Chapter 5

Electricity

Key points

- **In 2018, electricity consumption accounted for 17 per cent of the UK's final consumption.** This proportion has been relatively stable in recent years.

- **UK electricity generation in 2018 fell 1.6 percent to 333 TWh, the lowest level since 1996. The fuel mix continued to shift away from coal towards renewables** as renewable capacity continued to grow. (Table 5.1)**.**

- **Renewables' share of generation reached a record 33.0 per cent in 2018**, up from 29.2 per cent the previous year. (Table 5.6). The increase was driven by a 13.4 per cent increase in renewable capacity, to 20.6 GW (derated to reflect intermittency), accounting for 25 per cent of generating capacity. (Table 5.7).

- **The low carbon share of electricity generation rose to a record 52.6 per cent**, 2.6 percentage points higher than in 2017. The increase from renewables was moderated by a drop in nuclear generation which fell to a 19.5 per cent share due to outages and ongoing maintenance. (Table 5.6).

- **Coal generation continued to decline, to 5.1 per cent of generation in 2018 from 6.7 per cent in 2017.** Gas generation fell too, from 40.4 per cent to 39.5 per cent. (Table 5.6).

- **Total electricity supply was down slightly to 352 TWh** compared to 353 TWh in 2017 as overall demand fell 0.2 per cent. **Net imports rose to 19.1 TWh, accounting for 5.4 per cent of total supply**, up from 4.2 per cent of supply in 2017**.**

- **Final consumption was stable at 300 TWh compared to 2017**, with similar average temperatures across the period. Domestic consumption fell 0.3 per cent whilst industrial consumption rose 0.8 per cent.

Introduction

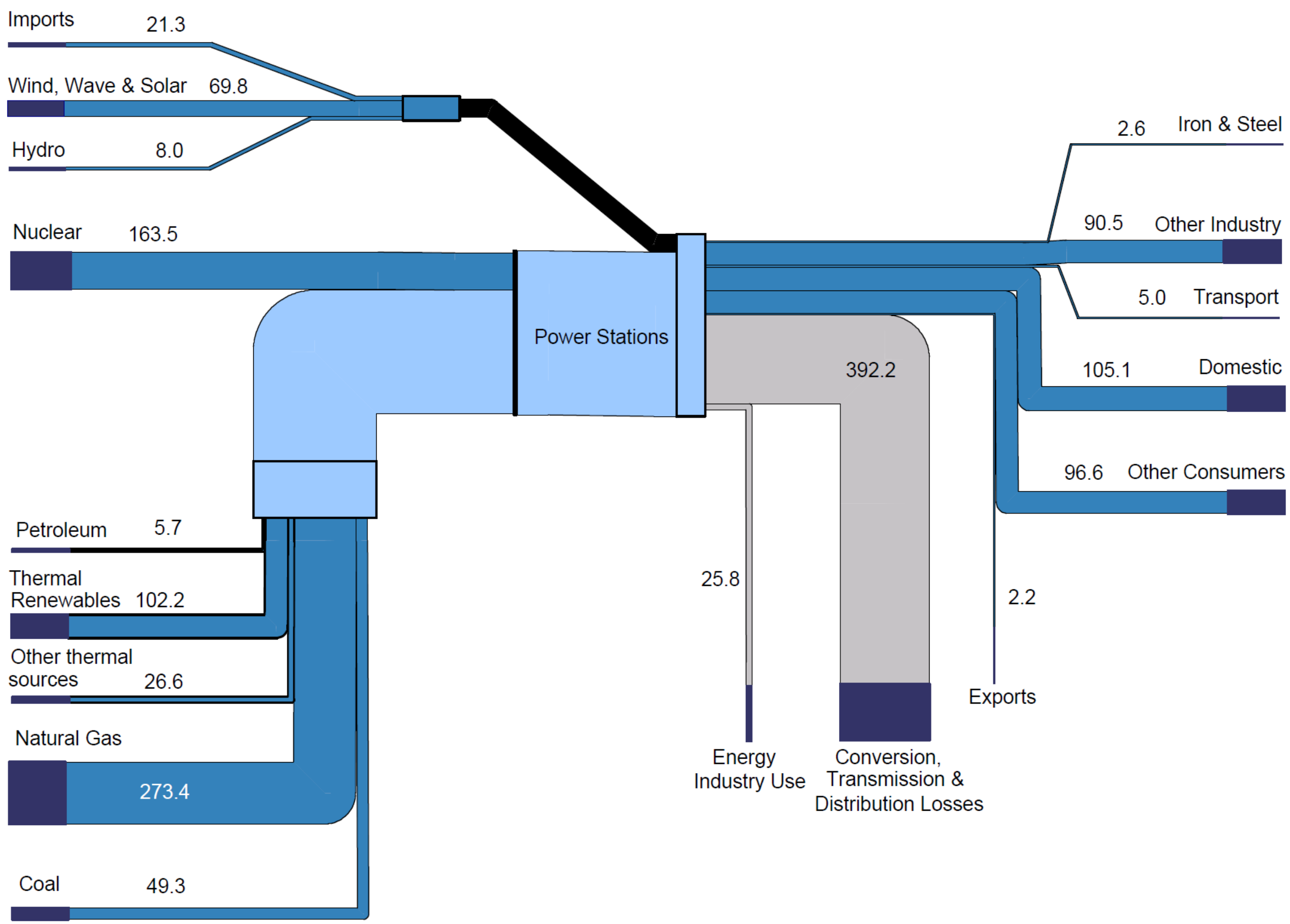
5.1 This chapter presents statistics on electricity from generation through to sales, and includes generating capacity, fuel used for generation, load factors and efficiencies. It also includes a map showing the electricity network in the United Kingdom and the location of the main power stations as at the end of May 2018. A **full list** of tables is available at the end of the chapter.

5.2 **In 2018, electricity consumption accounted for 17 per cent of the UK's final energy consumption[1].** This proportion has been relatively stable in recent years.

5.3 Below is an energy flow chart for 2018, showing the flows of electricity from fuel inputs through to consumption. It illustrates the flow of primary fuels used for the production of electricity through to the final use of the electricity produced or imported as well as the energy lost in conversion, transmission and distribution. The widths of the bands are proportional to the size of the flows they represent.

[1] *See section 1.16 for details.*

Electricity flow chart 2018 (TWh)



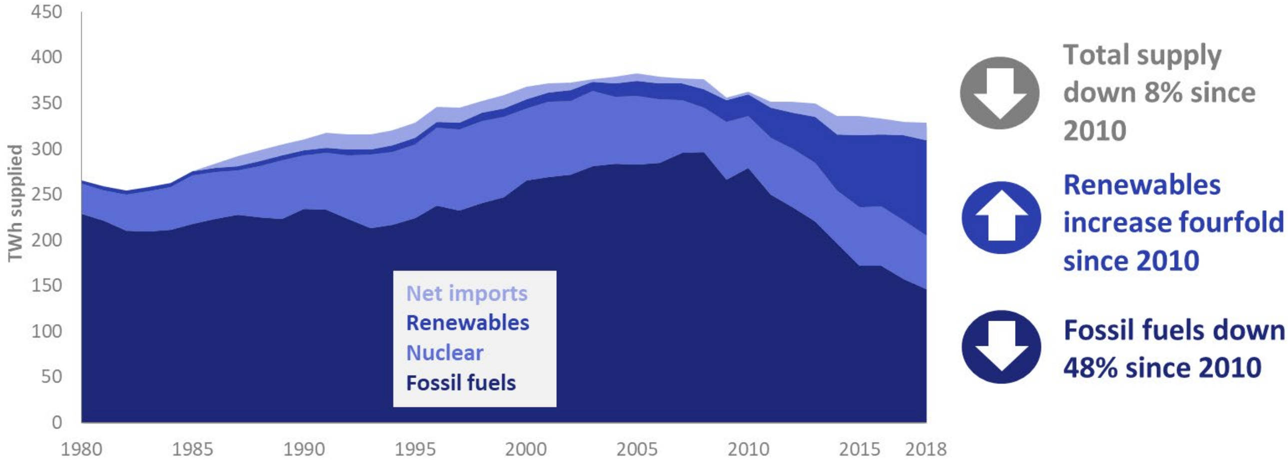
This flow chart is based on the data in Tables 5.1 (for imports, exports, use, losses and consumption) and 5.6 (fuel used).
1. Hydro includes generation from pumped storage while electricity used in pumping is included under Energy Industry Use.
2. Conversion, Transmission and Distribution Losses is calculated as fuel used (Table 5.6) minus generation (Table 5.6) plus losses (Table 5.1).

Electricity supply (Table 5.1)

5.4 Total UK electricity supply in 2018 was 352 TWh, down slightly from 353 TWh in 2017. UK generation (including pumped storage) accounted for 94.6 per cent of total supply, which was slightly lower than the proportion in 2017 (down 1.2 percentage points (pp)). UK generation decreased by 1.6 per cent in in 2018 compared to 2017 to 333 TWh – the lowest level since 1996. Net imports (imports minus exports) were 19.1 TWh in 2018, accounting for 5.4 per cent of total supply.

5.5 Electricity supply is driven by demand[2]. In recent years, demand has decreased as energy efficiency measures have improved and increased in number. Final consumption contributes significantly to demand; in 2018, it accounted for 85.1 per cent. Since 2014, final consumption has been broadly stable. A summary of UK supply is provided in Chart 5.1.

Chart 5.1: Electricity supply, 1980 - 2018



5.6 The UK is a net importer of electricity. **In 2018, net imports increased by 29 per cent on 2017**, as imports increased to 21.3 TWh (+17 per cent) and exports decreased to 2.2 TWh (-35 per cent). Table 5A below summarises interconnector capacity, net imports and utilisation.

Table 5A: Net Imports via interconnectors 2016 to 2018

	France – GB[a]	Ireland – N. Ireland[b]	Netherlands – GB[a]	Ireland – Wales[a]	Total
Capacity (MW)	2,000	540	1,000	500	4,040
Net Imports (GWh)					
2016	9,728	399	7,306	313	17,745
2017	7,181	-110	6,858	831	14,760
2018	12,890	-471	6,185	504	19,108
Utilisation (%)[c]					
2016	71%	19%	86%	33%	63%
2017	67%	14%	83%	46%	61%
2018	78%	26%	75%	47%	67%

a. Figures taken from the demand data available on the National Grid website at www2.nationalgrid.com/UK/Industry-information/Electricity-transmission-operational-data/Data-Explorer/.
b. Figures taken from data available on the SEMO website at www.semo.com/marketdata/pages/energysettlement.aspx.
c. Utilisation is total imports and exports across the interconnector in the year divided by the total possible imports and exports.

5.7 For the French interconnector, net imports increased 79 per cent in 2018 compared to 2017, due to a 41 per cent increase in imports and an 82 per cent reduction in exports. This marked a return to more typical net imports from France after a turbulent 2017. This turbulence was caused by interconnector damage in Q1 2017 and then a spike in French electricity prices in Q4 2017, driving up

[2] *In the statistics there is a small difference between electricity supply and electricity demand due to different data collection methods. This is called the statistical difference. Further explanations of the statistical difference can be found in paragraphs 5.112 and in paragraph A.19 of DUKES Annex A.*

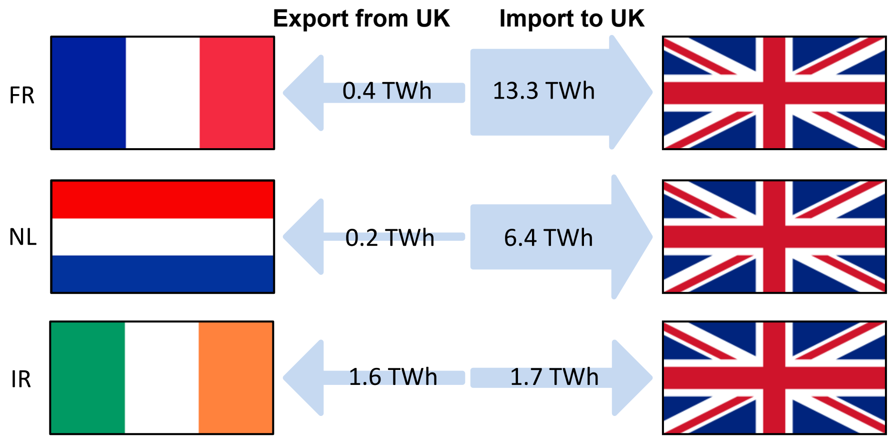
demand for UK exports. The French interconnector had a utilisation of 78 per cent in 2018, which was 11 pp higher than in 2017.

5.8 For the interconnector with the Netherlands, the UK remained a net importer in 2018; however net imports were 9.8 per cent lower in 2018 than 2017. This was driven by a 9.3 per cent reduction in imports but a 7.4 per cent increase in exports, reducing utilisation to 75 per cent.

5.9 For the Ireland-Wales interconnector, the UK was a net importer; though these were 39 per cent lower in 2018 than 2017, as exports increased. The interconnector's utilisation was slightly higher than in 2017.

5.10 In contrast to the other interconnectors, the UK is a net exporter on the Ireland-Northern Ireland interconnector. As both imports and exports increased, the interconnector utilisation increased 12 pp to 26 per cent. The interconnector trade flows are demonstrated in Chart 5.2 below.

Chart 5.2: Electricity imports and exports in 2018



Electricity demand and consumption (Table 5.1)

5.11 Total electricity demand in 2018 was nearly identical to 2017, down only 0.3 per cent to 352 TWh. Most of this demand (300 TWh, 85.1 per cent) was from final consumption. The remaining demand was split between energy industry use (27 TWh, 7.6 per cent of demand) and losses (26 TWh, 7.3 per cent of demand). There was no change in the final consumption figure compared to 2017. The demand from energy industry use had decreased by 2.7 per cent while the demand from losses had increased by 0.5 per cent compared to 2017.

5.12 While demand and final consumption in 2018 was were very similar to 2017, energy industry use decreased by 2.7 per cent. The largest proportion of energy industry use is electricity generation, which accounted for 59.9 per cent in 2018, up 1.5 pp on 2017. Compared to 2017, consumption for electricity generation only decreased 0.3 per cent. This was despite a reduction in electricity demand for pumped storage which decreased 12.1 per cent in 2018 compared to 2017 to 3.4 TWh. Pumped storage uses cheaper electricity to pump water to a higher reservoir. It can then be released later to generate electricity. While generation at all pumped storage plants reduced, the main driver was due to an outage at one of the plants for much of 2018.

5.13 Conversely, losses increased by 0.5 per cent in 2018 compared to 2017, to 27 TWh. However, losses' share of demand was broadly stable in 2018 compared to 2017 at 7.6 per cent (up 0.1 pp on 2017). Losses comprise three components[3]:

- Transmission losses (6.5 TWh) from the high voltage transmission system, which represented about 24 per cent of the losses figure in 2018;

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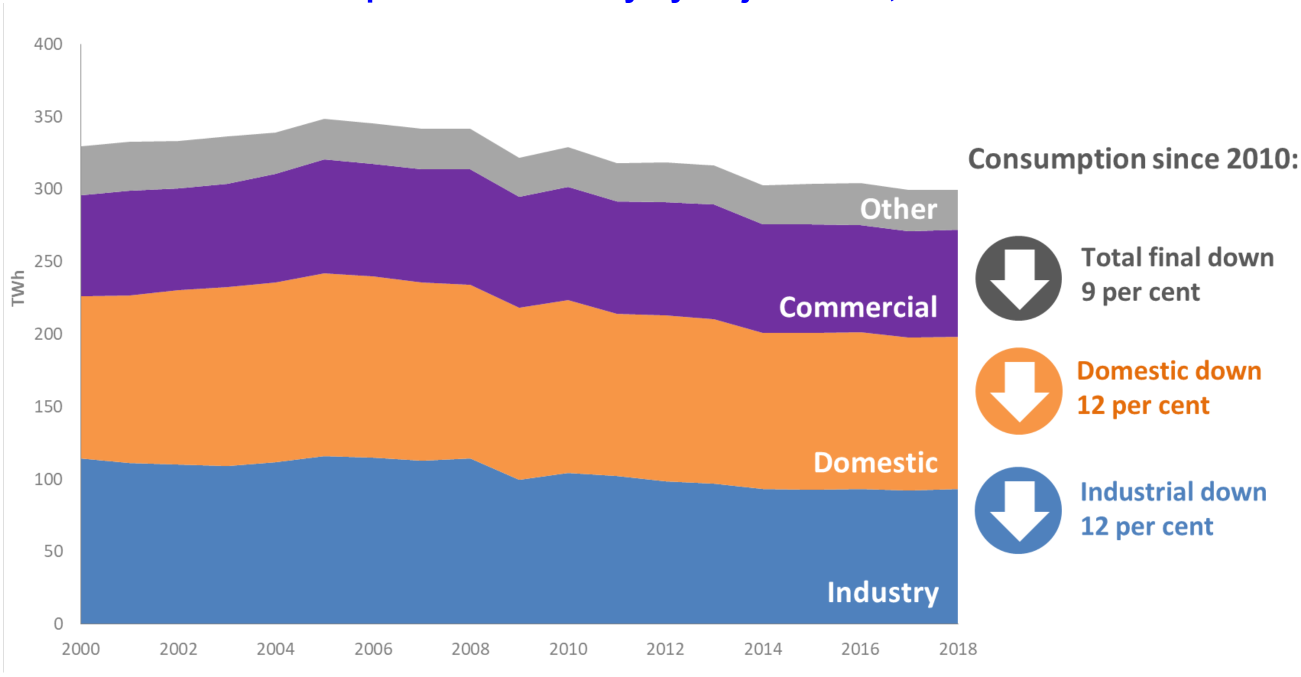
[3] *See paragraph 5.100 for further information on the calculation of losses.*

- Distribution losses (19 TWh), which occur between the gateways to the public supply system's network and the customers' meters, and accounted for about 71 per cent of losses; and
- Theft or meter fraud (just under 1.0 TWh, around 3.7 per cent).

5.14 Final consumption remained at 300 TWh, the same as last year. The breakdown across sector is shown in chart 5.3.

Chart 5.3: Final consumption of electricity by major sector, 2000-2018



5.15 Temperatures influence the actual level of consumption, especially in the winter months as customers adjust heating levels in their homes and businesses. The average temperature in 2018 was similar to that in 2017 despite quite notable seasonal variations with a particularly cold winter (due to the 'Beast from the East' cold weather system) followed by a warmer than usual summer. As a result, the annual consumption patterns for most sectors remained broadly similar.

5.16 Domestic consumption decreased slightly in 2018 compared to 2017 (-0.3 per cent). This broadly reflected the weather trends identified above. Since the peak of domestic consumption in 2005, at 126 TWh, it has generally declined annually, on account of milder winters and continuing energy efficiency improvements.

5.17 Transport consumption increased to 5.0 TWh. This was a 3.1 per cent increase on 2017. Rail accounted for 95.2 per cent of electricity consumption in the transport sector, with the remainder from road. Road consumption increased to 0.2 TWh in 2018 – an increase of 31 per cent on 2017, reflecting the growth in electric vehicles[4]. Despite the rise in electricity consumption, oil remains the dominant fuel for transport, with less than 1 per cent of UK energy demand for transport being met by electricity.

5.18 Industrial consumption increased to 93 TWh in 2018, an increase of 0.8 per cent on 2017. This trend reflected overall increased productivity in the manufacturing sector[5]. Since 2010, industrial consumption has declined 11 per cent, with annual increases occurring in 2016 and 2018.

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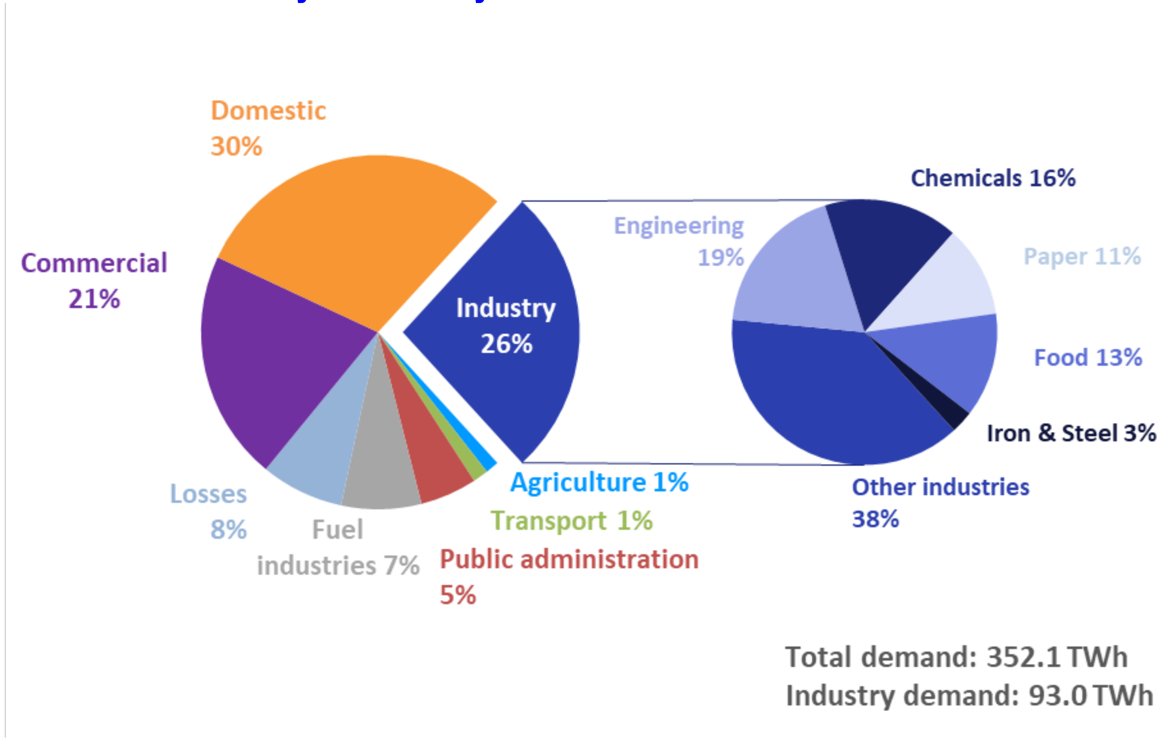
[4] *Department for Transport publish statistics on number of vehicles by propulsion type here: www.gov.uk/government/collections/vehicles-statistics*

[5] *Office for National Statistics (ONS) publishes the Index of Production available here: www.ons.gov.uk/economy/economicoutputandproductivity/output/bulletins/indexofproduction/previousReleases*

Chart 5.4: Electricity demand by sector 2018



5.19 Looking at the proportions of electricity demand for each sector, domestic demand has the largest share at 30%, followed by industrial demand at 26%. Chart 5.4 shows the full breakdown of the proportions of electricity demand accounted for by each sector, including a breakdown of the demand for different industries. Key figures are:

- Domestic demand: 30 per cent of final demand (unchanged since 2017);
- Industrial demand: 26 per cent of final demand (up 0.25pp on 2017);
- Commercial demand: 21 per cent of final demand (up 0.3 pp on 2017);
- Fuel industries demand (for generating electricity): 7 per cent of final demand (down 0.2pp on 2017)

Electricity distributed via the public distribution system and for other generators (Table 5.2)

5.20 The majority of electricity in the UK is supplied by the public distribution system (PDS), the interconnected high voltage transmission network and lower voltage distribution network. In recent years, the proportion of electricity from the PDS has reduced. In 2018, 323 TWh of UK electricity was supplied by the PDS, down 0.4 per cent on 2017. Major power producers[6] (MPPs) provide most of the power to the PDS, with the remainder made up of transfers from other generators[7] which can sell surplus electricity into the PDS, as well as net imports. The volume of electricity supplied by other generators increased by 1.4 per cent on 2017 to 29 TWh.

5.21 The volume of supply from MPPs decreased by 2.1 per cent in 2018 compared to 2017, to 279 TWh. However, electricity supplied from other generators increased by 2.2 per cent to 52 TWh, of which 43 per cent was transferred to the PDS. The transfers from other generators to the PDS were 3.3 per cent larger in 2018 than 2017. Additionally, net imports in 2018 were up on 2017[8], so ensuring that supply met demand.

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[6] *Further information on the definitions of MPPs and other generators can be found in paragraph 5.87.*

[7] *Other generators are businesses that generate their own electricity and may export surplus to the grid, and microgeneration by the domestic and commercial sectors. This includes autogenerators.*

[8] *For more information on net imports, imports and exports please see paragraph 5.6.*

5.22 Since 2009, autogeneration and local generation have increased, partly as result of small-scale renewable schemes, such as Feed-in Tariffs (FiTs), which has resulted in a reduction in the proportion of electricity supplied from the PDS. Since 2009, the share of electricity from the PDS has decreased from 95.2 per cent to 91.7 per cent (-3.5 pp). Other generators sell surplus electricity to the PDS ('Transfers' in Table 5.2); this amount has increased from 5.7 TWh in 1998 to 22 TWh in 2018.

5.23 While total energy industry use decreased in 2018 compared to the previous year[9], the energy industry use by other generators increased by 7.4 per cent to 7.7 TWh in 2018. This increased the proportion of energy industry use by other generators to 29.9 per cent (up 2.8 pp on 2017). For petroleum refineries, the proportion of consumption from self-generation was much higher than energy industry use in general, at 73.1 per cent.

5.24 In recent years, the proportion of final electricity consumption by other generators has followed an increasing trend; however, in 2018 this was stable on 2017 at 7.2 per cent (-0.1 pp). The 2018 proportion is still higher than 2016 (+0.8 pp) and 2015 (+1.5 pp).

5.25 Other generators and autogenerators produce electricity as part of their manufacturing or other commercial activities, principally for their own use. Similar to 2016 and 2017, over 10 per cent of industrial demand for electricity was met by autogeneration in 2018. Table 5.4 shows the fuels used by autogenerators to generate this electricity within each major sector and the quantities of electricity generated and consumed.

5.26 Domestic electricity generation by households with micro-generation units (such as solar photovoltaic panels) increased sharply since the launch of FiTs in April 2010 in Great Britain (see Chapter 6 on renewables paragraph 6.70 for further information on FiTs uptake). Continuing the trend in 2018, but at a slower rate, the domestic sector consumed 1.6 TWh of self-generated electricity. This was an increase of 12 per cent on 2017, but a considerable increase on the start of the scheme in 2010. However, self-generated electricity still accounts for only 1.5 per cent of domestic consumption.

5.27 For the domestic sector consumption, 16 per cent was reported as purchased from an off-peak pricing structure (e.g. Economy 7) in 2018 – the same as in 2017. Since 2011, domestic purchases through prepayment systems have remained stable; this trend continued in 2018 at 16.1 per cent of domestic consumption.

Combined Heat and Power (CHP) plants

5.28 Combined Heat and Power (CHP) is the simultaneous generation of useable heat and power in a single process and is frequently referred to as cogeneration. A large proportion of CHP schemes in the UK are covered by the CHPQA programme and are covered in detail in Chapter 7, along with background information.

5.29 In 2018, CHP comprised 10.1 per cent of MPP's thermal electricity generation, and 67.7 per cent of thermal autogeneration. Table 5B summarises the quantity of CHP capacity and generation covered in Chapter 7 using statistics sourced from the CHPQA programme compared to other CHP plants not covered by the scheme.

[9] *For more information on Energy Industry use see paragraph 5.11*

Table 5B: Combined Heat and Power (CHP) electricity generation and capacity in 2018, compared to UK generation and capacity

		Generation (GWh)	Capacity (MW)
Major Power Producers (Thermal)	CHPQA (ch 7)	6,723	1,990
	CHP (not included in ch 7)	15,883	2,349
	Other thermal generation	200,590	67,351
	Total MPP thermal generation	223,196	71,690
Autogenerators (Thermal)	CHPQA (ch 7)	16,144	3,995
	CHP (not included in ch7)	5,469	491
	Other thermal generation	10,325	6,150
	Total thermal autogeneration	31,938	10,635
Transfers		75,260	n/a
Total		**330,394**	**82,325**

Electricity fuel use, generation and supply (Tables 5.3 & 5.6)

5.30 With the small decrease in electricity generation in 2018, fuel used by all generating companies decreased by 0.9 per cent on the previous year. (Table 5.3). This trend was largely a result of the generation mix shifting to more low carbon alternatives – see Chart 5.5 overleaf.

5.31 For MPPs, fuel use decreased to 51 mtoe in 2018, a decrease of 3.5 per cent on 2017 – this decrease is attributable to a 2.1 per cent reduction in MPP generation in 2018 compared to 2017[10]. For other generators, their generation increased 2.2 per cent, so their fuel use increased by 13.7 per cent to 11 mtoe. However, these increases in generation and fuel use were driven by increases from renewable sources, rather than from fossil fuels.

5.32 Fossil fuels used in electricity generation decreased by 8.0 per cent in 2018 compared to 2017. Coal use decreased by 23.7 per cent in 2018 compared to 2017, to reach a record low level of fuel use at 4.2 mtoe. Gas use decreased by 4.4 per cent on the previous year to 24 mtoe used in electricity generation.

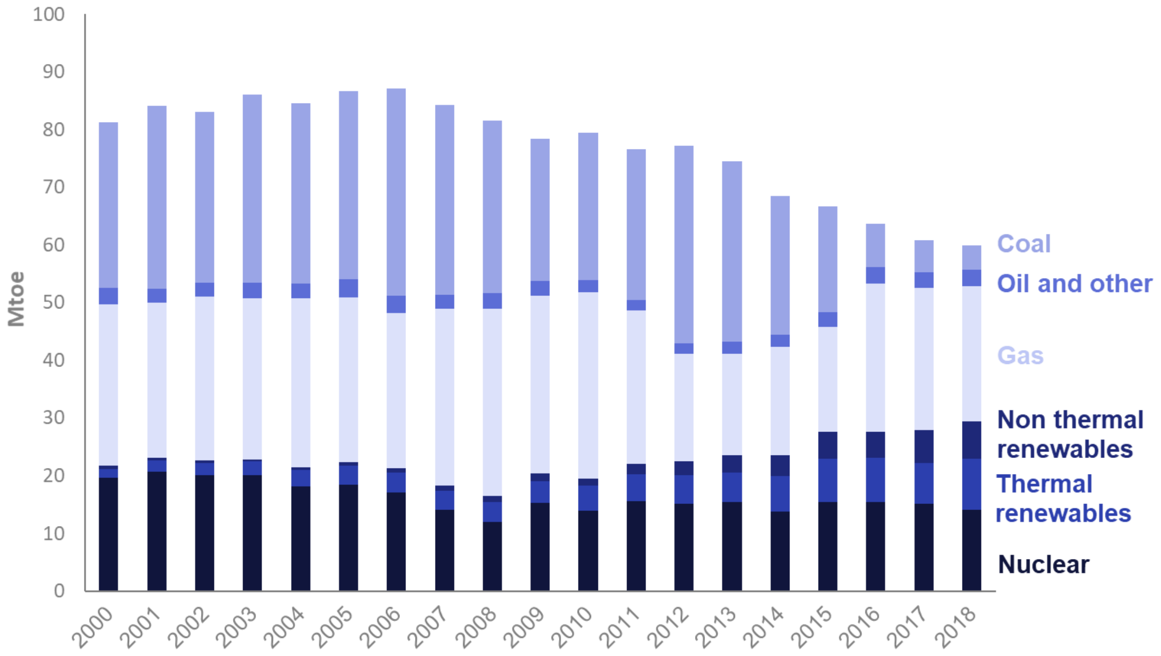
5.33 The UK generated 333 TWh of electricity in 2018, this includes 2.5 TWh of pumped storage generation. Of this generation, MPPs accounted for 85 84.4 per cent in 2018, which was 0.6 pp lower than in 2017 (Table 5.6).

5.34 Large shifts in the mix of fuels used for electricity generation have occurred in recent years, continuing in 2018. Similar to 2017, the largest change was in coal; generation from coal decreased by 25 per cent compared to 2017. Although gas generation also decreased, the decrease was smaller at 3.8 per cent compared to 2017 to 131 TWh. Gas was lower than 2016 and 2017 but was higher than in 2015. The main driver for the shift in generation between coal and gas was an increase in the carbon price floor in April 2015, from £9 per tonne of CO_2 to £18 per tonne of CO_2. Since coal generation produces more than double the carbon dioxide per GWh of electricity supplied compared to gas, this made generation from coal more expensive than gas. Therefore, the coal-fired plants tended to reserve generation for periods of highest demand. Additionally, coal-firing capacity was reduced in 2018 with the closure of Eggborough and the conversion of a unit at Drax.

5.35 Nuclear generation fell 7.5 per cent from 70 TWh to 65 TWh in 2018, which is the lowest level since 2014. Outages and maintenance at various nuclear plants reduced generation in 2018.

[10] *MPP generation taken from DUKES table 5.2*

Chart 5.5: Fuel Used in generation by all generators, 2000 - 2018



5.36 The growth in renewable generation continued as a major trend in 2018. Renewable generation[11] increased by 11 per cent in 2018 compared to the previous year to reach 110 TWh. While this increase is slightly lower than that between 2016 and 2017, renewable generation in 2018 was 33 per cent higher than in 2016. This trend is a result of weather conditions and capacity. In 2018, the average daily sun hours across the year were 14.7 per cent higher than in 2017, with average rainfall 0.9 per cent higher. However, average wind speeds were 1.6 per cent lower in 2018 than in 2017. On capacity, overall renewable generation capacity increased by 10.0 per cent (see paragraph 5.47 for more detail).

5.37 **Generation from wind and solar[12] sources increased by 14 per cent in 2018 compared to 2017 to 70 TWh.** This increase was driven by large increases in wind (+11.2 per cent) and solar (+2.6 per cent) capacity. However, hydro natural flow generation decreased by 7.0 per cent in 2018 compared to 2017, likely due to large fluctuations in rainfall over 2018.

5.38 Thermal renewables generation[13], which covers bio-energy including biodegradable wastes, increased to 35 TWh in 2018, an increase of 9.4 per cent on the previous year. This increase was attributable to an increase in capacity of 25 per cent, along with the conversions of previous coal power stations to biomass, such as Lynemouth. More information on renewable electricity can be found in Chapter 6.

5.39 Not all electricity produced by generators is available for use, as plants require a portion for their own works. In 2018, a total of 15 TWh was used on works, which gave a gross electricity supplied of 317 TWh (-1.6 per cent on 2017; Table 5.6). Further, when electricity used in pumped storage is accounted for, the net electricity supplied volume in 2018 was 314 TWh.

5.40 As a result of the shifts in generation outlined, there have been some significant shifts in the shares of generation. The share of generation from fossil fuels fell to 44.9 per cent in 2018, down from 47.6 per cent in 2017 (-2.7 pp). Most notably, coal's share of generation fell to 5.1 per cent in 2018, down 1.6 pp on the previous year; this was a record low share for coal. Gas's share of generation was

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[11] Renewables include wind, natural flow hydro, solar, wave, tidal and bioenergy (including co-firing).

[12] Including generation from wave and tidal

[13] For consistency with the Renewables Chapter (Chapter 6), non-biodegradable wastes (previously included in thermal renewables / bio-energy) have been moved to the 'other fuels' category for 2007 onwards for autogeneration and for 2013 onwards for MPPs. Prior to this, they have remained in thermal renewables.

39.5 per cent, which was 0.9 pp lower than in 2017. While gas's share was lower than 2017 and 2016, it was 10.0 pp higher than in 2015, reflecting the shift in generation from coal to gas due to the carbon price floor (see paragraph 5.34).

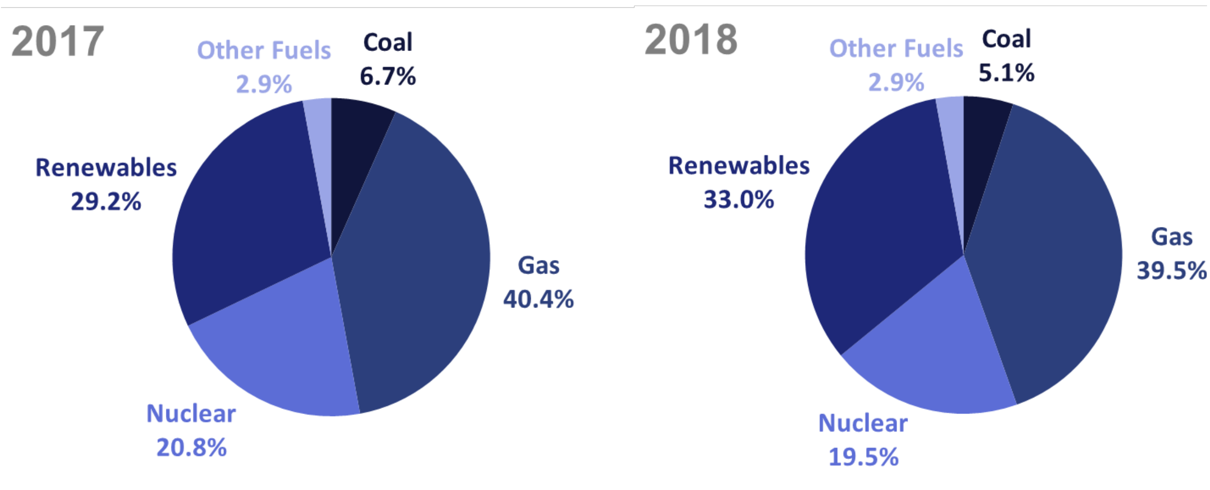
5.41 Renewables' share of generation reached another record high in 2018 at 33.0 per cent. The 2018 share was 3.8 pp higher than in 2017 and 27 pp higher than in 2008. This rise in renewables share was due to an increase in the share from wind and solar to 21.0 per cent (+2.9 pp on 2017) and thermal renewables to 10.4 per cent (+1.0 pp on 2017) – both of these were record high levels. However, the share of generation from hydro natural flow has been relatively stable across the time series and was 1.6 per cent in 2018 (-0.1 pp on 2017).

5.42 The rise in renewables share of generation drove an increase in low carbon's share of generation. Low carbon generation consists of renewable and nuclear generation. Low carbon generation reached a record high share of 52.6 per cent in 2018, which was 2.6 pp higher than 2017. This increase was not as large as the increase in renewables generation, as nuclear's share of generation declined to 19.5 per cent in 2018 (-1.3 pp 2017). The share of generation from nuclear was at its lowest level since 2014, as a result of outages and maintenance.

5.43 The large increase in renewables generation and the decrease in nuclear generation, resulted in an increase in the proportion of low carbon generation from renewable sources. In 2018, 62.8 per cent of low carbon generation came from renewable sources compared to 58.4 per cent in 2017.

5.44 A comparison of the shares of generation by fuel for 2018 and 2017 are provided in Chart 5.6 below. Further information on this and the alternative input basis of comparing fuel use can be found in paragraph 5.95.

Chart 5.6: Shares of electricity generation, by fuel

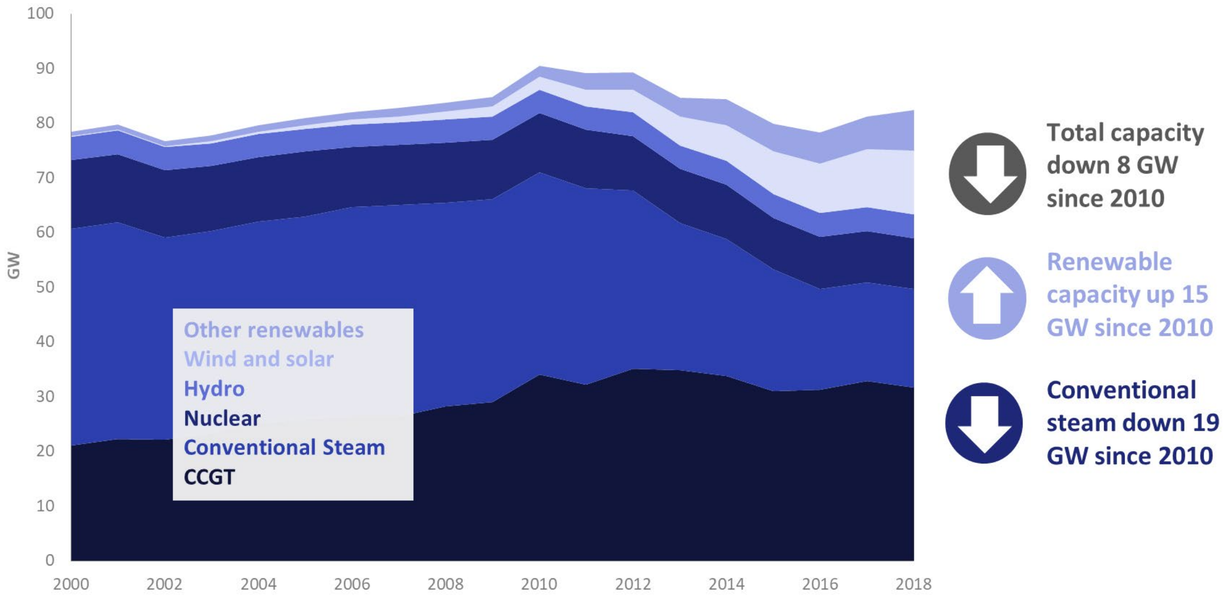


5.45 A historical series of fuel used in generation on a consistent, energy supplied, fuel input basis is available at Table 5.1.1 on the BEIS section of the GOV.UK website and accessible from the Digest of UK Energy Statistics home page: www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes

Plant capacity (Tables 5.7, 5.8 and 5.9)

5.46 Electricity generation capacity is the maximum power available to the UK at any one time. Capacity is provided by MPPs[14] and other generators including non-MPP renewables. In this section, wind, small scale hydro and solar PV capacity is **de-rated** to account for intermittency, to enable direct comparison with conventional fuels which are less dependent on the weather (Table 5.7).

Chart 5.7: Generating capacity of all power producers, 2000-2018



1. 'Conventional steam' includes a small proportion of non-CCGT plants, gas turbines and plants that can be fuelled by a combination of gas, coal and oil.
2. 'Hydro' includes natural flow and pumped storage.
3. 'Other renewables' includes biofuels.
4. Wind included from 2007

5.47 All generators total capacity increased to 82,932 MW in 2018; an increase of 2.2 per cent on the 81,170 MW capacity in 2017. This increase in capacity was largely driven by increases in renewables generating capacity.

5.48 In 2018, there were large increases in generation from renewable sources (see paragraph 5.35), which were largely driven by increases in capacity. Renewable generating capacity, across all generators, increased by 13.4 per cent in 2018 compared to 2017 to reach 20,600 MW. The increase in renewable capacity occurred for all types. Overall, renewables accounted for 25.0 per cent of total all generators capacity in 2018, an increase of 2.5pp on 2017.

5.49 Wind capacity increased to 9,361 MW, an increase of 11.2 per cent on 2017; this increased wind's share of capacity to 11.3 per cent (+0.9pp).

5.50 Solar capacity increased to 2,230 MW for all generators, an increase of 2.6 per cent on 2017. Overall, solar accounted for 2.7 per cent of all capacity.

5.51 Capacity for hydro generation was broadly stable in 2018 as in 2017. The capacity for pumped storage has remained static at 2,744 MW since 2007.

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[14] *From 2006 onwards, MPP capacities are measured in Transmission Entry Capacity (TEC) terms, rather than Declared Net Capacity (DNC). The effect of this change has been to increase the capacity of MPPs by about 2,000 MW in total. A full definition of TEC and DNC is given in paragraph 5.101. Wind, small scale hydro, and solar photovoltaic DNC is de-rated to take into account intermittency. Renewables installed capacity figures are given in table 6.4.*

5.52 Bioenergy capacity increased to 7,385 MW, up 24 per cent on 2017. Both MPP and other generator capacity increased, and partially reflects the conversion of power stations to biomass. These closures, changes and openings are summarised in Table 5C overleaf. For all generators, bioenergy accounted for 8.9 per cent of capacity, an increase of 1.6 pp on 2017.

5.53 The only non-renewable category with an increase in capacity in 2018 was gas turbines and oil engines, which increased 39 per cent on 2017 to 2,339 MW for all generators. This increase was due to the conversion of several plants to Open Cycle Gas Turbine (OCGT) and the opening of a new site at Chippenham. Gas turbines and oil engines accounted for 2.8 per cent of generation, up 0.6 pp from last year.

5.54 Meanwhile, fossil fuel conventional steam capacity decreased by 4.1 per cent to 15,668 MW in 2018 compared to the previous year. However, conventional steam still accounted for 18.9 per cent of all generators' capacity in 2018 (-1.2 pp on 2017). The decrease in capacity occurred for MPPs, due to the closure of the coal plant at Eggborough and the conversion of Drax from coal to biomass (summarised in Table 5C).

5.55 Combined Cycle Gas Turbine stations (CCGT) capacity decreased by 1.6 per cent in 2018 compared to 2017 to 32,267 MW for all generators. This decrease was a result of the closure of Deeside along with reduced capacity and conversion to Open Cycle Gas Turbine (OCGT) at Peterborough. Despite the decrease, CCGT continued to account for the largest share of capacity, which in 2018 was 38.9 per cent (-1.5 pp on 2017).

Table 5C: Major Power Producers thermal capacity opened, closed, converted, increased or reduced (as at end of May 2019), since end-2010

Site	Fuel	Status	Previous Capacity (MW)	New Capacity (MW)	Year of closure/opening, capacity change or conversion
Langage	CCGT	Opened	0	905	2010
Severn Power	CCGT	Opened	0	850	2010
Staythorpe C	CCGT	Opened	0	1,752	2010
Barkip	Waste	Opened	0	3	2011
Blackburn	CCGT	Opened	0	60	2011
Fife	CCGT	Closed	123	0	2011
Grain CHP	CCGT	Opened	0	1,517	2011
Riverside	Waste	Opened	0	80	2011
Teesside	CCGT/OCGT[1]	Partially Closed	1,875	45	2011
Tilbury B	Coal	Converted	1,063	0	2011
Tilbury B	Biomass	Converted	0	750	2011
Derwent	CCGT-CHP	Mothballed	228	0	2012
Grain A	Oil	Closed	1,300	0	2012
Kingsnorth A	Coal/Oil	Closed	1,940	0	2012
Oldbury	Nuclear[2]	Closed*	434	0	2012
Pembroke B	CCGT	Opened	0	2,199	2012
Shotton	CCGT-CHP	Closed	210	0	2012
Wylfa (Reactor 2)	Nuclear[3]	Partially Closed	980	490	2012
Cockenzie	Coal	Closed	1,152	0	2013
Didcot A	Coal/Gas	Closed	1,958	0	2013
Drax	Coal[4]	Partially Converted	3,960	3,300	2013
Drax	Biomass[4]	Partially Converted	0	660	2013
Fawley	Oil	Closed	1,036	0	2013
Ironbridge	Coal[5]	Converted	1,000	0	2013
Ironbridge	Biomass[5]	Converted	0	370	2013
Keadby	CCGT	Mothballed	749	0	2013
Kings Lynn	CCGT	Mothballed	340	0	2013
Roosecote	CCGT	Closed*	229	0	2013
Teesside	OGCT[1]	Closed	45	0	2013
Tilbury B	Biomass	Closed*	750	0	2013
West Burton	CCGT	Opened	0	1,332	2013
Barking	CCGT	Closed	1,000	0	2014
Drax	Coal[4]	Partially Converted	3,300	2,640	2014
Drax	Biomass[4]	Partially Converted	660	1,320	2014
Ferrybridge C	Coal	Partially Closed	1,960	980	2014
Littlebrook D	Oil	Closed	1,370	0	2014
Markinch CHP	Biomass	Opened	0	60	2014
Runcorn	Waste	Opened	0	86	2014

Site	Fuel	Status	Previous Capacity (MW)	New Capacity (MW)	Year of closure/opening, capacity change or conversion
Blackburn Meadows	Biomass	Opened	0	33	2015
Drax	Coal[4]	Partially Converted	2,640	1,980	2015
Drax	Biomass[4]	Partially Converted	1,320	1,980	2015
Ferrybridge Multi-Fuel	Waste	Opened	0	79	2015
Ironbridge	Biomass[5]	Closed	370	0	2015
Lynemouth	Coal	Mothballed	420	0	2015
Wylfa (Reactor 1)	Nuclear[3]	Closed	490	0	2015
Carrington	CCGT	Opened	0	910	2016
Ferrybridge C	Coal	Closed	980	0	2016
Killingholme A and B	CCGT	Converted	900	0	2016
Killingholme A and B	OCGT	Converted	0	600	2016
Longannet	Coal	Closed	2,260	0	2016
Rugeley	Coal	Closed	448	0	2016
Wilton 11	Waste	Opened	0	55	2016
Uskmouth	Coal	Mothballed	220	0	2017
Ballylumford B	OCGT	Closed	540	0	2018
Deeside	CCGT	Closed	498	0	2018
Drax	Coal[4]	Converted	1,980	1,320	2018
Drax	Biomass[4]	Converted	1,980	2,640	2018
Eggborough	Coal	Closed	1,960	0	2018
Lynemouth	Biomass	Converted	0	420	2018
Peterborough	OCGT[6]	Converted	360	245	2018
Barry	OCGT[7]	Closed	375	0	2019

* site was mothballed before closure

1. Reduced capacity from 1,875 MW (CCGT 1,830 MW / OCGT 45 MW) to 45 MW (OCGT) in 2011 before closing in 2013.
2. Reactor 2 with capacity of 217 MW closed on 30 June 2011, reactor 1 with capacity of 217 MW closed on 29 February 2012.
3. Reactor 2 closed on 30 April 2012, reactor 1 closed on 31 December 2015 (both with a capacity of 490 MW).
4. Partly converted to biomass. Two 660 MW units were converted to biomass, one in 2013 and 2014, before a third unit (also 660 MW) was converted to high-range co-firing (85% to <100% biomass) in 2015. A fourth unit (660 MW) was then converted in August 2018. Overall capacity remains at 3,960 MW (coal 1,320 MW, biomass 2,640 MW).
5. Converted from coal to dedicated biomass in 2013 (at 740 MW), before reducing to 370 MW in April 2014 after a fire at one of the biomass units.
6. Operated as a CCGT at 360 MW until 2018, but now operating as an OCGT (245 MW) with the steam side being decommissioned.
7. Operated as a CCGT until March 2018, before running as an OCGT for one year. The site was then closed in March 2019.

5.56 Since 2010, MPPs proportion of capacity has reduced from 92 per cent to 87 per cent in 2018. This declining trend is a result of MPP plant closures and a steady increase in small-scale renewable capacity from other generators.

5.57 Both MPP and other generators capacity increased in 2018 compared to 2017 – for MPPs this increase was 1.9 per cent to 72,297 MW, while for other generators the increase was 4.0 per cent to

10,635 MW. These increases were driven by increased renewables capacity, which for MPPs[15] increased 18 per cent and for other generators 5.2 per cent. A breakdown for capacity by type for all generators is given in Chart 5.7.

5.58 MPP generating capacity increased in each UK country in 2018 compared to 2017. A summary of MPP capacity by country is provided in Table 5D overleaf. The share of capacity in each country was broadly the same in 2018 as in 2017.

5.59 An increase in renewables capacity drove the overall capacity increase in each area. For 2018 in comparison to 2017, renewables capacity increased by 23 per cent in England and Wales, 10 per cent in Scotland and 21 per cent in Northern Ireland. As identified in 5.53, there was also a large increase in gas turbine and oil engine capacity in 2018 in England and Wales. (Table 5.8).

Table 5D: MPP Capacity Summary, 2015 to 2018

	2015	2016	2017	2018	% Change 2018 vs 2017
Capacity (MW)[1]					
England and Wales	58,306	57,984	60,125	60,476	0.6%
Scotland	9,970	7,921	8,448	8,802	4.2%
Northern Ireland	2,522	2,298	2,369	2,412	1.8%
Total	**70,798**	**68,203**	**70,942**	**71,690**	**1.1%**
Share (%)[2]					
England & Wales	82.4%	85.0%	84.8%	84.4%	-0.4%
Scotland	14.1%	11.6%	11.9%	12.3%	0.4%
Northern Ireland	3.6%	3.4%	3.3%	3.4%	0.0%

[1] Capacity data for MPP by grid country is taken from Table 5.8

[2] Share is calculated as the country's capacity divided by the total capacity

5.60 Other generators capacity increased in the majority of sector classifications in 2018. The largest increase in the industrial and commercial was in the paper, printing and publishing sector. Table 5.9 gives a full breakdown of the generating capacity for generators other than MPPs according to the industrial classification of the generator[16]. For CHP, schemes are classified according to the sector that receives most of the heat (as opposed to the sector in which the CHP operator was considered to operate).

Plant loads, demand and efficiency for MPPs (Table 5.10)

5.61 The maximum load (demand) in the UK during the winter of 2018/2019[17] was 50,412 MW, which occurred on 23rd January 2019, in the half-hour ending 18:00; this was 3.6 per cent lower than the previous winter's maximum (on 1st March 2018). In Great Britain the maximum demand was 48,800 MW, which was 3.7 per cent lower than the maximum the previous winter. For Northern Ireland, the simultaneous maximum load was 1,612 MW, which was 2.1 per cent higher than the previous year.

[15] *MPP renewables capacity excludes pumped storage.*

[16] *For CHP, schemes are classified according to the sector that receives most of the heat (as opposed to the sector in which the CHP operator was considered to operate.*

[17] *Maximum demand figures cover the winter period ending the following March. With the advent of the British Electricity Trading and Transmission Arrangements (BETTA) (see paragraph 5.78), England, Wales and Scotland are covered by a single network and a single maximum load is shown for Great Britain for 2006 to 2016.*

5.62 For the 2018/19 winter, the maximum demand was 69.7 per cent of the UK MPP capacity[18], which was 4.0pp lower than in 2017/18. This decrease was a result of a decrease in Great Britain, as maximum demand met in 2018/19 was 69.8 per cent of MPP capacity, which was 4.1 pp lower than in 2017. In Northern Ireland, the maximum demand met was relatively stable at 72.4 per cent of MPP capacity. These percentages do not include the capacities available via the interconnectors with neighbouring grid systems nor demand for electricity via these interconnectors.

5.63 As Northern Ireland operates from a separate electricity grid to Great Britain, its own maximum load occurred on 19th February 2019 in the half-hour ending at 18:00. The load was 1,745 MW, which was 1.8 per cent higher than the previous winter.

5.64 Plant load factors[19] measure how intensively each type of plant has been used, with a higher value demonstrating a higher intensity of use. For all plants in 2018, the load factor was 36.6 per cent, a decrease of 2.8 pp on 2017. While nuclear plants continued to have the highest plant load factor at 72.3 per cent in 2018, this was 5.1 per cent lower than in 2017, due to the reduction in supply from plant outages. The reduced supply of electricity from coal in 2018, resulted in a coal-fired power station load factor of 14.2 per cent, which was 3.2 per cent lower than in 2017. This is a new low for coal-fired stations.

5.65 Load factors for natural flow hydro and wind (as well as other renewables) can be found in table 6.5[20], with a summary of the trends on an unchanged configuration basis[21], provided below. Weather conditions affected the load factors of renewable generators, with lower wind speeds and rainfall but higher average sun hours.

5.66 In 2018, the overall wind load factor was 31.4 per cent, a decrease of 0.3 pp on 2017. Despite an increase in wind generation (+15 per cent on 2017), the increase in maximum generating capacity[22] was larger. When split by type of wind generation, the load factor for onshore wind decreased by 1.6 pp in 2018 compared to 2017 to 26.4 per cent, while offshore wind's load factor increase to 40.1 per cent (+1.2 pp). Higher average sun hours resulted in a small increase (+0.7 pp) to the solar photovoltaic load factor to 11.3 per cent in 2018 compared to 2017. Lower rainfall resulted in the hydro load factor decreasing (-2.9 pp) to 33.4 per cent in 2018 compared to 2017.

5.67 Thermal efficiency measures the efficiency with which the heat energy in fuel is converted into electrical energy. The efficiencies presented here are calculated using gross calorific values to obtain the energy content of the fuel inputs[23]. Generally, nuclear efficiency has remained between 38 and 40 per cent over the last decade and was 39.8 per cent in 2018. The largest change in thermal efficiency was for coal-fired stations, with a 0.8 percentage point decrease to 34.1 per cent.

Power stations in the United Kingdom (Tables 5.11 and 5.12)

5.68 **The total installed capacity of major UK power stations was 84,796 MW**[24] at the end of May 2019. Table 5.11 is a database of UK capacity with details of these Major Power Producers (MPPs) as well as the four interconnectors allowing trade with Europe, and an aggregate of other generating stations using renewable sources and smaller (<1 MW) Combined Heat and Power (CHP) plants

18 The MPP capacity is 72.297 MW, as measured at the end of December 2018. It is taken from Table 5.7 as measured at the end of December 2018.

19 The plant load factors for All plants and Conventional Thermal and other stations contain revisions back to 2010, ensuring that both the capacity and supply values are for MPPs only.

20 The load factors presented in table 5.10 use transmission entry capacity (as presented in table 5.7). For hydro and wind, this has been de-rated for intermittency, so is not suitable for calculating load factors. The installed capacity measure used in Chapter 6 has not been de-rated.

21 For renewables load factors, including the unchanged configuration and standard (average beginning and end of year) measures, see table 6.5.

22 Maximum generating capacity is the capacity multiplied by the number of hours in the year.

23 For more information on gross and net calorific values, see paragraph 5.104.

24 The total installed capacity for stations listed in table 5.11 differs from the total in table 5.7, as the latter is on a Transmission Entry Capacity basis and taken as at the end of 2018. See paragraph 5.101 for more information on the measures of capacity.

5.69 Table 7.10 shows CHP schemes of 1 MW and over for which the information is publicly available. Total power output of these stations is given (electricity plus heat), not just that which is classed as good quality CHP under the CHP Quality Assurance programme (CHPQA, see Chapter 7), since CHPQA information for individual sites is not publicly available.

5.70 Table 5.12 shows capacity of the transmission and distribution networks for Great Britain, Northern Ireland and the UK as a whole. The UK transmission network connected capacity reduced each year from 2012 to 2015 due to closures and conversions of coal, oil and gas plants. Since 2011 the distribution network capacity increased annually as embedded renewable generation was installed. Across the UK in 2018, transmission capacity was 71,801 MW, a decrease of 2.0 per cent on 2017, meanwhile distribution network capacity increased 4.5 per cent to 32,995 MW, more than double 2011's capacity.

5.71 Despite the overall decrease to transmission network capacity, capacity for wind and bioenergy both increased. However, these increases did not offset the decreases from coal, OCGT and CCGT gas.

5.72 **Over 2018 the total installed capacity (for both transmission and distribution networks) for the UK was 105 GW, the same as in 2017 (105 GW).** From this total UK capacity, 96.4 per cent of the UK's capacity was connected in Great Britain and 3.6 per cent in Northern Ireland. For Great Britain, it is estimated that 70 GW was connected to the transmission network, equivalent to 66.6 per cent of the Great Britain total capacity. From the Northern Ireland total capacity (3.8 GW), 54.2 per cent was estimated as connected to the transmission network.

Carbon dioxide emissions from power stations

5.73 **It is estimated that carbon dioxide emissions from power stations accounted for 17.9 per cent of the UK's total carbon dioxide emissions in 2018**. The overall emissions per GWh of electricity generated decreased in 2018 as the mix of fuels used changed, moving away from coal-fired generation and generating more from gas and renewable sources.

5.74 Emissions vary by type of fuel used to generate the electricity and emissions estimates per unit of electricity generation for 2016 to 2018 are shown in Table 5E below.

Table 5E: Estimated carbon dioxide emissions per GWh of electricity supplied 2016 to 2018 [1,2]

Fuel	Emissions (tonnes of carbon dioxide per GWh electricity supplied)		
	2016	2017	2018[3]
Coal	935	919	920
Gas	378	352	349
All fossil fuels	504	464	450
All fuels (including nuclear and renewables)	268	227	208

1 The carbon intensity figures presented in Table 5D are different to those produced for the Greenhouse Gas Inventory (GHGI). The differences arise due methodology differences, including geographical coverage and treatment of autogenerators but are principally due to the GHGI presenting figures based on a 5-year rolling average whereas those in Table 5D are presented as single year figures.

2. The numerator includes emissions from power stations, with an estimate added for auto-generation. The denominator (electricity supplied by all generators) used in these calculations can be found in table 5.6, with the figure for All fuels in 2018 being 314,076 GWh.

3. The 2018 emissions figures are provisional.

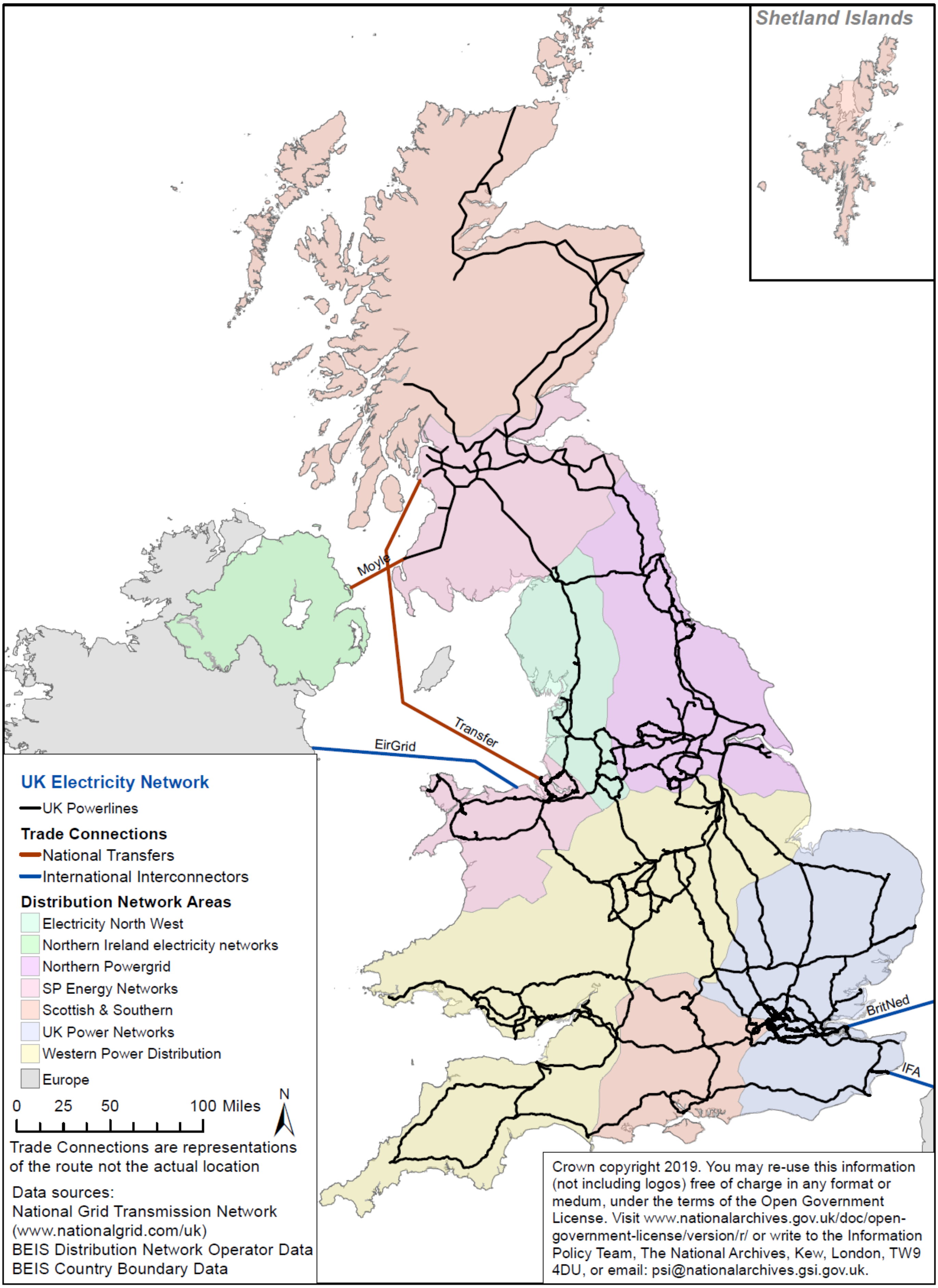
Sub-national electricity data

5.75 The collection of data relating to regional and local consumption of electricity began in 2004. For details of the availability of local level electricity (and gas) data see Chapter 4, paragraph 4.17 and the sub-national electricity statistics pages on the BEIS section of the GOV.UK website at: www.gov.uk/government/collections/sub-national-electricity-consumption-data. Data repeated here in previous editions of this publication as Table 5E are available via that link. The regional data will not sum exactly to the figures given in table 5.4 as the regional data are not based exactly on a calendar year and are obtained via different data sources.

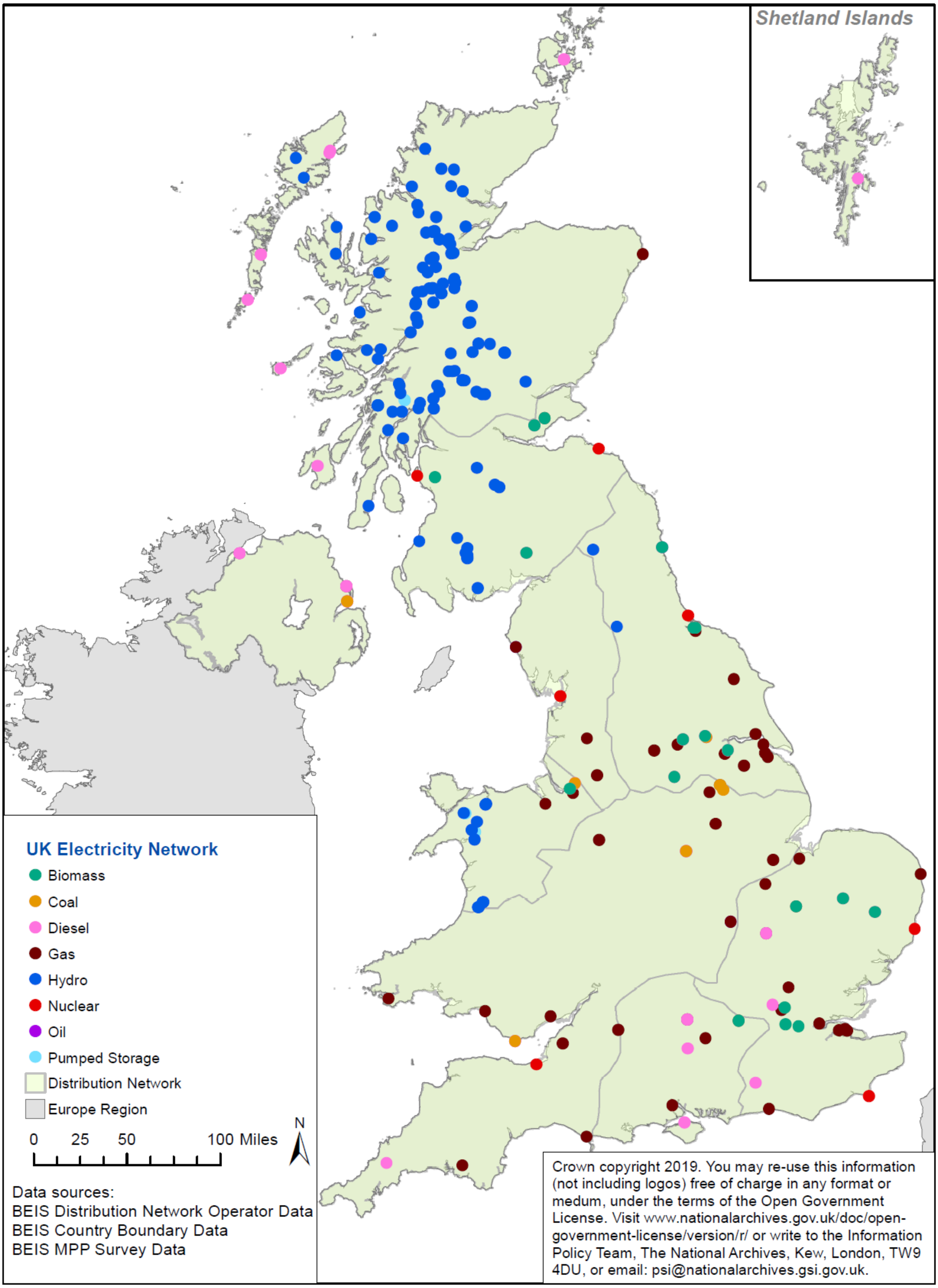
Electricity price and market penetration

5.76 Electricity price and market penetration data are published by BEIS in the Quarterly Energy Prices publication, available at: www.gov.uk/government/statistical-data-sets/quarterly-domestic-energy-price-statistics. Data on Domestic electricity market penetration, repeated here in previous editions of this publication as Table 5F, are available in table 2.4.1 of Quarterly Energy Prices.

UK Distribution Network Operating Areas and GB Power Lines Map



Major Power Producers in the UK (operational May 2019)



List of DUKES electricity tables

Table	Description	Period
5.1	Commodity balances for UK electricity	1998-2018
5.2	Commodity balances for electricity (separates out the *public* distribution system for electricity from the electricity generated and consumed by *autogenerators*)	1998-2018
5.3	Fuels used to generate electricity in the UK (by MPP/other and fuel)	1996-2018
5.4	Fuels consumed for electricity generation (autogeneration) by main industrial groups	1996-2018
5.5	Electricity supply, consumption and sales (links between DUKES tables and long-term trends data)	1996-2018
5.6	Electricity fuel use, generation and supply (by MPP/other and fuel type)	1996-2018
5.7	Plant capacity (MPPs, other and all, by type)	1996-2018
5.8	Major Power Producers Plant capacity (by region & type)	1999-2018
5.9	Capacity of other generators (by sector)	1996-2018
5.10	Plant loads, demand and efficiency	1996-2018
5.11	List of major power producers (power stations) in operation	May 2019
5.12	Plant installed capacity, by connection (GB, NI, by plant type)	2011-2018
	Long term trends commentary and tables on fuel use, generation, supply and consumption back to 1970 can be found on BEIS section of the GOV.UK website, at: www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes	1970-2018

Structure of the UK electricity industry

5.77 Up to March 2005 the electricity industries of Scotland, Northern Ireland and England and Wales operated independently although interconnectors joined all three grid systems together. From April 2005, under the British Electricity Trading and Transmission Arrangements (BETTA) introduced in the Energy Act 2004, the electricity systems of England and Wales and Scotland have been integrated. The paragraphs below describe the position up to March 2005 but indicate the further changes that have been made under BETTA.

5.78 From the period immediately after privatisation of the industry in 1990, when there were seven generating companies in England and Wales and 12 Regional Electricity Companies distributing and supplying electricity to customers in their designated area, there were many structural and business changes and residual flotations. Competition developed in mainland Britain as follows:

(a) From 1 April 1990, customers with peak loads of more than 1 MW (about 45 per cent of the non-domestic market) were able to choose their supplier;

(b) From 1 April 1994, customers with peak loads of more than 100 kW were able to choose their supplier;

(c) Between September 1998 and May 1999, the remaining part of the electricity market (i.e. below 100 kW peak load) was opened up to competition.

5.79 Since the late 1990s, there have been commercial moves toward vertical re-integration between generating, electricity distribution and/or electricity supply businesses. Those mergers that have taken place were approved by the relevant competition authority. Initially the National Grid Company was owned by the 12 privatised regional electricity companies but was floated on the Stock Exchange in 1995. National Grid (and its predecessors since 1990) has owned and operated the high voltage transmission system in England and Wales linking generators to distributors and some large customers. The transmission system is linked to continental Europe via an interconnector to France under the English Channel, and since 1 April 2011, to the Netherlands under the North Sea (see Table 5.10). Up to March 2005, the Scottish transmission system was regarded as being linked to that in England and Wales by two interconnectors but under BETTA National Grid also took on responsibility for operating the system in Scotland, to form a single Great Britain transmission network.

5.80 In Scotland, until the end of March 2005, the two main companies, Scottish Power and Scottish and Southern Energy, covered the full range of electricity provision. They operated generation, transmission, distribution and supply businesses. In addition, there were a number of small independent hydro stations and some independent generators operating fossil-fuelled stations, which sold their output to Scottish Power and Scottish and Southern Energy.

5.81 The electricity supply industry in Northern Ireland has been in private ownership since 1993 with Northern Ireland Electricity plc (NIE) (part of the Viridian Group) responsible for power procurement, transmission, distribution and supply in the Province. Generation is provided by three private sector companies who own the four major power stations. In December 2001, the link between Northern Ireland's grid and that of Scotland was inaugurated. A link between the Northern Ireland grid and that of the Irish Republic was re-established in 1996, along which electricity is both imported and exported. However, on 1 November 2007 the two grids were fully integrated and a joint body SEMO (Single Electricity Market Operator) was set up by SONI (System Operator for Northern Ireland) and Eirgrid from the Republic to oversee the new single market. In July 2012, an interconnector between the Irish Republic and Wales began operations.

5.82 In March 2001, the means of trading electricity changed with the introduction in England and Wales of the New Electricity Trading Arrangements (NETA). This replaced the Electricity Pool of England and Wales. These arrangements were based on bi-lateral trading between generators, suppliers, traders and customers. They were designed to be more efficient and provide greater choice for market participants, whilst maintaining the operation of a secure and reliable electricity system. The system included forwards and futures markets, a balancing mechanism to enable National Grid, as system operator, to balance the system, and a settlement process. In April 2005 this system was extended to Scotland under BETTA.

Technical notes and definitions

5.83 These notes and definitions are in addition to the technical notes and definitions covering all fuels and energy as a whole in Chapter 1. For notes on the commodity balances and definitions of the terms used in the row headings see Annex A, paragraphs A.7 to A.42. While the data in the PDF copy of this Digest cover only the most recent five years, these notes also cover data for earlier years that are available on the BEIS energy statistics website.

Electricity generation from renewable sources

5.84 Figures on electricity generation from renewable energy sources are included in the tables in this section. Further detailed information on renewable energy sources is included in Chapter 6.

Combined heat and power

5.85 Electricity generated from combined heat and power (CHP) schemes, CHP generating capacities and fuel used for electricity generation are included in the tables in this chapter. However, more detailed analyses of CHP schemes are set out in Chapter 7.

Generating companies

5.86 Following the restructuring of the electricity supply industry in 1990, the term "Major generating companies" was introduced into the electricity tables to describe the activities of the former nationalised industries and distinguish them from those of autogenerators and new independent companies set up to generate electricity. The activities of the autogenerators and the independent companies were classified under the heading "Other generating companies". In the 1994 Digest, a new terminology was adopted to encompass the new independent producers, who were then beginning to make a significant contribution to electricity supply. Under this terminology, all companies whose prime purpose is the generation of electricity are included under the heading "Major power producers" (or MPPs). The term "Other generators" (“Autogenerators” in the balance tables) is restricted to companies who produce electricity as part of their manufacturing or other commercial activities, but whose main business is not electricity generation. “Other generators” also covers generation by energy services companies at power stations on an industrial or commercial site where the main purpose is the supply of electricity to that site, even if the energy service company is a subsidiary of a MPP. Additionally (and particularly since 2010), this category includes generation from the domestic sector.

5.87 The definition of MPPs was amended in 2008 to include major wind farm companies, but this change only applies to data for 2007 onwards. Most generators of electricity from renewable sources (apart from large scale hydro, large scale wind, large scale solar and some biofuels) are also included as “Other generators” because of their comparatively small size, even though their main activity is electricity generation.

5.88 Major wind farm operators have been included under MPPs, for 2007 onwards, in the monthly, quarterly, and annual tables of electricity statistics produced by BEIS. Until then, all generation using wind turbines was excluded from the MPP classification. This was because originally such generation was by small independent companies and collecting data on a monthly basis was prohibitively costly and unnecessarily burdensome on such companies. Similarly, major solar site operators were included under MPPs for the first time in 2015.

5.89 Generation from wind has now become more concentrated in the hands of larger companies and BEIS has extended its system of monthly data collection to cover the largest wind power companies and, from 2015, solar. The intention is that, in future, any company whose wind generation capacity increases to above 50 MW will be asked to provide monthly data for generation from wind and thus be included in the list of MPPs.

5.90 The inclusion of major wind farm and solar site operators under MPPs affects the majority of the electricity tables in DUKES, with figures for MPPs and the public distribution system increased, and other generators reduced for 2007 onwards due to wind and from 2015 onwards due to solar.

5.91 **Major power producers at the end of 2018 were[25]:**

AES Electric Ltd., Anesco Ltd.†, Baglan Generating Ltd., BayWa R.E Ltd.*, Black Hill Wind Ltd.*, British Energy Generation Ltd., British Solar Renewables Ltd.†, Calon Energy Ltd., Carrington Power Ltd., Centrica Energy Ltd., CEP Wind 2 Ltd.*, Coolkeeragh ESB Ltd., Corby Power Ltd., Coryton Energy Company Ltd., Cubico Sustainable Investments Ltd.†, Drax Power Ltd., E.ON UK Plc.*, Ecotricity Ltd.*†, EDF Energy Ltd., EDF Energy Renewables Ltd.*, Eneco Wind UK Ltd.*†, EP Langage Ltd., EP SHB Ltd., Energy Power Resources Ltd., Falck Renewables Wind Ltd.*, Fellside Heat and Power Ltd., Ferrybridge Mulitfuel Energy Ltd., First Hydro Company, Fred Olsen Renewables Ltd.*, FS Shotwick Ltd.†, Greencoat Solar I LLP.*†, Greencoat UK Wind Plc.*, Indian Queens Power Ltd., John Laing Environmental Assets Group*, Kentish Flats Ltd.*†, Lightsource Renewable Energy Ltd.†, Londonwaste Ltd., Lynemouth Power Ltd., Magnox Electric Ltd., Marchwood Power Ltd., Octopus Investments Ltd.†, Orsted Burbo (UK) Ltd.*, Peel Energy Ltd.*, Pennant Walters Ltd.*†, Peterborough Power Ltd., REG Windpower Ltd.*†, Renewable Energy Solutions Services Ltd.†, Renewable Energy Systems Ltd.*†, Riverside Resource Recovery Ltd., Rocksavage Power Company Ltd., RWE Npower Ltd., RWE Npower Renewables Ltd.*, Saltend Cogeneration Company Ltd., Scira Offshore Energy Ltd.*, Scotia Wind (Craigengelt) Ltd.*†, Scottish & Southern Energy plc.*†, Scottish Power Plc., Scottish Power Renewables UK Ltd.*, Seabank Power Ltd., SembCorp Utilities (UK) Ltd., Severn Power Ltd., Slough Heat and Power Ltd., South East London Combined Heat and Power Ltd., Spalding Energy Company Ltd., Statkraft Energy Ltd., Statkraft Wind UK Ltd.*, SUEZ Recycling and Recovery (UK) Ltd., Temporis Capital Ltd.*, Third Energy UK Gas Ltd., Toucan Energy Services Ltd.†, Uniper UK Ltd., Ventient Energy Services Ltd.*, Viridor Waste Management Ltd., VPI Immingham LLP., Wadlow Energy Ltd.*, Willmount Ltd.*, Wise Energy Ltd.†, WPO UK Services Ltd.* and XceCo Ltd.*

25 ** company reports wind generation and † company reports solar generation*

5.92 **Major wind farm companies were added to the list of MPPs in 2007. At the end of 2018 these comprised:**
BayWa R.E Ltd., Black Hill Wind Ltd.*, CEP Wind 2 Ltd., E.ON UK Plc., Ecotricity Ltd., EDF Energy Renewables Ltd., Eneco Wind UK Ltd., Falck Renewables Wind Ltd., Fred Olsen Renewables Ltd., Greencoat Solar I LLP., Greencoat UK Wind Plc., John Laing Environmental Assets Group, Kentish Flats Ltd., Lightsource Renewable Energy Ltd., Orsted Burbo (UK) Ltd., Peel Energy Ltd., Pennant Walters Ltd., REG Windpower Ltd., Renewable Energy Systems Ltd., RWE Npower Renewables Ltd., Scira Offshore Energy Ltd., Scotia Wind (Craigengelt) Ltd., Scottish & Southern Energy plc., Scottish Power Renewables UK Ltd., Statkraft Wind UK Ltd., Temporis Capital Ltd., Ventient Energy Services Ltd., Wadlow Energy Ltd., Willmount Ltd., WPO UK Services Ltd., XceCo Ltd.

5.93 **Major solar farm companies were added to the list of MPPs in 2016. At the end of 2018 these comprised:**
Anesco Ltd., British Solar Renewables Ltd., Cubico Sustainable Investments Ltd., Ecotricity Ltd., Eneco Wind UK Ltd., FS Shotwick Ltd., Greencoat Solar I LLP., Kentish Flats Ltd., Lightsource Renewable Energy Ltd., Octopus Investments Ltd., Pennant Walters Ltd., REG Windpower Ltd., Renewable Energy Solutions Services Ltd., Renewable Energy Systems Ltd., Scotia Wind (Craigengelt) Ltd., Scottish & Southern Energy plc., Toucan Energy Services Ltd., Wise Energy Ltd.

Types of station

5.94 The various types of station identified in the tables of this chapter are as follows:

Conventional steam stations are stations that generate electricity by burning fossil fuels to convert water into steam, which then powers steam turbines.

Nuclear stations are also steam stations but the heat needed to produce the steam comes from nuclear fission.

Gas turbines use pressurised combustion gases from fuel burned in one or more combustion chambers to turn a series of bladed fan wheels and rotate the shaft on which they are mounted. This then drives the generator. The fuel burnt is usually natural gas or gas oil.

Combined cycle gas turbine (CCGT) stations combine in the same plant gas turbines and steam turbines connected to one or more electrical generators. This enables electricity to be produced at higher efficiencies than is otherwise possible when either gas or steam turbines are used in isolation. The gas turbine (usually fuelled by natural gas or oil) produces mechanical power (to drive the generator) and waste heat. The hot exhaust gases (waste heat) are fed to a boiler, where steam is raised at pressure to drive a conventional steam turbine that is also connected to an electrical generator.

Natural flow hydro-electric stations use natural water flows to turn turbines.

Pumped storage hydro-electric stations use electricity to pump water into a high level reservoir. This water is then released to generate electricity at peak times. Where the reservoir is open, the stations also generate some natural flow electricity; this is included with natural flow generation. As electricity is used in the pumping process, pumped storage stations are net consumers of electricity.

Wind farms use wind flows to turn turbines.

Other stations include stations burning fuels such as landfill gas, sewage sludge, biomass and waste.

Electricity supplied – input and output basis

5.95 The energy supplied basis defines the primary input (in million tonnes of oil equivalent, Mtoe) needed to produce 1 TWh of hydro, wind, or imported electricity as:

$$\text{Electricity generated (TWh)} \times 0.085985$$

The primary input (in Mtoe) needed to produce 1 TWh of nuclear electricity is similarly

$$\frac{\text{Electricity generated (TWh)} \times 0.085985}{\text{Thermal efficiency of nuclear stations}}$$

5.96 Figures on fuel use for electricity generation can be compared in two ways. Table 5.3 illustrates one way by using the volumes of **fuel input** to power stations (after conversion of inputs to an oil equivalent basis), but this takes no account of how efficiently that fuel is converted into electricity. The fuel input basis is the most appropriate to use for analysis of the quantities of particular fuels used in electricity generation (e.g. to determine the additional amount of gas or other fuels required as coal use declines under tighter emissions restrictions). A second way uses the amount of electricity generated and supplied by each fuel. This **output** basis is appropriate for comparing how much, and what percentage, of electricity generation comes from a particular fuel. It is the most appropriate method to use to examine the dominance of any fuel and for diversity issues. Percentage shares based on fuel outputs reduce the contribution of coal and nuclear, and increase the contribution of gas (by one percentage point in 2018) compared with the fuel input basis. This is because of the higher conversion efficiency of gas. Fuel input is set to match electricity output for non-thermal renewables.

Public distribution system

5.97 This comprises the grid systems in England and Wales, Scotland and Northern Ireland. In April 2005 the Scotland and England and Wales systems were combined into a single grid.

Sectors used for sales/consumption

5.98 The various sectors used for sales and consumption analyses are standardised across all chapters of the 2016 Digest. For definitions of the sectors see Chapter 1 paragraphs 1.57 to 1.61 and Annex A paragraphs A.31 to A.42.

Losses

5.99 The losses component of electricity demand are calculated as follows:

Transmission losses: electricity lost as a percentage of electricity entering the GB transmission system (as reported by National Grid); this is applied to the electricity available figure in DUKES 5.5 (334,058 GWh in 2018).

Distribution losses: electricity lost in distribution as a percentage of electricity entering the distribution system (as reported by the distribution network operators); this is applied to electricity available less transmission losses.

Theft: a fixed percentage of 0.3 per cent is assumed to be stolen from the distribution network. This is applied to electricity available less transmission losses.

Transmission Entry Capacity, Declared Net Capacity and Installed Capacity

5.100 Transmission Entry Capacity (TEC) is a Connection and Use of System Code term that defines a generator's maximum allowed export capacity onto the transmission system. In the generating capacity statistics of the 2007 Digest, it replaced Declared Net Capacity (DNC) as the basis of measurement of the capacity of Major Power Producers from 2006. DNC is the maximum power available for export from a power station on a continuous basis minus any power generated or imported by the station from the network to run its own plant. It represents the nominal maximum capability of a generating set to supply electricity to consumers. The maximum rated output of a generator (usually under specific conditions designated by the manufacturer) is referred to as its Installed Capacity. For the nuclear industry, the World Association of Nuclear Operators (WANO) recommends that capacity of its reactors is measured in terms of Reference Unit Power (RUP) and it is the RUP figure that is given as the installed capacity of nuclear stations.

5.101 DNC is used to measure the maximum power available from generating stations that use renewable resources. For wind and wave and small scale hydro a factor is applied to declared net capability to take account of the intermittent nature of the energy source (e.g. 0.43 for wind, 0.365 for small scale hydro and 0.17 for solar photovoltaics). Further information on this can be found at: www.legislation.gov.uk/uksi/1990/264/made?view=plain

Load factors

5.102 The following definitions are used in Table 5.10:

Maximum load – This is twice the largest number of units supplied in any consecutive thirty minutes commencing or terminating at the hour.

Simultaneous maximum load met – The maximum load on the transmission network at any one time, net of demand met by generation connected to the distribution network. From 2005 (following the introduction of BETTA – see paragraph 5.77) it is measured by the sum of the maximum load met in Great Britain and the load met at the same time in Northern Ireland. Prior to 2005 it was measured by the sum of the maximum load met in England and Wales and the loads met at the same time by companies in other parts of the United Kingdom.

Plant load factor – The average hourly quantity of electricity supplied during the year, expressed as a percentage of the average output capability at the beginning and the end of year.

System load factor – The average hourly quantity of electricity available during the year expressed as a percentage of the maximum demand nearest the end of the year or early the following year.

Thermal efficiency

5.103 Thermal efficiency is the efficiency with which heat energy contained in fuel is converted into electrical energy. It is calculated for fossil fuel burning stations by expressing electricity generated as a percentage of the total energy content of the fuel consumed (based on average gross calorific values). For nuclear stations it is calculated using the quantity of heat released as a result of fission of the nuclear fuel inside the reactor. The efficiency of CHP systems is illustrated in Chapter 7, Table 7D. Efficiencies based on gross calorific value of the fuel (sometimes referred to as higher heating values or HHV) are lower than the efficiencies based on net calorific value (or lower heating value LHV). The difference between HHV and LHV is due to the energy associated with the latent heat of the evaporation of water products from the steam cycle which cannot be recovered and put to economic use.

Period covered

5.104 Until 2004, figures for the MPPs relate to periods of 52 weeks as listed below (although some data provided by electricity supply companies related to calendar months and were adjusted to the statistical calendar). In 2004, a change was made to a calendar year basis. This change was made in the middle of the year and the data are largely based on information collected monthly. The January to May 2004 data are therefore based on the 21 weeks ended 29 May 2004 and the calendar months June to December 2004, making a total of 361 days. In terms of days, 2004 is therefore 1.1 per cent shorter than 2005:

Year	**52 weeks ended**
2003	28 December 2003
2004	21 weeks ended 29 May 2004 and 7 months ended 31 December 2004
2005 – 2018:	12 months ended 31 December

5.105 Figures for industrial, commercial and transport undertakings relate to calendar years ending on 31 December, except for the iron and steel industry where figures relate to the following 52 or 53 week periods:

Year	53 weeks ended
2003	3 January 2004
	52 weeks ended
2004	1 January 2005
2005	31 December 2005
2006	30 December 2006
2007	29 December 2007
2008	27 December 2008
	53 weeks ended
2009	2 January 2010
	52 weeks ended
2010	1 January 2011
2011	31 December 2011
2012	29 December 2012
2013	28 December 2013
2014	27 December 2014
	53 weeks ended
2015	2 January 2016
	52 weeks ended
2016	31 December 2016
2017	30 December 2017
2018	29 December 2018

Monthly and quarterly data

5.106 Monthly and quarterly data on fuel use, electricity generation and supply and electricity availability and consumption are available on the BEIS section of the GOV.UK website at: www.gov.uk/government/collections/electricity-statistics. Monthly data on fuel used in electricity generation by MPPs are given in Monthly Table 5.3 and monthly data on supplies by type of plant and type of fuel are given in Monthly Table 5.4. Monthly data on availability and consumption of electricity by the main sectors of the economy are given in Monthly Table 5.5. A quarterly commodity balance for electricity is published in BEIS's quarterly statistical bulletin *Energy Trends* (Quarterly Table 5.2) along with a quarterly table of fuel use for generation, electricity generated, and electricity supplied by all generators (Quarterly Table 5.1). Both these quarterly tables are also available from BEIS's energy statistics web site. See Annex C for more information about *Energy Trends*.

Data collection

5.107 For MPPs, as defined in paragraphs 5.87 to 5.94, the data for the tables in this Digest are obtained from the results of an annual BEIS inquiry, sent to each company, covering generating capacity, fuel use, generation and sales of electricity (where a generator also supplies electricity).

5.108 Similarly, an annual inquiry is sent to licensed suppliers of electricity to establish electricity sales by these companies. Electricity consumption for the iron and steel sector is based on data provided by the Iron and Steel Statistics Bureau (ISSB) rather than electricity suppliers since electricity suppliers tend to over-estimate their sales to this sector by including some companies that use steel rather than manufacture it. The difference between the ISSB and electricity suppliers' figures has been re-allocated to other sectors. A further means of checking electricity consumption data is now being employed on data for 2006 and subsequent years. A monthly inquiry is sent to electricity distributors, as well as the National Grid, to establish electricity distribution and transmission losses. Copies of the survey questionnaires are available in *electricity statistics: data sources and methodologies*, at: www.gov.uk/government/collections/electricity-statistics.

5.109 A sample of companies that generate electricity mainly for their own use (known as autogenerators or autoproducers – see paragraph 5.87, above) is covered by a quarterly inquiry commissioned by BEIS but carried out by the Office for National Statistics (ONS). Where autogenerators operate a combined heat and power (CHP) plant, this survey is supplemented (on an annual basis) by information from the CHP Quality Assessment scheme (for autogenerators who have registered under the scheme – see Chapter 7 on CHP). There are two areas of autogeneration that are covered by direct data collection by BEIS, mainly because the return contains additional energy information needed by the Department. These are the Iron and Steel industry, and generation on behalf of London Underground.

5.110 In addition to the above sources, some administrative data is used for renewable generation and capacity in the hands of non-major power producers - this includes data from the Renewables Obligation and Feed in Tariff schemes.

Statistical differences

5.111 Statistical differences are included in Tables 5.1 and 5.2. These arise because data collected on production and supply do not match exactly with data collected on sales or consumption. One of the reasons for this is that some of the data are based on different calendars as described in paragraphs 5.105 and 5.106, above. Sales data based on calendar years will always have included more electricity consumption than the slightly shorter statistical year of exactly 52 weeks.

5.112 Care should be exercised in interpreting the figures for individual industries in the commodity balance tables. Where companies have moved between suppliers, it has not been possible to ensure consistent classification between and within industry sectors and across years. The breakdown of final consumption includes some estimated data. In 2014, for about five per cent of consumption of electricity supplied by the public distribution system, the sector figures are partially estimated.

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