January to March 2017

Electric Insights Quarterly

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Demand & price
Demand 37.7GW
Price £46.25/MWh
Environment
Emissions 285g/kWh
Temperature 6.9°C
Supply
Coal 4.5GW
Gas 15.4GW
Solar 0.7GW
Wind 5.2GW
Hydro 0.7GW
Imports & storage 2.3GW
Biomass 2.1GW
Nuclear 7.6GW
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What is the production breakdown of All sources
Price: £33.95/MWh
Demand: 31 GW
Temperature: 11.6°C
Emissions: 163g/kWh
Coal: 1.6 GW 5.1%
Gas: 8 GW 25.4%
Solar: 0.8 GW 2.6%
Wind: 8.8 GW 27.7%
Hydro: 1 GW 3%
Imports & storage: 2.5 GW 7.8%
Biomass: 2.1 GW 6.5%
Nuclear: 6.9 GW 22%
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Headlines & summary

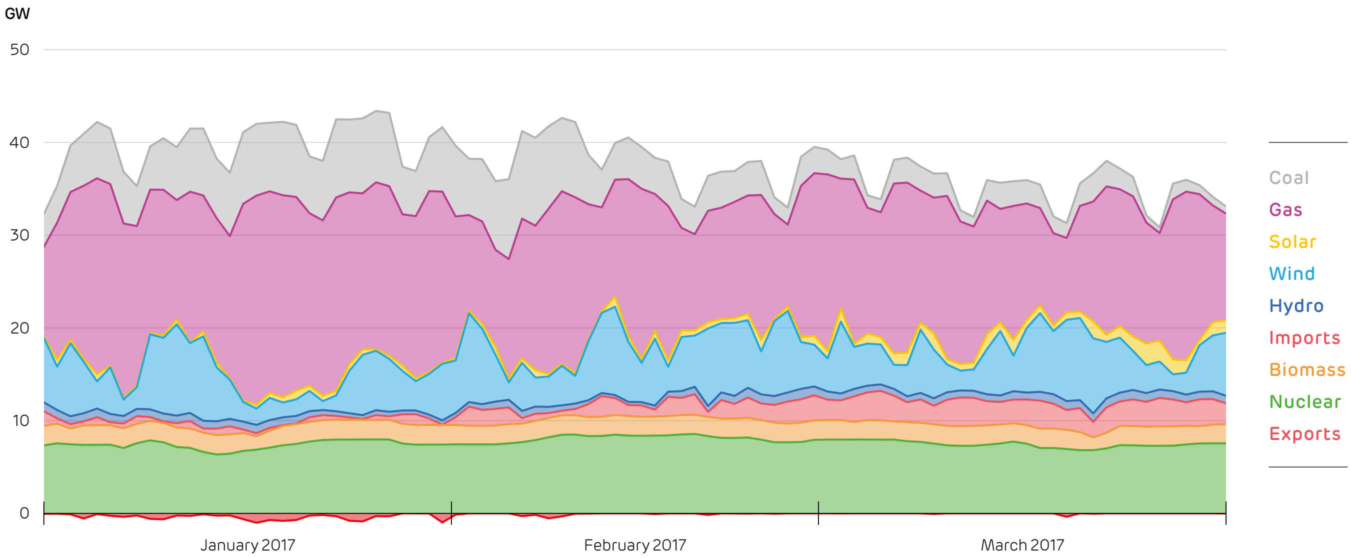
This quarter's issue looks at how the weather is increasingly affecting the power system. Britain's renewables are once again breaking records, with Quarter 1 seeing wind, biomass and hydro all register their highest energy production (see Article 2). At the end of March, solar also recorded its highest ever peak output, reducing demand on the national grid so far that afternoon demand fell below overnight levels for the first time ever. Article 3 explores how solar power affects the rest of the system, and how power stations are having to change their daily schedules in response.

Coal output fell 30% from this time last year due to high wind output and the mild winter. Carbon emissions were 10% lower than in Q1 2016 as a result. Britain's electricity has changed so radically that the generation mix in the dirtiest hour of this quarter was lower carbon than the average electricity produced between 2009 and 2013 (see Article 4).

The weather is also changing the gross consumption of electricity. Britain experienced another mild winter, reducing the need for electric heat in homes and workplaces. Article 5 looks at how this saves both money and carbon, but cannot be relied on to keep the lights on when capacity is in short supply.

The growth of weather-driven renewables and the increasing volatility of power prices have made the timing of electricity production more important and highly valued. Article 6 explores how much the market pays for electricity from different technologies, and why electricity from flexible and controllable generators is worth more.
Finally, Article 7 summarises the statistics for the quarter.

Daily average generation mix during the first quarter of 2017



New records for renewables

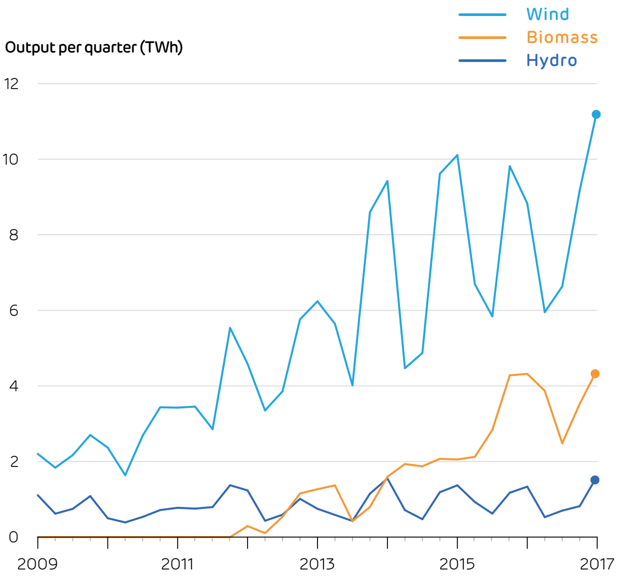
All forms of renewable energy had a record breaking quarter to start off the year. Britain's wind farms made the news for recording their highest ever quarterly output. Behind the scenes, biomass and hydro power stations also produced more than ever before, and solar power reached a new high for its peak output.

The weather helped wind farms to beat the previous production record (set in 2015) by more than 10%, generating 11.3 TWh over the quarter. Half of this gain came from new farms being built, as installed capacity grew 5% in the last year. Wind farms produced more electricity than coal on 57 out of the 90 days this quarter, and wind power has now beaten coal over the last four consecutive quarters.

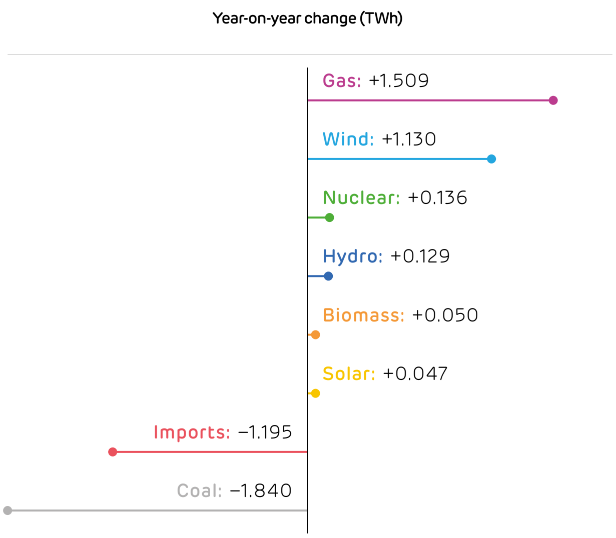
Biomass hit a new high of 4.4 TWh, meaning the fleet ran at 95% of full capacity over the quarter: higher than any other technology has achieved in the last 10 years.[1] Hydro power also had a record quarter hitting 1.6 TWh; 4% above its previous best in 2014. Finally, at the end of March solar reached a new peak output of 7.67 GW – enough to power a fifth of the country at the time.

Compared with last year, gas power stations saw the biggest increase in output, followed closely by wind. Coal was the biggest loser, down by 30% on last year, and imports from France were also much lower as the damaged interconnector didn't return to full power until February. The net impact of all these changes was a 2.6 million tonne fall in CO_2 emissions.

The total energy production from renewables which broke their production records in Q1 2017



The change in output from all technologies between Q1 last year and this year



1 Britain's nuclear fleet rarely exceeds 85% availability due to its age. The coal and gas fleets typically produce 30–60% of their full capacity over the year as their output varies in line with demand; the whole fleet only runs close to full output at peak times.

Disappearing daytime demand

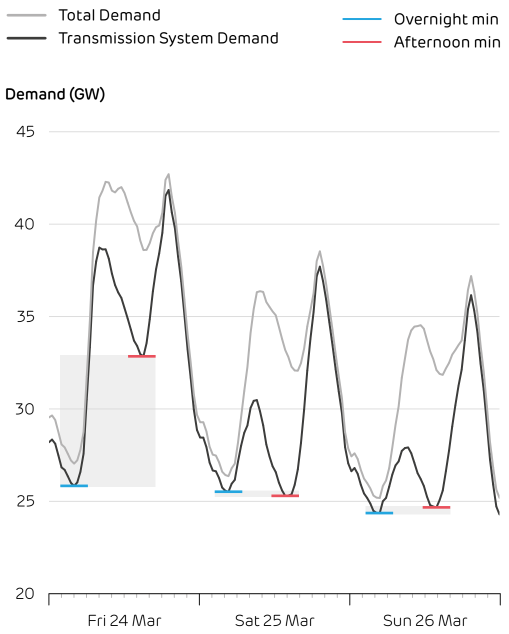
In the last weekend of March demand on the national grid was lower during the daytime than it was overnight – the first time this has ever happened. Prior to solar power becoming widespread, minimum demand was always seen during the night. Daytime demand never came within 5 GW of the night-time minimum; but in 2015 the gap narrowed to 2.4 GW, and on the 25th of March it disappeared completely.

Solar panels and smaller onshore wind farms are 'invisible' as they do not connect into the transmission system. Distributed solar panels carve a large chunk of demand out of the middle of the day, reducing the need for major power stations. But the sun isn't shining when factories and offices power up in the morning, or when people settle down at home for the evening. During March, demand net of renewables was 2.3 GW higher at 9 AM than at 1 PM, when solar panels reach their peak output. This gap will likely double by June based on data from past years. This effect is splitting the long daytime plateau (grey line in the chart, below left) into two separate peaks (black line).

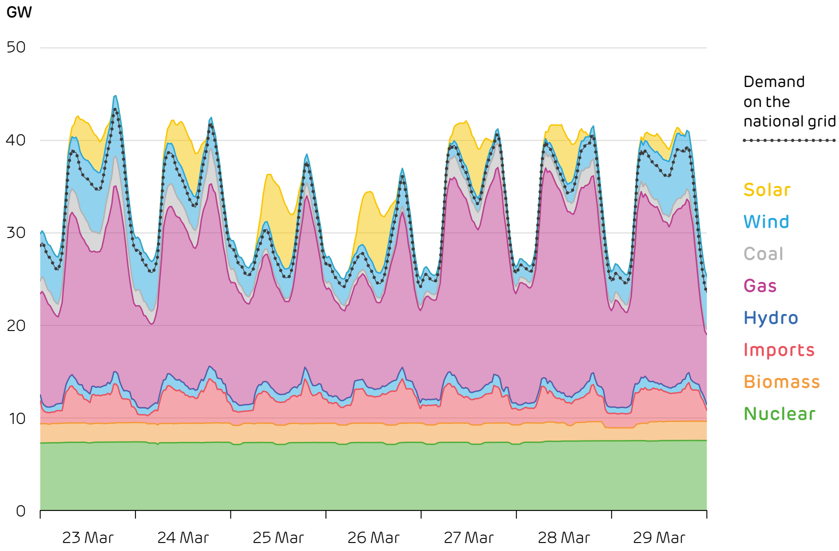
Power stations are having to change their operating patterns to cope with this. Many stations 'two shift', turning on in the morning and off again at night. These might have to start up twice a day ('double two shifting' perhaps) to cope with separate peaks. 5 GW of gas stations are already turning down in the middle of the day, soon they may have to start turning off completely.

Flexibility is needed at short notice in the morning and evening peaks due to the speed of ramping up and down, the short duration of the peak, and the fact that solar output is still relatively hard to forecast in advance. Technologies that are flexible and offer rapid response, such as gas or battery storage, will help accommodate these changes.

Total demand for electricity versus demand seen on the transmission system (which excludes solar and some wind power)



Electricity supply and demand over the last week of March. The dotted line gives the demand that is 'seen' on the transmission system. The wind and solar output above this line is 'invisible' to the grid



Britain's continuing decarbonisation

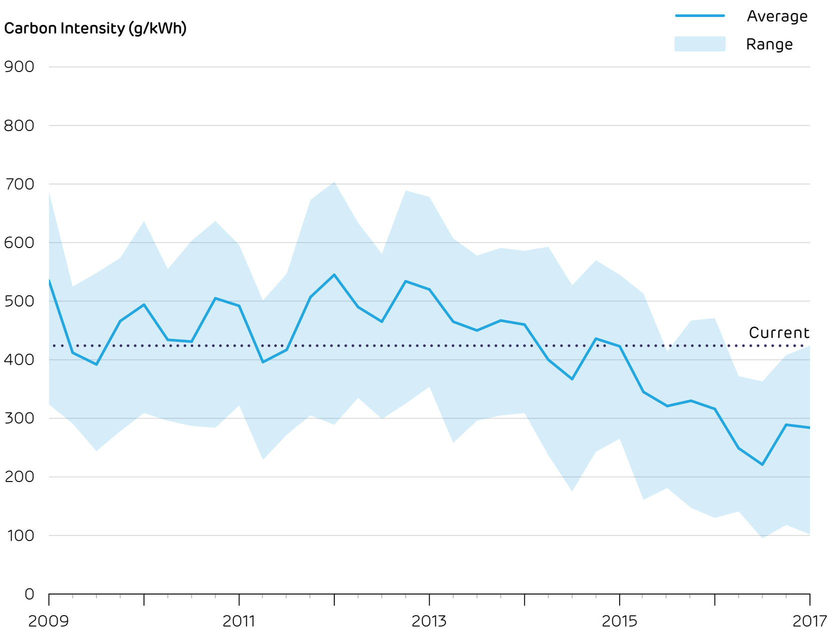
Q1 carbon emissions from electricity generation are down 10% on last year and 33% on the year before. As a sign of just how far British electricity has changed, the 'dirtiest hour' in the whole of this winter was lower carbon than the average generation mix just three years ago.

The carbon intensity of electricity averaged 284 g/kWh this quarter. It ranged from just 102 g/kWh on a windy Sunday night in March to 424 g/kWh on a cold and calm January evening when coal output was high. 424 grams of CO_2 would have seemed clean just a few years ago: the average from 2009 to 2013 was 471 g/kWh. Now it is the extremity.

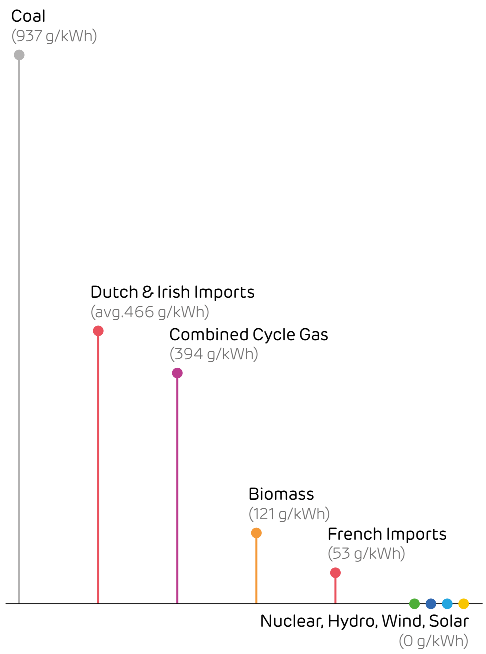
Since 2013, the carbon intensity of electricity has fallen by 66 g/kWh each year. The reason for this is clear in the chart below: coal stands out as by far the highest-carbon source of electricity, but coal output has fallen 82% in the last four years. The 21st of April was the first time since 1882 that Britain burnt no coal for electricity all day.

Coal has been replaced by mid-carbon gas, low-carbon biomass and imports, and zero-carbon wind and solar. Together these have driven electricity decarbonisation in line with (or even slightly ahead of) the country's decarbonisation targets – which are the most ambitious in the world.

The carbon content per unit of electricity consumed in Britain, showing the average and range in each quarter



Average carbon intensity from each generation source



The mild winter windfall

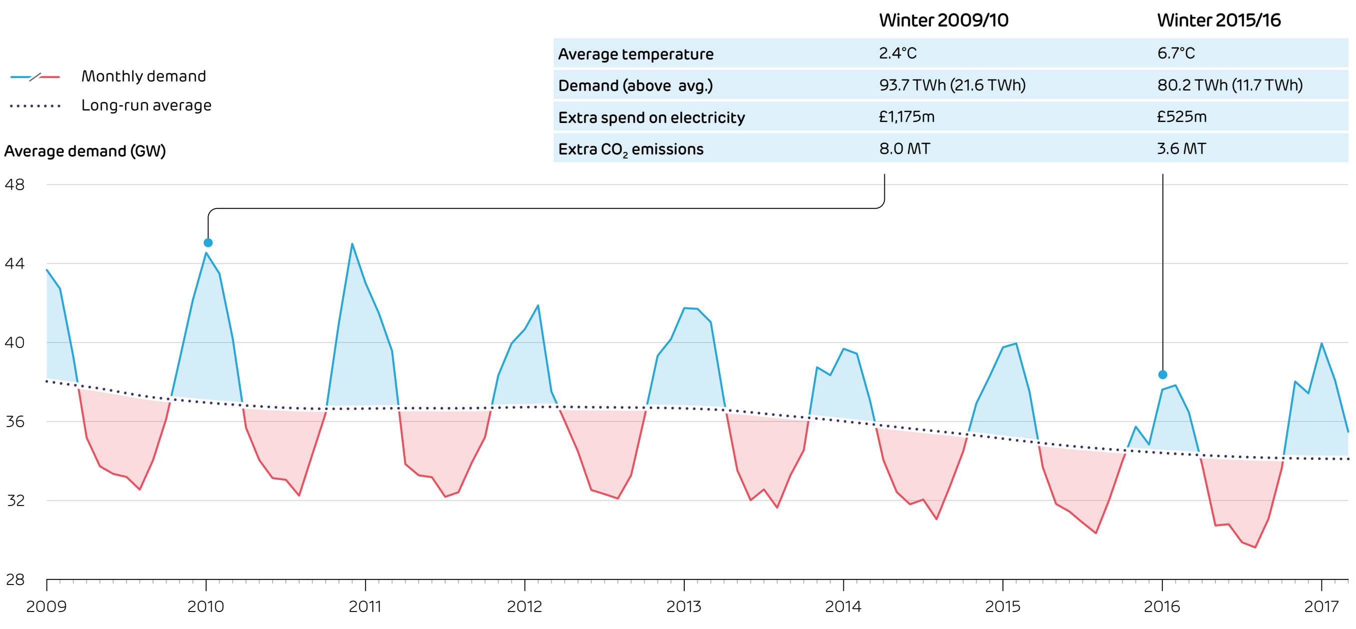
Britain has again experienced a mild winter, keeping down electricity bills and carbon emissions. 2017 has so far been 1.9°C warmer than the 20th century average, lowering the country's demand for electric heating.

Similarly, winter 2015/16 was the mildest for 150 years, meaning electricity demand over the winter months was just 12 TWh higher than in the neighbouring summers.[2] In contrast, demand was 26 TWh higher in the winter of 2009/10, which was the coldest for a generation. Comparing these, over 14 TWh of electricity didn't need to be generated in 2015/16 because of the mild weather, in addition to savings from efficiency and other factors that brought the long-term average down.

This mild weather translates into a windfall of around £650 million that didn't need to be spent on generating electricity.[3] Most of this reduced consumption comes from households and businesses – so the saving to end consumers would be at least double this, as they pay more per unit of electricity. The environment also benefits, as CO_2 emissions were 4.4 MT lower thanks to the weather.[4]

Mild winters also reduce the peak demand for electricity. This has fallen from 60.1 GW in 2009/10 to just 52.0 GW in 2015/16, making it easier to 'keep the lights on' at a time when much of the country's capacity is retiring. Britain's weather is far from reliable though, so demand can change drastically from one winter to the next.

Monthly average electricity demand, highlighting the deviation from the long-run average during the colder (blue) and warmer (red) months



	Winter 2009/10	Winter 2015/16
Average temperature	2.4°C	6.7°C
Demand (above avg.)	93.7 TWh (21.6 TWh)	80.2 TWh (11.7 TWh)
Extra spend on electricity	£1,175m	£525m
Extra CO_2 emissions	8.0 MT	3.6 MT

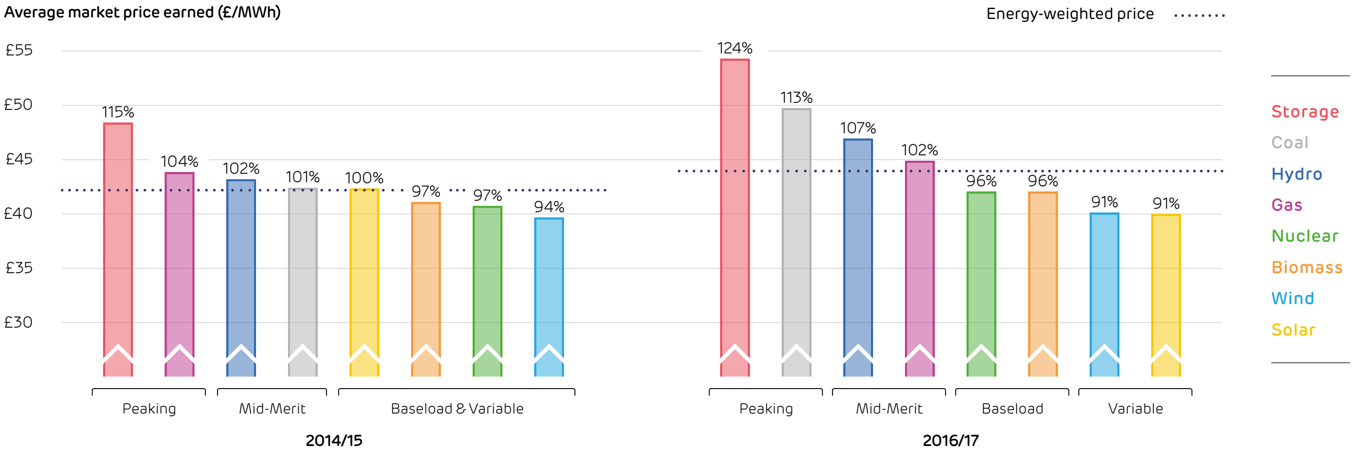
2 Dec 2015 to Feb 2016 compared with Jun-Aug 2015 and Jun-Aug 2016.
3 Assuming a long-term average day-ahead price of £45/MWh.
4 Assuming a constant average carbon intensity of 305 g/kWh (the average during winter 2015/16), to avoid miscounting the effect of carbon intensity falling since 2009/10.

What are different electricity sources worth?

People often assess the economics of power stations with their Levelised Cost of Electricity, but it also matters how and when the electricity is produced.[5] The growing share of weather-dependent renewables means that flexible and controllable capacity is now more valuable to the system. As power prices become more volatile, the range of prices earned by different technologies is widening.

The bar chart below shows the average day-ahead market price, weighted by the half-hourly output of each technology. Rather than showing the cost of production, this shows what electricity from each technology is 'worth' to the system.[6] Over the last two years, the average wholesale price has barely changed, but the premium for producing electricity when it is most needed is growing, as is the penalty for producing when it is not wanted.

The output-weighted price for different technologies on the spot market in the four quarters to Q1 2015 (left) and to Q1 2017 (right). Percentages show the technology earnings relative to the energy-weighted price[7]



The range of prices that technologies command can be explained by the different roles they play. Peaking plants run only when demand (and price) is highest, as they need to cover their start-up and running costs. Mid-merit plants instead run most of the time, flexing up and down in line with demand. Coal recently switched from being mid-merit to peaking as it was undercut by gas, and so their positions change between the two charts.

Baseload plants run day and night regardless of price. Nuclear reactors cannot turn down easily, and although biomass plants are flexible they choose to run baseload because of the support they receive. Wind and solar push down power prices when their output is high, even sending prices negative when they produce too much for the grid to handle. Understandably, they earn less than average once a large capacity is installed.

Prices on the wholesale market price are one thing; but the costs of transmission, balancing and providing peak capacity means the whole-system cost of providing the electricity we use is altogether different. The key to restraining this overall cost is having a good balance of technologies to choose from.

5 The Levelised Cost of Electricity (LCOE) divides a station's total capital and operating costs (discounted over time to reflect interest) by the discounted value of its output to give a single measure of its average cost.
6 This is not what each technology actually earned as only 5% of power is traded on the spot market at these prices. Most power is bought and sold on long term contracts months ahead of delivery (at prices not made public).
7 The time-weighted price (average of all half-hourly prices in a year) is what people see as the average price; but the energy-weighted price (each half-hour's price multiplied by the amount of electricity consumed) is what they end up paying. The energy-weighted price is 4% higher than time-weighted.

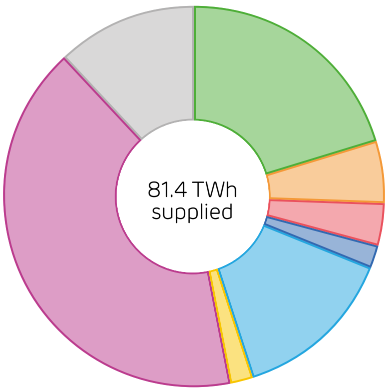
Capacity and production statistics

Following their problems last quarter, the French interconnector and nuclear fleet returned to normal, so imports gradually rose over February and hit an 12-month high in March averaging 2.9 GW (1.8 GW of which from France). Coal fell from 16% to 6% of the supply mix over February as imports rose and demand fell.

Coal output is down nearly 30%; not because plants are seeing lower utilisation, rather because three tenths of the fleet have retired in the last year. In their place, 3.2 GW of new renewables came online in the past year, predominantly solar power.

Power prices settled down from the volatility of previous quarters, suggesting the market was not so tight. They averaged £47/MWh and ranged from –£14 to £293 over the quarter.[8]

Britain's electricity supply mix in the first quarter of 2017



	Output (TWh)	% of mix
Nuclear	16.5	20.2%
Biomass	4.4	5.4%
Imports	3.0	3.7%
Hydro	1.6	2.0%
Wind	11.3	13.9%
Solar	1.5	1.9%
Gas	33.3	40.9%
Coal	9.7	11.9%

Installed capacity and electricity produced by each technology in the first quarter of 2017

	Installed Capacity (GW)	Annual change	Energy Output (TWh)	Annual change	Utilisation / Capacity Factor	Annual change[9]
Nuclear	9.5	–0.4 (–4%)	16.5	+0.3 (+2%)	81%	+5%
Biomass	2.2	~	4.4	+0.1 (+3%)	95%	+3%
Hydro	1.1	~	1.6	+0.3 (+21%)	69%	+13%
Wind	15.2	+0.7 (+5%)	11.3	+2.5 (+28%)	43%[10]	+7%
Solar	11.6	+2.4 (+25%)	1.5	+0.1 (+7%)	6%	–1%
Gas	28.4	+0.6 (+2%)	33.3	+3.3 (+11%)	55%	+5%
Coal	14.0	–4.3 (–28%)	9.7	–4.0 (–29%)	32%	–2%
Imports	4.0	~	4.2	–2.2 (–34%)	49%	–25%
Exports			1.0	+0.6 (+124%)	12%	+7%
Storage[11]	3.1	+0.1 (+4%)	0.7	+0.0 (+2%)	11%	~

8 Day-ahead prices averaged £47/MWh also, and ranged from £5 to £148.
9 In absolute percentage points.
10 See the methodology note in last quarter's issue for how wind capacity factors are adjusted, as the output data from National Grid and Elexon may not cover the entire fleet. The raw data from National Grid and Elexon suggests that the capacity factor for wind was 34.7% over Q1 2017, versus 28.3% over Q1 2016.
11 In previous quarters, pumped hydro storage was included with run-of-river hydro.

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