drax

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Electric Insights Quarterly

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Electric Insights was established by Drax to help inform and enlighten the debate on Britain's electricity. Since 2016 it has been delivered independently by a team of academics at Imperial College London using data courtesy of Elexon, National Grid and Sheffield Solar.

1. Introduction

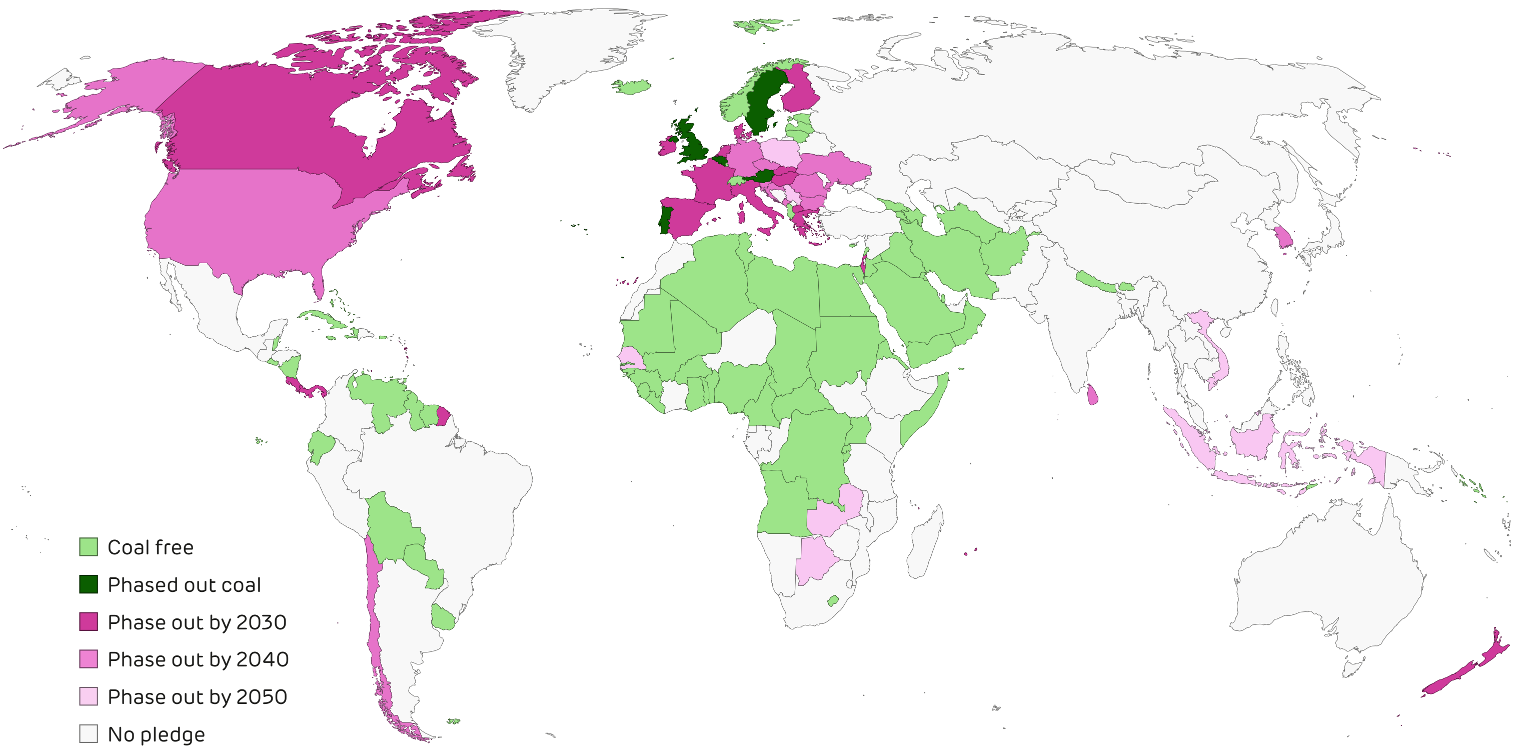
The UK made headlines around the world as the first major economy to completely phase out coal power. This marks the end of over a century of industrial history and another step on the road to net zero. But eliminating coal power is only one part of the challenge. Coal is still used in other parts of the economy, and is burned abroad to produce the things we import. It is also not the only high-carbon fossil fuel: phasing down natural gas is the next big step for the power sector, but that will be much harder.

Achieving the country's ambitions for a clean power system by 2030 will need immense investment in supporting infrastructure to cope with more supply from variable renewables and more demand from electric vehicles, heat pumps, data centres, and the like. This quarter saw the official launch of Eastern Green Link 2, a new interconnector between Scotland and England that will reduce stress on the transmission system. However, the chronic problem of delays in securing a grid connection remains a major obstacle.

Wholesale power prices rose 6% from the previous quarter, averaging £68/MWh between July and September. However, this is 27% lower than the same period last year. Balancing prices are moving in the opposite direction, up 21% year-on-year to nearly £12/MWh. Balancing now adds one-sixth to the cost of generating electricity, three times its share over the last decade. Although constraints caused by lack of transmission capacity form the majority of balancing costs, appearances can be deceiving. New rules around charging and setting fixed balancing prices have driven this rise.

The new government continued its string of energy sector announcements, pledging £22 billion towards carbon capture and storage (CCS) projects and approving several large solar farms. The National Energy System Operator (NESO) was launched to coordinate planning and operation across electricity and gas systems. With profound changes needed in the coming years, they will face interesting times.

62 countries have committed to phase out coal power by mid-century or have already stopped using it for electricity generation. Data from Xie et al.



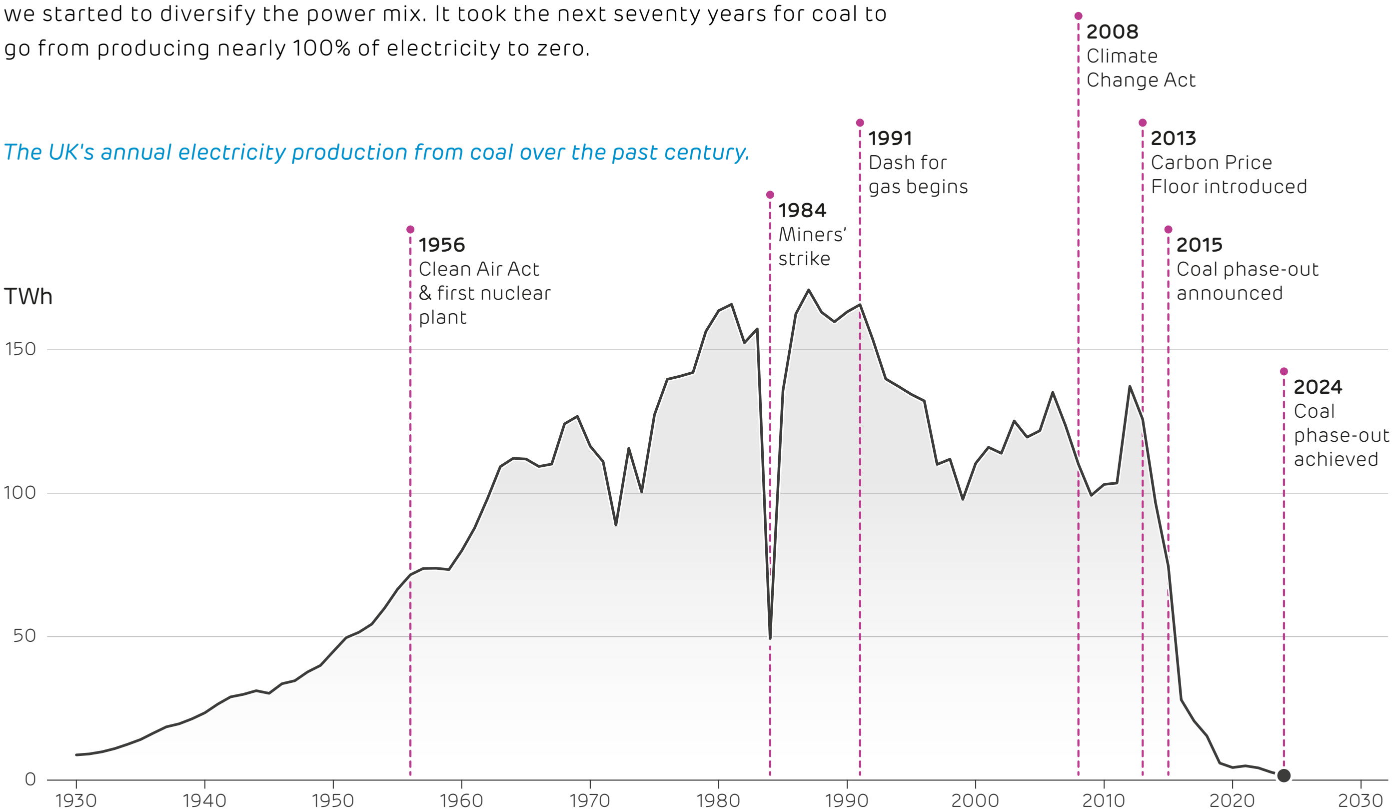
2. The UK leads the world in phasing out coal power

On 30 September at 3 PM the UK's last coal-fired power station, Ratcliffe-on-Soar, shut down for the last time. So ended 142 years of reliance on coal. This milestone makes the UK the first G7 nation to phase out coal power, and was reported around the world. We look at how the UK has phased down coal power, the impacts of its decline, and how soon other countries are expected to follow suit.

The end of coal power in the UK

Coal powered the industrial revolution. James Watts' steam engine transformed the modern world, and London's Holborn Viaduct became home to the world's first coal power station in 1882. Since 1850, we have dug up and burned some 25 billion tonnes of coal, enough to cover the entire UK 3 inches deep. For more than a century, coal was the mainstay of the UK's power system. But it was not until the Great Smog of 1952, which saw thousands killed by coal pollution, that we started to diversify the power mix. It took the next seventy years for coal to go from producing nearly 100% of electricity to zero.

The UK's annual electricity production from coal over the past century.



Absolute demand for coal power did not peak until the 1980s, when production of North Sea gas started rapidly expanding. The 'dash for gas' meant that, for the first time, gas was not only cleaner but cheaper than coal, driving the first stage of coal's decline. Progress stalled in the 2000s, but was kickstarted again in 2013, when the Energy Act blocked new coal plants from being built, and the carbon price floor rendered existing plants less competitive. Contracts for Differences (CfD) were introduced in 2014, increasing renewable capacity by 30 GW in the ten years since, and declining electricity demand reduced the need for generation, squeezing out coal further.

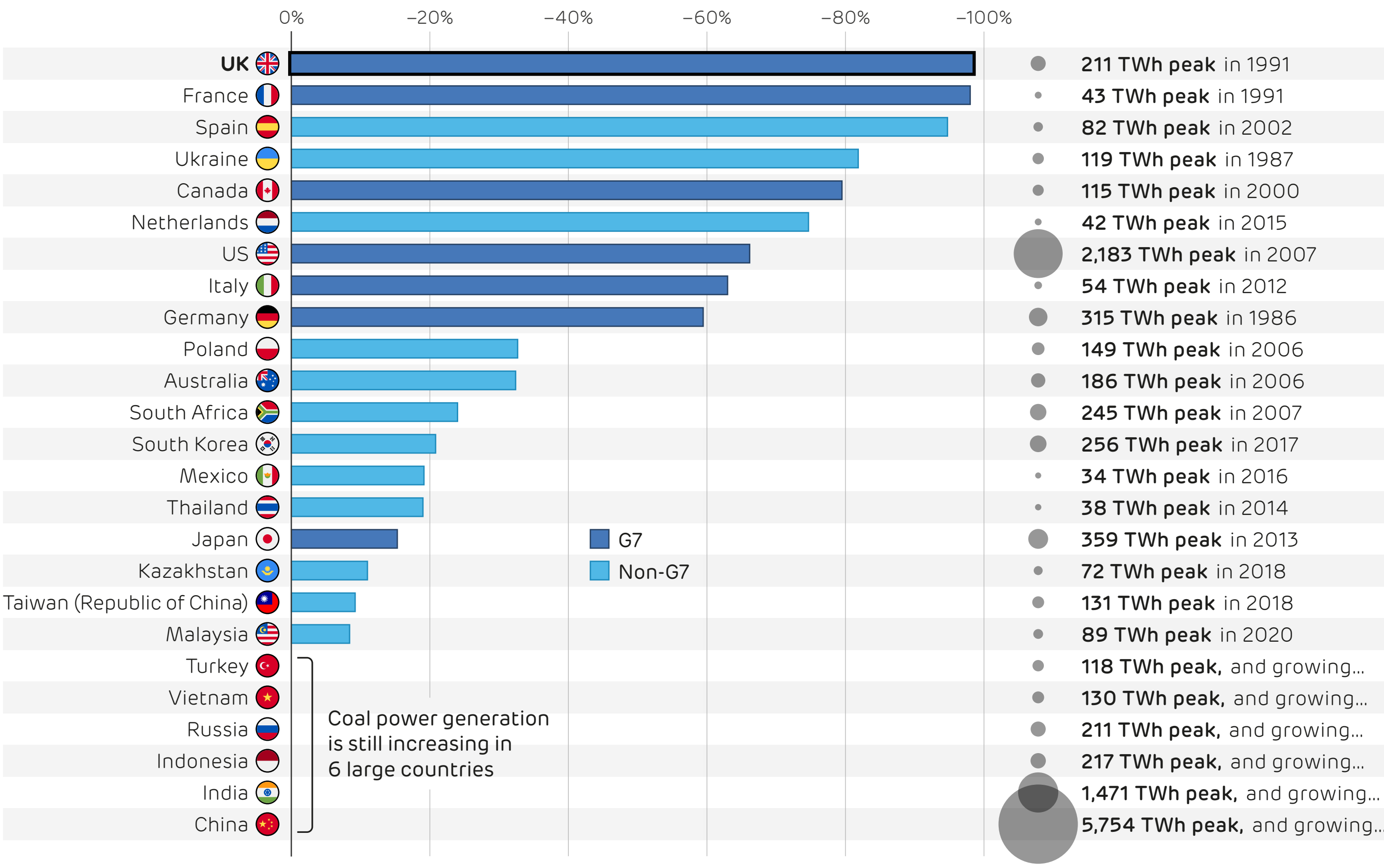
Cumulative CO_2 emissions from the UK's coal-fired power generation since 1920 stand at 9.8 $GtCO_2$, a little under China's total CO_2 emissions last year. Retirement of coal plants is responsible for one-quarter of the reduction in UK power sector CO_2 emissions since 2012. It also resulted in vast improvements in air quality. Compared with the Great Smog, sulphur dioxide and black smoke emissions in London are 100 times lower today. Fears of blackouts were commonplace when coal went into decline, yet the UK's winter blackout risk is now the lowest in four years. Yet, coal phase-out also re-shaped communities, as jobs in mining towns and at local coal plants were lost to the incoming gas and renewable energy industries. While decarbonisation brings new and consistent job growth, retraining and restructuring are essential to ensure people are not 'left behind'.

The coal phase-out league table

Among the world's largest economies, the UK tops the league table for coal phase out. As of 2023, the UK had reduced coal-fired generation by 98% from its peak, compared to a 63% average across the G7 group of rich nations. The UK is now the 5th country in the world to have completely phased out coal power, and the first large country to do so.[1]

Some of Europe is close behind, seeing more than a 90% reduction in coal generation. The US has seen its coal generation fall by two-thirds since 2007. Even countries that are synonymous with coal, such as South Africa and Australia, are burning 25% less than at their peak.

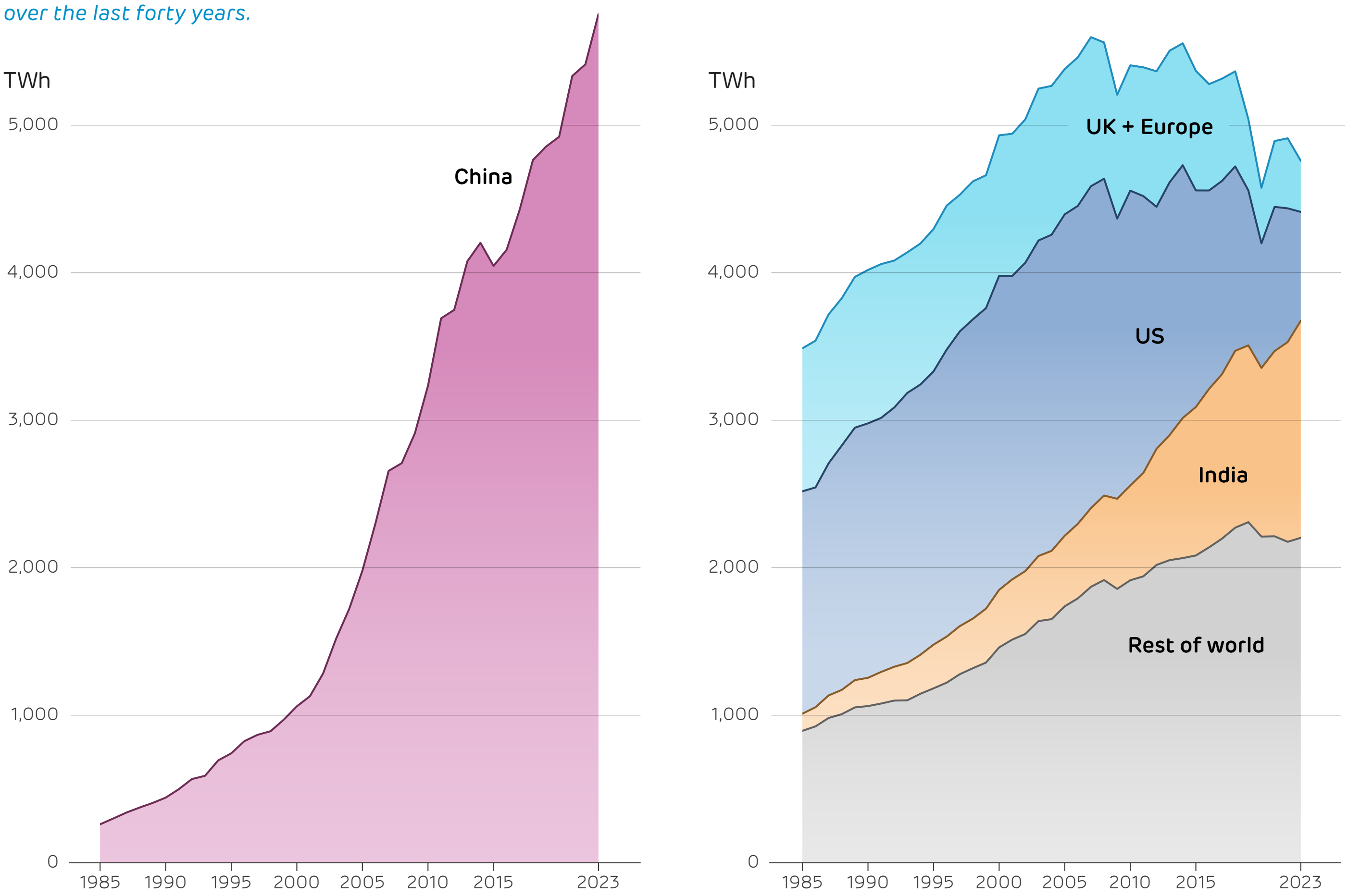
The global coal phase-out league table: Electricity generation from coal in 2023 relative to peak in the 25 largest coal-consuming countries.



1 Austria, Belgium, Portugal, and Sweden have all phased out coal, but only produced at most 5-15 TWh of coal-fired electricity this century, much below the UK's peak consumption.

However, this progress is overshadowed by the six large countries still increasing their coal-fired generation. Coal's share in the global electricity generation has dropped by just two percentage points over the past four decades. As global power demand continues to rise, total coal generation is higher than ever. China now produces more coal-fired electricity than the rest of the world combined, and was responsible for 95% of new coal power construction in 2023. Its coal generation stands at 5,754 TWh/yr, more than 20 times Britain's total electricity demand. Similarly, coal power generation in India has doubled in the last 10 years, and is now three times that of the European Union.

Electricity generation from coal in China and the rest of the world combined, over the last forty years.



After 140 years, the UK becomes just the fifth nation to phase-out coal power, showing clearly how financial incentives and regulation can combine to drive rapid decarbonisation. While this is an important step forwards, the first global stocktake, the UN's climate progress check, affirmed that the world is far off track from limiting warming to 1.5°C. At COP29, nations must build on the global pledge to 'phase-down' coal power with a firm commitment and timeline for phasing-out coal power across the world.

3. After kicking out coal, what comes next will be harder

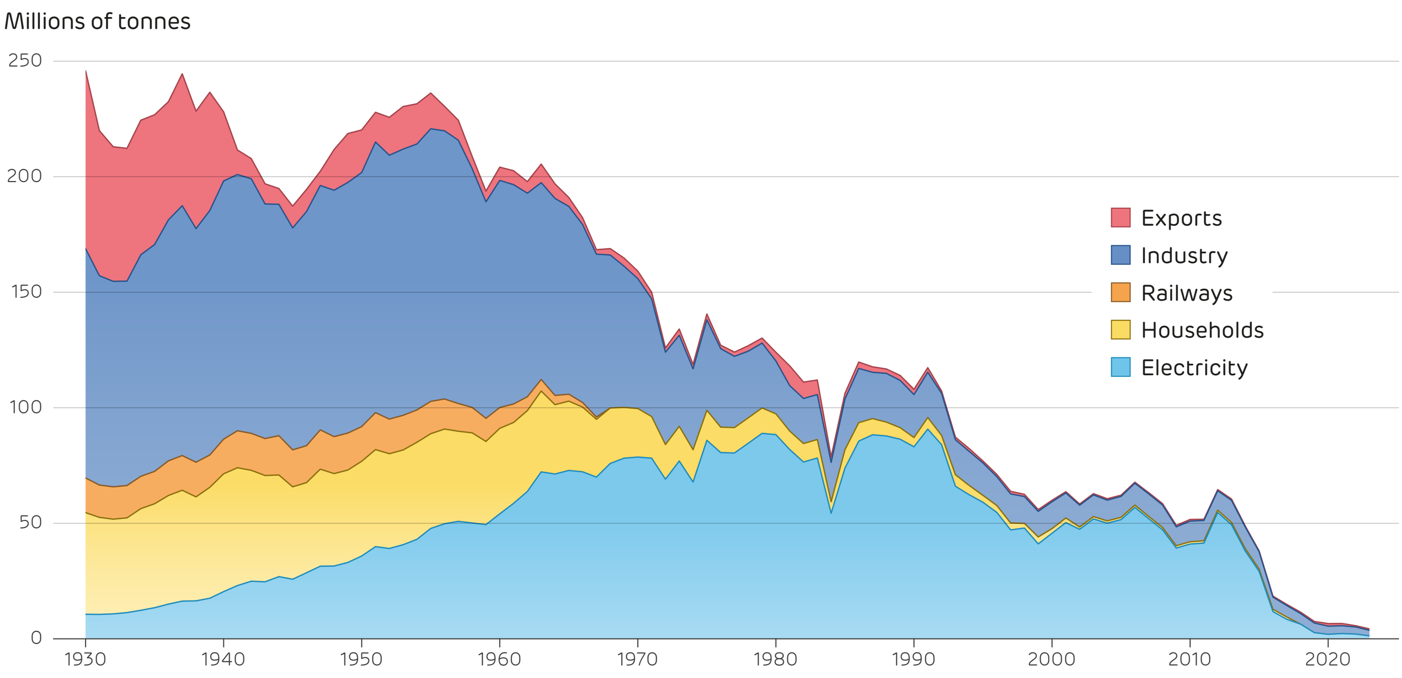
The UK's end to over a century of coal power is commendable; however, it cannot rest on its laurels. Its economy is still dependent on coal, which is used in industry and heavily embedded in the things we import. Coal is also not the only fossil fuel to worry about, for the power sector still relies heavily on gas to meet demand. So what is next for the UK? Not just in reducing its coal dependency, but in delivering a net-zero power sector.

Getting to zero coal

In 2023, UK industry consumed 3 million tonnes of coal. This was twice the amount used in power stations, but it has fallen more than 10-fold in a decade, and is just 1% of what was used in the 1950s. Around half of industry's coal consumption is in coke ovens and blast furnaces to produce steel. UK steel has been in decline for decades. In 1970, the UK was the fifth largest steel producer, but now it has fallen to 28th (behind Belgium). Only two coal-consuming blast furnaces remain in the UK at Chinese-owned British Steel's Scunthorpe mill, following the closure of Tata Steel's Port Talbot mill in September, but these may too close down by the end of the year. Both Tata and British Steel plan to replace their blast furnaces with electric arc furnaces, as the remaining steel industry moves towards a greener future.

The government has not yet announced a firm deadline to eliminate coal from all sectors, but its Industrial Decarbonisation Strategy will work towards this by promoting hydrogen and electrification for industry. The writing may already be on the wall, as economy-wide coal consumption in the UK has fallen by 23% per year over the past decade.

The UK's coal consumption and exports over the last hundred years, split by sector.

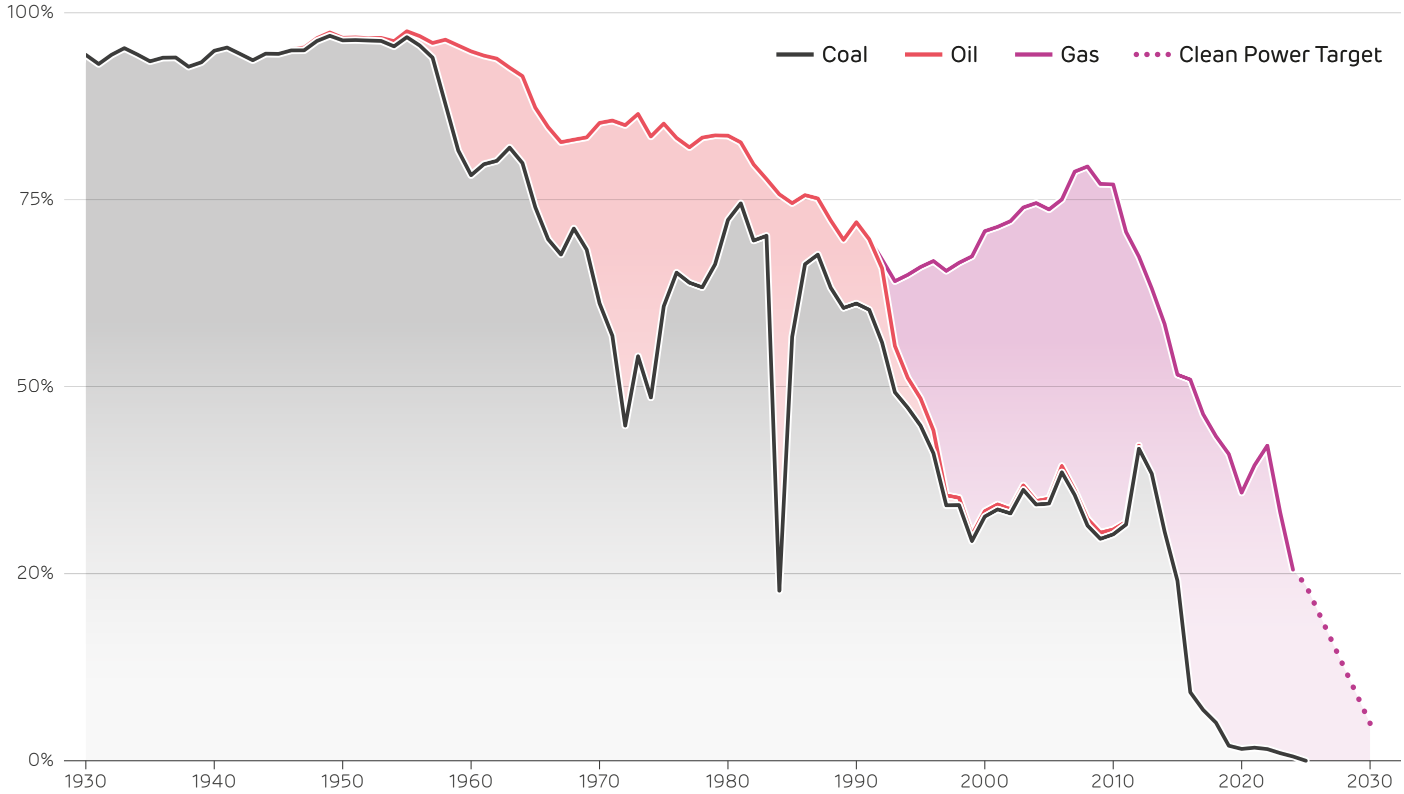


The UK has partly reduced its emissions by offshoring the most energy-intensive industries, instead relying on imports. Around one-third of the UK's carbon emissions come from imported goods. Many imported products come with a heavy coal content, as they are produced with coal-rich Chinese electricity. Carbon pricing plays a key role in decarbonisation but does not yet apply to imported products. The Carbon Border Adjustment Mechanism (CBAM), due to be introduced by 2027, is designed to ensure that embodied carbon emissions in imports are charged at the same price as domestic production, incentivising cleaner production abroad. Yet, critics of the CBAM point to higher prices for consumers and argue that it is unfair, shifting climate responsibilities onto countries with lower historical responsibility.

The elephant in the room: getting rid of gas

The Government is aiming for 100% clean power by 2030 – the most ambitious target of any G7 nation – although the enormity of this challenge has led to questions over its feasibility. The new NESO currently defines clean power as being 95% from clean sources, with the remaining 5% from unabated gas. The UK needs to reduce its share of gas from 25% to 5% in just six years. This means bulk energy generation must rapidly wind down, but provides some leeway for gas to provide essential balancing services via flexible gas turbines.

Share of the UK's electricity demand from fossil fuels, with the trajectory from 2024 to 2030 needed to meet the Government's expected definition of clean power.



Phasing down gas will be much more difficult than it was for coal. Coal was replaced partly by gas, which can operate flexibly according to demand. Now, however, gas is displaced largely by wind and solar which require other technologies, like long-duration energy storage and dispatchable thermal power, to maintain flexibility as they approach high shares. Connecting electricity generated by distant renewables to the regions that use it also requires vast grid upgrades. An alternative is to fit gas plants with carbon capture technology, allowing them to operate as before but with greatly reduced emissions. Both options require considerable investment, hence the Climate Change Committee note that the costs of decarbonisation escalate rapidly as you approach 100% clean power. The challenges are made more difficult still, as demand for electricity is expected to increase by 50% by 2035, requiring more capacity and greater flexibility to cope with bigger swings.

The target of 95% clean power by 2030 requires a rapid scale up of renewables. The Government's CfD scheme is instrumental to this transition, with the September auction delivering a record 9.6 GW of capacity. Yet, only 3.4 GW of this was new offshore wind capacity, meaning the next auction must deliver five times more capacity (16.6 GW) to meet the Government's target for 55 GW of offshore wind by 2030. The UK's progress towards its net-zero targets should be applauded, as should the new Government's ambitions to accelerate future progress. Major challenges lie ahead in delivering clean power and in decarbonising the wider economy, but the UK must lead by example as it encourages other nations to follow suit at COP29.

4. Britain to get new transmission, but bottlenecks remain

Investment in transmission infrastructure is key in reaching net zero. Grid congestion, mainly North-South between Scotland and England, has been on the rise in GB. The wasted energy due to bottlenecks is likely to reach 5 TWh in 2024, at a cost of almost £1bn per year, and set to more than triple until 2030, as Scotland is hosting the majority of the UK's onshore wind and has a 40 GW pipeline of new offshore wind (up from just 3 GW today).

To address the issues, National Grid Electricity Transmission (NGET) will invest £30bn by 2030 in grid infrastructure. As part of this investment, NGET and Scottish & Southern Electricity Networks (SSEN) are developing the Eastern Green Link 2 (EGL2) national interconnector project between Peterhead in Aberdeenshire and Drax in North Yorkshire, which will transport energy southwards, reducing the amount of wind that is wasted, and allowing more capacity to be sensibly added.

So far, the project has signed major contracts in February 2024 for HVDC cables and converter stations, was approved by Ofgem in August 2024, and commenced construction in September 2024. The project is planned to be fully operational in 2029. The project is developed alongside its sister projects, EGL1 and EGL3&4, which are yet to reach final decisions.

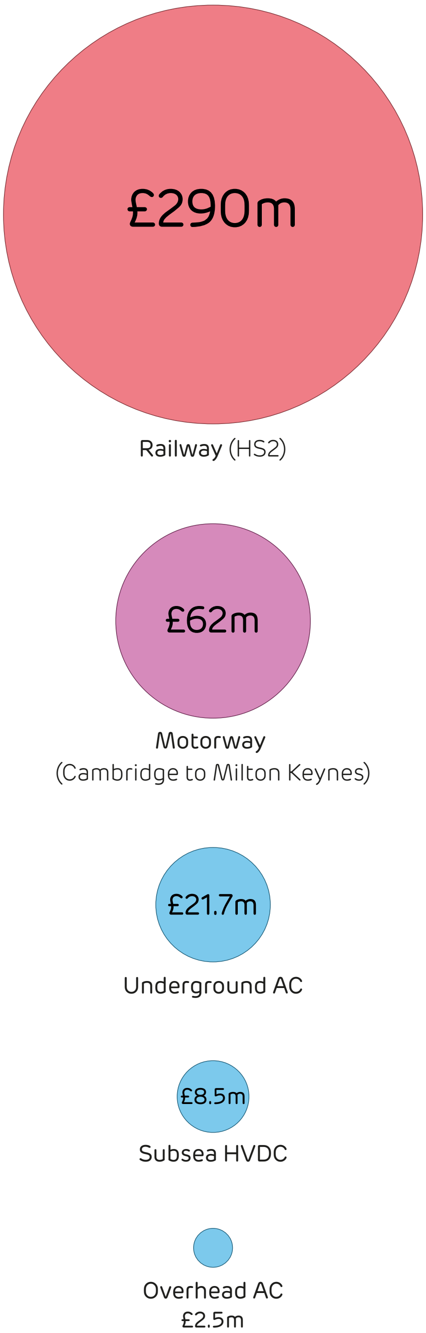
EGL2 is a 2 GW, 505 km long project, including 436 km of high voltage direct current (HVDC) cable, the longest within the UK. At an expected cost of £4.3 billion,[2] it is the single largest-ever investment in electricity transmission infrastructure in Great Britain, transporting power for two million homes.

EGL2 is mostly constructed as a subsea cable under the North Sea. This has the potential benefit of easier planning and construction, as it avoids lengthy planning disputes throughout Scotland and England, which have also blighted overland projects in other countries. Any delays in construction cost money (likely £100s of millions) in continuing to curtail wind farms, as well as additional financing and legal costs.

At £8.5m per kilometre, this project is 3.5 times more expensive than the £2.5m per kilometre cost of a 400 kV AC overhead line over land (the incumbent cabling solution). However, it is much cheaper than underground cabling at £18-25m per kilometre. While this sounds expensive (£1,000 gets you only 12 cm of the way), it is the same cost per kilometre as building a flat road in the UK, but only a fraction of the new motorway (the road equivalent to HVDC lines) between Cambridge and Milton Keynes, at £62m per kilometre, or HS2 at £290m per kilometre from London to Birmingham.

Major infrastructure costs in the UK.

£ per km



2 In 2024 currency.

EGL2 is the first of 26 projects to go through Ofgem's new Accelerated System Transformation Incentive (ASTI) framework. ASTI allows 26 new transmission projects, worth £19.7bn, to accelerate investment timelines by "up to two years" (Ofgem), streamlining the old project-by-project approach for a more holistic process.

ASTI does not solve new power stations and storage needing to wait for new wires and pylons to be built; the so-called connection queue. The reported queue is now 701 GW, likely to rise to 800 GW by the end of 2024, with similar numbers in Spain (180 GW in August 2022), Italy (337 GW in March 2024), and the US (a whopping 2.6 TW in April 2024). It is clear that most of these power plants and storage units are unlikely to be actually built. In the UK, the electricity generation from 800 GW would be quadruple of what is required in 2050. The queue is traditionally operated on a 'first come, first serve' basis, leading to problems for power plants in advanced projects that joined the queue later having to wait for less advanced projects to be connected (or removed) first. Consequently, some customers are now being offered connection dates in the late 2030s (Ofgem), which is not a serviceable arrangement for reaching net zero power by 2030.

In 2023, the Connections Action Plan to set out actions to improve the connections processes and timescales, resulting in 17 GW being offered an earlier grid connection, implementing the NESO's 'First Ready, First Connected' process (referred to as TMO41). There are also provisions in place to remove projects from the queue that do not meet their development milestones.

It is clear that the days of piecemeal infrastructure investments are numbered. The pace needed to reach net zero electricity requires a more holistic approach to grid construction, focussing on overall optimal outcomes, rather than project-by-project cost-benefit analysis. This holistic view is also expressed by the regulatory rules set by Ofgem, and can also be seen in the wider energy system, with the transition of NESO into public ownership, the implementation of Mission Control headed by Chris Stark, and incorporation of GB Energy.
If successful, it is likely that other parts of the energy sector will also be governed by increasingly holistic approaches.

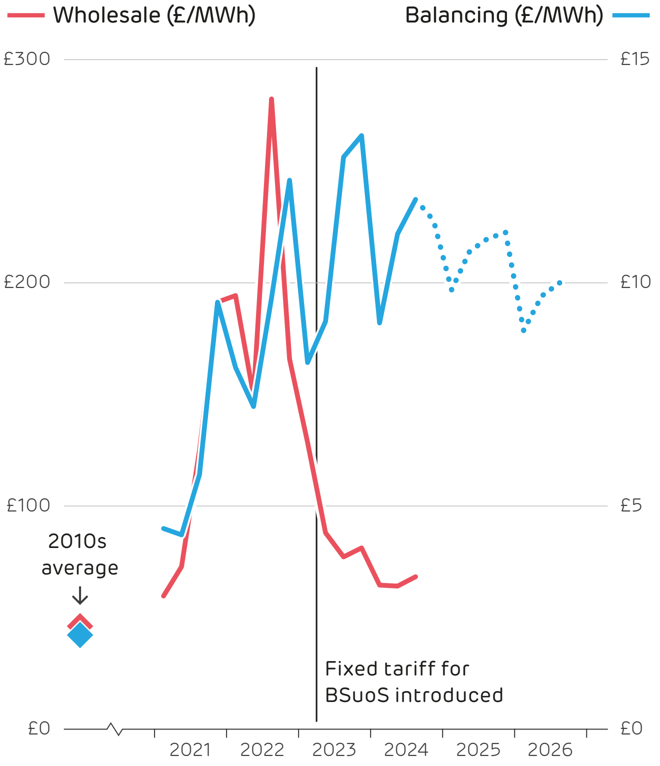
5. Forecasts and rule changes drive higher balancing costs

The cost of generating electricity has fallen two-thirds over the last two years, but the cost of keeping the grid stable has not followed suit. Balancing costs rose 30% over the same period, partly because lack of transmission increases congestion costs, but primarily because reforms have changed how consumers pay for balancing services.

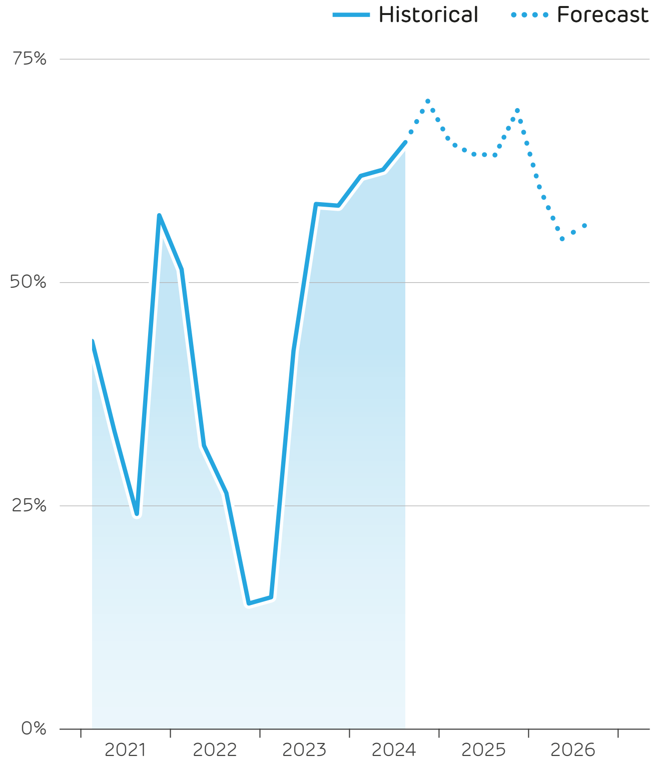
Balancing costs were stable through the 2010s, averaging 5% of the wholesale power price. They rose gradually with the share of variable renewables, as these make balancing supply and demand more complex. However, while gas and electricity prices returned to pre-crisis levels in 2023, balancing costs continued climbing to new highs. NESO forecasts they will remain above £10/MWh until 2026, five times higher than their 2010s average.

Constraint payments have contributed to this rise. Wind farms are paid to reduce output when the grid cannot handle their generation due to congestion, while gas (and other) plants elsewhere in the country are paid to increase output to compensated. Constraints accounted for three-fifths of total balancing costs so far this year, and National Grid forecasts similar levels for next year. However, constraint costs have grown steadily since 2010, so they are not the cause of last year's sharp rise.

Balancing prices decoupled from wholesale prices after 2023, and National Grid forecasts see them remaining high for years.

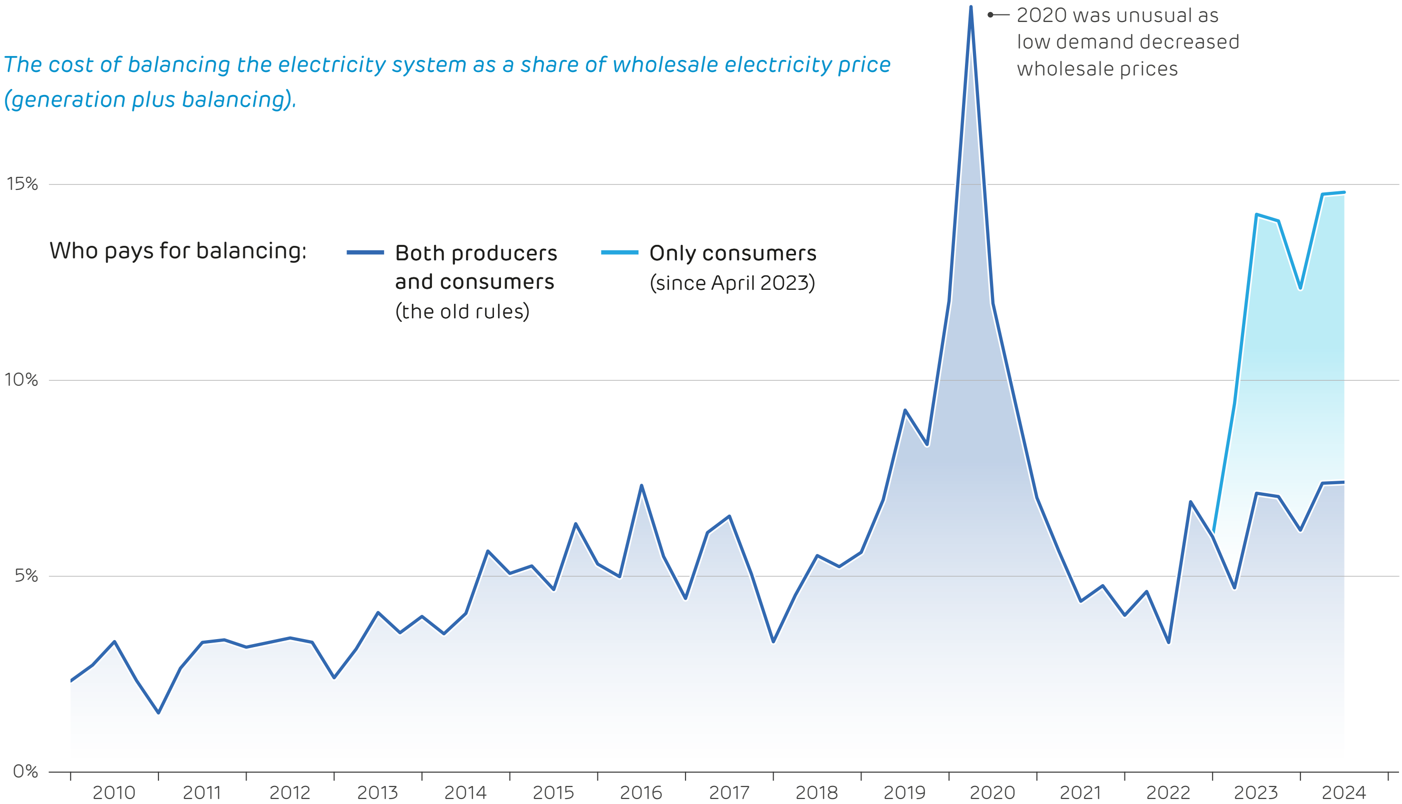


The share of total system balancing costs that come from constraint payments.



In April 2023, Ofgem made two reforms to the way balancing services are charged. First, all balancing costs are now paid by consumers, no longer split 50:50 between consumers and producers. This doubled the cost per MWh of energy as total costs are spread over a smaller group. However, as generators no longer pay for balancing, these savings could (in theory) be passed to consumers. Overall bills should remain unaffected, or may even fall as this change levels the playing field for smaller distributed and community generation projects.

The cost of balancing the electricity system as a share of wholesale electricity price (generation plus balancing).



Secondly, spot pricing was replaced with fixed charges across each half-year to increase transparency and reduce volatility on consumer bills. Charges are calculated 9 months in advance, based on a financial model forecasting wholesale prices 18 months ahead. This model expected wholesale prices hit record highs through to 2023, remaining above £150/MWh. In reality, prices fell sharply during 2023, reaching £64/MWh in 2024. As a result, NESO has over-charged for balancing services over the last year.

NESO estimated it held an £800m surplus as of April. This over-recovery of balancing charges will be returned to consumers over the coming years. NESO expects to return £270m during 2025/26, lowering balancing costs to £9/MWh. Ofgem will change how balancing costs are calculated from next year, shortening the notice period to reduce forecast errors.

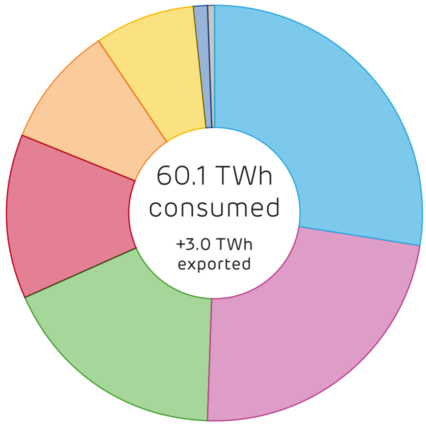
6. Capacity and production statistics

Britain's generation mix during Quarter 3 was very similar to the previous three months. Wind was the largest source, producing just over one-quarter of supply, followed by gas at just under one-quarter. The carbon emissions from electricity production again hovered just above the 100 g/kWh milestone, averaging 104 g this quarter, versus 103 g last quarter.

Gas generation fell by one third year-on-year, pushed down by increased imports from abroad, and production from biomass, solar PV and nuclear. Electricity demand was higher than this time last year, for the fourth quarter in a row.

Power demand as grown by 1.7% year-on-year, in part because prices have fallen, meaning households and businesses will cut back less on their consumption. Looking at longer-term growth, battery electric vehicles surpassed a 20% share of new car sales for the first time in August, and heat pumps have reached record sales this year. The growing stock of electric vehicles and heating will reverse the decades-long decline in British electricity demand.

Britain's electricity supply mix in the third quarter of 2024.



	Share of the mix
Wind	27.7%
Gas	23.0%
Nuclear	17.8%
Imports	12.7%
Biomass	9.4%
Solar	7.9%
Hydro	1.2%
Coal	0.4%

Installed capacity and electricity produced by each technology. [3 4]

	Installed Capacity (GW)		Energy Output (TWh)		Utilisation / Capacity Factor	
	2024 Q3	Annual change	2024 Q3	Annual change	Average	Maximum
Nuclear	6.4	~	10.7	+0.8 (+8%)	77%	89%
Biomass	3.8	~	5.6	+2.2 (+63%)	67%	100%
Hydro	1.2	~	0.7	+0.1 (+15%)	28%	78%
Wind	29.7	+0.3 (+1%)	16.6	+0.5 (+3%)	26%	65%
– of which Onshore	14.9	+0.3 (+2%)	7.1	+0.2 (+3%)	22%	54%
– of which Offshore	14.8	~	9.6	+0.4 (+4%)	30%	64%
Solar	15.7	~	4.7	+0.6 (+15%)	14%	68%
Gas	27.6	~	13.8	–6.7 (–33%)	23%	66%
Coal	0.0	–1.9 (–100%)	0.2	–0.3 (–55%)	6%	47%
Imports	9.2	~	11.0	+3.9 (+55%)	55%	93%
Exports			2.9	–0.5 (–14%)	15%	86%
Storage discharge	3.1	~	0.4	+0.1 (+23%)	6%	52%
Storage recharge			0.5	+0.1 (+19%)	8%	90%

3 Other sources give different values because of the types of plant they consider. For example, BEIS Energy Trends records an additional 0.7 GW of hydro, 0.6 GW of biomass and 3 GW of waste-to-energy plants. These plants and their output are not visible to the electricity transmission system and so cannot be reported on here.
4 We include an estimate of the installed capacity of smaller storage devices which are not monitored by the electricity market operator.

7. Power system records

Electricity generation from fossil fuels reached its lowest ever monthly average in August, falling below 5 GW for the first time. As a result, the carbon intensity of electricity reached a new low of 78 g/kWh, beating the previous record set in April by over 10 g/kWh.

Wind power came its closest ever to meeting Britain's entire demand for electricity early in the morning of 22 August. Demand was under 20 GW and wind was producing 18.5 GW, meaning Britain's interconnectors were exporting and its pumped storage charging at close to full capacity.

The tables below look over the past fourteen years (2009 to 2023) and report the record output and share of electricity generation, plus sustained averages over a day, a month, and a calendar year. Cells highlighted in blue are records that were broken in the third quarter of 2024. Each number links to the date it occurred on the Electric Insights website, so these records can be explored visually.

	Wind – Maximum	
	Output (MW)	Share (%)
Instantaneous	21,929	70.7%
Daily average	20,877	60.9%
Month average	14,525	40.4%
Year average	9,022	28.9%

	Solar – Maximum	
	Output (MW)	Share (%)
Instantaneous	10,747	35.1%
Daily average	3,788	14.5%
Month average	2,813	10.0%
Year average	1,397	4.5%

	Biomass – Maximum	
	Output (MW)	Share (%)
Instantaneous	3,831	16.8%
Daily average	3,316	12.9%
Month average	2,849	8.8%
Year average	2,216	7.1%

	All Renewables – Maximum	
	Output (MW)	Share (%)
Instantaneous	30,776	78.0%
Daily average	24,262	70.8%
Month average	18,334	51.0%
Year average	12,610	40.4%

	Gross demand	
	Maximum (MW)	Minimum (MW)
Instantaneous	60,070	16,934
Daily average	49,203	23,297
Month average	45,003	26,081
Year average	37,736	29,910

	Demand (net of wind and solar)	
	Maximum (MW)	Minimum (MW)
Instantaneous	59,563	1,365
Daily average	48,823	6,883
Month average	43,767	15,229
Year average	36,579	19,491

Day ahead wholesale price	Maximum (£/MWh)	Minimum (£/MWh)
Instantaneous	1,983.66	–77.29
Daily average	666.90	–11.35
Month average	353.36	22.03
Year average	198.16	33.88

Carbon intensity	Maximum (g/kWh)	Minimum (g/kWh)
Instantaneous	704	8
Daily average	633	31
Month average	591	78
Year average	508	148

All low carbon – Maximum	Output (MW)	Share (%)
Instantaneous	39,126	97.0%
Daily average	30,599	90.1%
Month average	23,941	75.5%
Year average	18,451	59.2%

All low carbon – Minimum	Output (MW)	Share (%)
Instantaneous	3,395	8.3%
Daily average	5,007	10.8%
Month average	6,885	16.7%
Year average	8,412	21.6%

All fossil fuels – Maximum	Output (MW)	Share (%)
Instantaneous	49,307	88.0%
Daily average	43,085	86.4%
Month average	36,466	81.2%
Year average	29,709	76.3%

All fossil fuels – Minimum	Output (MW)	Share (%)
Instantaneous	887	2.4%
Daily average	1,990	6.2%
Month average	4,831	16.8%
Year average	10,234	32.8%

Nuclear – Maximum	Output (MW)	Share (%)
Instantaneous	9,342	42.8%
Daily average	9,320	32.0%
Month average	8,649	26.5%
Year average	7,604	22.0%

Nuclear – Minimum	Output (MW)	Share (%)
Instantaneous	2,065	5.0%
Daily average	2,238	5.9%
Month average	3,292	8.9%
Year average	4,372	14.0%

Coal – Maximum	Output (MW)	Share (%)
Instantaneous	26,044	61.4%
Daily average	24,589	52.0%
Month average	20,746	48.0%
Year average	15,628	42.0%

Coal – Minimum	Output (MW)	Share (%)
Instantaneous	0	0.0%
Daily average	0	0.0%
Month average	0	0.0%
Year average	315	1.0%

Gas – Maximum	Output (MW)	Share (%)
Instantaneous	27,131	72.6%
Daily average	24,210	62.2%
Month average	20,828	54.8%
Year average	17,930	46.0%

Gas – Minimum	Output (MW)	Share (%)
Instantaneous	738	1.8%
Daily average	1,874	5.9%
Month average	4,748	16.5%
Year average	9,159	24.6%

Imports – Maximum	Output (MW)	Share (%)
Instantaneous	8,055	35.9%
Daily average	7,299	27.0%
Month average	5,557	20.8%
Year average	3,792	12.2%

Exports – Maximum	Output (MW)	Share (%)
Instantaneous	–5,662	–27.0%
Daily average	–4,763	–14.1%
Month average	–3,098	–9.8%
Year average	–731	–5.8%

Pumped storage – Maximum[5]	Output (MW)	Share (%)
Instantaneous	2,660	7.9%
Daily average	409	1.3%

Pumped storage – Minimum[5]	Output (MW)	Share (%)
Instantaneous	–2,782	–12.2%
Daily average	–622	–4.5%

5 Note that Britain has no inter-seasonal electricity storage, so we only report on half-hourly and daily records. Elexon and National Grid only report the output of large pumped hydro storage plants. The operation of battery, flywheel and other storage sites is not publicly available.

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