WILL NET ZERO REDUCE ELECTRICITY COSTS IN 2030?

Gordon Hughes

NET ZERO WATCH

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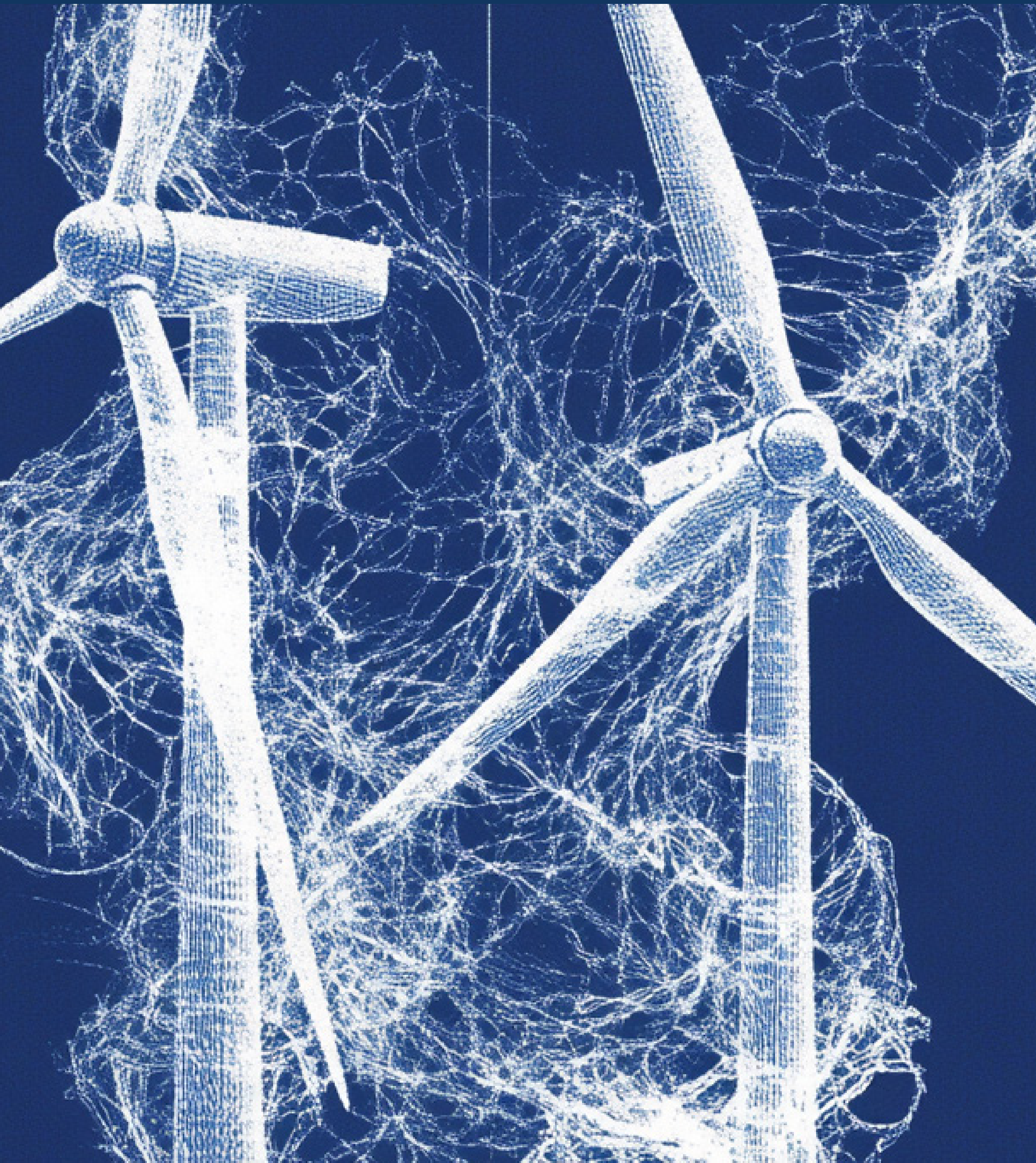

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About the author

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Introduction

In defending its policies to decarbonise, the current UK government has relied primarily on two claims. The first is that Net Zero will reduce the exposure of British electricity users to variations in gas prices, which they argue are the primary determinant of market electricity prices. The second claim is that, as a direct consequence of reducing the system's dependence on gas generation, average electricity bills will fall by a significant amount – between 10% and 20%.

This study examines both claims, drawing upon a detailed dispatch model for the GB electricity system. The model has been calibrated using generating and market data for the decade from 2015 to 2024. It has been extrapolated to 2030 under two scenarios: (a) the electricity system as it was in 2024, and (b) the electricity system described in National Energy System Operator's (NESO) Clean Power 2030 study (CP2030). The model takes account of the correlated random variations in weather conditions, exports and imports, and total demand over the 8-year period from 2017 to 2024. Further technical details of the analysis are given in the Technical Appendix, which can be downloaded via the link below.

Dependence on gas prices

The first of the Government's claims is unambiguously wrong. It reflects the extent to which policymakers get trapped by conventional wisdom and fail to understand changes in the way in which markets function. The claim may have been true a decade ago, but it has certainly not been true for the last five years. There is extremely strong statistical evidence that the primary determinants of electricity market prices in Britain are (a) the level of net imports, and (b) market prices in Germany and France.

The higher are imports, the higher are market prices. An increase in imports of 1 GW will increase the average market price in Britain by about £4 per MWh. Since the average level of net imports in 2024 was 3.8 GW, that element accounted for a little over £15 per MWh out of an average market price of £73 per MWh. The average market price in Germany (£66 per MWh) was only slightly lower than in Britain. An increase in German prices of £10 per MWh adds about £3.70 to British prices. Electricity market prices are lower in France (an average of £48 per MWh in 2024). Their impact on British market prices is weaker – an increase of £3.10 for each £10 per MWh increase in the French market prices.

It might be argued that higher gas prices in Europe push up electricity market prices in Germany and France. Any such effect would be weak. In 2024, gas accounted for less than 15% of electricity generation in Germany and less than 5% in France.

The key point is that the Secretary of State for the Department of Energy Security and Net Zero (DESNZ) does not appear to understand the first half of his department's title. Over the last decade, the British electricity market has come to rely increasingly on imports of electricity. In 2024 Britain was a net importer of electricity in 91% of hours in the year. Few would suggest that the British market's reliance on imports will fall over the next five years. Indeed, plans to build more interconnectors imply that the average level and hours of imports are likely to increase. That, on its own, will mean that British market prices are more likely to increase than to decrease.

While the commitment to decarbonise the electricity system is an additional element, the current government's policies reflect an obsession with exposure to world gas prices that goes back nearly two decades. In the mid-2000s the UK ceased to be self-sufficient in natural gas. Over time it came to rely increasingly on imports from Norway by direct pipelines, from Russia via North-West Europe, and LNG from the Middle East.

This change had two crucial consequences. First, there was a one-off increase in UK gas prices as the market switched from export parity (European prices *minus* transport costs) to import parity (European prices *plus* transport costs). Second, and very unfortunately, this switch from export to import parity prices coincided with a cyclical increase in gas prices from 2004 to 2008. The lesson that policymakers drew from this episode was that real gas prices would increase in the medium and long term. Hence, ever since the mid-2000s, the broad goal of British energy policy has been to reduce the country's reliance on gas.

The way of achieving this goal has been to use capital-intensive forms of electricity generation – nuclear power and renewables – in place of the direct or indirect use of stored energy in the form of fossil fuels. The justifications offered for this strategy have changed with the intellectual climate – from arguments about 'peak' oil and gas to emissions of greenhouse gases – but the common thread has been a conviction that gas prices will 'always' increase in future.

The current Secretary of State may be entirely sincere in his belief in the importance of Net Zero. However, the reality is that this is a veneer on the longstanding position of those responsible for UK energy policy, namely that gas will always become more expensive. Figure 1, which shows real gas prices for the quarter century since 2000, does not provide much support for this position. In each region, real gas prices have experienced occasional sharp spikes but have tended to revert to either a constant or declining mean trend. The belief that real gas prices will remain consistently high or even increase substantially over time is patently wrong.

An unstated assumption in the official story of the relationship between electricity and gas prices is that the ratio of the two is relatively stable. As Figure 2 shows, that is not true. The ratio between the market power price and the market gas price has varied from 2.17 to 4.12 over the 12 years from 2013 to 2024. The ratio tends to be relatively high when the gas price is relatively low, but the correlation is not especially strong. Further, the average ratio for the period 2013 to 2018 was 2.76, considerably lower than the average of 3.15 for 2019 to 2024 when the share of renewable energy in total generation was considerably larger than in the earlier period.

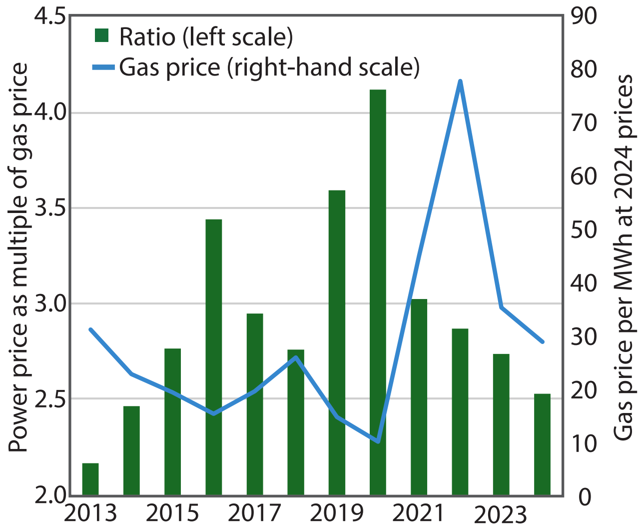

Figure 2: Power and gas prices

Power:gas price ratio (day ahead markets, left-hand scale) and gas price (right-hand scale). Source: Author's calculations based on data from Nordpool and National Gas.

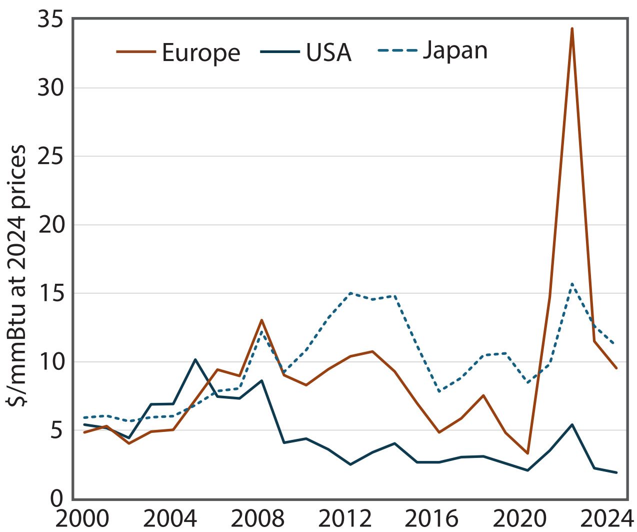

Figure 1: Real gas prices: EU, USA and Japan

Source: World Bank – Annual Commodity Prices

While it is convenient to blame the spike in gas prices for the very high prices in 2022, most commentators fail to point out that average net imports fell from 2.8 GW in 2021 to –0.5 GW (i.e. net exports) in 2022, before recovering to 2.7 GW in 2023. The major, though not the only, factor behind the large switch from net imports to net exports in 2022 was a reduction in French nuclear output, when plants had to be shut down for emergency repairs. This pushed up the wholesale prices of electricity very sharply throughout north-west Europe, an outcome that was exacerbated by a reliance on gas generation as the substitute for French nuclear power. Any benefit from the lower reliance on imports in the British market was greatly outweighed by the increase in German and French market prices.

Governments over the last two decades, including the one in which Ed Miliband was previously the Secretary of State responsible for energy, have chosen to increase the UK's reliance on electricity imports. That strategy has many advantages, but the government cannot escape responsibility for its direct consequences.

Will electricity bills fall?

To bolster the argument that Net Zero will reduce dependence on gas prices, its advocates have claimed that renewable energy is 'cheap' and will, therefore, lower the costs of electricity generation in the medium and longer term. Since solar and wind plants have until recently received large subsidies via various mechanisms, the claimed low cost of renewable generation refers to what may happen in future rather than what has been the case up to now. Again, there is heavy reliance on the idea that 2022 sets the baseline for future gas prices.

Two kinds of evidence are cited to support the assertion that renewable electricity generation is relatively cheap. One is that estimates of levelised costs for new solar and wind plants suggest that their costs per MWh of output are lower than the levelised cost of generation from gas plants (combined-cycle gas turbines – CCGTs). The problem is that such estimates rely heavily on invented assumptions for projects that will commence in 2030 or 2040 rather than actual data for recently completed plants.[1]

The second type of evidence is the outcome of auctions for subsidised generation from renewable plants. Some of these auctions suggested that developers were prepared to build new plants at offtake prices either below or close to prevailing market prices. Subsequently, there has been ample evidence of what economists call 'the winner's curse'. Successful bidders and their suppliers have reported large write-downs because they mispriced their bids. In addition, low auction prices do not allow for the system costs of managing intermittent supplies. Thus, comparing auction prices with the cost of operating, say, gas plants is a classic category error – a case of comparing apples and oranges.

Modelling system generation

To assess the claim that Net Zero will lower electricity bills, it is necessary to examine the full system costs with different generation mixes under a wide range of conditions that affect both supply and demand. This is difficult: even compiling reliable estimates of current generation costs requires a lot of work. As authors from Mark Twain to Niels Bohr have pointed out, prediction is difficult – especially about the future.

A crucial issue is how to capture the impact of variations in weather. For this assessment I have used half-hourly data on demand and generation by type from 2017 to 2024. The data have been scaled to match NESO'ss assumption of an increase in total demand of 11% in 2030 relative to 2023, together with NESO's assumptions about growth in generating capacity for renewable generators up to 2030. These and other assumptions are described in the Technical Appendix.

For each period, output from renewable generators and nuclear plants plus net imports is calculated to give base supply. This is adjusted to allow for storage – mainly batteries – which is topped up during periods of (relatively) low demand and run down when demand is high. When demand exceeds base supply, the gap is filled by backup generation. When base supply exceeds demand, the surplus is reduced using a priority list that takes account of variable operating costs, subsidy arrangements and the different situations of plants connected to the grid and distribution network. If there is still a surplus, generators receive compensation for curtailment.

The government has modified its Net Zero target for 2030 by accepting that some gas generation will be required to meet total demand and ensure the stability of the electricity system. The suggestion is that total gas generation in 2030 will be no more than 5% of total demand. That estimate appears to be rather optimistic. My analysis suggests that average backup demand, after allowing for battery storage, will be about 14% of total demand, with a range from 11% to 20% over the eight years examined.

The requirement for backup generation would be reduced if a much higher level of net imports could be relied upon, but, again, that would be very optimistic. As noted above, the interconnectors have, at different times, delivered net exports, as well as net imports. The combination of restrictions on French nuclear output and turmoil in other markets of northwest Europe had a very large impact on the British market. This and other experience have shown that the UK cannot rely upon interconnectors to balance a shortfall in domestic generation at a reasonable cost.

The consequence is that in 2030 the system will require more than 50 GW of backup gas or diesel generating capacity to match the reserve margin implied by capacity market contracts for 2024 after allowing for the contribution of battery and other storage. Currently, the system primarily relies for backup generation on a combination of (a) combined cycle gas plants close to retirement, plus (b) small gas and diesel turbines or reciprocating engines.

This arrangement would be both expensive and inefficient in 2030. Hence, I have assumed that backup generation will mainly comprise modern single-cycle gas turbines, which are relatively cheap to build on existing sites, and are designed to operate on standby. The previous government recognised that about 30 GW of new gas capacity should be built by 2030. The current government has given no indication of how it will manage this requirement. If little or no new gas capacity is built, then both system generating costs and emissions from power plants will be higher than shown below.

Generating costs in 2030

Using 2024 prices, and averaged over eight years of weather, trade and related variables, the generating cost to meet total demand in 2030 with an electricity system equivalent to the one we have today would be £28.9 billion. That figure includes the value of power at average market prices plus the cost of the Renewables Obligation and Contracts for Difference subsidies, but not the cost of Emissions Trading Scheme permits (see below). The total is equivalent to about £88 per MWh.

On a like-for-like base, the total generating cost for the Net Zero electricity system being promoted by the government for 2030 would be £42.1 billion, which is equivalent to about £128 per MWh – 45% higher. Hence, the original claim by the Secretary of State for the Department of Energy Security and Net Zero (DESNZ) that energy bills will fall by at least £300 and the more recent claim by NESO that electricity costs will fall by at least £10 per MWh seem implausible at best.

If the overall cost of meeting electricity demand is to increase by about 45%, the necessary reduction in network charges and other costs would have to be remarkably large for the overall cost of electricity to fall by a significant amount. Yet, for example, National Grid has made public statements to financial markets that it will need to invest up to £50 billion by 2030 to upgrade its transmission system to accommodate the needs of Net Zero. While there may be doubts about the feasibility of spending such large sums over six years, there can be no doubt that such investment will imply a substantial increase in transmission costs. The situation is similar for other transmission and distribution network operators.

Even though it is based on a misapprehension, Figure 3 examines the Secretary of State's argument that the Government's policies will reduce the UK's exposure to gas prices. How would that work out using average market prices and gas prices for the decade from 2015 to 2024? The estimates shown in the figure for the pricing year 2015 are calculated by running the analysis for the average wholesale electricity and gas market prices for 2015 converted to 2024 prices. The figure compares:

- total generation cost for the current system (blue)
- total cost of electricity at the average market price (orange), and
- total generation cost for the Net Zero system (green).

In each case, total demand is calibrated to match NESO's projection for 2030.

In every year except 2022, the Net Zero system has a higher total cost of generation than the current system. Over the decade 2015 to 2024 the average cost of generation under the Net Zero system will be £43.5 billion per year at 2024 prices compared to £32.4 billion under the current system. Equally important, the average cost of generation at market prices over the decade would have been £27.1 billion, even after allowing for the exceptionally high prices in 2022. To insure against one year of very high prices the Secretary of State wants to spend an average of £16.4 billion per year. This translates to an average increase of 55% in the system cost of generation relative to the average wholesale cost of electricity. The Net Zero system being promoted by current government policies can be expected to increase generation costs in nine out of ten years. It would provide a small measure of insurance against the combination of a crisis in the European gas market and closure of many nuclear plants in France, but with the certain consequence of incurring generation costs that are much higher over a decade. This seems like a rather bad bargain.

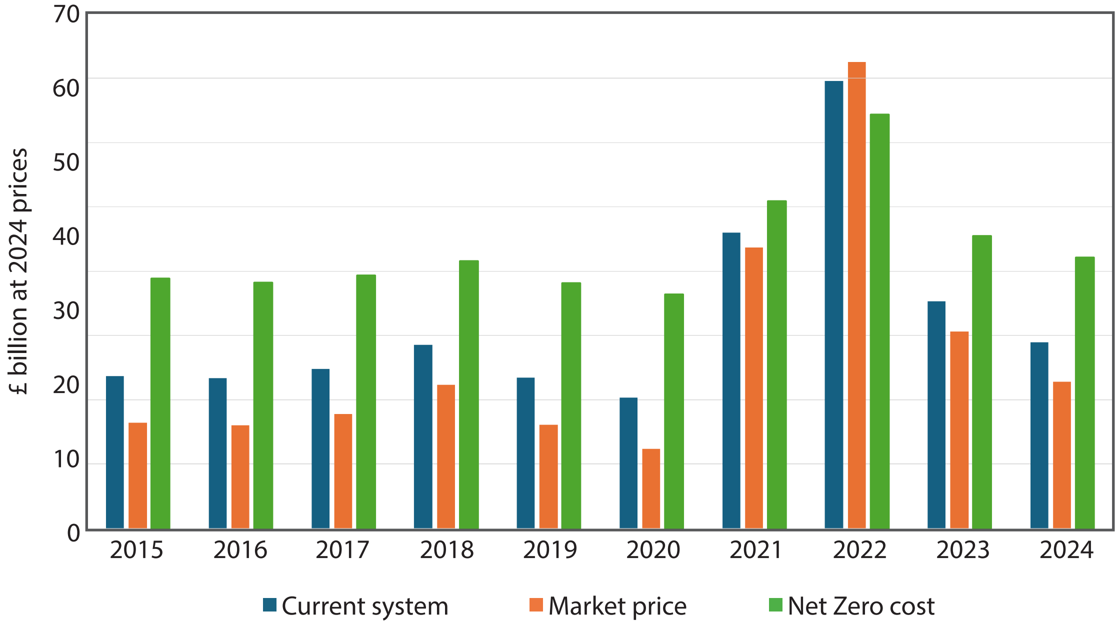

Figure 3: System costs with different systems

Source: Author's calculations.

Reducing carbon emissions

It will be argued that the Net Zero system will reduce carbon emissions, though at a considerable cost and not by as much as claimed. Still, that is not the assertion made by the current Government, which posits that its policies will *both* reduce costs *and* reduce emissions.

In fact, there is a hidden story here. Subsidies for renewable generation are only a part of green policy mix. For more than 15 years, generators burning gas and other fossil fuels have been required to purchase emission permits either via the EU Emissions Trading Scheme (ETS) (subject to a carbon price floor) or via the UK ETS that replaced it in 2021. Converted to GBP per tonne of CO_2-equivalent (tCO_2), the average permit price rose from £18 (the floor price) in 2015 to about £95 per tCO_2 in 2022, though the UK price has fallen substantially since then.

Using a standard emission factor of 0.37 tCO_2 per MWh of generation, the cost of emission permits added nearly £35 per MWh to the cost of gas generation in 2022. Applying the Secretary of State's argument, the cost of UK ETS permits pushed up the average market price of electricity from £189 to £224 per MWh in 2022. That added £11.4 billion to the cost of electricity at wholesale prices in Figure 3. The apparent advantage of the Net Zero system in 2022 is the product of emission charges whose cost escalated sharply during a period of extreme stress in the electricity market.[2]

The problem is that EU and UK policies concerning carbon taxes are an economic nonsense. It is correct to argue that there is a case for imposing a tax reflecting the economic cost of the externality caused by CO_2 emissions. However, that argument is only correct if there are *no* other interventions to promote low-carbon generation. This is not the case: both the UK and EU countries are wedded to a huge range of measures designed to promote wind, solar, biomass and other forms of favoured generation.

The result, as we have seen, is an expensive and inefficient structure of interventions in the electricity market, which have steadily pushed up the prices of electricity paid by households and businesses. To understand the full impact of measures to promote low-carbon generation, we should treat the costs incurred to purchase emission permits on a par with levies and taxes to fund renewable energy.

The average UK ETS permit price in 2024 was £37 per tCO_2. According to the plan announced in October 2023,[3] the volume of permits auctioned will fall by about 65% from 2024 to 2030. That is greater than the expected reduction of 45% in total generation from gas and other fossil fuels. Further, the share of gas generation from gas turbines (rather than CCGTs) will increase, so the average emission factor for gas generation is likely to increase by 25%, from 0.37 tCO_2 to over 0.45 tCO_2 per MWh. The net effect will be to greatly increase the share of total permits used by the electricity sector, from about 40% in 2024 to nearly 85% in 2030. It is inevitable that this will push up the real price of emission permits very sharply, since the demand for gas backup will be price inelastic.

If the UK ETS price rises to match its peak of about £100 per tCO_2 in 2022, the system cost of emission permits for electricity generation will at least double from about £1 billion in 2024 to over £2 billion in 2030, both at 2024 prices.

Other system costs

Likewise, the cost of system balancing and capacity market payments will increase sharply up to 2030. As described in the Technical Appendix, I have constructed a statistical model of period-to-period variations in balancing costs. This model suggests that the total cost of system balancing will increase from approximately £3 billion to £7.4 billion in 2030. More than 85% of this cost is directly linked to the share of generation from solar and wind plants.

The final element of the system cost of providing sufficient generation is the cost of capacity payments to ensure that the availability of firm capacity to meet system needs plus an adequate reserve margin. The levy to cover the cost of capacity payments increased from £120 million in 2017 to £1.13 billion in 2024. That cost will continue to rise. The capacity price for 2024 was £22 per kW at 2024 prices. The equivalent price for 2028 is £72 per kW. That was not sufficient to procure the amount of firm capacity needed for 2030, as the total requirement will increase by up to 20% while the potential supply is falling rapidly as plants are retired.

Experience of the PJM capacity market in the US indicates that capacity auction prices rise very greatly as the balance between supply and demand switches from excess supply to excess demand. Thus, a conservative estimate is that the total cost of capacity payments in 2030 will increase to about £7.4 billion in 2030 at 2024 prices. That reflects a capacity price in 2030 that is double the price for 2028. In the PJM market the auction capacity price increased nearly tenfold from 2023 to 2024, so such an increase is certainly not outside the bounds of the evidence available.

Summary

Table 1 summarises the results of my analysis. Total generation cost, including ETS permits, capacity payments and system balancing under the Net Zero system will be £58.9 billion, versus a total of £34.1 billion under the current (2024) system. Every element of the total cost will be substantially higher for the Net Zero system. Expressed per unit of total demand, the total generation cost will increase from £104 per MWh to £179 per MWh, an increase of 72%.

The total generation cost only accounts for about one half of electricity bills. Predicting what will happen to the other half, which covers network charges and supplier costs, is very difficult, because network operators are expected to invest heavily to extend and upgrade both transmission and distribution networks. Ofgem has squeezed the permitted rate of return on capital for networks at recent price reviews. However, operators will not agree to increase their investments, nor will they be able to raise the necessary finance, unless they are allowed a higher real return on capital. In consequence, the big uncertainty concerns how much network charges must rise to fund the investment in electricity networks assumed in the CP2030 strategy.

What is certain is that the network and supply component of electricity bills will increase alongside rising total generation costs. The only way in which electricity bills will fall is by a sleight of hand, such as transferring energy levies to gas bills or providing budgetary subsidies. Such measures do not reduce any of the costs but merely transfer them to different headings.

Table 1: Summary of system generating costs in 2030

	Total costs		Unit costs	
	2024 system	Net Zero system	2024 system	Net Zero system
	£ bn	£ bn	£/MWh	£/MWh
System generation cost	28.9	42.1	88	128
Emissions permit costs	1.1	2.0	3	6
Capacity payments	1.1	7.4	3	22
System balancing costs	3.0	7.4	9	22
Total generation cost	34.1	58.9	104	179

Author's estimates. All values in 2024 prices.

Is it true?

Many readers will be inclined to question whether such an increase in generation costs is likely to happen. I should emphasise that I am not making a forecast for actual generating costs in 2030. The figures in the table are my best attempt to compare total generating costs in 2030 under two scenarios that meet 2030 demand: (a) the electricity system as it operated in 2024, and (b) a Net Zero electricity system as described in NESO's CP2030 plan.

Some observers believe that British energy policies are formulated in a parallel universe, that is at best tangential to the world in which the rest of us live. This universe is one in which the constraints in investment and human resources do not exist. There are no queues for transmission equipment, gas turbines and wind turbines. The main operators of offshore wind farms are not cutting their investment budgets. And so on.

Reading between the lines of bureaucratic-speak, one might infer that NESO itself does not believe in the CP2030 strategy, since it relies on various implausible assumptions. Naturally, it is unwilling to speak truth to its political masters, so what we are given is fudge in large quantities.

What the analysis reported here makes clear is that implementing the CP2030 strategy will push up total generating costs considerably, almost certainly by 50% and quite probably by more than 70%. The claim that it will *reduce* electricity bills by as much as 20% is simply absurd. As a strategy to reduce the UK's dependence on gas, it is misconceived and very expensive. There is little more that can be said! Such is the nature of energy policy in the UK today.

Endnotes

1. I have written a study of levelised costs for the National Center for Energy Analytics, which will be published in the spring of 2025.

2. Sadly, this is a lesson that UK policymakers should have learned from the experience of the California market crisis of 2000–01. In that case, the probem was centred on the trading scheme for NOx permits, the price of which shot up when hydro generation was severely restricted by a drought. Californian gas plants were unable to operate profitably because of the cost of emission permits, and the system became even more reliant on imports from out-of-state plants. Because of price caps, the outcome was a period of rolling blackouts that caused great disruption to economic activity in California. UK energy policymakers have consistently demonstrated that they are unable to learn important lessons from the rest of the world.

3. https://www.gov.uk/government/news/emissions-scheme-to-reduce-sale-of-carbon-allowances-on-path-to-net-zero.

Technical Appendix

Introduction

This Appendix provides details of the simulation model and other analyses that underpin the results discussed in my paper on the impact of the current government's plans for the electricity sector on total generating costs.

The analysis makes use of a large time series database relating to electricity output and demand, interconnector flows, generation capacity, system balancing and constraints, wholesale markets in Britain and neighbouring countries, and related indicators. Many of the variables are recorded for each settlement period (30 minutes) for the trading system and balancing market, while the time frequencies for other variables vary from hourly to monthly.

The database has been constructed from many sources, some of which are public, while others are proprietary now or have been in the past. As an illustration, the two main operators of power exchanges in Europe (APX – now EPEX Spot – and N2EX/Nordpool) used to allow unrestricted access to data on hourly wholesale prices for their day-ahead and spot markets. A decade ago, they realised that such data is valuable for traders, so they started to limit the amount of data that is freely available and put restrictions on how it could be used. At the same time, they have contracts with customers such as system operators who are required by national or EU regulations to post such data to market transparency platforms. The result is multiple sources of noisy and sometimes inconsistent data that must be carefully filtered and cross-checked.

Both data management and analysis for this study have been written in Stata and its associated matrix language Mata. Stata is a commercial data management and statistical package that is used by many economists as well as by data analysts in medical and biosciences. Other data analysts prefer to use open-source software, such as R, or a programming language, such as Python, for such projects. My choice of Stata is based partly on familiarity, and partly on the combination of strong data management capabilities plus a matrix programming language that is comparable to Matlab.

Because some of the data is derived from commercial sources, I cannot make the database freely available. However, I am willing to assist researchers to reproduce the database and analysis, so long as (a) any requests are reasonable in terms of the time and effort required, and (b) any papers or other output acknowledge my work.

Finally, as for any large study of this kind, the data management and analysis is embedded in many thousand lines of code. All projects of this kind contain minor or less minor bugs. That is just a fact of life. I have done what I can to locate and correct errors as well as to validate the results of the analysis, but no-one can warrant that such an exercise is bug-free. I believe that the results reported in these papers are robust, but I am happy to make corrections if I discover that any remaining bugs have a significant impact on the results of my analysis.

Simulation model of dispatch

To estimate generating costs for a Net Zero electricity in 2030 and beyond I have built a dispatch simulation model based on half-hourly (settlement period) data for the 8 years from 2017 to 2024. The starting point are datasets published by NESO (formerly NG-ESO) and Elexon. The base data is half-hourly generation by fuel type supplemented with import-export flows over interconnectors and estimates of embedded wind and solar generation from NESO's demand dataset. Total wind generation is split between onshore and offshore plants using Elexon's Open Settlement data[1] – the ABV Settlement Final (SF) – combined with its register of BM units classified by generation type. Data on output constraints for wind farms by Settlement Period (SP) collected by the Renewable Energy Foundation[2] has been added to reported generation to obtain potential or offered generation by period and generation type.

It is easy to gain the impression from press releases from the system operator or websites such as Gridwatch[3] that the grid manager, and thus policymakers, have a detailed real-time view of the composition of electricity generation and supply for the GB market. That is rather misleading. Several of the real-time datasets are based on a combination of estimates (of uncertain and probably varying quality) or observations with a high level of missing or random numbers. After the event these errors and gaps may be corrected, but, even then, there will be significant uncertainty about the 'true' values and the retrospective error bounds.

The reason for utilising data for many periods over many years is not only to allow for variability in weather conditions but also to capture the distributions of errors in observational data. It follows that the primary outputs from the simulation model are distributions of outcomes, not point values.

The second category of data used in the simulation model concerns the capacity of generating plants of different types. In some cases, such as nuclear plants, this may be well-documented and slow to change. For other plants, such as offshore wind farms under construction, the operational capacity is either unknown or subject to significant changes within reporting periods. Finally, there are variations due to breakdowns and periods of maintenance which may be randomly distributed through the population of plants of the same type.

Generating capacity matters because the simulation model starts from the assumption that in each period plants within a given category have the same average load factor (total output divided by total capacity) in each period.[4] By applying the load factor for, say, 01 Nov 2018, SP 24 to estimates of expected total capacity of the same type in 2030 we get an estimate of output in 2030 under similar conditions. That is of limited value on its own, but when the same calculation is repeated for more than 140,000 periods the resulting distributions are useful.

The model takes account of other sources of generation including nuclear, bioenergy, and hydro. There is no period-by-period data on embedded generation from bioenergy and hydro, since official estimates of output rely primarily upon claims for feed-in tariffs (FITs), renewable obligation certificates (ROCs), and renewable energy guarantees of origin (REGOs) submitted monthly or even less frequently. Since such embedded generation must be added to both total supply and total demand, this does not affect the balance between supply and demand for the grid.

Table A1 shows the assumed levels of generating capacity in 2030 by payment type used for the dispatch model calculations. The totals match the generating capacity assumptions used by NESO in its CP2030 plan. The split between payment types is based on an analysis of data from multiple sources, including

Table A1: Low-carbon generating capacity in 2030 by payment type

	Payment type					
Category	Merchant (MW)	ROC (MW)	CfD1 (MW)	CfD2 (MW)	Drax (MW)	Total (MW)
Bioenergy	1,905	1,490	735	2,290	2,580	9,000
Hydro	1,880	–	–	–	–	1,880
Offshore wind	720	5,930	13,530	11,820	–	32,000
Onshore wind	1,860	8,980	650	13,510	–	25,000
Solar	960	16,100	40	29,900	–	47,000
Nuclear	3,630	–	–	–	–	3,630

Source: Author's estimates based on NESO assumptions.

the Digest of UK Energy Statistics 2024 (Energy Trends sections 5 and 6), Ofgem's Renewables and CHP Register, and the Renewable Energy Foundation's database of renewable generators. Almost all renewable plants built before 2017 registered for either Renewable Obligation Certificates (ROCs) or feed-in tariffs (FiTs). Only micro and small generators were eligible for FiTs, and a large share of FiT generation is used onsite, i.e. not exported to the electricity system. Since they represent a small share of total renewable generation, FiT generators have been omitted from both the demand and supply calculations.

Except for nuclear plants, the merchant generators in the table are plants that were registered for ROCs before 2010, and whose 20-year period of eligibility for subsidy will therefore have expired in 2030. The capacity estimate takes account of retirements and repowering of former ROC plants once their eligibility expires.

The assumed share of embedded generation by category varies from zero for nuclear power to 10% for offshore wind to 77% for solar. Over 95% of solar capacity was embedded in 2024, but that share will fall as larger solar plants are built to meet the NESO target and are required to connect to the transmission grid rather than to distribution networks.

There is a long queue for grid connections, so there are important reasons to doubt whether the NESO assumptions about new renewable generating capacity can be achieved. As a result, the figures in Table A1 are *not* a forecast of how things will turn out in 2030. Instead, they provide a basis for examining the claims made by DESNZ and NESO if their assumptions are correct.

The other side of the same calculation is total demand – not just demand for grid generation but also demand supplied by embedded generation – plus net imports or exports. Total demand is adjusted to match NESO's projections for 2030. On an annual basis, the adjustment factors vary from 1.051 for 2017 to 1.181 for 2024.

The issue of electricity trade is a little more complicated. Annual average interconnector capacity increased from 4.0 GW in 2017 to 9.8 GW in 2024, Annual average gross trade increased from 2.6 GW in 2017 to 6.2 GW in 2024, so the usage factor declined marginally from 68% in 2017–18 to 61% in 2023–24. A simple linear projection suggests that gross trade in 2030 will be 7.4 GW. That is used to adjust gross import and export flows for 2017 to 2024.

Gross imports or exports rarely utilise the full capacity of interconnectors. Supply and demand considerations usually determine flows rather than interconnector capacity. The assumption that interconnectors can, in effect, be used to balance surpluses or deficits in GB domestic generation is quite misleading.

It is more accurate to view interconnector links to the continent as the primary source of marginal supplies to the GB market.[5] In 2024 net imports from the continent into the GB market were positive in 92.5% of settlement periods. Thus, GB market prices are determined in most settlement periods by the willingness of traders in continental markets to supply the GB market.

The consequence is that GB market prices are primarily determined by the import parity cost of supplies from France, the Low Countries and Norway/Denmark. The Secretary of State's frequent claims that GB market prices are set by gas prices do not reflect current market conditions. The market has changed over the last decade. Of course, gas prices play a role in setting prices in West European electricity, but supplies from nuclear, hydro, wind and coal generators are more important in many periods.

In 2024 the day-ahead price was negative in 2% of settlement periods and was less than £5 per MWh in 3.3% of settlement periods. Such low prices suggest that the market was over-supplied with generation from sources with zero or low marginal costs. Still, in 42% of periods in which the day-ahead market price was less than £5 per MWh, net imports were positive and 10% of such periods net imports exceeded 3.4 GW. Presumably, either contractual or physical constraints prompted market participants to continue to supply imports even though prices were below the typical cost of transmission.

Since such considerations are very hard to model, the analysis assumes that (a) imports are zero when there is surplus generation, and (b) exports are zero when backup generation is required.

Battery storage

Alongside the projected increase in renewable generation, NESO expects that there will be a large increase in the capacity of battery energy storage systems (BESS) from 4.7 GW at the end of 2024 to 27.1 GW in 2030. New BESS installations in the UK tend to be 2-hour systems, i.e. their total storage capacity is 2 times their declared discharge rates. I have assumed that total BESS capacity in 2030 will be 54.2 GW, which is more than 8 times the BESS capacity at the end of 2024.

The simulation model assumes that BESS storage capacity is charged during periods of surplus generation and discharged when backup generation would otherwise be required. Even with a large increase in BESS storage capacity, batteries do little more than time shift the availability of, primarily, solar generation from periods of relatively low demand to peak periods. Over an average year they reduce the number of hours for which backup generation is required, but only by 10–15%.

An analysis that I carried out when writing a paper on the variability of electricity prices published in January 2025 by the Renewable Energy Foundation indicated that the expected storage margins for battery systems from arbitraging market prices were far below the costs of building and operating such systems.[6] The analysis assumes that BESS operators trade in the day-ahead market daily to maximise their net revenues from storage. On a small scale this is feasible, but with up to 27 GW of short-term BESS trading the daily distributions of prices will change to reduce storage margins. Thus, the calculations shown in the paper are the best possible outcome. By 2030 storage margins are likely to be considerably lower than they were in 2023.

The growth in BESS capacity will only occur to the extent that a large part of the fixed costs of new installations are covered by either capacity payments or subsidies. NESO applies a derating coefficient of about 20% for 2-hour BESS systems, meaning that 1 GW of nominal BESS capacity is treated as equivalent to 200 MW of firm capacity. At current or expected future capacity prices, revenues from capacity payment will not fill the gap between fixed costs and storage margins. This means that to meet NESO's expected increase in BESS capacity it will have to offer large additional payments – i.e. subsidies – to developers.

Backup generation

NESO, along with anyone else who has examined the prospects for power generation in 2030, recognizes that it will be necessary to rely heavily on gas plants to provide backup generation capacity in 2030. NESO has suggested that total gas capacity of 35 GW may be sufficient. That would not provide a adequate reserve margin to meet conventional standards of system reliability.

Figure A1 shows the distribution of hours in an average year for different amounts of backup capacity that will be required in 2030 under the base Net Zero scenario. To understand the figure, it shows that at least 8 GW of backup capacity will be required for 2,400 hours in an average year or roughly 27% of settlement periods. More than 20 GW of backup capacity

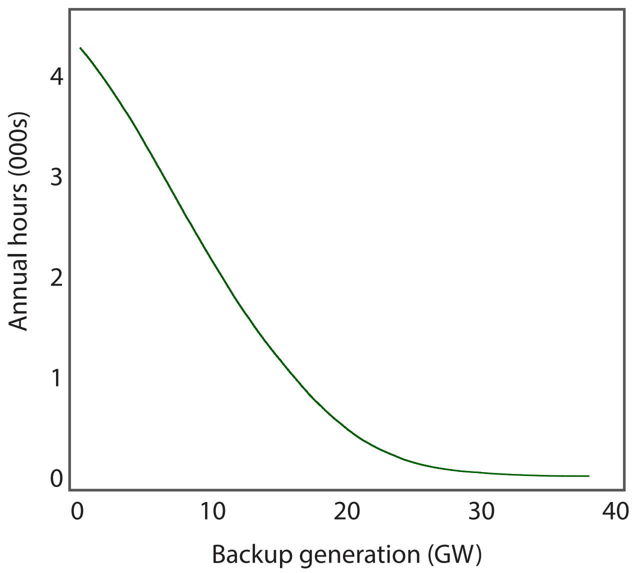

Figure A1: Backup capacity by annual hours
Source: Author's estimates

will be required for 500 hours in an average year. There is a small but positive probability that the amount of backup capacity required will be 40 GW. If a conventional reserve margin of 10% of grid demand is applied, then the amount of backup capacity available should be close to 50 GW.

Where would this gas capacity come from? In recent capacity market auctions the amount of firm gas capacity offered has been falling and is likely to be little more than 25 GW. There are several proposed CCGTs under development in the UK, but recent experience is that most of them are delayed or cancelled once the developer has to make a final investment decision. The market price of existing CCGTs is much lower than the cost of building new plants.[7] It is very unlikely that there will be significant market-driven investment, even allowing for 15-year capacity contracts, in new CCGTs within the next 5 years.

The most recent edition of the Digest of UK Energy Statistics (DUKES) shows that by 2030 only 6.9 GW of gas CCGTs will be less than 20 years old, while 14.5 GW will be more than 30 years old. It is costly and difficult to keep old CCGTs ready for backup operation, since they may incur high start-up costs. Environmental regulations may force the retirement of many plants or restrict the number of hours in the year that they can operate.

The alternative source of firm generation capacity – the fleet of open-cycle gas turbines (OCGT) – is even older, with only 230 MW less than 30 years old. Many OCGTs burn gasoil rather than gas, so both their thermal efficiency and emissions per MWh tend to be high.

With limited exceptions, the current fleet of gas plants in the UK does not match the 2030 requirement to provide high efficiency backup for renewable generation. If it is assumed that ten CCGT plants built since 2008 with 11.4 GW might continue to operate, alongside 120 GW of OCGT capacity built in the same period, that leaves a requirement for 30–35 GW of new backup capacity.

As the time available for such an investment program is barely five years, the only feasible option would be to install either industrial frame (H class) combustion turbines (CTs) or aeroderivative CTs at existing generating facilities. Industrial CTs are usually much cheaper per unit of capacity and should have a lower level of fuel consumption per unit of output. However, the lead time for delivery of new turbines varies greatly with global demand, and may be quite lengthy. Aeroderivative turbines are quicker to build, as well as having shorter start-up times and higher ramp rates in operation. Hence, they may be more suitable for occasional use, but they have higher fixed and variable O&M costs.

In practice, some mix of industrial and aeroderivative CTs would be required to implement an accelerated program of developing new backup capacity. The average cost would probably be between £0.6 million and £1 million per MW of capacity depending on the mix of turbines chosen. For a 15-year contract the cost of backup capacity would be £90 to £120 per kW per year, depending on existing infrastructure and type of plant.

The problem in relying upon such a program to provide the backup capacity required in 2030 is the longstanding inability of the government bureaucracy to act either competently or expeditiously. While the re-use of generating sites and infrastructure should shorten development times and reduce costs, regulations on carbon capture would have to be waived. Contracts would have to be awarded before all permits are granted to allow operators to place orders for turbines quickly.

Guaranteeing that sufficient backup capacity is available to meet the foreseeable requirements of a Net Zero system in 2030 is a political choice. It could be done but there is every indication that the current government is either not convinced of the necessity or is unwilling to spend the political capital required to ensure that it is done.

Surplus generation

In contrast with periods when some amount of backup generation is required to meet total demand, there are a smaller number of periods when the base supply of electricity from renewable sources (bioenergy, hydro, solar and wind) plus nuclear power plus net imports exceeds total demand plus use for charging batteries. The simulation model deals with such periods by moving down the marginal cost curve, i.e. successively excluding types of generation with the highest offer prices.

In the simplest cases the offer price for a generator will be the marginal cost of operating a plant – primarily the cost of fuel plus any variable O&M costs. Typically, bioenergy and hydro plants have higher offer prices than solar and wind either because they use fuels such as wood chips that must be purchased or because there is an opportunity cost of using a limited stock of water or gas that could be used in another period when demand and the market price is higher.[8] Solar and wind plants have offer prices that are zero or very close to zero.

There is another layer on top of basic production economics that affects the offer prices for different generators. This arises from the role of subsidies and/or power purchase agreements (PPAs). To simplify the analysis the model assigns each type of generator to one of four subsidy and price categories:

- Merchant generators. These plants, directly or indirectly, receive an off-take price that is linked to the wholesale market price. In most cases they are older plants whose subsidies or other support arrangements have expired. The current fleet of UK nuclear plants fall into this category. They have relatively low variable costs and in 2024 they did not reduce output significantly when market prices were below £5 per MWh.
- Generators receiving ROC or FiT payments. These plants receive very generous top-up payments, which for solar plants can be £130 per MWh at 2024 prices. For practical purposes they have no incentive to reduce supply under any but the most extreme market conditions. Since ROC generators receive ROCs for 20 years, any plant built after 2010 will still fall into this category in 2030.[9]
- Generators on CfD Type 1 contracts up to the third round of CfD auctions (AR3). These receive what are, in effect, guaranteed prices for 15 years. Prior to AR4 there is no restriction on payments when the market reference or day-ahead price becomes negative. These plants include the Hinkley Point C nuclear plant as well as some biomass plants, though not Drax – see the note above.
- Generators on CfD Type 2 contracts from AR4 onwards. For these plants CfD support is withdrawn if the market reference price becomes negative. This could mean a substantial withdrawal of capacity from the market when there is surplus generation. However, renewable generators claim that they have not built any significant loss of revenue into their financial models. This seems at odds with experience in Germany where negative prices are increasingly common – nearly 10% of hours in 2024. Generators may believe that, in some way, they can insure themselves against the loss of CfD payments when there is surplus generation. Since no plants with AR4+ contracts had started operation by the end of 2024 and more than 2 GW of such plants have cancelled their contracts, no-one knows how CfD Type 2 plants will respond to negative market prices in practice.

The model assumes that surplus generation will drive down market prices, and that this will prompt merchant generators from reservoir hydro, pumped storage, and bioenergy (including Drax) to reduce their output, either by enough to eliminate the surplus or down to zero. A combination of variation in plant characteristics and random factors will mean that price-responsive withdrawal of generation is likely to be gradual rather than discontinuous.

The same behaviour is likely to apply to merchant generators with very low or zero marginal costs. In principle, they have an incentive to continue to generate so long as the market price is positive, but in practice many may conclude that it is better to reduce wear and tear on their plant by reducing or switching off units when market prices are very low, especially if low prices will persist for several periods.

Hence, the model treats merchant solar and wind plants as being price-responsive, albeit only when prices begin to approach zero.

Unfortunately, the situation is entirely different if the generating surplus remains after price-responsive generation has withdrawn from the market. The incentives for generators with CfD Type 2 contracts change abruptly if the market price falls below zero, even by a very small margin. So long as the market price is zero or positive they would plan to produce as much as their resources – solar, wind or bioenergy – permit. However, the structure of CfD Type 2 contracts implies that all of these generators are expected to switch off immediately when the market price becomes negative.

My analysis suggests that there will be negative market prices because of surplus generation after all price-responsive generation has switched off in 15.5% of periods in 2030 or roughly 1,350 hours. In each of these periods the projected amount of CfD Type 2 generation exceeds the surplus generation, so switching off all CfD Type 2 generation would more than eliminate any surplus generation and lead to a requirement either for imports or backup generation to fill the gap. But, why would either importers or backup generators supply the market if market prices are negative?

The conclusion is that the CfD Type 2 contract is likely to lead to a profoundly unstable market structure in 2030. The discontinuity of supply built into the contract means that there is no stable market outcome that can be sustained during periods when potential generation from all sources exceeds total demand.

It is unclear whether NESO and/or DESNZ understand the issue, and whether they have any capability to rectify the contractual incentives that give rise to it. A pessimistic – or realistic – view is that no action will be taken until the indicators of market instability become too obvious to ignore. That is unlikely to be before a significant number of CfD Type 2 solar and wind farms have started to operate in the late 2020s.

At that point, the obvious solution will be to introduce some kind of out-of-market arrangement by which CfD Type 2 generators are paid (generously) to switch back on. Alternatively, the contractual clause prohibiting CfD payments when the market reference price is negative could be suspended and generators might be paid to be curtailed at the convenience of the system operator. The latter would be a more expensive solution, but it would be easier to implement under current arrangements. In essence, it would be an extension of the current constraint payment mechanism.

Figure A2 shows the distribution of surplus generation by expected average hours in 2030. The expected annual total of surplus generation is 6,200 GWh – this is the area under the curve shown in the figure. In monetary terms, if NESO were to pay an average of £100 per MWh to compensate generators for curtailing output, the average annual cost would be £620 million. This is a substantial amount, albeit small in relation to some of the other costs of operating a Net Zero electricity system.

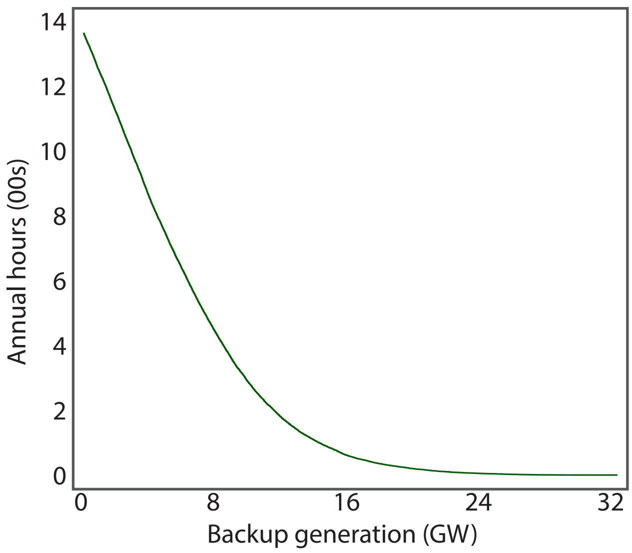

Figure A2: Surplus capacity by annual hours
Source: Author's estimates

Market prices

Attempting to forecast market prices for 2030 is an arbitrary and almost certainly vain exercise. One crucial reason is that the day-ahead price in the UK market is largely the volume of imports and market prices (converted to GBP) in Germany and France. The best fitting linear regression for hourly data in 2024 is:

$$\text{Day-ahead price} = 17.0 + (0.0041 \times \text{Imports}) + (0.37 \times \text{Price}_{DE}) + (0.31 \times \text{Price}_{FR})$$

in which prices are measured in £ per MWh and imports in MW. The t-ratios on the coefficients are all greater than 36 and the adjusted R-square is 0.69. These results indicate a very strong estimated relationship, but they mean that prices in 2030 cannot be forecast without making strong assumptions about imports and markets in key European countries.

For this reason, the estimates of generation costs reported here are based on 2024 market prices and subsidies adjusted for volume changes up to 2030. The average wholesale market price in 2024 was £72.6 per MWh, and the average wholesale gas price was £28.7 per MWh. Table A2 shows average wholesale market prices converted to 2024 prices derived from the Nordpool day-ahead market for electricity and the system average price for gas. The average ratio over the decade of the wholesale electricity price to the wholesale gas price was 3.08. The ratio in 2024 was 2.53, the lowest value over the decade. This suggests that any expectation that average electricity bills can be reduced without a significant fall in gas prices is exceedingly optimistic.

Table A2: Wholesale market prices 2015–24

	Electricity (£/MWh)	Gas (£/MWh)
2015	53.1	19.2
2016	52.0	15.1
2017	57.2	19.4
2018	71.2	25.8
2019	52.1	14.5
2020	40.8	9.9
2021	136.1	45.0
2022	223.9	78.0
2023	96.4	35.2
2024	72.6	28.7

Average wholesale prices (£2024). Source: Author's estimates based on data from Nordpool and National Gas.

Support for renewable generation

Over the last two decades there have been three main forms of support for renewable generation:

Feed-In Tariffs (FiTs)

This scheme, introduced in 2010, guarantees an offtake price for micro and small generators. The recipients of FiTs are embedded generators, and most of the costs of this support are borne by energy suppliers who are allowed to recover the costs via their charges. The scheme was closed for new installations in 2019. It was replaced by the Smart Export Guarantee scheme under which energy suppliers are expected to buy power exported to the grid. The export prices are set by the energy supplier but are usually close to the wholesale price. FiTs were particularly attractive for small solar installations, which resulted in a surge of applications in the mid-2010s. Consequently, FiT rates for solar were sharply reduced in 2016 and the number of applications was restricted. Most FiTs last for 20 years, so total output produced under the scheme will tail off after 2030. The overall cost of the scheme was £1.86 billion in 2023-24. Since FiT rates are indexed-linked, this total will increase with inflation but from its peak in 2021 total output supported by FiTs will gradually fall as installations deteriorate and become less productive as they age. By 2030, FiT-supported generation will be about 2% of total generation. Since the cost of the scheme will be the same for both scenarios and is covered by energy suppliers, I have omitted this support from the calculations.

Renewable Obligation Certificates (ROCs)

The ROC scheme was the primary form of support for renewable generation for small, medium and large plants from 2002 until it was closed in 2017. Generators received differing numbers of ROCs per MWh of output. For example, the number of ROCs per MWh received by ground-mounted solar plants started at 2 and gradually fell to 1.2

for plants registered after April 2016. The original design was that the value of a ROC would be set by market trading, but that notion was rapidly discarded. Instead, a managed system, in which the value of ROCs was set by a buyout price, was instituted. In effect, the Obligation was converted into an implicit tax on electricity use whose revenue was recycled to renewable generators in proportion to the number of ROCs which they earned. The buyout price in 2024 was £64.73 per ROC. The tax on electricity use rose from £12.90 per MWh in 2015-16 to £31.80 per MWh in 2024-25.

Eligibility for ROCs expires 20 years after initial accreditation so by 2030 all plants registered up to 2010 will have dropped out of the scheme. Hence, the output from ROC-supported generators is falling over time as plants registered in 2002, 2003, … transfer from being supported by ROCs to operating as merchant generators. Some – perhaps many – of them will cease to operate either because they can no longer cover their operating costs or because it is more attractive to repower sites with new equipment. Repowered sites are not eligible for continued or extended receipt of ROCs. Instead, they must apply for CfD support.

In the calculations, the payment per MWh for each type of ROC generator is calculated as the average market price plus the buyout price for 2024–25 multiplied by the average number of ROCs awarded per MWh of output for the type of generation. The average number of ROCs per MWh were calculated using data from Ofgem's Renewable and CHP Register[10] plus the Renewable Energy Foundation's database of renewable generators.[11]

Contracts for Differences (CfDs)

CfDs were introduced in 2014. Technically, a plant with a CfD contract receives (or refunds) a payment equal to the difference between (a) the market reference price (the day-ahead wholesale price), and (b) a strike price which is adjusted annually by inflation and for changes in network charges paid by the plant. For all but a small number of 'investment' contracts awarded at the outset of the scheme, the base strike price at 2011-12 prices is determined by intermittent auctions. The auction rounds are referred to as AR1, AR2 up to the most recent AR7 held in 2024. The CfD contracts for each round are lengthy but were, initially, poorly drafted, so that the contracts were little different from option agreements. In more recent rounds DESNZ has tried to tighten up the contracts but bidders have better lawyers and continue to game the system, especially with respect to schedules of when the contracts come into effect.

For practical purposes, CfD contracts offer generators a 15-year index-linked price guarantee at the point where power is delivered. The arrangements for most offshore wind farms are more complicated, but CfD contracts are designed to minimise the risk associated with offtake prices. The scheme is administered by the Low Carbon Contracts Company (LCCC) which maintains a register of CfD contracts.[12]

As discussed above, there is a crucial difference between Investment and AR1-AR3 contracts and those awarded from AR4 onwards concerning eligibility for CfD payments when the reference price is negative. Under AR4+ contracts generators will receive no CfD payments if the market reference price is negative. Currently there are no operating plants that have AR4+ CfD contracts, but there may be many such plants by 2030. As is consistently the case with the CfD scheme, the policy decision to make this change was not properly analysed. Negative prices were thought to be a very infrequent edge case, and no thought seems to have been given to how the wholesale market would function if the wholesale price is negative for 10% to 15% of all periods in a year. If, as my analysis suggests, this outcome is very likely in 2030, the provisions of AR4+ contracts are likely to give rise to a high degree of market instability.

Faced with this outcome, the terms of AR4+ contracts will almost certainly have to be changed retrospectively or NESO will have to introduce a mechanism to compensate generators that would otherwise wholly withdraw from the market when the reference price is negative. For AR7 the government effectively allowed earlier contracts for offshore wind to be amended because of concerns that operators might either (a) cancel projects that had been awarded earlier CfD contracts, or (b) withdraw from bidding for new projects. Those concerns have increased as several large operators have stated that they are reducing their investment budgets for offshore wind.

It is, therefore, reasonable to assume that the provisions of AR4+ contracts will be amended to permit some payment to be made when the reference price is negative in return for allowing NESO to curtail excess output without compensation. Hence, the calculations assume that the AR4+ generators will receive their regular CfD payments for whatever output is required to meet total demand during periods when there is surplus renewable generation.

The average prices per MWh paid to CfD generators used in the calculations are based on the LCCC's projections of average strike prices at 2024 prices for plants that are expected to be operating by 2030.

Table A3 shows the expected average revenues per MWh of output at 2024 earned by generators receiving different types of support. ROCs are particularly generous, especially for offshore wind. The expected average revenues for CfD2 assume that the strike prices for future allocation rounds are similar to those for AR7.

Table A3: Average revenue in £ per MWh at 2024 prices

	ROC (£/MWh)	CfD1 (£/MWh)	CfD2 (£/MWh)	Drax (£/MWh)
Bioenergy	150.3	163.8	72.6	72.6
Nuclear	–	124.6	124.6	–
Offshore wind	195.6	113.8	75.5	–
Onshore wind	130.9	79.2	79.2	–
Solar	153.5	79.2	79.2	–

All figures in £/MWh at 2024 prices. Source: Author's estimates.

Emission permits

For more than 15 years, generators burning gas and other fossil fuels have been required to purchase emission permits, either via the EU Emissions Trading Scheme (ETS) – subject to the UK's carbon price floor – or via the UK ETS, which replaced it in 2021. Converted to GBP per tonne of CO_2-equivalent (tCO_2), the average permit price rose from £18 (the floor price) in 2015 to about £95 per tCO_2 in 2022, though UK emission permit prices in the UK have fallen substantially since then.

Using a standard emission factor of 0.37 tCO_2 per MWh of generation, the cost of emission permits added nearly £35 per MWh to the cost of gas generation in 2022. Applying the Secretary of State's argument, the cost of UK ETS permits pushed up the average market price of electricity from £189 to £224 per MWh in 2022. That added £11.4 billion to the cost of electricity at wholesale prices. The apparent advantage of the Net Zero system in 2022 is the product of emission charges whose cost escalated sharply during a period of extreme stress in the electricity market.

Both the UK and EU countries are wedded to a huge range of measures designed to promote wind, solar, biomass and other forms of favoured generation. The result, as we have seen, is an expensive and inefficient structure of interventions in the electricity market, which have steadily pushed up the prices of electricity paid by households and businesses. To understand the full impact of measures to promote low carbon generation, we should treat the costs incurred to purchase emission permits on a par with levies and taxes to fund renewable energy.

The average price of UK ETS permits in 2024 was about £37 per tCO_2. According to the plan announced in October 2023,[13] the volume of permits auctioned will fall by about 65% from 2024 to 2030. That is greater than the expected reduction of 45% in total generation from gas and other fossil fuels. Further, the share of gas generation from gas turbines rather than CCGTs will increase so the average emission factor for gas generation is likely to increase by around

25%, from 0.37 tCO_2 to over 45 tCO_2 per MWh. The net effect will be to increase the share of total permits used by the electricity sector very sharply, from about 40% in 2024 to nearly 85% in 2030. It is inevitable that this will push up the real price of emission permits very strongly, since the demand for gas backup will be price inelastic.

If the UK ETS price rises to match its peak of about £100 per tCO_2 in 2022, the system cost of emission permits for electricity generation will at least double, from about £1 billion in 2024 to over £2 billion in 2030, both at 2024 prices.

Balancing costs

Until April 2023 balancing costs were charged 50% to generators and 50% to electricity suppliers – or, in effect, to electricity consumers. That arrangement was changed in April 2023 with all balancing costs being charged to electricity suppliers, so the BSUoS (Balancing Services Use of Service) charging rate paid by consumers roughly doubled at that point.

Ofgem claimed that there would be no effect on customers on the grounds that generators would no longer include balancing costs when bidding into the wholesale market so that market prices would fall by the same amount as the increase in balancing costs paid by customers. That argument would only be true in a market without exports and imports.

As I have pointed out elsewhere in this analysis, the marginal supplies to the UK market come from imports over interconnectors. Prior to April 2023 BSUoS charges were not applied to interconnector supplies, which gave interconnector imports an advantage relative to domestic generators. To the extent that interconnector imports remain the marginal supplies to the market, the effect of transferring BSUoS charges from generators to consumers was to benefit generators at the expense of electricity consumers.

Technically, the amount of the benefit received by generators depended on the supply elasticity of electricity imports. This is just a version of the classic incidence analysis used by fiscal economists when examining the impact of commodity and similar taxes. That it is necessary to point this out illustrates the dangers of relying upon a regulator who appears not to understand routine pieces of economic analysis.

There is a further complication. In parallel with the change in the application of BSUoS charges, Ofgem introduced a smoothing mechanism by which the BSUoS charging rate per MWh was fixed for 6-month periods. Actual balancing costs are charged to a balancing fund which is replenished by the fixed BSUoS charge with the surplus or deficit being paid back or recovered via the BSUoS in the next 6-month period. There are provisions for within-period adjustments if the cumulative balancing costs exceed predefined limits.

This arrangement is a variant of schemes for commodity price stabilisation that have been used since the 1950s. Experience shows that such arrangements work reasonably well for a period but almost always fail due to a combination of market stresses and political interference. The likelihood is that the balancing charges stabilisation fund will eventually fail in a messy way sooner or later.

To focus on the underlying costs, I have used the balancing costs reported by NG-ESO and now NESO for each 30-minute settlement period for more than 2 decades. I have assumed that via some arrangement these costs are paid by electricity users. The annual sum of balancing costs adjusted to 2024 prices has increased from about £1.3 billion per year in 2012–2014 to £3 billion in 2024. They were higher still in 2021-23 due to the spike in electricity market prices with a peak of about £5.1 billion in 2022. Balancing costs are affected by the spot market price for electricity since the system operator must buy electricity at, roughly, spot market prices to balance the system in aggregate as well as to offset constraints in the transmission system.

In order to estimate the likely level of balancing costs in 2030 I have estimated an econometric model of the determinants of balancing costs in each settlement period. It is a revised version of the analysis discussed in a paper entitled 'Renewable generation and the costs of balancing the UK's electricity system', which I wrote with co-authors in 2017. The total cost of system balancing at 2024 prices is estimated as a function of the system price, the outputs of wind and solar generators (plus their squares), temperature and variables reflecting the time of day, weekends and winter months. The system price is treated as an endogenous variable so the econometric model used instrumental variables to correct for the bias that would otherwise arise.

The crucial result is shown in Figure A3. The cost of balancing the electricity system increases consistently with output for both wind and solar generation. That pattern has prevailed since the mid-2010s and there is no likelihood that it will change over the next decade. The marginal cost shown in the figure is the average increase in balancing costs in a settlement period for each addition of 1 MWh of output from wind and solar generators.

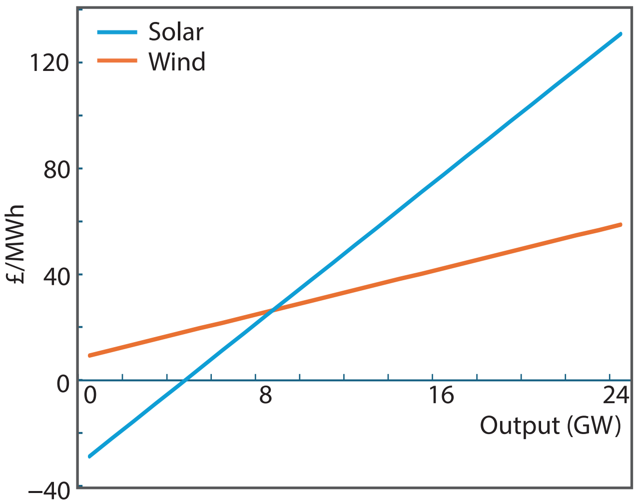

Figure A3: Marginal balancing cost vs wind and solar output
2024 prices. Source: Author's estimates using NESO data.

The average output from wind generators in 2024 was close to 10 GW. At that level the marginal balancing cost was about £30 per MWh. By 2030 that average output from wind generation will increase to close to 18 GW, so the marginal balancing cost for wind generation will increase to over £46 per MWh. That implies a substantial increase in total balancing costs.

The pattern for solar is more complicated. At low levels of solar generation, increasing solar output reduces balancing costs. The reason is that most solar generation is embedded, so additional output reduces system demand for the grid. If that reduction is not too great, solar output benefits the grid by reducing the need for balancing. However, too much of a good thing creates instability, so that for solar output above 4 GW the marginal balancing cost is positive and increases rapidly with additional solar output.

In 2024 the average level of solar output was less than 3 GW during periods when solar output was greater than zero, so overall solar output reduced balancing costs by a modest amount. However, in 2030 the average level of solar output will increase to nearly 8 GW. The costs of system balancing due to solar generation will increase very sharply.

In aggregate, the cost of system balancing is projected to increase from about £3 billion in 2024 to about £7.4 billion at 2024 prices in 2030. Of that cost, about 86% will be due to wind and solar generation, up from 66% in 2024.

Capacity market

The capacity market is a scheme, administered via auctions organised by the Low Carbon Contracts Company, to compensate generators for ensuring that there is sufficient secure generating capacity to meet periods of peak demand. The nominal capacity of generating plants is 'derated' to allow for the probability that plants will be able to deliver supplies during periods when there may be a shortfall between total supply and available supply – in the jargon these are called 'stress events'. Applying the derating factor to nominal capacity gives what is called Equivalent Firm Capacity (EFC).

The primary capacity auctions in recent years have focused on procuring what is called T-4 capacity, i.e. plants which are contracted to be available in 4 years' time. Thus, the T-4 auction that will conclude in 2025 refers to capacity that will be available in the operating year from October 2028 to September 2029. The critical sub-period is the winter months from November 2028 to February 2029. Hence, in considering costs for the Net Zero system in 2030, what will matter is the capacity auction that should conclude in 2027 for the year 2030-31. There will be a further T-1 or 1-year ahead auction in 2029 which can be used to adjust the amount of capacity procured for 2030-31.

Recent T-4 capacity auctions have had a target of 40–44 GW of firm capacity. However, the margins between the amount of EFC offered and the target amount to be contracted has narrowed in the 2020s. As a consequence, the market clearing price has risen very sharply. For example:

- For the T-4 2024–25 auction 51.9 GW was offered, 40.8 GW was contracted. The auction price was £18.00 per kW per year at 2019–20 prices.
- For the T-4 2025–26 auction 48.6 GW was offered, 42.4 GW was contracted. The auction price was £30.59 per kW per year at 2020–21 prices.
- For the T-4 2026–27 auction 46.0 GW was offered, 43.0 GW was contracted. The auction price was £63.00 per kW per year at 2021–22 prices.
- For the T-4 2027–28 auction 43.4 GW was offered, 42.8 GW was contracted. The auction price was £65.00 per kW per year at 2022–23 prices.

For the current auction round with a T-4 delivery year 2028-29, the target is a minimum EFC of 42.5 GW at the price cap of £75 per kW per year at 2023-24 prices. Based on last year's auction results it seems very likely that the price cap will apply but the amount procured will fall below the target EFC. This would be an almost automatic consequence of the change in the base year for price indexation.

Looking ahead to the delivery year 2030-31, one thing is clear. An EFC target of, say, 42 GW is far too low if total demand is expected to growth by 18% relative to 2024, as NESO expects. On a simple pro-rata basis, the amount of EFC contracted should increase to at least 50 GW. The derating factors for gas-fired and oil-fired capacity – CCGTs, OCGTs and reciprocating engines – fall in the range 91% to 93%, so a 50 GW EFC would translate to roughly 55 GW of nominal gas-fired or similar capacity.

About two-thirds of contracted capacity in recent auctions has been supplied by such plants. The total nominal capacity of gas-fired and oil-fired plants available to bid in the capacity market was about 31 GW and this is declining at a significant rate. Further, the amount of nuclear capacity is expected to fall and there is little or no growth in sources such as hydro, pumped storage and energy from waste. Total battery capacity is expected to increase to 27 GW by 2030, or an EFC of about 5.5 GW.

Thus, the capacity auction for 2030-31 will require at least 15 GW from interconnectors and demand-side response. Both are either expensive or of doubtful reliability. For 2027-28 interconnectors are the second largest source of capacity at 6.6 GW. Demand side response amounts to 1.1 GW but barely 20% of that is classed as 'proven'.

The treatment of interconnectors as 'firm capacity' makes little sense. The issue is not really about the availability of transmission but whether anyone is contracted to supply power during a stress event. Norwegian electricity companies are under no obligation to export power via the North Sea Link when it is convenient for the UK. The transmission may be fully functioning, but the companies may prefer to export to Germany or the Netherlands because they can earn more by exporting to other parts of Europe.

Interconnectors should only be treated as firm capacity when the operators of the interconnectors can demonstrate that there are contingent contracts with electricity suppliers which guarantee the delivery of power over the interconnectors under specified conditions. Such contracts will have a price, which is likely to be high. They imply that the contracted suppliers must forego more profitable opportunities to supply other markets or domestic pressure to give priority to the suppliers' home markets.

A large increase in demand side response (DSR) raises similar issues. In the past, the classic sources of DSR were manufacturing plants and other facilities with backup generators, so that DSR was effectively a way of mobilising spare backup capacity. However, the decline in energy-intensive manufacturing combined with hostility to reliance on backup generation relying on oil or gas will largely eliminate such sources of DSR. Instead, DSR must rely upon substantial immediate incentives and/or contracts that allow remote control of energy-intensive appliances. This is possible but usually it is considerably more expensive than relying on standby generating plants.

The conclusion is that to get an adequate quantity of genuine firm capacity the current price cap of £75 per kW per year must be increased by enough to cover the cost of bringing new capacity into the auction. Suppliers can offer firm capacity on 3-year and 15-year contracts but the price caps that have applied to these – £175 per kW for 3-year contracts and £340 per kW for 15-year contracts – are well below the costs of building new standby plants.

Considering the evolution of capacity prices from T-4 2024-25 to T-4 2026–27, the capacity auction price more than tripled in real terms from £19 to £63 (at 2021 prices) as the market tightened. Hence, it is conservative to assume that the capacity auction price is likely to at least double in real terms by 2030–31. That would imply a capacity price of £145 per kW per year at 2024 prices. For 50 GW of EFC the total capacity cost would be £7.3 billion in 2030–31.

As context, it is interesting to compare these numbers with the results of the most recent capacity auctions for the PJM market in the US. The PJM market covers the Mid-Atlantic region stretching from New Jersey to Virginia and as far West as Illinois. The population served by the PJM market is about 65 million people, similar to the size of the GB market. The T-1 capacity auction for 2025–26 resulted in a price of $98,500 (about £79,000) per MW per year at 2025 prices for most of the PJM area.

However, prices for Maryland and Virginia were considerably higher at £136,000 and £130,000 per MW. While these PJM prices were much higher than auction prices in previous years, there is a strong possibility that capacity auction prices for parts of the PJM area will be greater than £100,000 per MW per year. This would be for a market where there has been a much higher level of investment in gas-fired generation over the last decade than in the UK.

Endnotes

1. https://www.elexon.co.uk/data/open-settlement-data/
2. https://www.ref.org.uk/constraints/
3. https://gridwatch.co.uk/
4. I have adjusted the average load factors for relatively new (< 8 years) and old (> 15 years) wind plants. New wind plants tend to have higher average load factors because they have greater hub heights, which increases the average wind speed at hub height. Older wind plants have lower average load factors because of the effect of age on both availability and yield. The same adjustment is applied to older solar plants.
5. Flows to and from Ireland over the Moyle, East-West and Greenlink interconnectors tend to be determined by the state of the Single Electricity Market in Ireland.
6. https://www.ref.org.uk/attachments/article/385/Electricity-tariffs-variability.final.pdf
7. As an example, one of the major developers, EPH UK, purchased the Langage and South Humber CCGT plants with a total capacity of 2.3 GW from Centrica in 2017 at a price of £318 million. This was under £140,000 per MW, less than 15% of the cost of building a new plant at the time.
8. There is a difference between run-of-river hydro and storage or pumped hydro. Run-of-river plants have little storage and would have to spill water if it is not used for generation. Storage hydro plants whose reservoirs are full face the same choice. Such plants are like solar and wind plants in having a very low or zero marginal cost. However, for the model the potential error from treating all of the grid-connected hydro supplying the GB market as having a positive opportunity cost of water is very small.
9. The situation of the 4 Drax biomass units is complicated. Drax has received a combination of ROCs and CfDs with a messy set of arrangements covering different units. Its eligibility expires in 2027, so Drax and the UK government have announced a preliminary agreement for revised arrangements from 2027 to 2031. Both the Parliament Statement by DESNZ and the press release by Drax are vague and often incoherent, so the outcome is uncertain. In practical terms, it seems NESO (understandably) wants to ensure that all 4 Drax units will operate unless there is a surplus of renewable plus nuclear generation.
10. https://renewablesandchp.ofgem.gov.uk/
11. https://www.ref.org.uk/energy-data
12. https://www.lowcarboncontracts.uk/our-schemes/contracts-for-difference/register/
13. https://www.gov.uk/government/news/emissions-scheme-to-reduce-sale-of-carbon-allowances-on-path-to-net-zero.

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