al., 2014), or because it had become loss-making. Peaking plant consisted of 3.1 GW of oil which retired during 2013 and 3.7 GW of OCGTs, half of which retired during 2015. Despite total installed capacity rising to 90 GW at the end of 2015, conventional thermal capacity (excluding wind, solar, hydro and interconnectors) had fallen to 58.5 GW, 20% below its peak at the start of 2012.

Fig. 5 also shows the utilisation of the main generator types. Historically, thermal capacity factors were high: averaging 75% for nuclear, 67% for CCGT and 53% for coal over the period 1997–2006 (MacLeay et al., 2016). Utilisation has fallen dramatically in recent years due to shrinking demand and the rise of renewables. The average utilisation of gas CCGTs fell from 75% in the winter of 2010 to an average of 32% since 2012. Three years on, coal plants are now suffering a similar fate, falling steadily from a temporary high of 70% to below 10% in the summer of 2016. For the first time, coal has a lower capacity factor than solar.

Averaged over the seven whole years 2009–15, the average and standard deviation in capacity factors for wind and solar were  $30.3 \pm 3.4\%$  and  $10.2 \pm 0.6\%$  respectively. At the monthly level wind and solar are strongly anti-correlated ( $R = -0.66$ ), and during summer months (Jun–Aug) their capacity factors average 21.0% and 16.2%, while during winter months (Dec–Feb) they average 37.9% and 3.5% respectively.

#### 3.3. Generation

Fig. 6 shows the average generation mix across each week of the last 7½ years. Over this period fossil fuels have become increasingly squeezed by the growth of imports, biomass, wind and solar. Coal is seen responding to seasonal changes in demand, and displaced gas over the second half of 2011. Gas generation fell steadily from an average of 17.3 GW in 2009–10 to just 9.3 GW in 2012–13. This trend reversed over the course of 2015 with gas generation rising from an average of 9.0 GW in the first quarter of 2015 to 13.8 GW in the first quarter of 2016. By May 2016 coal generation fell to an average of just 1.1 GW, and on the 10th of May instantaneous coal output fell to zero for the first in over 130 years.

Fig. 7 shows the half-hourly profile of generation averaged over all

<sup>8</sup> In 2013: Kingsnorth, Didcot A, Cockerzie, Tilbury. In 2014: Ferrybridge C (1–2), Uskmouth B. In 2016: Ironbridge B, Longannet, Ferrybridge C (3–4), Rugeley B.

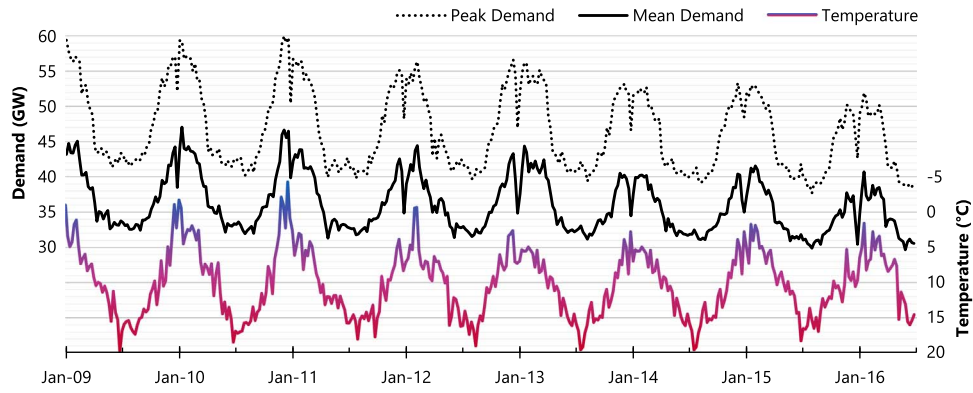


Fig. 4. Electricity demand and temperature in Britain aggregated to weekly averages.

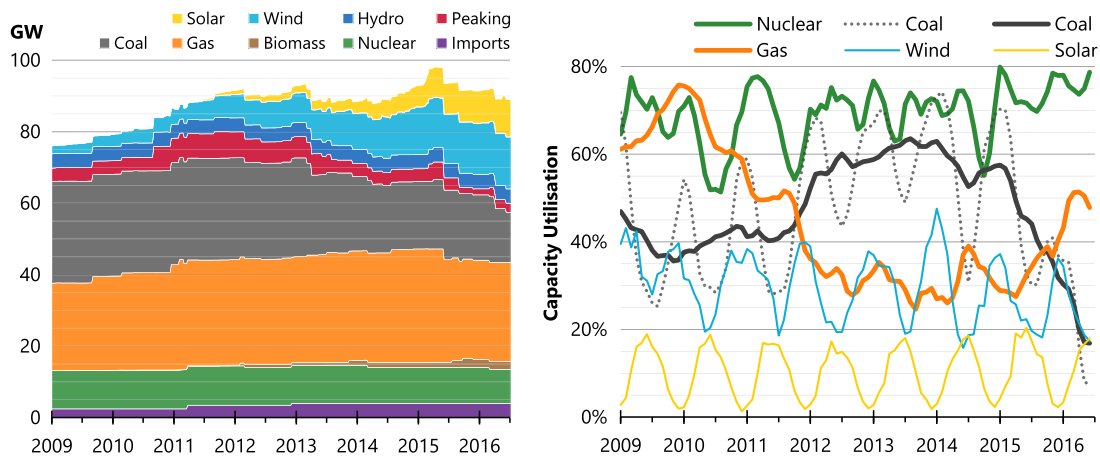


Fig. 5. Installed generating capacity (left) and average utilisation of major thermal plants (right). The dotted line shows monthly utilisation for coal plants, while the solid line shows the deseasonalised trend. Historic solar data from (Pfenninger and Staffell, 2016).

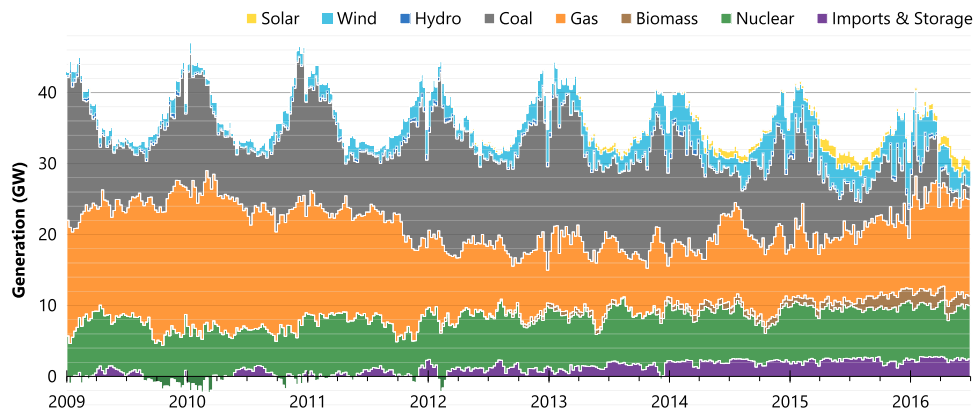


Fig. 6. Generation mix in Britain aggregated to weekly averages. Areas below the horizontal axis signify exports from Britain.

days in a given month. The four plots contrast summer and winter in the earliest and most recent years. Several features are worth comment. Demand (shown by the black line) has fallen sharply, and fossil fuels are being crowded out. This is particularly evident with December: between 2009 and 2015, demand was 7.3 GW lower, while coal and gas output fell by 7.1 and 11.3 GW respectively.

Wind output has grown substantially to average 2.7 GW in June and 5.8 GW in December 2015. It appears smooth over all hours due to the charts averaging across many days; if instead single days were plotted then significant variability would be seen. Solar also provides a significant chunk of demand during summer daytimes, creating a new ‘multi-shifting’ profile for thermal plants. Gas plants are now seen to ramp up for peaks in both the morning and evening, with lower

demand at night and (increasingly) during the daytime. Finally, the emergence of biomass and growth of imports are notable, as is the elimination of net exports, which were seen during 2009 where the black demand line falls below the shaded area.

Fig. 8 shows the share of demand that was met by each technology in each month. The left panel splits technologies into categories, with zero-carbon above the axis and with-carbon below to highlight the shift between them. The right panel shows the breakdown of renewable technologies.

Fossil fuels have gone from supplying 83% of British electricity in January 2009 to just 45% in December 2015; their share has fallen on average by 4 percentage points a year. Nuclear has remained steadfast at 20% of the grid mix, while renewables have grown from 4% to a peak

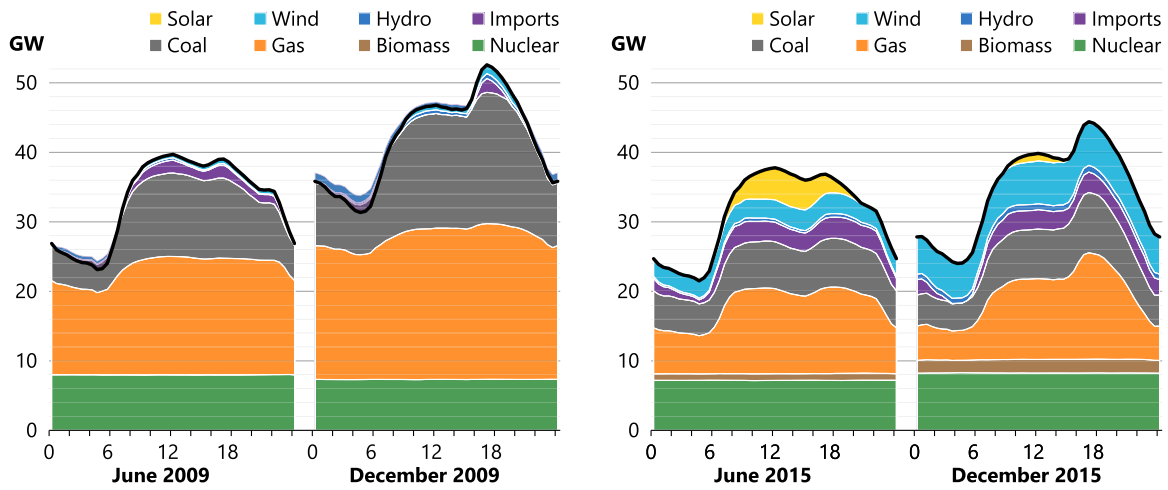


Fig. 7. The average daily profile of generation at half-hourly resolution in June and December, comparing 2009 and 2015.

of 25% in December 2015, averaging 19% over the whole of 2015. The second half of December 2015 saw wind overtake coal to supply 20% vs. 13% of electricity. May 2016 then saw coal supply less than wind, biomass or solar for the first time. Imports have grown steadily from being net-zero in 2009–10 to 7% of British demand by 2015, as the price differential between Britain and its neighbours grows. Biomass jumped from 2.5% to 5% share in July 2015, producing more energy than wind for two weeks of the year. During the first half of 2016, biomass supplied 30% of Britain’s renewable electricity. Hydro has remained constant at around 1% of supply, while wind and solar have risen to contribute 11% and 3% of demand over 2015. Wind peaked at a 17% share during December (averaging 5.8 GW output, 40% capacity factor), while solar reached a share of 6% in June 2015 (1.8 GW output, 20% capacity factor).

Constraints on the transmission system mean that not all of this wind output can be used. From analysis of Elexon’s data, 0.4% of wind generation was constrained between 2011 and 2013, averaging 6 GWh per month. This rose sharply in 2013 to 1.8% (42 GWh per month) due to the network upgrades taking some transmission assets out of service (National Audit Office, 2014), and has risen further to 3.3% in 2015. At its peak, 7.3% of wind generation was constrained in December 2015 (311 GWh, equivalent to a constant 420 MW).

Fig. 9 shows peak renewable output, depicting the contribution of each technology during the half-hour period with the greatest percentage supply from renewables. Peak output is roughly twice the average, and is growing at 5 percentage points per year, from 9% to 44%.

The increase in biomass output in the second half of 2015 is

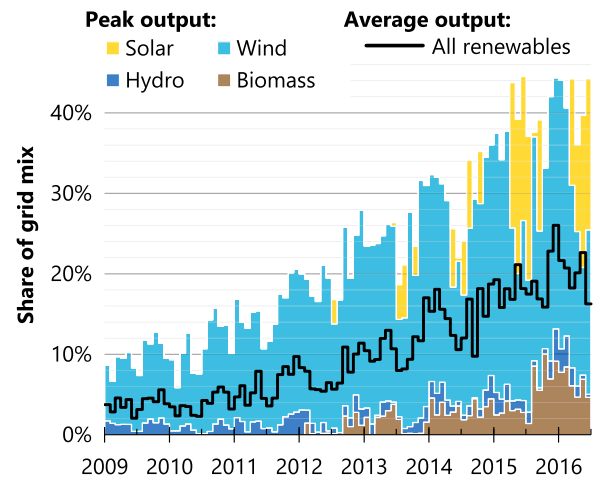


Fig. 9. The peak share of supply from renewables during each month.

evident, while the contribution from hydro is decreasing during these periods as it is dispatchable, and so operators find it more profitable to not generate during periods of low demand and high renewables. Solar started playing a major role since 2015, with a peak output of 7.0 GW compared to 9.3 GW from wind. During 2015, wind provided a peak of 33% of total supply (19-Nov), and solar provided 20% (07-Jun). As the two are uncorrelated, their combined total was 40% (06-Jun).

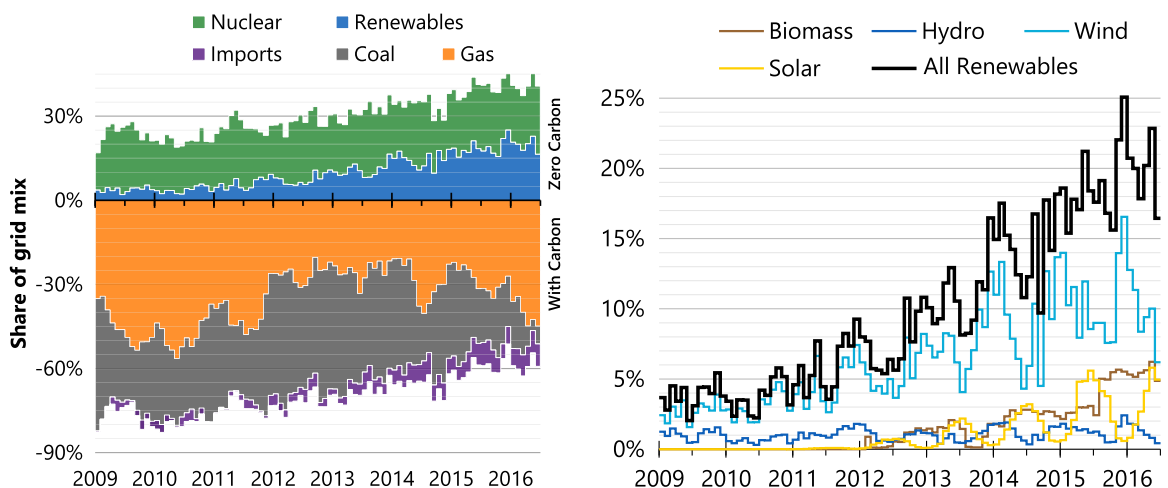


Fig. 8. Monthly average share of generation from conventional and renewable sources.

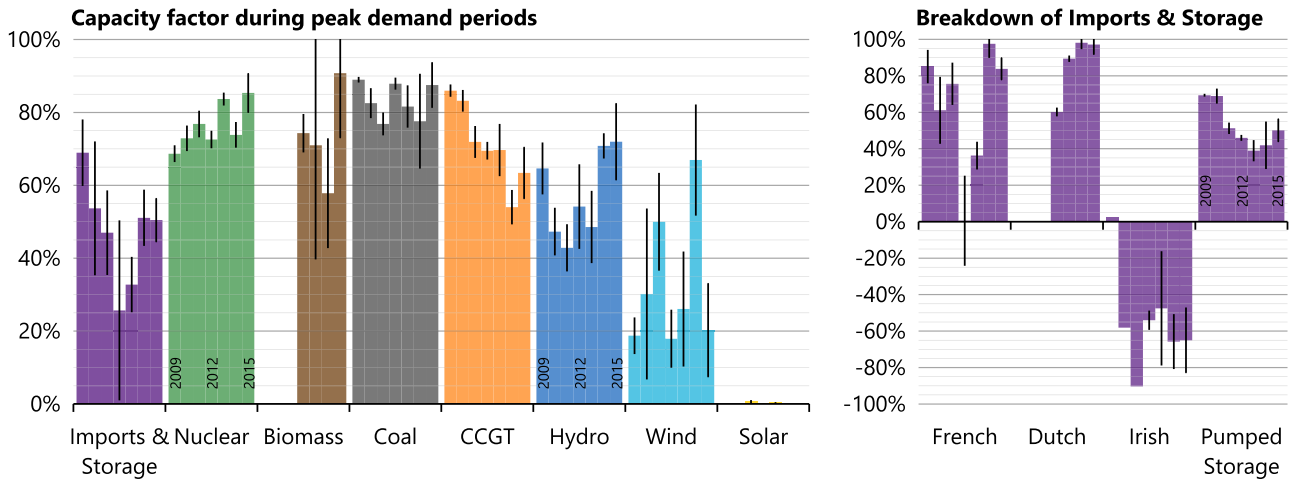


Fig. 10. The average capacity factor of generators during the top ten demand periods in each year from 2009 (left edge of each group) to 2015 (right edge).

3.4. System extremes

The rise of intermittent renewables means the gap between minimum and maximum net demand is widening. A major concern in recent years has been with meeting peak winter demand, and it is widely known that wind cannot be relied upon to produce at peak times (Gross et al., 2006). Fig. 10 gives a measure of how dependable different generators are for providing peak capacity. The figure shows their output as a percentage of installed capacity during the ten half-hour periods with highest demand in each of the last seven calendar years. Shaded bars give the average and thin lines the standard deviation within each year, so for example, wind power operated at a  $20 \pm 13\%$  capacity factor during the highest demand hours in 2015.

Nuclear plants have operated at between 69% and 85% of full output during peak demand periods, while coal has averaged  $83 \pm 7\%$ . Gas was similar during 2009–10 but has fallen since, presumably as there is less need for peak capacity while demand is falling rather than worsening reliability. Biomass operated above 90% during 2015, although this was almost entirely due to the output of one plant (Drax).

In contrast, Britain's wind farms produce anything from 7% to 82% of their full capacity during peak hours, depending on whether high

demand happens to coincide with high wind speeds. The average over all years is  $33 \pm 23\%$ , implying that a 10% capacity factor can be expected during at least five out of six peak demand hours. This agrees with the lower end of estimations for the 'capacity credit' that wind offers to power systems, with results from a dozen studies sitting in the range of 10–30% (Gross et al., 2006). Solar power does not provide any assistance during peak demand periods in Britain as demand peaks in winter evenings.

Interconnectors might naturally be expected to import during times of peak demand, but these only provide  $35 \pm 25\%$  of their capacity (weighted by their relative size). Breaking this down further: the interconnectors to France and the Netherlands operate at  $62 \pm 34\%$  and  $86 \pm 18\%$ , pumped storage at  $51 \pm 12\%$ , and the interconnectors to the Irish system actually export at British peak times, providing  $-54 \pm 28\%$ . Demand in Ireland peaks at the same time as in Britain, and being the more isolated system, Ireland is in greater need of imports.

Going forwards, peak winter demand may be superseded by the summer net minimum as the greatest challenge to the system. Security of supply has traditionally focussed on ensuring enough plants are available to meet peak demand, but now the reverse situation must be considered as the capacity of must-run nuclear and variable renewables

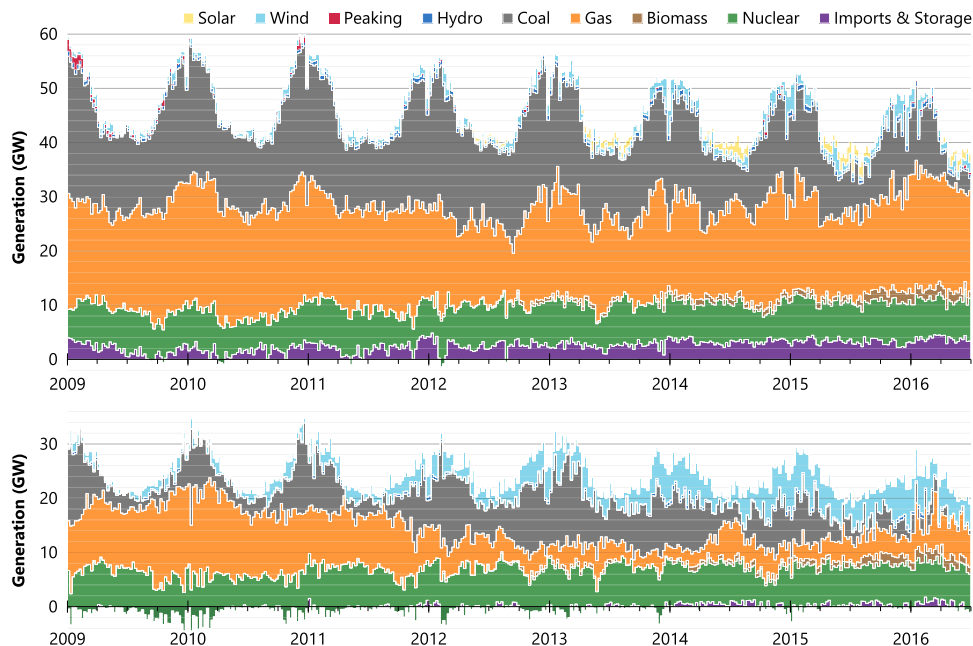


Fig. 11. Supply mix during the half-hour period with maximum and minimum net demand within each week. Areas below the horizontal axis signify exports from Britain.



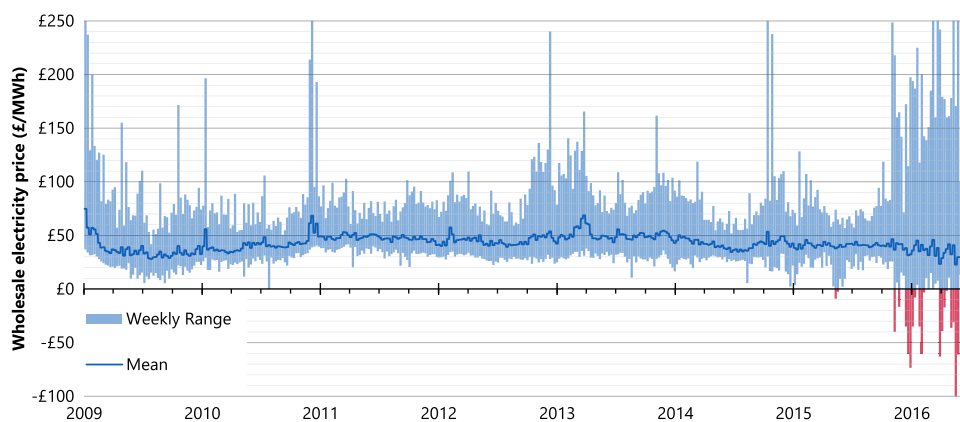


Fig. 12. Wholesale electricity prices over the period (in £/MWh), showing the weekly average and spread.

edges closer to double the level of minimum demand.

Fig. 11 shows the supply mix during the period when demand net of variable renewables (and thus output from conventional generators) was highest and lowest in each week. The output from wind and solar is still included in the figure to show their contribution relative to falling demand.

Meeting maximum demand has become easier to meet in recent years, with less recourse to peaking generation, although this is in part due to milder weather. Operations are getting ever tighter during periods of minimum demand, as the output from flexible fossil plants is getting compressed between renewables and nuclear.

Boxing Day 2016 saw the lowest output from flexible generators: demand net of wind, solar and nuclear was 5949 MW; down nearly 2 GW on the minimum in the previous year, 60% lower than in 2012. This net minimum has fallen by 1059 MW per year, so this headroom may be eliminated as early as 2020. Operational issues around inertia and frequency response may well arise before then.

### 3.5. Prices

The increasing share of intermittent renewables is impacting on wholesale prices, which are plotted in Fig. 12. Prices averaged £44.44 ± 5.77/MWh over the period, and while the weekly average rarely moves outside the window of £30–50/MWh, half-hourly prices are becoming more volatile.

The daily spread<sup>9</sup> has always been higher in winter than summer, but this discrepancy is growing. Considering the winter half-year (October through March), the daily spread averaged £37.36/MWh from 2009/10 to 2011/12, £48.41 from 2012/13 to 2014/15, then jumped to £80.75 in the winter of 2015/16.

The merit order effect of renewables is evident in Britain although not especially strong. The wholesale price weighted by wind output is 94.8 ± 2.1%<sup>10</sup> that of the energy-weighted price, and this is almost stationary over time. The solar weighted price is higher at 102.4 ± 6.7%, but is declining by 2.4% per year.

2015 was the first year to see negative prices in Britain. There were five negative-price periods across two days in May, followed by 4 in November and 16 in December. Half of these occurred between 2:30 and 4:30 AM, and all lay between midnight and 11:00 AM. Prices during these hours averaged -£34 ± 19/MWh, with several hours sticking at -£35, -£40 and -£50/MWh. As could be expected, demand was low and wind output was high during these hours, averaging 23.2 ± 2.0 and 5.9 ± 0.9 GW respectively (a 41 ± 5% capacity factor for wind). During the first half of 2016, there were a further 87 periods with zero or negative prices, averaging -£23 ± 21/MWh, going down to

a low of -£100/MWh. Negative prices also started occurring in groups, with two days when prices were ≤£0 for 4½ hours in a row.

The cost of balancing is increasing in line with installed wind and solar capacity. The BSUoS charge has increased at a rate of £0.17/MWh per year, from an average of £1.33/MWh in 2009 to £2.24/MWh in 2015. The number of days with a BSUoS price of over £5/MWh has increased from 15 per year during 2009–12 to over 100 in 2015.

## 4. Analysis: contributions to carbon reduction

The carbon intensity of electricity is an important metric, widely used for assessing the impacts of electric vehicles, electric heating, microgeneration and demand reduction on national emissions. Government departments and other organisations use various average carbon intensities for British electricity, ranging from 412 to 525 g/kWh (DECC, 2016a; Carbon Trust, 2011; BRE, 2014). Fig. 13 plots the weekly average carbon intensity, with the range of half-hourly values seen within each week.

The carbon content of British electricity recently peaked at 508 g/kWh in 2012, and has since fallen 30% in three years. The unseasonably warm December combined with high wind output led the last two weeks of 2015 to have the lowest ever carbon intensity, averaging 235 g/kWh, with a minimum of 150 g/kWh.

### 4.1. Weather and efficiency

To separate out the variability of the weather from other factors affecting electricity demand, Fig. 14 shows the relationship between electricity demand and temperature. Points show the daily averages across each working day, excluding weekends and bank holidays, when demand is depressed by 12.5% (~4.75 GW) on average. 2010 and 2015 are highlighted as the coldest and warmest years, which also had the highest and lowest demand respectively in the period studied, and smoothed lines were fitted to them using a non-parametric LOESS regression.

Correcting for temperature, demand on working days in 2015 was on average 3.0 GW lower than in 2010; being 2.6 GW lower when temperatures were above 10 °C and 3.9 GW lower when they were below 5 °C. The savings on non-working days are much lower, so these values are around 20% lower when averaged over all days of the year. It is clear that societal changes such as efficiency improvements and de-industrialisation are having a significant impact on demand, reducing electricity demand by 21 TWh per year.

The temperature sensitivity of electricity demand is almost unchanged over this period. For each degree that temperature falls below 15 °C national demand increased by 823 MW in 2010, and 819 MW in 2015, averaged across all working days. This stands in sharp contrast to France, where this sensitivity has increased 50% in the space of ten years to a 2.6 GW increase per degree centigrade, due to increased use

<sup>9</sup> Defined as the range from minimum to maximum half-hourly price in a given day.

<sup>10</sup> Standard deviation across monthly averages.

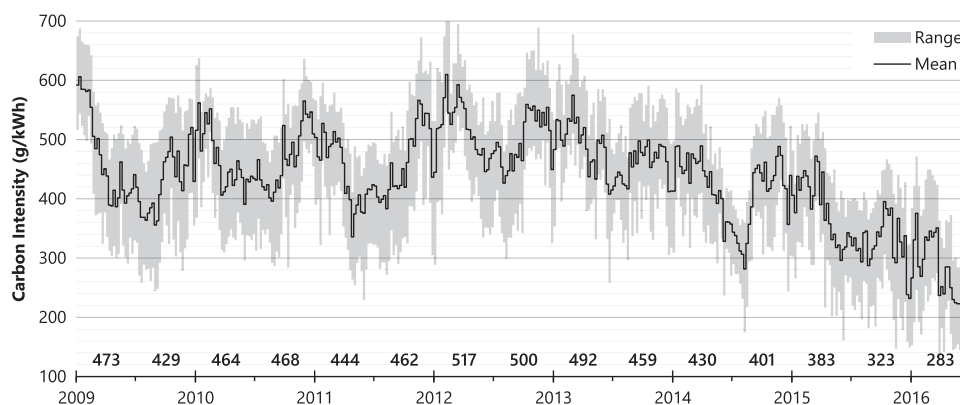


Fig. 13. The carbon intensity of British electricity, showing the average and range for each week. Biannual averages (in g/kWh) are listed above the x-axis.

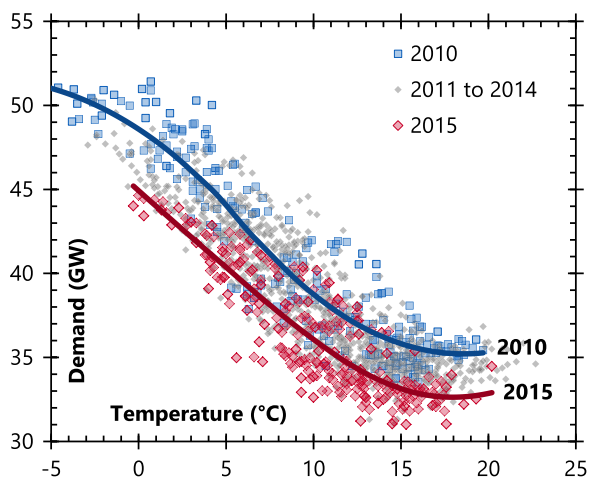


Fig. 14. Correlation between daily average temperature and electricity demand, highlighting the reduction in demand from 2010 to 2015.

of electric heating (Boßmann and Staffell, 2015). Based on the British sensitivity, a further 9 TWh of the demand reduction from 2010 to 2015 can be attributed to the milder weather.

Perhaps more importantly, mild weather is also causing the low peak demands seen in recent years. Comparing December 2010 and 2015, the peak demand due to heating fell from 14.5 to 6.2 GW. While this is a crude calculation, based on daily-average temperatures and an empirical estimate for the temperature sensitivity of demand, it highlights Britain's luck that mild winters have coincided with a much-feared shortage of winter capacity to avoid potential shortfalls.

#### 4.2. Share of emissions by source

Fig. 15 shows the carbon emissions by fuel type, showing clearly that the reduction since 2012 is due to falling coal consumption. Emissions from gas generation had been below 35 MT per year since 2012, but look set to return to their pre-2010 levels of around 50–55 MT. If gas consumption remains at current levels then Britain's CCGTs can remain part of the system down to a decarbonisation of two-thirds below 2010 levels. Further decarbonisation would require either unabated gas generation to reduce, or the gas itself to be decarbonised.

The emissions from peaking plants (oil and OCGT) are grouped with other sources in the left panel of Fig. 15, and by themselves have contributed less than 1% to emissions since 2012. Annual statistics from DUKES reveal this is part of a longer trend: emissions from peaking plants have fallen steadily from 16 MT (9%) in 1995 to 6 MT in 2005 (4%) and an estimated 0.5 MT in 2015 (0.5%). This may allay environmental concerns over the proliferation of OCGT and diesel generators in recent years to provide peaking capacity.

The UK carbon budgets do not account for emissions that are released abroad, either from imported electricity or imported biomass. Fig. 15 estimates the contribution these would have made each year, based on the emissions factors given in Table 1. In 2009 and 2010, Britain's exports to Ireland resulted in net savings of 0.7–0.9 MTCO<sub>2</sub>; however, since 2011 the growing imports from the Netherlands, and shrinking exports to Ireland mean Britain is exporting more of its emissions abroad (4.1 MT to Netherlands, and 0.5 from Ireland to France in 2015). The non-biogenic emissions from processing and transporting biomass have also risen since 2012 to 1.3 MT. Consumption-based accounting would raise Britain's emissions from 103.0 to 108.3 MT in 2015, or 343–360 g/kWh.

#### 4.3. Impact of renewables

The amount of carbon saved by intermittent renewables depends on how the rest of the system responds to their pattern of output. Not all power stations reduce their output equally when the wind blows or the sun shines; typically gas and coal will turn down, imports will decrease, and energy storage may be recharged, whereas nuclear and biomass will be unaffected. Previously, Cullen estimated that wind displaces a mix of 18% coal and 85% gas in Texas, saving  $496 \pm 66$  kg of CO<sub>2</sub> per MWh of wind output (Cullen, 2013), while Thomson estimated a 60% coal, 40% gas mix for Britain over the period 2008–13, saving 628 kg/MWh (Thomson, 2014). There are no known estimates for the marginal impact of solar.

The emissions saved by an additional MWh of output from wind and solar are estimated using a multivariate regression on the changes that occur between each half-hour period, as proposed by Hawkes (Hawkes, 2010). In Eq. (1), the change in emissions between each adjacent half hour period ( $\Delta E_t$ ) is regressed against the change in wind and solar output ( $\Delta W_t$  and  $\Delta S_t$ ) and in the level of demand ( $\Delta D_t$ ). The coefficients for each variable,  $\omega$ ,  $\sigma$  and  $\delta$ , give the marginal emissions factors for wind, solar and demand respectively.  $\alpha$  is a constant offset, and  $\epsilon_t$  is the error term.

$$\Delta E_t = \alpha + \omega \Delta W_t + \sigma \Delta S_t + \delta \Delta D_t + \epsilon_t \quad (1)$$

Furthermore, the specific mix of power stations that are displaced by wind and solar was estimated by replacing the changes in carbon emissions ( $\Delta E_t$  in Eq. (1)) with the changes in output from each type of adjustable generation in turn (nuclear, biomass, gas, coal, imports and hydro). Details of each regression and full results are given in the Online Supplement 3, and a summary is given below.

The study is split into two time periods: 2009–12 when there was insufficient solar capacity ( $\leq 1$  GW) to yield statistically significant results, and 2013–16 when both wind and solar could be studied together. In both periods the carbon impact of renewables is similar to that of reducing demand. During 2009–12, CO<sub>2</sub> emissions rose by 549

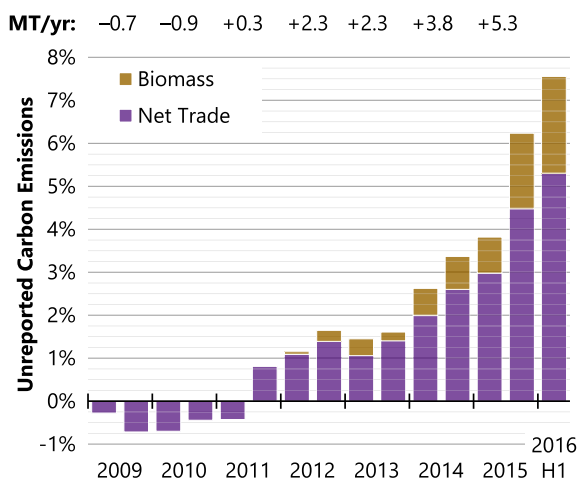
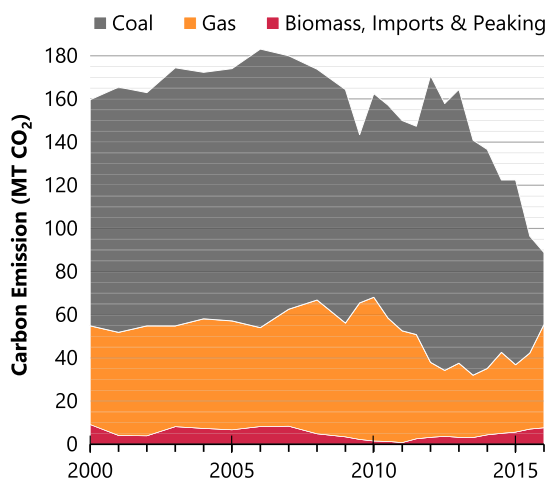


Fig. 15. Breakdown of annual carbon emissions by source, annual to 2009, biannual to H1 2016 (left), with the share coming from sources not considered in national statistics (right).

Table 2

The change in output (in MWh) from conventional generators to a 1 MWh increase in demand, wind and solar; when regressed over 2009–12 (left) and 2013–16 (right).

The impact of → On ↓	+1 MWh		The impact of → On ↓	+1 MWh		
	demand	MWh wind		demand	MWh wind	MWh solar
Coal	0.429	-0.379	Coal	0.220	-0.198	-0.186
Gas	0.367	-0.403	Gas	0.600	-0.592	-0.592
Imports	0.186	-0.206	Imports	0.155	-0.186	-0.178
Hydro	0.018	-0.015	Hydro	0.020	-0.022	-0.029
Biomass	0.000	-0.001	Biomass	0.004	-0.002	-0.006
Nuclear	0.000	0.002	Nuclear	0.000	0.003	-0.006

± 1 kg for each 1 MWh increase in demand, and fell by 532 ± 12 kg for each 1 MWh increase in wind output. Between January 2013 and June 2016, CO<sub>2</sub> emissions rose by 440 ± 1 kg per MWh increase in demand, and fell by 435 ± 5 kg and 435 ± 4 kg per MWh increase in wind and solar output.

Table 2 summarises the marginal grid mix that responds to changes in demand, wind and solar output over the two periods. A very similar mix of plants reacts to wind and solar, which is in turn similar to that which reacts to demand. This is perhaps to be expected given that there is a specific mix of technologies which have the flexibility to respond. Fossil plants and interconnectors primarily adjust their output: since 2013 it is approximately 60% gas, 20% coal and 17.5% imports/storage. Hydro accommodates around 2.5%, while biomass and nuclear are virtually unaffected. The standard errors on these results are all below ± 1%, and below ± 0.1% for hydro, biomass and nuclear.

Whilst the emissions and mix of plants displaced by wind and solar appear to be very similar in Table 2, their variation over time would suggest otherwise. Fig. 16 shows the results when these regressions were performed independently on each half-year (for the grid mix) and month (for the emissions). Solar appears to follow quite a different pattern over time, but when averaged over 2013–16 it displaces a similar amount of CO<sub>2</sub> per MWh.

Wind appears to be broadly equivalent to negative demand in terms of displaced carbon emissions. Marginal emissions fell by around 1/3 between 2010 and 2013 as gas gradually replaced coal as the primary component of the marginal grid mix. Comparing back to Fig. 2, this shift occurred two years earlier than the gas replacing coal in the average grid mix.

(Hawkes, 2010) calculated the marginal emissions factor of British demand to be 652 kg/MWh from 2002–09, speculating that it could

reduce to 482 kg/MWh by 2025 due to plant retirements.<sup>11</sup> This fall has occurred much faster than anticipated, with the marginal emissions of demand averaging 440 kg/MWh since 2013.

The long-run average capacity factor of British wind farms is 30.0% onshore and 35.8% offshore (Staffell and Pfenninger, 2016), so 1 GW of onshore wind should produce 2.628 TWh and save 1.14 MTCO<sub>2</sub> per year, and 1 GW of offshore wind would produce 3.136 TWh and save 1.36 MTCO<sub>2</sub> per year. Solar PV achieves an average 10.2% capacity factor (Pfenninger and Staffell, 2016), so 1 GW of solar panels should produce 0.891 TWh, and save 0.39 MTCO<sub>2</sub>.

#### 4.4. Impact of fuel and carbon prices

Fig. 17 shows fuel and carbon prices going back to 2000, putting the volatility of recent years into context. The left panel shows the estimated cost of fuel with and without carbon. The average price of fuel purchased by major power producers is divided by their average thermal efficiency to give the cost of fuel per unit electricity output, and the carbon intensity is multiplied by the prevailing carbon price.

The price of gas and coal (including carbon emissions) stayed roughly in line until 2011 as they are reasonable substitutes for one another. During 2012 and 13, the arrival of cheap imports from the US meant coal fell to around 60% of the cost of gas on a per-MWh-generated basis. Coal consumption in Britain could not rise sufficiently for their prices to equalise, both because many coal plants were constrained to limited running hours due to the Large Combustion Plant Directive (LCPD), and building new coal stations was considered too risky (or in fact illegal) due to climate policy.

The right panel of Fig. 17 uses the difference between fuel prices to calculate the carbon price that would be required to equalise the cost of generation from coal and gas.<sup>12</sup> Before 2005 this was negligible (£3.50 ± 2.90/TCO<sub>2</sub>) as fuel prices were pegged to one another. Gas prices rose in 2005–06 due to tightening global supply, so averaged over the period of 2005–11 a carbon price of £16.20 was necessary, which is approximately what the EU Emissions Trading Scheme (ETS) delivered (£13.80). Since then gas prices rose further whilst coal prices fell, and oversupply on the ETS collapsed the carbon price. At its peak in winter 2012/13 a carbon price of £49.30/T would have been required to incentivise fuel switching from coal to gas, but this has gradually eased off over the last three years. At the same time, the UK's Carbon Price Floor came into effect, raising the carbon price from £6 to £18 per

<sup>11</sup> These values are for gross generation for compatibility with the rest of this paper, Hawkes presented values with 5.5% transmission and distribution losses subtracted.

<sup>12</sup> This is calculated as the difference between the cost of gas and coal per MWh electricity produced, divided by the difference between their carbon intensities.

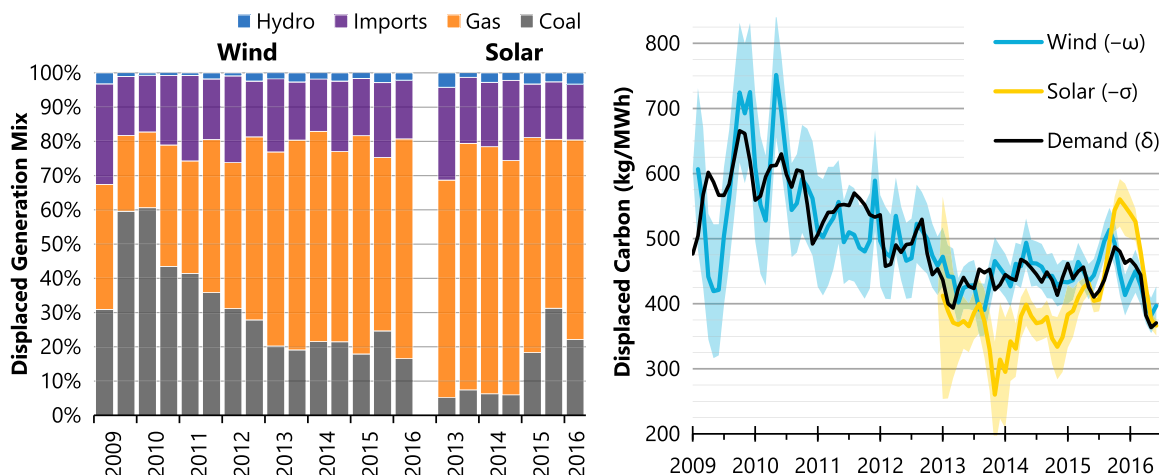


Fig. 16. The mix of generators (left) and CO<sub>2</sub> emissions (right) displaced by an additional MWh of wind and solar output. The shaded areas around each line represent the standard error on the monthly estimates, and the added emissions from an extra MWh of demand are shown for comparison.

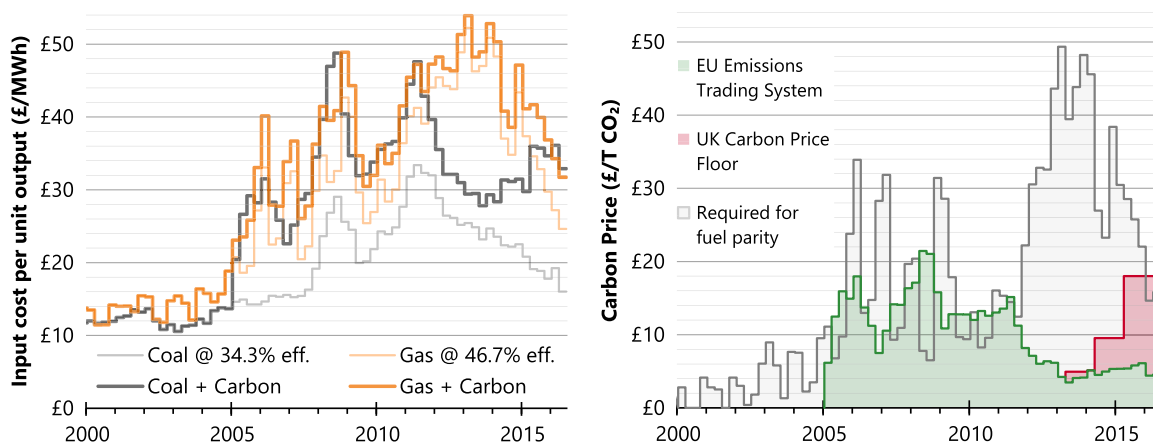


Fig. 17. The cost of fuel and emissions per unit of electricity output (left), and a comparison of the actual carbon price and the price required for coal and gas generators to have equal costs (right). Data from (Ares, 2014; DECC, 2016b; ICE, 2016).

tonne at the start of 2016; which has all but eliminated the gap between fuel prices, suggesting that some generators will have started switching in the merit order.

### 5. Conclusions

The British electricity system is in a radical period of change which has seen carbon emissions fall 46% in the space of three years. Since 2012, demand has fallen steadily and coal's share of generation has plummeted, displaced by gas, imports, biomass, wind and solar. Peak demand has not (yet) compromised system reliability, despite installed thermal capacity falling by 20 GW. However, minimum demand is instead rapidly becoming an issue as it approaches the point where intermittent renewables and inflexible nuclear collide.

These changes stem from a confluence of many factors, some that can be steered by policy, some that are simply beyond our control. Demand for electricity is falling, partly due to the energy intensity of the economy (and in turn efficiency improvement), partly due to unseasonably warm weather (perhaps influenced by climate change).

Generation from coal peaked in 2012 as the carbon price collapsed and gas prices rose to double the level of coal per unit output. This global phenomenon was influenced both by tight gas supply in the wake of the Japanese earthquake and cheap coal exported from America that was displaced from their power stations by the shale gas revolution. By 2015, electricity generation from coal had fallen to its lowest absolute level since 1955 (when demand was much lower and before the first

nuclear reactors were built), whilst the UK's production of coal has receded back to pre-industrial levels (DECC, 2015). The introduction of the UK Carbon Price Floor and its rapid rise to triple the level of the EU Emissions Trading System has brought coal and gas prices in line with one another again, making fuel switching commercially viable.

Coal and oil have also been pushed off the system directly by clean air legislation, with plants forced to retire because of the Large Combustion Plant Directive (LCPD) and the Industrial Emissions Directive (IED). They have also suffered indirectly as biomass, wind and solar deployment have been supported through Renewables Obligation Certificates and Contracts for Differences. Imports have also risen, both because more interconnection has come online, and because British electricity prices have become higher than those on the continent.

Many of these changes have been influenced by policies set at the European level: the 20-20-20 targets for renewable energy, the LCPD and IED, and the international emissions trading scheme. With the UK's decision to leave Europe, it is unclear whether these policies will be retained in the long-term. Retracting any of them is likely to increase Britain's carbon emissions; however, with the Carbon Price Floor Britain has shown the will to go further than European incentives to decarbonise, with impressive effect.

This paper compiles publically available data from various sources to help illustrate the transition that Britain's power sector is undergoing, to hopefully inform and enlighten the debate on how this transition will continue.

## Acknowledgements

This work was used in developing the Electric Insights reports and website ([www.electricinsights.co.uk](http://www.electricinsights.co.uk)), commissioned by Drax Group plc. No employee of Drax or any other commercial or government body had the opportunity to contribute towards or influence the content of this paper. I thank National Grid and Elexon for freely providing the data which made this work possible.

Support from the Engineering and Physical Sciences Research Council (EPSRC) via the project “Maximising the Carbon Impact of Wind Power” (EP/N005996/1) is gratefully acknowledged. I thank Richard Green, Rob Gross, Tim Green, Raphael Slade, Clara Heuberger, Keith Bell, Oliver Schmidt and Ajay Gambhir for discussing earlier drafts of this paper, Kate Ward for assistance with data cleaning, Graeme Hawker for advice on using Elexon's constraint data, and Robert Staffell for proof-reading.

## Appendix A. Supporting information

Supplementary data associated with this article can be found in the online version at [doi:10.1016/j.enpol.2016.12.037](https://doi.org/10.1016/j.enpol.2016.12.037).

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